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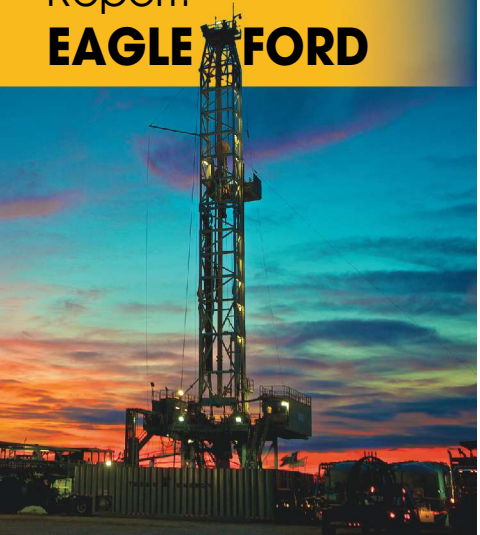

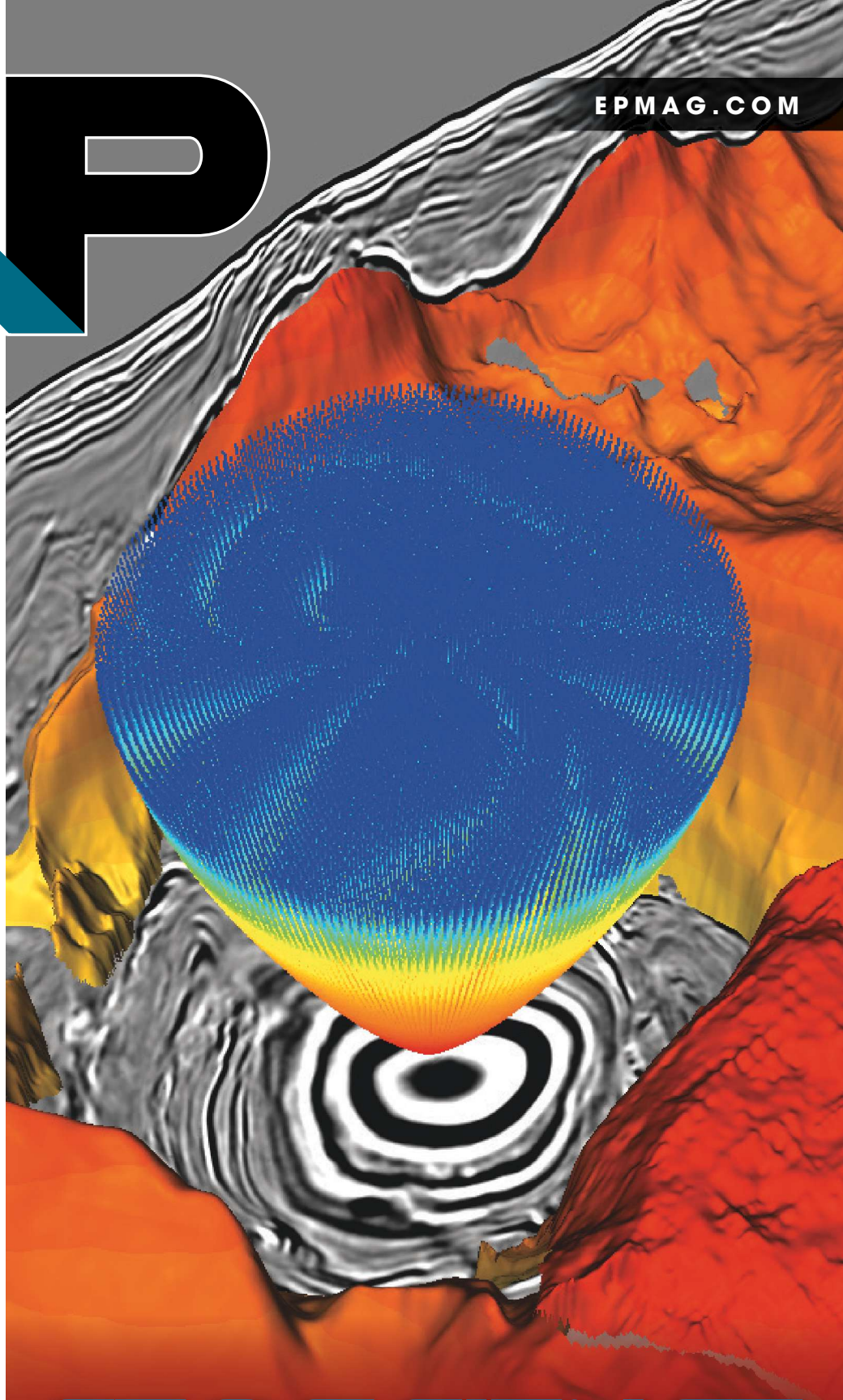

GEOSCIENCE MATTERS

Experts discuss the challenges and possibilities

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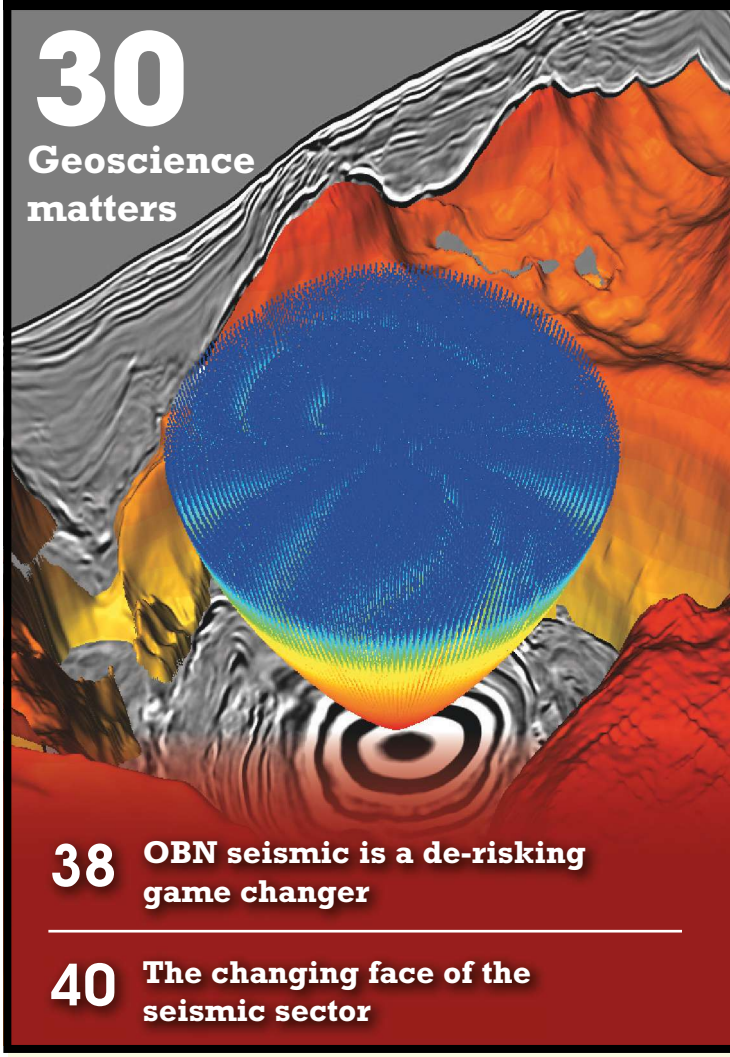

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COMING NEXT MONTH The November issue of ***E&P*** will focus on Big Data analytics and applications. Other features will cover presalt/subsalt, land rig advances, pressure pumping, emissions management and topsides solutions. The unconventional report will focus on the Denver-Julesburg Basin. 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 Ray bundles from a complex Gulf of Mexico salt body are used for migration velocity analysis. Cloud-based computing provides a scalable solution for resourcing the computer capacity necessary for complex imaging problems. Left, a ConocoPhillips drilling rig operates in the Eagle Ford Basin. *(Cover photo courtesy of Fairfield Geotechnologies; Left photo courtesy of ConocoPhillips; Cover design by Felicia Hammons)*

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ACTIVITY HIGHLIGHTS Subscribe at **EPmag.com/subscribe**

Anschutz schedules 10 Cretaceous wildcats in Johnson County, Wyo.

Anschutz Oil Co. has scheduled 10 horizontal wildcats targeting four Cretaceous zones on two common drill pads in a western Powder River Basin. The ventures in Johnson County, Wyo., will evaluate Cretaceous Niobrara, Sussex, Frontier and Muddy formations.

Offshore Sicily exploration approved for Vesta prospect

Cabot Energy Plc has received approval of its environmental impact assessment for an exploration well to be drilled on the offshore Sicily Vesta prospect.

Three Parkman wells completed at drill pad in Powder River Basin

Devon Energy Corp. completed three horizontal Parkman producers from a common drill pad in the southern Powder River Basin. The pad is in Section 28-37n-71w of Converse County, Wyo.

AVAILABLE ONLY ONLINE

BHGE, TechnipFMC talk survival of the fittest in digital era

By Mark Venables, Contributing Editor

Adapt to survive was the mantra preached by oil and gas service companies at ONS 2018. Executives from TechnipFMC and Baker Hughes, a GE company (BHGE), spoke on what it takes to thrive in the modern digital era.

Insight: Southern GoM frontier oil, gas exploration faces challenges

By Velda Addison, Senior Editor, Digital News Group

The geology of what is being called a largely frontier area could present obstacles for operators searching for oil and gas.

Oil, gas industry faces two-tier future for funding E&P activities

By Mark Venables, Contributing Editor

As the oil price continues to climb from recent lows, there is a higher demand for funding. However, some smaller players face a challenging funding landscape, according to financial experts speaking at ONS 2018.

Podcast: 'Women in Energy' Ep. 3—owning the table

By Jessica Morales, Video Reporter, and Emily Patsy, Associate Managing Editor, Digital News Group

Hart Energy's "Women in Energy" podcast is back with another installment focused on managing from the top level and the path of one industry executive to leading her own company.

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One billion reasons

The endless potential of the Gulf of Mexico's deepwater resources attracts a new player.

The exodus of experienced offshore operators from the U.S. Gulf of Mexico (GoM) to drier lands farther inland created a vacuum of sorts for the basin. So when the news broke in August of Kosmos Energy's foray into the GoM with its purchase of Deep Gulf Energy (DGE) from private-equity investment firm First Reserve, I did a double take. The international E&P company, known for its success offshore West Africa with its TEN and Jubilee projects and at Greater Tortue with BP, has found its entry point into the GoM.

"With many competitors leaving the Gulf of Mexico to chase onshore shale plays, a huge opportunity has opened in the basin. The best deepwater assets can compete with the best of shale, and now is a good time to enter the Gulf of Mexico," said Andrew Inglis, chairman and CEO for Kosmos, in a press release.

By acquiring DGE for total consideration of $1.2 billion, Kosmos will see about an additional 25,000 boe/d increase in its production numbers along with about an 80 MMboe increase in its 2P reserves, according to a press release.

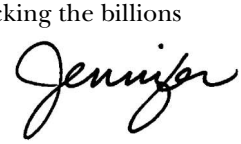
By entering the GoM, the company has placed itself in a good position to apply the geologic and technologic lessons learned offshore Ghana, Mauritania and Suriname in a new (for them) basin that, according to McKinsey & Co., could keep operators like Kosmos busy for the next decade or more.

In its June report "Unlocking Future Growth for Deepwater in the Gulf of Mexico," analysts for the firm posit that the basin's deepwater prospects will represent a sizable portion of new production expectations for 2030.

According to the report, if crude oil prices average $70/bbl over the long term, 36 MMbbl/d of new crude production from unsanctioned projects will be needed to meet demand in 2030, with 9.5 MMbbl/d expected to come from deepwater fields. More than 2 MMbbl/d of that 9.5 MMbbl/d will come from the GoM, second only to Brazil's 4.1 MMbbl/d.

As to where in the GoM all of these new barrels of crude will come from, the report noted that of the 5 Bboe of discovered reserves brought online in the GoM since 2005, 70% has been from the Miocene play, according to the report. Only 5% has come from the Paleogene play.

The prioritization by operators for "value over volume" has resulted since 2014 in the leveraging of subsea tiebacks in the basin's Miocene play with shorter cycle developments averaging three years from discovery to the production of first oil. Cracking the Paleogene, home to much larger but more technically complex resource plays, will keep explorers and technology experts busy far into the future. Perhaps the key to unlocking the billions of resource barrels in the ultradeepwater play can be found in the outside knowledge that companies like Kosmos possess. E&P



Generating positive energy conversations

A nonprofit organization offers documentaries and educational outreach programs for the next generation.

Brian Walzel, Associate Editor, Production Technologies

Scott Tinker, director of the Bureau of Economic Geology at the University of Texas at Austin, understands that in today's highly charged political environment, engaging in meaningful and thoughtful conversations about energy is challenging, particularly for younger people. Personal ideologies are attacked immediately and viciously, no matter your personal stance on the current and future global energy mix, Tinker explained.

Concurrently, the oil and gas industry is arriving at an era in which it is looking to those same young people as its future workforce, a potential workforce that Tinker believes is often fed misinformation.

"Right now it's pretty tough for young people to speak on anything that isn't renewables," Tinker said. "The education environment for them is one that isn't healthy. It's so biased and partisan. Energy matters, and all energy matters. There's a place for all of it."

SEA's Scott Tinker visited more than 20 sites to film the energy documentary "Switch." (Source: Switch Energy Alliance)

With that challenge in mind, Tinker helped establish Switch Energy Alliance (SEA), a nonprofit organization with the mission to inspire and motivate people of all ages to learn about energy, engage in those conversations and make informed decisions about the global energy future. SEA works to fulfill that mission by providing a multitude of high-quality, professionally produced educational videos and programs, highlighted by Tinker's award-winning documentary, "Switch," which was developed with Emmy-winning filmmaker Harry Lynch.

Tinker described "Switch" as an "old-school" style documentary, in which there were no protagonists or antagonists cast. The documentary was filmed in 11 countries and included more than 50 interviews and 20 site visits. "Switch" captures the state of the world's energy transition, explaining the benefits and challenges of nearly all energy sources, including solar, wind, nuclear, biofuels and fossil fuels.

Upon its release in 2012, "Switch" was chosen to open the Environmental Film Festival in Washington D.C., and later that year won the Best of the Fest award at the Colorado Environmental Film Festival. Since then "Switch" has been shown at more than a dozen film festivals, saw a limited theatrical run, was screened more than 1,000 times at more than 500 universities around the world and has entered the curriculum in more than 2,000 universities worldwide.

Tinker acknowledged that his initial perceptions about the energy mix changed the more he learned during the process of filming "Switch."

"The scale of demand was reimpressed upon me," he said. "Nuclear energy could have positive impacts, particularly if you're passionate about climate change. Some of the political challenges were made more tangible. There are so many different facets of society involved."

A sequel

Tinker and Lynch also realized something else later on: They had unintentionally left a few billion people of the world's population out of the film.

"Energy is the star of 'Switch,' so we went to the best energy locations in the world," he said. "We weren't going to many places in Sub-Saharan Africa, Southeast Asia, South America, parts of the Middle East [and] parts of North America that have very little energy."

According to SEA, more than 2.5 billion people around the world live in what Tinker called "energy poverty." He described energy poverty as those with limited energy or those who cannot afford energy.

Looking to bring to light those populations, the challenges they face in acquiring adequate energy and the solutions to those challenges, Tinker and Lynch are producing "Switch On," a sequel to "Switch."

"We don't really know how the film will turn out," Tinker said. "We do know that energy poverty exists, and that it's associated with real economic poverty. Energy poverty in Colombia is not unique. Nearly 1 billion people live in similar energy-starved circumstances globally."

The International Energy Agency estimates there are 1 billion people worldwide whose sole source of energy is either burning wood or biomass, which can lead to health problems, Tinker said. "Switch On" began filming in Colombia, Ecuador, Africa and Asia, and it will continue to shoot over the next eight months in some of the most challenging environments in the world, Tinker said. The expectation for the second documentary is that production and editing will wrap up next year and be released in 2020.

"We want to broaden the awareness of the deep networks we built in 'Switch' to the awareness of these challenges. When three-sevenths of the world lives this way, it affects us all. If we help the energy impoverished lift themselves from poverty, we will all be lifted," Tinker said.

The two concepts of "Switch" and "Switch On" will converge into a third film, tentatively titled "Making the Switch," due to be released in 2022.

"The first two films will have touched the whole globe with some of the positive aspects [of the energy mix and transition] and some of the challenges," Tinker

Scott Tinker (left) is the chairman of SEA, a nonprofit organization designed to expand energy education. (Source: Switch Energy Alliance)

said. "We really want to look hard at how you bring the environment and the economy and energy together to address some of the big challenges, and at least address them without the polarization that exists today around some of these big topics."

Energy education programs

In addition to feature-length documentary films, SEA's educational outreach includes a multitude of offerings primarily designed for schools and universities. The organization's website, *switchenergyalliance.org*, features 300 short-form videos that include primers on a vast array of topics such as geothermal and biofuels, oil and gas produced by hydraulic fracturing as well as more in-depth videos on the U.S. natural gas supply and carbon capture sequestration. Tinker said as many as 30,000 educators utilize the site's content in their classroom lessons.

"They are using these materials to supplement their education," Tinker said. "We've made a place and created a way for people to have conversations about energy that are rigorous but that are safe."

SEA's offering is expected to broaden in the coming years to include much more than web-based videos. Beginning in 2020 Tinker said the organization plans to offer a college-level course that includes videos produced in the style of "Switch."

Tinker said the "Switch" university course's concept is under development as a video-based energy course for university and upper-level high school students built on the inverted classroom model: Videos and online materials replace most of the lecture and textbook.

"This frees the classroom for professor- and student-led, objective, nonpartisan, collaborative problem solving, discussion and activities," he said. "We'll be featuring leading energy educators, discussing their areas of expertise and bringing them into the classroom."

Tinker's son, Derek, a petroleum engineer, works full time for SEA. Derek has led the redevelopment of the organization's website, which will feature substantial visual and content design and a more interactive user experience with deep analytics. The site will feature "Learn," a guided online video-based energy education program that Tinker said is designed to track the user's progress and compare it against other worldwide users, show user interests and even biases toward a particular energy source.

Also under development are efforts to create Switch Energy Clubs at high school and college campuses. Tinker said SEA would feed information to such clubs, which he said do not necessarily have to be named Switch, to facilitate conversations and education around global energy.

According to SEA, the goal of the energy clubs is to build an alliance of student leaders who understand the societal importance of energy and emotional issues impacting public discussion. Club activities could include public outreach, meetings and speakers, field trips and tours and industry roundtable events.

"If a campus doesn't have an energy club—and many do not—we'd like to help them start one with access to people and lecturers and maybe a little funding," Tinker said. "Students can start to have these conversations that are difficult but inclusive."

Those interested in engaging with SEA can visit the organization's website, sign up for digital newsletters and offer contributions. Tinker said all of SEA's information is provided free on its website.

"Our goal is to provide a way for people to have these conversations that are professional and respectful and civil," he said. "We are trying to inspire an energy-educated future." EP

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*.

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A glimpse into Oxy's artificial lift strategy

The Aventine facility and EOR asset acquisitions have begun to see returns.

Brian Walzel, Associate Editor, Production Technologies

Faced with the challenge of getting the most out of its 18,000 producing wells worldwide, Occidental Petroleum (Oxy), the Permian Basin's largest operator, relies heavily on a variety of artificial lift technologies and EOR mechanisms. Those efforts resulted in Oxy producing 639,000 boe/d through the second half of the year, according to the company's second-quarter 2018 investor report. That amount is expected to reach as much as 664,000 boe/d by the end of the year, with more than half of that production (about 374,000 boe/d) coming from Oxy's Permian Basin operations.

Tom Walker, Oxy's chief production engineer, provided a glimpse into the company's artificial lift strategy and operations at SPE's Artificial Lift Conference and Exhibition (ALCE) in late August in The Woodlands, Texas.

According to the company's website, Oxy leverages artificial lift on about 90% of its producing wells. During a keynote presentation at ALCE, Walker said of those on artificial lift, more than half are on beam pump lift. Electric submersible pumps (ESP), progressive cavity pumps and gas lift also all play key roles in the production strategy Walker characterized as "evacuating the wellbore."

Although beam pumps play the most significant role in Oxy's artificial lift operations, gas-lift systems are an emerging production method for the company. Gas lift is used on about 7% of the company's producing wells but accounts for 31% of Oxy's barrels per day production.

"So clearly we've got some big wells on gas lift," Walker said. "Right now we're adding more and more wells in our resource plays to gas lift."

Among the benefits gas lift brings to unconventional production, Walker said, is its ability to work well in sand and with wellbore deviation. He touched on the challenges of producing from ever-changing and complex horizontal wellbore construction designs and wells with gas-oil ratio (GOR) challenges.

"There is lots of discussion on gas," he said. "Usually GOR is going to continue to increase in most of our unconventional resources."

One of the solutions Oxy, along with many other operators, uses is downhole gas separators. Oxy applies downhole gas separators where natural gas production impacts the company's ability to pump wells primarily using beam pumps and ESPs, which Walker said "do not like a lot of gas." In particular, he pointed to a gas separator system that ties into the well tailpipe and dip tube to handle critical velocity issues.

"A lot of us know about critical velocities, and this is a way that we found can be helpful," he said.

He also addressed what he perceived to be an industry issue of nonworking rod rotators.

Oxy develops resources in the Wolfcamp and Bone Springs formations in the Delaware Basin. (Source: Occidental Petroleum)

"There are some [rod rotators] that are SCADA-monitored, so when they break and stop turning, you get contacted," he said. "The industry uses [rod rotators] and should have a lot more. Most are monitored visually by operators to assure they are working."

Walker also hinted at a potential future artificial lift strategy called Gas Assisted Liquid Lift Oscillating Pressure (GALLOP), which he said could be in use in the industry in the next 10 to 20 years. The GALLOP system is being developed at the Colorado School of Mines where laboratory work is being conducted with an eye toward future commercialization.

According to a study authored by Daniel Croce at the Colorado School of Mines, GALLOP "is designed to use a closed-loop intermittent gas-lift system to lift fluids from specific locations along the horizontal wellbore."

Croce wrote that the GALLOP system is composed of a dual small inside diameter tube run along the entire well with check valves strategically located along the liquid-filled sections of the horizontal wellbore. Croce explained that as opposed to traditional plunger lift systems, GALLOP uses pressure pulses that are only experienced by the GALLOP piping, allowing the reservoir to be produced continuously.

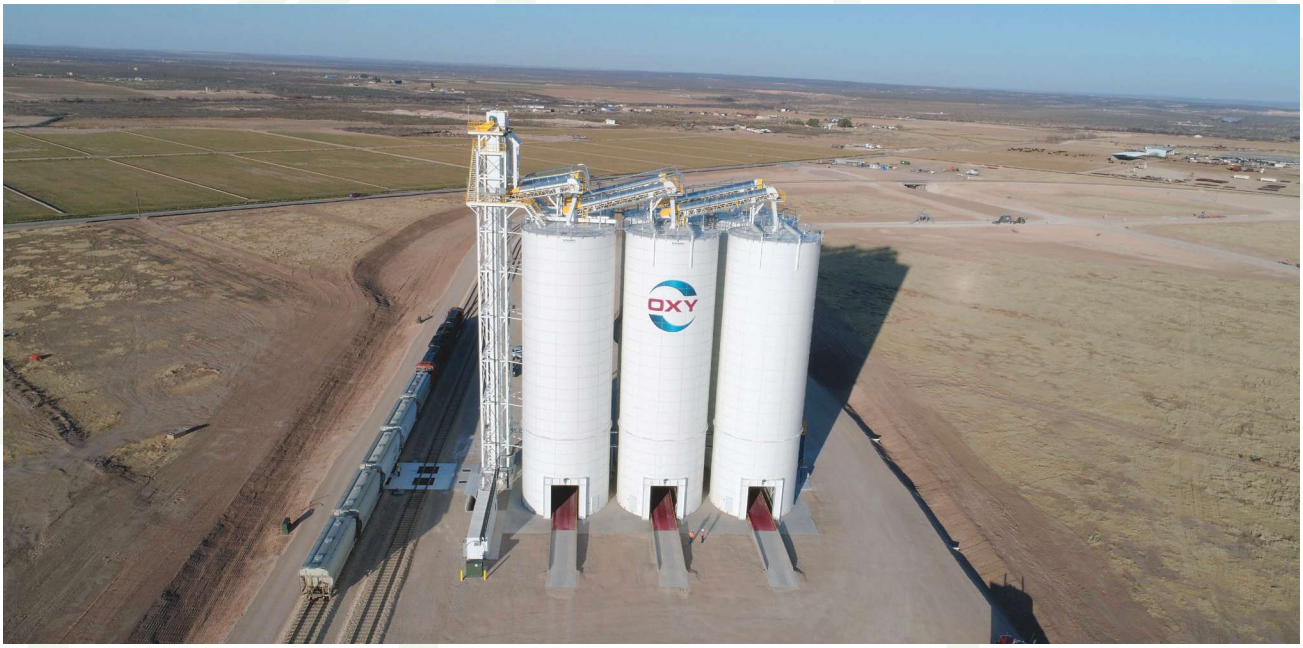
"This allows the steady buildup of liquids and reduces the amount of injected gas and surface facilities required," the study reported.

Aventine

In addition to its gains in oil and gas production, this year Oxy has seen its Aventine maintenance and logistics hub in Carlsbad, N.M., become operational.

According to Oxy's second-quarter 2018 investor report, the Aventine facility has delivered more than 2,700 rail cars of fracturing sand to Oxy's Permian Basin operations, and 60% of the oil country tubular goods used in New Mexico were railed in through the facility.

During the company's year-end 2017 investor call, Oxy CEO Vicki Hollub said Aventine would provide $500,000



The Aventine maintenance and logistics hub provides oilfield equipment and fracturing sand to Oxy's Permian Basin operations. (Source: Occidental Petroleum)

to $750,000 in initial savings per well as well as improved time to market, last-mile and wellsite logistics.

Permian EOR operations

Oxy is one of the few companies conducting EOR practices in unconventional production. The operator injects more than 27 Bcm (950 Bcf) of CO_2 for its EOR operations, according to the Oxy website. Oxy also has implemented four unconventional EOR pilots across the Midland and Delaware basins. The company estimates that its EOR operations increase ultimate recovery by 10% to 25% in the fields in which CO_2 flooding is deployed.

In June 2017 Oxy announced it had purchased Hess Corp.'s Permian EOR assets, which included producing, processing and pipeline interests. In the deal, Oxy acquired Hess' interest in the Seminole-San Andreas unit, its interest in the Seminole gas processing plant and ownership in the West Bravo Dome CO_2 field.

Jody Elliott, senior vice president and president of domestic oil and gas for Oxy, said during the company's second-quarter 2018 investor call that the acquisition is leading to cost savings in its Permian EOR operations.

"We continued our progress at the Seminole-San Andres unit by lowering opex an additional $2 per boe for a total reduction of $7 per boe since the acquisition," he said. "This $7 improvement is expected to generate over $400 million in [net present value], which is two-thirds of the acquisition cost."

Elliott also said Oxy has initiated a feasibility study for a carbon capture utilization and storage project with White Energy. According to Elliott, the project will capture CO_2 at White Energy's ethanol facilities in Hereford and Plainview, Texas, and transport the CO_2 to the Permian Basin for use in sequestration in Oxy's Permian EOR business.

Meanwhile, Hollub noted during the company's second-quarter 2018 call that Oxy could leverage excess capital to develop more conventional projects.

"Some of the incremental in our capital allocation is going to the Central Basin Platform and EOR to drill horizontal wells in conventional reservoirs," she said. "So we'll do some things to work on mitigating the decline of the Permian Resources business."

Ken Dillon, senior vice president and president international oil and gas for Oxy, said one such project Oxy is working on is the Teca-Cocorna steamflood project in Colombia.

"So far, the pilot appraisal is performing above expectations, and it's a classic Oxy International project implementing EOR techniques to an existing field discovered in 1963," Dillon said. "We expect the green light before year-end and expect to reach about 30,000 barrels per day gross in Phase 1. Initial response shows wells going from six barrels a day to 58 barrels a day with the impact of the steamflood." EP

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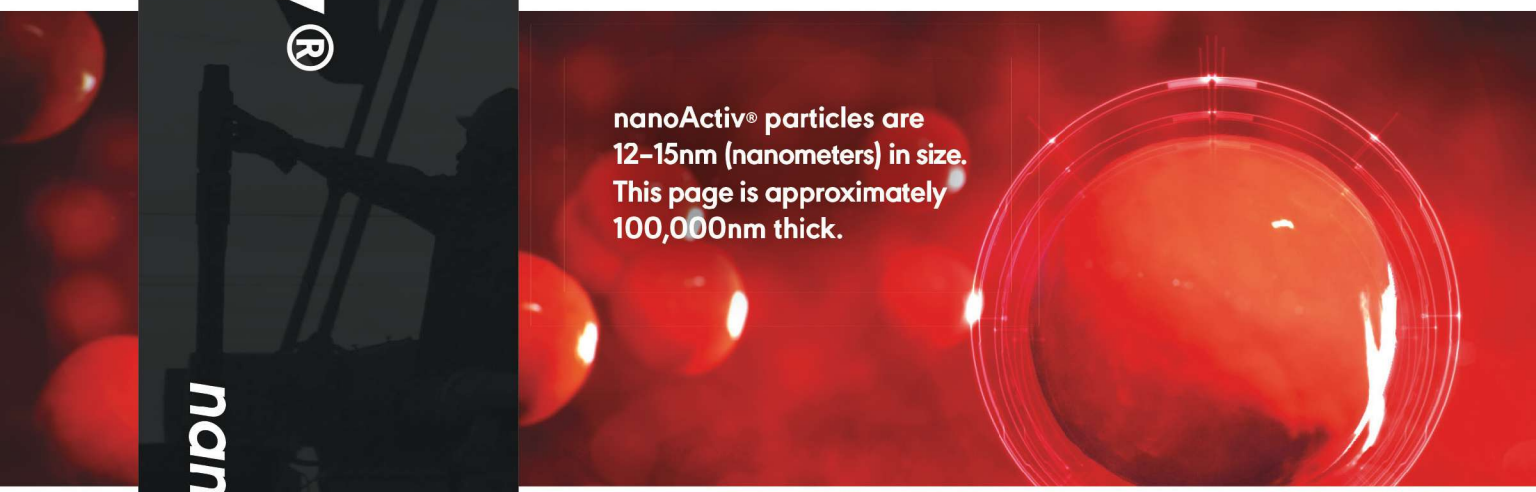

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Digital low-hanging fruit

The digital oil field is not a technology issue; it's a business model issue.

