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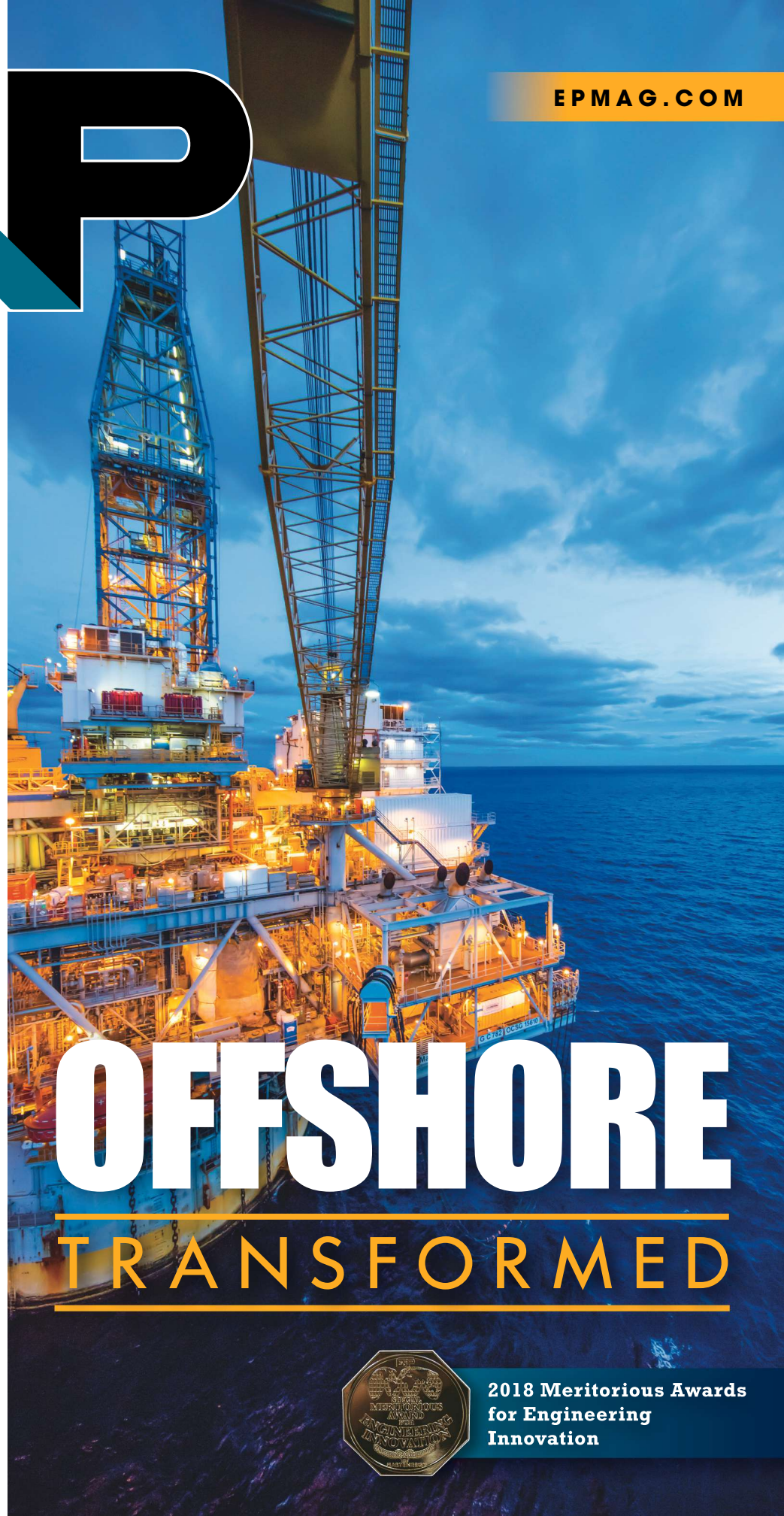
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COMING NEXT MONTH The June issue of **E&P** will focus on completions. Other features will cover marine seismic, drillpipe advances, sliding sleeve advances, surface systems and well intervention. The unconventional report will focus on the Permian 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 The massive Mad Dog platform is BP's only floating spar facility in the Gulf of Mexico. In 2016 the company sanctioned the Mad Dog 2 project that will include a new floating production platform with a capacity to produce up to 140,000 bbl/d from up to 14 production wells. Left, Hess' average well in the Bakken last year was drilled and completed for \$5.6 million. (Cover photo by Marc Morrison, courtesy of BP; Left photo courtesy of Hess Corp.; Cover design by Felicia Hammons)

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Energen completes four parallel-lateral Wolfcamp wells in Delaware Basin

Energen Resources Corp. has completed four parallel horizontal Phantom Field-Delaware Basin Wolfcamp producers from a drill pad on a 360-acre West Texas lease in Section 4, Block 3, H&GN RR Co Survey, A-4212, in Reeves County (RRC Dist. 8), Texas.

Second gas zone found in California's Rancho Capay Field

Sacgasco Ltd. is perforating and flow testing a discovery, #1-15 Dempsey, in Glenn County, Ca. The second zone of gas in the well has been perforated and is being tested.

Green Canyon Block 281 well hits 297 ft of net oil pay

Talos Energy LLC announced details from a second well drilled on the company's Green Canyon Block 281 project. The #2SS (ST) OCS G33242 hit 90.5 m (297 ft) of net oil pay across two upper Miocene sands.

AVAILABLE ONLY ONLINE

Podcast: Women in Energy, Ep. 1—Standing Out

By Jessica Morales and Emily Patsy, Digital News Group

In this episode of the Women in Energy podcast, Hart Energy hears from EY's Deborah Byers, who gave pointers on how to progress your career.



Schlumberger talks EOR transformation in shale

By Emily Patsy, Associate Managing Editor, Digital News Group

Pointing to low recovery factors, Schlumberger's Omer Gurpınar said bringing EOR methods to unconventional is crucial for the industry.

Brazil's onshore oil, gas sector faces challenges

By Bruno Braga, Contributing Editor

As Brazil's offshore segment flourishes, onshore opportunities have not gained much attention. But the Brazilian government is working to make its onshore assets more attractive.



Study: good news, bad news for Canada's oil industry

By Markham Hislop, Contributing Editor

While companies are finally seeing black in the financial reports again, oil and gas jobs are still lagging, a Conference Board of Canada study revealed.

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Making the impossible possible

The modern day petroleum industry—making the impossible possible for more than 150 years—embraces the millennia-old challenge of changing for the better.

Long ago humans discovered that harnessing the power of molecules could improve life. Lost in the annals of time is the name of the person responsible for the world's first exothermic reaction known as fire. Through the power of observation, this early innovator deduced that fire emitted the heat needed to keep their cave warm and pleasant, that fire illuminated their cave's darkest corners while also ensuring their safety by keeping predators away.

Imagination and creation, born out of curiosity driven by the desire to make one's surroundings secure and hospitable, led to the early day innovation of rubbing sticks together to spark a fire and using wood as a fuel to keep it burning.

These first discoveries led to the eventual creation of the modern day internal combustion engine in 1859, the same year that Colonel Drake drilled the oil well credited for launching the modern day petroleum industry. While it required multiple millennia for humans to evolve from basic fire starting to advanced engineering, our ability to explore, drill, produce, refine and use petroleum products to enrich our lives has required far less time, 159 years to be exact. In that relatively short span of time, the petroleum industry migrated offshore.

Imagination and creation, born out of necessity to meet the growing global thirst for cheap and accessible fuel resources, led to technology innovations like subsea compression, remote well monitoring, floating LNG and more. Many of these advances have garnered industry accolades and significant awards, like those presented at the Offshore Technology Conference (OTC) in Houston.

OTC announced in March that 17 technologies will receive the 2018 Spotlight on New Technology Award. The winning technologies "showcase the latest and most advanced hardware and software technologies," according to the press release.

"As OTC celebrates its 50th edition, we reflect on the innovations that have been achieved throughout the past five decades," Spotlight Award Committee Chair Paul Jones said in the release. "We can never forget that companies like the 2018 Spotlight Award winners are driving the technological advancements necessary to propel our industry for the next 50 years."

With a global population estimated to be 10 billion by 2050, many of those advances will likely harness the power of carbon-based fuels with the molecules of hydrogen, oxygen and nitrogen to meet the perpetually growing demand for cheap, accessible energy resources. And as time has demonstrated over multiple millennia, all that is needed is a little imagination, creation and innovation to make the impossible possible. **ESP**

Jennifer

Energy startups face challenges, but path to success exists

Taking the leap from concept to placement on the market is not impossible with help from 'dragon' investors.

Nicholas Newman, Contributing Editor

Today it has never been easier or cheaper to initiate an energy startup since many need little in terms of money or supplies as their ideas have gone no further than their laptops. The leap from concept to prototype to the market is when startups need to raise serious money for buy-in ability, equipment and premises.

"Bridging the gap between the idea and the prototype, that's the hard part," said Nicholas Flanders, CEO of Opus 12, which developed a technology for turning CO₂ into useful chemicals for the industry.

In recent years a specialized energy investment community of venture capitalists, or so-called dragons, has formed. ("Dragons" is in reference to the international reality TV

program "Dragons' Den.") But these investors, like innovators, face the challenge of detecting profitable opportunities in a market in transition. The only certainty is that demand for energy will increase but determining how is the challenge.

"Success stems from being able to envision an energy innovation's benefits or contribution to accomplish higher productivity or provide other products and comforts that can be monetized," said W. Ross Williams, CEO of Alfresco Group in Denver. "Basically, the marketing fundamentals apply: We don't pay for energy, we pay for the benefits that energy provides. Energy is only one ingredient in the value chain."

Challenges

For any startup to progress from the drawing board

requires capital, and this entails being able to convince potential investors of the merits of the proposal. Startup entrepreneurs need to answer the following key questions to satisfy likely investors: Who is the customer? What is the problem? What is the solution? How does it work, and how can it be monetized?

But as Nelson Phillips, professor of strategy and innovation at Imperial College Business School in London, said, "If the startup is trying to do something truly innovative, then good information on customer wants and needs will be very difficult to come by."

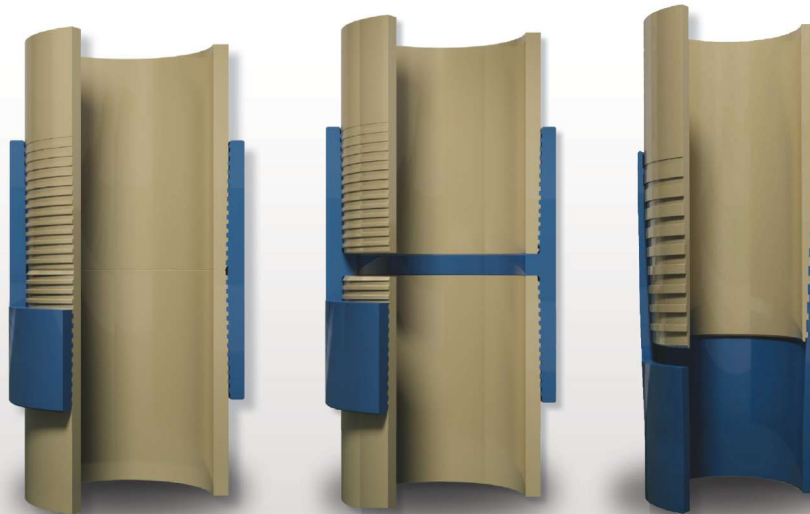


Extensive preparation is one of many critical steps necessary for an energy startup to take on the road to venture capital funding. (Source: Proton photo/Shutterstock.com)



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Saudi-U.S. CEO Forum highlights bilateral business collaborations

Senior executives with Saudi Aramco and numerous U.S. companies from a wide range of industries, including leading oil and gas corporations, recently met in New York City to discuss bilateral business and cooperation between the two countries as part of the Saudi-U.S. CEO Forum. A number of cooperation arrangements and prospective commercial collaborations were discussed, according to a Saudi Aramco press release.

The commercial cooperation between Saudi Aramco and 14 U.S. companies is worth more than \$10 billion, according to the press release. Schlumberger; Baker Hughes, a GE company; Halliburton; Weatherford; Emerson Electric Co.; and Honeywell International are a few of the companies that participated in the forum, according to the press release.

The forum builds on the success of the inaugural forum held in 2017 in Riyadh, Saudi Arabia, that resulted in the signing of agreements with GE and The Dow Chemical Co. These agreements, according to a forum press release, aligned with Saudi Arabia's Vision 2030 to create jobs and drive economic diversification. ■

Grow Venture Capital Group CEO Valto Loikkanen said, "The more 'deep tech' things go, the harder it is to prove the thing works as explained or can be made to work."

A case in point is thermal storage, where evidence for a market is lacking. Original ideas or disruptive solutions such as this find it hard to attract dragons.

In addition, investors are not only investing in the product or service but also in the leadership and the team members of the startup.

One thing is clear—having leaders with the qualities and media presence of Tesla CEO Elon Musk can help to attract investors. However, to get buy-in, the skills and experience of the team members matter just as much.

Secrets for success

For an energy startup to improve its chances of success, comprehensive preparation is vital.

For instance, Quatre Ltd., a company offering funding and insurance solutions for the decommissioning of oil and gas fields, spent three years building a multiskilled team able to deliver an investment and insurance

solution that meets regulatory requirements. Afterward, "moving quickly and being willing and able to adapt and evolve is the foundation for success," Phillips said.

Finding the right business dragon helps. Phillips noted that "many dragons provide critical access to networks, connections to potential customers and business experience that the entrepreneur may lack."

For example, Shell Technology Ventures supplied capital and knowledge of customers in the Persian Gulf to California-based GlassPoint, a manufacturer of solar steam generators for oil and gas companies.

Innovation brings buy-in

The pressures on companies to innovate have never been greater. So for many companies outsourcing is necessary since, as Loikkanen observed, "It's harder to come up with disruptive innovations in-house so most internal innovation is iterative."

Therefore, an increasing number of large energy companies are taking stakes in fledgling entrepreneurial energy businesses. For instance, some of Europe's largest energy companies, including Statoil, BP, Innogy and EDF have created venture capital funds totaling some €1 billion (US\$1.2 billion) to be invested in or buying into often disruptive innovations from startups.

Large organizations have many complementary assets that are vital to a startup's success. For instance, market knowledge and distribution channels are crucial for marketing innovative products and services. Total brings its distribution and sales ability to its interests in solar photovoltaic maker SunPower and battery company Sunverge. Outsourcing helps large energy companies stay ahead in a stormy marketplace characterized by sustainability, costs and productivity concerns.

To succeed, startups need imagination, luck and business skills. Fortunately, launching an energy startup is becoming cheaper for software- and hardware-based entrepreneurs. What is clear is that innovation can benefit not only the startup but also potential stakeholders, including energy giants and institutional and dragon investors. **ESP**

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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Transportation and the future of oil

Saudi Aramco's Nasser downplays emergence of alternative fuel vehicles.

Brian Walzel, Associate Editor, Production Technologies

Amin Nasser, president and CEO of Saudi Aramco, firmly believes the future of the oil and gas industry is secure, despite the advent of alternative fuel vehicles allegedly signaling that the end is nigh. Nasser, speaking at CERAWEEK by IHS Markit in March, said the emergence of energy efficient vehicles likely will not have a widespread impact on the world's demand for hydrocarbons, particularly as the world's middle class grows by an additional 2 billion people by 2050.

He described the future of oil as "misunderstood" and said he believed that the oil and gas industry is being wrongly portrayed amid an energy transition in the transportation sector, a segment that currently accounts for 20% of the world's demand for hydrocarbons, according to Nasser.

"Many wrongly believe it is a simple matter of electric vehicles quickly and smoothly replacing the internal combustion engine," he said. "It is not an either/or future, but far more complex."

Nasser named five "horses" in the mix to become the power train of the future: advanced internal combustion engines, hybrid electric vehicles, plugged-in electric vehicles, fully electric vehicles and hydrogen fuel cell vehicles.

"The first three are powered by an internal combustion engine," he said. "And let's not forget more than 99% of the passenger vehicles on the road today have an internal combustion engine and will be with us for a long time."

In fact, the number of vehicles worldwide is expected to more than double over the next three decades. In the BP Technology Outlook 2018, the company reported that "the world's total number of cars, vans and light trucks—the global 'light-duty vehicle fleet'—could grow to around 2.6 billion vehicles in 2050 from 1.2 billion in 2015."

But Nasser indicated it remains to be seen how much of that growth will come in alternative fuel vehicles. Affordability, public acceptance and driving range for alternative fuel vehicles are among the major challenges Nasser said such transportation options would need to overcome to potentially have a widespread disruption effect on the hydrocarbon industry.

"Especially when the other two horses in the race are pure battery electric vehicles and hydrogen fuel cell vehicles, they still face a range of problems," he said. "For example, electric vehicles will not deliver rapid and economic reductions in carbon emission reduction until the electricity fuel mix becomes sufficiently clean. Even 25 years from now coal will still comprise almost 50% of the energy mix, especially in fast markets like China and India."

A large segment of the vehicle-buying demographic of the future will likely be located in developing nations where customers will place a priority on upfront affordability and where massive infrastructure improvements are needed, not just for alternative fuel vehicles but also those utilizing combustion engines, Nasser said.

"So yes, electric vehicles will grow and have a welcome role to play in global mobility," he said. "But given the competition and complexity of the transition, their impact on the 20% oil demand should not be exaggerated. And that still leaves the other 80% of oil demand that continues to grow."

Nasser said he believes the broad-based oil recovery "remains on track" as a result of economic growth in emerging markets and production restraints by major oil producers. Like others at CERAWEEK, Nasser touted the need to cut carbon emissions to meet climate change goals. He suggested lowering emissions from internal



Amin Nasser (left), president and CEO of Saudi Aramco, addresses the CERAWEEK audience, along with Daniel Yergin (right), vice chairman of IHS Markit. (Source: IHS Markit)

combustion engines while finding new uses for hydrocarbons to better monetize a barrel of oil. He cited a recent agreement that Saudi Aramco signed centered on a technology that he said would convert almost 70% of a barrel of crude oil to petrochemicals. The result would be a 30% reduction in capital costs and substantially lighter “carbon footprint of oil consumption,” Nasser said.

“Investment in R&D innovation by individual companies will further lighten the carbon footprint of further energy sources and technology boosted by collaborative efforts such as the \$1 billion investment by oil and gas climate initiative partners,” he said. “In other words, I’m not losing any sleep over big oil demand or stranded resources. Oil and gas will continue to play a major role where all energy sources are required for the foreseeable future.”

For the industry to continue to play that role, Nasser cited several key areas in which he said “bold action” needed to be taken. Among those were an increased need to expand exploration as well as a need to offset

the decline in developed oil fields while also meeting the world’s growing oil demand.

“Even conservative estimates suggest that 20 billion barrels per day of new capacity is required over the next five years,” he said.

Nasser also called for \$20 trillion more in investments over the next quarter century to meet the rising demand for oil and gas. Finally, Nasser said oil companies needed to “intensify their efforts for in-house current technologies as well as create new, game-changing ones.

“That requires us to dedicate more resources to longer-term research, especially to low- to no-carbon products,” he said. “And it means regulators must be policy holistic and technology agnostic. Let the market decide.”

Nasser also gave an update on the state of Saudi Aramco’s potential IPO, which he said was progressing “very well.”

“The question that’s being asked is when and ... where we will be listed,” he said. “This is a shareholder decision and it’s up to the shareholders to decide.” **ESP**



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A new dawn for Gabon

A focus returns to the West African country as its government relaxes hydrocarbon code.

Mark Venables, Contributing Editor

When Pascal Houangni Ambouroué, the Gabonese minister of petroleum, emerged March 28 from three days of meetings, he declared that the country's new hydrocarbon code would herald a new dawn for the West African state.

"It is not a question of yielding a part of the revenues but making the code more flexible and to adapt to a complicated conjunctural situation that we know today," he told the assembled press.

Gabon is among the top five oil producers in Sub-Saharan Africa and has been an oil producer for more than 50 years. It reached its peak 12 years ago when oil production hit 370,000 bbl/d to its current level of 200,000 bbl/d. To combat the natural decline of mature fields, the government has focused on offshore resources, which account for more than 70% of the reserves.

Under the current code, Gabon takes a minimum 20% stake in oil projects, while country-owned Gabon Oil Co. is entitled to a further 15% stake. Like other oil-dominated economies of the Economic Community of Central African States' single-currency zone, Gabon has struggled due to the decline in crude prices, forcing it to seek support from the International Monetary Fund (IMF) in 2017.

Although full details are yet to emerge, the new codes will feature improved flexibility along with revisions to company tax and value-added tax. It is envisaged that the new code will become effective in June. With oil revenues at a nadir, down to 27% of GDP in 2017 compared to a high of 45%, Gabon was forced to turn to the IMF for support, which insisted Gabon diversify its economy.

Oil pedigree

Ambouroué said Gabon is among Africa's safest oil-producing countries.

"At the moment most of the oil wells that are producing are mature, which is why the Gabonese government has put in place a set of measures, such as the revisions to the hydrocarbon code, to improve production from these mature wells and also encourage exploration and discovery of new oil in deep water offshore," he said. "This will also stimulate the entry of new players with the major companies now focused on deep waters for production of oil and gas. Ongoing prospecting shows that Gabon has very good resources in terms of oil and gas for the future.

"To combat the natural decline of mature fields, the government has focused its attention on offshore resources, which account for more than 70% of the reserves," he said.

There are about 30 producing oil fields in the region, making Gabon the fifth largest oil producer in Africa. However, production is declining.

The Gabonese government launched its 10th bidding round in late 2013, generating new production-sharing

contracts with Marathon Oil, Petronas, Repsol, Noble Energy, Woodside, Impact Oil & Gas and Ophir Energy, which are all working on their exploration programs. Another round was launched just over two years ago, but the government was forced to suspend it as low oil prices and the proposed economic terms failed to attract the desired interest. This led to recent amendments to the code.

"We are very aware that oil and gas are important to the economic development of the country."

—Pascal Houangni Ambouroué,
Minister of Petroleum, Gabon

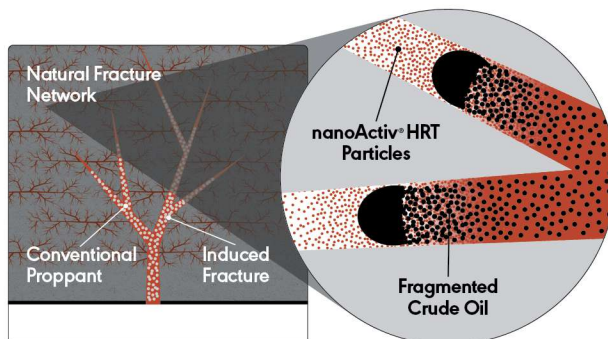
Promoting local benefit

As is common in most of Africa's oil- and gas-producing regions the government is seeking to support local small and medium-sized enterprises that provide services to multinationals along with increasing the employment and training of nationals. One of the tools being utilized is the creation of a special economic zone.

"The existence of this special economic zone is very important to support the industries that will build up around oil and gas exploration, and this activity will also support the development of the country," Ambouroué said. "It is important that we have a dedicated economic zone to support this. A strong economic base will arise

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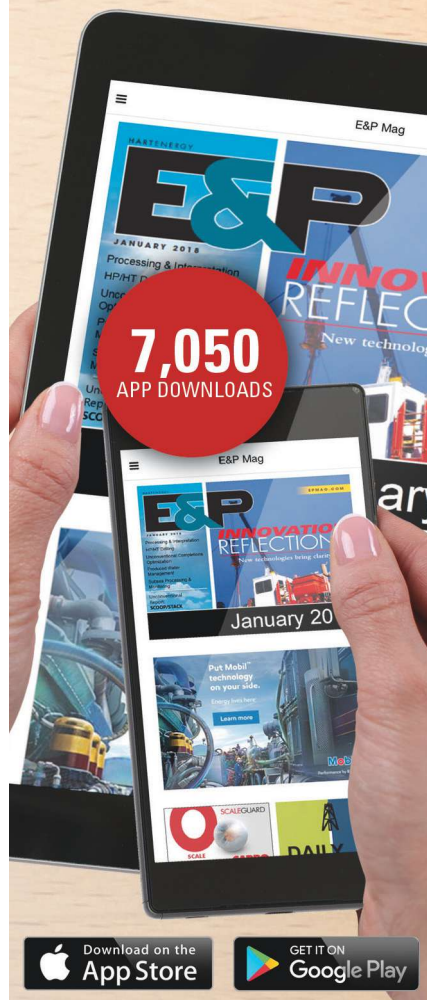
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world VIEW

from these areas. We are very aware that oil and gas are important to the economic development of the country, and we are implementing several areas of improvement in Gabon that will allow the people to benefit from the increase in activity that we are planning.”

Ambourou points to policies under development by Ali Bongo Ondimba, the Gabon head of state, which will allow the population of Gabon to benefit from the oil revenue generated.

“A part of that is ensuring that there are enough skilled workers, and so training is now playing a key role in Gabon,” Ambourou said. “We are putting in every effort to make sure we have the process in place to ensure that our workers are up to date with the modern trends in the oil and gas industry. We have two priorities: the first is to make sure we have in place the infrastructure that will allow local content in the developments, and the second item is the revision to the hydrocarbon code. In this area we will integrate for the very first time a new economic model for the local community, which is a win-win situation.”

Following the three-day seminar in Libreville, the capital of Gabon, which focused on revisions to the hydrocarbon code, Ambourou and his team will travel around the world on a road show to tell investors why Gabon is an attractive country for oil and gas investment.

“The original code was written when the oil price was at \$120, so this needs to be revised to make the oil and gas industry in Gabon attractive and encourage more people to invest in our industry,” Ambourou said. “The entire structure is drastically changing in Gabon, and we need to adapt our code so that the oil industry is once again attractive.”

Gabon seismic survey

The shallow offshore waters of Gabon have been explored for more than 50 years, highlighting the potential for oil discoveries. However, exploration of the more complex, salt-obscured geological structures requires an advanced support that only modern, regionally consistent 3-D seismic data can provide. Such support was the objective of a large-scale 3-D seismic program created through collaboration between Spectrum Geo and the Gabonese hydrocarbon authorities, Direction Générale des Hydrocarbures.

In late 2016 Spectrum commenced acquisition of an 11,500-sq-km (4,440-sq-mile) 3-D survey in the Gryphon area of Southern Gabon—the shallow offshore of Mayumba and Sette Cama, west of the Olowi Field—in water depths between 20 m and 1,000 m (66 ft and 3,281 ft). The survey attracted strong industry funding and was completed at year-end 2017. It now offers the most relevant 3-D imaging of the area and is the definitive dataset to image presalt and, for the first time, intra syn-rift plays can be targeted.

“We undertook some seismic testing with Spectrum and CGG that delivered some exciting results, but at the end of the day it recognized that we have good reserves; and this has been communicated all over the world. We carried out these surveys so that investors have the information they need, and we want to attract more investors to the country,” Ambourou said. “The information gained from the two countries will be available so that everyone can see the opportunities for investment. This is to help us to communicate the oil potential of Gabon to everyone, and this, alongside the revision to the hydrocarbon code, will help attract more investors to develop all the blocks.” **E&P**



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Datapoints and drilling rigs

Integrating real-time rig data and reservoir properties requires a holistic approach.

Richard Mason, Chief Technical Director

A drilling industry notion in the pre-rig class delin-eation days more than a decade ago postulated, “A rig is a rig is a rig.”

Adoption of alternating current variable frequency drive (AC-VFD) drilling technology ended the nostrum of the rig as a commodity service. Yet, the advent of Big Data analytics promises to revive that timeworn cliché in an unexpectedly positive way.

The Big Data movement in oil and gas is loosely bifurcated between production optimization, where benefits accrue to E&P companies from data mining archived well data, and the drilling process, which offers real-time data acquisition via the rig’s instrumentation package.

Those silos promise to converge into a holistic approach that integrates drilling, completion engineering and production optimization into a unified package that delivers better wells with lower lifetime costs.

Estimates on data volume from the drilling process are up to 7,000 items per second across 20 to 40 channels. But large volumes of data also carry the baggage of large volumes of noise. Efforts are underway to calibrate, normalize and identify the most important features of that rig-generated data stream. The process incorporates complex algorithms, development of key performance indicators and the ability to extract usable parameters for decision-making in real time for well construction via easily understood visualization.

In fact, the data, algorithms to parse the data and the ability to visualize and communicate the result exist now.

In February 2017 Exxon Mobil licensed its Drilling Advisory System and its machine learning algorithms to Pason Systems Inc., the largest provider of rental instrumentation packages for land-based drilling rigs. Pason recently completed a study that showed

the licensed advisory system improved ROP by 35% over a 360-well dataset featuring similar properties.

In January 2017 Pason acquired Verdazo Analytics Inc., a software company that creates visual analytic tools, templates and customizable reports integrating public and proprietary data into machine learning processes. Verdazo is integrating wellbore porosity predictions captured via drilling to assist completion engineering.

The end game is to expand beyond drilling a faster lateral into building a better lateral, which leads to reduced costs and mechanical issues, not just in the completion process but compounded over a well’s life cycle.

Service providers bring significant volumes of data to the table as every new well becomes a datapoint. The benefit from processes, such as machine learning, resides in extracting actionable options from large datasets curated in a way that provides quality information. The ability to capture, store and generate analytics via a simple interface is opening the path for machine learning in real time.

Instrumentation systems and analytics used in machine learning can fit modern AC-VFD rigs and be retrofitted for legacy diesel electric rigs. Technology is no longer the issue; the challenge

is overcoming human foibles. Full adoption may require the creation of regional consortia of aggregated drilling data, which allow E&P companies to benefit while preserving individual well anonymity—a concept easier said than done.

Integrating real-time rig data to improve reservoir insight requires a holistic approach from an industry that is characterized by discrete silos of expertise, whether in the form of services or internally across the organization for E&P companies.

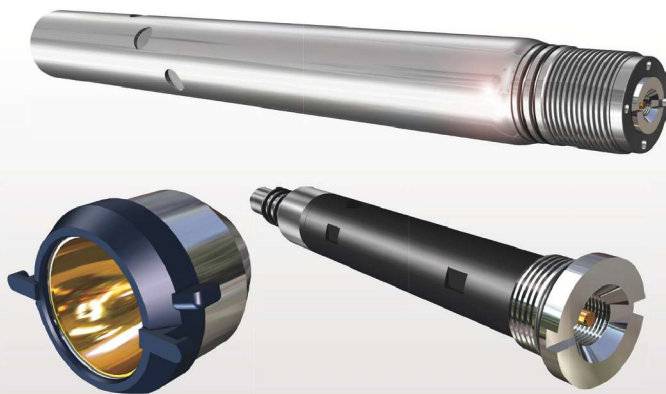
Doing so will create tangible benefits in hydrocarbon recovery and cost reduction via better wells by expanding communication between the ROP-focused drilling manager, the IP-focused completions engineer, the EUR-oriented production manager and the internal rate of return oriented investor relations officer. **ESP**

- **Rig-generated data provide a pathway to building better, lower cost wells.**
- **Rig-generated data allow smaller E&P companies to participate in the Big Data revolution.**

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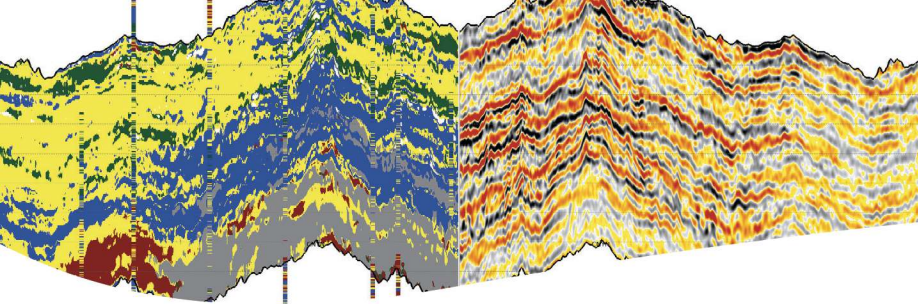
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Geological superheroes

Some of the world's most prolific basins were discussed at a recent conference.

The world is full of basins, areas that have had sediments deposited over eons that are prospective for oil and gas. But only a few get recognized as “super basins,” those that have produced at least 5 Bboe and have more than 5 Bboe left to produce.

These monsters were the topic of the recent Global Super Basins Leadership Conference co-hosted by the American Association of Petroleum Geologists (AAPG) and IHS Markit. All the presenters were asked to discuss the geoscience fundamentals of the basin, technology drivers, uniqueness, business conditions and next steps.

The two-day conference included a roundtable of sorts, where a group of experts discussed super basins in general as well as specific challenges the industry faces. Brian Horn, senior vice president and chief geologist for ION Geophysical, noted that regional geology plays a key role in the study of any super basin.

“These basins are not getting smaller,” he said. “When we acquired our 2-D program in the Gulf of Mexico in 2002, we called it ‘mega-regional’ because everyone assumed the basin was already covered in 3-D. But we were cobbling together multiple datasets, and there were still pieces missing.

“I’m a firm believer in looking at all different scales. It’s one of the best values in regional understanding.”

Greg Leveille, CTO for ConocoPhillips, added that the volume of hydrocarbons found in the U.S. in the last decade exceeds the amount that was found in prior decades. “It all comes down to geoscience if you get the right rocks,” he said. “And the geologist has to help find the sweet spots, understanding organic matter, overpressure and being in the right window as well as being the producer at a low cost of supply.” He added that his company has been using geochemistry to understand where the oil is draining in horizontal wells as well as seeking a more thorough understanding of fracture patterns.



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The Gulf of Mexico was one of the super basins discussed at a recent conference. (Source: Brian McDonald/Shutterstock.com)

“We did a test in the Eagle Ford, and the results were nothing like you’d read in a textbook,” he said. “And the fracture growth has a huge impact on production.”

Buddy Woodruff from Core Laboratories noted that fracture geometry is indeed a dark science. “We think we’re smarter than we really are,” he said. “A completions manager once said, ‘We know everything about hydraulic fracturing geometry except for the height, length and width.’”

He added that his company is looking at ways to find the sweet spots before actually perforating the well by putting tracers in the spacer between the drilling mud and the cement and then running a gamma ray log.

The conversation ultimately included questions from the audience that discussed topics such as the time and cost it takes to develop new technology. Horn responded that costs in remote operations often drive the development of new technology, and Leveille added that technologies that are already being used in areas such as the Permian Basin and South Texas can ultimately be transferred to global shale plays. Other discussions dealt with gender diversity and the challenges of training the next generation of geologists.

Current AAPG President Charles Sternbach summed up the discussion by noting, “It’s important for us to focus on the fact that geoscience matters.” **ESP**

Rhonda



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The return to the Skeleton Coast

An independent inks a drillship contract as part of its exploratory campaign offshore Namibia's storied coast.

Even as the crow flies Ghana is a long way from Ireland. With its successes offshore Ghana at the Jubilee and TEN fields, it could be said that it was a productive migration for Tullow Oil and its partners. The E&P independent founded in Tullow, Ireland, with headquarters in London is looking to extend its success farther south to Namibia.

The country shares its borders with Angola, Botswana, South Africa, Zambia and a most unforgiving neighbor in the form of the Atlantic Ocean setting the country's 1,572-km-long (977-mile-long) western edge. With the northern portion of its coastline being widely known as the Skeleton Coast due to its abundance of desert sand, bleached bones of whales, wrecked ships and more, Namibia is a striking contrast to its former geologic neighbor, Brazil.

Offshore Namibia is part of the plate tectonic conjugate of offshore Brazil and lies on the West African continental margin adjacent to Angola, according to Pancontinental Oil & Gas N.L. It is the company's opinion that the underexplored area has the potential to hold very large oil and gas reserves, per its website.

Considering the significant success of Brazil and Angola, exploration successes offshore Namibia have been few in number. The most recent occurred in 2013 with the recovery of a disappointing 1.8 liters of light oil from poorly developed reservoir rocks at the Wingat-1 well in the petroleum exploration license (PEL) 23 located south of PEL 37, according to Pancontinental. However, the company did note the importance of the recovery as having verified the presence of a working oil system in the Walvis Basin.

