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Rock Physics

Drilling Fluids

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Sand Management

SURF Solutions

Unconventional
Report:
HAYNESVILLE

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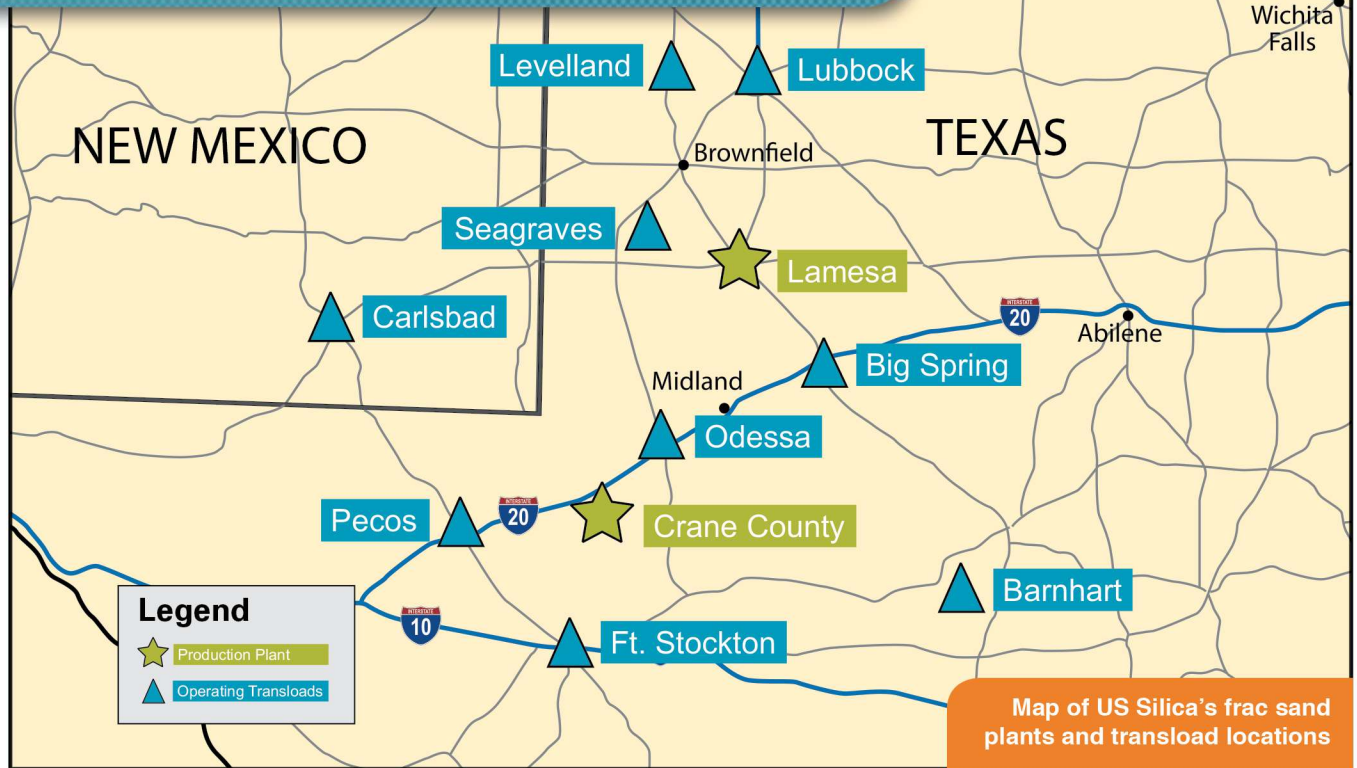


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January	Unconventional Yearbook
March	Water Management Techbook
May	OTC Show Daily
June	Artificial Lift/ Automation Techbook EAGE Show Daily
July	Permian Basin Map
August	Hydraulic Fracturing Techbook Oklahoma Map
September	Oklahoma Playbook
October	Permian Basin Playbook SEG Show Daily
November	Eagle Ford Playbook
December	Offshore Technology Yearbook

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COMING NEXT MONTH The March issue of **E&P** will focus on drilling. Other features will include reservoir characterization; coiled tubing drilling and tools; plugs; onshore well intervention; and deepwater production facilities. The unconventional report will focus on the Permian's Midland 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 24,000-tonne topsides for the *Aasta Hansteen* gas platform was floated over and connected to the floating vertical hull in December 2017. Left, Haynesville Shale operators are standing tall once more as gas production has returned to predownturn levels. (Cover photo by Olaf Nagelhus/Worldcam, courtesy of Statoil; Left photo by Tom Fox, courtesy of Oil & Gas Investor; Cover design by Felicia Hammons)

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Lea County stepout produces 6.911 MMcf of gas

In Lea County, N.M., EOG Resources Inc. has completed the first of two offsetting horizontal wildcats initially permitted by Yates Petroleum Corp. EOG's #2H Audacious BTL Federal Com was tested flowing 3.47 Mbbbl of oil, 195 Mcm (6.911 MMcf) of gas and 11.06 Mbbbl of water per day from the Upper Wolfcamp.

Upper Three Forks producer flows 3.438 Mbbbl of oil

In Section 25-152n-100w of McKenzie County, N.D., Whiting Oil & Gas Corp. completed a high-volume horizontal upper Three Forks producer in the Williston Basin. The #31-25-2TFH Koala was tested flowing 3.438 Mbbbl of oil, 144 Mcm (5.093 MMcf) of gas and 4.925 Mbbbl of water per day.

Haynesville completion flowing 27.683 MMcf/d of gas

IHS Markit reported that Covey Park Gas LLC completed a high-volume Haynesville Shale gas well that was tested flowing 784 Mcm (27.683 MMcf) of gas and 235 bbl of water per day. The discovery, #1-Alt Benbow 4-33HC, is in Section 4-15n-11w in Bossier Parish, La.

AVAILABLE ONLY ONLINE



Algeria aims to develop shale gas despite challenges

By Abdelghani Henni, Contributing Editor

Algeria ranks third globally after China and Argentina in technically recoverable shale gas reserves with 20 Tcm (706 Tcf), according to the U.S. Energy Information Administration.

Study: Only one-third of Canadian oil patch job losses expected to return

By Markham Hislop, Contributing Editor

Technology and the lower-for-longer price environment have wrought rapid changes—some good, some bad—to Canada's oil patch.



Oil, gas trends to watch in 2018

By Velda Addison, Senior Editor, Digital News Group

Deloitte talks production, exports, technology and more on what trends to watch out for this year.