Richard Mason, Chief Technical Director

Maybe we're approaching the digital oil field from the wrong angle.

Instead of moonshot efforts addressing complex data-intensive drilling or completion iterations, the narrative is really a "War of the Worlds" analog where the smallest things matter most.

In this case, the smallest of things attention-wise involves production optimization, the forgotten stepchild of actually generating the EUR promised by the IP.

The technology exists to optimize wellsite production, regardless of whether you are a multinational or large independent playing in the unconventional space or a private operator nursing production out of legacy conventional wells. The challenge is the adoption cycle.

- **The greatest benefit from the digital oil field lies in production optimization.**
- **The technology exists; getting industry buy-in is the challenge.**

Despite the focus on drilling and completion digitalization, the immediate low-hanging fruit may be found in production where personnel deal daily with wellbore construction problems originating from decreased drilling days and dogleg horizontals and completion practices that emphasize short-term IP versus long-term EUR.

The production team expends significant effort correcting unscheduled problems using an antiquated process involving pumpers and attendants making rounds in trucks to monitor production, oversee equipment and fend off relentless decline rates. It is a system based on trust and intuition, mostly involving repetitive tasks. It is a system ripe for optimization.

Two vendors of production optimization services outlined the possibilities at Hart Energy's DUG Permian conference last spring.

San Antonio-based WellAware spoke specifically on the chemical support side of wellsite operations where data show the margin of error using tank-based monitoring is "plus or minus" 20%, according to company COO Blake Carlson. When sensors are placed on flowlines, the data are more accurate but show chronic under-delivery of product.

The key is high-resolution data, which prompted WellAware to pursue a full stack approach involving a hardware data sensor and communications network, app-based software for management using desktop or mobile systems and a backshop analytics engine.

Separately, Houston-based Ambyint focuses on automating artificial lift. Data from field deployment show almost 60% of rod lift systems are overpumping while 25% are underpumping. The former uses excess electricity, increases wear and tear and creates service cyclicality that leads to workover costs. The latter leaves money on the table.

Ambyint is developing an autonomous lift model, sort of a self-driving car of wellsite production optimization, combining sensors, software and an enormous North American well database derived from sampling data at 5 milliseconds versus 15- to 30-minute polling on traditional SCADA and PLC systems.

Field experiments in the Bakken Shale indicate the current platform, which adjusts set points for rod lift, shaved 15% out of lease operating expense. Once the system becomes fully autonomous, which Ambyint expects to demonstrate before year-end, total lease operating cost savings for artificial lift may exceed 30%.

Ambyint is developing a model to address field anomalies via machine learning that detect and characterize anomalies and autonomously corrects issues. Ambyint CEO Alex Robart foresees ultimate benefits accruing from a combination of production uplift and a reduction in lease operating cost.

So, the technology exists. Getting industry buy-in is another issue altogether.

"How do we transfer the oil field to an autonomous operating model away from the standard simple exception model?" Robart asked.

WellAware's Carlson echoed the challenge. "This isn't just a tech problem," he said. "It's a business model issue." EP

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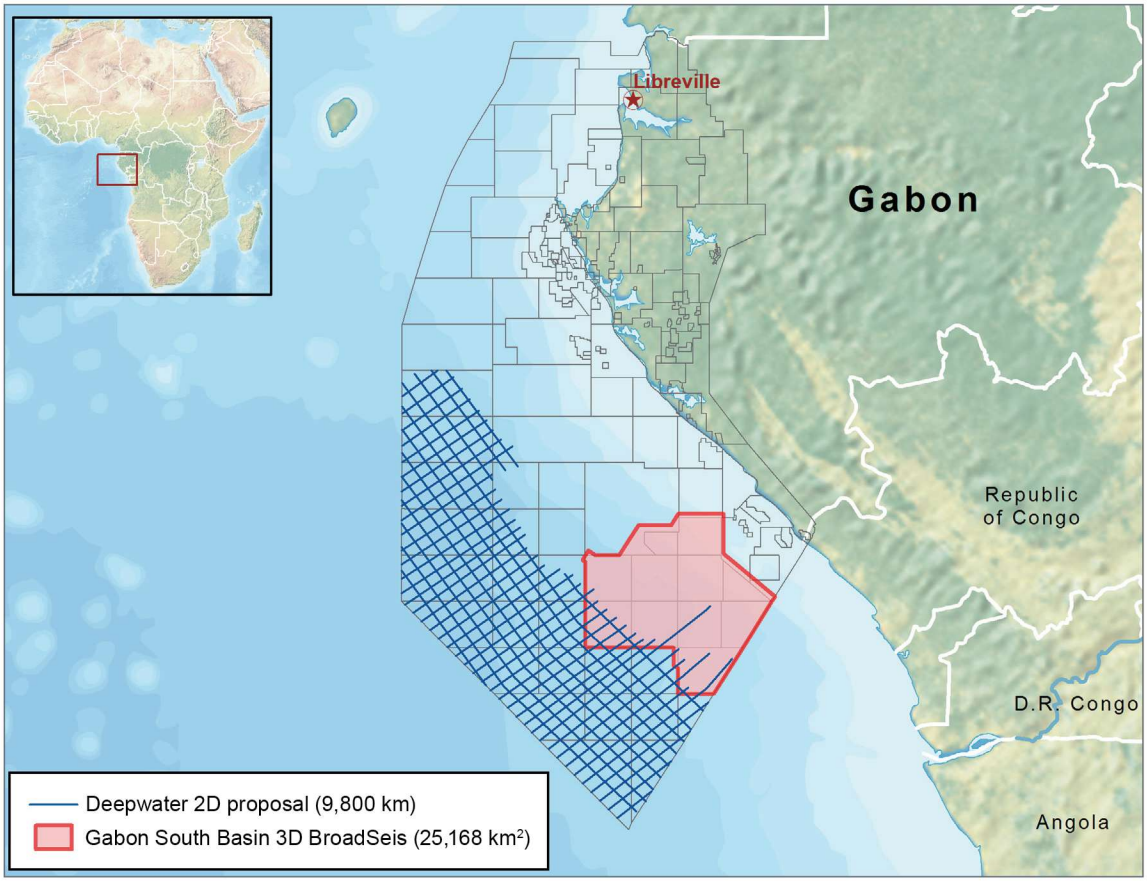
Deepwater 2D Multi-Client Survey



CGG is planning to acquire around 9,800 km of long-offset, 2D data to help define the full extent of existing and new plays in the Gabon South Basin and to understand the thickness variations in the sediment overburden for source rock maturity analysis.

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The next generation

A new crop of startups hopes to revive the seismic acquisition industry.

RHONDA DUEY
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Read more commentary at EPmag.com

When you read the October cover story (see page 30), you'll find that the seismic industry is being referred to as "beleaguered." This is not an overstatement. The extended downturn has caused several key players to exit certain parts of the business, particularly marine seismic acquisition, altogether.

This is not surprising. To put even a single crew on the water costs an inordinate amount of money for vessels, equipment and personnel. Given scant demand for their services, some companies have decided to focus elsewhere.

But there is always room for startups. A company called Shearwater GeoServices Holding AS obtained backing from a couple of major financiers: GC Rieber, a company founded in 1879 that has grown into a global shipping organization providing ship development; design construction; and operation services to the subsea, seismic and ice/support sectors, along with Rasmussengruppen, a company that has had international shipping at the core of its business since it started in 1936. The financing has helped the 2017 startup establish itself as a new entrant into the marine seismic acquisition business.

Most recently, Shearwater announced the acquisition of WesternGeco's marine seismic acquisition service. Schlumberger, which owns WesternGeco, announced its departure from the marine seismic acquisition business earlier in 2018. Shearwater, it seems, was an eager buyer.

While the transaction is subject to regulatory approvals, it is expected to close by the end of the year.

Shearwater plans to operate the combined businesses as a global, customer-focused and technology-driven provider of marine geophysical services, according to a press release. Once the acquisition is complete, the company will own and operate a fleet of 14 fully equipped seismic vessels offering the full range of services—3-D seismic, 4-D seismic and ocean-bottom seismic surveys. While WesternGeco plans to maintain its processing and interpretation business, Shearwater also will apply its own processing and imaging services to its latest venture.

In February, announcing its departure from the marine acquisition business, Schlumberger CEO Paal Kibsgaard noted that its customers were not willing to pay "a premium for differentiated seismic measurement and surveys." He added that this creates "a low technical barrier" for smaller players to enter the segment, keeping demand in a "chronic state of overcapacity," according to an earnings call.

So this is an opportune moment for Shearwater. "We will combine two strong complementary businesses and create an industry-leading full-service geophysical company with a solid financial and strategic platform," said Shearwater CEO Irene Waage Basili in a press release. "Our strategy has been to build a stronger company during the downturn, and we are very pleased to see the commitment made by our owners, [which] enables this transaction."

The press release also noted that Shearwater will have almost 600 employees and operate in all major offshore basins in the world.

Included in the press release was a statement from Maurice Nessim, president of WesternGeco, who said the divestiture would enable the company to strategically position itself as an "asset-light" geophysical service provider. There is a real paradigm shift going on here. In the past, the major marine geophysical companies have bulked up their fleets in anticipation of a major need for marine seismic while also investing heavily in R&D to give the oil and gas industry the cutting-edge technology it seemed to need to image difficult subsurface structures. Now these companies are hurting. It will be interesting to see what the next generation can bring. EP

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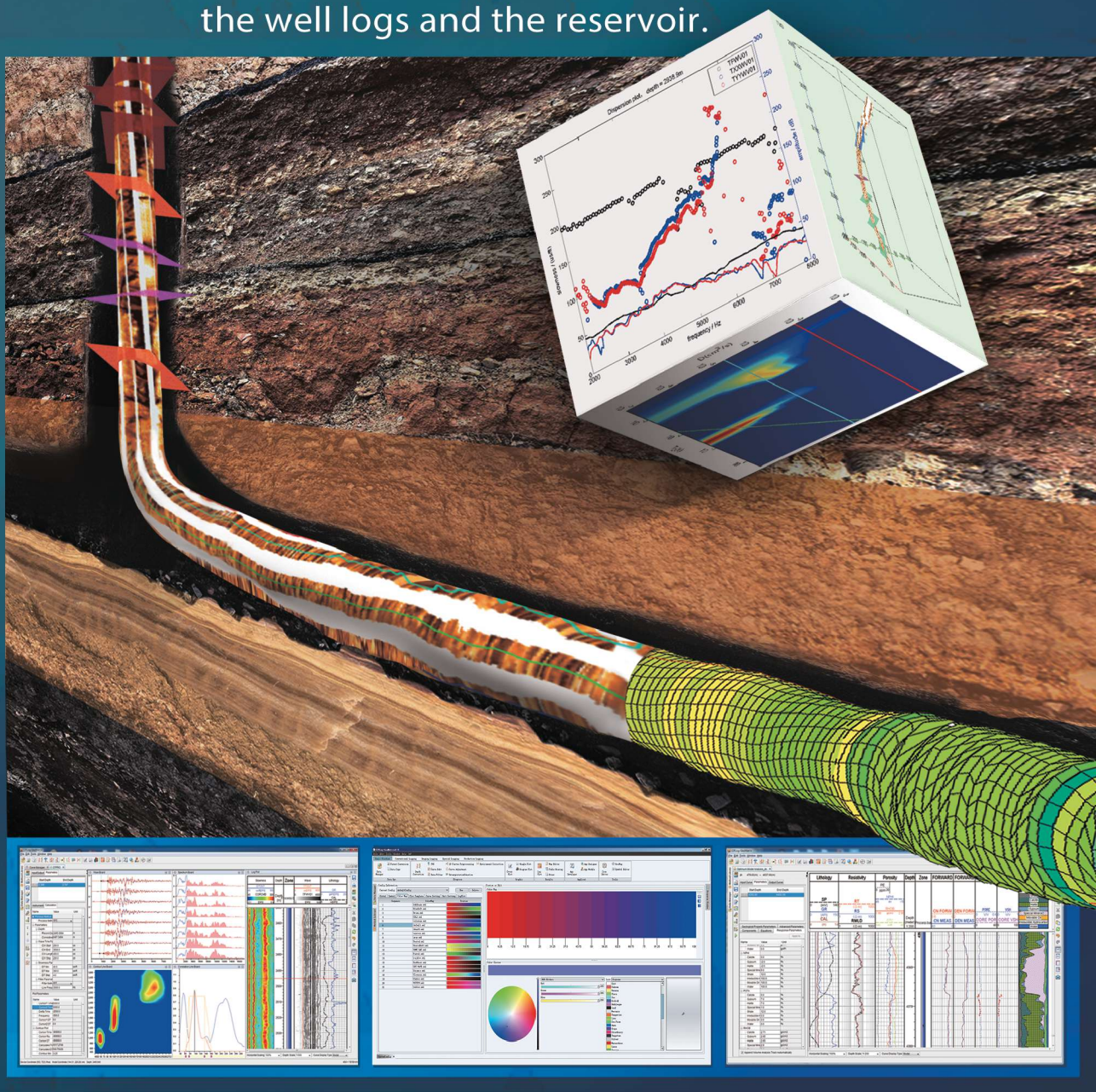

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Brand new name delivers 2030 vision

An NOC announces plans to drill thousands of wells in the NCS in the coming decades.

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Read more commentary at
EPmag.com

Changing a brand's name must be more than a symbolic gesture. It is an announcement of a shifting in the identity and culture of that brand. Equinor, the national oil company (NOC) formerly known as Statoil, found a name that is truly representative of its strategy and development as a broad energy company. The company is now more than oil and gas; it is now all energy. Under its new banner, Equinor embarked on a journey of transformation and of creation, with the Norwegian Continental Shelf (NCS) and offshore Brazil respectively as its intended destinations. This journey, announced at the Offshore Northern Seas (ONS) Conference held in August, looks to keep drillers and many other service providers busy far into the foreseeable future.

The company has introduced multiple measures to address the anticipated production declines in its big fields when the NCS enters a more mature phase after 2030.

"The NCS still holds a lot of potential; however, securing value creation and thousands of jobs for the decades to come is not an easy task," said Arne Sigve Nylund, Equinor's executive vice president for development and production Norway, in a press release. "The changes needed will be bigger than ever before and are necessary as we continue to develop as a broad energy company."

While onboard the Troll A platform, Equinor's Arne Sigve Nylund applies a decal to his hard hat signifying the company's new name. (Photo by Ole Jørgen Bratland, courtesy of Equinor)

Renewing the NCS will include the drilling of up to 3,000 production and exploration wells during the coming decade, almost as many wells as the company has drilled since its establishment close to 50 years ago, according to the release.

Drilling more wells is just one part of a journey that includes plans to drill 20 to 30 exploration wells in the NCS annually with an increased focus on natural gas.

Equinor and its partners also presented plans at the ONS conference to explore the possibilities of powering the Gullfaks and Snorre fields by using offshore wind turbines to supply renewable electricity to the installations.

As for Brazil, it is a "great fit with Equinor's strategy," according to a press release. It is a strategy that builds on the company's efforts in the country, and with daily oil production of more than 90,000 bbl/d from current fields, Brazil has become one of the company's core areas.

"We have been building a presence in Brazil since 2001, and we have been able to establish a broad energy portfolio in the country," said Anders Opedal, Equinor's executive vice president for development and production Brazil, in the release. "With around $10 billion already invested, and more than $15 billion expected to be invested until 2030, we show how we are working to create value for both Brazil and Equinor."

The company's assets include the producing Peregrino Field, a 25% share in the giant Roncador Field and significant presalt discoveries of Carcará and Pão de Açúcar. Drilling is underway at its Guanxuma well in the BM-S-8 license and was declared an oil discovery by Brazilian regulator ANP with good quality oil discovered in a carbonate reservoir, according to a press release.

True to its all energy strategy, the company also is a partner in the Apodi solar project to deliver energy to 160,000 Brazilian households by year-end 2018. EP

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Future of tight oil development costs

An analysis predicts costs to climb as core areas mature.

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Nothing good lasts forever, and a recent analysis by Wood Mackenzie suggests that will include the cost of producing tight oil. In a recent paper presented at the SPE Unconventional Resources Technology Conference in Houston, Robert Clarke, research director of the Lower 48 upstream at Wood Mackenzie, suggested that U.S. Lower 48 tight oil production will become increasingly expensive by 2027 as a result of high-cost new drilling operations and key core acreage having been drilled out.

Another factor contributing to the rising costs of unconventional oil development, Clarke reported, is increased competition from conventional plays. As oil prices dropped in 2014, high-cost conventional projects became uneconomic and were either delayed or completely scrapped. However, Clarke said key conventional projects have emerged as competitors to U.S. tight oil development, particularly in places like Brazil and Guyana, which feature substantially large reserves and high-quality reservoirs with breakevens that Clarke said are "lower even than most tight oil plays."

Clarke also noted that in more mature plays, like the Gulf of Mexico and the North Sea, operators have worked to bring down their development costs, which have consequently lowered their breakevens.

"Most projects now in the mix have changed in scope since first conception too, often subject to a total reworking of development plans," Clarke wrote in his SPE-2875019 paper. "Operator mentality has shifted to value over volume."

Wood Mackenzie reported that breakevens in the Delaware Basin dropped below $40/bbl in 2017. And although breakevens are highly basin- and operator-dependent and vary greatly (in some U.S. tight oil basins, breakevens run as low as $20/bbl and as high as $90/bbl, according to Wood Mackenzie), future production costs could likely fall in the $60/bbl range. In fact, Wood Mackenzie predicts that U.S. Lower 48 production will become one of the most expensive supply sources by 2027.

> "Operator mentality has shifted to value over volume."
> —*Robert Clarke, Wood Mackenzie*

"Models suggest that future tight oil drilling will become more expensive," Clarke wrote. "Well designs and completion formulas are no doubt continually evolving, but cost structures moving forward will be dynamic too with varying degrees of inflation seen across the supply chain. Additional productivity gains can offset this, but technology advancements will be massively critical as sweet spots become exhausted and less productive reservoir zones become reclassified as core assets."

Although costs will climb, Clarke said, unconventional oil development will play an increasingly important role as a future supply gap emerges—perhaps as much as 23 MMbbl/d in 2027, Wood Mackenzie estimated.

"[Lower 48 tight oil projects] are the future marginal cost barrels that will play a key role in setting the price in the next decade," Clarke wrote. "Specifically, the Permian drives this."

A key takeaway from Wood Mackenzie's analysis is that as a result of the depressed price environment, both unconventional and conventional operations found ways to survive and thrive. Operators have proven in unconventional operations—and likely soon conventional developments—that low oil prices won't cripple them in the long term. The future of energy is anything but certain, but the innovation that has helped bring the industry out of the downturn will continue to play a role as energy supply and demand evolve. E&P

Digitalization brings benefits to rig inspection, audits

Greater adoption and effective use of enhanced digitalization in the rig inspection and audit market are delivering benefits and reducing risk.

Austin Hay, Aberdeen Drilling Consultants

The recent rise in commodity prices has generated an increasing focus on drilling rig availability around the world and the reactivation of stacked rigs.

However, rig reactivation is not a straightforward process. An ill-informed decision has the potential to cost millions of dollars in nonproductive time (NPT) if the rig reaches its location and does not operate as designed or anticipated. It is therefore essential to mitigate such risks during the rig-tendering phase.

Rig management system

An example of this development has been the establishment of a software system by Aberdeen Drilling Consultants (ADC). The Technical Rig Audit Management System aligns the benefits of digitalization with the inspection and analysis of several hundred rigs of varying designs and specifications including land rigs, jackups, semisubmersibles and drillships.

The system captures and analyzes the findings from every rig inspection ADC has carried out over the past 10 years. Studying such data allows the targeting of known areas of risk through the undertaking of trend analysis using information such as the background of the drilling contractor, rig type, design or age, operational status, maintenance history, and equipment and systems assessment.

As an example, if a rig is stacked for a period of time in a sunny, hot and dry climate, it often can experience heat and ultraviolet degradation of perishable compounds such as rubber and elastomer components. A drillship, which was stacked in such conditions until earlier this year, was found to have similar challenges in advance of planned reactivation and deployment offshore Ghana. ADC was commissioned to ensure all drilling equipment and systems were inspected and operational during reactivation, and the vessel is currently drilling more than 97% uptime—a significant achievement following recent stacking.

Furthermore, during multiple rig selection surveys, rather than reports on individual inspection and assessment aspects being conducted and collated manually, digitalization of the process can provide the operator with a relatively quick, holistic and comparative analysis of the rigs, underpinned by the potential technical and/or financial risk of each option.

Risks to be considered during a rig inspection include rig capability requirements, client-specific requirements, management systems and operational status, equipment, third-party equipment, and modifications.

Upon completion of each rig visit, a report on the suitability of the specific rig for the planned operations is undertaken, before then comparing all rig options on suitability and potential risk based on the inspection's findings.

Deploying a digital system that operates in accordance with ISO19011 offers a global standard for reporting based on classic audit procedures, with the ability to incorporate company-specific standards. An effective system also should provide a streamlined reporting environment for the completion of all workscope-related tasks, the collection of data and the delivery of interactive visual reports.

Web enablement can provide online access to an ongoing project, allowing the operator to be "present" at the inspection or audit from anywhere in the world. The system also should have the capability to deliver a fleetwide or individual rig audit management system, sharing improvement opportunities and tracking the closeout of corrective actions as they happen.

With a thorough overview of the rig, the operator is able to identify the potential for equipment or systems failure and establish an accurate assessment of spares requirements, thereby avoiding over or under conservatism in spares purchases.

In addition, as the industry comes to terms with the challenges of cybersecurity—a particular issue for mid-generation rigs with potentially outdated software systems, which have been stacked for a couple of years—a system that can identify risk areas and suggest mitigating tactics has significant advantages.

Benefits of digitalization

On a recent BOP end-of-well inspection, the condition and functional operation of the BOP ROV intervention system were inspected and witnessed as well as a third party's ROV pumping skid equipment. The ROV intervention Type C stab may have fitted the Type A receptacle; however, the porting of the receptacle and the ½-in. hosing fitted to the BOP would have restricted the flow of fluid from the stab, preventing the intervention skid operating the critical BOP functions as designed and in compliance with American Petroleum Institute Standard 53 (API S53) maximum ram closure timings.

The timings for the operation of critical functions would not have complied with API S53 and could have delayed the shut-in of a well if operated in a real-time well control situation.

This was reported using the digital software system and communicated to the client. It identified that the same issue could be present onboard three more of the rigs currently on contract—all constructed in the same shipyard. Preventative action was then taken to minimize the risk to ongoing operations.

It is now possible to apply this known nonconformance to rigs and BOPs of the same rig type to predict and address the issue before the rig goes on contract. Using this example, considering daily operating costs of the sixth-generation drillship this related to, a conservative estimate of the cost to rectify this problem if the rig had been on contract would be approximately $4.5 million in NPT.

Across the industry, the advantages and benefits that the correct use of enhanced digitalization deployment can bring in reducing risks, operational challenges and time intensive manual processes are becoming clearer. This also extends to the inspection and auditing of stacked rigs and those being considered for reactivation.

Continuous learning from previous campaigns and ongoing improvement opportunities to enhance the digitalization process mean that operators can interrogate rig data from the past to make informed decisions and shape the campaigns of the future. EP

Digital transformation strategies

Producers of all sizes can benefit from digitalization at the wellhead.

Darren Schulz and **Nathan Tungseth**, ABB

All parts of the world economy are being affected by the Internet of Things and related technologies, including oil and gas. Although the idea of a digital wellhead has existed for many years, the oil price crash a few years ago encouraged operators of all sizes to start looking at the concept more seriously. This is something they are continuing to do even now that prices have somewhat recovered.

Digitalization sees smart devices exchange timely data in ways that help transform performance through the use of analytical programs, which guide operational decision-making to reduce risk while increasing efficiency and profitability. In the onshore upstream sector, it involves measuring devices, actuators and sensors on items like drilling rigs and wellheads that use the information to make decisions autonomously or under the supervision of operators that are now better informed.

Producers of different sizes have different priorities. However, all can benefit from the safe reduction in costs and output offered by increasingly affordable remote sensors and cloud computing, which put digitalization within easier reach of the onshore upstream sector. Thanks to the digital boom in the consumer arena, technology, storage and connectivity resources are so accessible that traditional and prohibitively expensive wired approaches are no longer needed for many wellhead applications.

That said, most onshore upstream companies are still in the early stages of evaluating technologies and developing a business case for digital investments. There is vast potential to develop a range of performance-enhancing applications for this sector.

Remote monitoring

There are approximately 1 million wellheads in North America alone, and field engineers spend considerable time traveling between sites to perform maintenance checks. Operators are keen to reduce this activity to save costs and, more importantly, improve safety, as road traffic accidents are a top contributor to workplace injuries.

With digitalization, it is possible to do most of these checks from a distance. It also ensures that any action taken is the best option available, thanks to analytics and cloud computing, which help operators to diagnose the situation more accurately and apply the most effective remedial action.

In recent years companies in the sector have shed staff to match the size of their organizations to a reduced revenue stream. Ten years ago one field operator might have covered 50 wells. Today the operator may be needed to cover 150. During this downsizing process, expertise has been lost. This has increased the importance of data-based decision-making to help fewer, and perhaps less experienced, people still make quality decisions. Digitalization also makes it feasible for centralized subject matter experts to help field technicians work more efficiently, freeing up these engineers to work on more tasks.

This rationalization process is still ongoing. As such, companies are continuously looking for ways to deploy

Digitalization helps operators with a few wells or many wells to maximize output and minimize downtime and operational costs. (Source: ABB)

technology and best practices that improve performance and safety in ways that best meet their operational needs and constraints.

Small producers

Those with 10 to 50 wells are looking for basic, cloud-based monitoring to extract more value from relatively tired assets. Typically, these operators have purchased their wells from the organization that first developed them. Digitalization can help them potentially get more production out of what is still left in their old assets and thus achieve a better return on their investment.

Medium producers

Operators with 50 to 500 wells in one region have different objectives for well digitalization as their focus is on exploration. The existing wells produce a cash flow that helps sustain their exploration programs. These companies seek technologies that reduce their operating costs while maximizing steady, predictable cash flow.

In onshore environments, operators are dealing with a declining asset from the day they start drilling, as opposed to offshore assets that generate high-volume output for long periods of time. Also, not all onshore wells are equally productive. Furthermore, it is not uncommon for different companies' wells to be drawing from the same reservoir, contributing to an accelerated asset decline.

Sensors and analytics can be used to prioritize activities such as maintenance on the most productive wells. Technology also can be used to minimize the rate of decline while maximizing production in both absolute terms and in comparison to a competitor drawing from the same reservoir.

Artificial lift is an example of how digital technology can help increase output. It is very rare now that hydrocarbons are brought to the surface by reservoir pressure alone. With the increased use of artificial lift systems, the need for electrification and automation increases. Sensors and technology can be used to get better information and ensure critical velocity is achieved, thereby ensuring the greatest output.

Remote monitoring improves safety by minimizing field engineer travel. (Source: ABB)

Also, it is worth noting that pumping and gas-lift systems create their own backpressures that need to be managed to keep production flowing effectively. Again, digitalization can help.

Large producers

Companies with 500 or more wells across several regions are perhaps the most advanced in exploring the potential of digital technologies to extract new value from the data flowing from digitalized wellheads. While they too are interested in increasing production to fund exploration efforts, they seek to maximize production at a global fleet level.

Their objective is to find where the costs are lowest, the wells most productive and the markets most profitable. The impact of fluctuating market conditions can be moderated when performance is digitally tracked and optimized across geographies.

Digitalization provides data to help senior decision-makers decide where to invest limited resources for the best return on their investment. Digitalization rolls up operational information and makes it easier to compare regions.

The current priority is on operational metrics, as opposed to predicting where the best price will be achieved. Once a well has been opened, the operator already will have invested so heavily that production continues regardless of price. Using digitalization, operators can ensure they make the best decisions to maximize profitability over time.

In addition to helping prioritize global investments, digitalization also is useful regarding predictive maintenance. Technologies exist that can confirm whether equipment is up to the task, how stable it is and whether it is possible to avoid costly shutdowns due to predictable maintenance issues.

Conclusion

In today's relatively low-price marketplace, there remains strong incentive to use technology to improve performance at the onshore wellhead, an area that had previously been overlooked in favor of the more resource-rich offshore sector.

The priorities are to maximize output, minimize downtime and costs while achieving this with low staff numbers and without sacrificing safety.