In the five years since that discovery, several companies, including Shell, ONGC Videsh and Total, have farmed into positions in the blocks surrounding the



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(Source: Wead/Shutterstock.com)

find. In February Exxon Mobil acquired a 40% participating interest from Galp Energia in PEL 82.

As the operator of PEL 37, Tullow Namibia Ltd. contracted Ocean Rig for the sixth-generation deepwater drillship *Poseidon* to conduct operations in PEL 37 at its Cormorant prospect in a water depth of about 550 m (1,804 ft),

according to a press release from Africa Energy in

March. The prospect is one in a series of extensive base-of-slope turbidite fan prospects with significant combined resource potential, the release noted.

"Exxon Mobil's recent entry into a block adjoining PEL 37 confirms our positive view of the geology in this region," said Jan Maier, Africa Energy's vice president of exploration, in the press release.

Partners in the PEL 37 joint venture include Tullow Namibia Ltd., ONGC Videsh Vankorneft Pte Ltd. and Paragon Oil and Gas. Africa Energy has an interest in the license through its share in a subsidiary of Pancontinental Oil & Gas N.L.

Time will soon tell if the flight from the Emerald Isle to Skeleton Coast may be one best suited for a seabird like the cormorant rather than a crow. **ESP**

Jennifer



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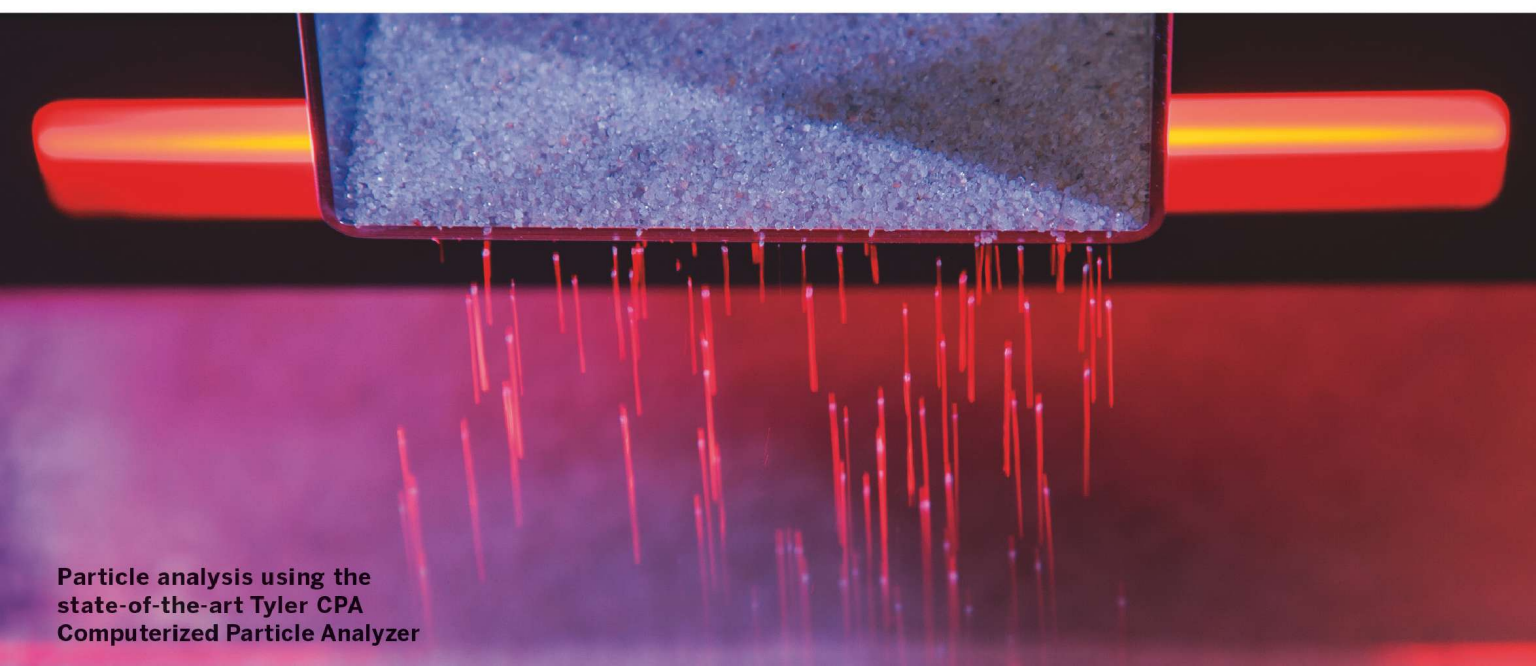


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Discovering alternatives in thermal EOR

Solar steam production unlocks heavy oil in the Middle East.

A common theme running through the high-level speeches at CERAWeek by IHS Markit was the ongoing need to implement renewables into the energy mix while continuing efforts to cut down on carbon emissions. Farming fossil fuels and applying wider use of renewables seems like ideological polarities, but there are several companies that see that challenge as an opportunity.

One such company is GlassPoint Solar, which, in addition to finding widespread uses for renewable energy, is tackling the challenge in how to cost-effectively cultivate heavy oil, a key element in producing the world's estimated reserves. According to the 2015 article, "Application of Neutron Activation Analysis for Heavy Oil Production Control," about 70% of the world's remaining oil reserves are estimated to be heavy oil.

GlassPoint Solar reconstitutes the process of steam injection from the traditional method of heating natural gas to unlock overly viscous oil by instead harvesting solar energy to create, along with those traditional methods, enough steam to heat a heavy oil reservoir.

GlassPoint Solar was founded in 2009. John O'Donnell, vice president of business development, said the company's maiden project was in 2015 at its Miraah solar facility in Oman, which will eventually produce more than 1,000 MW of thermal energy production. Last year GlassPoint was awarded a contract to build a similar facility in Kern County, Calif., one that will produce 850 MW of energy.

By foregoing the large-scale use of natural gas for EOR, particularly in a place like Oman where natural gas is needed for a variety of uses, GlassPoint's system is addressing issues on two fronts.

"In Oman there is a lot of competition for the available natural gas between oil recovery, which is using a very sizable fraction of all the gas in the country today,



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and other applications, [such as] power generation and other kinds of industrialization," O'Donnell said. "The solar supply can unlock gas supplies for those uses. We're creating permanent energy production assets that don't have a decline curve."

He explained that GlassPoint's system only works in places around the world with consistent sunshine

throughout the year—locations typically within about 40 degrees north and south of the equator. So, for instance, locations in Canada's heavy oil fields likely would not be strong candidates for solar steam injection, O'Donnell said.

Although O'Donnell didn't cite specific cost savings for such a project, he said that solar steam production offers "substantial" savings. According to the International Renewable Energy Agency, the use of solar

power for projects calling for greater than 300 MW of energy has decreased from about \$0.36/kWh in 2010 to about \$0.10/kWh in 2017.

O'Donnell said several heavy oil operators are either aware of the work GlassPoint is doing or are engaged in conversations at different levels with the company about its technologies.

"There are other producers that are looking at our track record, so we see bright opportunities for several other projects around the world based on our successes of building these first large projects," he said. **ESP**



GlassPoint Solar has developed a solar steam production facility in Oman for use in EOR efforts. (Source: GlassPoint Solar)

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Decommissioning demands spur technology development

The cost of safely removing offshore assets from service has given rise to investment in decommissioning technologies.

According to a Westwood Global Energy Group report issued in mid-January, the amount of money that will go toward decommissioning over the next decade is considerable—totaling about \$102 billion in Western Europe alone. Report author Ian McDonald, manager with EMEA Consulting, said in just that region there are 5,600 surface wells and 2,600 subsea wells that will have to be plugged and abandoned as part of the decommissioning process. According to McDonald, innovation underway could lead to new technologies that will offer alternatives to traditional plug and abandonment (P&A) activities.

Recent reports indicated a number of companies already are moving down that path. In mid-February, Ardyne reported it had saved more than a day of rig time on a planned 3.5-day operation and improved efficiencies by 35% on a P&A job in the North Sea using its proprietary Casing Recovery Toolbox. According to the company, the product incorporates a full suite of services and bottomhole assembly (BHA) systems, which company experts have used to create downhole BHA systems for well abandonments, slot recoveries and workovers.

Meanwhile, in the Gulf of Mexico, a company called Abrado has completed the first well in a multiwell P&A campaign using its proprietary Medusa expandable casing section-milling technology. The 9⁵/₈-in. by 13³/₈-in. dual-string casing windows were milled out to allow traditional cement barrier placement to seal the annuli. The company is continuing to investigate, operate and validate operations with its line of downhole video cameras for pre- and post-window inspection as well as barrier placement.

Advancement is taking a different route elsewhere, funded in part by the Oil & Gas Technology Centre, based in Aberdeen. The not-for-profit, industry-led technology R&D organization is investing £1.3 million (US\$1.8 million) in transformational P&A ideas with the goal of reducing decommissioning costs by 35%, a target set by the UK Oil and Gas Authority. In a



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recent call for ideas, the Oil & Gas Technology Centre received 48 submissions and has selected four of them for investment.

BiSN, one of the winners, is testing and verifying Wel-Lok M2M technology, which uses a modified thermite heater in conjunction with bismuth-based alloys to form a permanent barrier—an alternative to traditional elastomer seals, resins and cement. It is deployed on wireline without the need to remove tubing.

An idea submitted by the University of Strathclyde uses enzymes in a “biogrout” comprising low-viscosity nanoparticles that can repair or improve cement barriers in plugged and abandoned wells. And Heriot-Watt University is receiving funding on its plans to develop a modeling framework for well isolation design that researchers hope to use to improve risk management, increase efficiency and enhance decision-making.

The final technology selected for funding is being developed by Baker Hughes, a GE company (BHGE). BHGE is working on a plan to deliver cement logging through multiple casing strings, an improvement over existing solutions that would deliver logging behind only one casing or tubular.

With a large number of assets reaching the end of their operating lives, there is broad scope for new technology application. With luck—and a lot of hard work—these and other developing technologies will soon be field-proven and ready for use by the offshore industry. **ESP**

Analytics-driven energy management reduces carbon footprint

New self-service analytics tools allow SMEs to analyze, monitor and predict process and asset performance.

Edwin van Dijk, TrendMiner

The discussion about climate change has been taking place for many years and is still a hot topic. This debate has led to global initiatives to reduce carbon footprints, which is high on the agenda of almost every country's government. Regulations on a global, regional and local scale have been established to reduce greenhouse gas emissions, and this heavily impacts the oil and gas industry. To achieve those goals and prove regulatory compliance, companies in the industry are rapidly adopting the International Organization for Standardization's (ISO) 50001 standard to improve energy performance and make climate part of their corporate strategy.

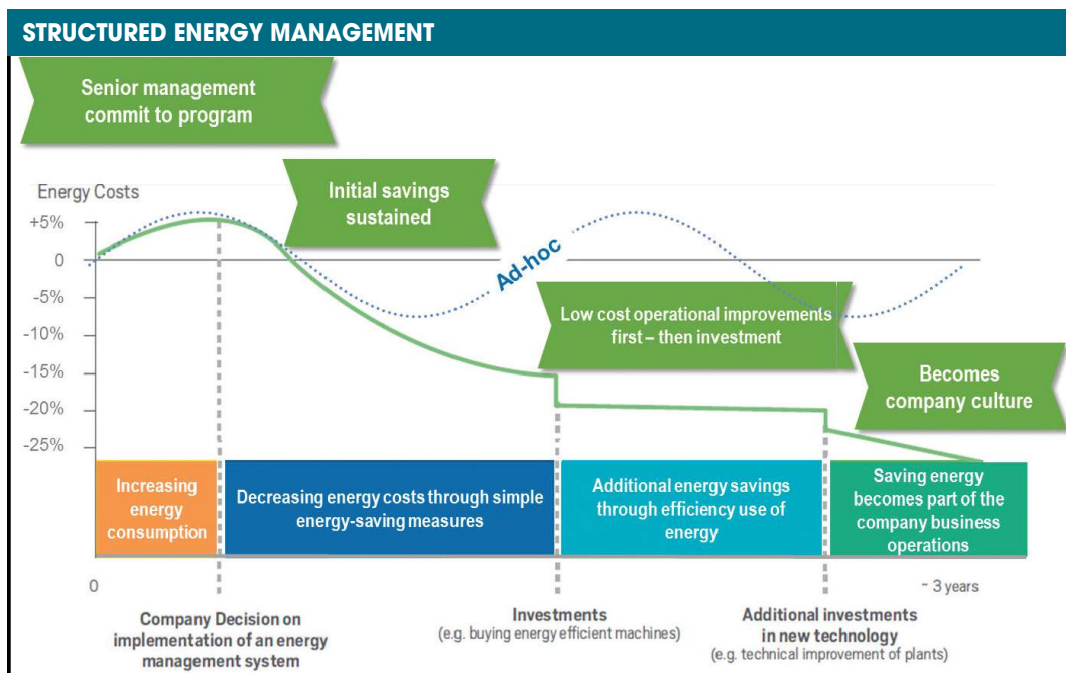
For instance, Total has made comments about its dedication to offsetting climate change. "The climate has been fully integrated into Total's business and strategic vision as

well as its organizational structure," said Patricia Barbizet, lead independent director, in a recent presentation.

Reducing the carbon footprint also has an overall profitability benefit. Within the oil and gas industry, energy often is one of the largest components of the company's cost structure. Energy management to reduce costs is not new, but it has become more important due to the imposed regulations. Most companies have formalized energy management programs and use automation and control technologies to help minimize energy costs. However, many companies need to take their efforts to the next level by monitoring and optimizing energy use in real time and leveraging Industrial Internet of Things generated data.

For many years process data have been captured in historians. All of these data need to be unlocked and leveraged for continuous improvement to lower the carbon footprint of the company. To some extent, data

analytics has been utilized by large companies for their larger onsite energy issues. These time-consuming, centrally led data modeling projects are less suited for process-related optimization projects that require subject matter expertise. New tools put advanced analytics in the hands of subject matter experts (SMEs) such as process and field engineers. This allows them to handle 80% of energy-related cases that contribute to the corporate goals for reducing the carbon footprint.



Discovery analytics helps engineers understand what has happened, and through diagnostic analytics the organization can start monitoring the performance of the site. (Source: TrendMiner)

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Energy management 4.0

Global interest in Industry 4.0 has accelerated digital transformation in the process manufacturing industry, including the oil and gas sector. Many companies have engaged in technology pilots to explore options for reducing costs and increasing overall equipment effectiveness and regulatory compliance. One of the best ways to leverage these new innovations is to apply advanced industrial analytics to production data generated by sensors. All the data provide unique opportunities for improving energy efficiency.

In general, energy savings can be achieved in various ways: through change in daily behavior (switching off the light), through installations of more energy-efficient equipment, through equipment maintenance or through process optimization and ensuring the use within the best operating zones. Process and asset performance optimization is probably the biggest area for energy savings, but it requires a deeper understanding of operational process and asset data (available in the historian).

Analyze, monitor and predict

SMEs, such as process, operations and maintenance engineers, have deep knowledge of the production process. The major process-related energy consumers include water, air, gas, electricity and steam and can be directly or indirectly analyzed through all sensor data. The data can be descriptively analyzed to determine what has happened, providing a better understanding if a long period of performance can be assessed. Sometimes, certain issues happen only a couple of times per year but can have a big impact on energy consumption (a trip causing a shutdown, for instance). Discovery analytics helps engineers understand what has happened, and through diagnostic analytics the organization can start monitoring the performance of the site.

Since asset performance is contextualized by the process function, the best performance windows need to be extracted from actual process behavior. Based on the historical data, fingerprints with an energy consumption focus can be created to monitor good and bad behavior. Additionally, monitoring live operational performance can be used for predictive analytics.

Practical use cases

There are already multiple instances where advanced analytics were successfully used to analyze, monitor and predict the process and asset performance of energy management.

One example is related to energy consumption within the cooling water network. Reactors consume cooling capacity from the utility network to cool water. Sufficient cooling capacity is critical for these reactors as thermal

runaway could occur when the available capacity is insufficient. To avoid this undesirable situation, a monitoring system using advanced analytics was set up. Early warnings were created and only triggered on actual problematic situations, avoiding false positive alarms that could be triggered by measurement noise or spikes in the data. Upon receiving a warning, the process engineer and operators have ample time to rebalance the reactors and deprioritize other equipment so that critical systems can consume the maximal cooling capacity and overall energy consumption is within target boundaries.

Another example is a predictive maintenance case for fouling of heat exchangers. In a reactor with subsequent heating and cooling phases, the controlled cooling phase is the most time-consuming. Fouling of the heat exchangers increases the cooling time, but scheduling maintenance too early leads to unwarranted downtime, and scheduling too late leads to degraded performance, increased energy consumption and potential risks. To enable timely maintenance, a cooling time monitor was set up, which extended the asset availability and reduced the maintenance cost and safety risks. All these benefits, including controlled energy consumption, ultimately led to a 1%-plus overall revenue increase of the production line.

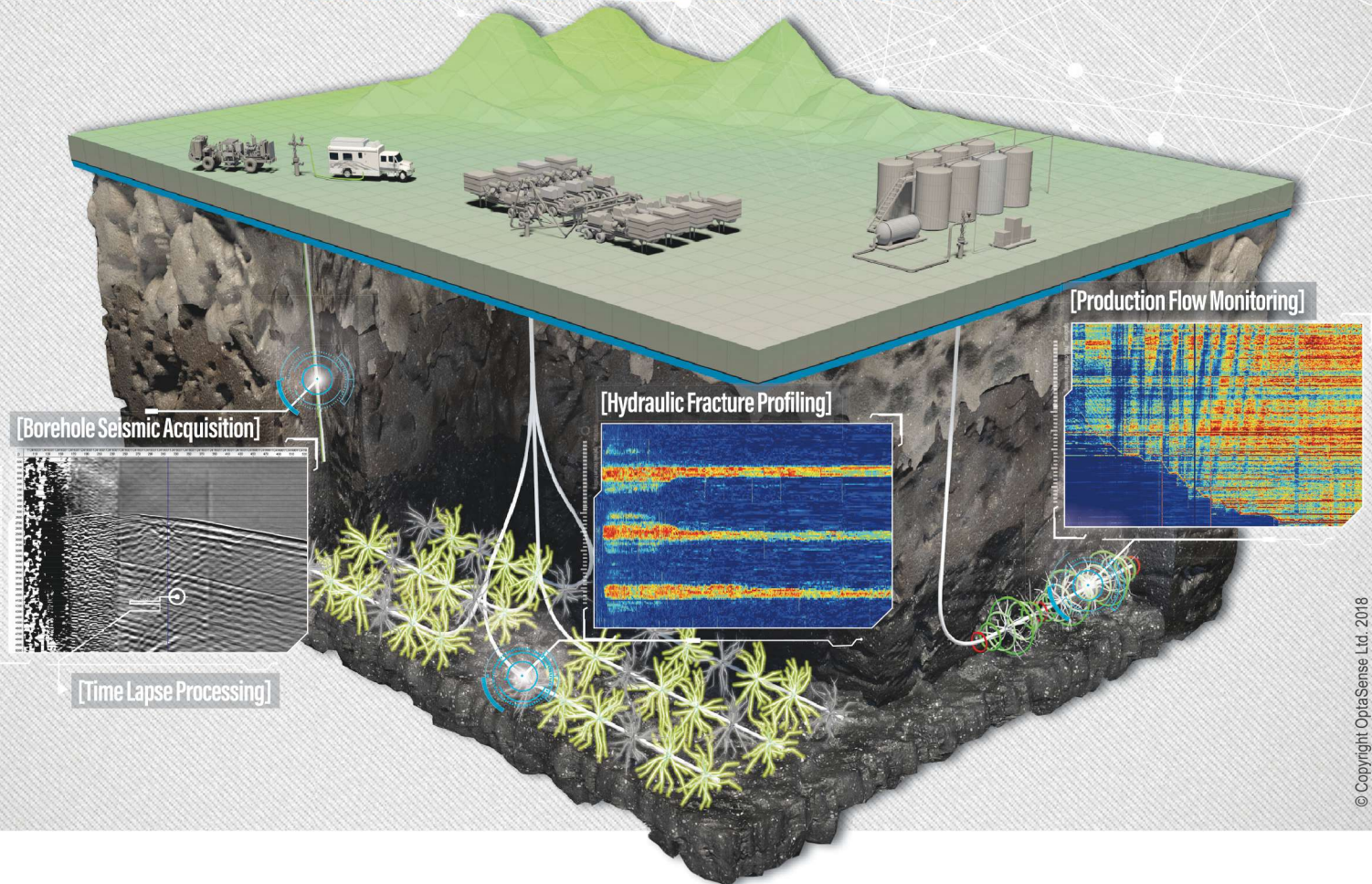
Continuous improvement 4.0

In general, finding and solving root causes for process deviations and anomalies results in a more energy-efficient operation. Monitoring the live production performance allows control of various production parameters, including energy consumption. When the total energy consumption of a specific year is taken as a baseline, monitoring of performance against corporate goals becomes possible.

Energy management also is important in other process industries. Covestro, a chemical company, initiated three major energy-savings projects for its polyether plant in Antwerp as part of the energy savings goals and ISO 50001 directives. Self-service industrial analytics solutions were implemented for online detecting (including root cause analysis and hypothesis generation), logging and explaining unexpected energy consumption, and for comparing the results with the reference year 2013. Using specific formulas and calculated tags, various energy consumers are monitored and controlled. Through monitoring the performance against the reference year, it showed the energy consumption has effectively decreased year over year, meeting the corporate goals. More importantly, with a growing knowledge and insight into the production process, Covestro is continuously improving its overall performance. **ESP**

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Improvements in AI, sensors and data highways will provide increased operational efficiencies moving forward.

Derick Jose, Flutura

As energy processes and industrial assets become digitized, they climb on an exponential growth curve instead of a linear growth trajectory. This digital transition is ripe with many possibilities, whether it is in artificial intelligence (AI), remote diagnostics using digital twins or next-generation usage-based operating models powered by sensor data. Oil and gas companies need to prepare for five trends.

Trend 1: Reimagine industrial AI-powered operating models

Most industrial AI applications are geared toward providing operational efficiency impacting the cost side of the balance sheet such as increased uptime and well yields and reduced HSE risks. For example, Flutura is powering a “digital prognostics as a service” model for a major upstream company where instead of reacting to asset downtimes, the company can proactively complete

remote diagnostics and in-person interventions based on fault mode predictions from an AI model that is watching real-time equipment sensor streams.

Innovative business models will transform the market landscape for drilling service providers, equipment manufacturers and owner operators. Winners and losers will be decided by the ability of these traditional industrial sectors to deeply embed AI into core equipment and processes. This requires that many entrenched players reimagine their business operating models.

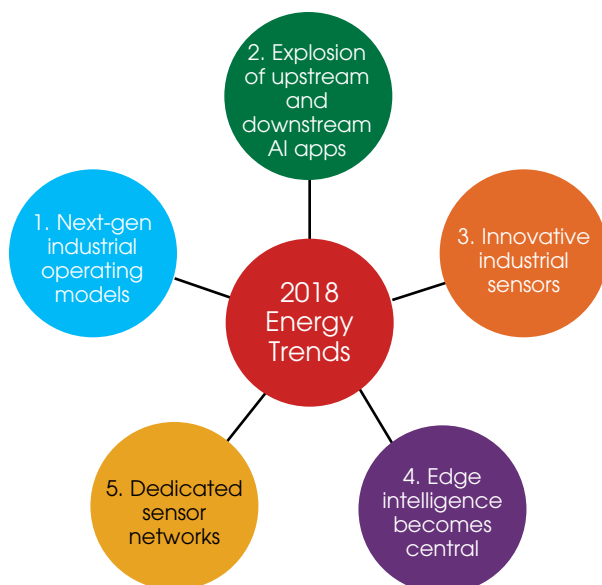
Trend 2: Upstream AI impacting well and equipment outcomes

AI platforms in 2017 were generic and untuned to the nuances of oil and gas. There has been a great deal of momentum in upstream areas. For example, Flutura’s Cerebra industrial AI application center has preconfigured solvers for ultraspecific upstream problems such as deepwater asset diagnostics, hydraulic fracturing, LNG and more. Expect to see more AI apps this year that will impact measurable outcomes using algorithms highly specialized to solve high-impact problems.

“Vanilla” data science will not suffice to solve mission critical problems in the oil and gas industry. As deep-learning algorithms become democratized, the importance of novel AI applications that solve a specific and complicated problem will increase. These applications will become more important than a horizontal AI platform, which requires immense tuning for the industry context.

Trend 3: Innovations in industrial sensors to see blind spots

A primary challenge in the practical execution of AI projects are blind spots in vital signals. For example, an upstream company realized through its work with Flutura that while its rotary assets had sufficient instrumentation (e.g., lube oil pressure and temperature, rpm, torque, etc.), there were critical blind spots when it came to vibration sensors and shock sensors that were a crucial signal for the deep-learning algorithm to spot anomalies leading to failure. Some specific blind spots where significant sensor innovation will be seen this



These top five trends in 2018 will positively impact the oil and gas industry. (Source: Flutura)

year include the detection of fluid and gas quality using optics based on differential interferometry, tampering of oil containers, emissions and noise anomalies in close proximity to rotating assets.

Making assets and process context aware requires increasing the asset sensitivity to events both within and around them. Model quality is directly correlated to the quality of sensor streams. The better the sensors get, the better the AI models become.

Trend 4: Edge intelligence

There are two types of intelligence: informational and actionable. For example, if a leased asset in an asset-as-a-service offering is repeatedly being misused by a worker, edge intelligence will notify the supervisor to intervene. This decision-making loop cannot afford the time needed to ship massive sensor event data over the network and then wait for the AI layer at the center to respond. Localized sense and respond layers are needed to be operationally effective. Edge intelligence

is ideal for “fail operational” behaviors where an asset or process can complete its core operation even when a part of it fails.

Edge intelligence also is ideal when reliability and latency are important. Large oil and gas projects have thousands of sensor events streaming across myriad wells with some decisions needing to be reliably made within milliseconds.

Trend 5: Sensor data highways

Today’s data networks are insufficient to keep up with the high rates of data transmission required by rising sensor density on upstream processes and assets combined with increased frequency of transmission. Companies like Sigfox and Ingenu are focused on building dedicated next-generation sensor data transmission infrastructures for moving sensor data. It will be like getting a dedicated lane on national highways where sensor data streams can move data that support machine-critical upstream processes and equipment. **ESP**

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Judy Murray, Senior Contributing Editor, Offshore

When Statoil took a close look at development costs a few years ago, it was apparent that things needed to change.

According to Torger Rød, Statoil senior vice president for project development, even before the drop in oil prices, the Norwegian operator realized costs were too high. “We started the improvement program in 2015, focusing first and foremost on what Statoil can really influence,” he said.

In examining what truly was within Statoil’s power to change, the company examined total value creation and identified five critical ingredients for improvement. The result, he said, is a “recipe” the company has been tweaking ever since.

Statoil began with the acknowledgement that, “not only do we have to do better, but we can do better,” Rød said. This recognition led to setting direction and specific targets, such as cost reductions and clear breakeven objectives, with an eye to where the company would like its portfolio to be.

Next was a focus on engagement, which meant bringing the team together so the company could strive cooperatively toward the same goal.

“There are very competent people in Statoil,” Rød said. “When we are able to ensure we are getting great engagement and good collaboration through the value chain, you see creativity and start to develop very efficient concepts.”

The fourth ingredient is what Rød calls “totality,” which means making sure the entire concept makes sense so the greatest gains can be achieved. “We have to avoid a suboptimal solution. This is about creating

value. This is about reservoir drainage and efficiency,” he added.

The final piece, he said, is collaboration, both within the company and with service providers, contractors and partners.

Evaluating assets

One of the first things to come under scrutiny was the assets being built and where they would be operating, Rød noted. “We started approaching our prospects and projects to optimize our concepts,” he said, and that led to considering a range of ways to develop offshore prospects.

In the case of the Johan Castberg Field in the Barents Sea, Statoil changed the design concept, moving to develop the field with a FPSO. This allowed the company to optimize the field layout, reducing the number of wells from 43 to 30 and the number of subsea templates from 15 to 10.

OFFSHORE

TRANSFORMED

Three leading operators explain how they are driving down the cost of developing challenging offshore fields and finding ways to recover more reserves.

The massive Mad Dog platform is BP's only floating spar facility in the Gulf of Mexico. In 2016 the company sanctioned the Mad Dog 2 project that will include a new floating production platform with a capacity to produce up to 140,000 bbl/d from up to 14 production wells. (Photo by Marc Morrison, courtesy of BP)



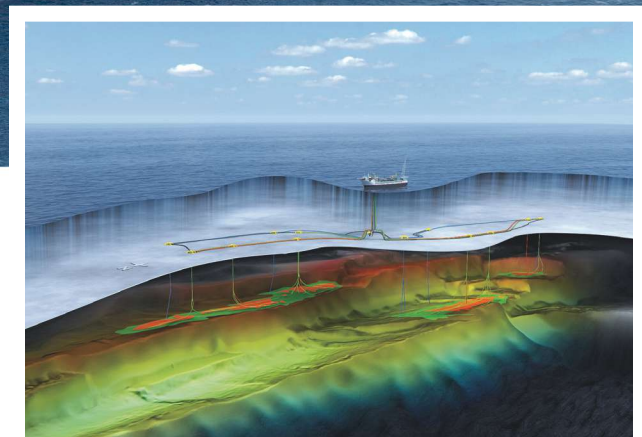
In achieving economies on the Johan Castberg Field in the Barents Sea, Statoil changed the design concept, moving to develop the field with a FPSO. (Source: Statoil)

“We started working together with subsea contractors to look at the subsea production system,” Rød said, “setting clear cost targets and recognizing that changing the subsea system would allow Statoil to achieve that goal.”

Decreasing complexity was part of the solution, but there was much more involved. By reducing company-specific requirements, Statoil enabled subsea experts on the contractor’s team to introduce efficiencies. In the end, the tree and manifold weight were lowered significantly, and the footprint was reduced by 45%. “We removed 10% to 20% of the weight,” he explained, “and less steel means less money.”

The Snøhvit Expansion project is another in which working closely with partners and suppliers led to greater profitability. In this case, what began as a marginal project became a worthwhile development as a result of collaboration aimed at finding ways to optimize value creation and reduce total cost of ownership. “We are testing ideas on one another,” Rød said, “and when we see a program doesn’t have value, we stop pursuing it.”

The subsea layout using bundled infield flowlines on the Snøhvit Expansion project is a good example of how Statoil followed the lead of one of its contractors. “Subsea 7 proposed this,” he said, noting that it has been many years since Statoil used such a layout. “We assessed the pros and cons, the upsides and downsides, and were able to see that this is adding benefit for the project.”



The final field layout for Johan Castberg features 30 wells instead of the original 43 and 10 subsea templates rather than the 15 suggested in the initial plan. (Source: Statoil)

Simplify, standardize, industrialize

This approach to improving operations is part of a program called SSI, which means “simplification, standardization and industrialization,” Rød explained. “I think the biggest benefit so far has been in simplification—defining the right concept, defining what to build and reducing complexity.”

Another advancement, he said, was to step back and redefine what standardization means. “A lot of people believe standardization is only about hardware, about tangible things, but it’s also about how we are interacting and collaborating with suppliers,” Rød said. Inviting input from suppliers is one way to standardize requirements by capitalizing on their expertise and “making sure they are working on their home turf, so to speak.”

The end goal is to become more predictable as a company regarding project execution and project management so contractors know what to expect from Statoil.

When it comes to hardware, one of the easiest things to standardize is components, not necessarily the end product, he said, pointing as an example to the various pieces



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that make up a subsea production system. Making this shift requires a willingness on the part of the operator to reevaluate some of the components it used to have tailor made.

Another more straightforward instance of how Statoil is leveraging standardization is the freshwater makers it installs on offshore assets. Using the same system across the board resulted in enormous cost savings, reducing capex by nearly 90%. “This is an example of good collaboration between operator and supplier,” he said.

Automation, digitalization improve safety, reduce costs

Statoil also is realizing efficiencies through automation. According to Rød, drilling automation has delivered considerable gains. Used with great success last summer in the Barents Sea campaign, drilling automation delivered greater efficiency in performance and allowed drillers to detect issues and problems earlier. “This means less downtime and fewer sidetracks,” he said, “and that improves safety.”

Automation allowed Statoil to avoid drilling two sidetracks during the campaign when the automated system picked up an anomaly that the driller missed. The overall savings were 100 million NOK (US\$12.9 million) over the course of five wells.

Statoil also is making advances in digitalization, which is enabling a move toward safer operations. “I strongly believe digitalization is impacting what we build, how we build it and how we operate,” Rød said.

Proof of the organization’s willingness to push the implementation of digital technology was the announcement in early November 2017 that Statoil had opened the Valemon control room in Bergen, where onshore staff operate the North Sea Valemon platform, the first in Statoil’s portfolio to be remotely controlled from land.

“Safety is priority No. 1 when we assess new concepts, new systems and tools,” Rød said, noting that the important thing about Statoil is, “We are never afraid to implement new technologies and new innovations to take us a step farther.”

Strategic direction at Statoil is determined by embracing new technology and driving for continuous improvement, he said. “By applying technology, innovation and creativity, we are building a big toolbox of concepts and technology that enables us to tailor make our business cases to create value and enhance recoverable reserves.”

Defining a competitive advantage

Shell has concentrated its efforts over the last three years on what Edwin Verdonk, vice president of development, deep water, called, “restoring competitiveness.”

Having operated in deep water for 40 years, Shell is proud of its performance as a leader in overcoming technology challenges.

Today, the focus is on finding “good, integrated low-cost economic solutions for our deepwater fields,” Verdonk said.



For the Appomattox Field development program, Shell was able to take 25% of cost out after the FID. (Source: Shell)



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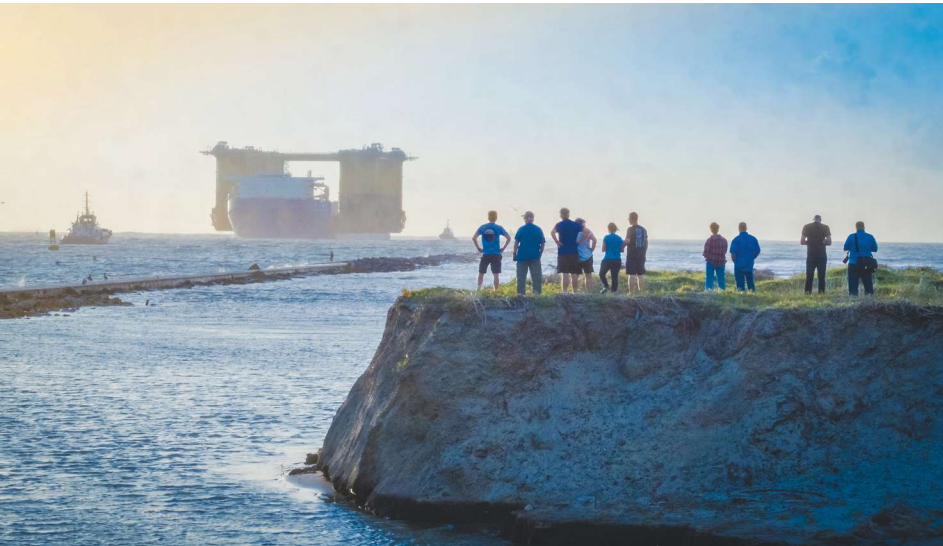
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The *M/V Xin Guang Hua*, operated by COSCO Shipping, delivered Shell's 40,335-mt Appomattox hull to Ingleside, Texas. This marks the largest and heaviest cargo transported to date by COSCO's fleet of semisubmersible heavy-lift vessels. (Source: Shell)

The seven-step solution

Getting to the heart of “restoring competitiveness” means recognizing areas for improvement, Verdonk said, noting that Shell has identified seven of these to help reach that goal.

The first is competitive scoping, which he explained as, “responsibly determining what the minimum technical scope is for a particular development” and recognizing that some of what the company was doing added unnecessary complexity.