US in danger of lagging in renewables investment

By Joseph Markman, Senior Editor, Digital News Group

Survey shows that the renewables sector merger and acquisitions activity will likely favor China and Germany, with U.S. policies curbing investors' interest.



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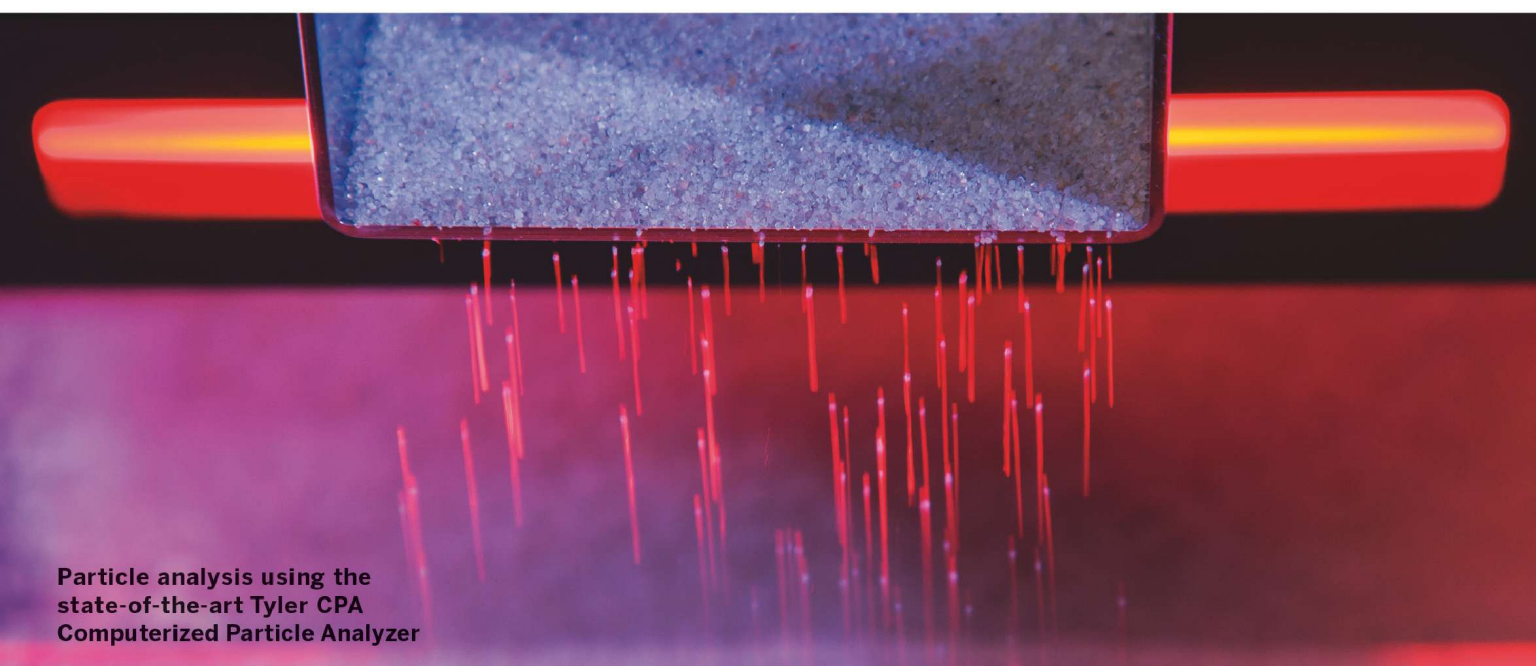


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Facing a changed future

A slimmer and trimmer offshore segment emerges in 2018.

A new year always brings with it fresh ideas, goals and plans to make the year ahead better than the last. With 2016 a year of cost cutting and 2017 a year of living within means, the oil and gas industry is facing 2018 with a renewed sense of purpose. While predicting when the industry will return to a more sustainable level, there are indications that the hard decisions made these past few years are starting to deliver returns.

John England, vice chairman, U.S. Energy & Resources leader for Deloitte LLP, noted in his 2018 outlook on oil and gas, “the question coming into 2017 was whether the [cost] reductions are sustainable,” adding that the evidence going into 2018 indicates success as “breakeven costs across the major U.S. shale plays still are 30% to 50% below the levels of early 2015.”

As for the offshore segment, the “megaproject” days of old are on hold. Shell, in its final investment decision announcement for its deepwater Kaikias project in the Gulf of Mexico (GoM), said the field will be competitive at oil prices below \$40/bbl.

BP and Statoil returned to their respective drawing boards to slash costs on their major offshore projects. At its Mad Dog Field in the GoM, BP trimmed Phase 2 development project cost to \$9 billion from a high of \$20 billion with a breakeven of about \$40/bbl, per the company. Statoil at its Johan Sverdrup development project cut costs so significantly that field breakeven cost dropped from \$100/bbl to \$27/bbl, according to a company release.

Applying lessons learned from previous projects, simplifying designs, using existing infrastructure and working with suppliers were cited by the operators as keys to success when it came to making these major offshore projects profitable.

These are keys that suppliers like TechnipFMC also have adopted to ensure continued profitability. With its Subsea 2.0 approach, the company reduced the weight and size of the subsea system while simplifying the configuration for flowlines and installation. For example, the Subsea 2.0 tree is about 40% smaller, 50% lighter and has 60% fewer parts, according to Paulo Couto, senior vice president of integrated sub-systems for the company.

“Our strategy is to make things cheaper, faster, accelerate production, resolve integrity issues and make it more serviceable,” Couto said during the company’s analyst day in late November 2017. “The goal is to lower the breakeven of the economics, enabling many more subsea fields, making more subsea fields viable,” he said.

By being simpler, smaller and smarter—less mega—the offshore oil and gas industry appears ready to face a changed future. **ESP**

Jennifer

The vibration threat

Web tools enable effective piping vibration management.

Rob Swindell, Wood

In the field of asset integrity management, it is corrosion and erosion that attract the lion's share of management time, resources and analysis. This is because corrosion or erosion is almost inevitable, with potentially catastrophic consequences.

In contrast, vibration and its consequences attract significantly less attention and management activity. Inadequately managing the threat of vibration can be equally catastrophic. In fact, it accounts for a relatively high percentage of reported failures, notably in harsh environments.