Although this is still an emerging area for the onshore upstream sector, companies need to stay on top of developments. Those that are slow off the starting blocks may find themselves leapfrogged by more agile competitors. E&P

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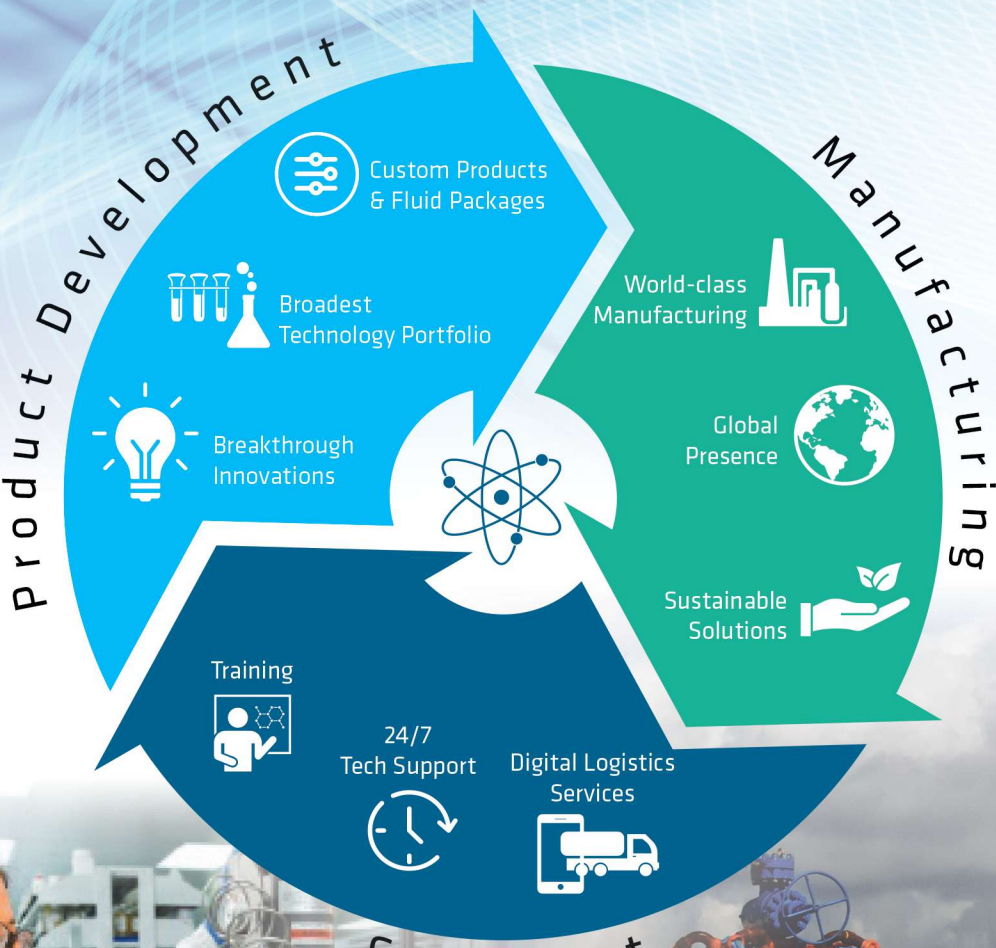

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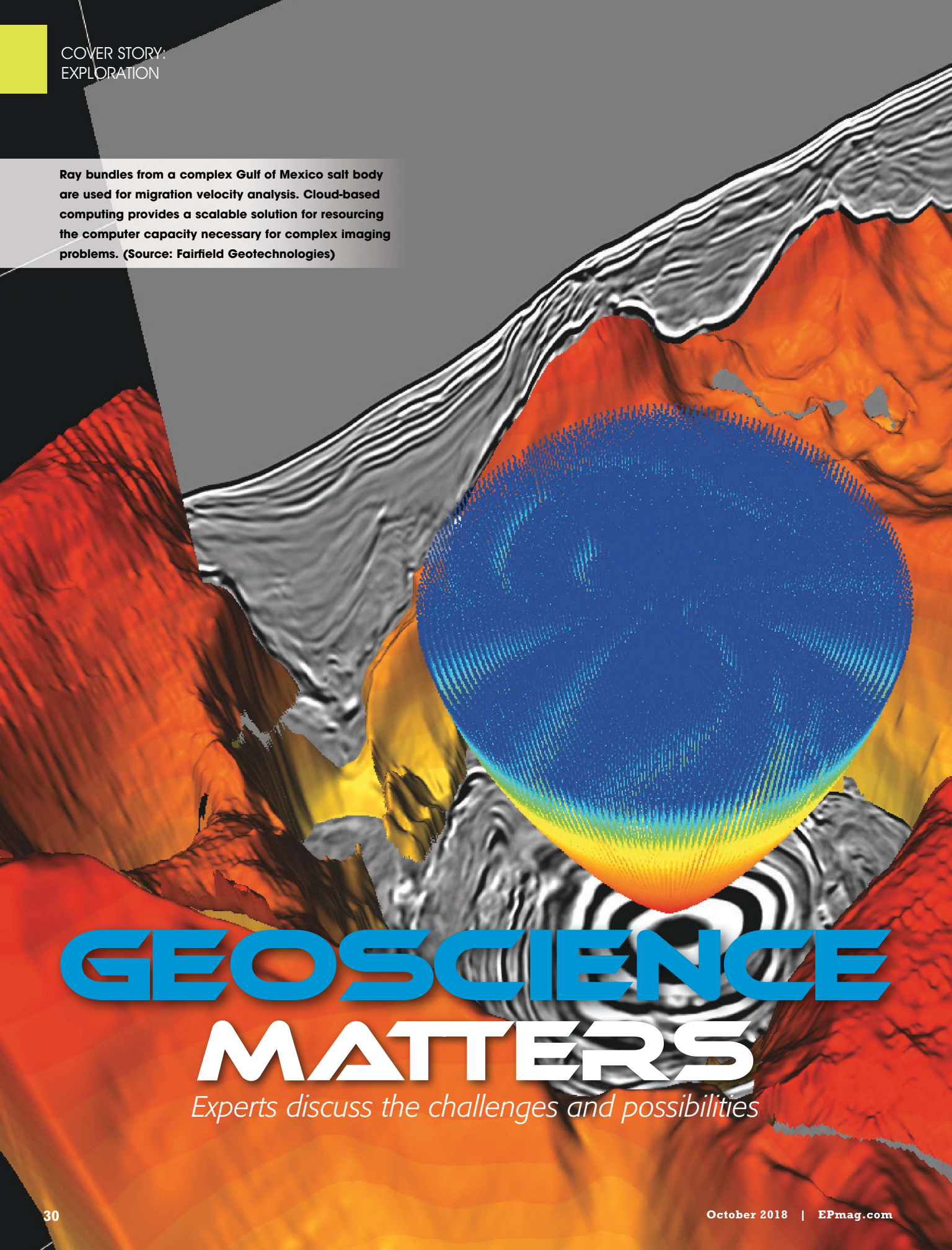
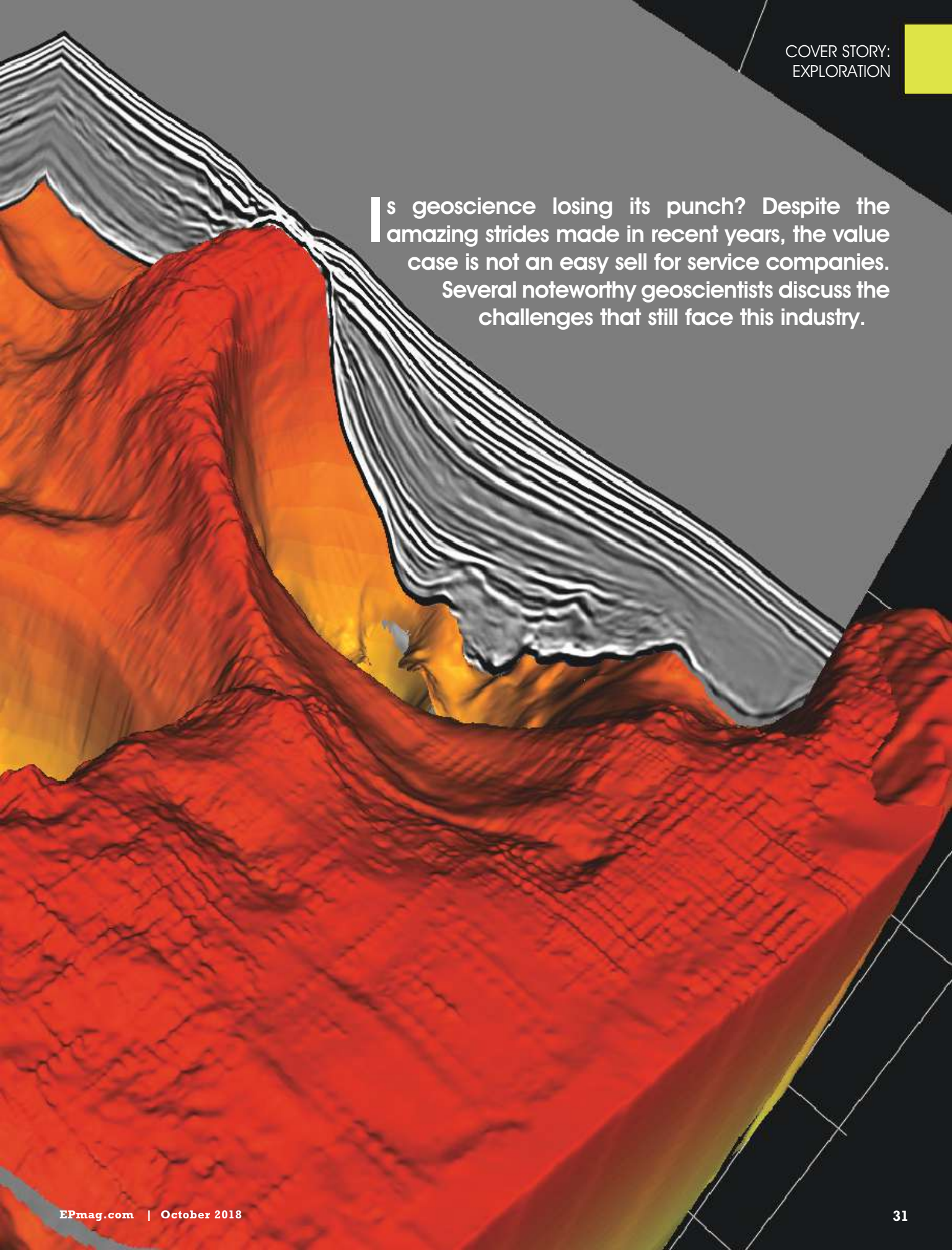


Ray bundles from a complex Gulf of Mexico salt body are used for migration velocity analysis. Cloud-based computing provides a scalable solution for resourcing the computer capacity necessary for complex imaging problems. (Source: Fairfield Geotechnologies)

GEOSCIENCE MATTERS

Experts discuss the challenges and possibilities



Is geoscience losing its punch? Despite the amazing strides made in recent years, the value case is not an easy sell for service companies. Several noteworthy geoscientists discuss the challenges that still face this industry.

The world needs more geophysics

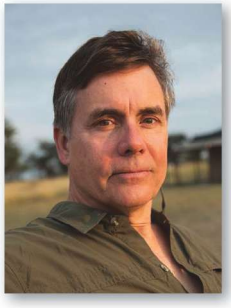
Despite tremendous technological strides in recent years, companies are finding it challenging to stay on top of their game.

Rhonda Duey, Senior Editor, Exploration

The geoscience industry is in a state of flux. WesternGeco recently got out of the marine seismic acquisition business totally, and some of the other major companies have filed for bankruptcy or laid off staff to try to cut overhead. Granted, the industry has been in a downturn, and geoscience expenses are often the first to be cut. But this comes at the same time that the technology is constantly improving, with imaging technology advancing and processing technology tackling larger and larger datasets and finding more in them, everything from more traces to seismic monitoring for producing fields.

E&P recently sat down with several geoscientists to discuss the state of the industry. Among the group were Richard Degner, president and CEO of Geophysical Technology Inc.; Dave Monk, director of global geophysics for Apache Corp.; Mike Bahorich, former CTO for Apache; and Allen Gilmer, co-founder of Drillinginfo. The conversation was essentially a discussion about why geophysics and geoscience still matter in the oil and gas industry.

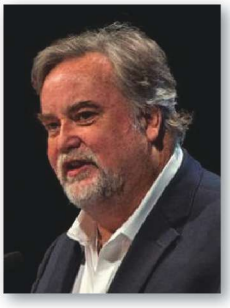
***E&P*: Do you feel like the oil and gas industry is still interested in geoscience?**



Mike Bahorich

Bahorich: Among the largest super-independents, there are some that have had tremendous success using seismic to maximize the value of their shale assets. Almost all the shale players use seismic for geosteering, and I cannot imagine geosteering without it. After geosteering, there are many other uses that should be considered. There is often a good impedance contrast with frack barriers, so companies use seismic to track frack barrier location and thickness. In some situations it is possible to use seismic to interpolate characteristics that relate to the richness of the shale. If you review investor presentations from top operators, you will find several that generate shale reservoir models using petrophysics and seismic.

Regarding the cost of seismic, we're talking about pennies compared to drilling dollars, and petrophysical reservoir models that incorporate seismic can help them understand not just the location of quality rock but also can help them decide the sequence in which they should drill their wells. If they understand something about the rock quality, which they can do through a reservoir model, then they can do a better job of executing their capital programs. I think many companies could learn from some of the leaders in this space.



Allen Gilmer

Gilmer: You're stating something that we take to be a ground truth. But if that was the case, we would be shooting lots of 3-D surveys, and we're not. And so the concept is that if you want to stay in the zone, are you going to use 3-D in every case absolutely across the board? Yes, yes, yes. That's what we would say every time. And we can go out there and demonstrate the efficacy of doing those kinds of things because it's getting better. But if you were to ask the people who are responsible for executing on those drilling programs how valuable 3-D seismic is, you would get a few that would say it was very valuable, but you would get a lot who would discount it regardless of the value. I think it really is just a question of finding the value and framing it so that people are really testing that value all the time.

Dave Monk

Monk: The biggest issues that people have with the completions are trying to determine how far apart the wells should be, how many fracks they should do [and] how many stages should be in a lateral, and those completion engineers haven't determined that yet. They don't think they can get their information from the seismic. They understand where they're going to

drill, how they're going to do the lateral, that they've got to steer them, and the problem that they all want to solve today is how far apart to put laterals and how many stages they should drill. Geophysics might be able to help them.

***E&P*: They can't get the information, or they don't think they can get it?**

Monk: We're struggling to prove that they can get the information.

volumetrically extrapolate all of this incredible well information so that they can take hydrocarbon percentage or brittleness of rock or whatever the petrophysical properties are [and] extrapolate them out, obviously adding enormous value over millions of acres to understand how to extract these hydrocarbons in the most efficient way.

When I started dividing everything by acre, I said seismic will cost you $50 to $100 an acre These operators are leasing land for $30,000 or $40,000 per acre, and they're drilling and completing it for another $20,000

"Almost all the shale players use seismic for geosteering, and I cannot imagine geosteering without it." —**Mike Bahorich**, *Apache Corp. (retired)*

Gilmer: I think we can say, categorically, that they can get that information. If you structure all the information right, categorically you can get it. The issue is that it's just not been delivered to them in a way that they understand, and I think it really is a nomenclature difference.

I credit Richard [Degner] when he first started selling seismic data by the acre. Frankly, that was simple, and it worked brilliantly because it was the first effort to try to put seismic data into the context of what the engineers were thinking about with regard to the cost, being able integrate it. I think the more that we can do to start really just putting things into the nomenclature of engineering as opposed to the nomenclature of seismic or geophysics is really, really important.


Richard Degner

Degner: And I think I did that just so that I could try to understand it myself because I don't understand E&P execution the way that these guys do, but I see how for $50 to $100 an acre we can record a survey that has a sampling of 4 million or 5 million traces per square mile. Twenty years ago, we were recording 20,000 or 30,000 traces per square mile.

Monk: We just completed a survey at 76 million traces per square kilometer.

Degner: So 200 million traces per square mile, equivalent. We record these amazing surveys, and the operators

or $30,000 per acre. If you spent 10 times that much more and had 5% better execution or even 1% better execution, isn't that an amazing payback?

Gilmer: But it's the time. With regard to shooting, processing and interpreting seismic data, the time frames are so long that it really kind of precludes the utility. The ability to collapse that time frame is here, but it just hasn't been as important. Is the time frame really that critical?

Degner: Is it really that short-term of a decision? The development of these shale plays covers the next decade, not the next 10 weeks.

Bahorich: I think it can be an issue. It depends on the situation. Ideally, you want to use seismic for your initial drilling program. But if the cost of capital is significant and waiting on seismic causes a delay of some huge drilling project, that delay can be more costly than a seismic survey.

Gilmer: You have to optimize the wells you have on your lease so that you can develop locations to have the maximum value. So it becomes financial. Those are the things that we have to be conscious of. But yeah, they're going to be developing it over a decade, and they'll be able to layer those things in.

Bahorich: One of the benefits of having a large spec program acquired and processed ahead of time is that this great big problem goes away. Sometimes it can be

difficult for the seismic service company that's actually laying out the dollars to pay for that spec program, but in terms of overall benefit to the industry, it solves a significant time value of money problem.

***E&P*: Are operators able to wait for those results?**

Monk: Geophysics has the capability to measure the information about what operators do when they actually frack the well. Whether they can do it in real time is another question. They then modify the frack program, but it's not surface seismic the way that we've done it before.

Gilmer: How do we integrate geology and geophysics more tightly with regard to being able to provide that magic information between reservoir models of seismic and geology? That is a really interesting space right there. I think that the concept of using seismic data as a soft control for geology to approach that whole problem from a geological perspective as opposed to this purely seismically driven perspective is an interesting place for us to be.

Degner: I think there's enormous promise in technologies like ambient reservoir monitoring, tomographic fracture imaging and imaging the continuous emissions of sound from the permeability that exists in the earth. We're just now starting to come up with seismic sensors at the surface that have enough dynamic range and high enough coupling that operators can really be recording those tiny microseismic events and recording them over time, getting confidence in where they're coming from and then imaging them. I think that's a sector that ultimately will bring a lot more credibility to the geophysical industry in general. And it'll help tie together some of the things that the engineers are doing with the basic regional seismic datasets out there.

Gilmer: I'm an optimist on this whole thing, and the reason is because I'm impressed with the petroleum engineering students that are coming out of school today that have been really hungry to learn about this. When I got out, I didn't know anything about petroleum engineering at all. It is coming, and I'm very heartened by that. I'm really impressed by the programs and the students coming out of those programs. The people that geoscience has attracted have been among the best scientists on the planet, and the amount of work done is amazing. The value of it is, unquestionably, remarkably high.

"I'm impressed with the petroleum engineering students that are coming out of school today that have been really hungry to learn about (geophysics)." —**Allen Gilmer**, *Drillinginfo*

Bahorich: What that brings up is that we have a responsibility to communicate what seismic can do and what it can't do.

Gilmer: There's another problem. Once the cookbook for completions is dialed in to provide above a 20% internal rate of return, then anything a company does to adjust that is looked at as a science risk, and the whole process turns toward how many wells an operator can get drilled through the regional playbook as fast as possible.

So they always think in terms of the regional playbook, but regional playbooks leave a lot of oil behind. The next step, and this is where I think seismic would really shine, is what I call location-specific optimization, which means how they complete a particular location because the rocks look alike or because of their proximity to faults and what have you. And that means not using a cookbook; it's location-specific, and seismic is critical for that. And the amount of hydrocarbon to be had by going from regional to location-specific is probably 20% more.

Degner: Agreed. The industry recorded surveys 25 years ago at 20,000 traces per square mile for around $100 per acre and is now using high technology and exceptional logistical execution to record surveys with many millions of traces per square mile for that same $100 per acre. We have delivered efficiencies using technology to improve resolution of earth imaging by many orders of magnitude. There's also a sense from the regulatory bodies that as soon as something happens that's catastrophic, they shut down the geophysics. Why would you shut down geophysics? Why wouldn't you increase it tenfold so you have better information to have better understanding?

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"Geophysics has the capability to measure the information about what operators do when they actually frack the well." —**Dave Monk,** *Apache Corp.*

Bahorich: We don't want to poke holes everywhere. We want to look first with a geophysical image.

Monk: So there is a capital argument against this that I've come across in the past. Before Apache, I did some consulting work for a bank that lent money drilling wells and doing seismic. There were people who did not want to shoot seismic because they thought it would condemn their acreage.

Gilmer: The only way you collapse an uncertainty cloud is to collect more broad data.

Degner: So the question is, are more traces always better? At the price that we're talking about, when you're paying $50 to $100 per acre while spending $60,000 to $80,000 to lease it and to develop it, it always matters.

Gilmer: But if you were going to use geology only, you'd be very successful on a portfolio approach. If you're going to drill 100 wells, you can get a good understanding of what those 100 wells will do in aggregate. If you want to determine what a single well will do, you need seismic data.

"There's enormous promise in technologies like ambient reservoir monitoring, tomographic fracture imaging and imaging the continuous emissions of sound from the permeability that exists in the earth." —**Richard Degner,** *Geophysical Technology*

Degner: I was in Baghdad a few years ago, and they wanted to know all about the U.S. shale plays. The *in situ* hydrocarbon in place is 14%. Eventually in this energy hungry world, we'll need to be harvesting the hydrocarbons in those massive Middle Eastern shale reservoirs.

My question is that, in less mature oil fields, is geophysics worth more? It seems like geophysics is readily applied earlier without hesitation internationally because they don't have all the well information.

Gilmer: From a conventional point of view, it's still mother's milk. You have to have it to drill those wells.

Bahorich: It's the tool that you need.

Degner: Today, because of the bleak balance sheets of the geophysical service companies, many can't buy new technology. And oil companies have budgets now. One national oil company in Latin America told us, 'We haven't shot seismic in five years. Our management just came to us and said we're supposed to shoot 5,000 square kilometers [1,931 sq miles].' They didn't know how to do it because the supply side of the service business is decimated. So they're looking at procuring geophysical technology direct themselves.

Gilmer: I think that's pretty fascinating.

Degner: It hasn't happened in 30 years. It's almost like we need a different commercial paradigm and a different commercial mechanism to create more efficiency and to leverage a lower cost of capital.

***E&P*: Do you think the oil companies will go back to owning their own crews?**

Degner: Anything that creates value makes sense. When the oil company has a cost of capital of 5% and the smaller service industry players have cost a capital of 40%, the only way the oil company is going to get the service done is if it pays the cost of capital of a service company that's in a beleaguered state.

Gilmer: What was the result of the oil companies divesting themselves of service company investments? They put the cost of R&D and capital on the service industry. Every time there was a boom, the seismic equipment manufacturers financed other companies. It's very efficient, but it didn't build anything.

Monk: But the evolution might be that the oil companies start building their own crews again, and five years from now they spin them off into separate companies. E&P

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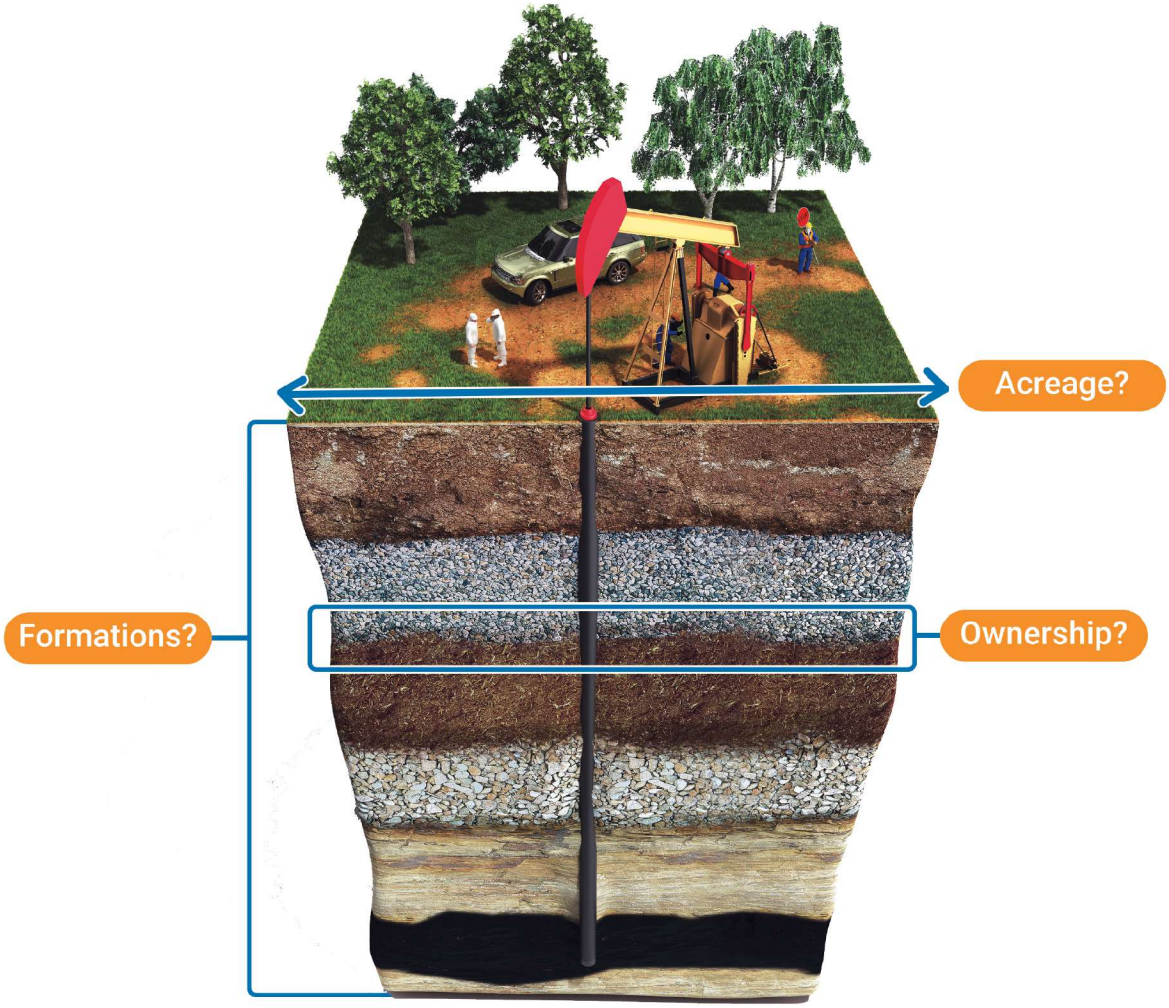

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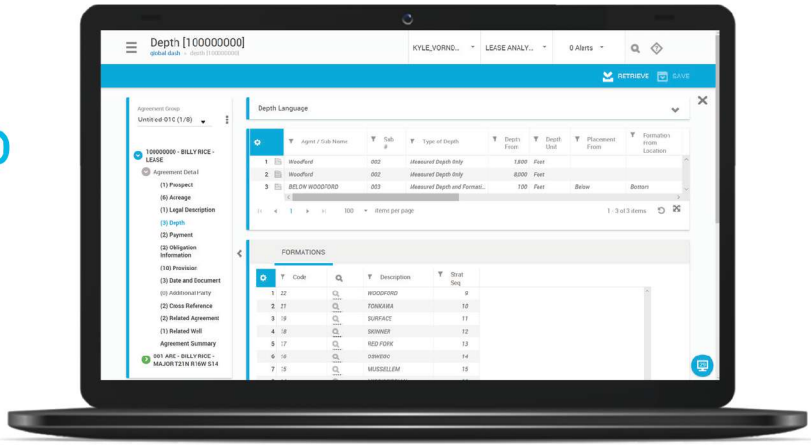

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OBN seismic is a de-risking game changer

The latest marine seismic technology has explorers taking notice.

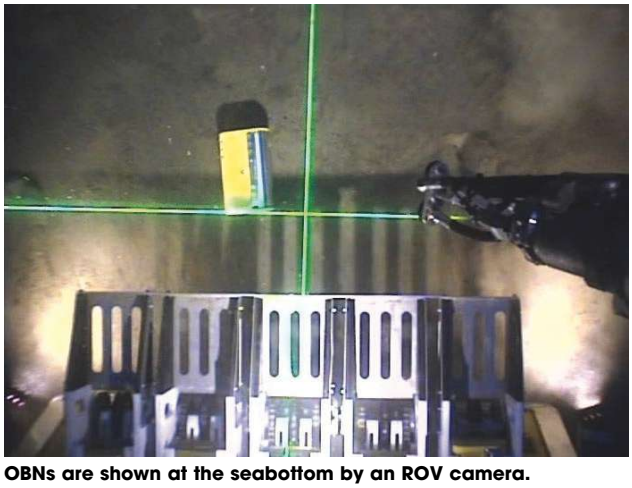
Per Christian Grytnes, Magseis; and
Rick Donoghue, Crescus

Years ago marine 3-D seismic data acquisition and processing was laborious and expensive but was deemed well worth the cost as it greatly reduced drilling risks. Since then, technological advances in towed streamer technology, vessel design, positioning systems, computer power and software have all combined to dramatically reduce the cost so that the collection of 3-D data is a routine part of the E&P cycle.

However, use of the highly cost-effective towed streamers technique is not always suitable or possible. For example, there are certain settings that cannot be imaged with sufficient resolution using towed arrays of sensors, such as those with complex geological structures, gas clouds or salt. To collect the data in these scenarios, multisensor ocean-bottom cable (OBC) systems were developed. Although they provided superior images, the additional cost of acquisition meant they were only used when absolutely necessary.

The OBC technique had its own limitations, particularly in highly obstructed areas. So in more recent times, autonomous ocean-bottom node (OBN) systems have been designed that allow large numbers of sensors to be placed anywhere on the seabed. What these autonomous units lack in real-time data transmission was more than compensated for by their deployment flexibility and data quality.

An OBN system potentially provides the best chance of acquiring the highest quality seismic data given its direct coupling with the seabed, its use of multiple sensors and the complete freedom to place them in any location. Historically, however, all ocean-bottom systems have suffered from slow deployment and recovery. Although, in the case of OBN, the absence of a cable provides greater flexibility and it also poses significant technical challenges related to system endurance (power usage), data storage, data quality control (QC) and timing synchronization between the nodes. Why, then, has OBN use over the last 10 years increased, and why is it predicted to double in the next three to four years?



OBNs are shown at the seabottom by an ROV camera. (Source: Magseis)

Technology advances

Significant engineering attention over the last decade has addressed many of the technical issues. Advances in battery technology, for example, have allowed some OBN units to record continuously for up to 150 days before they need recharging. This allows far more flexibility in survey design and improves operational efficiency.

Nodes are usually deployed, positioned and recovered in deep water by ROVs. Although ROV operations are slow, they enable the nodes to be placed reliably and accurately. ROVs also can be used to help synchronize the crystal oven clocks used in some types of nodes.

Configuration and health data from each individual node are broadcast to the deployment vessel, allowing real-time QC of the node and thereby facilitating its immediate replacement if it is not operating correctly after deployment. Information relating to data storage and battery life can also be transmitted, allowing further useful real-time QC and subsequent corrective action.

Technically, OBNs have reached the stage where they are widely accepted as able to provide reliable high-quality seismic data. These technical advances have all helped in the overall efficiency of OBN acquisition, and together with the fact that larger numbers of units are being manufactured, the unit costs have been reduced and will likely continue to

come down. However, the main aspect of an OBN operation that impacts the overall efficiency and hence the overall cost of a survey is the method of deployment and recovery.

Deployment and recovery

Most suppliers have designed their nodes to be attached to a passive cable or rope. This so-called "node on a string" technique offers some considerable advantages. A thin steel wire (or fiber rope) is deployed from the deployment vessel and the autonomous nodes attached to the wire, which is then "snaked" from the vessel down to the seabed to form a continuous loop of parallel receiver lines.

This type of deployment, at speeds of up to 6 knots, make the node-on-a-string technique a relatively efficient operation compared to OBC or ROV-laid nodes. This, in turn, is bringing down the cost of OBN and helping to fuel its recent and future predicted growth.

To be competitive in the OBN market, companies must be able to not only innovate but also manufacture the technology. (Source: Magseis)

A recent survey indicated that if suppliers can reduce the cost of an OBN survey so that it is just 50% more expensive than a towed streamer survey, then companies will gladly pay for the greater flexibility and higher data quality.

Future trends

So is the industry there yet with the quality being delivered by node technology? It seems that clients clearly recognize the quality of node data, so now it is a question of getting the cost right. But the industry also needs to focus more on selling innovative solutions to its clients to de-risk their activities and less on the technologies and surveys themselves.