Historically, Shell had constructed what Verdonk called “extremely heavy wells that had an incredible number of pieces of steel.” When company experts looked at the designs from a risk and safety perspective, they found that the wells designed this way did not materially improve safety.

Minimizing complexity took a different form on the deepwater Kaikias Field in the Gulf of Mexico (GoM). “Previously, we would have an extra flowline or umbilical,” Verdonk said, but in evaluating a range of options, Shell and its partner, MOEX NA, decided to tie Kaikias back to the nearby Ursa platform with one flowline and one umbilical.

With the scoping complete, the next focus is efficient execution. “Do it right in the first go and really look at all the waste in execution,” he said. “Be more nimble and agile.”

One of the ways Shell has improved efficiency is by looking at the way it had been drilling wells and realizing much of the work was being performed sequen-

tially. “We found out we could do many things in parallel,” Verdonk said, and this shortened the drilling process. “We were able to achieve on average 35% reduction in drilling time over wells we drilled in 2014. Now we are drilling wells at 50% of the cost incurred in 2014.”

Efficiency does not end there though. “Once executing, we are finding much slicker and smarter ways to manage logistics and the sequence of activities to get a lot more cost out,” he said. For the Appomattox Field development program, Shell was able to take 25% of cost out after the final investment decision (FID).

Shell also transformed its supply chain, completely reevaluating pricing and cost structures.

“Most people think you just drive prices down,” Verdonk said, “but this goes a lot further.” In Shell’s case it is work that is

being done in cooperation with suppliers. “Simply by sharing and making helicopters and vessels available to our total portfolio, we have been able to take \$600 million out of logistics costs over a number of years on that bill alone.”

The fourth way the operator is saving money is by putting technology to work on such things as well completions. “We used to complete development wells in extremely large hole sizes and with a lot of expensive and difficult equipment to give us endless flexibility,” he said. “Then, Shell asked the question, ‘Can we not devise, from a technology point of view, a much slimmer version of this completion?’ The answer was yes.”

Verdonk continued, “We found out through testing in a technology setting that slimmer completions deliver similar results as bigger completions.”

This realization has led to a transformational change in how Shell evaluates and executes deepwater projects, he said. “These are not just ideas. This is happening now.”

According to Verdonk, Shell also is investing in digital technology. “Digitalization can be transformational for our industry,” he said, in much the same way it has changed the way individuals communicate, shop and interact. “That wave of transformation needs to be fully embraced in the hydrocarbon industry.”

In essence, Verdonk believes every element of the deepwater sector is going to be touched by digitalization in some way. “I’m extremely excited about the very positive effect this can have,” he said.

Another critical focus for Shell is cutting cycle time. “By managing cycle time, we raise the competitiveness



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An artist's rendering shows the Mad Dog 2 semisubmersible, the FPU selection that allows flexibility for additional tiebacks and water injection capacity if field productivity increases. (Source: BP)

of our deepwater projects,” Verdonk explained. “We had been looking at deepwater projects sequentially,” and that approach was slowing down execution.

The operator recognized that it could take positions earlier in the program while some phases had not been completely finished. “Parallelizing activities and compressing certain stages can take a number of years out of the very long time lines for constructing deepwater hubs,” he said.

Using multiple yards to execute components simultaneously is allowing Shell to achieve significant efficiencies. Successfully bringing the pieces together is a matter of meticulous planning and active management of every part of the project. According to Verdonk, “It requires intervention and constantly looking at all of the components, particularly those on the critical path.” That focus on progress and execution is what he classifies as “flawless integration.” It requires top-class integrated schedules, Verdonk said, “but we have not run into any issues whatsoever.”

The next item on Shell’s list is system engineering, acknowledging that the total value of a project is in the total system. That means looking at a project from the barrel price of oil all the way to the platform and the subsurface, Verdonk said. “Shell is much more able now than before to model aspects of a project to see what the total effect is on the total value of the system if we change any element of the value chain.”

On Appomattox, for example, Shell has every piece of equipment on the platform electronically stored in a

3-D format that can be used to show how components have been inspected, how they interact and how they affect the system. “This is helping us to manage the total system,” he said.

Finally, Verdonk said, the company is working through joint industry projects and joint development programs to advance safety, collaborating on technologies such as capping systems. “Together, we can come to a good technical solution for an emergency,” he said.

Shell also has been supporting high-pressure solutions for 20-ksi operations, hoping to develop a cost-effective way to unlock resources that are difficult to access because of high pressures. The way the industry works together is changing, Verdonk said, and he is optimistic about the potential successes that could be achieved. There is a higher level of cooperation, he added. “It is happening, but from an efficiency point of view, we can always do better.”

Doing things better really is the ultimate goal.

The oil and gas industry must achieve greater efficiencies to make it competitive, according to Verdonk. “Deepwater will need to constantly improve itself and reinvent itself to stay on that competitive edge,” he said.

Catching the runaway dog

The need for competitiveness in an exacting low-price environment is precisely what drove BP and its partners, BHP Billiton and Chevron, to hit the reset button on the Mad Dog 2 development in 2013 when the total project cost surpassed \$20 billion.

“We basically went back to the drawing board,” said Bill Steel, BP’s Mad Dog 2 project manager. “It was a bold decision for the company leadership to take with a project at that level of maturity.”

It was evident that the original plan was not going to be cost-competitive, so it was important to consider the project with the mindset that every dollar matters, he said. “We were very deliberate and thoughtful about the decisions we had to make. The team was given the time and space to get it right, and it was essential that we get it right after the recycle.”

Given where the project stands today—with development cost estimated at approximately \$9 billion, a reduction of more than 50%—it is apparent the team did just that. But the journey to success was not a cakewalk.

It began with the team developing a tiered decision-making process to manage the myriad decisions.

According to Steel, the most significant Tier 1 development decision was defining the strategic theme. And the most fundamental Tier 1 decision was the one that determined the production system that would be used. The choices, he said, were grouped into three themes: “start small,” “transformer” or go “all in.”

A small facility would allow the operator to begin producing the field and use reservoir performance data to make further decisions. A unit that could be transformed would be a larger facility with a reasonable level of capacity to manage a downside reservoir outcome but with the capability for expansion in the event of a greater volume of production. The “all-in”

decision would be the biggest option, with the maximum number of wells and the biggest water injection capacity to manage life-of-field development for a huge reservoir outcome.

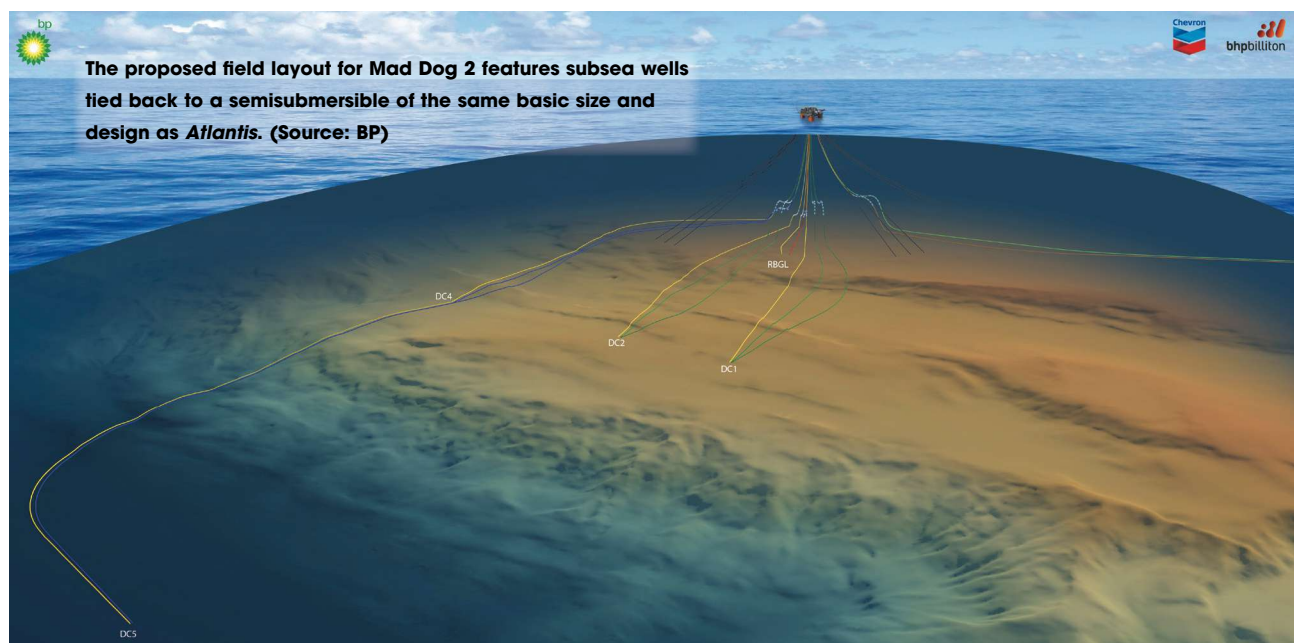
The team evaluated these options and chose the middle road, selecting a semisubmersible as the alternative to the original spar concept.

For the spar, Steel said, “We had massive topsides, three big modules, accommodations and a flare tower,” which would require a time-consuming and expensive offshore hookup and commissioning. “For our needs, a semi was more appropriate because it could be fully built onshore with quayside hookup, and it could be built to allow room for expansion.”

With the design basis established, BP began the process of specifying the design, which began with an assessment of its operating semisubmersibles.

“We talk about Mad Dog 2 as an *Atlantis* lookalike,” Steel said, explaining, “*Atlantis* has worked well. Why wouldn’t we base this next development on something we know has been successful?”

The proposed field layout features subsea wells tied back to a semisubmersible of the same basic size and design as *Atlantis*. “What we realized is that we didn’t want to constrain ourselves if there was an upside outcome,” he said. There is a lot of prospectivity in the area, and BP had appraised the field and determined that it has the potential to be a world-class reservoir. “With a small pre-investment in real estate, we get the capability for future expansion,” Steel said.



If more discoveries lead to additional tiebacks, water injection capacity can be added along with processing capacity. “Subsea architecture is very scalable,” Steel said, “and there is a lot of flexibility in the FPU [floating production unit].”

Industry-led solutions

According to Steel, the downturn in the oil price allowed BP to talk more directly with suppliers to achieve better alignment. The message was one of solidarity rather than competition.

“We’re all in this together,” he said. “We told our suppliers we thought we could make Mad Dog 2 work as a deep-water project, but we needed their help. These people have great ideas, and they know their equipment. What we had to do as a company was demonstrate to them that we were serious about being open to their ideas.”

BP was challenged with finding a way to change preconceived expectations and demonstrate the company was in its intent to take suppliers’ ideas onboard. “We tried to be provocative in giving them some ideas we were up for to show we were serious. In the past, we haven’t always listened. This time, we didn’t really need bespoke specifications. We wanted industry standard equipment,” Steel said.

What BP wanted was “industry-led solutions,” which meant suppliers were being asked if any of their standard products would fit BP’s needs, meeting functional specifications rather than detailed specifications outlining materials and design conditions.

In using more standard components, BP could lower costs and at the same time improve safety, reliability and scheduling using proven equipment that suppliers could build with the basic components they had on the shelf. According to Steel, this approach paid off. As an example, he said, “We’ll take delivery of our first subsea trees this year because OneSubsea had the basic building blocks available.”

In addition to employing standard equipment, BP is building on automation—a focus of its modernization and transformation agenda—to find ways to increase efficiency and effectiveness of equipment inspections and ensure the production system’s operability and maintainability.

Containing costs

Some of the efficiencies BP achieved were based on using equipment identical to the kit on *Atlantis*. The knowledge that it had worked reliably was one of the drivers. Another was knowing exactly what that specific equipment had cost.

“We knew cost discipline was going to be important,” Steel said. “We dug out invoices and contracts from

Atlantis and said, ‘We want that piece of equipment at that price.’”

Because Mad Dog 2 was sanctioned in the aftermath of the oil price drop, BP was forced to make cost discipline a priority, but according to Steel, an upward trend in oil and gas prices will not change this mindset.

“What we’re trying to instill is a culture across our global projects organization that discipline is good for all seasons,” he said. “We can’t get sloppy again. We need to avoid price inflation because of inefficiency; otherwise, deep water won’t be competitive in the long run.”

Profiting from partners

Another departure from the beaten path is the continuing collaboration among the co-owners of the Mad Dog 2 development. “We give them a lot of access to what’s going on in the project, and they give us a lot of technical input,” Steel said, and that has led to shared technical lessons.

One of these is how to improve water injection. “BHP has been operating a large-scale waterflood on the Shenzi Field in the deepwater GoM for several years,” he said. Because Mad Dog is a similar reservoir, a lot of BHP’s experience is relevant, which has given the operator a role in advising on system design and setup.

It also is capitalizing on Chevron’s project management experience with the recent construction of the Jack/St. Malo production system at the Samsung Heavy Industries yard in South Korea. “Chevron shared their experience not only on project management, but on engineering, safety, quality management and how the yard works,” Steel said.

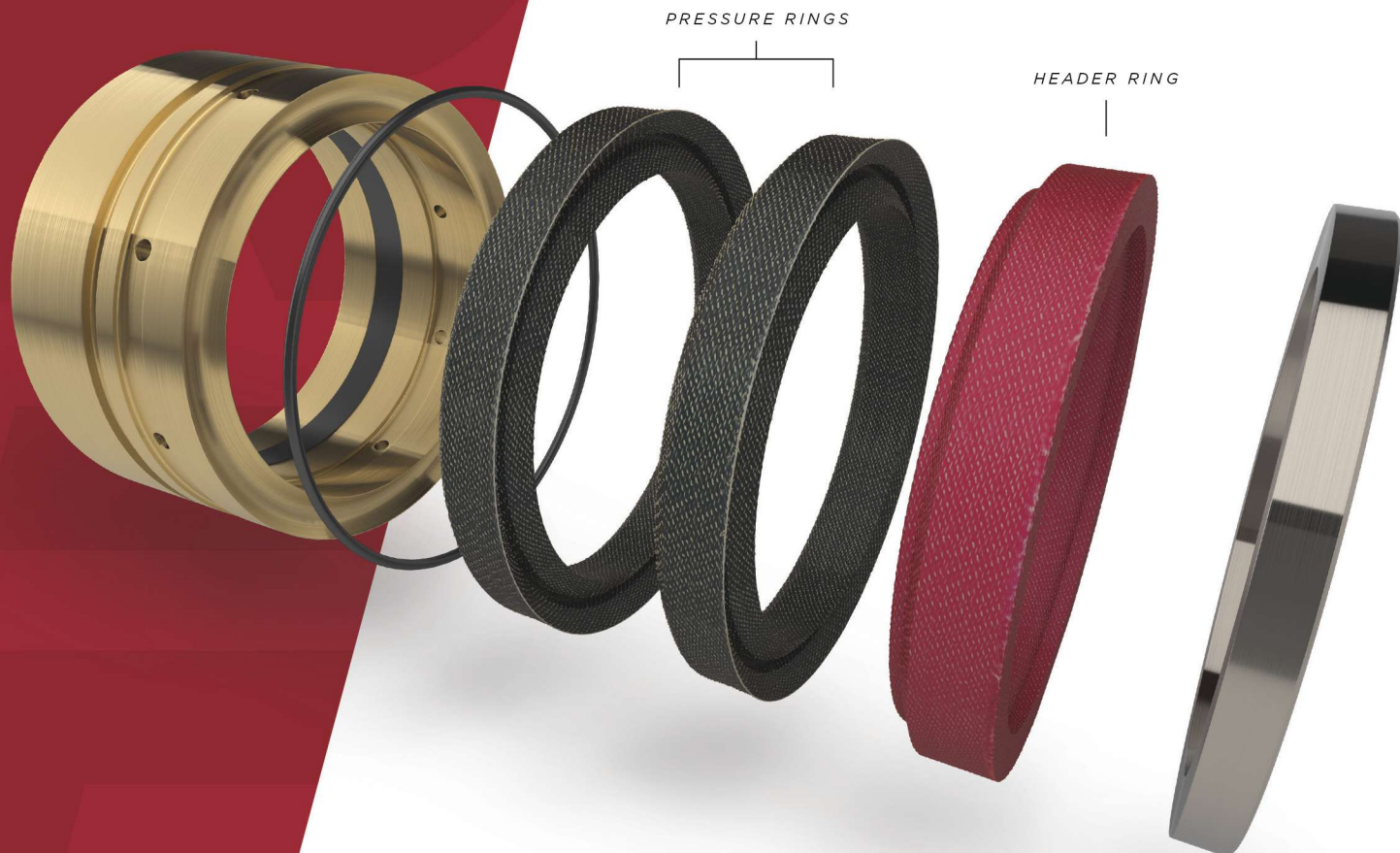
Continuing the crusade

Going forward, modernization and transformation will guide BP’s project development. While there will be specific lessons from Mad Dog 2, Steel said, the broader objective is to transform BP’s business.

“What we’ve done on Mad Dog 2 is not unique in BP, but it’s consistent with changes we are implementing across the upstream organization and our global projects organization,” he said.

The results thus far are impressive. Although BP made a deliberate decision not to chase every barrel in Mad Dog 2, the expectation today is for production to exceed 100% of the original estimated reserves, and this will be achieved at about half the cost.

BP has rebalanced the cost and revenue equation such that its GoM business free-cash breakeven point is less than \$40/bbl, roughly half of what it was in 2014, and has managed to push down production costs 35% since 2015. **ESP**



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Stones Field stands on the shoulders of past innovation

Decades of technology advances laid the foundation for the world's deepest producing oil and gas field.

Jennifer Pallanich, Contributing Editor

When Shell's Stones project went online in 2016, it became the world's deepest producing oil and gas field. Discovered in 2005, the field is in 2,895 m (9,500 ft) of water in lease Block 508 of the Walker Ridge area about 322 km (200 miles) off the coast of New Orleans, La. Shell reported at the time of sanctioning in 2013 that the field contained more than an estimated 2 Bboe of oil in place.

Safely developing and producing from the Lower Paleogene reservoir located about 8,077 m (26,500 ft) below sea level and 5,182 m (17,000 ft) below the mud line would require the harnessing of old technologies and new for Shell and SBM to realize success at Stones. The field was developed using a FPSO vessel and an industry-first pairing of a steel lazy wave riser system with the largest disconnectable buoy turret mooring system.

"There was a lot of innovation in the turret configuration. It was a major engineering exercise to fully develop the design," said Andrew Newport, SBM Offshore's technology director for mooring systems, risers and renewables.

SBM had been developing one of the needed technologies in-house and a second for another project; two others were specifically developed for Stones.

Connection, tension

SBM developed the in-line mooring connector as an in-house project. The company took it to Technology

Readiness Level (TRL) 4 in 2012. Newport said the in-line tensioner has a number of potential applications because of the advantage of tensioning legs from a workboat rather than from the floater itself.

Normally, mooring legs would be connected to the turret and then tensioned using a winch on the turret, but that's not possible with the buoy. Instead, Newport said it was necessary to connect the legs to the buoy on station without the turret present, which without the in-line connector would have meant using a subsea winch to pull in the legs and connect at depth, or pulling the buoy to the surface and making dry connections.

"The tensioning device sits within the mooring leg," he said. "We took a large-scale prototype and qualified it to TRL 4 in the North Sea, but Stones is the first application."

SBM also had developed a high-capacity distributed locking device to TRL 4. The early design work for the technology was carried out for the Shtokman project in the Russian sector of the South Barents Sea, but Stones was the first application. Newport said disconnectable systems are typically sought for use in areas with tropical storms but also are applicable for ice fields where the systems may have to disconnect under very high mooring loads.

The locking device arrangement allows SBM to take any

single connector out of operation, check it and return it to service. The distributed locking system around the edge of the buoy latches the buoy into place once it is pulled in.

"We saw the need for a high-capacity locking device and had already done a lot of design work ahead of Stones. We expect to reuse this system in the future," he said.



The in-line mooring connector makes it possible to connect the legs to the buoy on station without the turret present. (Source: SBM Offshore)

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Floating the Loop

The buoy for Stones was so large—partly because of the ultradeep water depth, the Gulf of Mexico’s infamous Loop Current and the high-pressure steel risers—that SBM and Shell came up with the idea to use syntactic foam blocks rather than traditional steel plate when designing the buoy. The foam blocks provide the buoyancy needed to carry the mooring legs as well as the risers. There are 1,100 tonnes of risers weight that need to be supported.

When the buoy is disconnected to allow the FPSO to leave the field, the buoy stabilizes about 100 m (328 ft) below the surface. However, the Loop Current can drag it down to 200 m (656 ft), placing higher pressures on the outside of the buoy. Using a traditional steel buoy design, thick steel walls would have been required to resist this pressure, Newport said, leading to the need for even more buoyancy to balance the steel weight.

“Instead, the design we developed is an open steel frame, and the buoyancy is provided by the syntactic foam blocks inside. This was a first for us,” Newport said.

Also because of the buoy’s size—it has 6,000 tons of displacement and is larger than any buoy that’s been built to date—a novel heave-compensation system was necessary to address the fact that the buoy and FPSO would both be moving independently during reconnection operations.

“If the buoy and vessel come together, there would be slack in the reconnection winch cable and then a high snatch load as they move apart again,” he said.

The use of a heave compensation system, reeling in and paying out the winch cable to maintain a constant tension avoids the generation of the snatch loads.

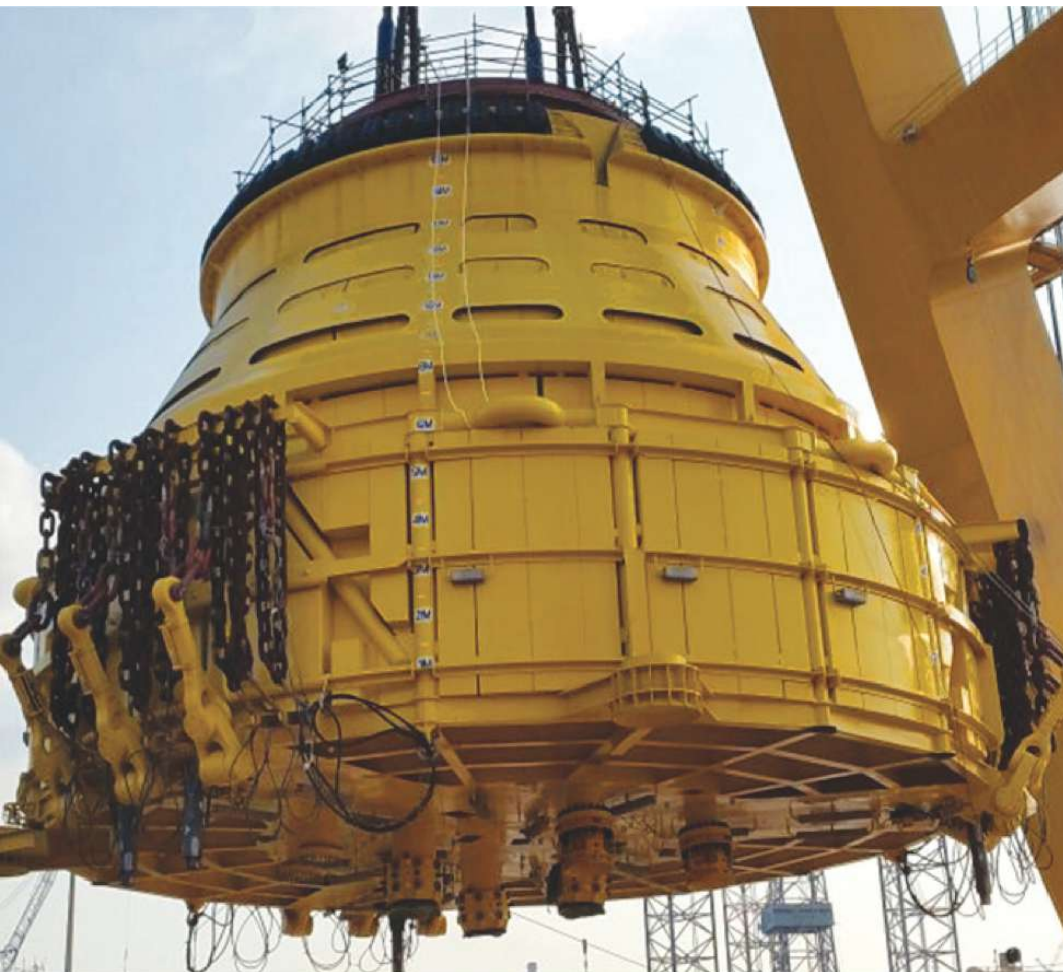
The first use of steel lazy wave risers with a turret mooring system was for Shell’s Espirito Santo Field. SBM leveraged this experience and success for Stones, adding value by using a field-proven technology.

The *Turritella* represents the second application of steel lazy wave risers with a turret mooring system and the first use with a disconnectable buoy.

“A lot of our innovation projects have been with Shell,” Newport said.

He cites other existing technologies that were necessary for the Stones mooring system to become a reality.

One example is swivels, which transfer well fluids, power, signals and chemicals between the geostationary turret and the weathervaning vessel. Another is the bogie bearing weathervaning system, which was first used on the harsh environment *Schiehallion* FPSO West of Shetlands and is now used on all of SBM’s large diameter turret mooring systems. The weathervaning system allows the vessel to rotate around the turret to the position of least resistance to the prevailing waves, current and wind, minimizing the loads on the mooring system and vessel hull. **ESP**



The *Turritella* buoy comprises syntactic foam blocks, which provide the buoyancy needed to carry the mooring legs as well as the risers. (Source: SBM Offshore)

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Identifying potential for more wells per section

Microseismic analysis shows potential for better returns in the San Andres Formation of the Permian Basin's Central Basin Platform.

Carl Neuhaus, MicroSeismic Inc.

Throughout the most recent downturn, the Permian Basin has quickly emerged as a play of historic proportions, with record-high asset valuations accounting for the majority of the acquisition activity and record-low breakeven prices. On any given day during the first half of 2017, almost half of all U.S. horizontal drilling rig activity was located in the Permian Basin. Today the oil and gas industry enthusiastically discusses the vast potential the Permian Basin holds with multiple high-quality reservoirs stacked on top of each other and drilling locations that are anticipated to last for decades.

Most of this discussion focuses on the Delaware and Midland sub-basins, almost neglecting the regional structural high known as the Central Basin Platform (CBP). It is important to note that it contains the same formations as the other two areas of the Permian Basin,

with oil and gas production over thousands of feet in depth in rocks from the Ordovician to the Permian periods. Recent development activity in the CBP has been slower compared to the Delaware and Midland sub-basins but, likely driven by the relatively high cost to acquire acreage in the neighboring basins, it is starting to gain more attention.

There has been significant production from a variety of zones in the CBP, and operators are beginning to investigate the feasibility of horizontal drilling programs similar to the rest of the Permian. Many targets, such as the San Andres, are platform carbonates and very different than the shale plays it neighbors.

Production from the San Andres has been fairly variable and reflective of geologic heterogeneity. In a study area in Cochran County, Texas, at the northern end of the CBP, San Andres wells tend to have high water cuts and EURs are generally lower compared to the south in Gaines and Andrews counties. Due to recent commod-

ity prices, development plans and completion designs are being scrutinized for potential improvement.

Case study

In 2017 a Permian Basin client approached MicroSeismic about challenges it was having in the San Andres Formation in Cochran County, Texas. The client hired the company to understand the best field development plan for the current fracture design and wellbore spacing.

Microseismic analysis for a horizontal well was used to build a reservoir model and understand wellbore density for highest capital efficiency. Depletion modeling showed significant uplift in total EUR and net present value (NPV) for six wells per section compared to the initial development plan of four wells per section.

The study well was landed at about 1,554 m (5,100 ft) true vertical depth

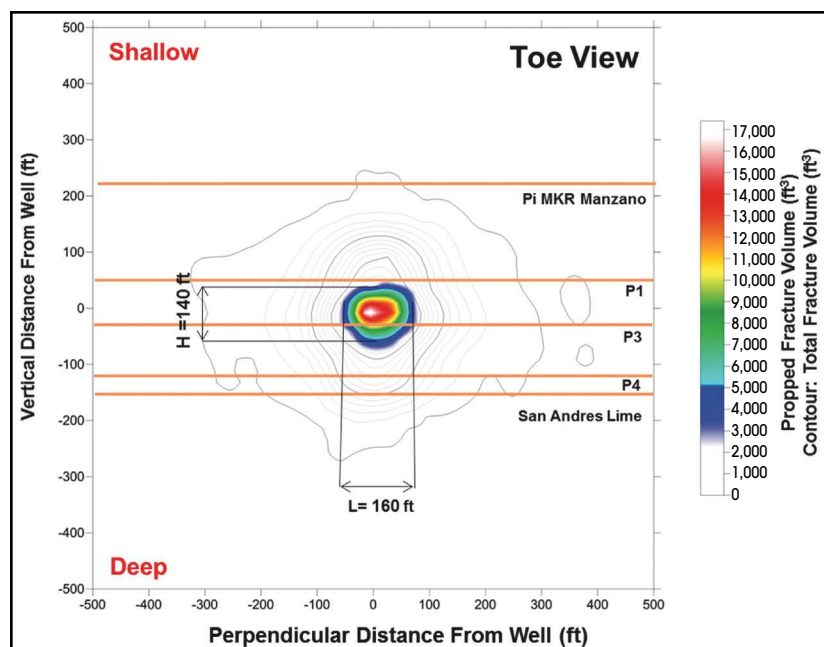


FIGURE 1. This toe view shows the total fracture volume in black contours with a heat map of the propped fracture volume. (Source: MicroSeismic Inc.)

and completed with 34 plug-and-perf stages over a lateral length of approximately 2,286 m (7,500 ft). Data were acquired with an 11-arm, star-shaped surface array during the treatment and used to image microseismic events and the created fracture network. The data were recorded with calibration shot errors of about 3 m (10 ft) in x, y and z axes and accurate magnitude detection down to a moment magnitude scale of -3.

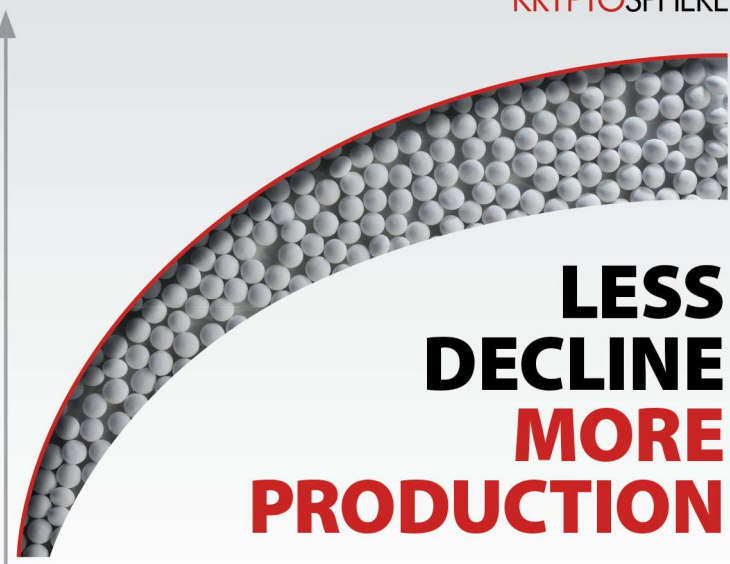
The data allowed the observation of multiple types of rock failure that are typical for the San Andres. Microseismic activity was fairly symmetrical about the wellbore with fracture planes oriented mostly at N 93° E and some failure between 100 and 130 degrees. Maximum horizontal stress direction was determined at about 40 degrees. Horizontal stress anisotropy was determined to be low.

Individual fracture plane orientation and size were obtained from focal mechanisms and event magnitudes. These individual planes were assembled into a discrete fracture network (DFN) that was then filled with proppant according to the actual treatment schedule. Analysis showed a hydraulic half-length of about 91 m (300 ft) with a propped half-length of about 24 m (80 ft). While a significant amount of activity was observed above and below the target interval, the total propped height was only 43 m (140 ft). The geometry of the created fracture network and the propped part can be seen in Figure 1.

The observed fracture geometry indicated potential upside by increasing wellbore density from the original development plan of four wells per section to an optimized plan of six wells per section. Wellbore spacing decreased accordingly from 402 m (1,320 ft) for the four-well case to 268 m (880 ft) for the six-well case. To investigate the amount of interference and the impact of the increased wellbore density on total EUR per section, a microseismic-based reservoir model

was built for each development scenario using conventional well logs and pressure-volume-temperature and core data to define the matrix. Microseismic data were included by calculating the permeability enhancement in the reservoir from the hydraulic stimulation and

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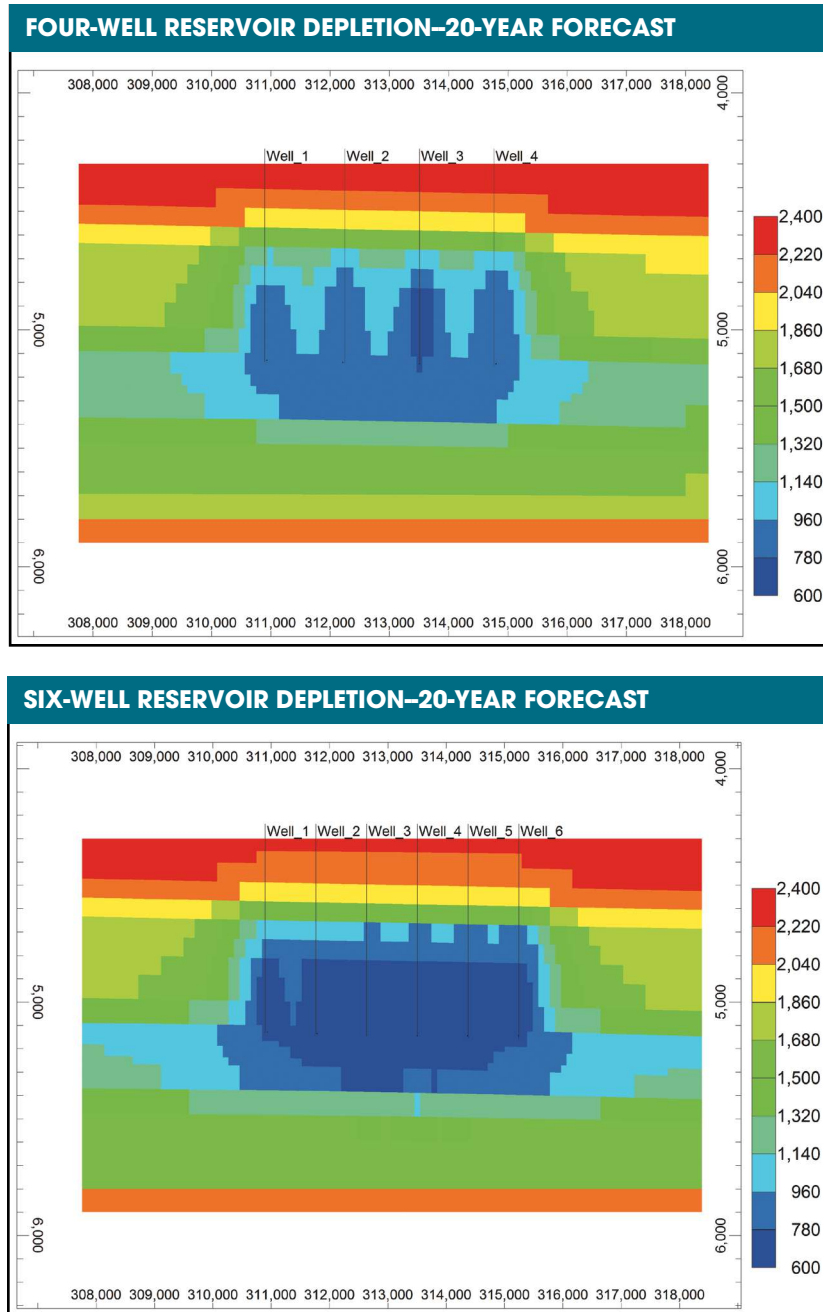


FIGURE 2. A cross section of the 20-year pressure depletion for the four-well scenario (top) and six-well scenario (bottom) shows increased pressure depletion in the six-well scenario. (Source: MicroSeismic Inc.)

its distribution within the stimulated reservoir volume (SRV) from the number, geometry and orientation of fractures in the DFN. The methodology produced three different zones in the reservoir model: the unstimulated background reservoir with matrix permeability, an unpropped portion of the SRV that will

lose most of its initially created conductivity with pressure depletion, and the propped part of the DFN that follows a different permeability-pressure dependency and will provide substantially better long-term conductivity.