The approach to vibration management is becoming more proactive, preventative and global. This has been driven by three factors: demand from operators with an international perspective, wider dissemination of existing standards and industry guidance, and the supply of enabling technologies that bring vibration to the heart of asset integrity management.

Managing vibration risk

Piping vibration management is not traditionally a problem that's pre-empted. By prioritizing cure over prevention, operators fail to spot weaknesses in their infrastructure and implement optimal mitigation strategies. Vibration affects offshore, subsea and topside piping, and associated equipment.

There have been regional differences in attitudes toward vibration management. In the U.K. the Energy Institute's 2008 document outlines the issue of vibration and how changes to design could solve problems seen on new commissions onshore and offshore.

There has been a shift to a more global approach, which has been driven by North Sea oil majors. Having used the institute's approach in their European operations for some time, they are now encouraging operators across the world to consider vibration as an issue that should be proactively addressed.

Where companies lack a European connection, it is only in the past few years that interest in vibration issues has grown. Having experienced their own vibration-



Veridian is Wood's web-based screening tool used to identify and assess vibration risks in process piping systems, regardless of the scale or size of an asset. (Source: Wood)



Veridian can integrate with many integrity management programs and identifies and mitigates potential risks to piping systems designs. (Source: Wood)

induced failures, companies in North America, Australia and the Middle East recognize that vibration can be painful and expensive.

The institute's document remains the de facto standard. Common piping design codes have historically not addressed vibration issues properly, and other standards are limited to specific aspects. Additionally, the standards provide the most in-depth approach to identifying and mitigating vibration issues from a variety of flow-induced excitation mechanisms.

Identifying vibration risk

The institute's position also accounts for vibration management during design. This is aided by some design codes now referencing institute guidelines on severe cyclic service designs.

The screening approach takes basic piping information and the range of process conditions and enables operators to identify potential vibration hot spots. This strategy is designed to provide the necessary information to address potential issues before the plant is commissioned.

While using piping vibration measurements to identify potential issues is a useful technique, it often is dependent on how the plant is operated and the flow rates. A vibration-measurement survey is just a snapshot of what is happening at the time. A far better understanding of risk can be built by combining a plantwide screening assessment with a targeted vibration-measurement survey covering all operating scenarios. This results in a targeted approach to vibration-measurement surveys, system modifications and the implementation of suitable

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Project work scope example: installation of a new process module on an existing offshore platform

Stage 1: qualitative assessment

During the FEED stage, project process design engineers can use the Energy Institute's approach to identify potential high-risk piping systems. In this qualitative assessment, operators can consider mitigating potential issues before purchasing any equipment or materials, e.g., larger pipe diameters (lower flow velocities), specialist (long lead time) flow control valves or more robust, small bore connection designs for instrumentation. This approach enables engineers to reduce time spent on redesign and minimize any associated project delays, ultimately reducing the overall project costs.

Stage 2: quantitative assessment

Piping engineers can include a vibration assessment as part of their scope to ensure the detailed piping design is at low risk of fatigue damage. This quantitative assessment could include small bore connection designs and bracing, side branch arrangements, instrument tubing

and pipe supports. This assessment will minimize the long-term risk of vibrations and provide information on the impact of the new process on the existing process pipework. Armed with this information, modifications to the existing plant (if required) can then be planned and implemented in a timely and cost-effective manner prior to startup of the new module.

Stage 3: construction

During construction a plant survey should be run to ensure the as-built piping reflects the optimized design and any as-built anomalies are identified and rectified prior to startup. This stage is effectively a quality check targeted at minimizing the risk of a piping failure during startup and commissioning. This assessment process can be carried out and managed using Wood's Veridian software package, with standard process and piping input information. The outputs can then be uploaded into the operator's existing integrity management system. ■

control measures. Risk-based vibration-screening assessments use very similar data to that used for risk-based inspection programs.

Screening benefits, challenges

As asset integrity management becomes increasingly important, vibration screening is expected to be more widely adopted. Where there is no vibration screening in place, the operator often has little option but to replace the damaged equipment if a plant experiences a failure. This could result in design flaws or structural weakness being built in, potentially leading to a recurring problem that results in shutdown or throughput reduction while an external consultant analyzes the failure.

By using screening techniques that give a helicopter view of the plant, operators can see potential risk locations and deploy resources accordingly.

The methodology and algorithms for effective vibration screening are readily available. There is growing recognition that it is key to any effective asset integrity management program. There also is increasing interest

from companies worldwide to apply these methodologies at the design stage and on operational facilities from companies worldwide.

But practical challenges remain. One technological hurdle is the placement and accessing of algorithms into a spreadsheet. This opens operators up to spreadsheet risks.

The second challenge is the inability to track issues as they are identified. A time-stamped report is of limited value, however accurate the recording. Since the consequences of vibration vary enormously as process conditions change, a snapshot view becomes rapidly out of date.

For example, after identifying several weak small-bore connections on piping systems that present risks, operators need to register those locations for tracking. The register needs to capture the results of a line walk-down and should include any action already taken.

Building a dynamic register or anomaly database that is linked to the screening "engine" enables operators to maintain information on the status of any anomalies within a dynamic operational environment. **ESP**



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What could 2018 hold for offshore oil, gas exploration?

With companies still in budget-cutting mode, new emerging exploration hot spots will be rare in 2018. However, some active exploration spots from 2017 will continue to be a focus this year.

Velda Addison, Senior Editor, Digital News Group

Although unfavorable market conditions with lower but slowly improving oil prices left E&P companies' exploration budgets battered in 2017, the year still managed to bring a few notable gems that put exploration into the positive spotlight.

Exxon Mobil Corp. picked up where it left off in 2016 offshore Guyana with its Liza discovery in the Stabroek Block, adding more resources to the mix in 2017. The company kicked off 2017 with the Payara-1 well discovery, following up about six months later with news of more oil discovered at Payara. In between came news of the company's third oil find, Snoek, on the block. This was followed in October by yet another discovery—Turbot—bringing the total gross recoverable resources on the block up to an estimated 2.75 Bboe.

But that wasn't the only major exploration news to unfold in what turned out to be hot areas for activity or attention by industry players.

Mexico said state-run Pemex made its biggest onshore oil discovery in 15 years in November 2017 when the Ixachi well struck oil in Veracruz. Original volumes in place were estimated at about 1.5 Bboe.

Talos Energy and partners Sierra Oil and Gas and Premier Oil hit up to an estimated 2 Bbbl of light oil in shallow-water offshore Mexico with its Zama-1 well.