OBN suppliers have worked hard to increase productivity over recent years. But further significant increases in deployment recovery speeds can be realized. The industry has been improving deployment speeds with the node-on-a-string technique over the last five years, and it can now optimize the deployment approach to each individual survey. Though ROV operations benefit greatly from having such a small node to handle, both standard ROVs and higher speed survey ROVs are not ideally suited to node deployment. There is an opportunity for a fit-for-purpose node ROV to further increase productivity. There also are opportunities for working with clients at the survey design stage so only the appropriate amount of equipment is deployed for a specific survey to increase productivity.

And there are market developments in the life-of-field sector. Life-of-field is a generally growing market. ROVs can very accurately position nodes for repeat surveys, and clients do not have the large upfront capex of a permanent system. They are also not faced with high maintenance costs, the risks of failure or the fact that they are stuck with ever-aging technology.

Increasing competition

The entry barrier to this sector has always been high, so it is unlikely that any new competitors will come to market. Of course, there may be opportunities for those whose model would be to lease equipment on the spot market. But there will always be a need for innovative technology companies.

The market will continue to grow. The estimated $1 billion 2018 ocean-bottom seismic market will continue to flourish as it takes further market share from the towed streamer and reservoir monitoring sectors. Great opportunities for more extensive surveys using much larger amounts of equipment exist. The future is very optimistic. EP

A Shearwater vessel acquires a marine seismic survey. The startup recently purchased WesternGeco's marine seismic acquisition assets. (Source: Shearwater GeoServices)

The changing face of the seismic sector

Despite the downturn, there is room for new, flexible and fit-for-purpose contractors.

Tom Hay, Shearwater GeoServices

The last 10 years have been a difficult period for the seismic industry, with the last five being particularly brutal. In the previous decades the industry had grown accustomed to the fact that it was cyclical. Demand for seismic services was either high, in which case contractors were able to increase margins and invest in new technology, or demand was low, and contractors survived by acquiring poorly funded nonexclusive surveys and laying up crews while looking forward to the next upswing. Since 2012 the seismic demand trend has been one way only, and the established players are shadows of their former selves. In mid-2018 there were 21 active high-capacity 3-D vessels operated by the major contractors compared to about 75 a few years ago.

Signs of some sort of recovery are becoming evident from the worst downturn the industry has ever experienced. With the backdrop of a higher prevailing oil price and positive financial results from oil companies, this year's European Association of Geoscientists and Engineers conference in June was the most upbeat for several years.

After the significant layoffs and restructuring over recent years and with the majority of contractors burdened with heavy debts, is the industry in a fit state to be able to capitalize on any market improvement if it arrives? A cold-stacked vessel is estimated to require about $50 million to get it back into action. Who can fund that sort of expenditure?

Reacting to the challenge

Shearwater GeoServices was founded in 2016, moving into the gaps left by some of the major seismic contractors. The company has focused on efficiency and quality, with growth as its next goal.

Shearwater emerged from the downturn with four modern high-capacity vessels and its own proprietary data processing and imaging software. Solid backing has come from GC Rieber, a company founded in 1879 that has grown into a global shipping organization providing

ship development; design; construction and operation services to the subsea, seismic and ice/support sectors, as well as Rasmussengruppen, a company that has had international shipping at the core of its business since it started in 1936. Both saw the potential of acquiring the marine seismic acquisition assets and operations of WesternGeco ahead of an anticipated increase in demand for marine seismic services. This move will transform Shearwater into a full-service marine geophysical company.

Agile fleet

High-transit speeds help cut down on unprofitable travel time between surveys and also allow the vessels to consistently and safely tow large streamer configurations at highly efficient acquisition speeds that bring down the total duration of each project. This power and redundancy not only mean reduced risk in highly obstructed areas where loss of power could be catastrophic but also consistent and efficient ground speeds in sea areas where strong head currents or harsh weather conditions occur. This last issue has historically hampered many surveys worldwide, where strong currents impede progress, increase survey duration and drive up cost.

Processing and imaging

The flexibility and cost efficiency in terms of the number and configuration of streamers and sources that can be towed by the new fleet is mirrored by the company's processing and imaging services. These can combine both offshore real-time data processing and onshore processing flows that are designed to meet the quality, timing and cost constraints of each project. To add additional flexibility and efficiency to processing solutions, a new concept called "pop-up" processing brings the power and expertise of a major processing hub to a client's doorstep.

For example, a series of onshore data processing projects has recently been completed in a processing center in Mumbai for a major client in India. Commencing in January 2017 and using its data processing software, the company processed 4,500 sq km (1,737 sq miles) of 3-D imaging from four new 3-D surveys in both time and depth.

The team consisted of 15 geophysicists working in a center in Mumbai, but it was managed from a main processing hub in the U.K. because the center in Mumbai was installed to process a specific volume of work and was not designed as a permanent processing hub. The hardware and personnel have now been redeployed elsewhere.

Set up in under a month, this bespoke project-driven model allowed the company to provide very cost-efficient, high-quality results in Mumbai using local partnerships and experienced and dedicated support.

This approach to data processing services allows the company to provide full processing and imaging services on a global scale, setting up centers quickly and easily wherever clients require. This model is an example of the industry's new capabilities to provide highly flexible project-designed processing solutions that are not constrained by location or existing processing models.

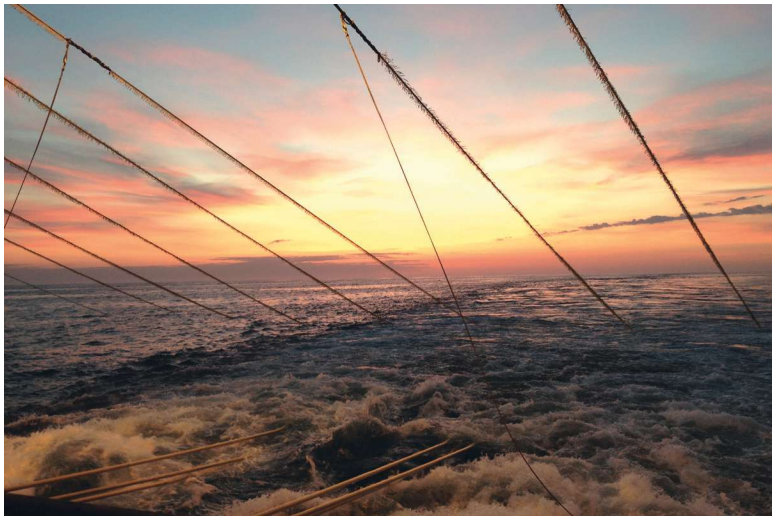
Time and depth processing

One of Shearwater's offerings is Reveal, a proprietary software that performs time and depth processing and imaging for both land and marine data within a single user interface. Reveal has been designed and built in recent years, making it unique since most processing packages date their origins to the 1970s and 1980s.

A dedicated Reveal R&D team ensures continuous development and rapid deployment of new functionality and response to customer requirements.

The platform is intuitive, interactive and adaptable and has the flexibility to be scaled to run on a laptop in the field as well as a large data center. Processing results are displayed in real time, which gives a better understanding of how the data are being affected and allows more informed decision-making. Reveal also provides a developer's environment to customers who want the flexibility to integrate their own existing workflows and processing systems, bringing new life to old code.

In an industry that often seems moribund, companies that take a new approach offer hope on the horizon. EP



Shearwater's vessels have improved propulsion power and redundancy, providing a high-transit speed and the ability to tow large streamer configurations. (Source: Shearwater GeoServices)

Complex prescription

Surfactant and solvent chemical blend enhances reservoir production.

Jennifer Presley, Executive Editor

Oil and gas producers face no shortage of complex challenges. To remain competitive in times of low oil prices, the industry's focus on cost reductions intensifies only to then shift to cost management when the price per barrel of crude ticks upward. Maximizing production from existing fields is one of many levers pulled in the quest to remain competitive. Low prices or high, every additional barrel pumped provides much needed cash flow. Of the many tools available to enhance production returns, Flotek Industries offers a chemical blend called Complex nano-Fluid (CnF) that is making an impact in new wells and old.

"The CnF technology is a patented combination of solvent and surfactant. It is multidimensional in that it can be used in the applications across the entire life cycle of the well," said James Silas, senior vice president of research and innovation for Flotek.

The technology helps with fluid mobility and increases productivity between the reservoir and the wellbore, helps reduce capillary pressure and more. It is built and designed to address different challenges within different reservoirs.

"We partnered with our clients over the years to solve what we think is almost every possible challenge, whether it's to enhance production earlier on a new well completion, or to extend the life and improve later year production on secondary recovery," said Flotek's CEO John Chisholm.

Rather than recommend ways to enhance production, the company uses a prescriptive chemistry approach, Chisholm noted.

"We use information provided by the client, like drill cuttings, oil and water samples, and more, to prescribe what the proper approach would be to improve production," he said. "It is like going to the doctor, answering their questions and giving blood samples so that the proper course of treatment for you is prescribed."

Determining the best approach

It is not an apple but an orange that helps keep the doctor away, as a primary component of the CnF blend is d-limonene, a major constituent in citrus oils. For more than a decade, CnF technologies and the prescriptive chemistry process has been used in thousands of wells all over the world, according to Chisholm.

"The prescribed chemistry we use in Argentina is different than in the Middle East, and that's different than the chemistry prescribed for use in the Delaware Basin," he said.

The first step in determining the best approach is conducting a geological reservoir analysis, according to Silas.

"We have basin studies on all the active areas currently within North America and around the world that we use to help us identify what the baseline challenges could be within an area," he said. "Then we work with the client to narrow down that universe of challenges to what, specifically, they are going to encounter within their application."

Based on this internal analysis, Step 2 is design of the entire fluid system that should be used to optimize production from that specific reservoir by the company.

"Whether that's identifying the types of clay and clay control that would be needed or the exact type of Complex nano-Fluid technology that would be most effective within their reservoir, or whether there's particular production challenges that could be coming from the oil (i.e., paraffins or asphaltenes), these different components of the oil can cause production challenges that can be addressed within the original fracture stimulation," he said.

Administering the prescription

Step 3 in the process is to deliver and monitor quality during onsite chemical delivery.

"When we're looking at the entire fluid system that we want to apply, we'll actually extend beyond just the Complex nano-Fluid itself and prescribe every chemical component within that fluid system, including clay and scale controls, biocides and more," Silas said. "We have generally seen that the combination of Complex nano-Fluid with those other chemistries helps them all to work better."

It is this multidimensional aspect of the technology, its ability to not only deliver the solvent and surfactant but also the other necessary chemistries to the reservoir surface, that helps ensure reservoir improvement, he added.

The amount of time needed for an improvement in production to be realized depends on the application.

"In cases where we're looking at including [the technology] within an initial fracture stimulation, then it'll be weeks during the completion that it will be in

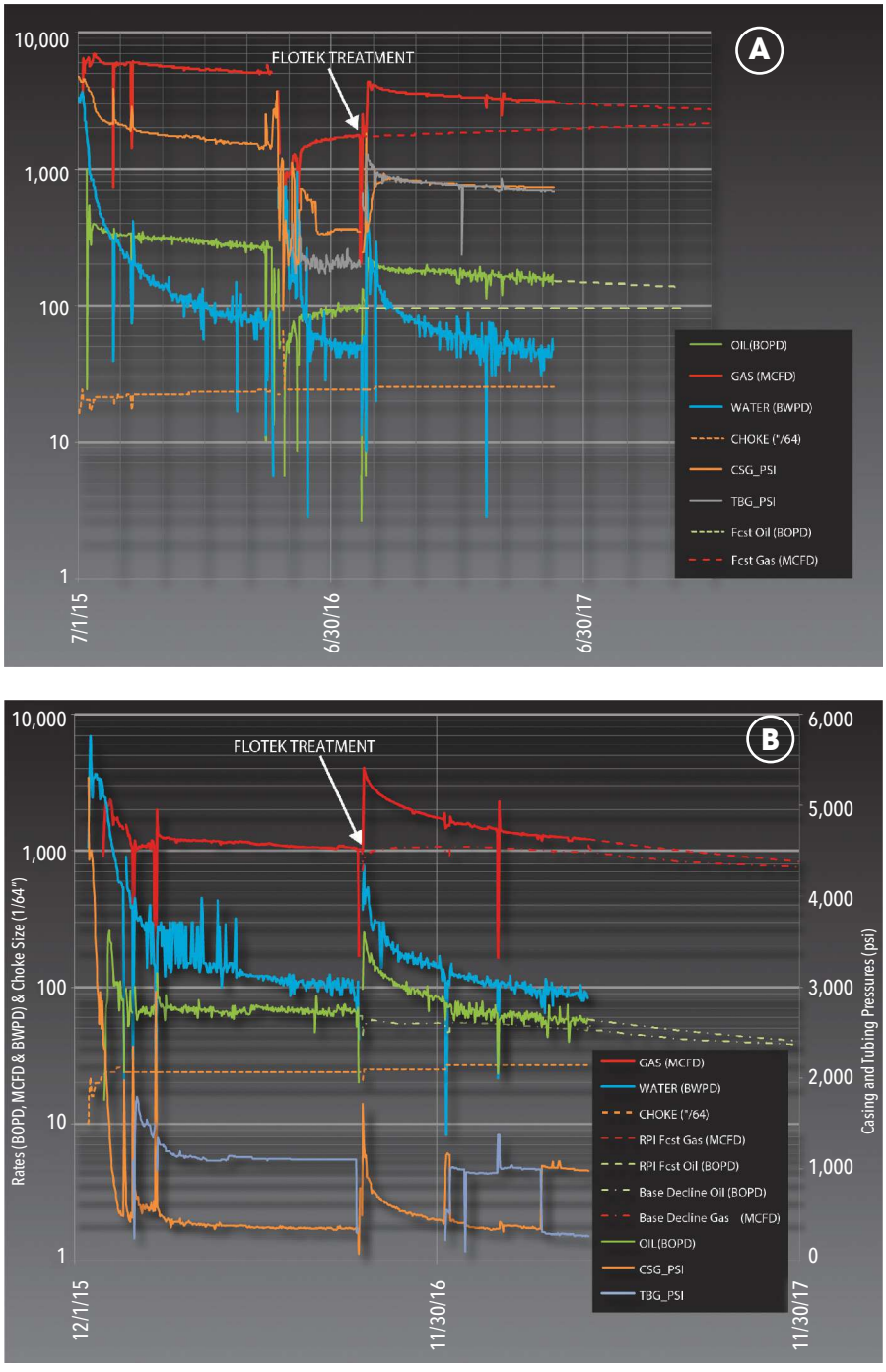
contact with the reservoir," Silas said. "Then during flowback, it'll essentially have been in contact with the reservoir for months at that point. In a remediation, it's going to be a short time period, maybe a 24-hour soak or 48-hour soak, where we normally see that application."

Case study

An example of this successful prescriptive approach involved an operator with acreage in the Woodford play in Grady County, Okla., that was experiencing negative effects of fracture treatments from nearby offset wells (fracture hits). In addition, production was lower than expected based on predrill estimates. Production challenges are pervasive in the Woodford intervals where clay content, structure and natural fracture density impact well and completion design. Additionally, reservoir pressure is variable across the Woodford in this county, according to the URTeC-2902400 paper. Flotek partnered with the operator to perform a pilot analysis to determine how to reverse the negative effects and improve production.

Analysis determined that the two fracture hit wells were drilled 457 m to 487 m (1,500 ft to 1,600 ft) apart with a similar lateral length and completion design containing 6.6 MMlb to 7.3 MMlb of proppant over approximately a 1,371-m (4,500-ft) perforation length, which were normalized. In addition, the two wells that underperformed on initial stimulation had a perforated interval that varied from 1,272 m to 2,024 m (4,175 ft to 6,640 ft) with 7.6 MMlb to 10.1 MMlb of proppant, which were normalized in the analysis, according to the paper.

These four wells were treated with a customized mix of CnF, hydrofluoric acid, hydrochloric acid and ammonium chloride. The treatment delivered positive results, with increased production realized in each well. Production was restored to prefracture hit rates in one well and resulted in a fourfold increase in preremediation production rates in another. EP



Production increased after treatment of the fracture hit wells (A) and underperforming wells (B) with CnF technologies. (Source: Flotek Industries)

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*.

Optimizing hydraulic fracturing biocides for system and shale compatibility

A cost-effective microbial control program can offset negative impacts on affected production.

Christina Pampena and **Sheila Tinetti**,
Dow Microbial Control

There are many sources of microbial contamination during the hydraulic fracturing process as fracturing fluid passes from the surface into the downhole environment (Figure 1). Microbial growth negatively impacts production rates, asset integrity and hydrocarbon quality, making an integrated microbial control program essential for smooth operations and optimal return on investment. Compounding these challenges, completions engineers have one chance to select the most effective biocide program for their well. The following is a deeper dive into biocide efficacy, strengths and weaknesses, and selection strategies to optimize system and shale compatibility.

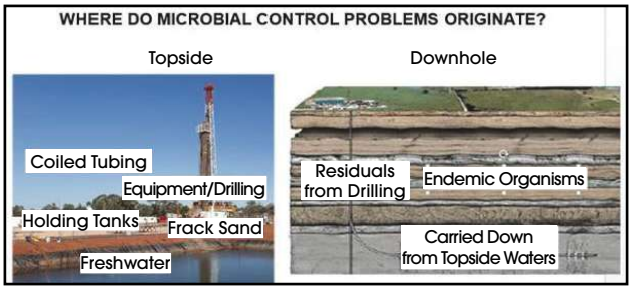


FIGURE 1. Microbial control issues can originate in several areas in hydraulic fracturing operations. (Source: Dow Microbial Control)

An integrated approach

Although biocides make up a small amount of fracturing fluid, they play a critical role in maximizing productivity and reducing operational costs over the lifetime of a well. Biocide selection must always be based on the specific application conditions of each phase of the hydraulic fracturing process (Figure 2). Phases can vary significantly in terms of temperature, salinity, aerobic/anaerobic conditions, shale type, additive compatibility and desired duration of control.

During preparation of the water topside before it is injected into the well, an abundance of microorganisms often are present due to natural nutrients and/or the use of recycled produced water. Treating this water with quick-kill biocides, such as 2,2-dibromo-3-nitrilo-

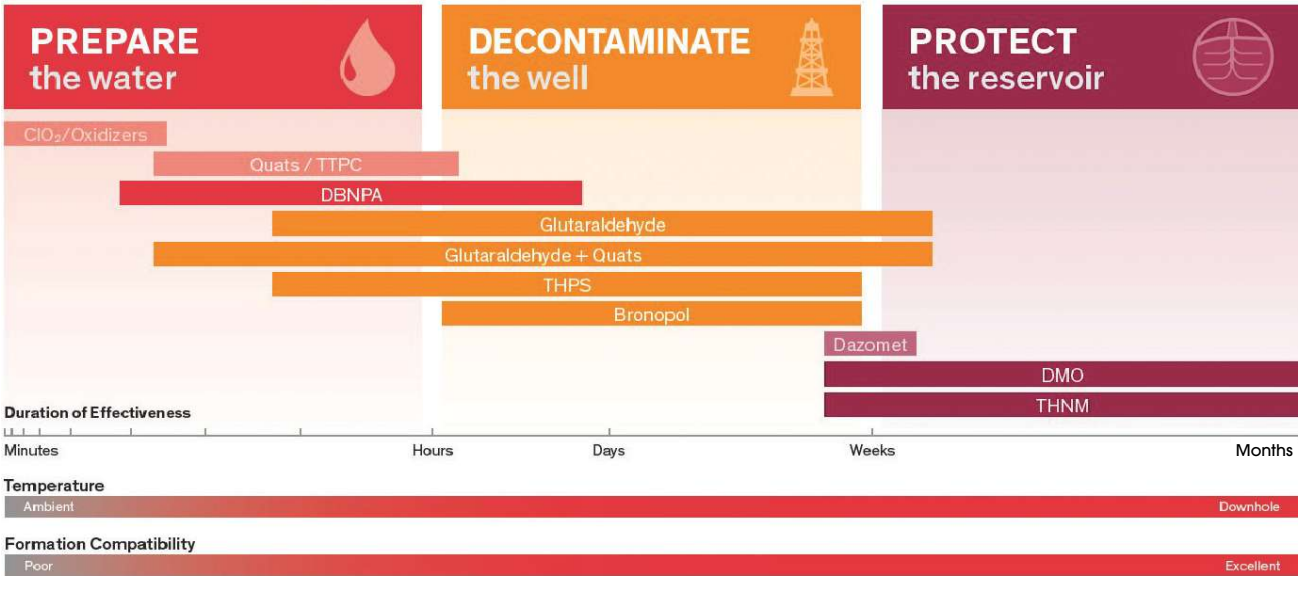


FIGURE 2. This chart depicts comparative efficacy of biocide chemistries during the phases of hydraulic fracturing. (Source: Dow Microbial Control)

propionamide (DBNPA), will decrease the initial bioload and enhance biocide performance used in later stages of the process.

Biocides also are necessary during the well decontamination phase to control organisms introduced during drilling and completion activities. This is best accomplished using chemistries such as glutaraldehyde or glutaraldehyde/quat blends to provide microbial control for several weeks during drillout and IP.

Reservoir protection biocides, which must remain effective for long periods and under extreme heat and salinity conditions, are vital during the final phase of hydraulic fracturing as organism growth can cause formation damage and produce H_2S over time. Dimethyl oxazolidine (DMO) and tris(hydroxymethyl)nitromethane (THNM) are examples of biocides that remain efficacious in the downhole environment, and they can delay or reduce souring and corrosion over a period of months.

Biocide diversity

Biocide selection based on the different phases of the hydraulic fracturing process is only a start. Operators interested in maximizing the benefits of their integrated microbial control program must consider compatibility with proppants, friction reducers and other fracturing fluid additives. For example, the trend of using greater volumes of proppant increases the potential for microbial contamination from the proppant itself.

Diverse biocides and dosage levels are required to both decontaminate the well and protect the reservoir. Many hydraulic fracturing operators have learned that although inexpensive options like chlorine dioxide (ClO_2) and tributyl tetradecyl phosphonium chloride (TTPC) are effective as quick-kill biocides during topside preparation of the water to reduce bioburden, they will not decontaminate the well or protect the reservoir.

There is also an increasing amount of slickwater fractures in use today, so operators need to know that cationic surface-active chemistries such as TTPC often are incompatible with anionic friction reducers, like hydrolyzed polyacrylamide. It also is critical to understand that glutaraldehyde is incompatible with the primary amines found in some corrosion inhibitor additives, and that oxidizers such as ClO_2, are highly reactive with many fracturing fluid additives and other organics.

Biocides for shale compatibility

Oilfield biocides have been studied extensively in relation to compatibility with other fracturing fluid chemicals, but much less effort has been dedicated to understanding biocide compatibility with the reservoir shale itself. Recognizing that shale can have a significant impact on both microbial growth and biocide efficacy in the downhole environment, Dow Microbial Control recently designed and performed an extensive study to evaluate biocide performance in the presence of shale formation rock. The following is a summary of one portion of that study.

Dow Microbial Control's tests used facultative anaerobic bacteria in an anaerobic environment to mimic downhole conditions. A broad range of commonly used oilfield biocides were tested (Table 1).

TABLE 1. MICROBIAL EFFICACY STUDIES WITH SHALE ROCK

Surface-active Biocides	Electrophilic Biocides	Long-term Preservative Biocides
ADBAC	Glutaraldehyde	DMO
TTPC	THPS	THNM
PHMB (polymeric)	DBNPA	
	Bronopol	

(Source: Dow Microbial Control)

Rock and bacteria were placed together to closely mimic actual oilfield conditions during the well decontamination and reservoir protection phases. Biocide efficacy was compared in the presence of shales from three different plays: Mancos, Marcellus and Barnett. Biocide efficacy was tested at 4 hours to represent biocidal action while decontaminating the well as well as after seven days to represent longer-term protection of the reservoir (Figure 3).

As shown in Figure 3, after 4 hours decontaminate biocides, such as glutaraldehyde and tetrakis(hydroxymethyl)phosphonium sulfate (THPS) remained fully effective, independent of the presence or type of rock. The surface-active, quick-kill biocides—TTPC and alkyldimethylbenzylammonium chloride (ADBAC)—were adsorbed onto the rock and completely lost efficacy after 4 hours. As expected, slow-acting preservative biocides, DMO and THNM, required more than 4 hours to be effective.

After seven days, total organism growth (even in unpreserved samples) was influenced by the rock type. As illustrated, glutaraldehyde remained fully effective in the presence or absence of rock. However, THPS efficacy was dependent on the rock type, losing significant effectiveness in the presence of Mancos and Barnett shale. TTPC and ADBAC completely lost efficacy in the presence of all three shale types. For the long-term preservatives, the efficacy of DMO and THNM also was dependent on rock type.

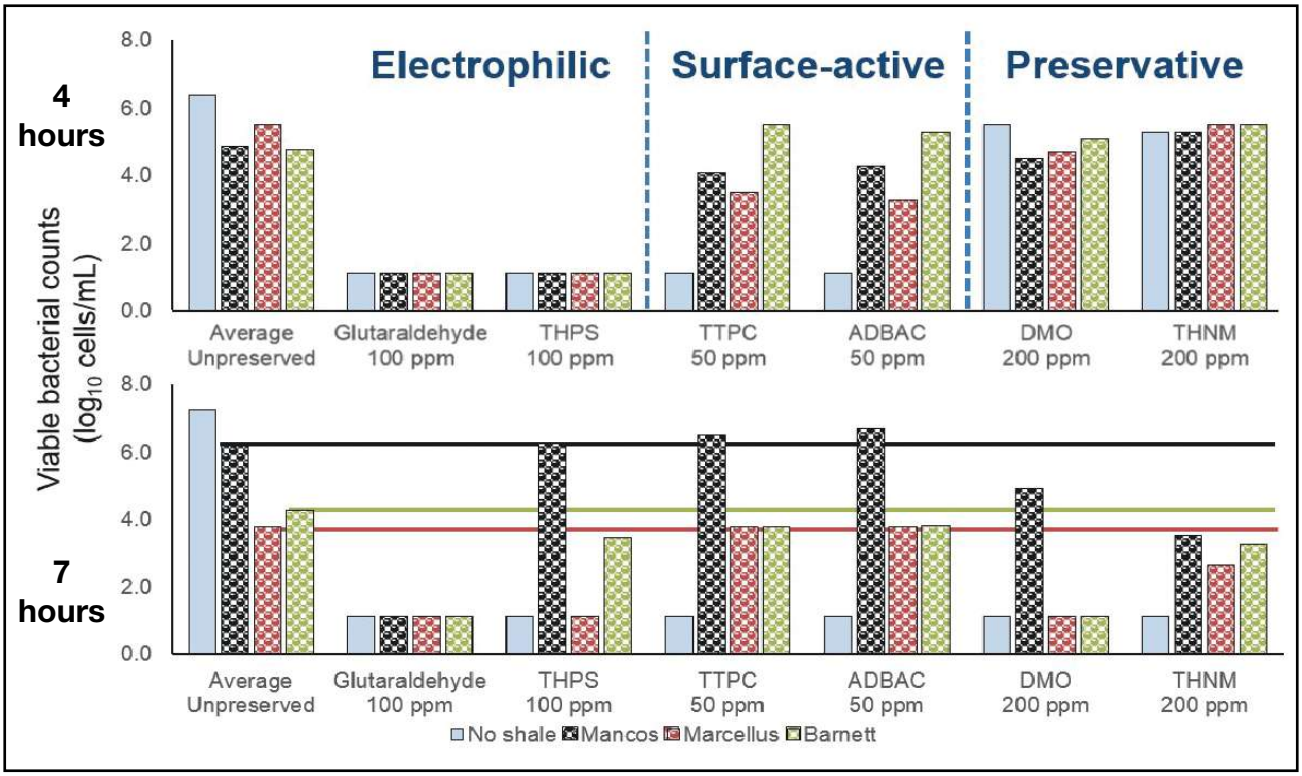


FIGURE 3. Comparative biocide efficacy in the presence of different shales are shown. (Source: Dow Microbial Control)

These studies demonstrate that shale compatibility is an important consideration when selecting an effective biocide to control organisms in the downhole environment. In the presence of shale, surface-active biocides—ADBAC and TTPC—show reduced availability in the aqueous phase, resulting in loss of efficacy against planktonic bacteria. There was no effect of the shale or the shale type on efficacy of electrophilic biocides—glutaraldehyde, DBNPA and Bronopol—but there was some shale-dependent loss of efficacy with THPS. Long-term DMO and THNM preservative efficacy was entirely dependent on the shale type.

No 'silver bullet'

There are a wide variety of biocides available to protect hydraulic fracturing operations from microbial growth, and they all have strengths and weaknesses. Biocide selection begins by understanding overall efficacy during the three phases of hydraulic fracturing:

- Biocides most appropriate for preparing fracturing water topside include DBNPA, TTPC, glutaraldehyde, glutaraldehyde/quat blends and ClO_2. Glutaraldehyde in particular is versatile, proven and readily biodegradable;
- Glutaraldehyde and Bronopol are appropriate for decontaminating a well. So is THPS, although efficacy may be dependent on the type of shale; and
- Biocides most appropriate for long-term protection of the reservoir include DMO and THNM, but shale compatibility is an important consideration in final selection.

Beyond their fracturing phase efficacy, optimal biocide selection depends on compatibility with fracturing fluid additives, such as friction reducers, proppant, type of shale, pressure and temperature resilience, and/or the blend of fresh and produced water being used.

The bottom line is that there is no "silver bullet" biocide capable of handling every phase of the hydraulic fracturing process in tandem with other fracturing components or different shale plays. Biocide selection is not as simple as checking a box, but microbial control suppliers can simplify matters considerably as operators create and optimize a cost-effective, profit-protecting and integrated microbial control program. EP

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*.