Forward modeling showed pressure depletion far outside the created fracture network as expected for a carbonate reservoir. As seen in Figure 2, the six-well case showed more interaction between the wellbores than the four-well case and increased pressure depletion in the range of 200 psi to 300 psi in the SRV after 20 years. Cumulative oil production over 20 years increased by 20% from 718,000 bbl to 865,000 bbl whereas gas production increased by 68% from 113.3 MMcm (4 Bcf) to 189.7 MMcm (6.7 Bcf) per section, largely due to the additional pressure depletion and the bubble point pressure for the study well. Overall total EUR increased by 43% or almost 600,000 boe.

The six-well case showed more interaction between the wellbores than the four-well case and increased pressure depletion in the range of 200 psi to 300 psi in the SRV after 20 years.

The amount of production increase per section was significant enough to offset the additional cost of \$2.5 million per well. Assuming a flat price deck of \$50/bbl and \$3/Mcf, as well as a 10% discount rate, the six-well scenario resulted in a NPV increase of 28%. For Cochran County the study well identified significant upside and indicated that acreage in the area offers more attractive returns than previously expected. **ESP**

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FUS offers different development options

A new design offers offshore operators an economical and reusable solution for field development.

Stafford Menard, Audubon Engineering; **Arun Antony**, Atkins, member of the SNC-Lavalin Group; and **Roy Francis**, Gulf Island Fabrication

It has been nearly four years since oil prices ranging from \$105/bbl to \$110/bbl plummeted to today's prices of \$50/bbl to \$60/bbl, yet the industry still has not seen any substantial innovative solutions to the industry challenge of economically producing crude oil from small to mid-size deepwater reservoirs. The industry focus continues to be on reducing the cost through optimization of large floating production systems at the expense of the project schedule. This may not be the best solution for maximizing the return on investment for smaller reservoirs.

Over the past two decades, the industry has developed and installed numerous floating production systems (tension-leg platforms, spars and semisubmersibles) in the Gulf of Mexico (GoM) that are connected

to a network of deepwater pipelines and further connected to shelf platforms and pipelines. Most of these floating production systems are still operating and have available ullage and boarding capability and have been utilized for local tiebacks (hub and spoke concept).

This has proven to be a very economical solution for fields that are within an acceptable distance (less than 40.2 km [25 miles]) from the host. To extend the acceptable distance to 80.4 km (50 miles) or 161 km (100 miles), the technology would need to be safe, reliable and economical. If these benefits were provided and the front-end spend and schedule from discovery to first oil were reduced, the industry would have an acceptable alternative.

Innovative approach

A floating utility system (FUS) has been developed by US Spars, a consortium comprising Audubon Engineering, Atkins/Houston Offshore Engineering, members

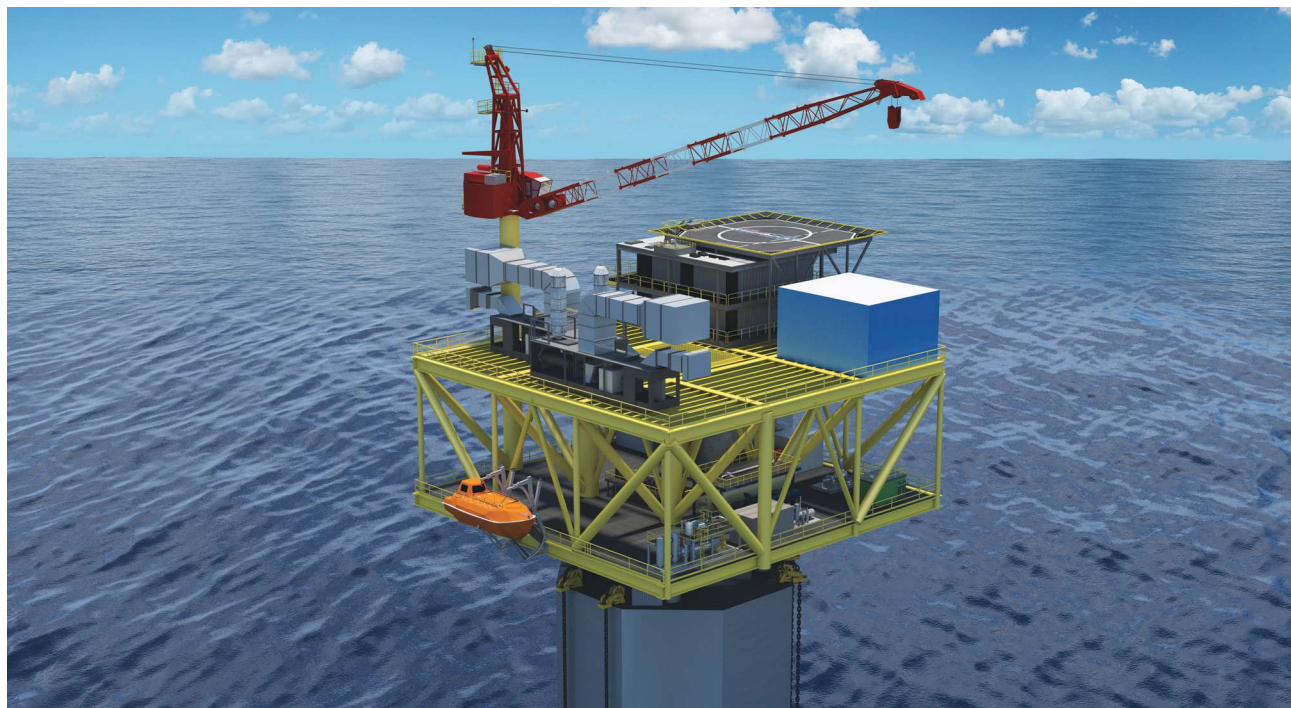


FIGURE 1. The FUS-60 spar provides an economical and reusable option for the development of small to mid-size offshore reservoirs. (Source: US Spars)

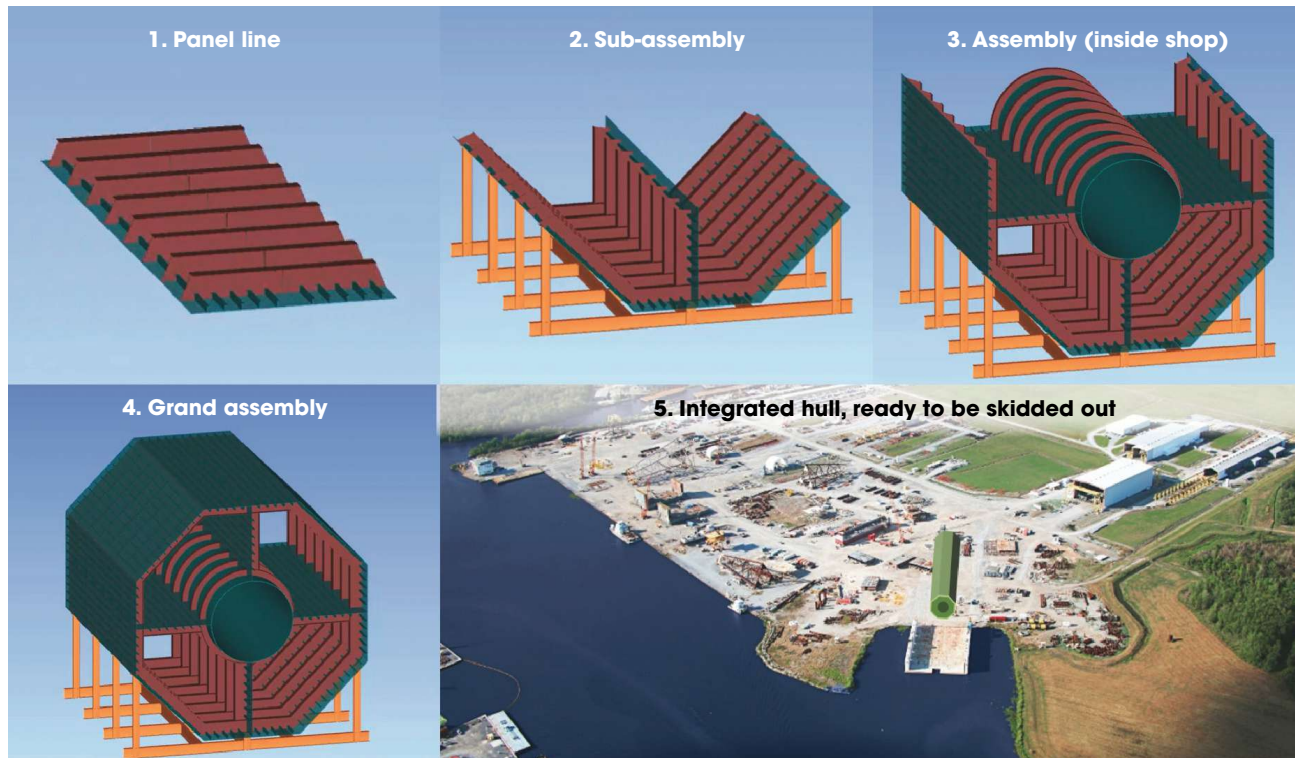


FIGURE 2. The fabrication sequence for the FUS-60 spar was developed with consideration given to the existing yard infrastructure and capabilities. (Source: US Spars)

of the SNC-Lavalin Group and Gulf Island Fabrication (GIF). As the name suggests, the FUS-60 provides the utility services to the field at the well site (Figure 1). It can provide power to subsea booster pumps for production of up to 60,000 bbl/d of crude oil and provide storage and injection for flow assurance chemicals. The FUS also can provide well control, high-integrity pressure protection system support, ROV deployment, accommodation spaces and/or water injection capability. This low-cost standalone floater enables long distance tiebacks to existing floaters while also providing a development option for marginal fields.

The floater developed for this methodology is a spar-based FUS due to its insensitivity to water depth and good motion characteristics. The topsides consist of a two-level deck that is 26 m by 29 m (85 ft by 95 ft) in size, allowing under-the-roof construction and the elimination of the third deck lift and float that are common for conventional three-level spar decks. The deck can provide power for up to 60,000 bbl/d of crude oil mud line pumping, provide 300 bbl of methanol storage along with storage space for five additional chemicals and accommodate up to 20 people onboard. The use of proven, standardized vendor equipment packages reduces risk, schedule and

cost. The reduced offshore lift weight (under 2,000 short tons) is within the lift capacity of multiple derrick barges.

Fabrication and installation

The cross section of the spar hull is octagonal-shaped, providing the benefits of flat plate fabrication. The flat plates are standardized and use the automated panel line facility (conventional barge fabrication) at the GIF yard. Eliminating the need for plate bending and utilizing the automated panel line for most of the hull fabrication reduces man hours needed for hull fabrication.

The fabrication execution plans for the hull and topsides were developed with consideration to the existing yard infrastructure and capabilities. The hull panels are assembled on prefabricated jigs and five out of the eight sides are assembled inside the assembly shop (Figure 2). The fully outfitted hull grand assembly is transported to the skidway by transporters that are available at GIF.

The hull blocks will be integrated on the existing skidway, and the completed hull will be skidded onto GIF's 122-m-long (400-ft-long) floating drydock. The floating drydock will be moved over a permitted "deep hole" at the fabrication yard and lowered to float-out the hull. As the hull is a classic spar, it will float nearly

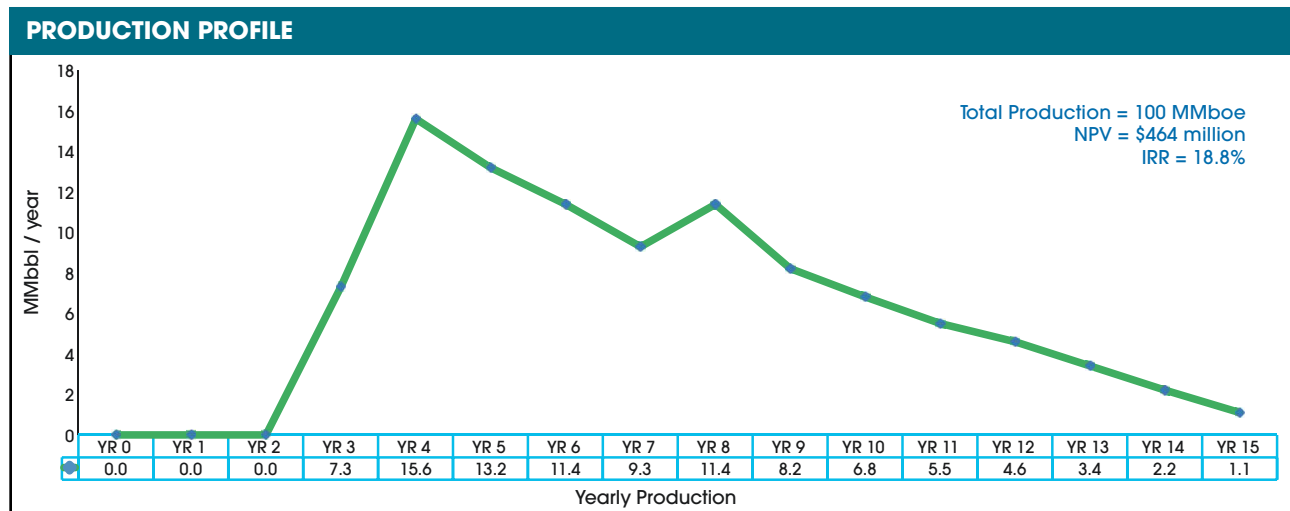


FIGURE 3. This P-50 production profile was used to calculate the project's NPV and IRR. (Source: US Spars)

TABLE 1. FIELD DEVELOPMENT COST BREAKDOWN		
Item/Event	Estimated Cost (Million)	Year of Event
Discovery well	\$125	0
Appraisal well #1	\$125	1
Production well #1	\$155	1
Production wells #2 and #3	\$310	2
Production well #4	\$155	7
Geology and seismic	\$10	0
Total installed cost of FUS-60	\$215	1 and 2
Host modifications	\$50	2
SURF (includes mud line pump package)	\$175	1 and 2
Export pipe (subsea pumps to host)	\$95	2
FUS-60 decommission for relocation	\$25	16
Plug and abandon production wells	\$80	16

(Source: US Spars)

TABLE 2. ASSUMPTIONS FOR NPV AND IRR CALCULATIONS	
Crude price	\$50/bbl
Pipeline tariffs (host platform to shore)	\$3.50/bbl
Facility opex	\$6/bbl
Production handling fee (third-party host)	\$4.50/bbl
Royalties	\$6.25/bbl
Net crude price	\$29.75/bbl

(Source: US Spars)

even keel and thus provide sufficient clearance to wet tow through the channel.

The offshore installation of the FUS-60 will be simpler than conventional spars due to the lower topside weight and fewer mooring lines. The system has a targeted 24-month schedule from project sanction to installation and commissioning.

Traditional production facilities are dependent on the field/reservoir characteristics for final optimization of the design. Changes in production properties, like the gas-oil ratio, result in the production equipment differing among facilities. Because the FUS-60 is standardized and field independent, it can be relocated to a different field after the initial deployment with little to no modifications. The FUS-60 also can be adapted for use as a normally unmanned installation.

Cost breakdown

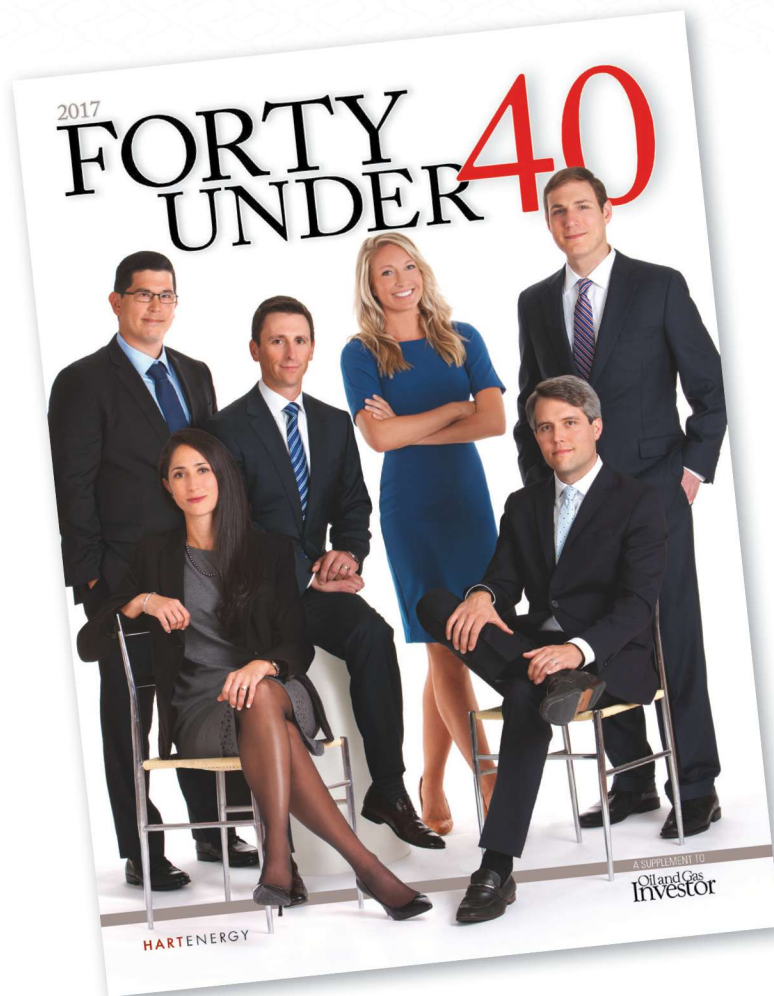
For a commercial evaluation of the FUS-60, consider a representative GoM reservoir with 100 MMboe reserves in a remote area 80.4 km from the nearest host. The cost breakdown in Table 1 and additional cost assumptions in Table 2 were used to calculate the project's net present value (NPV) and internal rate of return (IRR).

In addition, the net crude price and cost were inflated at 2% per year. A 10% discount rate and the P-50 production profile were used for NPV and IRR calculations (Figure 3). Maximum production (Year 4) is 72% of system capacity, allowing well and FUS-60 downtime. This evaluation yielded a NPV of \$464 million and an 18.8% IRR, attractive for a marginal field that otherwise would have been noncommercial. **ESP**

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A digital approach to large-scale asset management

A new optimization platform leverages digital technologies to elevate production performance.

**Manoj Nimbalkar, Douglas Rauenzahn and
Bimal Venkatesh, Weatherford**

As the oil and gas industry adjusts to the “new normal” oil price environment, it faces the challenge of managing a vast array of field assets with limited resources.

This is particularly true in producing fields with hundreds or thousands of wells on some form of artificial lift and with fewer engineers available to oversee them. The number of engineers with decades of experience in rod pumping, for example, is lower than it was five years ago—a loss of expertise that cannot be quickly replaced. Those remaining in the field are stretched thin and cannot effectively manage thousands of wells or make fast, informed changes to each well’s lift system as well conditions change.

Connecting the production ecosystem

The manufacturing sector is in the midst of a transformation that is driven by the Internet of Things, smart sensors, cloud computing and machine learning concepts. This trend toward greater automation and data exchange in manufacturing, a concept commonly referred to as Industry 4.0, delivers vast improvements to efficiency, safety and production optimization.

The oil and gas industry already has started adopting Industry 4.0 concepts to leverage its resources more

effectively in various parts of the value chain. Working from this foundation, Weatherford created a technology and business vision for a Production 4.0 ecosystem. The ForeSite production optimization software platform was developed specifically to help the industry use these concepts to lift field production to new levels of efficiency. Combining physics-based models and historical trending with machine learning data analytics, the platform helps operators improve performance across diverse oil and gas asset types, including unconventional, conventional, onshore and offshore.

The ForeSite platform was introduced in 2017 with the aim of providing the industry’s first system combining optimization support and predictive analytics for reciprocating rod lift systems. The platform has recently been expanded to provide support for gas lift, electric submersible pump (ESP) systems and naturally flowing wells—all from a single platform.

The extensive range of engineering calculations and modeling engines has fine-tuned performance in more than 150,000 wells around the world over the past 15 years.

The ForeSite platform combines these technologies with Industry 4.0 principles to deliver methods of optimizing the performance of each asset. By harnessing data across the production ecosystem from the reservoir

to surface facilities, operators can make more informed decisions that maximize production rates at a lower cost per barrel.

Optimizing assets from afar

By providing real-time access to production data and the ability to analyze it at a granular level, the platform helps operators make smarter optimization decisions for an ever-growing range of artificial lift types. The platform affords live asset production tracking from an



The ForeSite platform uses physics-based models and advanced analytics to analyze data from every corner of the asset, enhancing decision-making. The platform delivers a production optimization ecosystem that expands as the well count and asset base grow. (Source: Weatherford)

intuitive, visual interface and real-time diagnostics that identify any atypical behavior in a well's performance. For example, the platform can compare rod lift dynamometer characteristics with an extensive card library to help operators diagnose factors affecting well performance.

When it detects changes in production trends or operating parameters deviating outside of set points, the platform sends intelligent alarms to the user's desktop or mobile device. Additionally, because all ForeSite software integrates with Weatherford's CygNet SCADA platform, operators have the option of creating a closed-loop, end-to-end optimization cycle. For example, if the data analysis suggests that a field parameter (e.g., the position of a choke, a compressor setting or the speed of a pump) needs to be changed to improve well performance, the SCADA engine allows the command to be securely sent and applied remotely.

Because artificial lift requirements often change over time, the platform is designed to help operators select the right form of lift for each stage in the life of the well. Using both current and projected data, including inflow and completion modeling, fluid properties, pressure-volume-temperature analysis and flow dynamics, the platform anticipates problems and offers insights that ease the transition to alternate lift methods as reservoir conditions change.

Reducing failure frequency

To help ensure asset optimization and reliability on a longer time horizon, the platform's predictive analytics proactively identify minor performance issues before they develop into bigger, more expensive problems. This feature combines field data with advanced analytics tools to gauge the performance of each asset.

Using equipment failure history as a guide, the platform applies artificial intelligence to predict subsurface failure by lift component. By routinely tracking equipment performance at the individual component level, operators are able to extend the mean time between failures through proactive corrective measures. Operational settings can be tweaked to extend equipment runlife, and workover rigs and maintenance crews can be dispatched ahead of time to reduce downtime and associated production losses.

When well intervention becomes necessary, the platform's Field Services Management module enables users across different areas of the operation, including third-party rig crews, engineers, production planners and management, to collaborate on workover plans. The module includes an application for economic analysis, enabling engineers to evaluate all jobs in the

queue and prioritize the rig schedule based on which activities will bring the highest return on investment. It also visualizes historical data in a way that helps users analyze operational issues, understand cost drivers and determine best operating practices.

The platform's failure prediction and early warning capabilities give operators the tools to manage their assets by exception. This lets already-stretched field operations and work crews devote more time to optimizing performance rather than looking for problems. Embedding predictive failure analysis into the production workflow is a key advantage, enabling users to perform physics-based analysis and advanced analytics on the same platform.

Future developments

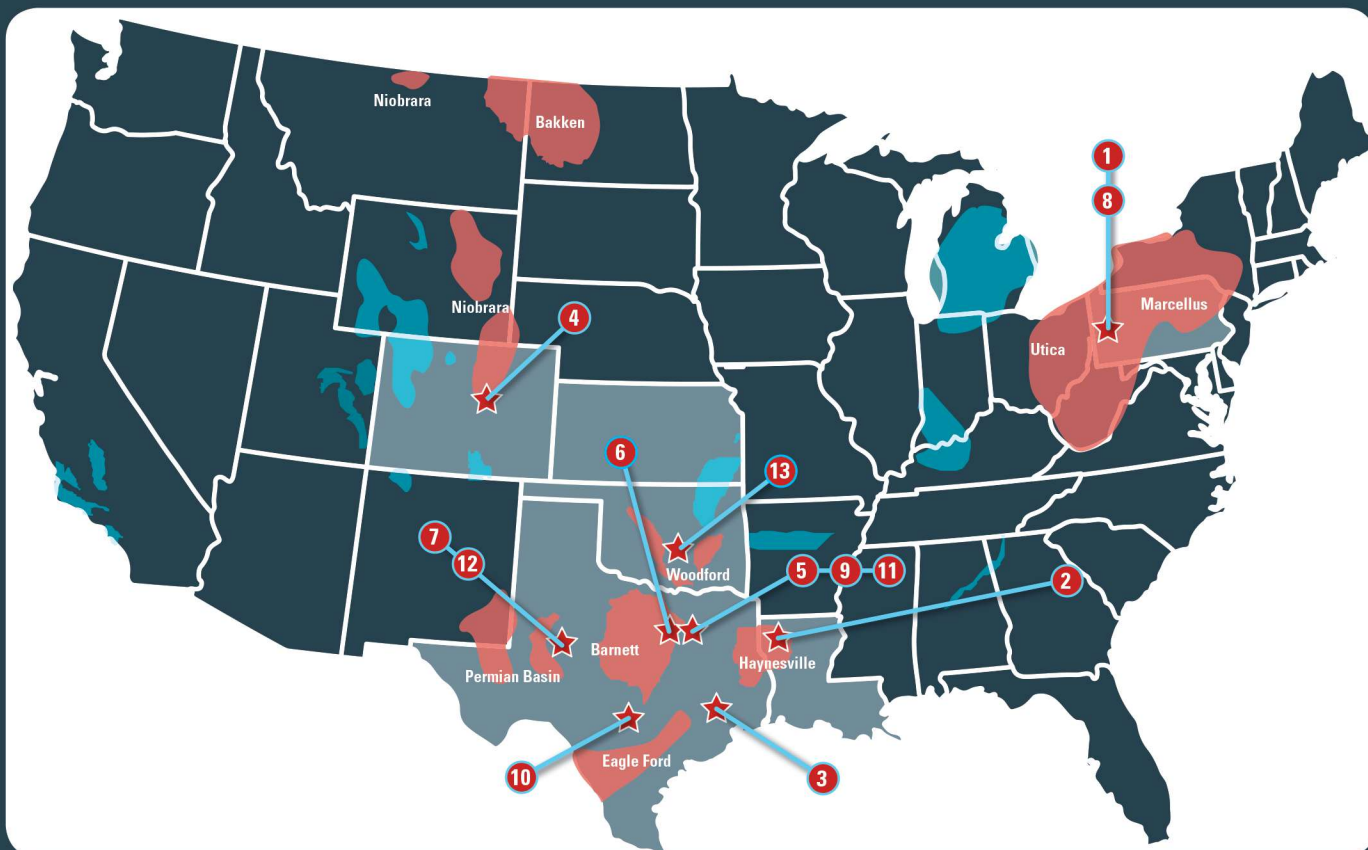
In addition to the platform's current capabilities, further developments are underway to expand its applications. One ongoing project involves predictive analytics for failure management of ESPs, which deliver high production rates but are expensive to repair. Advanced analytical models for ESPs aim to minimize downtime that costs an operator in terms of both high workover rates and deferred production.

The platform's modeling and predictive analytics capabilities continue transitioning to the cloud, which eases installation and minimizes maintenance issues. This is a particular benefit for smaller E&P companies that are emerging from the downturn with limited in-house IT infrastructure and a deficit of the field expertise required to optimize performance. These companies want the optimization capabilities that the software platform provides, but they do not have the manpower or IT budget to manage it themselves.

Through a cloud-based solution, companies can access the platform from a secure, Weatherford-hosted website. They can then analyze all production and artificial lift system data from the site to make their own decisions aimed at improving performance at each well or across the field. For operators requiring both the software and engineering consultation, Weatherford's team of production advisers review the data with them and provide insights and recommendations that inform a deeper understanding of each asset and help ensure that the best optimization decisions are made.

As the oil and gas industry emerges from the downturn, it enters a new era of automation and digitalization. Technologies such as the ForeSite platform can help operators harness their field data for vastly improved analysis, predictability and long-term production at a significantly lower operating expense. **ESP**

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11

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Understanding what makes super basins work will be key to unlocking the ultimate potential of these areas.

Brian Horn, ION Geophysical

Within the E&P industry super basins are a well-known concept. While the term “super basin” is a relatively new idea, coined by IHS Markit, it is based on a series of subsurface and surface characteristics: These basins must have 5 Bboe of produced hydrocarbons and at least 5 Bboe of remaining resource. The prolific production of hydrocarbons from them has buoyed the quest for energy since the early 1900s. Many of the giant fields known today were discovered in the early phase in these basins and led to the exploration drilling and discovery of about 10 Bboe of reserves in basins around the world (the Arabian basins, the Niger Delta basin, the Gulf of Mexico, Permian Basin, Alaska’s North Slope and the Brazil presalt, to name a few). The continued search for additional hydrocarbon resources has resulted in many innovations, changes in technology, leaps in geologic understanding and improvement in the exploration process, which have created the potential for the U.S. to regain its foothold as the largest producer of oil.

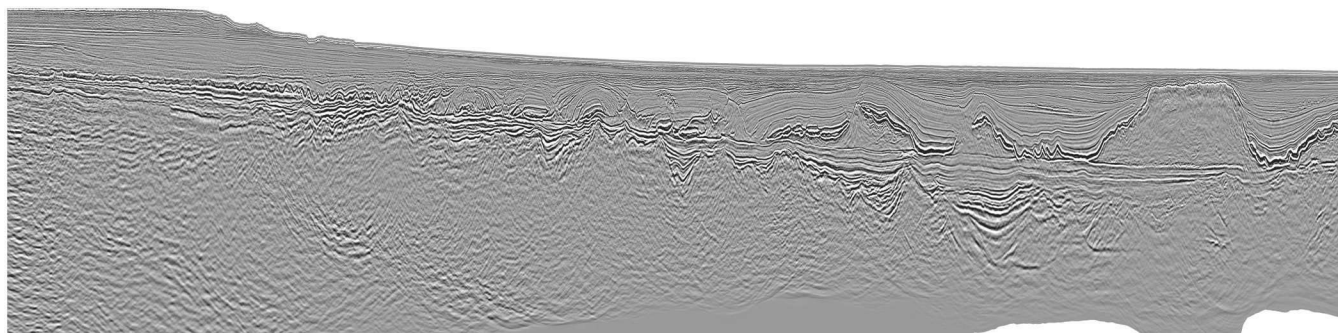
The unconventional revolution is now quite conventional and has become a dominant method of exploration and exploitation of hydrocarbon resources in North America. While technology continues to provide new access to what once were uneconomic hydrocarbon accumulations, much of this activity is focused on what are generally considered mature basins.

Old place, new ideas

A quote from Parke Dickey in 1958 is truer today than ever before: “We usually find oil in a new place with old ideas. Sometimes we find oil in an old place with a new idea. But we seldom find much oil in an old place with an old idea.” The caveat to be added is that when the old place is a super basin, the industry has probably not discovered the full potential of that area.

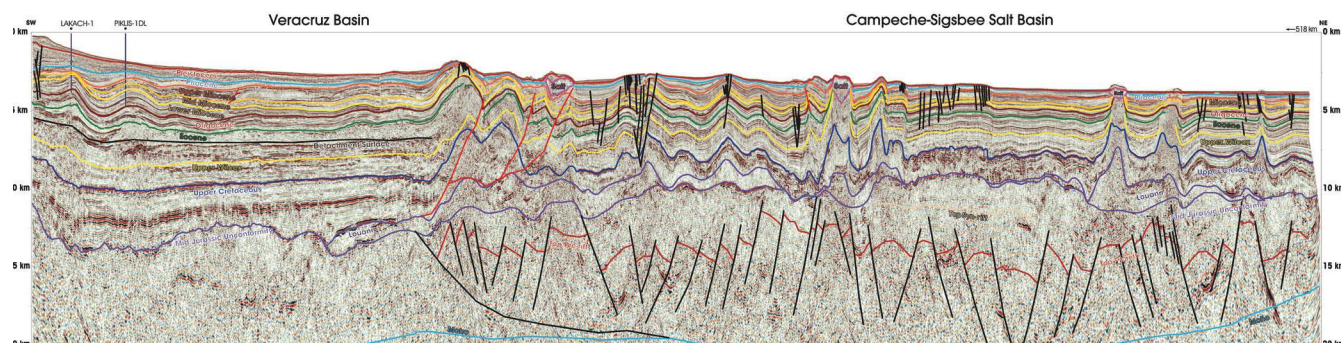
Ian Vann, former executive vice president of exploration for BP, once said, “If you want to find oil, you must look in the oily places.” At first glance this seems to be a rather simplistic thought, but the truth of these words underpins the essence of a super basin. Super basins are unique, and as technology continues to progress, the industry will continue to unlock the ultimate potential of many “oily places.”

Perhaps the biggest change in the continual rejuvenation of many mature basins has been the ability of seismic data to provide a better image of the subsurface geometry and lithology and the ability to understand basin evolution through time. Long-record long-offset data provide a better image of the deepest parts of a basin. Multiazimuth data enable attribute analysis to better predict fluid types, rock properties and fracture orientation. The development of drilling and completion technologies has changed the conventional idea of reservoir rock quality. The understanding of petroleum systems and the prediction of fluid type variability across a basin provide new ways to drill and complete multiple reservoirs and



An understanding of the geology offshore Brazil can help geologists better delineate the conjugate margin offshore West Africa.

(Source: ION Geophysical)



Super basins like the Gulf of Mexico must have 5 Bboe of produced hydrocarbons and at least 5 Bboe of remaining resource.

(Source: ION Geophysical)

to better understand the interplay of lithology and petrophysics, fluids, pore space, rock physics, pore pressure and geomechanical properties in the subsurface.

New ideas

The biggest driver will continue to be fiscal terms. High production takes by national oil companies or governments along with taxation or regulation are impediments to continued drilling and future exploration growth.

The access to land leases or blocks in a consistent and transparent manner is also a key factor. If the financial or regulatory hurdles remain high, future exploration will be challenged. A technological innovation or step change in cost structure could provide the ability to overcome fiscal hurdles and lower the cost.

Finally, infrastructure and security are closely related factors. There are many significant discoveries around the world that are not developed due to security risks or the lack of adequate infrastructure to produce the fluids and bring them to market. This changes over time but is an important consideration in understanding exploration drilling in emerging areas.

Regional evaluations and analysis in offshore exploration, particularly in salt basins, relies primarily on seismic data and the development of play fairway concepts. Reconstructing the conjugate margin of what initially was a single basin can provide insight into new ideas in a new area. How does our current understanding of offshore Brazil impact the search for hydrocarbons on the conjugate margin of West Africa? Is the scale relevant? Does it help us develop new methods and understanding that will lead to a new exploration play concept in an area that has been previously drilled without success?

The recent discoveries along the transform margin of Africa in Ghana are a great example of a play type that has been extended to the conjugate margin, as evidenced by the major discoveries in offshore Guyana. Understanding

similarities and differences in analogous play types around the world will continue to be a key factor in transforming emerging basins with significant discoveries (e.g., East Africa/Senegal) into the next super basin or guide us to look for a similar play type in a new area.

The ability of high-speed computing and data storage has led to the creation of large 3-D datasets. These legacy data acquired over the past 25 years from multiple different surveys can add significant value at a much lower price point. Development in seismic processing algorithms such as reverse time migration and full waveform inversion has enabled companies to reprocess legacy seismic data acquired with various parameters to be merged and reprocessed, creating new fit-for-purpose 3-D data that provide a product that is comparable to many modern wide-azimuth surveys at 10% of the cost. This innovation provides operators with a more cost-effective solution for license round evaluations. Similarly, the consistency of a large volume of data enables companies to create exploration opportunity portfolios that are well calibrated.