Reservoirs beneath Mexico's shallow water also were good to Eni, which raised its resource estimates of the Amoca Field to 1 Bboe in place and the Area 1 estimated resource base to 1.3 Bbbl of oil in place.

Action also heated up on Alaska's North Slope where Repsol and partner Armstrong Energy celebrated a massive oil find in March 2017 in the Nanushuk Play. With 1.2 Bbbl of recoverable light oil, Repsol and Armstrong claimed the discovery was the "largest U.S. onshore conventional hydrocarbons discovery in 30 years."

So what could be in store for 2018? Shuqiang Feng, the upstream director for Stratas Advisors, shared insights on exploration spending and hot spots with Hart Energy.

Hart Energy: Exploration spending by oil and gas companies plummeted during the downturn as many cut back on spending. But now that oil prices are climbing up, are more companies stepping up exploration plans? How much is exploration spending expected to increase in 2018?

Feng: Even though the oil prices are recovering, we have not seen a quick recovery of companies' exploration spending in 2018. Oil companies are still in the budget-cutting mode in terms of exploration. Anadarko announced a budget on exploration and LNG development of only \$350 million for 2018, more than 50% down from 2017 budget of \$770 million. Chevron's exploration budget in 2018 pretty much remains the same as \$1.1 billion (\$1 billion in 2017 budget). Companies' capital spending will still focus on existing assets and ongoing new developments. Until oil companies start generating larger cash flows with sustainable higher oil prices, it's less likely for them to start jumping on aggressive exploration activities.

Hart Energy: Internationally, few can argue that all eyes were on Exxon Mobil's discoveries offshore Guyana. Will the new year bring more exploration offshore Guyana? What about to nearby Suriname? Are success stories developing there?

Feng: After five discoveries offshore Guyana in the same Stabroek Block, Exxon plans to do further exploration drilling in 2018 in the multiple leads already identified.

The other two blocks in Guyana that might have exploration drilling in 2018 are the Tullow-operated Orinduik Block and the Repsol-operated Kanuku Block. 3-D survey acquisition was completed in September 2017 in Orinduik, and Total got in an option agreement with Eco Atlantic to acquire a 25% working interests of the block. 3-D survey acquisition was also completed [in 2017] in the Kanuku Block, and Repsol sees Kanuku as a good prospect for medium-sized discoveries updip from the Liza trend.

Exploration drilling continued in 2017 in Suriname; however, no successful stories yet.

Tullow is active in Suriname, but the wildcat Araku-1 drilled on Block 54 [in 2017] came out uneconomical. However, the setback is not likely to kill the company's interests in the Guyana Suriname Basin, as the company is shifting focus to Guyana in 2018.

Kosmos Energy owns two blocks (42 and 45) in Suriname and plans to drill two prospects there.

Apache has also been active in Suriname but so far has hit two dry holes in Block 53, Popokai-1 well in 2015 and Kolibrie wildcat [in 2017]. Apache also owns the exploration Block 58, where a 3-D survey was done earlier [in 2017]. Potential exploration drilling exists in 2018.

Hart Energy: What other exploration hot spots could be in store for 2018?

Feng: As companies are expected to continue to tie up their spending budget, new emerging hot exploration spots are rare, at least in 2018. However, there are spots that will continue to be active on exploration in 2018 as they were in 2017.

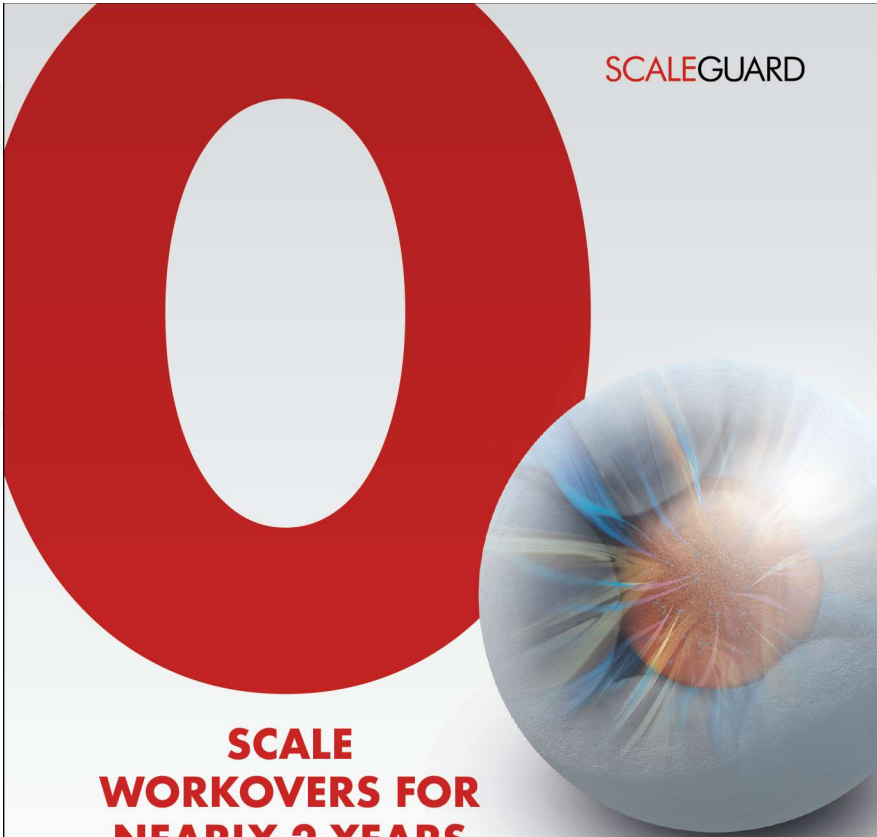
Statoil, Aker BP and Lundin were active in the Barents Sea offshore Norway in 2017, but the drilling results were very disappointing. The companies are planning to continue to explore there in 2018, but most likely with a similar activity level as 2017.

Encouraged by the big Zohr gas discovery in the Mediterranean Sea offshore Egypt, Eni and other oil companies are expected to continue to drill for the next big find in the area, especially offshore Egypt and Cyprus. In Cyprus Total and Eni plan to drill in Block 6 in 2018, and QP and Exxon Mobil plan to drill in Block 10 in 2018.