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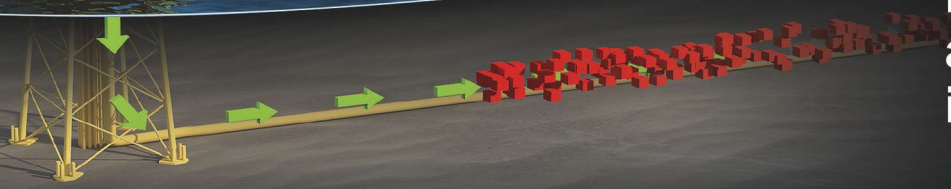

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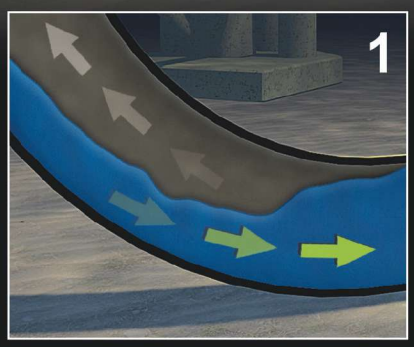

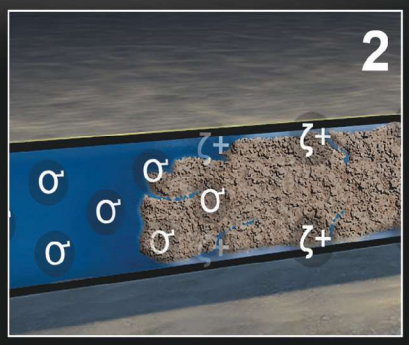

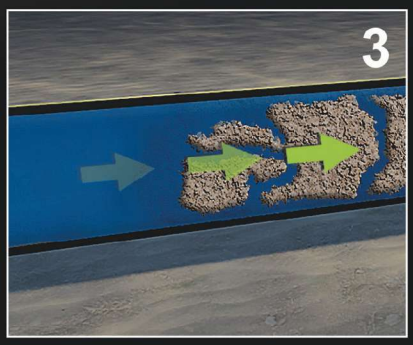

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Aasta Hansteen on fast track

Digital technologies, including running a virtual startup, look set to save 40 days from the run-up to first gas processing on Equinor's Aasta Hansteen development.

Elaine Maslin, Contributing Editor

Norwegian operator Equinor is on track to deliver what could be the world's fastest upstream project startup at its Aasta Hansteen development in the Norwegian North Sea later this year, thanks to a drive toward automation and running virtual startups.

The project, which is Norway's first spar development and the country's deepest water development to date, is due onstream in the fourth quarter this year, following tow-out of the 70,000-tonne, South Korean-built facility to the Norwegian Sea in April.

The project is a year behind its original 2017 startup date due to delays in construction. But Swedish power and automation group ABB said that by using its ABB Ability digital solutions to review the plant's operability and then run a virtual startup, using a dynamic model, to find and resolve any issues before the actual startup, an estimated 40 days—or 2,700 man-hours—could be saved.

The time-saving was found by automating more of the startup procedures—some 1,000 manual interventions were reduced by 98% to 20—and finding and resolving some 57 issues ahead of the startup procedure, according to ABB.

"We believe this will be the world's fastest startup," Marius Aarset, vice president of advanced services and products for the Norwegian hub of oil, gas and chemicals at ABB, told Hart Energy in an interview before the company's announcement at ONS 2018 in Stavanger, Norway.

Reducing delays

Delays in commissioning typically take 12 to 18 months, according to Aarset. He said they are a regular industry problem and have been exacerbated in some of the boom periods when access to experience has been slim. Even now, there are regular issues with commissioning, despite the industry's relative maturity.

"There are common issues at a basic level," he said. Part of the issue is a lack of focus on operability and a lack of effective feedback, according to Aarset.

"So, what you see is that, even though a plant is built to specification, there are still a lot of issues, like a valve going a different way to what the operator thinks it should or control structures around one or more compressors, which probably work, but are more or less impossible for the operator to understand," he said.

The challenge is that these issues go unnoticed until startup and then cause costly delays.

On Aasta Hansteen, which is in 1,300 m (4,265 ft) water depth in the Vøring area 300 km (186 miles) offshore, ABB is deploying its ABB Ability platform and its in-house domain expertise. This includes identifying logical sequences that take place during startup, such as having a valve in the right position, activating a control sequence and then piecing them together. They can be activated with one intervention, instead of multiple, so that it is a more automated process, according to Aarset.

ABB also used a dynamic model to test the design. "In the past, dynamic models were

The Aasta Hansteen spar platform was towed to the field from Stord in April. (Photo by Olaf Nagelhus, courtesy of Worldcam/Equinor)

used for training the operators," said Borghild Lunde, senior vice president for the Norwegian hub of oil, gas and chemicals at ABB. "Now we're using them to test if there are flaws in the design."

ABB Ability 800xA contains a replica of the control loops and allows processes to be simulated so the system can be tested—what some would call a digital twin.

"Our teams went through the startup steps, identified and defined obstacles that needed to be improved, then used our ABB Ability System 800xA simulator to do a virtual startup of the plant," said Per Erik Holsten, managing director for ABB oil, gas and chemicals. "At this stage, we made a lot of improvements for starting up and operating the plant. Through automating much of the process, we managed to reduce a complex set of manual interventions to just 20, which means we are all set to deliver what we believe to be the world's fastest startup at first gas."

Optimizing faster

In addition to reducing the time to first oil or gas, these systems have benefits during operations, according to Lunde. That includes helping to achieve optimum production faster by being able to tune facilities more easily with more automated processes.

"When you have to shut in a well for maintenance and want to start up again, you also get the benefit from this," Lunde said. "It's faster. We have cut the time it takes back to hours when it used to be almost days."

It has taken the upstream industry a long time to adopt these ideas. Lunde started work on this area when her son was born, and he's now 20.

"We have gained a lot of experience from various applications on various sites, but it's not until recently [upstream] customers have been interested in the whole spectra, from commissioning through to startup and production as part of daily operations," Lunde said. "In downstream this has been more accepted, because they have had to make money [and] they have to be performing. It's now clearly on the table. For some of the smaller players, this can offer more value. For some operators, the ultimate goal is a more autonomous asset."

Indeed, Aarset said Equinor would like to take its automation of the startup procedure even further, to have just one button, like you start a car. "This means operators can then put their focus on monitoring how the startup goes instead," he said. "Like cars, we've gone from keeping a set speed to keeping a set distance from the car in front so the driver can focus on the overall picture in the traffic."

Aarset said ABB already is working on what could be called "auto-pilot" systems for ramping up wells.

Anchoring operations for the Aasta Hansteen spar platform were performed in April. (Photo by Henning Selstad, courtesy of Equinor)

"There's a way to go [to full automation], but there are elements that can be implemented," Lunde said. "This is part of a bigger picture; there is a movement. In the last couple of years, we have seen a change. Digital is now more on the agenda, and there's more acceptance that you can do more with software. These are additional skills, and there's been a willingness to investigate and use them."

At Aasta Hansteen, which was discovered in 1997 by BP and comprises three separate discoveries: Luva, Haklang and Snefrid South, ABB also is providing a condition monitoring system to monitor more than 100,000 maintenance conditions from more than 4,000 pieces of equipment, tools for alarm management and alarm rationalization, several safety critical applications, data storage solutions and third-party system integration of essential data traffic.

Equinor had engaged ABB early on in the Aasta Hansteen project development, valued at $3.84 billion when it was submitted for government approval and now estimated to cost about $4.4 billion, for which ABB also has delivered full automation and safety systems and telecommunications. EP

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*.

Continuous steering approach reduces tortuosity in horizontal wells

Efficiency and accuracy of directional drilling is improved with new proportional steering system.

Albaraa Alrushud, **Denise A. Livingston** and **Muntasar Mohammad**, Baker Hughes, a GE company

In their ongoing push to simultaneously improve operational efficiencies and reduce drilling costs, drillers have to carefully weigh their options when it comes to selecting the right rotary steerable system (RSS). The optimal drilling system for a given formation will help the driller achieve a high average ROP while minimizing tortuosity and deviations in the well path.

Some degree of deviation is necessary for course correction purposes—to redirect the drillbit to ensure the wellbore reaches target depth and location, and maximizes contact with productive zones in the reservoir. However, too much tortuosity, which is being defined for these purposes as the unwanted undulations around the well plan, raises the cost of the drilling operation. It also can diminish hole quality, which increases the potential for problems while running the completion and can negatively impact production in both the short and long term.

Different mechanisms, similar drawbacks

Two of the most commonly used steering mechanisms are push-the-bit and point-the-bit systems. In a typical push-the-bit system, a force is applied against the wellbore side wall through multiple pads mounted on the body of the RSS. One pad is activated at a time by diverting some mud flow through a controller valve, and the action of the pad pushing against the wellbore directs the bit in the desired direction. Point-the-bit systems instead rely on internal deflections running through the RSS to tilt the bit into the desired well path.

Both systems work on the principle of on/off steering cycles. The pads or tilting mechanisms are deactivated, or off, until a predetermined inclination threshold is crossed. At this point, the systems reactivate to build angle and correct the inclination to remain within the desired value. It is quite common to overshoot the target when passing the correct inclination angle until the switch-off threshold is achieved. Consequently, the pads and tilting mechanisms go into an ongoing cycle of opening and closing to meet the directional plan, and the wellbore will continuously oscillate around the planned well path until target depth is reached.

This on/off steering principle, and the resulting tendency to overshoot the target, makes the drilling process longer and less efficient. These systems also tend to create more tortuous well paths that compromise ultimate recovery.

Continuous proportional steering

A third RSS mechanism known as continuous proportional steering operates by a different principle. Instead of an on/off cycle, the system delivers directional control by applying pressure through three independent pads mounted on a slow rotating sleeve. Internal hydraulics power the steering pads, with an electronic processor controlling the continuous distribution of pressure to the pads. Each pad receives the exact proportional force magnitude required to keep the bit moving in the desired direction.

Steering control is not affected by drilling dynamics, like bit pressures, flow rates and drilling fluid properties, as it is in many competing systems. As a result, the technique ensures more precise and consistent directional control.

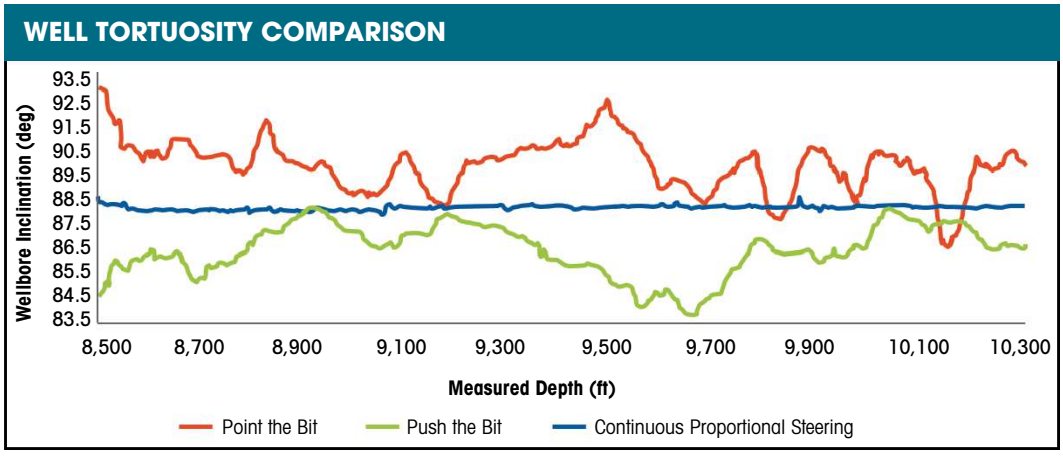
Continuous proportional steering is the underlying technology in the AutoTrak RSS, developed by Baker Hughes, a GE company (BHGE). The system has been successfully deployed in horizontal wellbores around the world, reliably delivering smoother, in-gauge holes and precise well placement as well as improved overall drilling performance. BHGE system's operational flexibility enables operators to match the drillbit design to the formation challenges, thus improving efficiencies on the rig and in the hole.

Verifying field performance

An operator in the Middle East has deployed all three RSS technologies in its wells, but the operator was uncertain as to how effective each mechanism was at delivering a high-quality hole that would optimize subsequent completions and production operations. Therefore, the operator partnered with BHGE to conduct a

joint study aimed at quantifying the tortuosity and deviations created by the three RSS tools.

The study quantitatively compared available RSS technologies by running high-resolution wireline surveys in more than 700 wells in the same field. Although different RSS technologies were used in these wells, other conditions such as geologies, trajectories and bottomhole assemblies (BHAs) were similar. The study effectively isolated the RSS as the primary variable, enabling a like-for-like comparison between steering technologies. All survey data were gathered from areas of mature directional drilling operations, ensuring that the early learning curves for RSS BHA design and operation were already complete.



A comparison of well tortuosity using high-resolution wireline surveys from three offset wells clearly shows that the continuous proportional steering method delivers substantially superior hole quality and minimal tortuosity compared to push-the-bit and point-the-bit techniques. (Source: BHGE)

The high-accuracy, high-density wireline surveys took measurements at 3-in. intervals throughout the horizontal sections of the wells. This provided highly accurate insights into hole quality that could not be observed with MWD surveys. The longer survey intervals required for MWD systems—typically anywhere from 9 m to 29 m (30 ft to 95 ft) to collect one datapoint—simply would not offer an accurate representation of wellbore hole quality concerning tortuosity. While MWD results show that push-the-bit and point-the-bit systems do not deliver the same hole quality as continuous proportional steering, the wireline data revealed pronounced differences and high local doglegs invisible in MWD datapoints.

The novelty of the wireline survey approach lies in its ability to precisely evaluate wellbore tortuosity using a far greater number of datapoints. Four points are recorded over a distance of .30 m (1 ft), which provides a much finer level of analysis compared to standard MWD results.

The results of the study confirmed this. When examining the high-resolution wireline data, it became clear that both the push-the-bit and point-the-bit RSS tools significantly increased wellbore tortuosity. The underlying on/off steering mechanics used by these systems were incapable of drilling a horizontal wellbore without a significant level of tortuosity. Increased tortuosity during drilling has immediate cost and efficiency consequences, requiring reaming, backreaming and cleanup cycles. As these consequences are multiplied across wells, tortuous wellbores can have a significant cumulative effect on field development, production and profitability.

Conversely, the study demonstrated that continuous proportional steering reduced tortuosity by four to six times when compared to push-the-bit and point-the-bit methods, and it consistently delivered better hole quality in horizontal drilling. Continuous proportional steering left a clear path that improved drilling efficiency with a greater ROP, reduced the likelihood of stuck pipe or lost BHAs, improved control to stay in the pay zone and reduced time to target depth. It also reduced costs and improved efficiencies while running casing and installing completions. A less tortuous wellbore increases the well's production potential by improving reservoir contact and makes for easier workovers and abandonment operations as the well matures.

The operator has used this research study as a useful reference to analyze the performance and efficiency of RSS mechanisms across drilling and workover operations. Other operators are encouraged to deploy similar high-density wireline surveys in their fields and see for themselves how continuous proportional steering systems, such as AutoTrak RSS, help improve the efficiency and accuracy of directional drilling compared to traditional RSS technologies. EP

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

Taking the right steps to automation

There is an impact on data infrastructure when using real-time analytics.

David C. Johnson, Petrolink

With the growing rate of available sensors and the increased data density that is accessible to companies involved in drilling for oil and gas, the processes and approaches used by data management and IT departments, and the impact of advanced analytics on these systems, need to be re-evaluated. As a part of this increase in data reliability and availability, Petrolink sees a parallel increase in variability and data density. When the changes in data are paired with the adoption of richer data analysis through deep machine learning (ML) and artificial intelligence (AI) processes, people must also change their approach to data management or risk success due to failing infrastructure.

Shifting analysis

The first and foremost job of any real-time centric data management infrastructure is to ensure the preservation of that real-time data. A close second responsibility is to make the data available to those processes that are essential to real-time process safety, real-time efficiency, and shared and real-time situational awareness.

With the introduction and adoption of analytical processes into the drilling process, the need to interact at granular levels with the growing data is becoming more urgent. This type of deep and detailed analysis unlocks the valuable insights and patterns that can help to assess potential risks and, most importantly, improve overall functionality and productivity. This is where AI and ML technologies come in. These technologies allow companies to delve deep into massive volumes of data and uncover meaningful insights from them. However, there is an inherent risk. If these processes are pointed at the primary locations of the corporate data, their intense interactions might easily overwhelm the primary function of the data management infrastructures.

One approach is to use copies of the real-time data operating in isolation. These copies are referred to as sandboxes, virtual copies or digital twins by the industry. Their purpose is to provide a subset or copy of the selected data in a safe and controlled environment. ML processes use these digital twins to minimize the risk they have as they design, evolve and grow their algorithms and models. This process typically works through a process of data mining, analyzing and then reviewing findings. In some cases, new data are created, and in others, the data are destroyed or adjusted.

There are two primary risks to the data management infrastructure when ML and AI processes are used: risk to the data itself and risk to the systems that are managing the real-time infrastructure. For example, the machine that is running the database has a limited amount of cycles, so if the central processing unit is flooded with queries it is distracted from its primary job of listening for data.

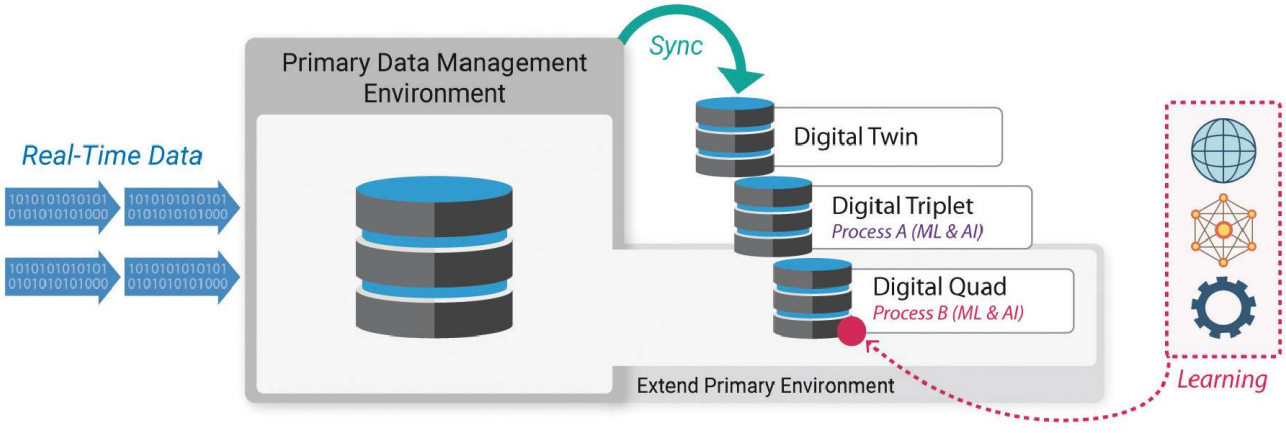
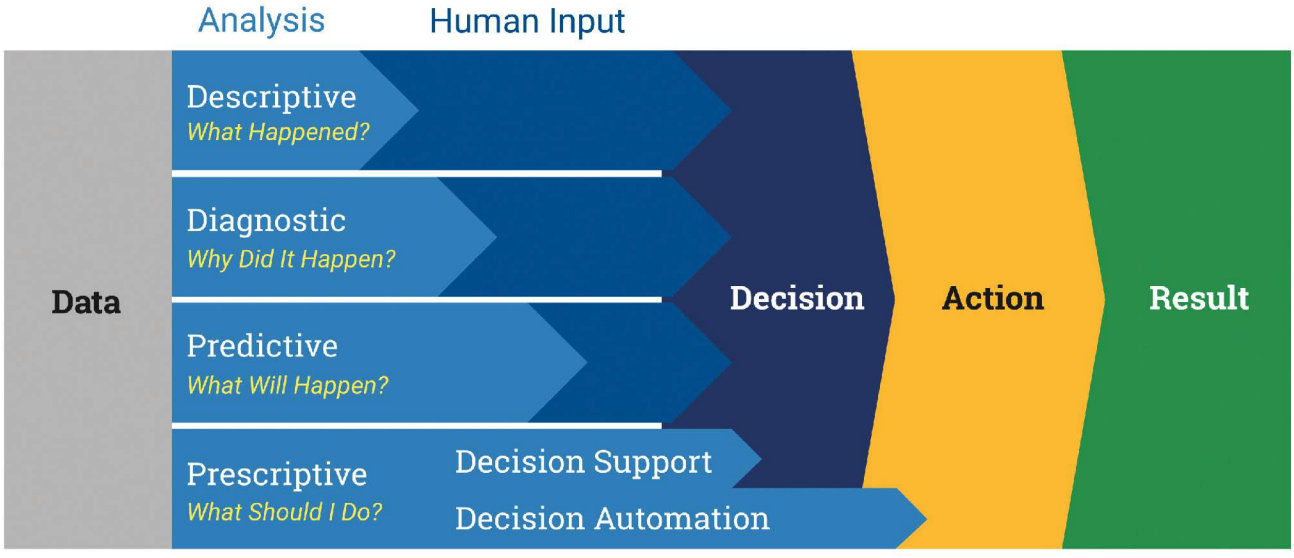


FIGURE 1. The complexity of data infrastructure increases as ML algorithms are introduced in real time. (Source: Petrolink)



Adapted from Gartner Research, 2013

FIGURE 2. There are four types of analytics that require different levels of human involvement and support. (Source: Petrolink)

Scalability of the digital twin

Although a digital twin is a viable solution, it also is part of the problem. As Figure 1 shows, Process A in the ML algorithm needs a large quantity of information while Process B needs completely different information. The result is two simultaneous, very different and intense queries asking for data against the digital twin. Very quickly, the digital twin cannot keep up as it has a physical limit to the number of queries it can accommodate. A natural and logical option is to expand the digital twin—a digital triplet.

Then, as the number of processes in the ML algorithm increases, it creates digital quintuplets and so on. This scenario requires companies to purchase more servers and ultimately is not sustainable as too much time is spent synchronizing information between the systems, and this cost grows exponentially as the number of twins increases. A second challenge is tied to how insights are gained from the various ML processes back into the corporate or production environment where decisions are made.

Making the data usable

Now that critical information is residing in the digital twin, how does one get that information back into the main system where it can be used? One answer is to move the results.

Although this solves the problem of getting the information where it is needed, there is no context on how it was created or who created it. So using that information takes a big leap of faith. The second option is to extend the production environment and include the digital twin in that environment. However, this results in the system now having two sources of truth. The third answer is to move the ML algorithm to the production environment and run it there. This is a viable option and can be achieved by using industry standards such as predictive model makeup language. However, it does slow down the system. None of these three options is a perfect solution that is going to work all of the time.

Getting to automation

ML uses data to help understand what the most likely outcome will be. However, ML is only as accurate as the data it is fed. AI says there are patterns to follow, where it can predict what the outcome will be even without having all of the data to define the scenario. While ML requires constant tuning, AI moves far beyond what is currently known. The path to proper AI is a progression: descriptive, diagnostic, predictive and prescriptive (Figure 2). Companies looking at AI and automation should consider moving in a step process that starts with analytics, which are data-intensive, people-intensive and process-intensive, then move to ML and AI to automation.

Leveraging the power of AI and automation is something that many industries have already tapped into around the world. According to McKinsey & Co., AI is predicted to get even better. Advances in algorithmic research, together with increasingly powerful computer hardware, will allow AI to demonstrate autonomy and creativity.

In the coming years, AI-based machines will find ways to create solutions to complex problems within a given solution space. The drilling industry should be there too. EP

Enhancing tight and unconventional reservoir productivity with flowback surfactants

A new additive helps lower surface and interfacial tension.

Ahmed Rabie, Solvay

Hydraulic fracturing has always been associated with tremendous volumes of fracture fluid invading the formation matrix resulting in water blockage and reducing relative permeability to gas or oil. This has become more challenging in shale and tight formations, because capillary forces have profound impact on water retention and, hence, water recovery and subsequent oil productivity. Surfactants and microemulsions have been applied as flowback additives to lower surface and interfacial tension (IFT) to maximize water recovery.

Most of the current surfactants or microemulsion formulations were tested and validated based on a single or a few testing methods to validate for flowback use. In many cases, surface tension (ST) or IFT measurements were solely used to screen out or qualify a surfactant. The industry has not been precise on the specifications of these measurements or how they correlate to the flowback process. A packed column test with gas or oil often is adopted to simulate production and assess water recovery and hydrocarbon phase production. This method can resemble production from major fractures or gravel packing, but it will fail to mimic oil or gas production from the reservoir matrix where the water blockage occurs and critically impairs oil or gas flow.

Solvay developed a sustainable formulation to meet all specifications for a successful flowback additive, and it was qualified against other current products through a carefully designed coreflood testing method.

Key driving characteristics

Solvay has developed its flowback formulation utilizing environmentally friendly non-ionic, anionic and amphoteric surfactants. The final product, Plexflow 220, is an aqueous formulation that is 100% water-based, which makes it compatible with any type of fracturing fluid. The product is not a microemulsion, where stability can be a concern, yet it exceeds any requirement for the flowback key characteristics including ST, IFT and wettability alternation.

Crude oil Formation	Specific Gravity, (-)	IFT in mN/m (dyne/cm)
Strawn Sand	0.826	5.0
Eagle Ford	0.840	2.45
San Andres	0.828	1.5
Barnett	0.823	0.7
Bone Spring	0.845	0.15
Sprayberry	0.867	0.10
Fullerton Clear Fork	0.813	0.10
Lower Brushy Canyon	0.814	0.05

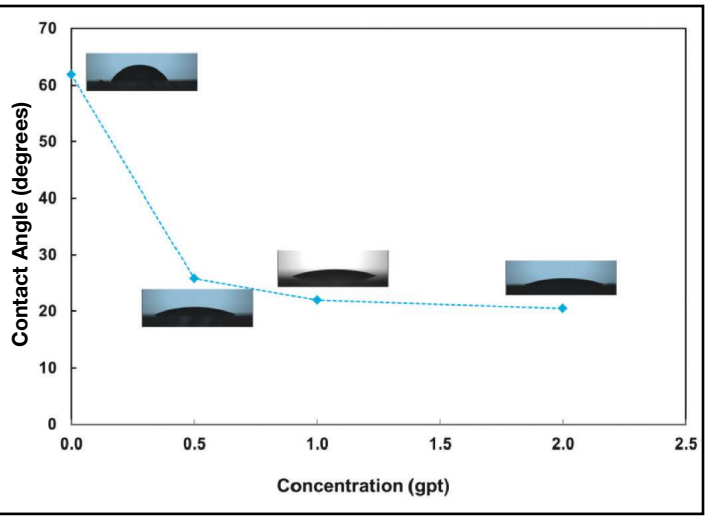


FIGURE 1. The charts depict IFT of 2 gpt of Solvay's Plexflow 220 flowback surfactant with various crude oils (left) and contact angles of 0.5 gpt, 1 gpt and 2 gpt of Plexflow 220 in 5% KCl at 20 minutes on polycarbonate substrate (right). (Source: Solvay)

Although the industry standard for ST is about 30 millinewton per meter (mN/m), the new formulation shows 26 mN/m at a typical load of 1 gal to 2 gal per thousand (gpt) (0.1 wt% to 0.2 wt%) and maintains such value regardless of the level of water salinity with a critical micelle concentration between 0.1 gpt to 0.3 gpt (0.01 wt% to 0.03 wt%), depending on the water salinity.

IFT measurements were conducted extensively in 0 ppm to 350,000 ppm total dissolved solids formation brine, 2% to 20% potassium choloride (KCl) and calcium chloride solutions. The hydrocarbon phase varied from simple alkanes and light distillate (Isopar-M) to actual crude oils from the Permian Basin, Eagle Ford, Strawn Sand, Central Texas and others. These measurements were taken at room temperature and up to 60 C (140 F) and also included full fracturing fluids with friction reducers, clay stabilizer and biocides. IFT was reduced significantly when Plexflow 220 was used and reached as low as 0.05 mN/m based on the crude oil type.

Wettability is best determined through contact angle measurements. A formulation that results in restoring the wettability to the original water-wet condition is desired to maximize oil-relative permeability. The low ST then enables pore pressure to overcome the capillary pressure and ease the water flow through the matrix. Solvay's Plexflow 220 can significantly lower the contact angle and increase wettability. Polycarbonate substrate was used as a hydrophobic controlling surface, and the data show 25 degrees, 22 degrees and 20.5 degrees of 0.5 gpt, 1 gpt and 2 gpt of the new surfactant in 5% KCl. A summary of the IFT and contact angle measurements is illustrated in Figure 1.

Other desirable characteristics of flowback surfactants include good thermal stability, compatibility with various fracturing additives, high flash point and low foam or emulsion tendencies. Solvay's Plexflow 220 flowback surfactant meets all of these criteria, and extensive laboratory testing showed the formulation has excellent emulsion-breaking capabilities and synergistically boosts

Case	Normalized Flow Rate of Isopar, (ml/hr)/md			Water Recovery in 8 hrs, %		
	50 psi	100 psi	250 psi	50 psi	100 psi	250 psi
No-Surfactant 5% KCl	0	6	32	29	38	50
Benchmark 1	0	4	20	33	41	50
Benchmark 2	0.74	7	25	30	38	44
Solvay Plexflow 220	**1.35**	**10**	**37**	**33**	**42**	**50**

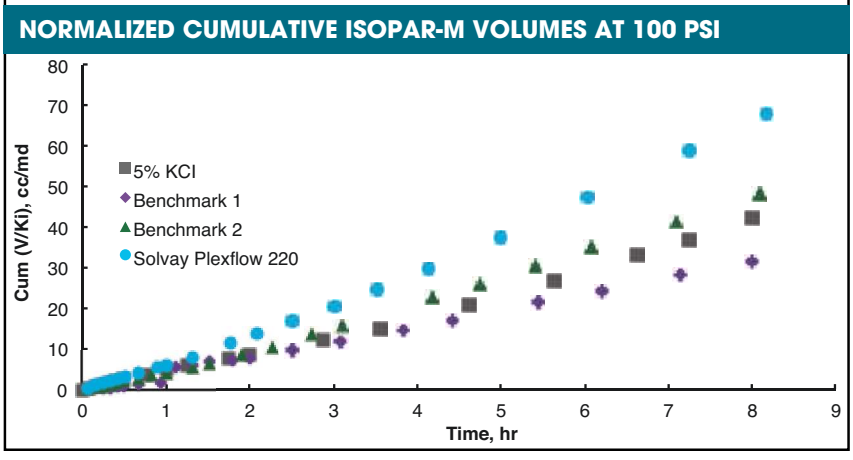


FIGURE 2. The coreflood test results show normalized Isopar-M flow rate and water recovery as a function of stage pressure (top) and cumulative Isopar-M volume produced at 100 psi as a function of time (bottom). Solvay's Plexflow 220 surfactant shows much higher Isopar-M flow rates than other products across pressures. (Source: Solvay)

friction reducer performance in terms of faster hydration time and enhanced final friction reduction.