Looking toward the future

Super basins are not super by accident. Their endowment of hydrocarbons is the result of many different factors that have developed in the optimal time frame with the optimal petroleum system. Understanding what makes these basins work, why they contain the recoverable reserves of great magnitude and the salient similarities and differences between super basins will be keys to unlocking the ultimate potential of these areas. Perhaps the most important factor is the presence of prolific source rocks. Without an active petroleum system there are no exploitable hydrocarbons. Sound fundamental analysis and technical innovation will be essential in future exploration programs in these basins. However, as Wallace Pratt said, "Oil is first found in the final analysis in the minds of men." **ESP**

Taking a new look at frontier exploration

New developments in geoscience and regional understanding can help reduce risk.

Rhonda Duey, Senior Editor, Exploration

Exploration isn't dead, and the need for continued exploration is not going away, according to Mike Simmons, the Halliburton Technology Fellow for Geosciences and Exploration. In his recent webinar, Simmons discussed the current exploration environment, citing several sources. One was BP's 2017 Energy Outlook, which looked at technically recoverable reserves for oil versus predicted demand between 2035 and 2050. "What appears to be evident from this quite provocative figure is that there are already abundant discovered hydrocarbon resources," he said. "This seems to exceed likely demand for the next 35 years or so."

But this doesn't tell the whole story. For one thing, the BP report did not factor natural gas into the mix. Perhaps more importantly, BP's analysis is of technically recoverable reserves, not economically recoverable reserves. In Simmons' view this means that rather than focusing on EOR techniques to "squeeze the very last drops of oil from an old oil field," it makes sense to continue searching for new, more economically viable reserves of hydrocarbons.

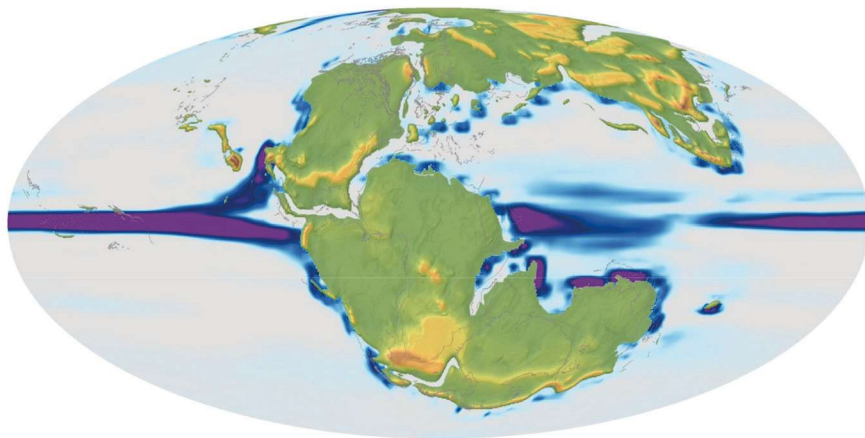
Unfortunately, according to information from Rystad Energy, reserves replacement over the past 17 years has rarely been above 100% and in some cases has been as low as 20%. "This is an issue for concern because ultimately that performance can't continue," he said, adding that a new approach to exploration is needed.

New factors driving exploration

While North America has unlocked the keys to unconventional development to some extent, and while these efforts have mostly been through advances in drilling and completions technology rather than exploration technology (at least until now, though that is changing), Simmons said "the vast majority of production still comes from conventional reservoirs." This was recently acknowledged by a Wood Mackenzie report noting that its Macro Oils team has released a new insight looking at global cost curves that indicate many prefinal investment decision projects, even in deep water, are now competitive with tight oil plays in the Lower 48 on a breakeven basis.

"However, this competitiveness has come at the expense of volumes," a press release noted. "The trade-off of cost efficiency versus volumes means that in the medium to long term, the cost of supply is set to increase, highlighting the Lower 48's new role as an important marginal barrel producer."

Simmons said while about \$60 billion was spent on exploration in 2017, this is just one-third of what it was four or five years ago. "There has been a dramatic decline in discovered reserves, particularly over the last five years," he said. "That's partly due to fewer wells being drilled and less investment, but it's also because exploration is in some ways becoming more difficult. Geological risks are increasing—we often incorrectly predict the presence of charge; we incorrectly predict the presence of quality reservoirs and effective reservoirs at depth."



This paleoclimate model highlights areas of predicted upwelling during the Early Jurassic. (Source: Halliburton)

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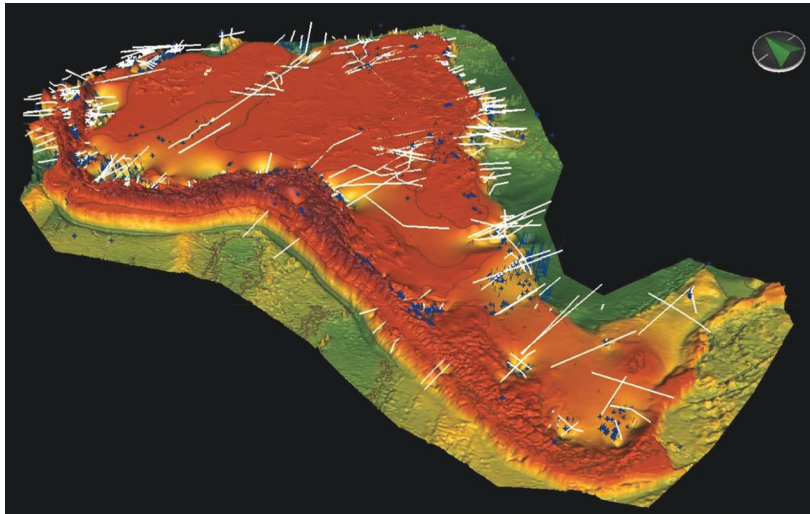
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This South America regional depth framework highlights data inputs, including lines of section, outcrop geology, wells and surface geology data. (Source: Halliburton)

And while the “super basin” concept is appealing, looking in areas like the Permian Basin that still have vast untapped reserves, other companies will still be looking at completely new frontiers such as offshore Argentina, offshore Eastern Canada, parts of West Africa, parts of Southeast Asia and the Arctic. “[These areas] are very tempting because the prizes are potentially very huge,” he said.

Potential solutions

Machine learning is one solution to help the industry cope with the huge amount of data and to make the exploration process more efficient. Additionally, the industry needs better techniques to predict the location of the reservoir, charge, seal and trap, and it needs to capture the uncertainty in these assessments.

Simmons gave an example by British academic Jenny Bond. Bond gave a synthetic seismic image to more than 400 participants and asked them to interpret it. Perhaps not surprisingly, the results were influenced by the interpreters’ areas of interest.

“Those with experience in salt tectonics invoked salt in the structural configuration,” he said. “Those with expertise in sequence stratigraphy might see a more sedimentological genesis. Those with compressional experience saw a lot of thrusts.”

Overall, only 21% of the participants actually came up with the “right” interpretation.

How can this bias be overcome? Two words: regional geology. For instance, the synthetic image did show evidence of salt tectonics. “If we had known it was coming from West Africa, we might have understood it and per-

haps related it to some of the salt basins that formed as the Atlantic was opening,” he said.

The goal, then, is to improve effectiveness in regional screening. This is done by developing gross depositional maps to map the distribution of potential source, reservoir and seal elements. Burial depth is an important element to determine the maturity of the source rocks. This allows the interpreter to generate charge, reservoir and seal maps, which are then stacked together in a composite common risk segment map to high-grade the most prospective areas.

Simmons showed an example offshore Argentina, which is receiving considerable attention due to an upcoming licensing round. While much of the region has been

mapped, only a few areas meet all of the criteria.

“How do we come to interpretations such as that?” he asked. “Clearly we have data where reservoir sands are present and where source rocks are present. And we can use geological techniques including source-to-sink and plate tectonic geodynamic history to start to model where potential facies are present, which could be either a reservoir source or seal.”

Another tool is to reconstruct past climate history. Paleoclimate studies can map areas that received intense rainfall in the past, which in turn led to increased runoff and potentially more likely reservoir presence. Or they can be used to predict upwelling and other factors that drive source rock deposition. These maps are generated by understanding topography, atmospheric CO₂ and bathymetry, which in turn enables predictions of ocean and atmospheric circulation.

Another technique Landmark is using is creating regional depth frameworks to find the sedimentary depocenters that determine maturity of source rocks and, for example, considerable thicknesses of sand systems. And the source-to-sink process looks at the depositional processes, drainage patterns and sediment conduits from river deltas into ocean basins. Finally, studying sedimentary architecture provides an understanding of rock interbedding, important in resource play exploitation.

Overall, Simmons said geoscientists have several tools at their disposal, from stratigraphic architecture to modeling past climates. With several basins around the world still vastly underexplored, this arsenal should help reduce the uncertainty associated with frontier exploration. **ESP**

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Pressure control innovations improve reliability

A new valve design and enhanced condition monitoring system lowers total cost of ownership.

Curt Kling and Stephen Forrester, NOV

Although there has been some recovery and stabilization in market pricing, rig day rates are still down from their historical highs. Contracts remain elusive, and differentiation with upgraded equipment and technology packages are effectively the only way for one contractor's rig to stand apart from the rest. The oil and gas industry continues its search for meaningful cost-cutting measures that will allow idle rigs to get back to work. To this end, National Oilwell Varco (NOV) has pursued improvements in its pressure control products to lower the total cost of ownership by improving reliability and reducing required maintenance.

New valve design

The Low-Shock subplate mounted (SPM) valve designed by NOV is the first major SPM valve development in almost four decades and addresses the most common failure modes caused by water hammering, corrosion and assembly induced infant mortality.

The new design has shown improved performance and has the potential to reduce circuit failure due to a reduction in hydraulic shock (Figure 1). By controlling the timing of the valve shift, hydraulic shock was reduced from nearly 10,000 psi to just over working pressure in the most extreme cases. The SPM pilot shifts the valve in less than a second with no interflow. This controlled shift reduces the end rush of hydraulic fluid, protecting downstream components during valve opening and upstream components during valve closure.

components during valve closure.

In addition, although previous versions of the valve had multiple seal sizes, a new high-gap seal design was created to prevent installation errors and the use of incorrect seals. The new seals are pressure activated, which leads to reduced equipment replacement due to wear and tear and enables the user to repair pockets in the field. The traditional assembly process also was altered through the use of a machined rod, which removes the bottom nut on the spool. This simple item has led to many installation errors and resulted in field failures. Another

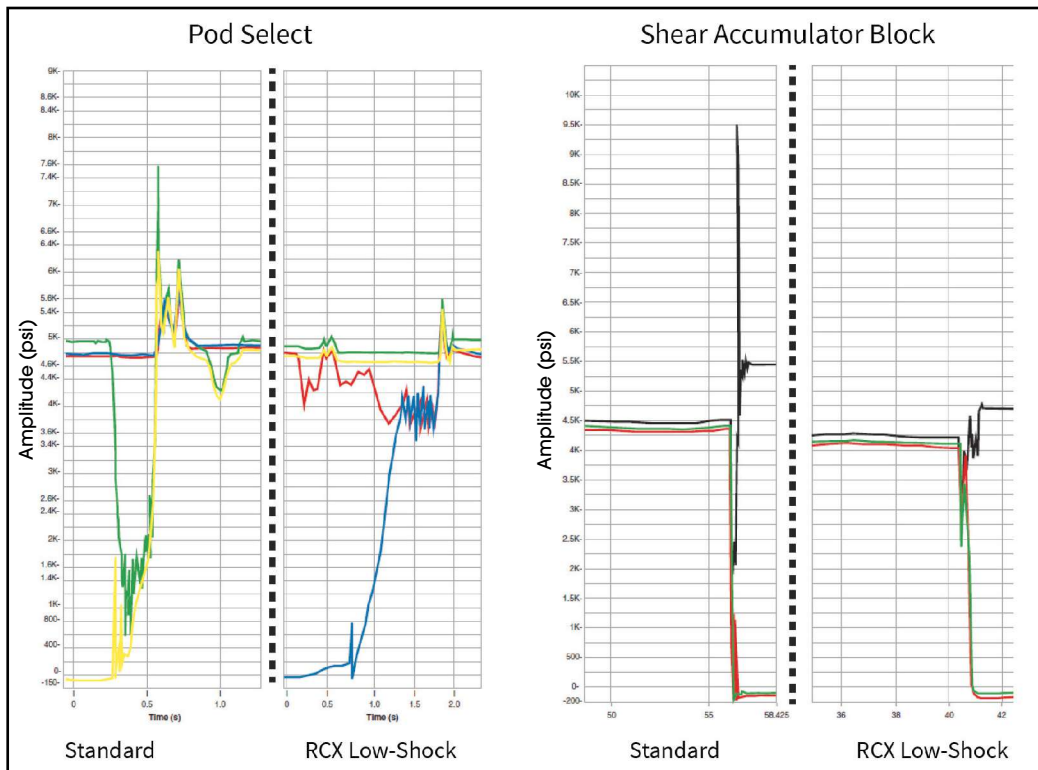


FIGURE 1. These performance graphs show comparisons between standard SPM valves and Low-Shock SPM valves. (Source: NOV)

source of field issues was a spring housing that was flooded with seawater, resulting in long-term corrosion. To combat this risk, the spring housing is now flooded with control fluid, leading to improved valve life. Field results already have shown distinct and significant reductions in pressures.

Enhanced condition monitoring

The Rigsentry condition monitoring system is a comprehensive system designed to transmit real-time data to shore, reporting on system status and algorithmically predicting failures rather than reacting to them. The system is in use as part of a BOP monitoring system that focuses on the subsea BOP and its associated controls to reduce the total cost of ownership. Data have long been understood to hold the key to system performance, component improvement and long-term maintenance planning. However, the single largest hurdle in the use of these data has been getting relevant information to shore so the data analysts can act on it. The new system addresses this deficiency by putting real-time, actionable data at the operator's fingertips via an interactive dashboard (Figure 2).

The level of monitoring is effectively broken down into two service categories. The standard offering provides actionable insight that converts BOP control system data into a secured protocol for transmittal to shore when communications from the rig are possible and buffered for future transmittal when not possible. The system collects and stores data in NOV's secure cloud-based data platform and can be accessed through a web portal by data scientists, company representatives and third parties as allowed by the customer.

Current system status can be observed using a cell phone, tablet or PC while analog tags, event reports and alarms can be viewed through the live connection. Smart notifications inform relevant rig personnel, including onshore representatives, of maintenance requirements, alarms and system status.

Reports can be configured and periodically run to compare data with historical trends. This has proven valuable to operators in assisting offshore personnel in timely and accurate system repairs. Ultimately, use of the system ensures that a field technician is never without critical issue support from onshore experts.

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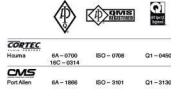




FIGURE 2. The Rigsentry BOP monitoring system provides critical equipment information in real time to predict failures. (Source: NOV)

The second level of monitoring transforms the initial BOP insight into prediction, affording operators the opportunity to predict failures using prognostic analytics. Multiple models have been created to enable computers and data scientists to mine live data for known deviations from a healthy system that would indicate future failure.

For example, by using the high-pressure supply regulator model, the system conducts an examination of minute pressure changes to identify weak components prior to failure. As they are constantly in use during drilling operations, regulators are often the culprit of BOP failure. Previous solutions were reactive rather than proactive, identifying issues only after operations were already compromised; in normal operation, an offshore technician could identify an issue prior to full failure but nearing failure mode.

The system allows data scientists to mine historical data to identify potential failure modes and assist engineering with product improvements. Prior to the era of Big Data, product improvements were limited to only the most critical failures found offshore and reported back to the original equipment manufacturer.

System stability will continue to improve as more data are received and analyzed. The regulator model—using more than a decade of historical data with 6 billion datapoints—can identify a pending regulator failure several weeks prior to the potentially catastrophic event. Operators using this system can effectively use planned downtime to diagnose and address at-risk components, to streamline between-well maintenance so that rigs can remain active without long periods of downtime, and to prevent unnecessary BOP stack pulls.

Additional predictive models, such as leak detection and operation modes that create risk to the system, are under development.

During a predictive event, a smart notification is sent to those contacts identified by the customer for notification of a potential issue. Engaging the rig crew well in advance of a failure can significantly reduce the risk to operations and personnel. It is critical that the industry works together to continue improving safety, reducing operation costs and embracing digitalization. **ESP**



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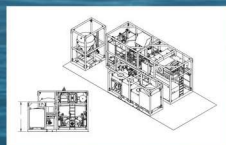
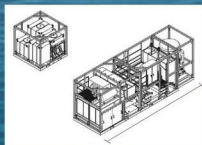
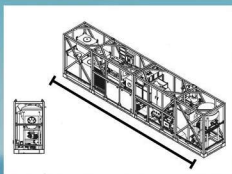
There are many factors considered when designing offshore facility layouts. Fixed minimum separation distances between pieces of equipment are at a minimum, putting extra demand on considerations such as safety, along with ease of access to the equipment. These challenges are made even more complex when considering things such as the relative processes between equipment, the timing in which different pieces of equipment are available for installation, and more.

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Augmenting well control

A new active control device design eliminates the need for conventional rotating control devices in deepwater applications.

**Austin Johnson, Brian Piccolo, Henry Pinkstone,
Justin Fraczek and Bo Anderson, AFGlobal**

Well control in deepwater drilling operations often is overmatched. In this challenging environment, a wellbore influx sets in motion a decades-old and increasingly insufficient response that has its roots in much more benign applications.

Experience makes it apparent that drilling from floating rigs in deeper waters and unpredictable pressure regimes too frequently exceeds the basis of conventional well control philosophy. That line is clearly defined by a litany of risks, including large kicks, stuck pipe and riser gas, and their contribution to greater safety concerns and higher nonproductive time and project costs.

These limitations are addressed by augmenting conventional deepwater well control with applied sur-

face backpressure-managed pressure drilling (ASBP-MPD). The use of this methodology redefines the primary well barrier to include a closed circulating system with the capability to dynamically and rapidly control wellbore pressure. Implementation favorably resolves many conventional well control limitations with new capabilities such as rapid kick detection and response and the ability to safely circulate an influx out of the wellbore and riser.

An open and closed case

In conventional well control, the subsea BOP (SSBOP) is closed once the rig crew has confirmed that an influx has been taken. This is a proven response in standard drilling operations, but up against unique deepwater demands, its slower execution, imprecision and mechanical limitations are proving to be less effective.

When an influx is detected or suspected, the first step is to stop rotating the drillpipe, pick up off bottom and space out tool joints relative to the SSBOP rams. Mud pumps are then stopped in advance of a static flow check. The result is a loss in time and a significant reduction in bottomhole pressure (BHP), which brings the well further underbalanced and, in a step backward, increases the influx volume.

The static flow check to determine if the well is flowing takes critical time and must consider masking factors such as vessel motion and wellbore breathing. Meanwhile the wellbore remains open to the atmosphere and risk increases.

This is all a prelude to actually securing the well and stopping the influx by closing the SSBOP. And with it closed, other concerns arise. As cuttings settle they threaten costly stuck-pipe events, and circulating through a small inside diameter (ID) choke line results in wellbore backpressure that can cause lost circulation. Furthermore, if an influx is large enough to exceed kick tolerance, closing

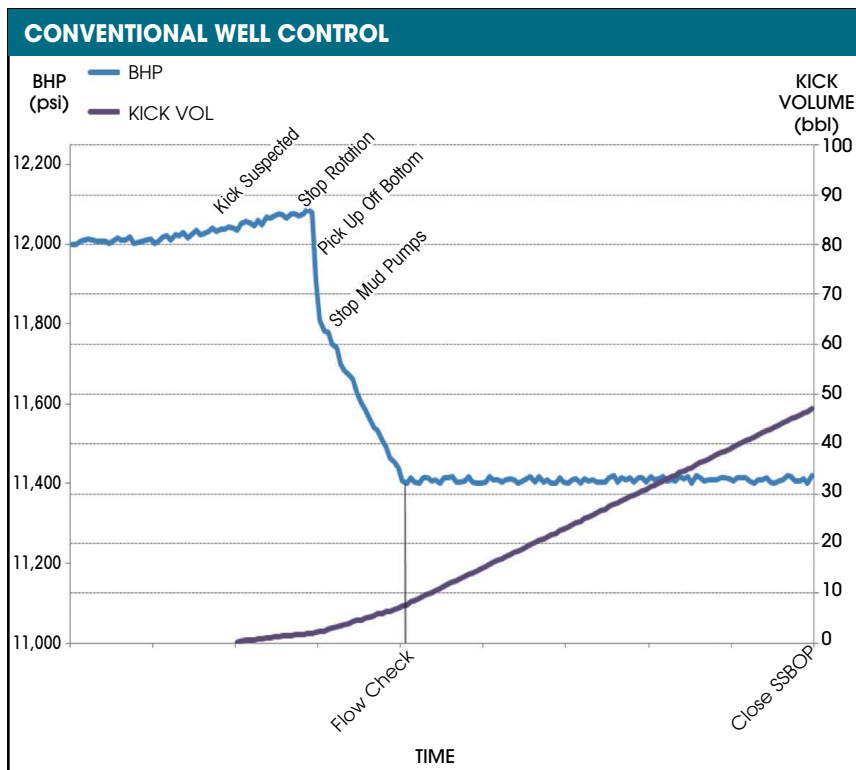


FIGURE 1. Conventional well control can cause a significant drop in BHP and increased influx volume before the well is secured. (Source: AFGlobal)

the SSBOP does not stop the influx. In this case, an exposed, weaker formation becomes fractured, enabling hydrocarbons to continuously displace drilling mud from the wellbore. Riser gas also is a threat as an influx dissolved in oil-based or synthetic mud systems comes out of solution above the closed SSBOP (Figure 1).

Riser gas is a unique deepwater threat. With increased water depth comes a longer riser and higher hydrostatic pressure. In these circumstances, with an oil-based or synthetic mud in the hole, a hydrocarbon influx at formation depth may not break out of solution until it is circulated undetected above the SSBOP.

The high-intensity outcome is a riser unloading event that discharges mud and gas through the rotary table with little prior warning. In low-intensity events, the diverter packer may be closed in time to divert mud overboard, which may create an environmental event.

MPD system

ASBP-MPD equipment and processes resolve these conventional well control limitations by enhancing the primary hydrostatic barrier with rapid, accurate wellbore pressure control. This is achieved by integrating an assembly of drilling chokes, flow-in and flow-out measurement and a continuously sealed wellbore and riser with the rig's system (Figure 2).

Flow within this closed system begins when the subsea MPD riser sealing system or MPD riser annular diverts flow to the topside MPD equipment via a subsea flow spool and mud return hoses. A distribution manifold at the surface directs riser flow to a MPD manifold, which consists of drilling chokes and Coriolis meters. Returns are processed through a dedicated MPD mud gas separator or the rig's mud gas separator and ultimately routed to the shakers. Coriolis meters installed upstream of the rig pumps measure fluid flow rate and density into the well.

One form of a MPD riser sealing system is an active control device, which forms a wellbore seal around the drill-pipe to establish a closed system and divert riser flow to the surface MPD manifold. The closed system enables

dynamic adjustments to wellbore pressure, accurate flow-rate measurement and safer mud gas separation.

AFGlobal's active control device technology eliminates rotating components, energizes dual spherical BOP packers to close on a dual-seal element assembly, forming a wellbore seal. As the seal elements wear, hydraulic closing pressure on the annular packers actively adjust to maintain wellbore sealing integrity. The active control device also enables condition-based monitoring of the seal elements.

During routine replacement of a worn seal element assembly, wellbore pressure is trapped with the MPD riser annular BOP. Closing it continues to direct flow to topside MPD equipment. A flow spool installed directly below the MPD annular and MPD sealing system provides a redundant flow path for drilling returns. A distribution manifold directs return flow to the MPD manifold. It also provides overpressure relief protection, enables mud cap drilling technology and provides a tie-in for glycol/methanol injection.

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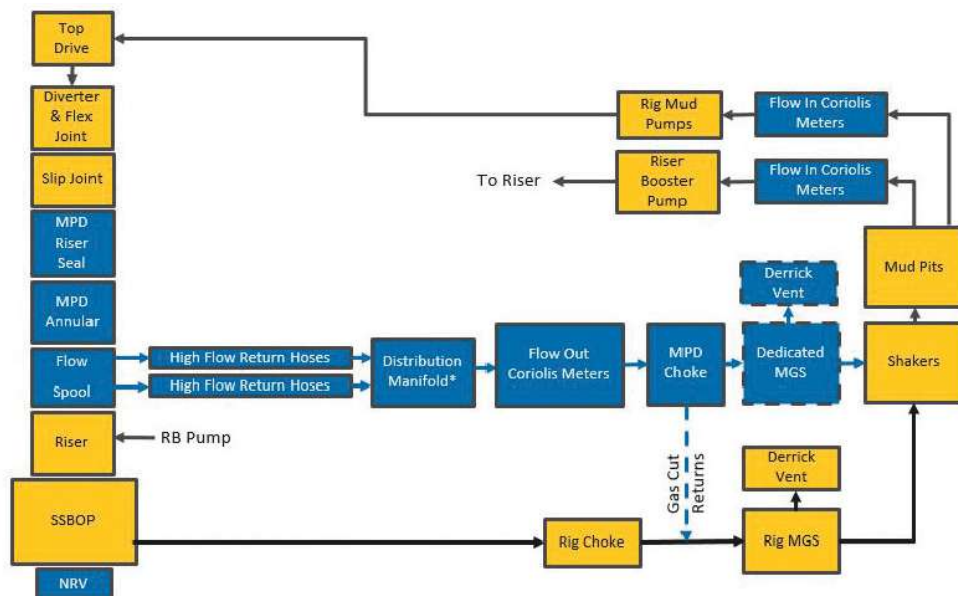


FIGURE 2. The ASBP-MPD system is part of the primary barrier, which is now defined to reflect dynamic pressure control capability within a closed system. (Source: AFGlobal)

The MPD manifold enables pressure control and measures flow from the well. Constant wellbore pressure is maintained with choke controls that use algorithms and hydraulic modeling software. The Coriolis meters installed upstream of each mud pump accurately monitor flow rate and density into the well. These data are used to quickly determine if a change in outflow or density is due to rig activity or wellbore influx.

Small gas influxes are handled using either a dedicated MPD mud gas separator or the rig's well control separator. A FEED study must be conducted to assess and plan MPD operations within the limits of this component.

Drilling returns flow through high flow-rate hoses between the MPD riser flow spool and the topside distribution manifold. The large ID hoses are rated for multiphase flow and are specified to reduce frictional pressure loss.

Deepwater advantages

The key deepwater advantages of an ASBP-MPD system are confident, early kick detection and a rapid influx response, which lead to smaller influx volumes and the possibility to circulate an influx out of the well without shutting in the SSBOP.

An influx controlled within the primary well barrier may be safely circulated out of the wellbore without prematurely resorting to secondary well control. As such, a MPD influx circulation avoids excessive choke line friction and reduces the risk of stuck pipe by enabling circulation at higher flow rates and the ability to rotate

and reciprocate the drillstring. Wear on the SSBOP from unnecessary use also is reduced.

Furthermore, kick detection and response are fast and accurate. Influxes are detected in gallons instead of barrels, and confidence is high enough to eliminate a static flow check. On detection, surface backpressure can be applied immediately in contrast to the lengthy conventional well control process. The riser is already sealed to protect against sudden riser unloading events.

Confident rapid kick detection is made possible by accurate measurement of inflow and outflow of the closed system. The use of Coriolis flowmeters and isolating outflow measurements

from vessel heave helps reduce influx size and the reliance on a static flow check. Isolation is achieved by locating the MPD riser seal below the riser slip joint. Meters installed upstream of the pumps and on the downstream side provide direct measurements of the fluid flow rate and density to enable mass balance control.

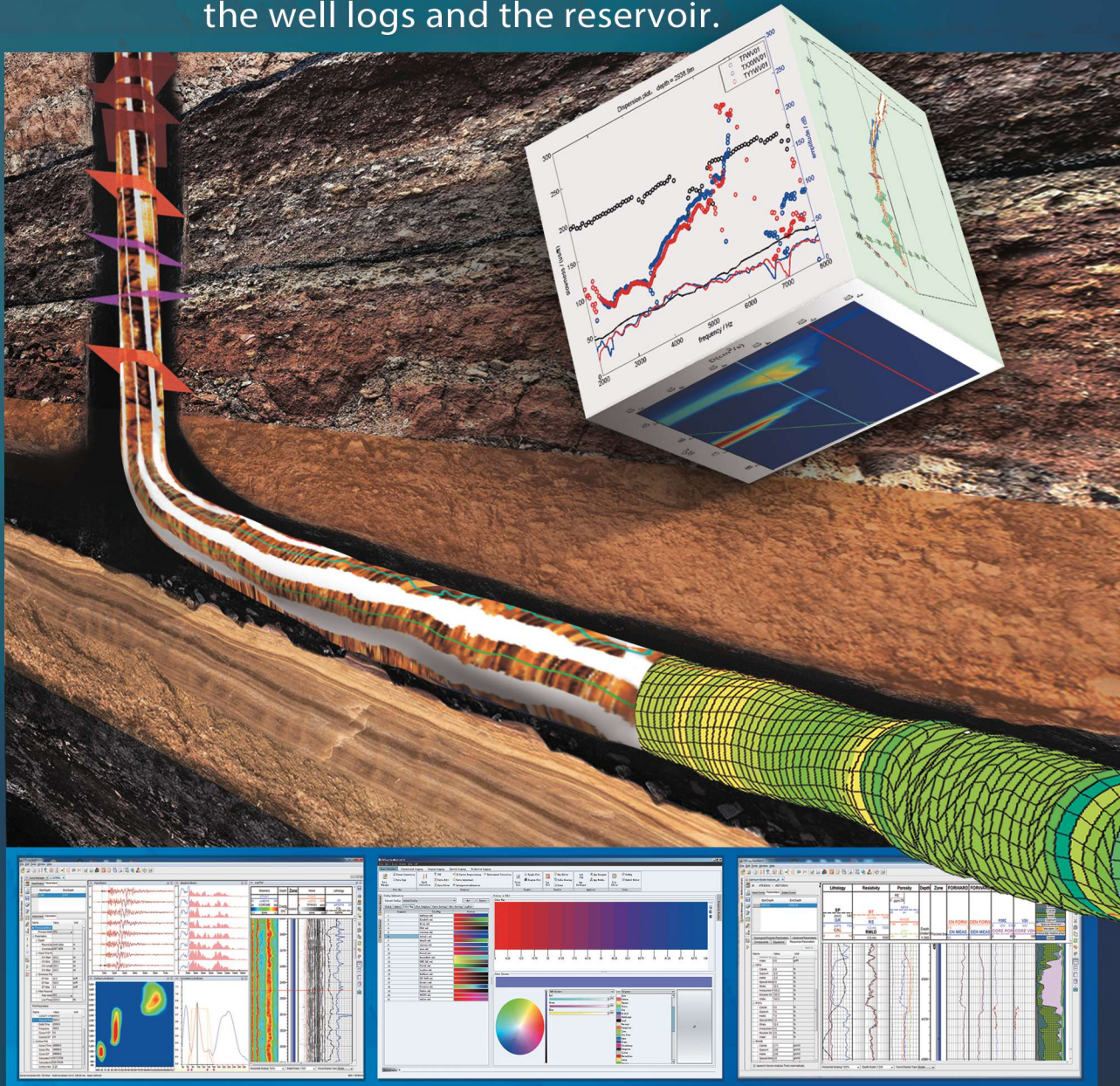
In-hole sections where the MPD sealing system is inactive, the riser annular also may be used to augment well control.

Kick detection remains conventional, but once the riser annular is closed, an influx can be controlled and circulated from the well through the topside MPD equipment instead of resorting to the secondary barrier. This mitigates excessive choke line friction and stuck pipe and allows low-intensity riser gas events to be addressed without diverting overboard. However, the most secure way to protect against sudden high-intensity riser unloading events is to drill with the MPD riser sealing system providing a continuous seal.

It should be noted that any use of the MPD system for influx management is done so within agreed upon engineering and operational limits. Such limits may be updated for the worst-case scenario in each hole section. In the event that these limits are exceeded, control of the influx is turned over to the secondary well control as always done in the past. A highly structured communication plan also is created to ensure a smooth transition between primary and secondary well control. **ESP**

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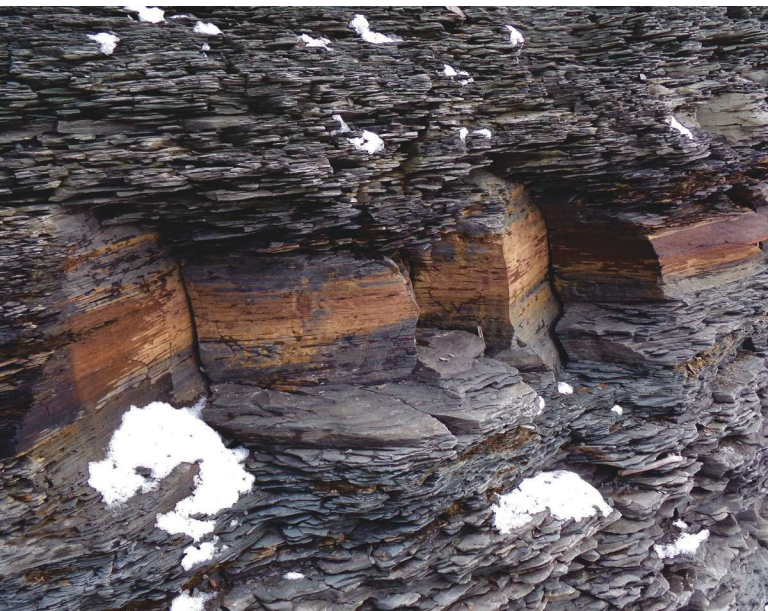
Going global

Recent activities point to increasing unconventional resource development outside of North America.

Jennifer Presley, Executive Editor

If one were to write a musical about the revolution in unconventional resource development, it would be more “Oklahoma” than “Les Misérables” in that the majority of the resource development activity has occurred on U.S. and Canadian lands. With an all-star cast of high-performing players, starting with the Shale Boys led by Barnett and his brother Haynesville, a technology wildfire has blazed across the land and upset the global marketplace for more than a decade. There is seldom a day that goes by without some mention of the Permian Basin twins—Delaware and Midland—or the two-headed “Beast from the East” known as the Marcellus-Utica in the news or on the lips of interested investors.

However, while hydraulic fracturing was born in the U.S., neither the technology nor the shale and tight resources are exclusive to North America. Global efforts to develop shale and tight resources have been underway for several years, and with success stories coming from exotic locales in South America, the



Shale knows no regional boundary lines, ensuring that all countries can benefit from it. (Source: Dana283/Shutterstock.com)

Middle East and U.K., the cast of characters appears to be rapidly growing.

Argentina

Activity in Argentina’s Vaca Muerta, long considered the next greatest shale resource outside of the U.S., is picking up. The country’s state-owned oil company, YPF SA, expects shale oil and gas production to grow 35% as costs in the play continue to fall, according to Daniel Gonzalez, the company’s CFO, as reported in a recent article from Reuters.

The company has plans to drill 100 wells in 12 different areas of Vaca Muerta this year, after drilling costs for horizontal wells fell to \$1,390 per lateral foot in the fourth quarter 2017 compared with \$2,270 in 2016 and \$3,050 in 2015, according to the article.

In February the company announced the ratification of Phase 3 of the Bitter Girl pilot project with its partner in the project, Petronas. Phase 3 was made possible due to the good results realized in the first two phases of this joint development of the La Amarga Chica area. Located in the Neuquén Basin, the area is characterized by its richness and potential in shale oil, according to a press release. Planned activities for this final phase could include the drilling of 10 horizontal wells and the construction of new works and facilities to transport the production of shale oil that is obtained in the area, the release said. With a joint investment commitment of \$192.5 million, the phase is planned to end in the third quarter.

Middle East

The Abu Dhabi National Oil Co. (ADNOC) announced the details of its first-ever block licensing strategy that includes six geographical oil and gas blocks open for bidding in the initial round, according to an April press release. The strategy represents a major advance in how Abu Dhabi unlocks new opportunities and maximizes value from its hydrocarbon resources, according to the company.