Interest in the overlooked offshore area of West Africa's Mauritania and Senegal increases since big discoveries were made by Cairn Energy and Kosmos Energy. Majors are getting into the area: BP partnered with Kosmos Energy in Senegal in 2016, Exxon Mobil is close to signing a deal to explore for oil and

gas offshore Mauritania, and Total acquired new deep-water acreages in Mauritania in 2017. Tullow and Kosmos Energy have been active players in the area for years. Exploration drilling in the area is expected to remain active in 2018. **ESP**

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A sandstorm is coming

The move to massive proppant loading involving finer mesh sands will boost 2018 demand even in a flat rig count environment.

Richard Mason, Chief Technical Director

Correlation is not always causation. That rings true for 100 mesh sand, a proppant that has moved to the forefront of downhole discussion.

Earnings calls are replete with E&P companies and sand mining operations alike discussing proppant varieties as though they were the finest of wines.

When it comes to completions, the tight formation revolution entails the reversal of previously held norms. E&P companies once used coarse grains and viscous fluid to place proppant in crude oil well stimulation. Later, the industry moved to light volumes of coarse sand in early slickwater treatments for fracturing tight formation gas. Over the last half decade, the industry flipped to massive proppant loading of finer sand grades using larger fluid volume and higher pump rates in a slickwater plug-and-perf (PNP) configuration, whether fracturing tight formation oil or gas.

The move to slick water occurred simultaneously with oilpatch price deflation following the 2014 peak. But correlation is not causation. E&P companies used the downturn to experiment with massive proppant loading of finer grades of sand in a slickwater PNP configuration in concert with longer laterals and closer stage spacing. Finer grade proppant use grew because it worked.

Consequently, interest in finer sand grades is rising as the industry recovers. And yet laboratory models fail to describe definitively how the proppant behaves in the field. E&P companies traditionally deployed 100 mesh and larger pellets as a diverter rather than a proppant. In the laboratory, 100 mesh at crush point tends to shatter, creating flow-blocking fines. In practice, 100 mesh sand often correlates with greater productivity. Performance may reflect formation scouring, as any fracturing service provider will attest when discussing wear and tear

on pumping unit fluid ends. Or performance may reflect E&P companies' high-grading wells to the best rock primarily during the downturn where finer mesh proppants exhibit beneficial influence.

Although the mystery remains, a rising chorus of E&P companies now sings the praises of finer mesh sand. Proppant consumption is projected to grow 25% to 100 million tons in 2018. Of that, 100 mesh sand could capture 30% of demand, up from 22% in 2017. A perusal of 6,000 horizontal wells in 2017 on the FracFocus website finds sand comprises 94% of proppant—half undifferentiated by grade—with resin-coated sand accounting for 5% and ceramics making up the remainder.

Most 100 mesh sand originates from surface mines in the upper Midwest. Now a sand rush is underway as newly discovered Permian Basin deposits threaten

to alter sand market fundamentals. Nameplate capacity for Permian sand production is projected to top 60 million tons of mostly 100 mesh sand annually within a half decade.

Sand market dynamics are in open debate for 2018. Regional sand supplied 35% of oilpatch demand in 2017. The story will

play out in the Permian Basin, which is projected to account for 45% of 2018 demand.

Unknowns remain. Laboratory tests indicate Permian sand exhibits lower performance characteristics versus premium Northern White. That won't matter for Permian E&P companies in shallower regions of the southern Midland or northern Delaware basins. Other E&P companies will stick with traditional Northern White, particularly as providers offer flexible inter-regional transfer and last-mile delivery solutions.

If it were about performance only, field practice and laboratory tests show coiled-tubing-activated sliding sleeves and engineered proppants generate a bigger harvest. But the methodology and materials are more expensive by a factor of five. Like The Dude in "The Big Lebowski," demand for finer grades of sand abides for 2018. **ESP**

- **Sand consumption to top 100 million tons in 2018.**
- **100 mesh sand is capturing market share.**
- **New Permian mines will disrupt sand market.**

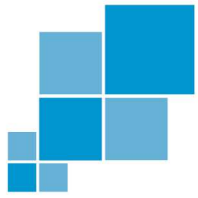


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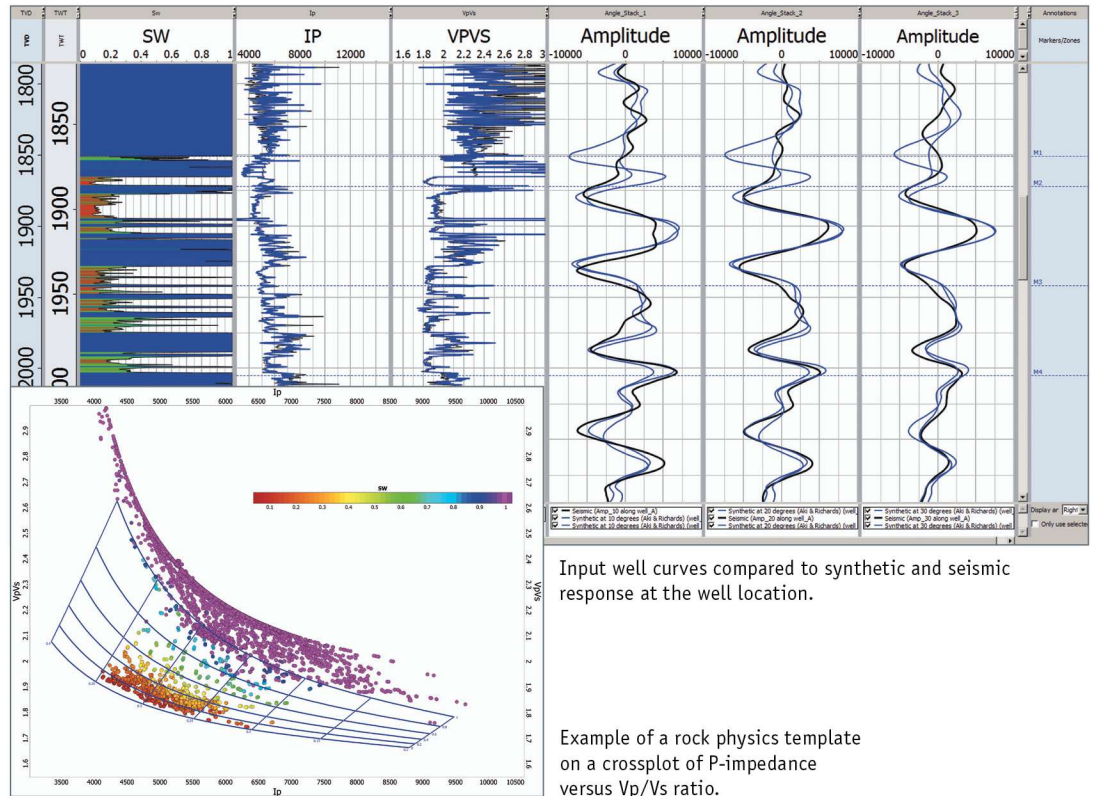
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Innovation in a downturn

Maintaining discipline and patience can pay dividends in an R&D program.