Unique core flow testing

As mentioned previously, the vast majority of data for flowback surfactants are generated using packed column methods, which can investigate the effectiveness of flowback surfactants on enhancing the flow in relatively high-permeability zones such as main fractures and gravel packing. Simulating the flow from the reservoir matrix requires flowing through structures with much lower permeability. Although the few previous coreflood studies examined the flowback at constant flow rate, Solvay's testing method used 0.23±0.03 md Kentucky sandstone cores saturated with brine/surfactant. Isopar-M was then injected following a constant-pressure schemes of 50 psi to 500 psi displacing the brine or the brine-surfactant phase. Samples from the effluent were collected over extended periods of time and the volume of each phase after separation was measured.

Water recovery, water saturation, oil productivity and cumulative volume produced were all determined during each test. The impact of the variation in the initial permeability was minimized by normalizing the resulting Isopar-M flow rate in each case by the initial permeability of the corresponding core.

Conducting the study at constant-pressure injection allowed Solvay to compare the impact of capillary forces, represented by the IFT, versus the viscous forces on the flow of Isopar-M. At low pressures, such as 50 psi, a significant difference between the surfactant cases and the 5% KCl case was observed. That is because at this pressure, capillary force dominates and lowering the IFT is critical for the displacing efficiency. At higher pressure, viscous flow dominates and the effect of IFT is minimum. In fact, if the wettability is not restored to water-wet (or optimally non-wet), the surfactant case can even show lower Isopar flow rate.

The coreflood results confirmed this hypothesis and showed the benefit of using Solvay's Plexflow 220 surfactant for flowback versus nonsurfactant cases at all pressure stages and more profoundly at low- to mid-pressure. At a 50-psi pressure difference, no oil was observed in the 9-hour nonsurfactant experiment, while Solvay surfactant resulted in Isopar-M breakthrough after 5 hours. Another product (benchmark 2) also resulted in early flow; however, the Isopar-M final stabilized flow was 50% less than what was observed in Solvay's product case. At 100 psi, 250 psi and 500 psi, the oil productivity with Plexflow 220 surfactant was 63%, 16% and 22% higher than the base case, respectively.

Solvay's testing method was applied to other industrial benchmark products, where all have shown less oil productivity than the Plexflow 220 product. A summary of the coreflood results for the different cases and the 5% KCl base case is shown in Figure 2.

Based on the results, a surfactant that combines low ST (less than 30 mN/m), low IFT (less than 1 mN/m) and a contact angle that reflects a good wettability, with no emulsion tendency will exhibit excellent potential as flowback additive. Solvay's Plexflow 220 surfactant has fulfilled all these requirements in addition to being a sustainable, water-based solution, fully compatible with any fracture fluid. EP

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A new reality for fracturing fluids

Market forces mandate better evidence-based tools to drive decisions in oilfield services pumping operations.

Bruce MacKay, Schlumberger

To say things have changed in North American well stimulation over the last decade is an understatement almost as large as the scope of the changes themselves. Permeability of the typical reservoir has gone down by roughly three orders of magnitude. At the same time, the industry is focusing three orders of magnitude more material on a fracturing work site.

In this changing landscape, the habits of fracturing fluid optimization have had to catch up to a new reality where the reservoir has rewritten the rules and market forces mandate better evidence-based tools to drive decisions about what is pumped.

A new dominant work practice

Service companies and E&P companies have put considerable effort into understanding how to chemically modify and enhance the properties of water so that it can be injected into a reservoir to complete the well and connect it to the producing reservoir efficiently and effectively. The chemical engineering objectives of a fracturing fluid fall into three categories:

- Initiate and propagate a hydraulic fracture;
- Convey a propping agent into the fracture; and
- Ensure the proppant pack and formation connect efficiently to the wellbore with minimal damage.

Most optimization has historically concerned the first two points. The dominant work practice has become the use of friction reducers based on high-molecular-weight synthetic polymers. These distribute smaller proppant grains within a complex and unpredictable fracture network using the turbulence resulting from high pump rates (occasionally exceeding 120 bbl/min). Given the increase in job volumes, it has become clear that polymer emulsion costs need to be optimized (which they largely have) and the preferred propping agent is a friction reducer that disperses and hydrates within seconds of injection.

The new high-viscosity friction reducers are seeing increased usage due to their ability to affect proppant distribution. However, it is not clear from field application that higher viscosity always connects to completion success. These products appear to perform differently in different basins, irrespective of the viscosity measurements performed. Further, the industry is beginning to understand that there is a sense of diminishing returns at higher product loadings, where production impairment can set in from too much polymer use. The oilfield solution to this situation has been to run an oxidative breaker to reduce fluid viscosity.

Myths and science of breakers

While it is true that breakers will reduce viscosity in a laboratory test, the water that is returned on initial flowback is typically salinated by contact with reservoir rock that has not seen water for millions of years. This salinity can have a stronger effect on solution viscosity by shrinking the polymer's hydrated radius than breakers have on the polymer's molecular weight. Further, it is puzzling that breakers applied to degrade polymer in the subterranean environment are the same class of chemicals used to assemble the polymers from their monomers. There is no clear argument that breakers selectively degrade polymer, and the unpredictable nature of breaker chemistry includes possibilities where gelation and even adventitious crosslinking of the polymer can occur.

Operators in infill drilling campaigns have the choice to evaluate these chemical issues as they move through a field. First, practical operational evaluation of the minimal required amount of high-viscosity friction reducers to execute a job design can be explored safely by working down from roughly 1 gpt per ppa to a basin-specific baseline level that places proppant to design (*gpt = gallons per thousand gallons; ppa = pounds of proppant added per gallon*).

Second, the question of breaker efficacy can be assessed directly by comparing offsets with and without breaker. Single-well operators are pooling their information to make these decisions, harvesting publicly available information to support these decisions.

Flowback surfactants are another area where the industry has lacked a good prescriptive model to drive rational product selection and application until recently. Flowback surfactants assist in dewatering the proppant pack and, perhaps more importantly, the fine cracks and small features that retain fluid within the dis-

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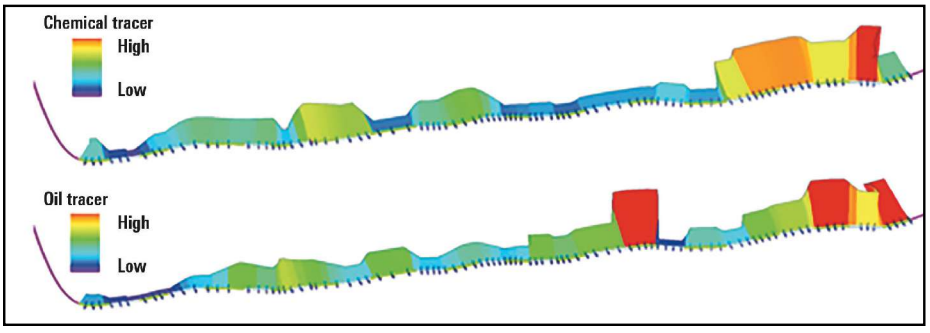

FIGURE 1. After the optimized stimulation and completion operations, oil and chemical tracers indicated that all stages were flowing and contributing to production. (Source: Schlumberger)

tal portion of the fracture network where the capillary pressures are highest.

Comparing flowback surfactants rationally

The problem for the operator in infill mode becomes balancing the potential uplift against the cost. There has been no easy way to accurately determine how the reservoir material would respond to the surfactant. For this reason, experts were guessing based on "pack drainage tests" that did not really measure an actual physical property of the system.

The lesson learned in optimization, both in the laboratory and the field, is the reservoir does not care how sophisticated the surfactant is; the rock simply wants what it wants. Sometimes no surfactant is necessary, and sometimes the least expensive offering shows the best potential to reduce the threshold pressure to initiate flow out of high-capillary-pressure cracks. The measurement breakthrough came from rational development of a scientifically sound experiment that measures contact angle on customer shale samples.

The test works with cuttings or core material, and it features high reproducibility and a robust underlying mathematical model so the test results are not confused by variations between test packs (a confounding feature of the more common pack drainage test that is widely used to recommend surfactants). Operators are beginning to request and retain this service for all new completions when facing high reservoir heterogeneity.

In the Permian Basin, the Schlumberger ShalePrime rock-fluid diagnostic service helped Manti Tarka reduce stimulation cost by 25%, mostly by pumping a lower concentration of a more effective and economical flowback surfactant (Figure 1).

Understanding fluid diversion

Another area of fluid design undergoing a renaissance of optimization is fluid diversion. The practice of pumping pills of degradable particles to ensure even wellbore coverage during a stage is well established, but unfortunately it is difficult to know the balance of clusters taking fluid versus clusters not taking fluid to enable a planned approach to diversion.

Schlumberger has applied an acoustic technique called the WellWatcher Stim stimulation monitoring service to make probabilistic statements about which zones are taking fluid. This enables on-the-fly design of diversion pills for near-wellbore diverters such as the company's high-efficiency BroadBand Sequence fracturing service materials. The new stimulation monitoring technology also gives information about bridge plug location and wellbore integrity in real time, giving operators additional layers of certainty as wells are completed.

The WellWatcher Stim service can confirm the efficacy of stimulation treatments. In the Haynesville Shale, the service identified fluid entry points and verified efficient diversion (Figure 2).

Integration of laboratory measurements, real-time field data and retrospective analysis of completed projects are combining to enable a new paradigm for fracturing fluid optimization that will help unlock further value in unconventionals. E&P

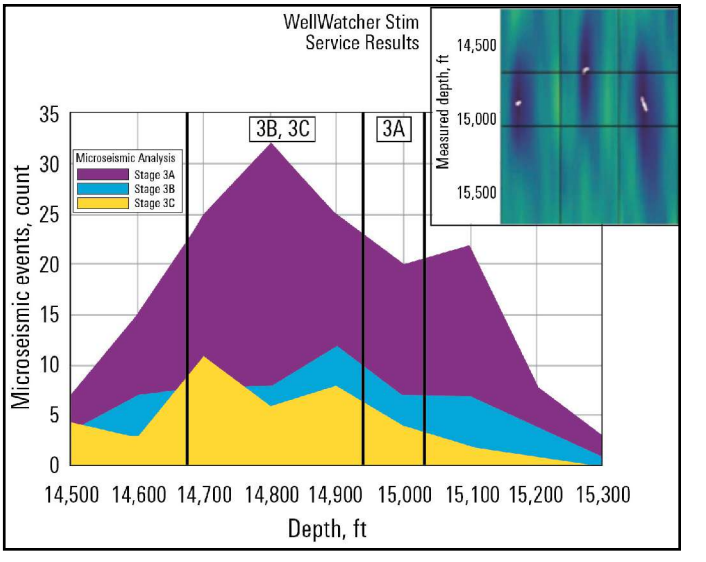

FIGURE 2. WellWatcher Stim identified fluid entry points where microseismic analysis showed only a set of widely scattered events. (Source: Schlumberger)

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Getting the most out of mature wells

Slimhole completion systems help to refracture existing wells and boost production.

Rod Schnell, Packers Plus

Mature fields and reservoirs provide operators an opportunity to access untapped production or reserves with the potential for the same or better returns than the original stimulation treatment of existing wells in the region. This can be done by drilling infill wells, using water injector wells to increase reservoir pressure and sweep hydrocarbons to nearby producer wells, or restimulating existing wells.

Restimulation requires pumping additional fluid and proppant or acid into new and/or old zones of an existing well. Existing wells are commonly restimulated for the following reasons:

- Initial stimulation was inadequate due to low proppant or fluid volumes, overflushing or damaging fluids;
- To restore lost fracture conductivity or poor connection to the wellbore; or
- Access (previously bypassed) reservoir rock (e.g., closer fracture spacing).

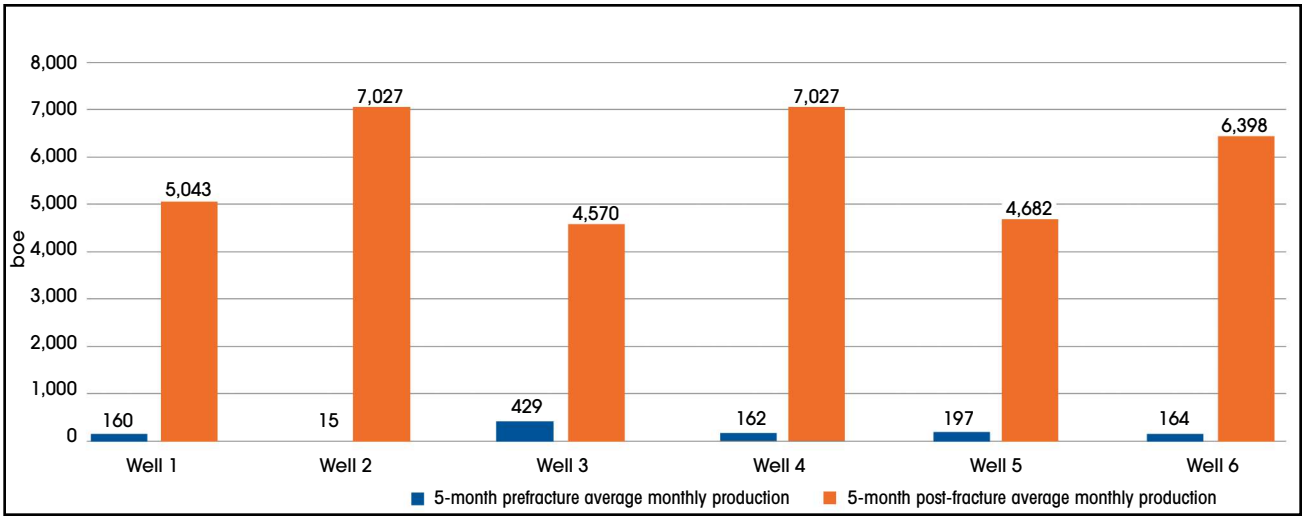
Slimhole completion systems provide a robust restimulation option by installing an entirely new liner inside the existing well using permanent mechanical isolation packers to isolate each zone.

Restimulation methods

There are several treatment methods used today to restimulate wells. This includes ball sealers, chemical diverters, isolation tools conveyed by coiled tubing (CT), cemented liner inserts, expandable liner patches and slimhole systems using packers for isolation.

Ball sealers and chemical diverters are low cost and operationally simple restimulation methods often used by operators. Both of these methods are used as plugs to divert fracture treatment fluids to other entry points along the wellbore. Challenges for chemical diverters include determination of diverter pill size and concentrations, fluid leak-off, damage caused due to inadequate cleanup and overflushing of proppant stages. With ball sealers, if the fracturing operation is temporarily halted, much of the effect of the ball sealer diversion can be lost. The effectiveness of this method also depends on the type of completion method being used, whether it is perforations of a plug-and-perf (PNP) system, a slotted liner or a system using sliding sleeves. Ball sealers also might be difficult to retrieve if nondegradable balls are used.

CT-deployed tools provide flexibility for operators with tools that are rapidly deployed and where a rig is not required for installation. Major challenges of this system include limited pump rate capacity due to the

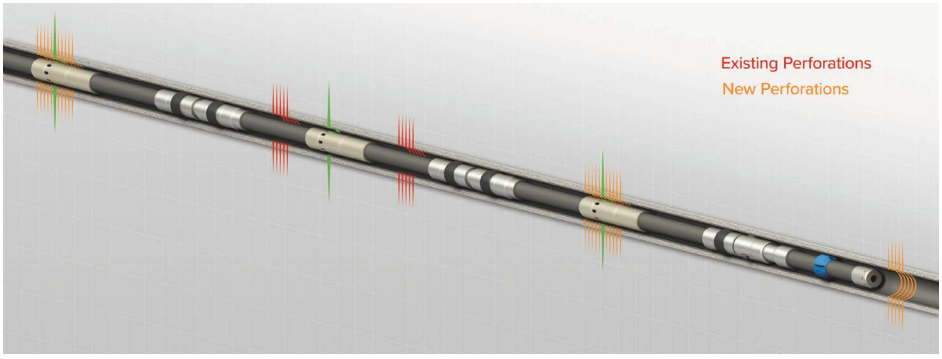


This chart depicts five-month monthly production averages for six horizontal sidetracked laterals drilled from existing vertical wells in the Cleveland Sand tight gas reservoir in Texas. (Source: Packers Plus)

smaller diameter of the CT, the inability to successfully deploy in long laterals and high costs.

Other methods, such as expandable and cemented liners, can be inserted inside an existing system and require PNP setting similar to new well completions. Scales and fines can, however, negatively impact the expansion operation resulting in sticking or lost tools.

Slimhole systems offer a means of permanent isolation inside an existing system using mechanical packers and ball-activated sliding sleeves. Packers provide an effective means of stage isolation by permanently setting inside the existing casing. The arrangement of sliding sleeves in the wellbore enables exact placement of stimulation fluids into the wellbore. An additional benefit of slimhole systems is that a new liner is installed inside the existing well, mitigating the need to compensate for any damage to the original liner.



The four-stage StackFRAC Slimhole system works inside an existing cemented liner with existing and new perforations. (Source: Packers Plus)

Slimhole systems can be used to restimulate existing wells and also to re-enter existing vertical wells into sidetrack drilled horizontal wells to increase reservoir coverage.

Restimulation of a PNP well

A well more than 10 years old in the Glauconite Formation in Canada was completed with 4.5-in. casing to surface. There were two existing sets of perforations in the casing from the original stimulation treatment approximately 30 m (100 ft) apart and one-third of the way into the lateral. To maximize the effectiveness of the well and cover the entire lateral, the operator shot three new sets of perforation clusters approximately 150 m to 300 m (492 ft to 984 ft) apart. Using the Packers Plus StackFRAC Slimhole system, a solution was designed for the operator consisting of four stages using a 2.875-in. liner.

The ball-activated FracPORT sleeves of the slimhole system were strategically placed to target the fracture treatment through the new perforations as well as to allow production from the existing perforations. Based on five-month monthly production averages for both prestimulation and post-stimulation, a factor increase in the production rate of 59 times was observed. In one year, restimulation with the StackFRAC Slimhole system resulted in more than 12 MMcm (435 MMcf) of additional gas.

The total end completion cost for the original well was $514,000 and $805,000 for the restimulation. After more than 11 years of production, and based on an estimated current oil price of $70/bbl, the difference between the barrels of oil equivalent produced with restimulation and the estimated production without restimulation is 197,667 boe. This amounts to $13.8 million of additional revenue with the restimulation treatment, more than 10 times the total end completion cost of the original liner and the new slimhole liner combined.

Re-entry into vertical wells

The Cleveland Sand tight gas reservoir in Texas was discovered in the 1950s and initially developed with hydraulically fractured vertical wells. With many wells having flat decline rates, operators looked to re-entry as a cost-effective solution to boost production and reduce the cost of drilling a new well. Six vertical wells that initially began producing in the 1970s through the 1990s in Lipscomb County were targeted by an operator between 2005 and 2008. The wells were re-entered using whipstock connections to drill sidetracked horizontal laterals from the existing vertical section. Each well consisted of three to five completion stages, stimulating lateral lengths up to 610 m (2,000 ft). Up to 320,000 lb of proppant was pumped for each well. Based on the monthly production averages for both prestimulation and post-stimulation, a factor increase in the production ranging from 10 to 468 times was observed.

Conclusion

Restimulation of existing wells is a useful, field-proven technique that can be used to increase production from mature or depleted reservoirs. Slimhole systems enable operators to enter existing wells that need restimulation using an entirely new liner and permanent packers for reliable zonal isolation to target new, old or previously bypassed zones. Carefully selected candidate wells for restimulation have the potential for massive returns. E&P

Enabling autonomous downhole operations

A new wireless downhole tool unlocks the potential for significant cost reductions.

Mark Venables, Contributing Editor

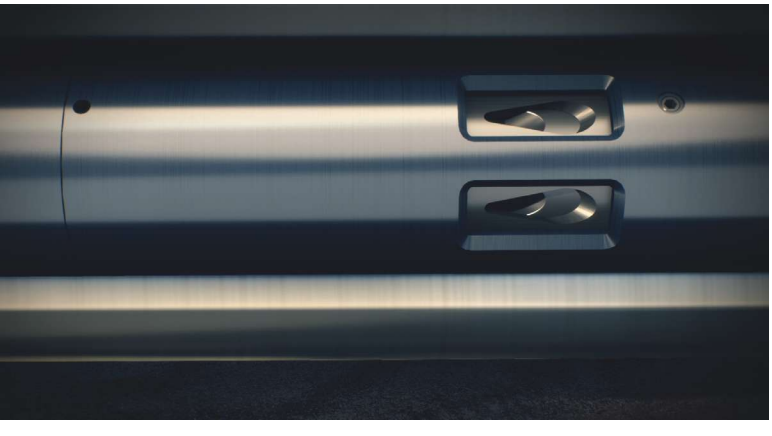
Tendeka has reached another milestone in its quest to demonstrate the capability of its PulseEight wireless technology with a major North Sea operator. Working with Aberdeen-based Oil & Gas Technology Centre (OGTC), the company is progressing with Phase 1 of a project to install and test PulseEight as a replacement for an insert safety valve. The device successfully detected several simulated emergency events and further deployments are planned for later in the year. Testing included operations in a live producing offshore well.

"The test was hugely important from the sense that it's moved this from a system that was only transmitting data to surface for wellbore monitoring or controlling the flow for production optimization to something that is reacting to surface events and helping to assist the safety case for the wells," said Paul Lynch, advanced completions director at Tendeka.

The North Sea trial follows a successful field test with OMV Group in Austria earlier this year.

Good to talk

The system uses unique pressure pulse telemetry to channel wireless communication between a well's downhole monitoring and control system and the wellhead. The downhole device also is able to operate autonomously providing a true intelligent solution, enabling well data to be transmitted to any location in the world in real time.



Tendeka's PulseEight system uses unique pressure pulse telemetry to channel wireless communication between a well's downhole monitoring and control system and the wellhead. (Source: Tendeka)

The communication methodology allows the operator to receive information from the tool position in the wellbore wirelessly. The operator also can communicate back down to the tool to tell it to do different things.

"That ability to speak in a flowing wellbore environment without adding any additional equipment or tools is important," Lynch said. "There are tools that exist now, but they all require a wire run into the well and that wiring functionality must be put in the well during the completion phase."

Intelligent tools

There are certain situations that occur within a wellbore or reservoir that are known and planned, such as depletion of reservoir pressure or wellbore events that can lead to safety incidents.

"These all have some key characteristics that the tool can recognize within the wellbore and chose to function autonomously," Lynch added. "That autonomous action as well as our communication method really opens the ability to manage reservoirs in a real-time situation."

In normal circumstances it takes time for data to be sent back to the surface, to reach a desktop for an engineer to conduct an analysis, which may take a few hours, and then decide what actions to pass back to the rig. PulseEight can make those decisions itself in real time and close, open or choke the flow of the well.

With the dawn of Big Data also comes the advent of the analysis that is required for this type of operation.

"If the tool can be conducting edge analytics of key data, then it allows the reservoir simulation team to focus on more complex analysis and take that part of the job into an autonomous action and automatically control the flow of the wells for optimum production," Lynch said.

Autonomous operation

The conventional safety valves, either tubing or wireline mounted, work by having a control line that delivers

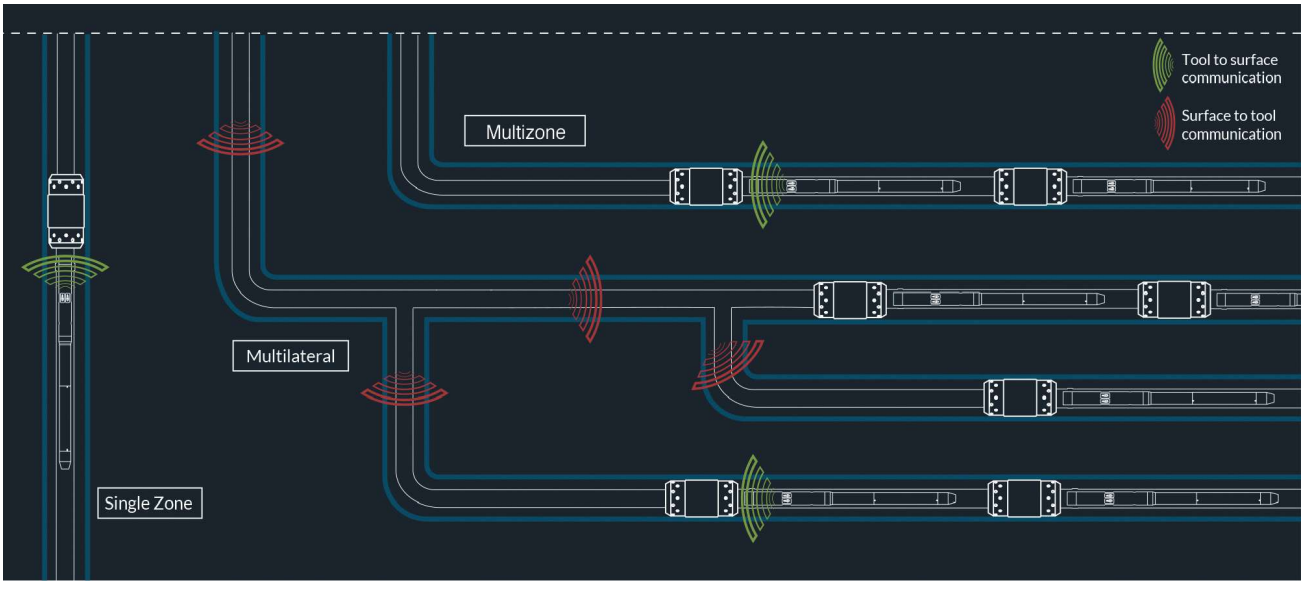
a constant hydraulic pressure to them to hold them open. Upon the loss of that hydraulic pressure, the tools will close. If the failure mechanism is in the valve itself, then conventional insert valves work very well. But if the failure mechanism is in the control line, then the means of speaking to or controlling that tool go away. "Where PulseEight offers the benefit is that in situations where you have lost that communication methodology, we have a tool that will still be able to function," Lynch said.

As for the willingness of an often change averse sector to adopt this technology, Lynch believes the industry is very willing to look at it as a replacement for an insert safety valve.

Flow from the reservoir enters ports in the tool and flows to the surface. (Source: Tendeka)

"Traditional ambient valves are often the only other option, and these are very difficult to work with in the sense that they need a lot of setup and continuous testing," he said. "In operations they allow you to flow the well at its maximum potential while still retaining the control similar in manner of a conventional safety valve."

The vision for the system is to start including more analytical functionality within tooling downhole so that information can be communicated back to surface as part of the Big Data transmission. "This will facilitate better wellbore and reservoir monitoring," Lynch concluded. "We also want to further the tool's autonomous ability so that we can have tools do a number of different things relative to changes in either the flow or reservoir conditions." EP



Wireless intelligent well technology can extend the operating envelope for the advanced completion. (Source: Tendeka)

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SEG 2018 to feature troubleshooting technologies

Companies at the SEG Annual Meeting will be exhibiting solutions to some of the most difficult challenges facing geophysicists.

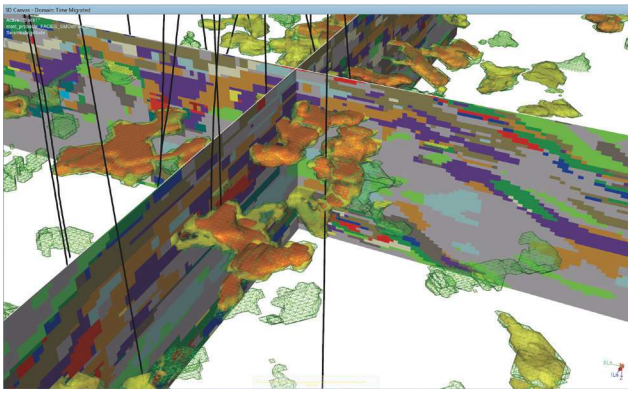
Thousands of professionals within the geosciences sector gather annually to learn industry best practices with the newest technologies. This year, the Society of Exploration Geophysicists (SEG) International Exposition and 88th Annual Meeting is taking place Oct. 14-19 in Anaheim, Calif.

The following is a sampling of some of the latest technologies and products that will be showcased at the SEG conference.