“The launch of these large new licensing blocks is an important step for Abu Dhabi and ADNOC as we develop and apply new strategies to realize the full potential of our resources, maximize value through

competitive bidding and accelerate the exploration and development of new commercial opportunities,” said His Excellency Dr. Sultan Ahmed Al Jaber, United Arab Emirates minister of state and ADNOC Group CEO in the release.

In addition to the country’s conventional oil and gas accumulations, some of the offered blocks also contain significant unconventional resource potential. Four of the six blocks open for bidding are onshore, with the total area of the six blocks comprising about 30,000 sq km (11,583 sq miles). Registration is open to companies with expertise and technology in developing conventional and unconventional hydrocarbons.

Bahrain announced in early April the discovery of its largest oil field since 1932. This new resource is estimated to contain at least 80 Bbbl of tight oil, as reported in a recent article by Reuters.

“Initial analysis demonstrates the find is at substantial levels, capable of supporting the long-term extraction of tight oil and deep gas,” Bahrain’s Minister of Oil Sheikh Mohammed bin Khalifa Al-Khalifa said in a statement to Reuters.

The tight oil and gas resource was discovered in the offshore Khalij al-Bahrain Basin, which spans some 2,000 sq km (770 sq miles) in shallow waters off the country’s western coast. The field also contains an estimated 396.4 Bcm (14 Tcf) of gas, according to an Associated Press report.

UK

Cuadrilla Resources announced in early April that drilling for the country’s first horizontal shale gas well had been completed successfully at its Preston New Road site in Lancashire. The well was drilled through the Lower Bowland shale at a depth of 2,700 m (8,858 ft) and extends laterally for about 800 m (2,625 ft), according to a press release.

Work on a second horizontal well through the Upper Bowland Shale has commenced at the site. Approval has been granted for drilling of up to four horizontal wells at the site. Next steps, according to the release, are to apply for consent to fracture the first well, with the company planning to fracture both wells in the third quarter.

Core and test data taken from the vertical pilot well drilled through the two shale members confirmed that the formation has a low overall clay content and is “very well suited to hydraulic fracturing,” the press release said.

Plans call to perform an initial flow test of both wells after fracturing for six months. Upon completion of the test, the company plans to connect the two wells to the local gas grid network in 2019, according to the release. **ESP**

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Scientific report may open road for hydraulic fracturing in Australia

Inquiry finds that hydraulic fracturing could be safely managed in the Northern Territory.

Dale Granger, Contributing Editor

The Australian Petroleum Production & Exploration Association (APPEA) has welcomed the results of a scientific inquiry into hydraulic fracturing that finds it could be safely managed in the Northern Territory (NT).

The peak Australian oil and gas body said the report, which resulted in a similar conclusion to the draft report that any risk associated with onshore gas development and hydraulic fracturing in the NT could be managed by effective regulation, should encourage the government to immediately lift the moratorium on hydraulic fracturing in the state.

Matthew Doman, APPEA's director for South Australia and the NT, said the conclusion of the 15-month inquiry meant the NT government must make a decision swiftly to "give certainty to investors, local businesses, traditional owners, landholders and all Territorians."

"The final report confirms that developing the Territory's natural gas resources would have significant economic and employment benefits for the NT," Doman said. "It has debunked many of the myths spread by activists opposed to onshore gas development."

While APPEA argued against the need for yet another inquiry into hydraulic fracturing, the inquiry has enabled genuine questions in the community to be addressed in an independent and expert manner, according to Doman.

APPEA said the conclusion reached in the report confirmed the findings of numerous other scientific inquiries and reviews that any risks associated with hydraulic fracturing can be minimized or eliminated with proper regulation.

"The report makes 135 recommendations, which will need to be considered carefully," Doman said.

"Some of these recommendations go beyond the terms of reference to matters of national policy and would be impossible for the NT government to implement, as the report itself acknowledges," he continued. "APPEA's member companies stand ready to invest billions of dollars in new projects in the Territory if the industry is allowed to resume exploration activity. There is no reason the Territory cannot



Australia's NT has a potential gas resource of 7.3 Tcm, greater than Australia's entire identified conventional gas resources.

(Source: TRossJones/Shutterstock.com)

manage the safe, sustainable development of its considerable natural gas resources."

Last year Santos CEO Kevin Gallagher called on Australia to take its cue from the U.S. by lifting onshore exploration and development bans in Victoria and New South Wales and the hydraulic fracturing moratorium in the NT.

Gallagher said the NT's potential gas resource of 7.3 Tcm (260 Tcf) was greater than Australia's entire identified conventional gas resources and big enough to expand the Darwin LNG project and supply the gas-famished East Coast.

"To look at the potential benefits of a thriving natural gas industry in the Northern Territory, you don't have to look farther than the U.S.," he added.

Gallagher said gas was boosting the U.S. economy by supplying nearly half of all power capacity in a country where electricity prices had dropped to about 30% of the \$100/MW it costs in the Australian state of Victoria and 17% of the \$150 charge in South Australia.

In addition, Gallagher said the U.S. had cut energy-related carbon emissions by 21% since 2005, a reduction of 400 million tonnes of emissions every year.

"All of this has been as a result of the U.S. government being pro-gas and pro-development," Gallagher said. "By contrast what we are experiencing here in Australia has resulted from a series of moratoriums and restrictions to new developments, limiting new supply." **ESP**



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Maximizing well potential

Operators gain production control and increase flow assurance through sand monitoring.

Jan Olaf Gomnaes, Emerson Automation Solutions

As profit margins remain tight, it has become essential for operators to deploy cost-effective, flexible and innovative solutions to ensure that wells perform to their full potential, production goals are met and that there is economic and seamless delivery of hydrocarbons from reservoir to refinery.

Yet, flow assurance is dependent on a broad variety of factors from reservoir fluid properties to hydrate buildup to scale and heavy oil. One of the main obstacles for flow assurance is the presence of sand, and several technological innovations address this challenge.

Threat of sand

Sand remains a major threat to oil and gas flow assurance. Erosion from produced sand can have a signifi-

cant impact: damaging production wells, pipelines and flowlines; eroding completion components; and impeding wellbore access.

Furthermore, sand also can interfere with the separation of oil and water and—if such sand particles become entrained—may even cause further erosive and production damage when water is reinjected into the reservoir.

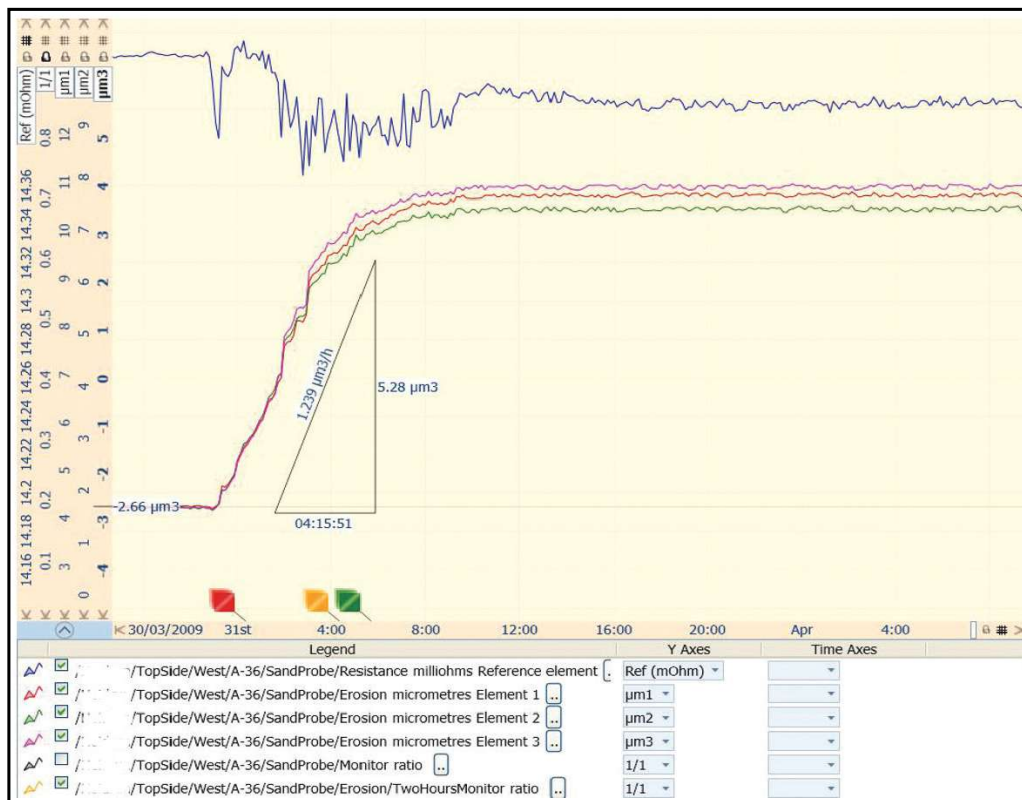
It is estimated that more than half of all existing wells will require sand control throughout their lifetimes. Aging oil and gas assets and the increased complexity of deepwater wells with higher fluid velocities both increase the likelihood of the presence of sand.

Although it was previously deemed acceptable to limit well production to avoid the potential for sand contamination, the rising water production and increased pressures to optimize recovery have established conditions where the presence of sand is often the norm.

Electrical resistance and acoustics

Whereas previously flow rates, water cuts, pressure drops and temperature distributions were used as an approximate guide to sand production, technology innovations over the past few years in electrical resistance and acoustics have led to a more immediate and detailed insight into sand.

Erosion-based intrusive sensors measure actual metal loss caused by the impact of sand particles. Many are based on the electrical resistance principle, where metal loss on the element is measured as increased electrical resistance in a sensing element exposed to sand erosion. Sand production rates can then be quantified by



This chart features data collected from both a sand erosion probe and acoustic detector operating together. (Source: Emerson Automation Solutions)



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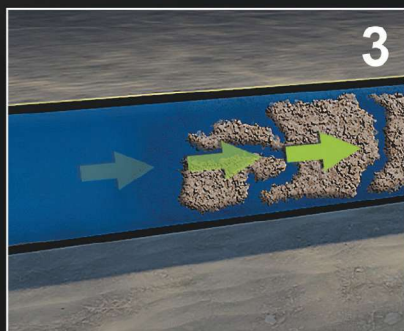
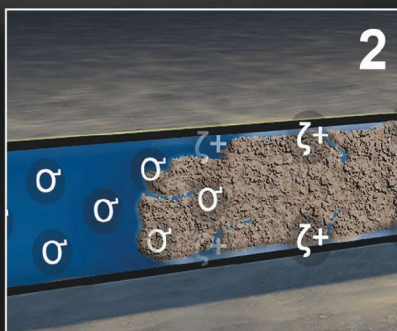
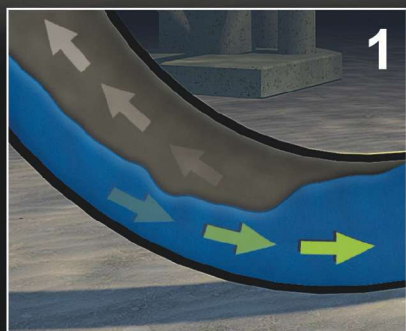
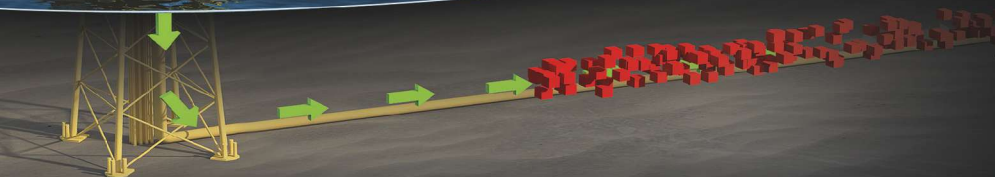
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combining measured metal loss rates with average sand particle size and flow data.

In one example, Emerson's in-line sand erosion probes measured metal loss during an unexpected sand burst at a North Sea oil and gas platform. Sand bursts can be complex and unpredictable events with a significant potential impact on flow assurance and the operational effectiveness of the well.

In this case, the burst was detected almost immediately when a sand probe registered a metal loss of 50 nanometers, triggering an alarm and a prompt adjustment of production rates to a level where sand production stopped. Within 4 hours the sand incident was mitigated, the well was saved, and flow assurance and production continued. Total metal loss during the period was 5 μm .

Acoustic-based nonintrusive sensors monitor the noise caused when sand particles impact on the pipe wall. Such sensors utilize the acoustic energy generated by sand particles to calculate sand production in multiphase pipeline flows, with sand quantification often measured in grams per second.

However, both in-line electrical resistance erosion sensors and nonintrusive ultrasonic, acoustic sensors are all the more effective when combined where they can confirm the occurrence and severity of a sand event and give operators the necessary confidence to make the right production decisions. The technologies have different benefits as well. In providing an immediate response to the onset of sand production, acoustic sensors are well-suited to production optimization programs and the need to estimate maximum sand-free production rates.

Sand erosion-based sensors, on the other hand, are able to accurately determine the short- and long-term effects of damage caused by sand with a wider coverage of sand distribution inside the flowline. Both systems also quantify the amount of sand produced when flow velocity information is provided as an input.

In addition to the North Sea, Emerson's acoustic and erosion-based sand monitoring sensors are being used on key deepwater fields such as Petrobras' Cascade and Chinook fields in the Gulf of Mexico. In these cases, the sand sensors are working alongside multiphase meters and pressure and temperature sensor systems to minimize erosion damage, optimize production flow rates and secure flow assurance.

It is the ability of sand monitors to work alongside other instrumentation that has ensured sand instrumentation forms an important element in protecting flow assurance. This is facilitated by a scalable and distrib-

uted software architecture—in Emerson's case, Roxar Fieldwatch—that distributes detailed data from subsea instrumentation for efficient online analysis, condition monitoring and flow assurance.

One example of Roxar Fieldwatch in action is the Heidrun Field, operated by Statoil, where there was a need to increase the field's sand monitoring capabilities to allow the maximum amount of sand without affecting production and flow assurance requirements. The software also would enable Statoil to meet the challenges of increased water content and more gas (more sand and higher velocities).

A new sand management module was developed jointly between Statoil and Emerson for the field. The software enabled Statoil to respond faster to changes in sand production conditions, thus allowing Statoil to secure control of significant sand production from a well and establish maximum acceptable sand rates for production optimization and flow assurance.

Growth in wireless technology

The growth in automated and, in some cases, unmanned platforms also has changed the parameters for flow assurance solutions with a growth in wireless-based and automated instrumentation. Wireless technology significantly reduces installation costs compared to wired online systems and enables monitoring in previously inaccessible areas.

It is for this reason that Emerson has developed topside corrosion and sand erosion wireless transmitters based on intrusive sensors installed into pipes or vessels. The transmitters can be directly integrated within WirelessHART networks, a wireless sensor networking technology, to provide a complete asset integrity management and flow assurance system for operators.

In addition, ultrasonic instruments—wireless devices that measure wall thickness by looking at the time it takes an ultrasonic pulse to travel through the metal—also can operate alongside other sand monitoring sensors. Ultrasonic instruments are a valuable topside integrity confirmation tool in a full flow assurance solution.

One recent sand erosion wireless monitoring deployment was with integrity management specialist Stork on a North Sea platform, where the wireless devices helped extend equipment life, increase production and protect flow assurance.

Flow assurance strategies are all about negating production threats, providing an insight into operations and maximizing production. Sand monitoring and management technologies are doing just that. **ESP**

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Getting the wax out

Water-based PPD dispersion helps tackle deposit challenges in cold regions.

Zongming Xiu, Solvay

As crude oil comes to the surface and exits a well, it cools down, generally causing the wax components of the crude to gel. The gelled crude chokes the well, leading to restricted or blocked production and costly downtime for operators. One of the most common chemical solutions to address the wax deposit challenge is the application of wax inhibitors or pour point depressants (PPDs) to the production stream.

Most of the PPDs used in the field are organic solvent-based. To maintain a stable, free-flowing formulation at very low temperatures, these PPDs need to be heavily diluted down to about 2% to 5%. The solvents of choice quite often are large quantities of toxic organic solvents such as aromatic solvents (e.g., xylene, toluene or methanol). If the proper solvent is not used or the activity of the formulation is too high, the PPD will gel, becoming extremely difficult to handle and dose efficiently. The application of a large amount of solvent is not cost-effective and poses threats to the environment, storage facilities and the safety of the personnel handling the materials.

Qualifying PPD use

To address this challenge, Solvay developed a water-based PPD dispersion system centered on the company's polymerization technology. This technology is a specifically designed amphiphilic polymer that is synthesized with a hydrophilic polymeric head group and hydrophobic tail. The molecular weight and, specifically, the architecture and particle size of this polymer can be controlled, creating a unique and stable dispersion. This synthesized product can maintain high activity (15% to 30% or higher) and remain pumpable even under -40 C (-40 F) after properly formulating the polymer with a mutual solvent and wetting or dispersing surfactant. Generally, the viscosity of the PPD, at 40% activity, is between 200 cp and 250 cp at room temperature with a milky color.

There are four common standards for which to qualify a PPD for use. The first is that the product must be thermally stable. Solvay's water-based PPD is stable up to 200 C (392 F) under 500 psi tested by a Chandler Viscometer 5550. Second, the material should be environmentally friendly. The PPD is dispersed in water or a water-mutual solvent package, which replaces the need for the application of toxic solvents. The third standard

is the viscosity of the formulation at -40 C. Solvay's PPD has a pour point of -30 C (-22 F) at 40% activity and can be formulated to be pumpable under -40 C. Finally, the flash point of the material must be considered as both a concentrate and a formulated product. This PPD is not hazardous in this aspect since it is dispersed in water and/or a high flash solvent.

PPD testing

Once the four standards are met, the deposit control and pour point reduction performance is examined. The performance of Solvay's first-generation water-based PPD dispersion was evaluated using several crude oils from West Texas. This first-generation PPD was compared to some commonly used solvent-based PPDs, and the results showed that the Solvay PPD significantly reduced crude oil wax deposition by nearly 70% and

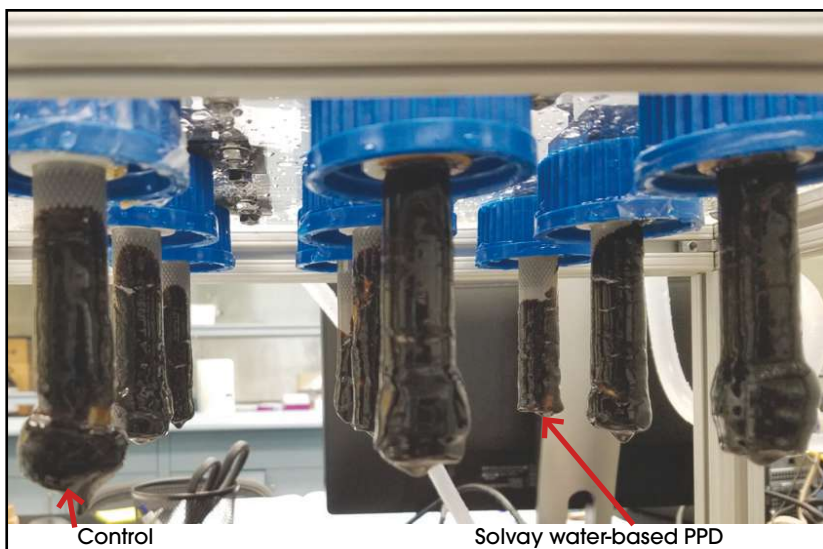


FIGURE 1. In a cold-finger test of West Texas crude oil, use of Solvay's water-based PPD led to much better wax deposit control than the control sample or competitive PPDs. (Source: Solvay)

reduced the pour point of the crude by 18 C (64.4 F). The deposit control performance was evaluated using a standard cold-finger apparatus, and the pour point reduction was tested using a PSL Systemtechnik GmbH pour point tester (Figure 1).

It is well-known that PPD performance is crude-specific. To make an accurate comparison, a model crude oil is blended following a published recipe. The model crude oil comprised a mixture of paraffin waxes (from Sigma Aldrich) dispersed in a low molecular weight hydrocarbon such as decane, dodecane and tetradecane. The low molecular weight hydrocarbon was used as a solvent for the wax and to aid differentiation of the fractions by gas chromatography if required.

The mixture of paraffins (5%) was added to the solvents. The performance attributes of the aqueous polymer dispersions and commercial wax inhibitor/PPD polymers were screened by adding them to samples of 5% weight to volume paraffin wax in aliphatic hydrocarbon. The polymers were dosed at 500 ppm (as active), respectively. The samples were mixed thoroughly and stored at 85 C (185 F) (above the wax appearance temperature) for 1 to 2 hours to eliminate the thermal history of the samples before cooling overnight in a refrigerator at 0 C to 5 C (32 F to 41 F).

The appearance of the samples was noted after removal from the refrigerator and assessed using a polarized light microscope with camera attachment.

The microscope was set at 100x magnification (Figure 2), and the textures observed were viewed either with crossed polarizers or crossed polarizers and mica filter ($1/4 \lambda$ test plate). Images of the textures were taken using a digital camera and processed using image capture software (Figure 2). The model crude oil gelled up and formed a large amount orthorhombic or needle-shaped (bayonet) crystals (10 μ m to 30 μ m). The competitive PPD inhibited the formation of large wax crystals, but the size of the wax crystal (about 10 μ m) is much larger than that in the water-based PPD disper-

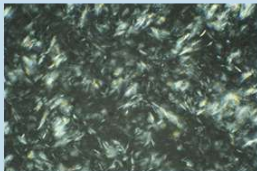
Formulation	Appearance at 0 C	Wax morphology (100x magnification)
Control (without wax inhibitor)		 Orthorhombic or needle-shaped crystals (10 - 30 μ m)
500 ppm competitor PPD dispersion		 Wax crystals ~ 10 μ m
500 ppm Solvay water-based PPD dispersion		 Small crystals ~ 1 - 5 μ m

FIGURE 2. This example tested the wax inhibition performance of the water-based PPD in simulated crude oil comparing other commercial PPD products observed by microscope. The simulated crude remained flowable with little wax crystals formed compared to competitor products. (Source: Solvay)

sion (about 1 μ m to 5 μ m). Also, the model crude oil has higher viscosity (not flowing as well) compared to the Solvay water-based PPD, indicating a much better performance of the Solvay water-based PPD.

Moreover, compared to the conventional organic PPD, Solvay's water-based PPD has an advantage in low-temperature applications. An example of a situation where Solvay's PPD dispersion will have an advantage is in its use in very cold climates. To be able to successfully apply a typical PPD in a cold environment, the PPD would have to be heavily diluted to about 2% to 5% active, using xylene to maintain low viscosity so that it can be dosed into the well. The amount of active polymer actually applied is very limited, and much of the solvent added is wasted simply as a carrier. However, Solvay's water-based PPD dispersion can remain pumpable at 20% activity, a far greater active level than traditional PPDs and thereby increasing efficiency.

PPD and wax inhibition performance is certainly very crude-specific, as it depends on many particular parameters of the crude, including API gravity, light ends, asphaltenic content and carbon chain distribution to name a few. Solvay is developing a series of these polymeric water-based PPD dispersions to address the many different crude varieties, helping the industry tackle this important flow assurance challenge. **ESP**

Investing in spill response and containment

JIPs, new products and advanced research combine to improve spill prevention and oil recovery.

Judy Murray, Senior Contributing Editor, Offshore

The low oil price has intensified the industry's focus on improving oil recovery and reducing costs, but while these initiatives have been in the spotlight, somewhat in the shadows is a vital body of work that is advancing technology to improve operations by mitigating risk.

Over the past eight years, there has been considerable investment in spill response and containment technology development that has brought about significant advances. Out of these initiatives have emerged some noteworthy new products and some very interesting R&D efforts that are aimed at managing unplanned hydrocarbon discharges in new and exciting ways.

Operator advances

One notable program organized by the oil and gas industry to advance spill and containment technology

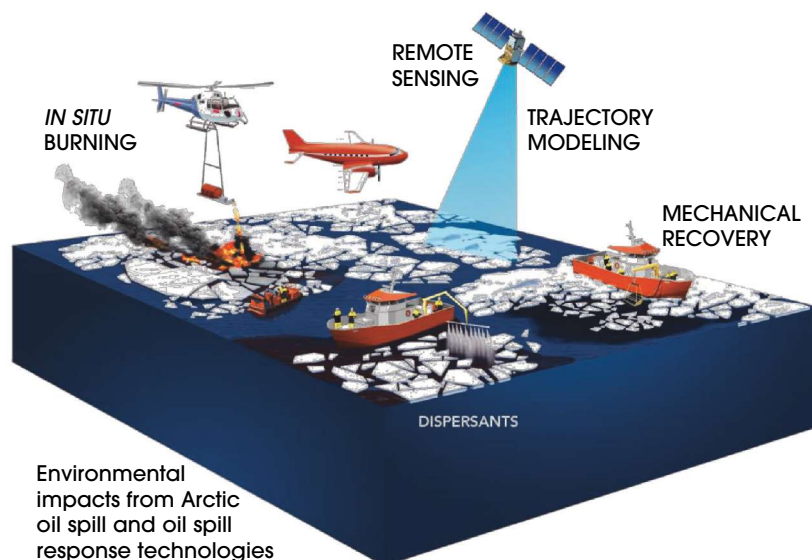
was the Arctic Oil Spill Response Technology Joint Industry Programme (JIP). Initiated in 2012 with the support of the International Association of Oil and Gas Producers (IOGP), the JIP brought together nine international oil and gas companies (BP, Chevron, ConocoPhillips, Eni, Exxon Mobil, North Caspian Operating Co., Shell, Statoil and Total) to advance oil spill response capability in Arctic regions. The focus was on six key areas: dispersants, *in situ* burning (ISB), mechanical recovery, environmental effects, trajectory modeling and remote sensing.

This JIP is described as the most extensive to date to focus on enhancing the available tools, extending their capabilities with new strategies and systems and providing a better understanding of operating windows for each tool. The overarching goal was to achieve a higher level of industry preparedness. This included not only developing a better understanding of the spill and containment options available but investing in training that will equip personnel with the knowledge and skills to respond quickly and effectively in the case of an incident.

Concluded in 2017, the JIP published a summary of the results of five years' work that included achievements in assessing and characterizing spill and containment tools and providing responders the flexibility to apply the most effective tools to control the source of a spill as rapidly as possible.

Work on dispersants included behavior assessment of dispersed oil in a range of Arctic offshore conditions. Oil type, dispersant type, water salinity, turbulent energy level and ice concentrations were tested in varying configurations, resulting in information that will improve future contingency plans and lead to better real-time responses based on scientific data that reflect how dispersants are likely to perform in different scenarios.

An evaluation of ISB options resulted in the development of a new integrated



The Arctic Oil Spill Response Technology JIP worked in six key areas: dispersants, ISB, mechanical recovery, environmental effects, trajectory modeling and remote sensing. (Source: Arctic Response Technology)

aerial delivery system for herding and burning slicks, expanding the application of herders to open water, evaluating potential herder toxicity and the creation of a new engineering concept for a higher capacity, longer-range aerial ignition system. According to the summary, this effort has introduced a new rapid-response capability independent of surface support, improved effectiveness in responding to unplanned releases in remote areas and provided greater confidence in the operational performance and environmental acceptability of herders.

The JIP also used results from laboratory and field tests along with modeling studies to improve understanding of oil frozen in ice, how microbiology reacts to oil in ice and what the exposure potential is to sea ice ecosystems. According to the summary, this work filled an important knowledge gap, demonstrating that there are no significant environmental effects on the sea ice ecosystem as a result of oil, oil mixed with dispersant or ISB residue frozen into the ice surface.

The group's trajectory modeling work centered on supporting development of high-resolution ice drift models that outperformed existing models in pack ice environments both in high-ice concentration areas and marginal ice zones. A significant step in making the new models available internationally was the insistence that ice model outputs be provided in internationally accepted data exchange formats. The result is that the two most commonly used behavior models can efficiently import data from a range of ice models to provide more accurate predictions of oiled ice movements in a range of ice conditions.

Remote sensing test programs undertaken by the JIP resulted in better understanding of relative sensor capabilities and their strengths and weaknesses in oil and ice situations above and below the ice. Collected data were used to create a first-of-its-kind graphical field guide that outlines 12 oil and ice scenarios, complementing work by others that summarizes best practices and available sensors for remote sensing in open water.

Interestingly, in assessing mechanical recovery options, the JIP concluded that substantial improvements through design and engineering were unlikely and that using technological advances in other fields could prove more beneficial.

New offerings

Some tangible results of spill containment and response efforts within the industry have emerged in the form of new tools entering the market. Among the newly introduced solutions is a subsea well capping technology, Offset Installation Equipment (OIE), that was launched



NorLense booms contain the spill and recover it onto a vessel with the Framo TransRec Oil Skimmer System. (Source: Framo AS)

in March by Oil Spill Response Ltd. (OSRL). The result of a joint effort among OSRL, Saipem and members of the Subsea Well Response Project (SWRP), the technology is designed specifically for scenarios where direct vertical access to a wellhead is not possible. The OIE enables well capping or related equipment to be installed quickly at a safe distance from a release or spill, considerably reducing the time it takes to cap a well or stop a critical blowout.

According to the company, this is a first for the oil and gas industry, introducing equipment that can be deployed up to 500 m (1,650 ft) from an incident site and can work at 75 m to 600 m (250 ft to 2,000 ft) water depth. OIE is fully compatible with OSRL's capping equipment, which creates an end-to-end capping and containment solution suitable for almost all subsea scenarios.

Each of the member organizations has trained, experienced personnel who understand the capabilities of the system and can operate the OIE during an incident. At the conclusion of the SWRP, the IOGP through its Well Experts Committee will work with OSRL to ensure stakeholders gain awareness of OIE's capabilities as part of promoting global adoption of good practices.

While OSRL is introducing its new technology, a group of Norwegian suppliers has organized the Oil Spill Recovery Vessel (OSRV) Group to offer spill response services. Participants Framo, Maritime Partner, Norbit Aptomar and NorLense have pooled their efforts to offer emergency response equipment comprising Norwegian-manufactured components that collectively deliver proven solutions.

In a press release publicizing the offering, OSRV explained the components: Aptomar's radar and infrared camera identifies and produces an overview of the oil slick, Maritime Partner's high-speed vessels pull



The Arctic Oil Spill Response Technology JIP brought together nine international oil and gas companies to advance oil spill response capability in sensitive Arctic regions. (Source: ggw/Shutterstock.com)

booms provided by NorLense into place, and the Framo TransRec Oil Skimmer System recovers the oil onto a vessel. One of the benefits of the OSRV is that any one of the partners can organize a complete turnkey solution.

An ounce of prevention

An interesting program at the University of Houston (UH) is looking for ways to predict when a drilling rig is at risk for a potentially catastrophic accident. In December 2017, UH announced that the National Academies of Sciences, Engineering and Medicine has provided a \$1.2 million grant for the project—one of six initiatives in the Gulf Research Program of the National Academies to develop new technologies, processes or procedures to improve the understanding and management of systemic risk in offshore oil and gas operations.

The particular focus of this research is gas kicks. A team of university researchers is working with the oil industry to develop new ways to develop ways to monitor the flow of gas and other hydrocarbons, applying fundamental science and engineering processes to predict when a catastrophic event might occur and to develop new methodologies to monitor the process.

The work will involve modeling using advanced computing to better understand what happens—and under what conditions—as gas moves up the drillpipe to determine how to predict when the gas buildup poses a danger.

Thinking outside the box

Additional research efforts are looking farther down the path, developing ways to recover oil if an incident cannot be prevented. For the most part, these are “academic” achievements at present, but they illustrate the scope of innovative thought and the potential value that

can be derived from looking at problem-solving from a different perspective.

One of these interesting technologies is a substance known colloquially as “frozen smoke,” a hazy blue aerogel. Developed in the U.S. nearly 90 years ago by a Stanford University researcher, aerogel is the world’s lightest solid. It is an open-celled material made up of more than 99.8% air, according to NASA. An Austin, Texas-based company called AeroClay LLC is using this same substance to create a low-density exceptionally absorbent material that can trap either oil or water, depending on its chemistry. Visionaries anticipate booms made with aerogel being used to absorb oil. An interesting characteristic of aerogel is that once the material is saturated, the absorbed oil can be extracted and reclaimed.

The Pennsylvania State University also has developed an absorbent polymer material that reportedly has demonstrated the ability to soak up 40 times its own weight in oil. The polyolefin-based petroleum superabsorbent, developed by a professor of materials science and engineering, was trademarked as Petrogel by Houston-based OsComp Systems Inc. (now Hicor Technologies), which owns the trademark and commercialization rights. In addition to being exceptionally oil-absorbing, Petrogel, like aerogel, can release absorbed hydrocarbons.

Meanwhile, researchers at the University of Michigan have developed a special filter coating that can strain oil out of water. While conventional surfaces absorb oil, this combination of polymer and nanoparticles creates a surface that repels oil and attracts water. To test the coating, researchers soaked small scraps of polyester in the coating solution and cured them with ultraviolet light before exposing them to multiple oil and water mixtures. The material functioned with 99.9% efficiency.

Innovation and invention

Technology has been an enabler for offshore oil and gas development and continues to be the foundation upon which the industry builds its future.

The efforts that have gone into spill prevention and containment have produced solutions and prospective solutions that have the potential to reduce the risk of unplanned hydrocarbon releases and mitigate the environmental effects of such releases by rapidly recovering oil that could otherwise damage sensitive ecosystems.

The willingness to look beyond what is possible today and to envision how nascent technologies might be applied to resolve offshore challenges will be a differentiator for the industry. **ESP**

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A special gala luncheon celebrating the selected honorees will be held February, 2019 in Houston.

All honorees will be profiled in a special report that will mail to *Oil and Gas Investor* subscribers in April, 2019.

The deadline for nominations is Friday, August 31, 2018.

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Brandon Seale
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President, Natural Gas &
Refining Division
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Laura D. Speake, Ph. D
Regional Chief Economist,
Energy & Transportation
Caterpillar Inc.

—ADDITIONAL SPEAKERS—

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Chief Commercial Officer
Frontier Energy Services LLC

Allan Roach
Senior Vice President-Global Strategy
Watco Companies LLC

Joseph R. Dancy
Executive Director, Oil & Gas,
Natural Resources, and Energy Center
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2018 MERITORIOUS AWARDS FOR ENGINEERING INNOVATION

An expert panel of judges has selected the top 14 industry projects that open new and better avenues to the complicated process of finding and producing hydrocarbons around the world.

The *E&P* editors and staff proudly present the winners of the 2018 Special Meritorious Awards for Engineering Innovation, which recognize service and operating companies for excellence and achievement in every segment of the upstream petroleum industry. The pages that follow highlight 14 winners, picked by an independent team of judges. The winning technologies represent a broad range of disciplines and address a number of challenges that pose roadblocks to efficient operations. Winners of each category are products that provided monumental changes in their sectors and represented techniques and technologies that are most likely to improve artificial lift, drillbits, drilling fluids/stimulation, drilling systems, exploration, formation evaluation, HSE, hydraulic fracturing/pressure pumping, intelligent systems and components, IOR/EOR/remediation, nonfracturing completions, onshore rigs, and subsea systems.

This year some of the brightest minds in the industry from service and operating companies entered exceptionally innovative products and technologies that have now been

measured against the world's best to be distinguished as the most groundbreaking in concept, design and application.

The awards program recognizes new products and technologies designed by people and companies who understand the need for newer, better and constantly changing technological innovation to appease the energy-hungry world.

The expert panel of judges comprised geologists, geophysicists, petrophysicists and engineers from operating and consulting companies worldwide. Each judge was assigned a category that best utilized his or her area of expertise. Judges whose companies have a business interest were excluded from participation.

E&P would like to thank these distinguished judges for their efforts in selecting the winners in this year's competition.

As in past years, *E&P* will present the 2018 awards at the Offshore Technology Conference in Houston.