No question, downturns are tough on investments. But companies that invest in R&D don't have to abandon that quest altogether. They just have to invest smarter.

Erika Biediger, drilling and subsurface function manager for Exxon Mobil Upstream, spoke at a recent luncheon about the need to maintain an R&D strategy regardless of the oil price. In what quickly turned into an open discussion about innovation, Biediger said that a lot of good R&D has taken place in downturns in the past, noting that developments such as polycrystalline diamond compact bits and top drives were ideas that came out of down markets.

But these cycles are not without their challenges, and these can vary by location. For instance, technical challenges in deep water include cost reduction and increased reliability, while in remote locations the challenges include cost reduction but also equipment supply. Unconventional challenges revolve around sustainable cost reduction while improving recovery efficiency.

"There is physics-based cost reduction and supply chain cost reduction," she said.

Companies also need to be on the lookout for innovations that come from unexpected places. This could include technology transfer from other industries and collaborative partnerships. Biediger added that often an idea will come up that's not currently feasible. Her researchers check back on that idea from time to time to see if it's become doable. Biediger also said sometimes small ideas can lead to waterfall breakthroughs.

"But to succeed, everyone needs skin in the game," she said.

In a low-price environment companies tend to form joint industry partnerships (JIPs) and other collaborations, but these can have their own pitfalls. For instance, intellectual property is challenging in these situations because service companies don't want to give their intellectual property to universities since those institutions can then license that intellectual property to the competition, she said.

"Oil and gas is a high-cost business, and there's still plenty of space for the entrepreneurial spirit."

**—Erika Biediger,
Exxon Mobil Upstream**



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"The slowest member of a JIP sets the pace for development," she said. "There's a tendency to group up, but you have to be selective about the numbers."

One audience member noted that college graduates are increasingly being drawn to startups.

"Oil and gas is a high-cost business, and there's still plenty of space for the entrepreneurial spirit," she said, adding that some partnerships are more willing to take risks than others.

"We're not all Steve Jobs," she said. "It's more like, 'Here are my problems, and here's a pool of money.' Then you frame the problem in a way that makes sense."

She gave the example of an approach to improving ROP. It started with a model developed in the 1950s on how to break rock using a curve that related ROP to weight on bit. But it wasn't a steady curve.

Researchers determined the curve was limited by hole cleaning, directional control and motor differential rating. Then they identified the physics behind each function, monitored vibration data and performed analytics on the mechanical specific energy equations. This resulted in an increase in ROP from 137 m per day to 207 m per day (450 ft per day to 680 ft per day).

According to Biediger, barriers to technology innovation and commercialization include physics; economics; reliability; integration and logistics; alternative technologies; HSE; and regulations, patents and public perception. And down market conditions amplify the need to go from concept to commercialization in less time. **ESP**

Rhonda



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NDT shaves days off BOP inspection time

Digital solution reduces downtime and cost while improving productivity for offshore drilling operations.

A fingerprint's beauty is found in its uniqueness. In each arch, loop and whorl of the print, lie the identifying characteristics that set one person apart from another. Machines also bear similar tell-tale marks of individuality. So do the bolts, flanges, nuts and studs holding those machines together. But short of cracking open its exterior, how can one visually inspect the condition of a machine's interior components?

One way is through nondestructive testing (NDT) to ensure all components of a system are functioning in a reliable and cost-effective manner. In 2015 Baker Hughes, a GE company (BHGE), formerly GE Oil & Gas, piloted its NDT BOP Inspection Technology System that leveraged 4-D scanning using digital fingerprinting to deliver rig-based inspection and recertification of BOPs without disassembly.

Using robotics, analytics and phased array ultrasonic testing, periodic inspections create a 4-D comparison of BOP components. The fingerprint becomes the baseline for equipment condition at any point in its life cycle. By digitally comparing the current scan against previous scans, changes are highlighted and mapped. The system has been used with several customers, including four BOP stacks for Diamond Offshore as part of the contractual services agreement the companies entered into in 2016.

Enhancements made to the system since the start of the pilot program include the ability to see the individual threads of the bolts, nuts and studs securing flanges.

"You've got a stud coming through a flange with a nut sitting on top of it," said Dave Bowen, product leader for digital and services for BHGE's drilling systems business. "The moment you release that nut, you're taking pressure off the system and changing the dynamics of what's happening to that seal. We developed a technology that gives us the ability to put a scanning device over a nut, stud or bolt and see the threads to determine if there are any issues that would lead us to believe that the part is nearing the end of its life."



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He continued, "Performing an inspection on the fasteners within a BOP stack—nominally 500 to 600 per stack—typically takes 30 minutes to an hour per fastener. With digital fingerprinting that inspection time reduces to about two minutes per bolt," which he said is "a radical change and one that delivers huge savings to our customers."

In addition to time savings, scanning the equipment is a far safer process than breaking down and inspecting the components. It takes a day for the technicians to set up the equipment, with the scanning occurring on the second day, according to Bowen. Depending on the component being inspected, the entire process would take six to seven days.