Editor's note: *The copy herein is contributed from service companies and does not reflect the opinions of Hart Energy.*

Automate processes critical to recovery of hydrocarbons

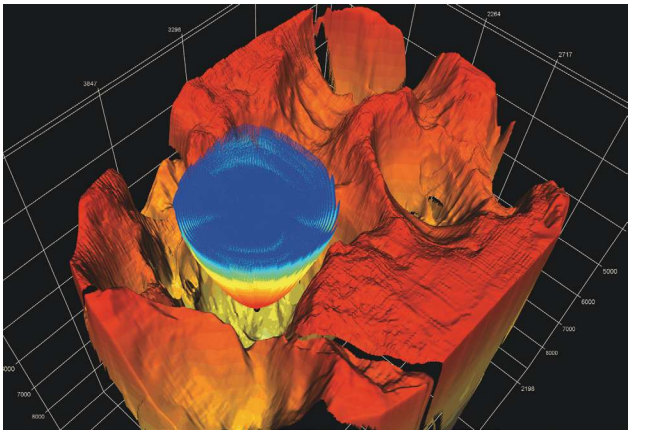
At the SEG conference, Emerson's E&P Software and Services business will feature applications of machine learning to geophysical data and methods as a visible and impactful component of the industry's digital transformation, a transformative effort to automate, integrate and improve processes and deliverables that are critical to the location and recovery of hydrocarbons. Key highlights include 1) applications of deep learning to full-azimuth "directivity gathers" to image subsurface features such as faults, salts and reefs—a game-changing step toward automatic interpretation of prestack data, and 2) creative use of ensembles of neural networks to generate probabilistic facies models from seismic data and wellbore data for a better understanding of reservoir heterogeneities. The program also will include the use of machine learning methods to automate Big Loop workflows, from seismic data to reservoir simulation, incorporating geophysical uncertainties for better production forecasting and accelerated project turnaround times. *emerson.com*



Geobodies are detected in rock type classification. (Source: Emerson Automation Solutions)

A move to cloud computing

In a move to increase efficiencies, lower operating costs and decrease project turnaround time, Fairfield Geotechnologies has completely transitioned its seismic data processing to cloud-based computing. Cloud computing provides on-demand burst capacity that reduces the need to invest in fixed assets (computing and infrastructure), removes concerns about "peak" load and over-provisioning of hard assets, allows provisioning of resources to satisfy any client demand, eliminates maintenance issues and provides automatic technology refresh. Seismic data

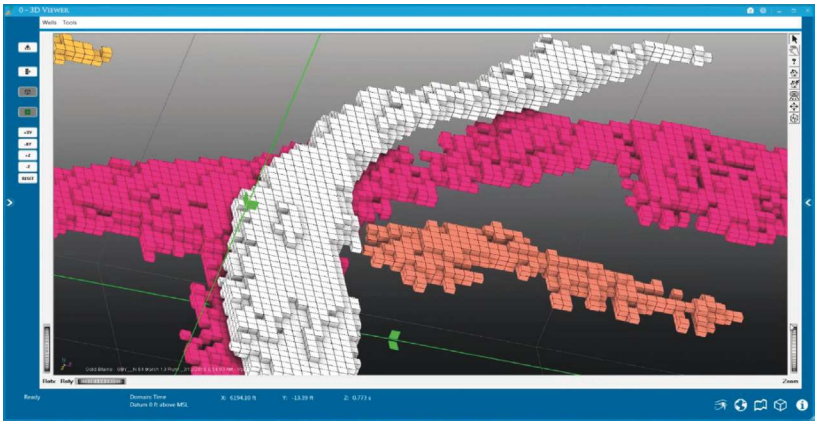


Ray bundles from a complex Gulf of Mexico salt body are used for migration velocity analysis. Cloud-based computing provides a scalable solution for resourcing the computer capacity necessary for complex imaging problems. (Source: Fairfield Geotechnologies)

processing is well-suited to the coarse-grained distributed processing that web-based solutions provide. In seismic imaging, for instance, the problem can be broken into small pieces that can be independently solved in a parallel manner by many CPU cores. From an efficiency perspective, cloud computing provides a scalable solution for accepting processing jobs too large for fixed, on-premises compute capacity; reduces run time for individual processing jobs, improving analyst's productivity; compresses project turnaround; and increases total project throughput. *fairfieldgeo.com*

Isolate, investigate areas of interest in neural classification volumes

Geophysical Insights has released the new Geobody Analysis capability in the Paradise machine learning platform. Geobody Analysis is a result of machine learning that enables geoscientists to isolate and investigate areas of interest in neural classification volumes. Using the tool, interpreters can isolate geobodies according to their size; investigate geobodies at the sample level of each neuron; capture details on areas of interest, including volumetrics and statistics; and edit/clean up selected geobodies by filling in areas or pruning extraneous samples. Geobody Analysis produces volumetrics based on interpreter-provided geologic inputs. The output includes sample volume, gross rock volumes, net rock volumes, pore volumes and hydrocarbon pore volume for each geobody. At the SEG conference, Geophysical Insights will highlight more information on Geobody Analysis and other applications of machine learning, including picking horizons based on neural classification results, identifying seismic facies using convolutional neural networks and using machine learning for automated lithofacies classification. *geoinsights.com*



The screenshot displays a geobody automatically isolated through machine learning in the Paradise platform. (Source: Geophysical Insights)

Digitize the world: from physical media and paper to data analytics

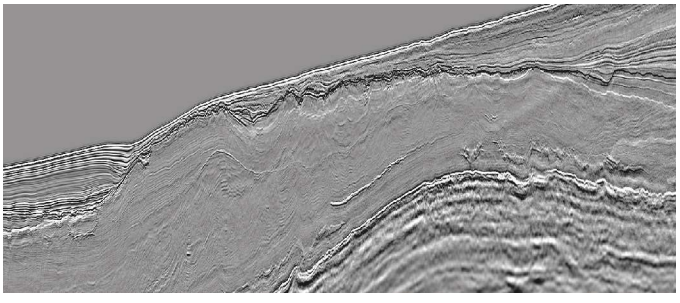
Oil and gas companies moving toward Big Data analytics are missing a critical dataset in their analytic data pool by keeping information locked up inside legacy seismic media, paper logs and well files. Transforming legacy media to modern technology and scanning well files from paper to digits is part of Katalyst Data Management's initiative to digitize the world. By creating a searchable, accessible digital version of all data types, from well files to interpretation projects to seismic data, Katalyst provides exploration companies with the ability to capture the value of both historical and current data in their analytics platforms and interpretation software. Katalyst's iGlass software supports a multicloud architecture for both data and metadata. Now Professional Petroleum Data Management Gold Compliant, iGlass allows users to access multiple subsurface data types from a single Esri GIS map interface. *katalystdm.com*

Seismic and well data are accessible in a secured cloud environment via iGlass data management software. (Source: Katalyst Data Management)

A new way of acquiring and processing marine seismic data

The next phase of the PGS technology evolution is known as eSeismic and involves the use of continuous source and receiver wavefields to fundamentally change the way that marine seismic data are acquired and processed. This method is under development in the company's R&D unit, and the potential benefits include reduced environmental impact, improved efficiency and better data quality. Peak sound pressure levels and sound exposure levels can be significantly reduced by distributing the emitted signals from the sources in time. From

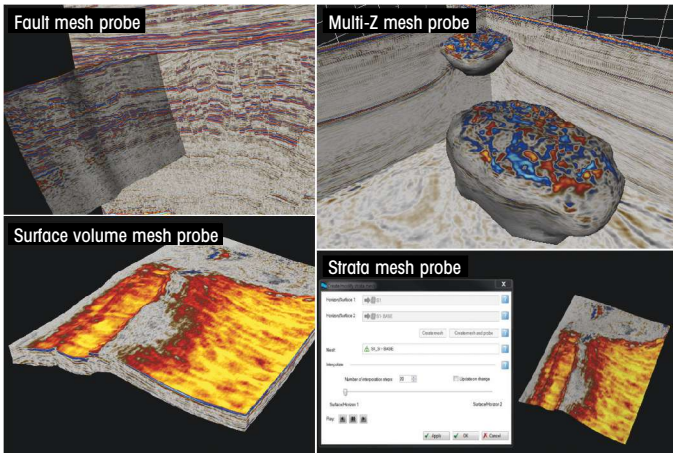
an efficiency standpoint, there are no speed limitations because the method does not require the seismic recording or the sources to be triggered with specific spatial intervals and also because no listening time is needed. Rapid coverage of the target during acquisition by operating several sources simultaneously and increasing the spread width of the sources also improves efficiency. Data quality is even better with potential uplifts related to the continuous wavefields and to the spatial sampling of source positions. The imaging of low-frequency signal benefits especially from the long records. The continuous sources wavefields can be generated with either marine vibrator technology or with traditional air gun hardware. *pgs.com/eSeismic*



eSeismic is a Demo2000 project funded by The Research Council of Norway, Equinor and PGS. (Source: PGS)

Modules help solve complex structural, stratigraphic challenges

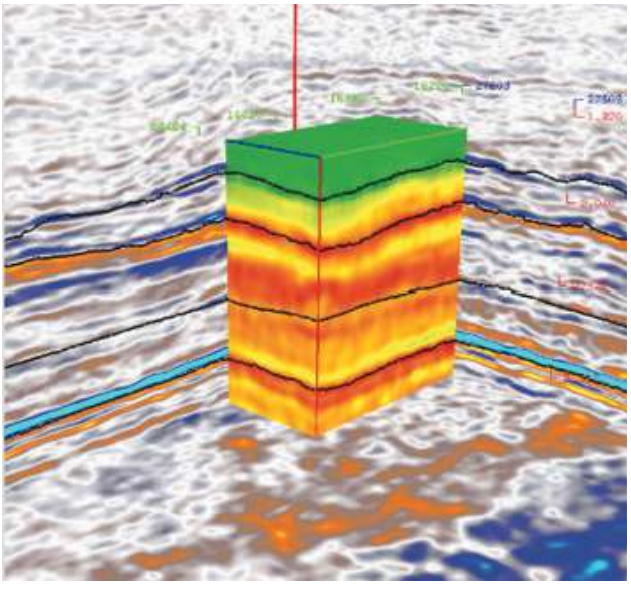
Schlumberger's DELFI cognitive E&P environment petrotechnical suite along with the company's Petrel E&P software platform modules, including the geology and geophysics, provide seismic and quantitative interpretation to the geophysics community. These modules enable E&P operators to solve the most complex structural and stratigraphic challenges from regional exploration to reservoir development. At the SEG conference, technical experts will highlight machine learning, high-performance computing, data ecosystem and the new Petrel platform features focusing on increased accuracy in seismic rendering with the introduction of seismic mesh probes. In addition, booth attendees will learn about management of seismic reference datums and streaming of real-time mud log data in the well section. With these new technologies, petrotechnical domain experts can work seamlessly in a unified, collaborative environment to make the most informed decisions from reservoir characterization to completion and production. *slb.com*



The geophysics module with the Petrel 2018 platform introduces a new seismic probe based on meshes, applicable to faults (upper left), multi-z interpretations (upper right), surfaces (lower left) and strata (lower right). (Source: Schlumberger)

Software evaluates size and quality of oil and gas reservoirs

Sharp Reflections uses Big Data computing technology to evaluate the size and quality of oil and gas reservoirs and reduce predrill risk. The company's Pre-Stack Pro (PsPro) software, using a highly parallel, in-memory compute architecture, supports interactive visualization and analysis of prestack and post-stack seismic data. Using a rich toolkit, which includes integrated processing-amplitude applications and specialized prestack azimuthal and inversion modules, the company processes, analyzes and inter-



An interactive co-rendering of a prestack inversion cube, horizon amplitude extraction and seismic is displayed. (Source: Sharp Reflections)

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prets full fidelity raw signal from conventional and unconventional 3-D seismic datasets to predict reservoir and fluid properties away from well control. All PsPro applications can seamlessly be scaled to multiple servers or executed on the company's Amazon Web Services cloud-hosted resources to interactively analyze terabyte-size datasets in hours. *sharpreflections.com*

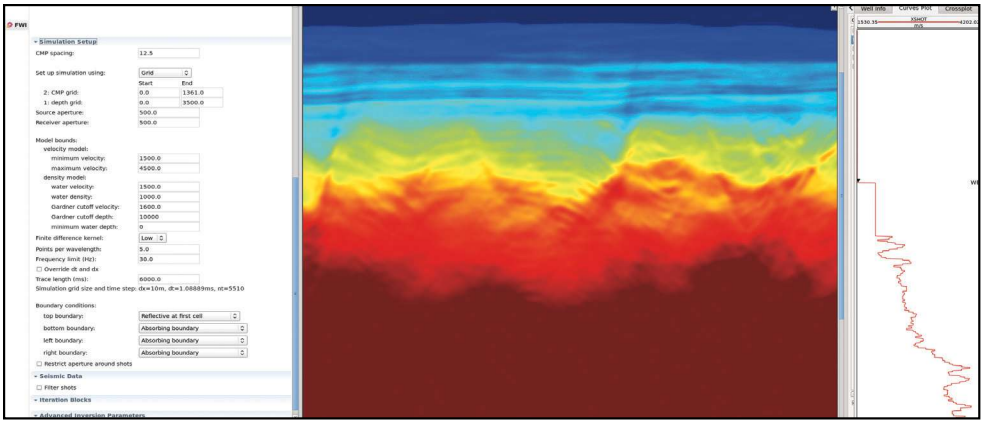
Using refractions, reflections to create 2-D and 3-D velocity models

Shearwater GeoServices' full wavefield inversion (FWI) offering is an implementation of the latest in inversion technology developed by Imperial College, London, for the FULLWAVE consortium. Intense research over the last eight years has resulted in an algorithm to gives users a velocity field over frequencies previously considered impossible. Used within Reveal's modern architecture, system users can easily move from time processing to depth imaging in a single user interface. With the continuing research being carried out by Imperial College, Shearwater is ensuring the future of FWI in Reveal. The company offers an advanced FWI algorithm in Reveal, utilizing all refractions and reflections to create the most accurate velocity model—in 3-D to the company's fellow consortium members and 2-D to all nonmembers. *shearwatergeo.com*

From left to right, Wireless Seismic's cable-free and real-time RT3, METIS and RT2 seismic data acquisition units provide real-time data acquisition. (Source: Wireless Seismic)

Systems provide real-time data acquisition

Wireless Seismic provides the industry's only fully scalable wireless seismic recording systems with real-time data acquisition. Wireless Seismic's RT2 is a field-proven wireless seismic recording system with real-time data transmission for conventional surveys and passive monitoring projects. RT2 features new electronics that have reduced the system's power consumption by approximately 50%. RT3 is Wireless Seismic's next-generation seismic recording system that addresses the growing need to deploy ultrahigh channel counts for larger and denser seismic surveys. RT3 delivers full real-time data transmission via a new high-performance radio telemetry system that operates up to seven times faster than traditional cabled systems. METIS is a collaborative R&D program, in partnership with Total and other technology innovators, that aims to significantly reduce the costs and turnaround time associated with exploring in hard-to-access areas, such as foothills. The seismic acquisition components of METIS are based on the real-time and high-performance radio telemetry of RT3. *wirelessseismic.com* E&P



A screenshot displays FWI data processing in Shearwater Reveal seismic software. (Source: Shearwater GeoServices)

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The Electric Powered Double Cementer features a modular skid design manufactured for an existing rig installation. The unit is equipped with 1130 HP DC Electric Motors for powering the downhole pumps and with 75 HP AC Electric Motors for powering each of the centrifugal pumps. The cementer utilizes rig electricity, which provides necessary power for complete well operations at maximum efficiency.

AR 380
CONTROLLER

A Local Enclosure is mounted directly to the unit and contains the **AR380 Controller,** power distribution, relays, and bulkhead connection.

The **AR380 Touchscreen** allows the user to *Slide and Swipe* between screens, with *Touch and Hold* icons representing various major components.

Eaglebine play re-emerges

As operators continue to bring the Eagle Ford back to peak production, they refocus their attention to the north.

Brian Walzel, Associate Editor, Production Technologies

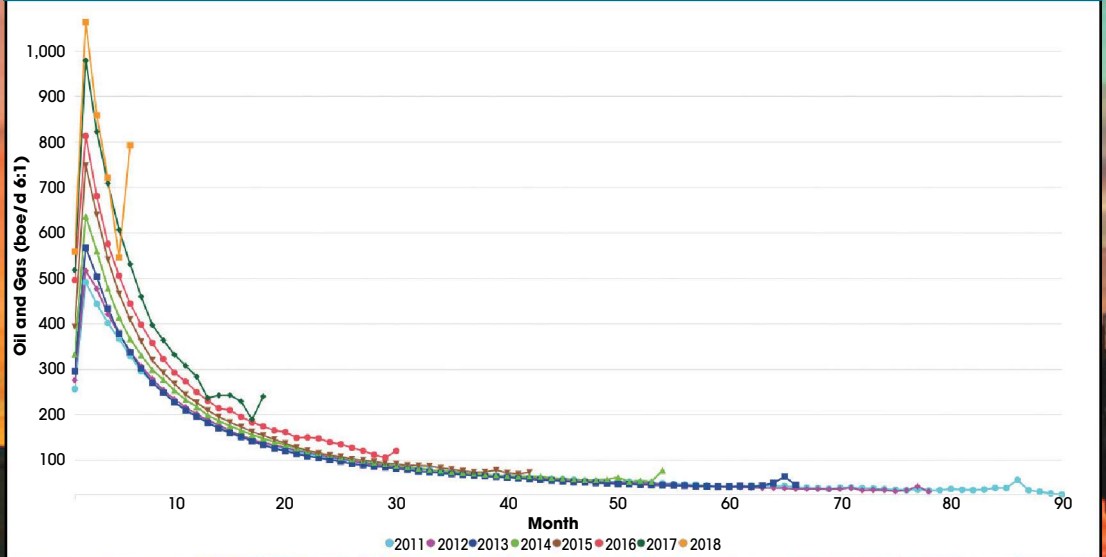
The Eagle Ford Basin is continuing its slow and steady climb back to peak production, recently reaching a production level that hasn't been seen in South Texas since 2016. According to the U.S Energy Information Administration (EIA), in September the Eagle Ford produced an estimated 1.4 MMbbl/d, up 1.7% over August's oil production. Compared to the same period last year, Eagle Ford oil production is up 23%, according to the EIA.

The Eagle Ford continues to be led by EOG Resources, which as of March was producing 247,789 bbl/d, according to ShaleProfile. Other leading producers include Marathon Oil (108,267 bbl/d), ConocoPhillips (122,248 bbl/d), Chesapeake Energy (118,942 bbl/d) and Devon Energy (52,401 bbl/d), ShaleProfile reported.

Akash Sharma, senior analyst at Drillinginfo, said permitting in the Eagle Ford has steadily increased since the third quarter of 2017, rising about 18% in that time to nearly 700 permits in the second quarter of this year. DeWitt, Karnes, La Salle and Live Oak counties have led permitting growth over the past year, although Sharma noted growth in the Eaglebine play—northeast of the Eagle Ford in counties such as Burleson, Lee and Washington. Drillinginfo data show 15 rigs operating in the Eaglebine with 20 horizontal wells having been drilled there so far this year. Permits in the Eaglebine have doubled over the last three quarters, from about 50 in the third quarter of 2017 to about 150 through the second half of the year, according to Drillinginfo.

Sharma said he expects activity to continue to migrate toward the Eaglebine region, while the Eagle Ford offers infill well growth potential, based on the large number of permits recently filed within core counties there. EP

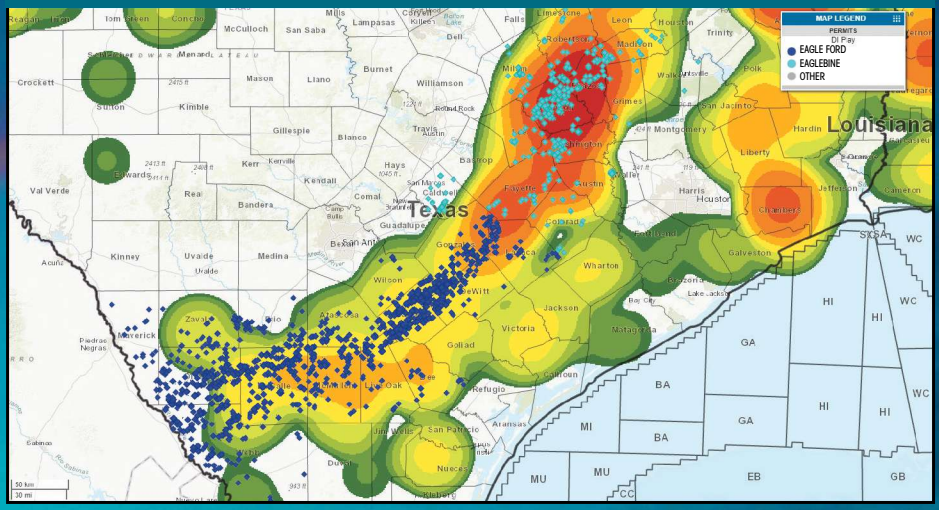
COMPARATIVE TYPE CURVE



Improved type curve production rates in the Eagle Ford and Eaglebine combined from 2016 onward are compared to previous years. (Source: Drillinginfo)

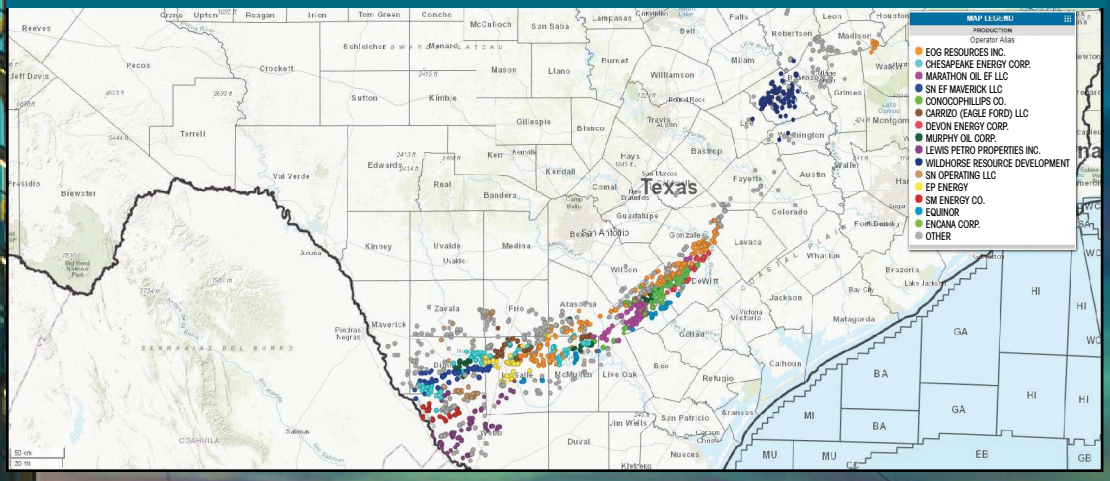
A ConocoPhillips drilling rig operates in the Eagle Ford Basin. (Source: ConocoPhillips)

LEASING AND PERMITTING TRENDS



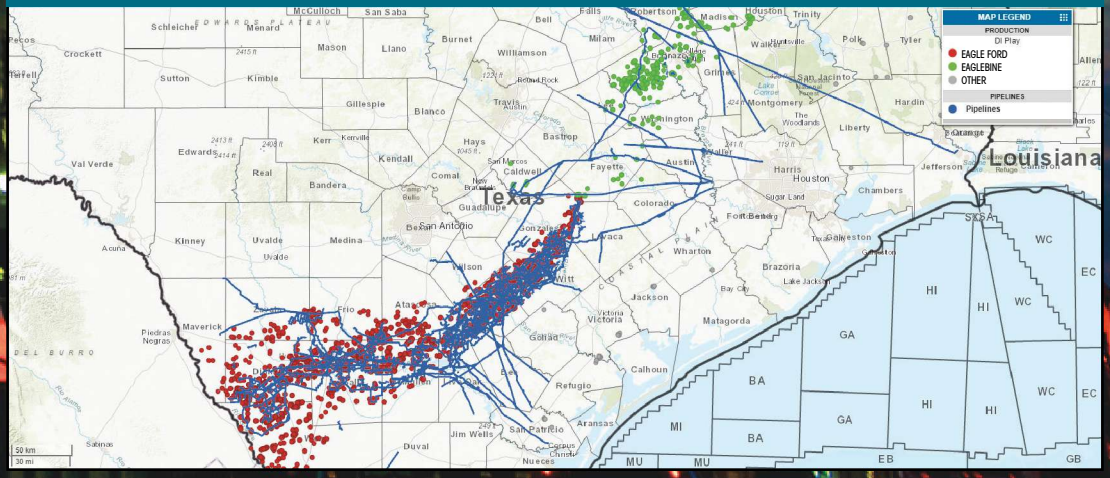
Leases indicate a shift in direction toward the Eaglebine. (Source: Drillinginfo)

HORIZONTAL WELLS BY OPERATOR SINCE 2016



This map depicts horizontal wells by operators in the Eagle Ford and Eaglebine since 2016. WildHorse Resource Development operates several wells in the Eaglebine in Burleson County. (Source: Drillinginfo)

RECENT WELLS AND CRUDE PIPELINES



Crude infrastructure is well developed in the Eagle Ford but will likely need further development in the Eaglebine. (Source: Drillinginfo)

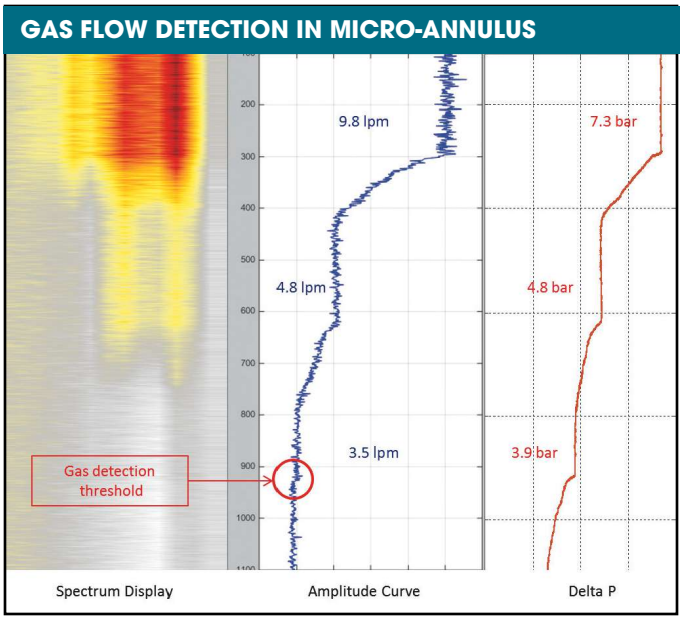
Evaluating cement performance

A new cementing system enhances barrier integrity.

Duncan Troup, Archer

Ever since the drilling of what is recognized as the first commercial oil well in 1859, the problem of isolating different zones in the rock formations has been prevalent. To address the problem of unwanted water threatening that first well, a section of cast iron pipe was run in the hole, becoming in the process the first ever casing string to be set. Despite the installation of casing becoming standard procedure, however, problems with water entering the well by moving behind the casing persisted. This, in turn, gave rise to the practice of trying to fill the space between the casing and the rock formation with a bonding material or cement to stop any unwanted movement.

Theory and practice not always being in alignment, there was a need for some method of evaluating the success of the cement job. It was not until the advent of the acoustic-based cement bond log in the 1960s that the ability to directly confirm the presence of cement between casing and formation became available. This tool, still in widespread use in various forms, relies on attenuation of a transmitted acoustic pulse to infer the properties of the cement bond.



Combining spectrum and energy level data allows precise evaluation of flow dynamics. (Source: Archer)

Conventional approaches

All of the currently accepted cement evaluation techniques rely on active sensing or, described differently, a stimulus is applied to the casing/cement/formation combination and the response is analyzed to draw conclusions about the quality of the bond.

The inclusion of multiple sensors, or single sensors that may be rotated circumferentially, allows a radial map of cement presence to be generated. This can confirm that cement has been placed around the casing, not leaving channels within the cement that might provide paths for fluid movement.

But these techniques, sophisticated as they have undoubtedly become, can only give the assurance that the cement is physically there. What they cannot do is detect whether the cemented barrier is actually sealing against unwanted flow. There are innumerable examples of wells that exhibit sustained annular pressure despite the recording of a "good" cement condition log either during well construction or later on in its life cycle.

The leak rate might be very small, taking hours or days to build up to an appreciable level, and for normal well operations this might very well be acceptable. When a well needs to be abandoned in perpetuity, there is no acceptable level of leakage because after the plug-and-abandonment (P&A) operation is complete, there is no going back into the well to affect a remediation. In such cases, the confirmation that the well is actually secure becomes paramount, and a metric of the performance of the cement is required rather than verifying that it is merely present.

A new direction for evaluating cement

The ultimate test of a cement barrier is whether it allows the fluid to pass. The movement of fluid along a tortuous path will result in the generation of acoustic energy, even if the rate of movement is small. This energy may be detected by a suitably designed and sensitive acoustic receiver and can be used as a definitive indicator that there is flow within the cement barrier.

Archer has developed a new generation of ultrasensitive logging instruments. Under the Acoustic Listening

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Platform, the VIVID sensor has been designed from the start to be sensitive to practically any frequency of sound to be found in a borehole environment and to have the lowest detection threshold available on passive acoustic sensors.

In most conventional designs, the sensor itself is housed in an oil-filled chamber for reasons of pressure compensating against hydrostatic forces due to well fluid. This results in the attenuation of acoustic signals and an increase in the minimum detectable noise level. A pressure-balanced insertion assembly allows the acoustic window of the VIVID sensors to be coupled directly to the well fluid, thereby removing a level of signal attenuation and at the same time acoustically isolating the tool body from the sensor. The end result is a measurement device with unparalleled sensitivity to direct acoustic signals that also is relatively impervious to unwanted "road noise" transmitted along the tool string body.

Archer's VIVID tool provides an approach to cement evaluation. (Source: Archer)

Rigorous testing

Testing of the detection range of the VIVID service was performed under controlled conditions using test cells specifically engineered to reproduce known cement defects. A micro-annulus is notoriously difficult to detect using conventional techniques and might go undetected in many cases, especially if it is a cement-to-formation micro-annulus. A test cell consisting of 7-in. tubing cemented inside 9⅝-in. casing was made and included an engineered exterior micro-annulus. This was rigged up in such a way that a fluid, either liquid or gas, could be pumped at pressure into the annular space between tubing and casing at a variety of flow rates.

The results demonstrated the VIVID tool was able to detect water flowing in the micro-annulus down to 0.08 liter/min. The acoustic signature of gas movement in the micro-annulus was observable even at low differential pressures (2-4 bars) with rates as low as 3.5 liter/min (metered at standard conditions).

Field-proven service

To date, 10 wells have been surveyed with the Archer VIVID Cement Performance Evaluation service. As part of the preparation for a fieldwide permanent abandonment program, investigation of the source or sources of sustained annular pressure in the B and C annuli exhibited by several wells was undertaken. All surface indications were that gas at relatively low pressure was the charging medium, and for each well a bespoke program was crafted by the Archer specialists to fully investigate all potential failure modes. Despite the low rates of gas migration, VIVID was able to successfully detect and map the flow in each case, giving invaluable insight to the dynamics of the integrity breach.

P&A campaign planning

The proven ability to detect migrating gas, even at low rates and differential pressures, brings a benefit to the planning of permanent abandonment campaigns. The small diameter of the tool (1 11/16 in.) coupled with its extremely low detection threshold allows investigation of the sources of sustained annular pressure through tubing before mobilizing a rig to location. Full investigation of any well exhibiting anomalous surface pressure behavior might be undertaken on a fieldwide basis before commenting operations, allowing detailed planning to be conducted to maximize the efficiency and minimize the cost of the campaign.