An entry form for the 2019 Special Meritorious Awards for Engineering Innovation contest is available at EPmag.com/mea. The deadline for entries is Jan. 31, 2019. **ESP**

2018 MEA JUDGES

Ken Arnold
K Arnold Consulting Inc.

Allen Bertagne
BRT Energy Advisors

Ben Bloys
Chevron

George King
Apache

Mike Forrest
Consultant

Dick Ghiselin
Qittitut Consulting

Dave Johnston
Differential Seismic LLC

Bill Pike
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Peter Lovie
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Carl Montgomery
NSI Technologies

Nelson Oliveros
Petrofac, IES

John Thorogood
Drilling GC

Patrick Ryan
Chevron

Steve Sasanow
Knighton Enterprises Ltd.

Eve Sprunt
Consultant

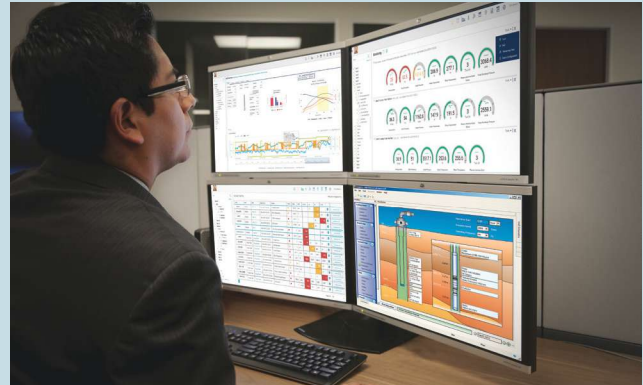
E. Lance Cole
Society of Exploration Geophysicists

**ARTIFICIAL LIFT WINNER**
SCHLUMBERGER | LIFT IQ

Schlumberger Lift IQ production management service transforms data into solutions by integrating 24/7 monitoring and surveillance with engineering analysis, identification of remedial actions and remote operations. The result is improved equipment uptime, lower operating costs and optimized productivity for a single well or an entire field.

Sensors and motor controllers at the well site transmit data to Artificial Lift Surveillance Centers (ALSCs). There, a software solution merges the data into one synchronized platform that integrates alarms, well and field performance indicators and downhole events. Using analytical tools embedded in the platform, dedicated surveillance engineers can conduct well system diagnostics in real time and optimize data to understand the reasons behind every event to take corrective steps. In addition, the service provides long-term monitoring and analysis and proactively manages pump operation for the production life cycle of the well.

Engineers monitor a dashboard of data to prevent or mitigate adverse events, diagnose probable causes and recommend remediation measures. ALSC engineers can use the data to correct discrete problems, update pump regimes to



Lift IQ service monitors well or field data to identify downhole problems, recommend solutions and optimize production.
(Source: Schlumberger)

match fluctuating conditions or identify underperforming wells that could benefit from further pump optimization.

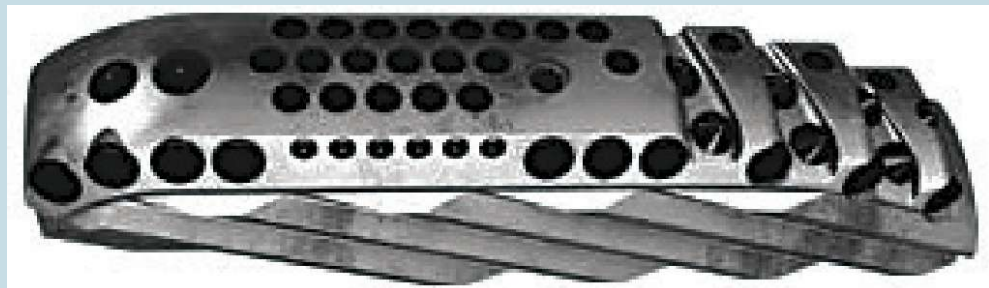
Operators can tailor the service to monitor hardware in a single well to proactively and remotely optimize operations and equipment across an entire field. ■

DRILLBITS WINNER
SCHLUMBERGER | STINGBLOCK

The StingBlock advanced stabilization conical element cutter block is designed to improve footage and ROP in drilling applications that pose a high risk of vibration to the bottomhole assembly and impact damage to conventional cutter blocks. The cutter block features a staged gauge pad for increased stability and Stinger conical diamond elements for enhanced impact resistance. Field tests have demonstrated up to a 29% increase in ROP and a 56% increase in footage compared with benchmark results in the Gulf of Mexico.

In high-impact and challenging applications, cutter blocks with a single gauge pad lack the necessary stabilization when encountering hard and interbedded formations. The increased area of the main gauge pad, coupled with the

additional staged gauge pads, uniformly distributes the cutter block forces, enabling significantly enhanced stability with lower lateral displacement. During the testing of multiple cutter block sizes in different formations, finite element analysis simulation studies show an average of 65% less lateral vibration compared with standard blocks. Full-scale drilling tests demonstrated an average reduction of 83% in lateral vibrations. ■



The StingBlock cutter block features a staged gauge pad design and Stinger conical diamond elements. (Source: Schlumberger)

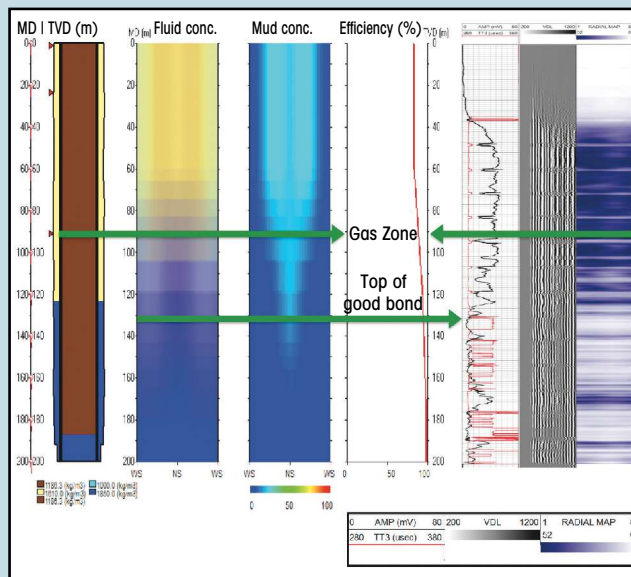


DRILLING FLUIDS/STIMULATION WINNER PEGASUS VERTEX INC. | CEMPRO+

The well cementing community has long experienced difficulties designing cement jobs, particularly in the area of displacement efficiency. Poor cement bond can be a costly problem. Cementers want to optimize operation parameters and avoid mud channeling. However, available tools are limited because predicting displacement efficiency involves extremely complex calculations that traditionally have been performed using computational fluid dynamic (CFD) numerical simulation. This approach can require hours of simulation time.

CEMPRO+, developed by Pegasus Vertex Inc., provides engineers a comprehensive and efficient modeling tool to model hydraulics, temperature and displacement efficiency. This simulation is based on fluid mechanics theories and CFD methods.

An efficient finite volume method on 3-D grids is built into the software that is capable of simulating high-fidelity multifluid displacement flow within a short period of time. Displacement efficiency is simulated and results are graphically displayed using animation to show the progress of fluid mixing. ■



The CEMPRO+ simulated and the measured cement bond log results show mud displacement for the bottom 30% of the annulus with intermixing of fluids above. (Source: Pegasus Vertex Inc.)

DRILLING SYSTEMS WINNER HALLIBURTON | JETPULSE HIGH-SPEED TELEMETRY SERVICE



Well construction is becoming more challenging across all asset types, and large amounts of downhole data are needed in real time to enable operators to make timely decisions. The increased need for large volumes of

The JetPulse service can deliver over 140 bits per second to the surface using multiple compression algorithms tailored to specific data types. (Source: Halliburton)

real-time data creates a higher demand for telemetry systems that can transmit data at high speeds. Halliburton Sperry Drilling's JetPulse high-speed mud-pulse telemetry service delivers real-time drilling and formation evaluation measurements. The service is designed for complex and extended-reach wellbores in deepwater and mature fields and can operate in high-pressure environments up to 30,000 psi.

The JetPulse service includes an integrated downhole generator that provides power to the bottomhole assembly. The generator can be run with lost-circulation material (LCM) concentrations greater than 100 lb/bbl. The system also can be deployed in a battery-only mode, which removes any LCM limitations from the telemetry system. The service is less affected by depth and delivers consistent data rates across wide depth ranges. ■



DRILLING SYSTEMS WINNER

WEATHERFORD | ENDURA DUAL-STRING SECTION MILL

Many offshore abandonment projects require a permanent barrier to be set outside of a dual-casing string comprising 9 $\frac{5}{8}$ -in.-by-13 $\frac{3}{8}$ -in. casing. There is a limited number of feasible solutions, including cutting and pulling or pilot milling thousands of feet of casing. In situations where traditional casing retrieval or milling techniques are not optimal because of well or operational constraints, Weatherford's Endura dual-string section mill (DSSM) offers a viable solution. The DSSM passes through the inside diameter of 9 $\frac{5}{8}$ -in. casing, stabilizes and then mills a window in the adjacent 13 $\frac{3}{8}$ -in. casing. This process exposes the formation, which enables an uninterrupted and verifiable cement



plug to be set and prevents formation-fluid migration.

In one example, the DSSM was deployed from a jackup rig to set a rock-to-rock barrier across a depleted zone in an offshore production well. While adhering to strict plug and abandonment regulations, the operator sought to reduce overall costs by minimizing milling trips required for a conventional job. When compared to traditional milling methods, the DSSM saved the operator 17 days of rig time. ■

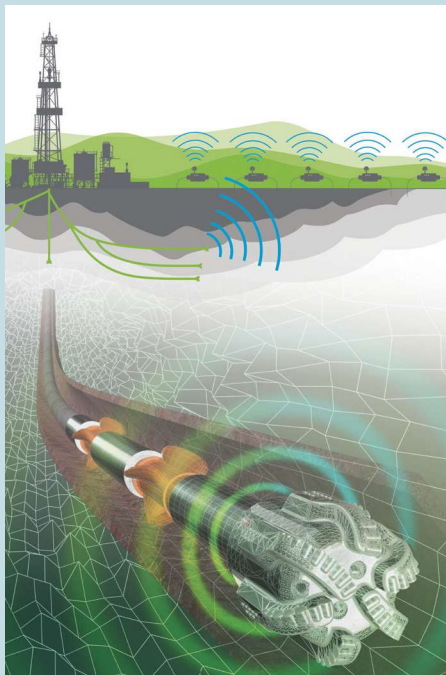
The Endura DSSM greatly reduces the amount of casing that needs to be removed from the well. This results in increased personnel safety and decreased costs. (Source: Weatherford)

EXPLORATION WINNER

SAUDI ARAMCO | DRILLCAM

DrillCam is an integrated real-time system that images and predicts ahead of the bit and around the well based on the seismic-while-drilling analysis. This technology is designed to enable accurate predictions for geosteering in high-quality reservoir zones, avoiding high-pressure formations, and determine coring and target depths, which will result in optimized drilling decisions and EOR with estimated returns and cost reductions.

The technology is based on acquiring seismic data in real time using the drillbit as a seismic source and cableless surface receivers that can provide 1) real-time recording and transmission of reflected seismic data to a central recording unit



for immediate decision-making and 2) adaptive survey geometry with flexible receiver spacing and areal coverage to focus the seismic image as the drillbit depth increases. This, coupled with the recent advances in seismic sensors sensitivity, imaging algorithms and computational resources that can be deployed in the field, open a whole new set of possibilities. One of the key factors of this technology is optimizing the acquisition geometry to obtain the best image ahead of the bit as the drillbit increases in depth. ■

DrillCam is designed to optimize drilling decisions, mitigate risk, increase steering accuracy and reduce cost. (Source: Saudi Aramco)



FORMATION EVALUATION WINNER

SCHLUMBERGER | PULSAR MULTIFUNCTION SPECTROSCOPY SERVICE

Schlumberger has released the next-generation in cased-hole logging based on pulsed neutron technology. With a slim 1.72-in. diameter, the Pulsar multifunction spectroscopy service easily fits through most completion restrictions to provide new measurement capabilities and higher accuracy in formation evaluation and reservoir monitoring in cased boreholes.

The service integrates a high-output pulsed neutron generator with multiple detectors to significantly improve acquisition accuracy and increase both logging speed and measurement precision. Because detector resolution degrades only minimally at high temperatures, the Pulsar service does not use conventional flasking and operates without time limits



Pulsar multifunction spectroscopy service is a standalone cased-hole formation evaluation and reservoir monitoring service. (Source: Schlumberger)

at up to 175 C (347 F). The service's measurements are complemented by powerful algorithms delivering robust answers that compensate for variations in the borehole fluids and completion.

Because Pulsar service does not depend on conventional resistivity-based approaches to rock and fluid identification, it accurately determines saturations in low-resistivity pay and for any formation water salinity, and it can be deployed in wells at any inclination from vertical through horizontal.

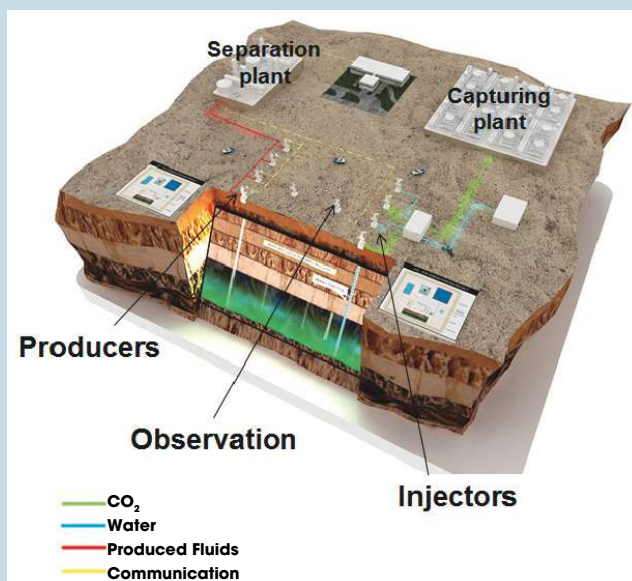
Without a rig, Pulsar provides environment-independent measurements that make standalone cased-hole formation evaluation and reservoir monitoring a reality to improve both drilling efficiency and well productivity. ■

HSE WINNER

SAUDI ARAMCO | CO₂-EOR AND SEQUESTRATION PROJECT WITH A COMPREHENSIVE MONITORING PROGRAM

Saudi Aramco recently launched the Kingdom's first carbon capture and sequestration (CCS) and CO₂ EOR project at Uthmaniyah Field. It is the first of its kind in the Middle East in terms of scale and operation as well as one of the largest in the world, according to the company. It involves capturing about 40 MMscf/d, which is approximately 800,000 tons of CO₂ per year that would have been ordinarily emitted into the atmosphere, compressing the CO₂ and piping it across 85 km (53 miles) and injecting it into a watered-out zone of Uthmaniyah Field, part of the giant Ghawar Field. The CO₂ is being injected in a water-alternating-gas mode. The primary objectives of the project are to permanently sequester part of the injected CO₂, and enhance oil recovery beyond water-flooding. The project sequesters CO₂ and enhances oil recovery and is part of Saudi Aramco's corporate Carbon Management strategy and roadmap.

The project consists of two major components: 1) the surface—CO₂ capture, dehydration and compression and 2) subsurface—injection and production facilities. ■



Saudi Aramco's CCS and CO₂-EOR project sequesters CO₂ and improves oil recovery. The image depicts a futuristic oil field deploying new technologies. (Source: Saudi Aramco)



HYDRAULIC FRACTURING/PRESSURE PUMPING WINNER STAGE COMPLETIONS | SC BOWHEAD II

Stage Completions' SC Bowhead II is a single-point entry system that meets the design-change demand limitations of traditional pinpoint fracturing systems. As a dissolvable ball- and collet-activated fracturing sleeve system designed for cased hole and openhole applications, it offers multiple profile length configurations that facilitate precise valve activation. Able to complete longer laterals and unlimited stages with tighter spacing, the system drives high utility of capital, increased EURs and removes the limitations found in other available systems.

The tool is engineered so that there is no need for an initial pump down trip to set a plug. A second pump down trip to seat a ball is eliminated and no electric line perforating is required. Coiled tubing is not needed to activate Stage Completions' sleeves. To open up a Stage Completions system sleeve, operators need to pump down the collet to the desired depth, which requires the use of a single wellbore volume.

If the collet is promptly chased by a fracturing treatment, then a hydraulic fracture can be initiated after opening the sleeve, which mitigates wasting any fluid.

Subsequent collets can be launched and displaced as part of the "flush" portion of the fracturing treatment for the previous zone, making the fracturing operation almost continuous from stage to stage. ■



The SC Bowhead II fracturing sleeve was used in an Eagle Ford completion where it accurately placed 11.6 MMlb of sand and 361,000 bbl of fluid. (Source: Stage Completions)

INTELLIGENT SYSTEMS AND COMPONENTS WINNER SCHLUMBERGER | WELLWATCHER ADVISOR



Schlumberger's WellWatcher Advisor real-time intelligent completion software transforms acquired data into actionable intelligence at frequencies as high as 1 second. This results in data analysis workflows that used

WellWatcher Advisor software simplifies the work of analyzing data from intelligent completions, enabling real-time decision-making. (Source: Schlumberger)

to take weeks and months of manual study that can now be completed automatically in hours and days.

WellWatcher Advisor software gives users up-to-the-second insights into well data from any location on any computer. The system is tailored to work with most existing real-time data streams to bring deeper understanding by incorporating computations such as flow-rate estimation, pressure gradient and productivity index estimation. These computations and an alerting system point users toward problem areas, eliminating time spent investigating where issues might be.

The software can be connected to an operator's real-time data sources or to remote production operations centers. The on-premise software is installed locally on the operator's computers, and all data remain within the operator's network, enhancing security. ■



IOR/EOR/REMEDICATION WINNER

BAKER HUGHES, A GE COMPANY | TORUS

Baker Hughes, a GE company (BHGE), has developed the Torus insert safety valve. The valve is designed to deliver flexibility to thru-tubing completion operations by enabling rigless deployment of a range of production enhancement equipment on insert strings while maintaining safety valve functionality.

Common methods of boosting production in maturing wells include installing electric submersible pump systems, gas-lift systems, velocity strings or chemical injection systems. Rigless thru-tubing deployment of these systems is economical. However, maintaining a robust well barrier during their installation and the subsequent production phase is complex and cost-prohibitive. This is because traditional safety valves used for these jobs have flapper-style closure mechanisms that require an unobstructed inside diameter for their operation, which prohibits the passage of coiled tubing (CT), control lines or cables through the valve. As a result, a workover rig has to be mobilized to recompleat the well and permanently install flapper-style valves deeper in the well, below the production enhancement equipment.



The BHGE Torus insert safety valve is designed to help reduce opex by an average of 50% while lowering HSE risks. (Source: BHGE)

The Torus valve replaces the flapper valve with a sliding sleeve design to control production. This makes the Torus the only insert safety valve to offer a permanent concentric conduit for capillary lines, cables and CT, enabling rapid installation of production-enhancement equipment in mature wells without the need for a workover rig. ■

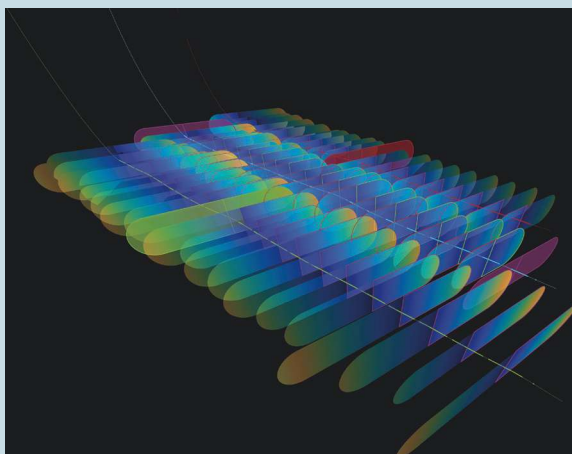
NONFRACTURING COMPLETIONS WINNER

REVEAL ENERGY SERVICES | IMAGE FRAC

Reveal Energy Services' IMAGE Frac pressure-based fracture maps allow operators to monitor 100% of their wells with streamlined pressure-based fracture maps that validate their completion designs with minimum operational risk and cost.

This technology serves as a completion design early warning system for factory mode field development that increases reservoir contact. The technology offers an early look at completion effectiveness. The tool requires only a pressure gauge and a bridge plug to generate fracture maps that highlight the fracture attributes.

An example of how the tool works is represented in a treatment well that will be hydraulically fractured and



Field personnel, downhole tools and downtime are not required with the IMAGE Frac suite, which also is designed to reduce the cost by 80%. (Source: Reveal Energy Services)

is full of fluid, along with an adjacent well, known as the monitor well, with an isolated stage that has been fractured and has a pressure gauge placed at the wellhead. Because new fractures generate a stress field pressure response in the monitor well, Reveal Energy Services can compute a pressure-based fracture map. The map is computed using a fully coupled 3-D model that compares the modeled pressure response with the observed pressure response in the monitor well.

The IMAGE Frac suite is field proven in more than 2,500 stages during the past 18 months in several major North American basins. ■



ONSHORE RIGS WINNER

WEATHERFORD | AUTOTONG SYSTEM

Tubular running accounts for a large percentage of an average well construction budget; it's also the backbone of life-of-well integrity. Simple operator-influenced makeup errors wreak havoc on connection quality, operational efficiency and long-term well integrity.

The Weatherford AutoTong system automates the final connection makeup and evaluation. As a fully integrated tubular-running technology, the system includes a mechanical tong and AutoEvaluate software. Using high-resolution data to autonomously appraise connections, the tong-mounted computer manages each connection with smooth, computer-controlled



The AutoTong system delivers connection integrity with fewer personnel as it is operated by a single user for both the tong and torque-turns monitoring system. (Source: Weatherford)

precision. By removing nearly any chance for negative human influence, the system removes connection-makeup errors, eliminates flat time, reduces safety risks and significantly decreases tubular-running costs.

Rather than a visual check of the makeup graph against known profiles, AutoEvaluate software automates the connection evaluation process. Using proprietary algorithms and real-time makeup data, the software accurately interprets 10 times more datapoints than the human eye can see. The system automatically evaluates the makeup graph to ensure conformance to original equipment manufacturer criteria. ■

SUBSEA SYSTEMS WINNER

DIAMOND OFFSHORE | HELICALLY GROOVED BUOYANCY

Helically Grooved Buoyancy for vortex-induced vibration (VIV) suppression is polyurethane or syntactic foam buoyancy with a pattern of helical grooves on the outer diameter for suppression of VIV.

Helically Grooved Buoyancy was originally developed and patented in 2009 by Diamond Offshore Drilling, subsequently optimized for more than three years using computational fluid dynamics (CFD), and is manufactured and marketed by Trelleborg Offshore for drilling and production risers in both polyurethane and syntactic foam.

In 2017 Helically Grooved Buoyancy was tested in SINTEF Ocean's Marine Laboratory Towing Tank in Trondheim, Norway. These model tests validated Diamond's CFD models, established parameters for riser analysis software and confirmed that Helically Grooved Buoyancy has VIV suppression and drag reduction comparable with existing riser fairing designs. The Helically Grooved Buoyancy system transports, handles, runs and stores like standard cylindrical buoyancy. The system was successfully tested for stacking "crush" forces and is typically



The Helically Grooved Buoyancy is deployed alongside the Ocean BlackRhino drillship. (Source: Diamond Offshore)

stronger in crush than conventional buoyancy. It has a small cost premium over conventional buoyancy and uses existing molds and standard manufacturing methods.

Helically Grooved Buoyancy decreases drilling riser drag, which improves differential pressure station-keeping and reduces vessel emissions and allows fitting of riser fairings for extreme current conditions. ■

Bakken making its push

Enhanced completions fuel basin's steady production.

Brian Walzel, Associate Editor, Production Technologies

If North American oil production were a race, the Permian Basin would, of course, have lapped everyone else in the field long ago. But in this theoretical competition, the Bakken is neck and neck with the Eagle Ford, with each producing about 1.2 MMbbl/d, according to the U.S. Energy Information Administration (EIA). Although the Eagle Ford has higher max production potential, as evidenced by its 1.7 MMbbl/d of output in 2015, the Bakken represents resiliency and predictability;

it didn't quite suffer the valleys other basins did post-2015, and its production levels are expected to remain at its current pace for the foreseeable future.

Stephen Beck, senior director, upstream, at Stratas Advisors, said he expects the Bakken's productivity to maintain a 1.2-MMbbl/d production level through 2022 and taper off slightly to 1.1 MMbbl/d through the end of the decade. According to the EIA, the Bakken's total oil production increased by 12,000 bbl/d between February and March.

Beck explained that the Bakken is a well-harvested asset in which many operators such as Continental Resources leverage their cash flow from the basin to other plays, such as—in Continental's case—the Midcontinent Stack. The Bakken's maturity and production characteristics could lead to a growth in consolidation over the next few years, Beck said.

"That cradle along the Missouri River, you have a bit more gas and you have a gas drive that has been at the heart of where most of the [drilling] activity has been," he said. "As that gets more and more drilled, it only makes sense that the remaining Bakken assets would trade hands into the most capable operators and the operators who have interest in staying there for the longer term."

Among those committed operators, Beck said, are likely to be Hess and Whiting, with the likes of Continental Resources, EOG Resources and ConocoPhillips among the basin's leading players.

Continental

According to *shaleprofile.com*, Continental is the region's leading producer, having averaged 159,801 bbl/d in January from its 1,597 operating wells, and that amount was up 6% from December 2017 when Continental produced 150,856 bbl/d.

Continental experienced all-time high growth in 2017 in the Bakken, according to a 2018 investor presentation, with production up 58% over fourth quarter 2016. As with most other unconventional operators, the increased production rates are a result of optimized completion designs, the company reported.

Production from its 134 optimized completions resulted in a 12.5% increase over the first 300 days of production compared to the company's 1,100 Mboe type curve—a result of 270,000 boe for its optimized wells compared to 240,000 boe in its type curve.



Hess' average well in the Bakken last year was drilled and completed for \$5.6 million. (Source: Hess)

Hess

Hess ramped up its Bakken production at the tail end of 2017 and into this year, having produced 85,491 bbl/d from 1,375 wells in October 2017, an amount that increased 13% in January to 96,639 bbl/d from 1,403 wells. The company's total boe production in 2017 was 105,000 boe/d, said CEO John Hess during the company's fourth-quarter 2017 investor call.

Hess said the company intends to grow its production in the Bakken to 175,000 boe/d by 2021.

"Through the application of geosteering, optimized spacing, higher stage counts and profit loading, we have increased our well productivity by approximately 50% over the last two years," he said. "These improvements, together with our low drilling and completion costs, have enabled us to generate returns that are competitive with any shale play in the United States."

He added that Hess is forecasted to average between 115,000 and 120,000 boe/d this year.

During the investor call, Hess President and COO Gregory Hill said the company executed pilots of 60-stage completions with increased proppant loading, which resulted in a 10% to 15% uplift in IP180.

"As a result, we've increased our EUR from our Bakken acreage to 2 billion barrels of oil equivalent from our previous 1.7 billion barrels of oil equivalent," Hill said.

EOG Resources

David Trice, executive vice president of E&P at EOG Resources, said during the company's fourth-quarter 2017 investor call that EOG's focus in the Bakken last year was on drawing down its inventory of legacy drilled but uncompleted wells (DUCs), which he said were not drilled with the company's recent precision targeting techniques.

"Once we completed our inventory of DUCs, we completed a few fantastic wells in both the Bakken and the Three Forks targets," Trice said.

EOG's Bakken production, however, receded last year from its June production peak of 70,115 bbl/d, accord-

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September	Oklahoma Playbook
October	Permian Basin Playbook SEG Show Daily
November	Eagle Ford Playbook
December	Offshore Technology Yearbook

E&P

ing to *shaleprofile.com*. By January EOG was producing 46,344 bbl/d, a 34% decline.

EOG plans to complete about 20 wells this year in the Bakken Core and Antelope extension compared to the 35 it completed in 2017. Its Bakken/Three Forks completions feature 2,560-m (8,400-ft) laterals with 198-m (650-ft) spacing.

“We’ll also drill a number of step-out wells in the Bakken Lite and other areas to continue testing and redefining our latest precision targeting and advanced completions outside our core operating areas,” according to Trice.

Over the past two years, EOG has reduced well costs by more than one-third, down to \$4.6 million per well last year, he said.

“We expect to continue lowering costs through a recently implemented seasonal drilling and completion program,” Trice said. “Wells are drilled year-round, then completed mostly during the summer. This program will eliminate the additional expense incurred by handling water during the freezing winter months and dealing with road restrictions during breakup.”

ConocoPhillips

ConocoPhillips is applying its own technology-enhanced completion optimizations across the Eagle Ford, Delaware and Bakken resource plays. According to a 2018 investor presentation, the company is

expecting to maintain a production level of 70,000 boe/d through 2020.

According to *shaleprofile.com*, ConocoPhillips’ production in the Bakken has steadily increased since December 2016 from 49,186 bbl/d to 79,453 bbl/d in January 2018.

Whiting

Whiting is North Dakota’s second leading producer, behind Continental Resources, producing 103,897 bbl/d in January. The company reported in its fourth-quarter 2017 investor presentation that it expects to increase its overall boe production compared to last year by 9% to 128,400 boe/d. To improve recoveries, Whiting has tweaked its completion designs in the Williston Basin over the past eight years to its Generation 4 completions. According to a 2018 company investor presentation, its Generation 1 completions, which the company ran from 2010 to 2012, featured 240 lb/ft of proppant, 115.8-m (380-ft) stage spacings and 115.8-m cluster spacings, along with a ball-and-sleeve and packer completion.

In 2018 Whiting will apply completions that feature 600 lb/ft to 1,200 lb/ft of proppant, 60.9-m to 91.4-m (200-ft to 300-ft) stage spacings and 9.1-m to 15.2-m (30-ft to 50-ft) cluster spacings, with cemented liner plug and perf. The company expects well costs to range from \$6.5 million to \$7.1 million, according to the investor presentation. **ESP**



ConocoPhillips expects to produce 70,000 boe/d in the Bakken through 2020. (Source: ConocoPhillips)



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Advancing downhole conveyance for reliability

Smart wireline tools help improve downhole performance with real-time data.

Jason Hradecky, Impact Selector International

Leaders in the downhole conveyance segment of the oil and gas industry are rapidly moving away from a fundamental reactionary mindset to a more studied, proactive approach that incorporates pre-run wellbore modeling for optimum tool string configuration with planning based on the model's projected frictional forces, impact and sticking force analysis.

These data are used to configure the tool string with a range of conveyance products such as rollers, jars, tension devices, measurement equipment and more. In addition, measurements of the downhole performance of the tool string are used to validate data and assess the planning process.

These customized solutions are designed to successfully deploy downhole tools and most importantly provide assurance of safe, reliable conveyance and accuracy of validation data through measurement. This front-end approach provides operating company personnel with the highest quality data to make key operational decisions throughout the entire life cycle of the well.

One area where effective downhole conveyance is critical is found in the current U.S. onshore market,

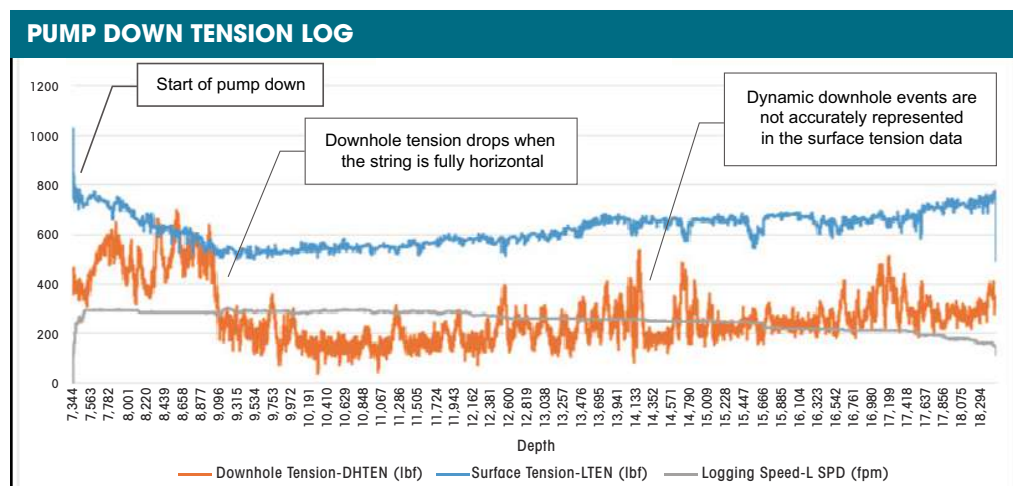
which has experienced explosive growth in perforation and pump down applications. In response to this situation, numerous advanced products have been developed to ensure reliable conveyance of tools, gathering of reliable downhole data and providing for validation of the perforation and pump down effort. For example, an integral part of any successful downhole conveyance operation is pre-job planning and tension modeling software. Proprietary modeling software is playing a key role in optimizing tool string design and configuration for successful perforation and pump down operations.

Tools of the trade

Wireline tension monitoring devices maximize efficiency and minimize risk during challenging wireline operations. These measurement devices provide real-time downhole cable tension measurement, eliminating uncertainty and providing the operator with increased control. Maintaining safe cable tension downhole is challenging, particularly in highly deviated and lateral wells, because surface measurements do not account for friction.

If the cable tension is allowed to become too low, then slack cable and released torque can result in cable damage. Correspondingly, if the tension is allowed to become too high during pump down operations, for example, the weak point on the cable can break.

This same ability to measure wireline tension can provide for increased visibility of such downhole events as plug setting and perforating guns firing. These downhole measurements can be particularly valuable when compared to surface tension readings, which often are inconclusive. These new tensioning tools feature a robust design for reliability and are easy to use in the field. Some of these devices also offer



The surface cable tension (blue) does not accurately capture real-time events as compared to the tension measured directly downhole (orange). (Source: Impact Selector International)

plug-and-play compatibility, ensuring that many service companies can use these tools directly with no additional surface equipment required.

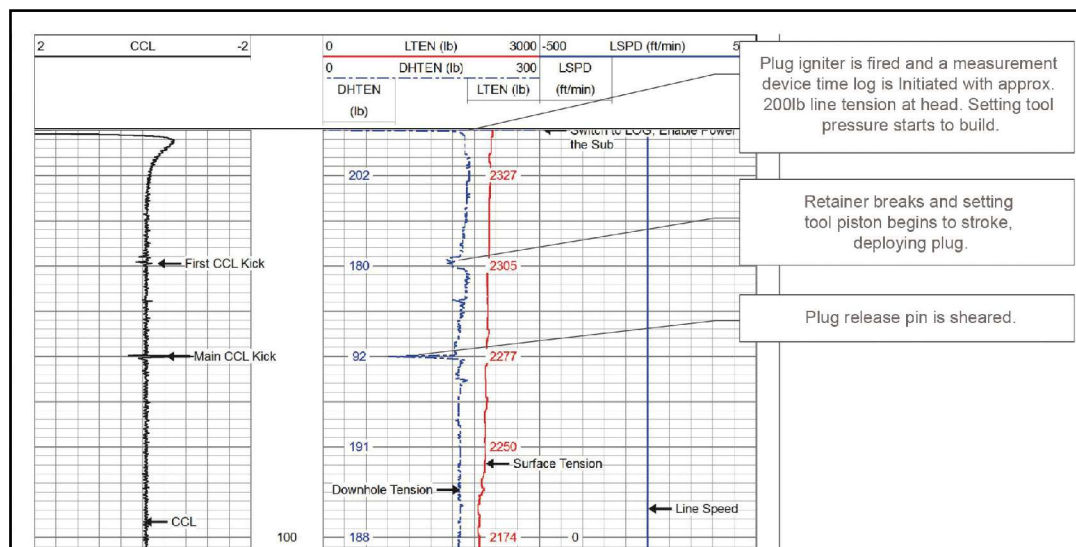
Recently developed release tools employ a specialized detonator-initiated joint to separate them from a tool string that has become stuck. This specialized joint gives the tool a high tensile rating, allowing it to be utilized anywhere in the string, including below perforating guns and in conjunction with jars. These advanced release tools ensure that the tool string can be retrieved out of the hole each time.