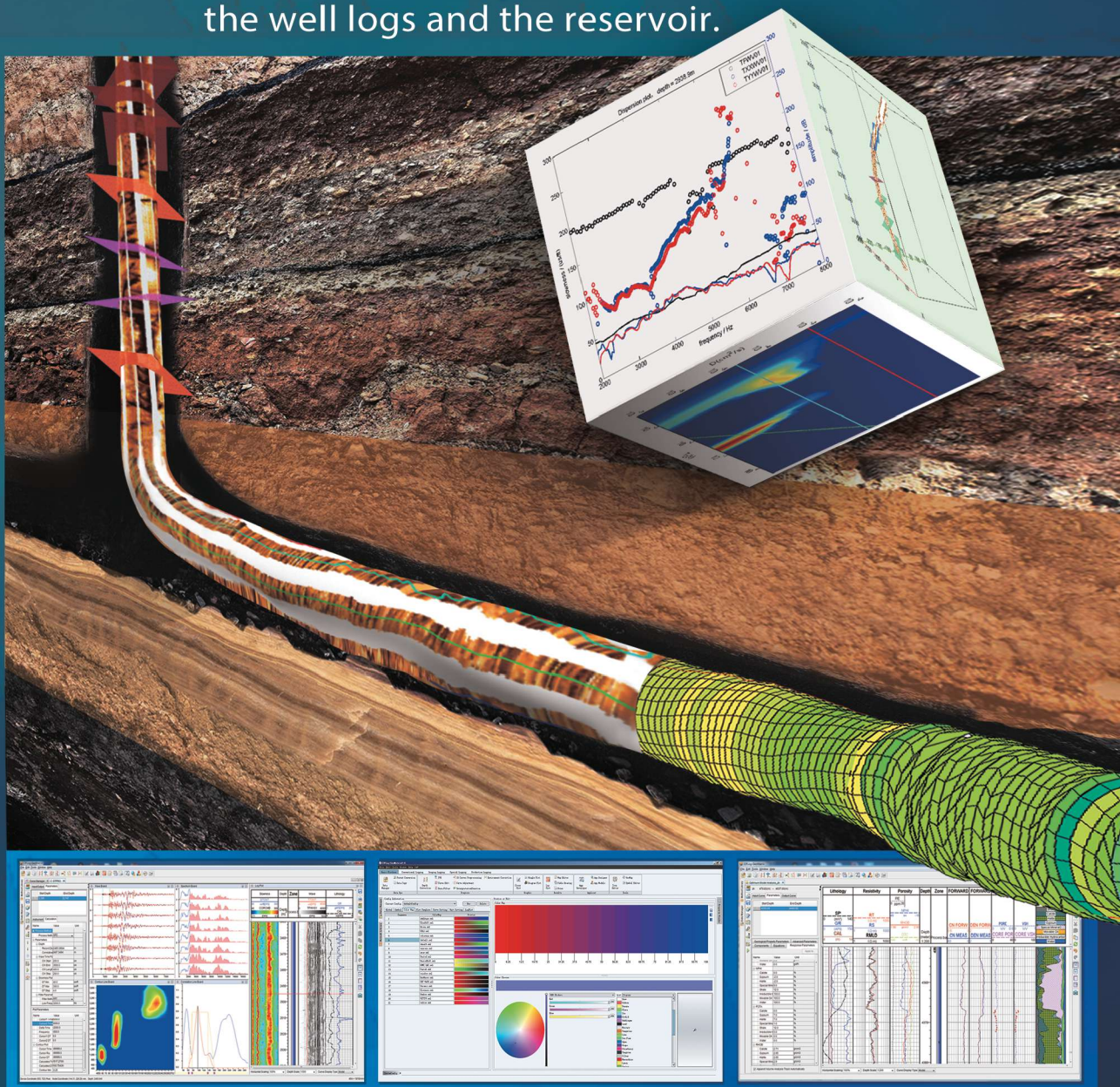
"We estimate there's a 40% savings just in the time to do the inspection itself," he said. "But what it doesn't calculate—which is going to be just very dependent rig to rig—is the amount of time it takes to go break down a BOP in a confined space and in a very tough environment. It represents a big safety hazard to the individuals at work. It also represents the opportunity for significant damage to that equipment that can occur from disassembling and reinstalling."

Taking everything apart and inspecting can take 30 to 40 days versus a week if the scan is done *in situ* using the digital fingerprinting technology, Bowen said. "The safety and time savings makes the benefits of the *in situ* inspection solution almost incalculable." **ESP**

A stylized, handwritten signature of Jennifer Presley in black ink.

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Maintaining asset integrity

Maintenance programs can help save costs and enhance long-term production.

The re-emergence of the U.S. oil industry over the past decade has coincided with the introduction of new advanced technology and equipment in the oil field. More rigs, more fleets and more production facilities present new challenges in maintaining that equipment to ensure the fields from which they are producing remain productive for an extended period. Avoiding downtime and ensuring cost savings are additional benefits realized through regular equipment maintenance. Successful maintenance programs also can lead to increased production rates over time.

But different companies take different approaches to maintaining their equipment—some implement systematic preventative maintenance programs, some adhere to what data are telling them and some just run equipment until it dies or breaks. Some companies see the importance of a quality equipment maintenance program, but they may not have the means to implement it.

Alison Mackey, production manager, digital, for Baker Hughes, a GE company (BHGE), said BHGE often sees customers that either implement a wide-ranging maintenance plan or have a reactionary approach to maintenance.

“We don’t see a lot of middle ground,” she said. “Either there’s a big focus from the top down—it seems they really do take a strong interest in maintenance—otherwise they run [equipment] to failure and it’s very reactive.”

Mackey said by planning maintenance programs even six to eight months in advance, operators can avoid significant downtime and see substantial cost savings.

Roy Aune, director of maintenance for Liberty Oilfield Services, said the oil and gas industry as a whole has yet to buy into the idea of a systematic predictive maintenance program.

“The new buzzword is proactive maintenance, so—as much as possible—that’s what we are trying to



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do. We are trying to find the perfect mix of proactive maintenance,” he said.

As with many sectors of the industry, equipment maintenance and asset integrity management are turning to digitalization, with its proponents saying it is instrumental to understanding equipment reliability and performance.

“There is more and more emphasis on data-driven decision-making,” said Charles Yang, reliability project manager for NOV. “There are a lot of new focuses and new emphasis on condition-based maintenance and how do we reduce the cost around maintenance and how do we introduce new elements to monitor the conditions of the equipment performance and try to see what maintenance is needed to ensure reliability.”

Companies today often are faced with the act of balancing high IP rates versus longer-term production.