At a time when the industry continues to focus on efficiencies, costs and safety, robust and comprehensive cement evaluations are becoming more important than ever. Over the life of a well, it is no longer acceptable to consider only the physical presence of cement as an effective barrier. Archer and VIVID are addressing just that—investigating the performance of cement and detecting even small fluid movements, characterizing migration paths with unparalleled sensitivity and allowing confidence in future barrier integrity. E&P

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

Gyro-while-drilling service increases drilling survey efficiency, reliability

Schlumberger has released its GyroSphere microelectro-mechanical system (MEMS) gyro-while-drilling service for a faster and more rugged gyro-surveying-while-drilling tool that increases drilling efficiency and reliability while reducing drilling risks, according to a product announcement. As the first application of MEMS technology for gyro surveying while drilling in the oil field, the GyroSphere sensor performs gyro surveys faster than conventional systems and avoids the need for recalibration between runs. Solid-state technology enables the sensor to withstand the downhole shock and vibration that occurs during drilling beyond the limits of current gyro technologies. Additionally, the GyroSphere service can reduce gyro-survey uncertainty by up to 45%, providing more accurate access to smaller reservoir targets. The GyroSphere service has been proven through extensive testing and field trials in the North Sea, Ecuador, Africa and Russia. In Russia the GyroSphere service enabled a customer to avoid wellbore collisions while accessing reservoirs from existing structures, eliminating drilling risks associated with deploying conventional gyro surveys. *slb.com/gyrosphere*

Service introduces automation to hydraulic fracturing

Halliburton has released its Prodigi AB Service, a first-of-its-kind offering that introduces automation to hydraulic fracturing, according to a company press release. By automating the breakdown process of a fracturing treatment, the service helps deliver better well performance. The service uses algorithmic controls and is supported by a Halliburton completion adviser who will tune the system to optimize the performance. Prodigi AB Service is designed to help improve overall efficiency, maximize the performance of perforation clusters and mitigate the risk of screenout. The service provides consistent design execution, better distribution of fluid across the perforated interval and improved treatment pressures and rates. The service delivers improved precision to achieve a lower cost per barrel of oil equivalent. Halliburton has used Prodigi AB Service in the Permian Basin with outstanding results for Primexx Energy Partners. The service reduced overall treating pressures, increased consistency of the formation breakdown process and resulted in an immediate improvement in cluster efficiency. *halliburton.com*

Data aggregator provides accurate downhole measurement

Varel International Energy Services' DrillPerf is a software program that provides real-time decision support

Drilling dysfunction indicators are displayed in the alarm panel on the right. (Source: Varel International Energy Services)

using only surface data, which are retrieved from a well information transfer standard makeup language server, according to a company product announcement. The software can be deployed in several configurations to support decision-making on site and off site so users can view the output. Decisions are supported through analyzing real-time data streams of parameters measured only on the surface. The algorithm packaged into DrillPerf combines several years of scientific research and field-proven models on drilling dynamics, drillbit behavior and drilling performance assessment in various drilling environments. When the software is calibrated at the rig using local data of current drilling practices and with basic drillbit attributes, such as bit size, cutter size, blade count and average rake angle, DrillPerf can be started and run with input from rig sensors to detect drilling dysfunctions. Comparative studies showed a great accuracy between downhole measurement using MWD/LWD data and drilling dysfunctions detected with the software using exclusively surface data. *vareloilandgas.com*

Companies partner to develop wireless wellsite monitoring systems

Strainstall has partnered with Baker Hughes, a GE company (BHGE), to pioneer the development of a wireless monitoring solution now open to almost all upstream wellsite operations, helping to improve safety, reduce costs and drive efficiencies, a press release stated. BHGE originally requested Strainstall to develop a wireless line tension monitoring. Strainstall's approach was to engineer a plug-and-play system that required no changes to existing sheave arrangements by integrating its highly accurate tension load cells with its hazardous area certified wireless technology to provide both real-time and built-in data logging capabilities for line tension monitor-

The Wellsite Monitoring Solutions suite can be easily retrofitted and is compatible with existing wellsite equipment. (Source: Strainstall)

ing. This work led to Strainstall's development of a modular, fully hazardous area certified wireless system that could integrate with any type of third-party sensor for any application where operator safety is a key concern, without needing International Electrotechnical Commission Explosive recertification. Strainstall has released its suite of Wellsite Monitoring Solutions, which address wellsite safety and efficiency issues, initially focusing on wireline, slickline and MWD activities. The wireless technology supports wellsite operations by eliminating the use of cabled sensors and removing trip hazards. *strainstall.com/wms*

Device can detect up to seven gases

Dräger has released its X-am 8000 multigas detector, which can simultaneously detect up to seven gases including flammable gases, vapors and oxygen, a press release stated. The X-am 8000 is a smaller, lighter device with an easy-to-read color screen, and it has a compact product design that can be used with just one hand. In addition, the mobile device can easily be converted to a fully functional area-monitoring device. The detector's practical functionality allows users to switch between pump and diffusion mode, saving energy and increasing the operating time of the device without requiring factory modification. *draeger.com*

The signaling design and assistant functions of X-am 8000 ensure complete safety throughout the process. (Source: Dräger)

Connection for horizontal drilling and oil exploration

Precision LLC has released the HOSS premium connection to the horizontal drilling and shale gas production market. The connection is designed to withstand higher torques, severe bends and higher fracture pressures to allow faster, safer and more profitable well completions, a press release stated. *precision-llc.com*

Nontoxic paraffin treatments result in cleaned flowlines, production increases

Locus Bio-Energy Solutions' AssurEOR FLOW is a new nontoxic, customized approach to paraffin dispersal for cleaning flowlines and rods. AssurEOR FLOW is an environmentally safe biochemical treatment and is the first paraffin dispersal product that is tailored to the specific characteristics of individual wells and increases production, according to a press release. This approach has been uniformly successful, with results leading to increased demand and swift expansion from the Appalachian and Permian basins into the Powder River Basin. *locusbioenergy.com*

Formulation boosts oil production from mature vertical wells by up to 250%

Cleansorb, a provider of chemical well treatments that enhance hydrocarbon production, announced that it has increased oil production by up to 250% from mature vertical wells in Canada by treating them with its DEEPA formulation. DEEPA increases the matrix permeability of the rock and simultaneously remediates nearby wellbore damage, according to a company press release. These mature vertical wells, which have been producing for nearly 40 years, are located in the carbonate Swan Hills Formation in Canada and have a slight tendency to accumulate scale near the wellbore. The treatment, which delivers organic acid deep into the rock matrix via *in situ* acid generation, increases permeability uniformly around the wellbore. The Swan Hills Formation wells were treated with a custom DEEPA formulation suitable for a bottomhole static temperature ranging from

DEEPA increases the permeability and porosity of formations through uniform carbonate dissolution. (Source: Cleansorb)

90 C to 110 C (194 F to 230 F). Following a brief 24-hour shut-in period to allow the treatment to dissolve the scale and penetrate the rock, production in each well rose by 200% to 250% and remained at those levels. Since the initial wells were treated in the carbonate Swan Hills Formation, similar results were achieved when applied to mature wells located in sandstone formations containing 5% to 10% carbonate. Approximately 30 mature wells in Canada have been successfully treated with DEEPA. *cleansorb.com*

Elastomer-to-metal wellhead cap for HP/HT environments

Trelleborg Sealing Solutions has released a new metal end cap seal specifically engineered for HP/HT wellhead tubing and casing hanger sealing environments. The seal combines the pressure and extrusion resistance of a metal-to-metal bonded component with the flexibility of an elastomer, according to a press release. The high-performance elastomer-to-metal bonded sealing elements provide the high level of extrusion resistance necessary for HP/HT casing and tubing hanger applications. Combining the range of Trelleborg's proprietary XploR rapid gas decompression and sour gas resistant elastomers with corrosion-resistant metal end caps, Trelleborg Sealing Solutions engineers can design a customized seal to meet specific oilfield requirements. *tss.trelleborg.com* E&P

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

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Vice President – Audience Development

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1 US

Eclipse Resources Corp. announced details on a horizontal super-lateral well in Monroe County, Ohio. The Rolland C 5H well was tested flowing 1.1 MMcm/d (40 MMcf/d) of gas from the Utica Shale before being shut in for offset operator activity. The Cranenest Field well is in Section 29, Antioch 7.5 Quad and was drilled from a multiwell pad to 7,933 m (26,027 ft) with a 4,659-m (15,285-ft) northwest-trending lateral and a true vertical depth of 2,982 m (9,783 ft). The company is about to begin completion operations at the Painter 2H well in Tioga County, Pa. The well was drilled to 7,625 m (25,017 ft), 3,429 m (11,250 ft) true vertical, and bottomed about 4 km (2.5 miles) to the southeast.

2 Cuba

An independent resource assessment for Melbana Energy Ltd. indicated that Cuba's onshore Block 9 contains a recoverable prospective resource of 718 MMboe. The best estimate of oil in place increased by 24% to more than 15.7 Bbbl, and there was an increase of recoverable prospective resources of 13% to 718 MMboe from three prospects and 16 leads. The assessment includes a 17% increase in the aggregate of best estimate prospective resources to 236 MMbbl of oil from the four targeted objectives contained within Melbana's initial two-well program of Alameda and Zapato.

3 Guyana

The most recent evaluation for the offshore Guyana Stabroek Block indicated that the discovered recoverable resources are more than 4 Bboe. Based on the evaluations, Exxon Mobil plans a third phase of development and two possible additional phases. The increase follows completion and testing at appraisal well Liza-5 and the incorporation of the Longtail and Pacora discoveries. The previous recoverable resource estimate was 3.2 Bboe. The first development, Liza Phase 1, will use an FPSO vessel to produce 120 Mbbl/d of oil starting in early 2020. Liza Phase 2, which is sanctioning for the end of 2018, will use an FPSO designed to produce up to 220 Mbbl/d and is expected to be producing by 2022. The collective discoveries on the 26,800-sq-km (10,348-sq-mile) Stabroek Block to date have established the potential for up to five FPSOs producing more than 750 Mbbl/d by 2025, with the potential for additional production including the Ranger discovery. Exxon Mobil is the operator with 45% interest in the block along with Hess Corp. (30%) and CNOOC Ltd. (25%).

4 Brazil

An Equinor wildcat well in the Guanxuma Prospect in Brazil's Santos Basin was announced as an oil discovery with 700 MMboe to 1.3 Bboe in recoverable reserves. Equinor is evaluating the volumes and commercial potential of the well. It was drilled to 6,600 m (21,654 ft) in the deepwater Block BM-S-8 presalt area near the Carcara Field. The Guanxuma-1 discovery well is part of the project to develop the block, including the unitization of the Carcara Field with the Norte de Carcará area. Additional appraisal drilling is planned for a Norte de Carcará appraisal and another in Carcara Field. Equinor is the operator of BM-S-8 and the Guanxuma-1 discovery well with 36.5% interest in partnership with Exxon Mobil (36.5%), Petrogal (17%) and Barra Energia (10%).

5 Namibia

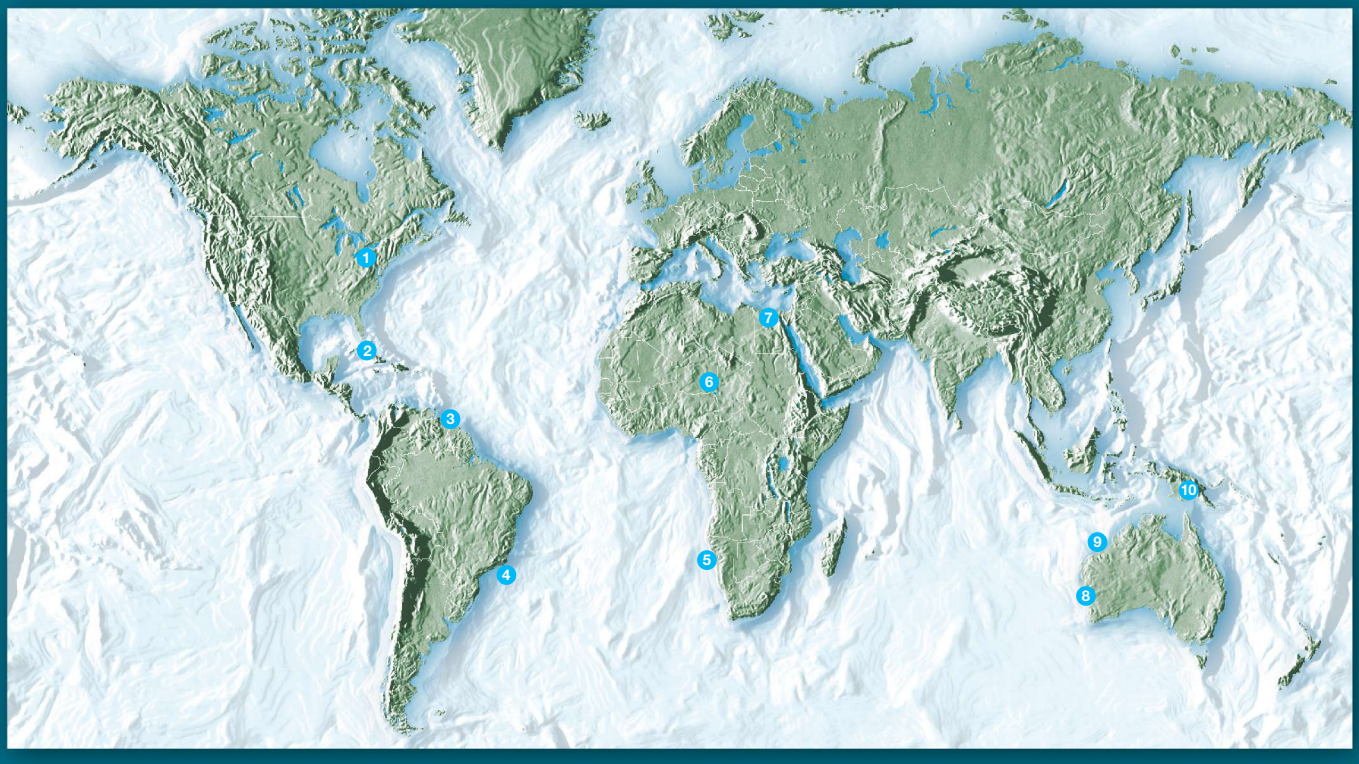
Tullow Oil Plc is preparing to drill an offshore Namibia well in the production exploration license 37 block in the Walvis Basin at the Cormorant-1 well. According to Tullow, the prospect is one in a series of extensive base-of-slope turbidite fan prospects with significant combined resource potential. The fans directly overlie a mature oil-prone source rock of Aptian age that was recently proven by nearby wells. The 3-D seismic surveys over the block indicated that it has the potential of about 124 MMbbl in recoverable oil. The other prospects in the basin are estimated to contain as much as 915 MMbbl.

6 Niger

Savannah Petroleum has completed testing at exploration well Eridal-1 (E1) in the R3 portion of the R3/R4 concession in the Agadem Basin in Niger. Wireline logs, fluid sampling and pressure data indicate the well encountered a total estimated 13.6 m (44.6 ft) of net oil-bearing reservoir sandstones in the E1 reservoir unit in Eocene Sokor Alternances with good reservoir quality and light oil. The well was drilled to 2,542 m (8,340 ft) and is being suspended for future re-entry. Production testing is planned.

7 Egypt

A gas discovery was announced by SDX Energy at the SD-3X well in Egypt's South Disouq Concession. The well was drilled to 2,390 m (7,842 ft) and hit 9.9 m (32.6 ft) of net conventional gas pay in Abu Madi and Kafr El Sheikh with an average porosity in the pay sections of 21.7%. The well flowed 455,901 cu. m (16.1 MMcf) of gas during an eight-hour cleanup period and was then shut in for 8 hours, with no



observed pressure decline. SDX will continue testing the Kafr El Sheikh.

8 Australia

A study by Triangle Energy indicated that up to 29 MMbbl of prospective oil initially in place is in the Cliff Head Field license area in the Perth Basin, with 10.2 MMbbl in near-field exploration targets. The near-field prospects are close to the producing reservoirs of Cliff Head. The static model shows a near-field exploration potential that could potentially recover up to 10.2 MMbbl (unrisked, best estimate).

9 Australia

Quadrant Energy Pty Ltd. has confirmed that the company has made additional oil discoveries in the Crespin and Milne Members at exploration well Dorado-1 in its Phoenix project in offshore Western Australia's Block WA-437-P. Wireline evaluation found additional oil in Caley as well as Crespin and Milne. Light oil was recovered from Crespin containing a gross hydrocarbon package of 50 m (164 ft), a net oil pay thickness of 22 m (72 ft) and average porosities of 14%. Light oil also was recovered from Milne containing a gross hydrocarbon package of 30 m (98 ft) and a net pay thickness of 18 m (59 ft) with average porosity of 13%. According to Quadrant, pressure data have confirmed that the Dorado structure contains multiple oil columns in Caley, Crespin and Milne with a gas and condensate column in Baxter and the total net hydrocarbon pay of 132 m (433 ft), with no water encountered in Caley, Baxter and Milne.

10 Papua New Guinea

Oil Search Ltd. reported that it hit 25 m (82 ft) of net gas pay within the Toro and Hedinia reservoir at the Barikewa-3 well in Papua New Guinea's onshore Forelands region. According to the company, the appraisal well successfully intersected a gas-water contact in Hedinia. A drillstem test was performed in Toro at 1,729 m to 1,743 m (5,672 ft to 5,718 ft) and flowed 991,089 cu. m (35 MMcf) of gas to surface during testing on a 68/64-in. choke. The well is in permit area PRL9 and was drilled to 1,943 m (6,375 ft). It will be plugged and abandoned after testing is complete. Participants in the well are Oil Search (45.1%), Barracuda (40%) and NPCP Oil Co. (14.9%). E&P

For additional information on these projects and other global developments:

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PEOPLE

EnerVest Ltd. has appointed **Jud Walker** president. EnerVest Operating LLC has promoted **Alex Zazzi** to CEO and president and **Jim McKinney** to COO and executive vice president. In addition, **James M. Vanderhider** plans to retire as CFO and executive vice president later this year, and **Nicholas Bobrowski** has been named his successor.

Rob Saltiel has been named CEO, president and director of Key Energy Services Inc.

MEG Energy Corp. has elected **Derek Evans** CEO, president and a board member, succeeding interim CEO **Harvey Doerr**, who will return to his role as an independent director.

Enstor Gas LLC has named **Paul W. Bieniawski** CEO. In addition, **Masoud J. Kasraian** has been elected chief commercial officer and president.

Robert J. McNally has been promoted to CEO and president of EQT Corp. upon completion of the company's upstream and midstream business separation. McNally will succeed interim CEO and president **David L. Porges**. Porges will step down from the board of directors, and **James E. Rohr** will become chairman.

Energy Recovery Inc. has elected **Josh Ballard** CFO.

J. Daniel "Danny" Gibbons has retired as CFO and senior vice president of W&T Offshore Inc., and **Janet Yang** (left) has been appointed acting CFO.

InterMoor Inc. has named **Martin Kobiela** president, replacing **Tom Fulton**, who was appointed CTO.

Exterran Corp. has appointed **Girish K. Saligram** COO.

Amanda M. McMillian (left) has been appointed executive vice president and general counsel of Anadarko Petroleum Corp. In addition, **Robert K. Reeves** will retire as executive vice president and chief administrative officer at year-end 2018.

Murphy Oil Corp. has named **Eric M. Hambly** executive vice president of onshore, **Thomas J. "Tom" Mireles** senior vice president of technical services and **Michael K. "Mike" McFadyen** executive vice president of offshore. In addition, **Eugene T. "Gene" Coleman** has been appointed executive vice president of exploration and business development, and **Maria A. Martinez** has been appointed vice president of human resources and administration.

Add Energy has appointed **Damon Bowler** vice president of its Asset and Integrity Management division.

Consumers Energy, a subsidiary of CMS Energy, has named **Roger Curtis** vice president of public affairs.

Zineddine Benhadid (left) has been appointed managing director of CMR Group's Tunisia manufacturing operation. In addition, **Lassaad Ketata** has been promoted to group manufacturing leader.

Bureau Veritas has appointed **Lars Kverneland** (left) oil and gas manager of Norway, following the retirement of **Steinar Gronsand**.

Anita Nelson has been hired as director of training for Pharma-Safe Industrial Services.

Nicole Keltscha has been named an OMV spokesperson on the public relations team.

Oil States International Inc. has appointed **Robert "Bob" L. Potter** chairman following the resignation of **Mark G. Papa** as director and chairman. Papa has joined Schlumberger Ltd.'s board of directors.

Hal Goldie has joined Enpro Subsea's board of directors as a nonexecutive director.

Pemex Procurement International has elected **Leslie Beyer**, president of Petroleum Equipment & Services Association (PESA), to its board of directors.

Brian Hall has stepped down as chairman of Aminex Plc, and **Keith Phair** has been elected interim chairman.

Charles "Chuck" Davison Jr. has been named chairman of Fairfield Geotechnologies.

Jim McKerlie will retire as a director of Beach Energy Ltd. in November.

Gastar Exploration Inc. has appointed **Marc Beilinson** and **William L. "Bill" Transier** independent directors of the board.

Global Marine Systems Ltd. has named **Ian Bryan**, **Mike Daniel** and **Mark Preece** to its board of directors.

Chesapeake Energy Corp. has welcomed **Mark A. Edmunds** to its board of directors.

David M. Sparby has been elected to MDU Resources Group Inc.'s board of directors.

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COMPANIES

Transocean Ltd. and **Ocean Rig UDW Inc.** have entered into a definitive merger agreement under which Transocean will acquire Ocean Rig in a cash and stock transaction valued at approximately $2.7 billion. The transaction is expected to be completed during the first quarter of 2019.

Diamondback Energy Inc. has acquired **Energen Corp.** in an all-stock transaction valued at approximately $9.2 billion, including the company's net debt of $830 million.

Santos has acquired **Quadrant Energy** for $2.15 billion. The acquisition will have an effective date of Jan. 1, 2018, and completion is expected by the end of the year.

Shale Support has opened a logistic hub and fracturing sand storage facility in Grand Cane, La.

Milestone Environmental Services has opened a new facility in Glasscock County, Texas. The plant will primarily accept drilling waste streams, including water-based mud and oil-based mud, along with some completion and production waste such as tank bottoms and water waste streams.

Trelleborg Sealing Solutions has opened its Innovation Center in Stuttgart, Germany. The 14,000-sq-m (150,695-sq-ft) center houses the business area's global headquarters, its German headquarters and various global support departments as well as an extended R&D area and an Internet of Things laboratory.

Unique Group, a provider of integrated offshore solutions, has completed its acquisition of **Water Weights**, a load-testing equipment provider. E&P

ADVERTISER INDEX

Impacting operational performance through customized fluids

Embracing digitalization can help operators maintain a competitive advantage.

Ryan Ezell, Halliburton Baroid

In an industry that has long been shaped by volatility, a focus on innovation that drives productivity and efficiency is fundamental. The question facing the oil and gas industry is how operators and service companies can collaborate to deliver a step change in rig site execution in all drilling domains from land operations to offshore plays. The industry requires stakeholders to redefine the rules of engagement in how we collaborate across the value chain from operator to suppliers to create value in performance, innovation, safety, environmental stewardship and industry returns across the cycle.

Consider for a moment the impact of drilling fluids on operational performance and efficiency. The main recurring operational issues that impact cost, performance and safety that can be mitigated through properly engineered fluids include pressure control, hole cleaning, wellbore stability, lost circulation, waste generation and more.

The impact of customized fluids on reservoir productivity is key to improving industry returns.

To ensure fluid performance to maximize well value for the operator, having a customized fluid coupled with a mechanical separation solution to drill the overburden is critical to keeping a field viable. This approach improves drilling efficiency and lowers cost with waste disposal. These methods separate cuttings at the surface, ensure optimal treatment and recovery of fluid for reuse, and help maximize the ROP.

The impact of customized fluids on reservoir productivity is key to improving industry returns. Fluid experts should be part of upfront planning when production and completion decisions are made. This ensures that fluids used for reservoir drill-in, wellbore cleanup and completion operations are tested and designed to help protect reservoir permeability, increase productivity and extend the life of the asset.

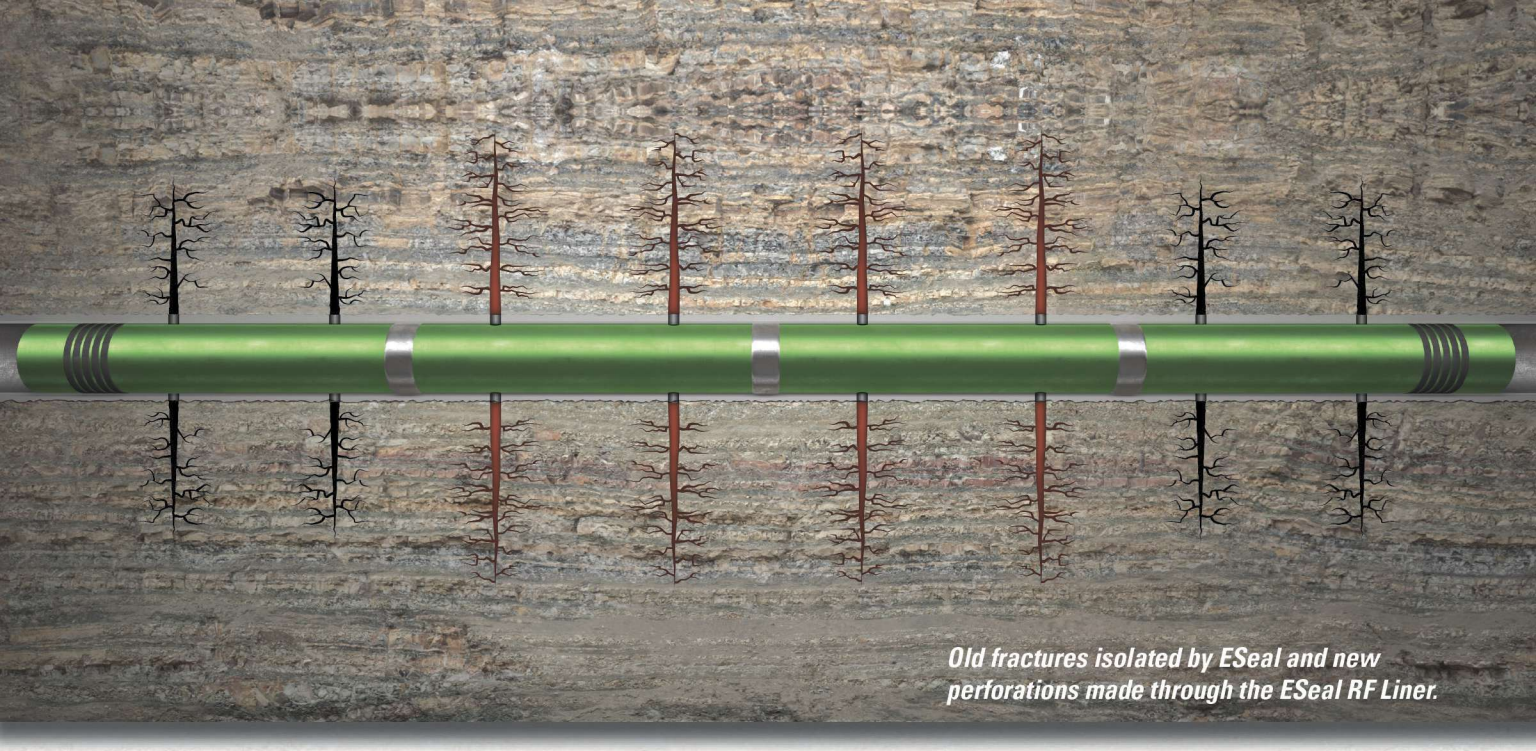
The value of including fluid experts in production and completion planning can be illustrated with a recent project in Latin America where early collaboration helped increase production in heavy oil wells. By tailoring the proper formulation and anticipating potential downhole issues, Halliburton helped an operator treat more than 100 wells resulting in a 30% production increase throughout the entire field.

Service companies also deliver value to operators through closer collaboration to bring digitalization to drilling and completion fluids and enable separation equipment. Drilling fluid measurements are usually done manually in the field. When this occurs, the nuances of fluid changes are lost between measurements, which are supplied one to four times daily. Detecting these small changes through real-time measurement can result in significant savings, which are realized by enabling the true ROP optimization.

The application of a real-time hydraulics software model to provide predictive analytics is equally important. Predictive analytics enables operators to look ahead of the bit and determine the maximum ROP that can be drilled versus optimizing instantaneous ROP. This helps optimize casing to casing speed. The digitalization of fluid data reduces risk, provides consistent well delivery and speeds up decision-making by connecting people and information.

The value of real-time fluids data can be demonstrated through a recent project in the Middle East where multiple issues related to drilling fluid control in HP/HT conditions were encountered on offset wells. By monitoring fluid data from the Halliburton BaraLogix unit, engineers helped an operator drill its well with zero instability issues 13 days faster than planned. This saved an estimated $650,000 in operational costs and avoided an expensive sidetrack well saving more than $1 million.

Embracing the digitalization and application of customized fluids through well-developed people, technology and processes across drilling and completions can help operators maintain a competitive advantage as they look to succeed through future volatility. EP



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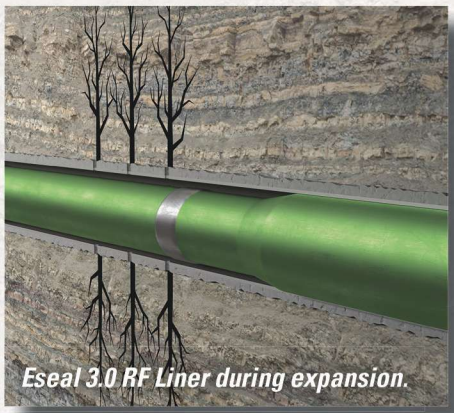

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CONTROLLED INTENSITY™

Pinpoint fracturing delivers aggressive infill completions one frac at a time, with less risk of well bashing.

Multistage Unlimited® pinpoint fracturing delivers maximum SRV with far less risk of frac hits and well bashing during infill field development, compared with plug-and-perf. You put fracs where you want them, and you control how much sand you pump into each one, preventing "super clusters" that can hurt production from offset wells. With repeatable frac placement from well to well plus recorded downhole pressure/temperature data, you can truly optimize stage count and spacing in a given formation with just a few wells.

More stages per well

NCS pinpoint fracturing delivers more individual entry points with far higher frac efficiency than plug-and-perf. For example:

- 168 stages (Montney)
- 165 stages (Montney)
- 161 stages (STACK)
- 159 stages (STACK)
- 155 stages (Bakken)
- 147 stages (Permian)

More sand per well

More intensity means pumping a lot more sand, and NCS Multistage pinpoint fracturing handles it:

- 18.2 million lb @1,870 lb/lateral ft (Montney)
- 16.2 million lb @2,190 lb/lateral ft (Montney)
- 15.0 million lb @1,711 lb/lateral ft (Duvernay)
- 14.2 million lb @1,973 lb/lateral ft (Permian)

Faster execution

NCS Multistage pinpoint completions are being executed faster than ever. Here's why:

Higher rates. Technology and design advances have boosted Multistage Unlimited frac rates through the coiled tubing/casing annulus to nearly 80 bbl/min in 5.5-in. casing, far higher "per cluster" than plug-and-perf and more than enough to transport sand (>12 ppg) with slickwater.

Fewer coiled tubing trips. Almost 90% of NCS Multistage jobs are performed in a single coiled tubing trip. As many as 168 sleeves have been fracced without tripping out of the hole.

99+% sleeve success rate. More than 165,000 NCS sleeves have been installed, with the highest sleeve-shift success rate of any coiled-tubing completion system.

Learn more at ncsmultistage.com

NCS MULTISTAGE

Predictable. Verifiable. Repeatable. Optimizable.

ncsmultistage.com