Newly engineered single-time, high-intensity jars are designed to deliver a single jarring force to a perforating string. Engineered to provide a high-intensity jarring force in long horizontals, where cable tension is not available, these jars serve as insurance if a faulty plug-setting tool shear pin needs to be broken or a stuck perforating gun requires a jarring force.

This new style of jar stores energy in a vacuum chamber that is released using a standard detonator. Wellbore fluid pressure accelerates a piston within the jar upward (along with the upper tool string) before hitting a hard stop. The impact of that hard stop shocks the lower tool string upward, providing significant jarring energy. This new style of jar ensures that perforating strings come out of the hole each time.

Rollers are designed to reduce frictional resistance and enable access to high deviations. With a proven track record of success at inclinations up to 87 degrees and at depths in excess of 7,620 m (25,000 ft), rollers can be installed at any point in the tool string. These advanced rollers serve to lift the string off the wellbore and onto highly efficient rollers, eliminating contact friction and allowing easier and deeper wellbore access.

The roller body rotates around the mandrel, which is connected to the host tool string, providing for a free range of motion. Today's rollers feature unique body shapes that ensure the rollers are oriented to the low side of the tubing at all times. Rollers also



The well log confirms successful deployment of the plug. (Source: Impact Selector International)

are available in a wide range of sizes and connection profiles allowing them to suit various tool strings and wellbore requirements.

Post-operational analysis

An industry goal is to better validate progress once a job or operation is completed. All parties involved in a downhole operation can validate the progress made using data acquired during the process. This validation completes the feedback loop, which is vital to better understanding the well's life-cycle program and providing intelligence for future operations.

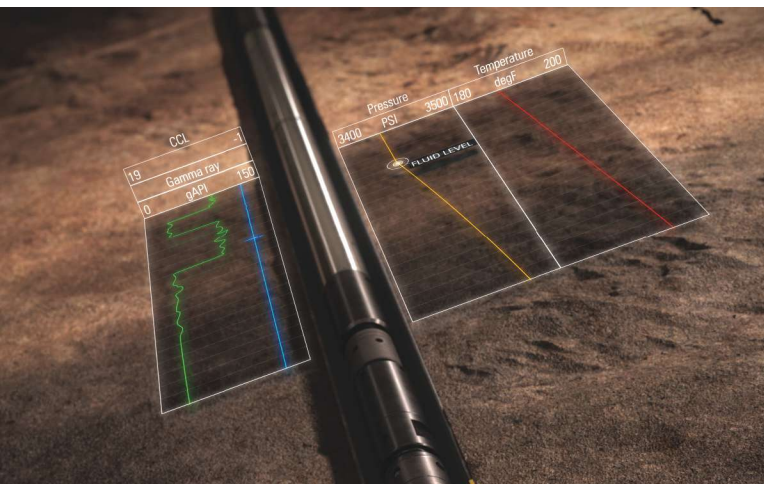
The long-term goal of this new technology is to be able to deliver reliable conveyance solutions that mitigate risk, enhance efficiency, reduce cost and improve safety for customers working in the upstream oil and gas industry. For optimum effectiveness, a program of this sort should also be able to access deployment experience and knowledge.

Some of this critical experience and expertise left the industry during the recent downturn, as much of the industry focused on cost reduction, discounts and downsizing. However, some service and E&P companies have invested heavily in technology and developed new conveyance alternatives and best practices that are beginning to define a new future in deployment and conveyance. **ESP**

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.

New perforating gun system increases well productivity

Schlumberger introduced the Tempo instrumented docking perforating gun system at the SPE/ICoTA Coiled Tubing and Well Intervention Conference and Exhibition in March, according to a press release. This combination of a plug-in gun design with real-time advanced downhole measurements enables and monitors the well's dynamic underbalance to create clean perforations that boost reservoir productivity. The proprietary docking components of the compact gun system streamline the deployment of up to 40 guns for selective initiation to efficiently perforate multiple reservoir zones with a maximized explosives payload in a single trip in the well. The Tempo system has the flexibility to accommodate most perforating gun sizes and shaped charges. The simplified arming process increases safety and reliability by eliminating the variability introduced by wellsite crimping and wiring, which are the primary causes of misruns and misfires. *slb.com*



The Tempo system fully integrates a plug-in gun with real-time advanced downhole measurements for monitoring and confirming operations to mitigate risk. (Source: Schlumberger)

Motor allows downhole adjustment of motor bend setting

National Oilwell Varco has released the SelectShift downhole adjustable motor to its portfolio of drilling motor technologies. The SelectShift is a proprietary advancement in motor technology that works with Vector series motors to allow downhole adjustment of the motor bend setting. This improves hole quality and limits sliding, as the motor can bend more when faster correction is needed in the lateral while the straight setting limits hole tortuosity and aids in hole cleaning,

The SelectShift is a proprietary advancement in motor technology that works with Vector series motors to allow downhole adjustment of the motor bend setting. (Source: National Oilwell Varco)

according to the company. The SelectShift also improves ROP by increasing rotary/bit rpm in the straight position, which requires less sliding in the lateral and curve, and reduces side loading of the bit. The motor features high-torque capability, 100% flow to the drillbit and a reduced bit-to-bend length, which enable significant time savings—one to two trips per well on average—and eliminate the need to displace the oil-based mud after the curve section. Initial trial runs on three test wells, with 8¾-in. curve-to-lateral sections between the three totaling approximately 1,981 m (6,500 ft), have been positive, with build rates at 14 degrees or more per 30.4 m (100 ft) seen on both laterals and sustained ROP as high as 61 m/hr (200 ft/hr) in the laterals and 38 m/hr (125 ft/hr) in the curves. *nov.com*



Laser-based system measures small methane leaks in large outdoor areas

Researchers have conducted the first field tests for a new laser-based system that can pinpoint the location of very small methane leaks over an area of several square miles, as reported in a press release. The new technology could one day be used to continuously monitor for costly and dangerous methane leaks at oil and gas production sites. Today a person or team must travel to different sites to check for leaks with a special camera that is sensitive to methane at close distances. This approach is time-consuming and could result in missing methane leaks that are intermittent in nature. "Our approach allows measurements to be autonomous, which enables continual monitoring of an area," said co-lead author of the study, Sean Coburn, from the University of Colorado in Boulder. "This technology could play a significant role in reducing methane emissions from production activities, easing tension between urban development and oil and gas production and helping avoid disasters like the 2015 Aliso Canyon methane storage leak that released 90,000 mt of methane into the atmosphere." *osa.org*

CT string with high fatigue resistance

Tenaris' BlueCoil technology, released in 2015, achieved more than 670,560 running meters (2.2 mil-

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lion running feet) in the Permian Basin, according to the company. The technology is a stronger coiled tubing (CT) string with high fatigue resistance achieved through Tenaris' proprietary manufacturing process utilizing steel designs. The product is designed to last two to four times longer than a conventional string. A CT service company operating in the Permian installed a 2.375-in.-diameter HT 125 string and ran it for nearly a year, achieving running footage and fatigue milestones not seen with conventional CT. The operator pushed the fatigue limits farther, registering a new industry record of 670,560 running meters at 99% fatigue on the model. tenaris.com/bluecoil



Since 2015 Tenaris has deployed more than 350 BlueCoil strings, totaling more than 2.1 MMm (7 MMft) shipped worldwide.

Platform maps all Permian fracturing ponds

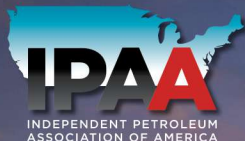
Sourcewater has made finding fracturing ponds simple by having every fracturing pond in the Permian Basin mapped, analyzed and uploaded into its database with more than 100,000 water sources at sourcewater.com, according to a company product announcement. Sourcewater eliminates the need to drive the oil field and manually scan old satellite imagery in Google Earth to find fracturing ponds. Instead, the company uses satellite imagery that is less than a month old and analyzes it with its proprietary artificial intelligence to identify each fracturing pond. The company then matches the fracturing pond locations with land parcel records to identify whose land the pit is on. Then the square footage of the pit and total volume of water in the pit are estimated. Finally, the company's in-house research team calls each pit owner and determines if the pit is for lease or if the water in the pit is for sale and for how much. sourcewater.com

Developing the next generation of robotics for oil and gas

According to a press announcement the Oil & Gas Technology Centre has invested in three robotics projects to transform pressure vessel inspection, which costs the industry hundreds of millions each year and poses significant safety challenges. The projects were selected as part of the center's first Asset Integrity Call for Ideas, which launched in 2017. Pressure vessel inspection was identified by the industry as a crucial challenge to maximizing economic recovery from the U.K. Continental Shelf. Nonintrusive inspection (NII) of pressure vessels can deliver significant cost and safety benefits. Sonomatic's aim is to develop the next generation of robotic NII technology, with improved speed, agility and autonomy compared with existing systems. The robot, incorporating advanced inspection technologies, will help increase production uptime, reduce costs and improve efficiency. Separately, the center is working with the University of Strathclyde to develop a new robot crawler equipped with 3-D laser scanning and nondestructive testing technology. Existing crawlers are typically deployed only when there is a clear line of sight for the operator. The university's solution will construct a virtual, dynamic 3-D representation of the inspection site, meaning it can be operated safely from a remote location. The center also is supporting the University of Strathclyde in the use of swarms of small unmanned aerial vehicles, or drones, for visual inspection offshore. Drone swarms could deliver a safe, flexible and cost-effective alternative to human inspection. theogtc.com

Simulation meets automation to enhance ROV training and analysis

Forum Subsea Technologies and BluHaptics Inc. have announced a joint agreement enabling technologies from both companies to be combined to provide solutions for ROV and subsea engineering applications, according to a press release. The VMAX Software is a 3-D ROV simulation product used for training and evaluation of ROV pilots as well as by subsea engineering teams for modeling and verification of procedures involving intervention tasks related to installing and maintaining subsea equipment. As Forum's VMAX ROV Simulator provides a variety of ROV training scenarios designed to test pilots' skills within realistic operational scenarios, many of which require the use of a seven-function manipulator, the user interface for manipulator control is key to providing a realistic user experience. BluHaptics' Dex-OS manipulator control system provides an intuitive user interface with the ability to introduce vari-



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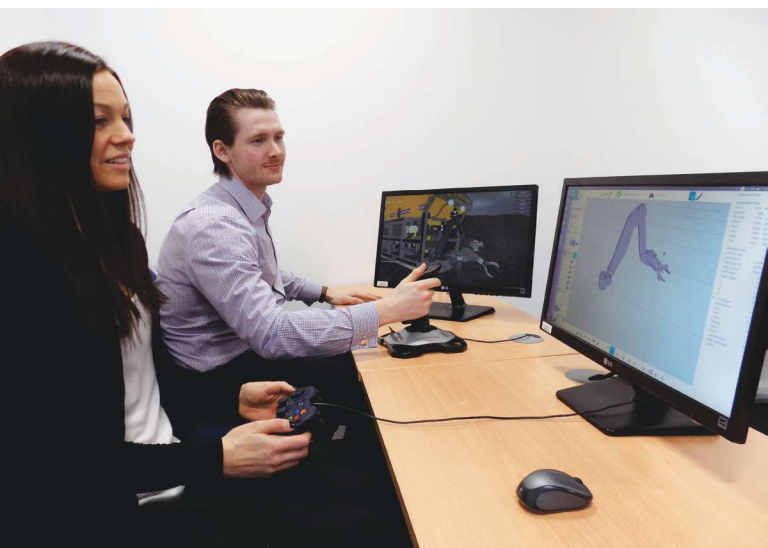


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able levels of automation to make execution of subsea intervention tasks more safe and efficient, as reported in the press release. Dex-OS also provides variable levels of automation to offer inspiration for engineering teams seeking to improve operations involving increasingly complex intervention scenarios. For ROV operators who are interested in implementing BluHaptics Dex-OS technology into their ROV fleet, VMAX and BluHaptics can now offer a simulated environment as a platform for demonstration and transition training to ROV pilots without tying up expensive ROV assets. Both systems operate on laptops, which offer mobility, convenience and flexibility. bluhaptics.com, f-e-t.com



A manipulator control using Dex-OS software is integrated into the VMAX ROV simulator during engineering analysis. (Source: BluHaptics)

New multibeam sonar for small observation class ROVs

Kongsberg Mesotech has released the Flexview multibeam sonar designed specifically for small observation class ROVs, according to a press release. Delivering superior image quality and coverage, the compact and lightweight sonar provides high-quality distortion-free images at a range of



Flexview is the first multibeam sonar to introduce a removable transducer, offering rapid field service with little downtime. (Source: Kongsberg Mesotech)

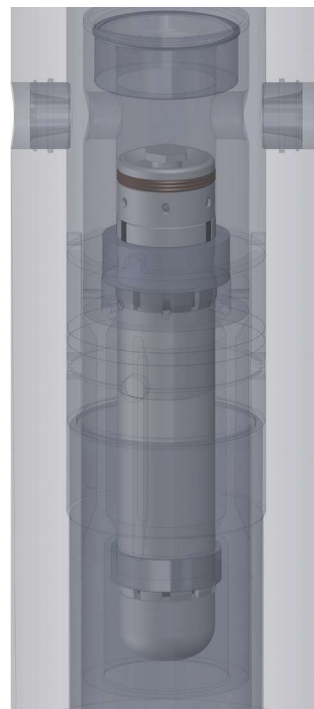
up to 200 m (656 ft) over a 140-degree sector, reducing the time it takes to search for and locate targets. The Flexview's removable transducer is the first of its kind, offering field replacement of a damaged transducer in the unlikely event of a catastrophic impact, the release stated. It also allows potential new transducer configurations to be exchanged in the future, depending on the job being performed. km.kongsberg.com

Perforating for remedial cementing

GEDynamics has released its ISOLOC plug and abandonment (P&A), specialized-perforating systems for remedial cementing and circulation, according to a press release. ISOLOC perforating systems are used to establish communication between two or more strings of tubing or casing. The systems greatly improve cement plugging, squeeze and circulation operations with controlled damage to the secondary or tertiary string. Perforating for remedial cementing operations without damaging the outer strings of the casing is an essential element to efficient P&A and well circulation operations. The new ISOLOC perforating systems reduce both risk and rig time, allowing operators to optimize remedial intervention efficiencies; some operators have reduced the time to complete a job by as much as 90%, according to the release. perf.com

Boosting annular velocity in challenging geothermal wells

Churchill Drilling Tools is partnering with operators to improve hole cleaning and project performance by using its DAV (dart activated valve) MX Circ-Sub. The DAV MX was put to the test recently by a European operator in a challenging onshore geothermal well in the Netherlands, as reported in a press release. Optimal hole cleaning was essential given the challenging multitapered casing profile of the string. By



The DAV MX is designed to improve hole cleaning and project performance. (Source: Churchill Drilling Tools)



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deploying two DAV MX CircSubs, the operator boosted annular velocity and optimized its hole cleaning process across two separate runs, according to the release. It cut the time to transport cuttings to the surface by about 50% if using a single CircSub and 75% if no CircSub was in the string. In optimizing the hole cleaning process, the operator also prevented any concern of managing a stuck-pipe situation. *circsub.com*

Digital drilling vessel designed to improve efficiency

GE and Noble Corp. Plc have launched the world's first digital drilling vessel, aiming to achieve 20% opex reduction across the targeted equipment and improve drilling efficiency, according to a press release. The Digital Rig solution, powered by GE's Predix platform, deployed on the *Noble Globetrotter I* drilling vessel has been successfully connected to all targeted control systems, including the drilling control network, the power management system and the dynamic positioning system. Data are collected through individual sensors and control systems, harmonized and centralized on the vessel before transmitting in near-real time to GE's Industrial Performance and Reliability Center for predictive

analytics. The delivered implementation and analytics on major marine and drilling equipment already have shown promising results, as the Digital Rig solution captured multiple anomalies and has produced alerts to inform potential failures up to two months before they would occur. The Digital Rig combines data models from a digital replica of physical assets, known as a digital twin, along with advanced analytics to detect off-standard behavior, providing an early warning to operators to mitigate a problem before it strikes. Thanks to vessel-wide intelligence, personnel both on the vessel or onshore can gain a holistic view of an entire vessel's health state and the real-time performance of each piece of equipment onboard, according to the release. *noblecorp.com, ge.com*

Platform allows visibility among all parties

New tech startup Rig CallOut announced its precommercial launch in late March. Rig CallOut connects the entire oil and gas supply chain from suppliers to trucking companies to end-user E&P and midstream companies with its platform, according to a company press release. Using intuitive technology and a cloud-based application, Rig CallOut brings everyone together under one system, from project inception to delivery completion. The platform enables all parties the visibility to see what's happening at any point in time and communicate in unison, eliminating false data and the dreaded telephone game, the release stated. Rig CallOut's user experience allows individuals to view the specific shipments that are most important to them. From detailed product load information, digitized shipping and load documents, real-time tracking, and time stamps of pickups and stops, the application allows everyone to have complete visibility in their communication, location details, estimated time arrivals and more. *rigcallout.com* **ESP**

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



GE and Noble Corp. Plc have launched the world's first digital drilling vessel. (Source: GE and Noble Corp.)



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1 US

Chesapeake Operating Inc. completed a Haynesville Shale well with a lateral length exceeding 3,048 m (10,000 ft), according to IHS Markit. The #1-Alt Nabors 13&12-10-13HC well is in Louisiana's Sabine Parish in Section 24-10n-13w and bottomed about 3 km (2 miles) to the north in the neighboring DeSoto Parish also in Section 12-10n-13w. The Benson Field well flowed 971,268 cu. m (34.3 MMcf) of gas and 790 bbl/d of water from acid- and fracture-treated perforations at 3,792 m to 6,772 m (12,441 ft to 22,218 ft). It was drilled to 6,805 m (22,325 ft), and the true vertical depth was 3,628 m (11,904 ft).

2 Guyana

Exxon Mobil announced a seventh offshore Guyana oil discovery at exploration well #1-Pacora in the Stabroek Block. The well hit approximately 20 m (65 ft) of a high-quality, oil-bearing sandstone reservoir. The well was drilled to 5,597 m (18,363 ft) in 2,067 m (6,781 ft) of water. The latest discovery is located approximately 6.4 km (4 miles) west of #1-Payara. After completion operations are done at the #1-Pacora well, the drillship will move to the Liza Field to drill the #5-Liza well and complete testing. Additional exploration and appraisal drilling is planned on the block.

3 Falkland Islands

An independent evaluation for Borders & Southern Plc of the Darwin East discovery and the adjacent Darwin West untested offshore Falkland Island block indicates the unrisksed best estimate total recoverable liquids (condensate and LPG) for Darwin East and West is 462 MMbbl. The evaluation was based on extensive 3-D seismic and well data, including

technical studies, interpretations and dynamic models of the reservoir. According to the Gaffney, Cline & Associates study, the untested Darwin West fault block displayed similar seismic characteristics and attributes to the Darwin East fault block, and hydrocarbon samples from a gas condensate discovery at the #61/17-1 well demonstrated that the gas is a very rich, sweet gas capable of producing liquid condensate and LPG. The combined liquids production of condensate and LPG peaks is estimated at 91,000 bbl/d. Operator Borders & Southern holds 100% interest in the three Falkland Islands production licenses and its Darwin East and West discoveries.

4 Morocco

SDX Energy reported a gas discovery in Morocco's Sebou Block at the #2-SAH well in the northern Rharrb Basin on the Tanja-Titwan-Elhussima Peninsula. The discovery was drilled to 1,304 m (4,278 ft) and encountered 5.2 m (17 ft) of net gas pay across two zones in Guebbas and Hoot with an average porosity of 33% in the pay section. It will be completed, tested and connected to existing infrastructure.

5 Norway

In offshore Norway's production license 340, Aker BP has completed wildcat well #24/9-12 S and appraisal well #24/9-12 A. The #24/9-12 S well was drilled to 2,251 m (7,385 ft) and was targeting Eocene (Intra Hordaland group sandstones). The well hit a 10-m (33-ft) oil column in the Hordaland group with good reservoir properties. Three 5-m (16-ft) oil-bearing, partially cemented sandstone layers were encountered higher up in Hordaland group. The objective of #24/9-12 A was to delineate the discovery and

obtain information for the placement of a potential development well. The appraisal hit an oil column of about 30 m (98.4 ft) in reservoir sandstone layers in Hordaland group with good reservoir properties. Preliminary estimates indicated 5 MMcm to 10 MMcm (176.5 MMcf to 353.1 MMcf) of recoverable oil. The #24/9-12 A was drilled to 2,162 m (7,093 ft) and was terminated in Hermod (Paleocene). Area water depth was 120 m (394 ft).

6 Norway

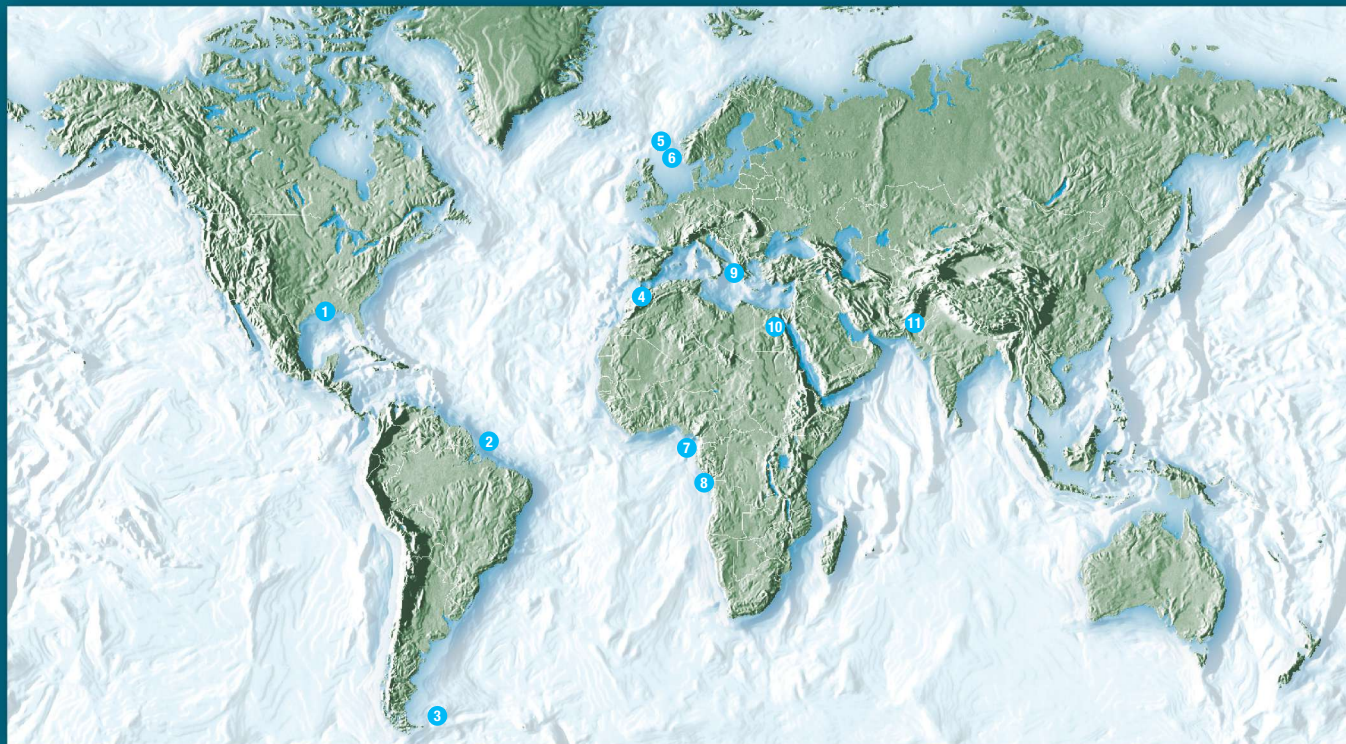
Lundin Petroleum AB has received a permit to drill appraisal well #16/1-28 S in production license (PL) 338 C. Lundin is the operator of PL 338 C with an ownership interest of 50%, with Lime Petroleum (30%) and OMV (20%). The area in this license consists of a southern part of Block 16/1 and a northeastern part of Block 16/4.

7 Nigeria

Erin Energy announced results from the #1-Oyo-NW well in the Nigerian sector of the Gulf of Guinea on Block OML120. Preliminary evaluation indicated a hydrocarbon discovery in Miocene. It was drilled to a proposed depth of 3,724 m (12,218 ft) and penetrated multiple sand units with total gross thickness of 79 m (260 ft) between 2,149 m and 3,314 m (7,052 ft and 10,873 ft). Evaluation of data showed the Miocene sand units U7.0 and U8.0 contained gross thickness of 25.4 m (83.6 ft) that are hydrocarbon-bearing. Additional testing is planned before appraisal drilling and development. Erin is the operator of Block OML120, the Oyo Field and the #1-Oyo-NW well with 100% interest.

8 Gabon

Petronas has announced an oil and gas discovery at exploration well



#1-Boudji in Block F14 (Likuale) located in South Gabon. The deep-water exploration well was drilled in water depths of 2,800 m (9,186 ft), and it encountered 90 m (295 ft) of high-quality, hydrocarbon-bearing presalt sands. Additional completion details were not available, as of March 21.

9 Greece

A consortium led by Total, with Hellenic Petroleum and Energean Oil & Gas, has received approval from the Greek Parliament to explore four western Greece blocks. Operator Total, which owns 50% interest, will drill two wells in offshore Block 2 in the Ionian Sea. Hellenic will drill in onshore blocks Arta-Preveza and Northwest Peloponnese, and Energean will drill in the Aitolokarnania Block. In addition, Hellenic also has the license to explore Greece's

Patraikos Gulf off the Peloponnese Peninsula. Work is expected to begin in 2019.

10 Egypt

An oil discovery was announced by SDX Energy at the #5-Rabul well in the West Gharib Concession in Egypt. The 1,609-m (5,280-ft) well encountered approximately 46 m (151 ft) of net heavy oil pay across Yusr and Bakr, with an average porosity of 18%. Additional testing and evaluation of the discovery are ongoing. After completion operations are done, the rig will be moved to drill the #4-Rabul well, the second of two appraisal wells planned for the Rabul feature this year.

11 Pakistan

Oil & Gas Development Co. Ltd. (OGDC) reported a gas field discov-

ery at exploration well #1-Umair in Pakistan's Sindh Province, Ghotki District in the Guddu Block (2869-9). The well was drilled to 790 m (2,592 ft) and was targeting the Pir-koh and Habib Rahi Limestone. During a short prestimulation test on a 36/64-in. choke, the well flowed commingled gas from the two formations at an average rate of 69,942.6 cu. m (2.47 MMcf/d) with a flowing pressure of approximately 330 psi. The well will be completed as a gas producer. OGDC is the operator of the Guddu Block and #1-Umair with 70% interest in partnership with Jura Energy Corp. (13.5%), IPR Transoil (11.5%) and Government Holdings Private Ltd. (5%). **ESP**

For additional
information on
these projects
and other global
developments:



PEOPLE



BP has appointed **Susan Dio** (left) president and chairman of BP America Inc. Dio succeeds **John Mingé**, who will retire from BP in March 2019.

Janeen S. Judah has been appointed to Patterson-UTI Energy Inc.'s board of directors.

James L. "Jim" Gallogly will resign from Continental Resources Inc.'s board of directors May 17. His departure is in connection with his appointment as president designate of The University of Oklahoma.

Husky Energy's CFO **Jon McKenzie** resigned in April, and **Jeff Hart** has been appointed acting CFO.

Sophie Zurquiyah has been appointed CEO of CGG replacing **Jean-Georges Malcor**, who has decided not to pursue his mandate once the company's restructuring process is complete. In addition, CGG's board of directors has announced the cooptation of **Helen Lee Bouygues**, **Heidi Petersen**, **Colette Lewiner**, **Philippe Salle** and **Mario Ruscev**.

EQT Corp.'s CEO and President **Steven Schlotterbeck** has resigned for personal reasons and has stepped down from the company's board of directors. **David L. Porges** has been elected interim CEO and president.

Katherine Roe has been elected CFO of Wentworth Resources Ltd.

Philip R. Houchin has been appointed CFO of Mid-Con Energy GP LLC.

GTI has promoted **James Ingold** to CFO, senior vice president of finance, and treasurer. In addition, **Quinton Ford** has been elected cor-

porate secretary and acting general counsel, replacing **Peter Witty**.

David M. Alexander has been appointed CFO of Stamper Oil & Gas Corp., replacing **Omar Choudhry**.

SEACOR Marine Holdings Inc.'s CFO and Executive Vice President **Matthew R. Cenac** has stepped down, and **Jesús Llorca** has been appointed to fulfill the roles.



Pradeep Verma (left) has joined Kreuz Subsea as chief commercial officer, and **Marek Kaminski** (right) has been welcomed as director of marine assets for the company.

Earthstone Energy Inc. has promoted **Robert J. Anderson** to president and **Leonard W. "Lenny" Wood** to vice president of exploration and development. In addition, the company has ratified the appointment of **Lane T. McKinney** to vice president of land.

Dave Payne has been named corporate vice president of HSE for Chevron Corp. He succeeds **Wes Lohec**, who will retire from Chevron in June after 37 years of service.

Flotek Industries Inc. has promoted **Matthew Marietta** to executive vice president of finance and corporate development, and he will serve as principal financial officer. In addition, CFO **H. Richard Walton** will assume the responsibilities of chief accounting officer.



M² Subsea has named **Andrew Imrie** global sales and marketing director.

The National Subsea Research Initiative has appointed **Tony Laing** director of research and market acceleration.

RED Engineering has appointed **Will Hopps** lead engineer, **Barry James** a senior engineer and **Adam Lockett** a design engineer.

Sintana Energy Inc. has elected **Dean Gendron** as a director.

Carrizo Oil & Gas Inc. has elected **Frances Aldrich Sevilla-Sacasa** to its board of directors.

Rob Chang has been appointed to Ur-Energy Inc.'s board of directors.

Gulfport Energy Corp. has appointed **Deborah G. Adams** to its board of directors and to serve on its audit and compensation committees.

Katherine H. Støvring has resigned from Tethys Oil's board of directors for personal reasons.

Energy XXI Gulf Coast Inc.'s board of directors has elected **Gary C. Hanna** board member and chairman.



Mikhail Putin has been elected member and deputy chairman of Gazprom's management committee.

COMPANIES

Petroteq Energy Inc. has opened its development facility, Petrobloq Blockchain Labs, in California.

Henderson, a provider of drilling rigs services and capital drilling equipment, has secured a rigup facility that will provide turnkey, multi-rig refurbishment and manufacturing. The 7,432-sq-m (80,000-sq-ft) property is located in Humble, Texas, and this acquisition will be finalized during the 2018 Offshore Technology Conference.

Siemens will make a €30 million (US\$36.8 million) investment in a



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3-D printing facility in Worcester, U.K., which is set to open in September.

Concho Resources Inc. and **RSP Permian Inc.** have entered into an agreement under which Concho will acquire RSP in a transaction valued at approximately \$9.5 billion. The transaction is expected to be completed in third quarter 2018.

Fara Holdco Ltd., owners of **Bibby Offshore**, has merged with **Rever Offshore AS**. The transaction is expected to close soon, according to a March Bibby Offshore press release.

Diversified Gas & Oil Plc has completed its acquisition of certain oil and gas leaseholds, wells, working interests, licenses, related equipment and other assets from **CNX Gas Co. LLC**. The company paid a cash consideration totaling \$85 million.

Bodycote, a provider of heat treatment and thermal processing services, has opened a specialist technologies facility in Mooresville, N.C. The facility was expected to be operational in March.

Opero Energy, a provider of gas processing and treating technologies for the oil and gas industry, has opened a 5,574-sq-m (60,000-sq-ft) fabrication facility in Houston. The facility will be equipped with the fabrication tools and technologies to support pipe fabrication, structural steel fabrication and module assembly.

Calumet Specialty Products Partners LP, a producer of specialty hydrocarbon and fuels products, has completed the acquisition of **Biosynthetic Technologies LLC**, a startup and developer of proprietary renewable technology, for an undisclosed amount. **E&P**

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Fracturing and the cloud

Implementing the cloud for hydraulic fracturing must include all the stakeholders.

Contributed by AFGlobal Corp.

Big Data is one of the most significant trends in the hydraulic fracturing business. But realizing the potential of cloud database systems has been limited. Identifying and understanding a complex set of stakeholder needs early in the development process are the keys to avoiding problems and creating long-term solutions.

Cloud systems offer many opportunities for improving hydraulic fracturing execution, efficiency and results. Huge volumes of data, remote operations and multiple stakeholders create a dazzling array of potential applications ranging from managing fracturing fleet maintenance to integrating field operations with enterprise information portals. Lessons learned by other industries clearly demonstrate that it is important to create a roadmap before embarking on this journey.

The core value of a cloud system is the ability to turn the data into useful, actionable information. However, initial efforts have had limited success in achieving this, largely because the applications are either so narrowly focused or so broadly applied that they miss a substantial portion of the potential value of the cloud at either end of the spectrum. The real solution resides somewhere in between.

Finding that middle ground requires engaging operators, pressure pumping companies and other stakeholders in a wide-ranging conversation about their experience, immediate needs and future objectives. Stakeholder interests must be understood across a full scope of applications, including operations, accounting and maintenance. It is a complex challenge. A recent AFGlobal market analysis, not surprisingly, yielded hundreds of issues and areas where cloud computing can and will offer a solution.

This huge potential is perhaps the most immediate challenge faced in implementing cloud-based systems. Sorting out priorities and realities prompts the next step, which is assessing the relative values of resolving specific

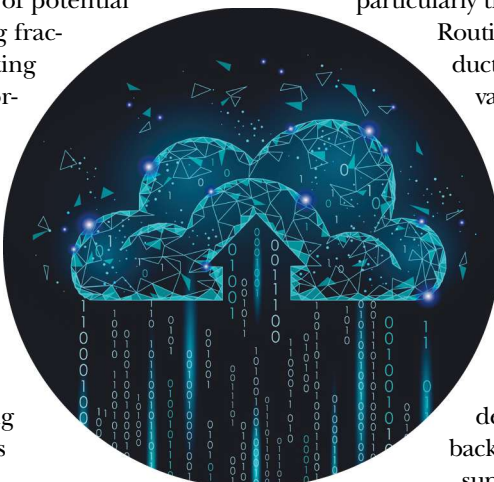
problems. That leads to identifying applications that can be implemented immediately to create the greatest value. This involved development process is further complicated by the need to do it all within a framework that also recognizes futures steps, both known and unknown.

AFGlobal's market analysis pointed to initial applications centered on managed maintenance of pressure pumping equipment to reduce failure in the field. Most of the maintenance on a hydraulic fracturing spread occurs with the fracturing units, and there are a lot of them onsite. While engines and transmissions can fail, most of the day-to-day maintenance involves the pumps—particularly the fluid ends.

Routine maintenance procedures conducted between stages and jobs, such as valve changes and repacking, make a cloud system well suited to tracking and scheduling the process. Accessing this large volume of data presents many opportunities to improve job performance through consistent, dependable operations and greater efficiency. For example, sophisticated maintenance schedules can easily recognize less demanding idle time accumulated by a backup pump; accumulated wear data can support predictive analytics so that pump deployment can be managed relative to the job requirements.

These maintenance capabilities address a key operator objective of achieving a smooth, uninterrupted job. Onsite equipment failure sets a cascade of problems in motion. Job safety and execution are compromised when people are scrambling to keep the job going, maintenance and repairs add time to one job and delay the next, and diminishing job quality hurts well performance and complicates design assessment.

Underlying all these are massive amounts of data. The advantage that cloud systems offer is the ability to collect and analyze it. Success requires a conversation with all the stakeholders as well as careful planning early in the development stage to meet and anticipate the complex set of needs presented by hydraulic fracturing operations. **ESP**



(Source: LuckyStep/Shutterstock.com)



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