Equipment maintenance is a long-play game and could result in as much as 20% more production if it’s fully committed to, according to Aune. It’s often difficult to commit money to something that does not produce an immediate, tangible result or benefit, and such is the nature of maintenance in the oil and gas industry. But the companies that are willing and able to commit to it could very likely see a long-term benefit through cost savings and increased production. **ESP**



Maintenance technicians perform routine inspections at a job site. (Source: photostock77, Shutterstock.com)



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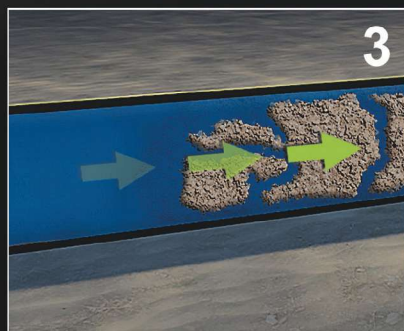
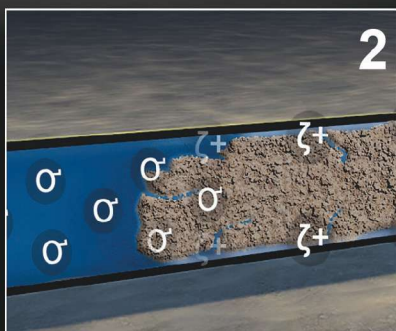
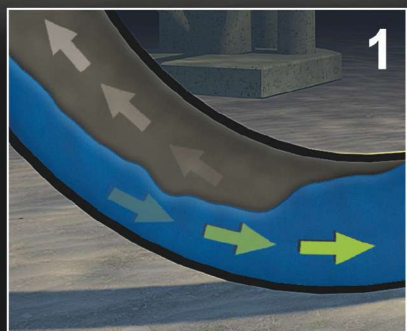
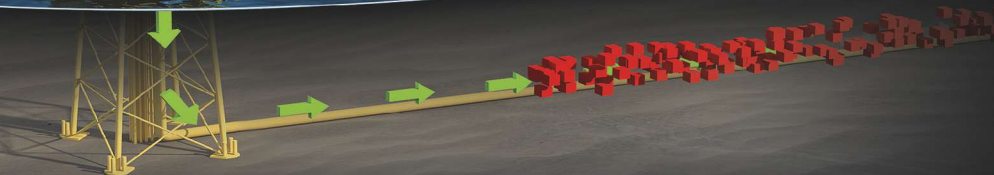
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OSVs evolve to survive

The new 'normal' is a catalyst for change.

It is not a surprise to those following the construction market that the offshore support vessel (OSV) fleet is in dire straits. In March 2017 VesselsValue, a group of analysts that follow yard activity, reported that the already oversupplied OSV market was facing a record number of deliveries in 2017, with 465 vessels expected to join the global fleet. Data published in October indicated nearly 80% had not yet been delivered.

While current market forecasts for this year indicate better times are on the way, the likelihood is slim that a balmier business climate will rescue the OSV sector from its current distress. As with other market sectors, innovation will be the determining factor for success.

In taking on the new "normal" of lower oil and gas prices and limited demand for their services, OSV owners are taking a critical look at their fleets and reassessing their value in a very different market to chart the best—and most profitable—way forward.

Some owners, like Harvey Gulf International Marine, were ahead of the game in recognizing that changes needed to be made to give its fleet a competitive edge. In 2015 it became the first U.S. vessel operator to supply a vessel capable of operating exclusively on natural gas. The newbuild *M/V Harvey Energy* was the first LNG-powered OSV in service in North America.

Meanwhile, owners with idle vessels in their fleet are looking for ways to convert existing units to deliver more marketable services. In some cases that means enhancing capabilities. This is the route Ulstein took mid-2017, identifying a need for inspection, repair and maintenance vessels that could support subsea installation in addition to offshore wind operations. The company announced it would deliver "new-life solutions" through "a well thought-through conversion" that would allow medium-sized PX121 platform supply vessels to compete for short- and medium-term contracts.

Venturing even farther off the beaten path, Silverstar Marine has proposed the idea of converting an OSV into what it described as "a high-quality, prac-

In taking on the new "normal," OSV owners are taking a critical look at their fleets to chart the best—and most profitable—way forward.



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tical, heavy seas explorer/adventure yacht." Among its selling points is price. A finished refit of an OSV would yield a larger superyacht at a lower cost than could be achieved with a newbuild.

While some companies are finding ways to keep existing units busy, others are designing newbuilds with specialized markets in mind.

In December 2017 Jumbo signed a letter of intent with China Merchants Industry Holdings for detailed

engineering and construction of a new DP2 heavy-lift crane vessel (HLCV) that will be delivered in first-quarter 2020. The *X-BOW* HLCV, designed with Ulstein Design and Solutions B.V., will be powered by dual fuel engines and can run on LNG.

Also in December, Wärtsilä Corp. announced a new hybrid tug design, a version of the Wärtsilä HYTug, with a fully integrated hybrid power module that combines engines, an energy storage

system using batteries and power electronics optimized to work together through a newly developed energy management system, reducing emissions and noise and improving performance. The design, which was developed for use in China, has received Approval-in-Principle recognition by the China Classification Society.

The range of concepts and capabilities shows clearly there is no one-size-fits-all solution for this oversupplied market, but grit, determination and imagination could go a long way toward turning things around. **ESP**

Solving upstream's data trust gap

A robust technology system delivers directly measured multiphase metering data for improved operations.

Giles Edward, M-Flow

Accurate measurement has perennially been one of the upstream sector's greatest challenges, with many believing that data and digitalization could help solve measurement dilemmas. This will only become reality if the data are reliable and reproducible.

Oil company senior managers are often involved in disputes over what and how much has been measured. It is very difficult to prove to a legal standard. Even during relatively straightforward operations, like sending crude from storage to measuring stations, there can be disagreements about what volumes were sent and received. And as soon as it gets to court, it usually costs millions of dollars to resolve, with decisions essentially being based upon unreliable data.

Measurement ambitions

When a combination of fluids such as oil, water and gas flow from a well it has traditionally been difficult to correctly measure individual phases without separating

them. Multiphase metering first started with the aim of addressing inaccuracy and reliability, providing valuable data and delivering cost reductions. Those newly realized savings also would facilitate single well tiebacks, shared use of existing pad and pipeline facilities and continuous online monitoring for economically marginal wells—or so the theory went.

The upstream sector takes great pride in its use of technology, science and risk assessment. However, there is a data trust gap between what is being promised and what is being delivered. This is due to the multiphase metering market not fulfilling its potential over the years.

It is rare to find a business that claims to get better than 10% accuracy from its multiphase meters. But more astonishingly, it is very common to hear people in the field say they are lucky to get 20% to 30%.

Such a level of uncertainty matters. For example, one field operator noted that an emulsion formation would develop as soon as the well went above a 40% water cut, resulting in full storage tanks and the need to shut in the field to empty everything. This is just one example, but it is a ubiquitous issue. Even on a 1,000-bbl/d field an emulsion incident can really hurt the bottom line.

This inaccuracy in large part is due to traditional meters not being optimized for reliability. Manufacturers have prioritized expensive technology that embeds uncertainty in flow-rate measurement over accuracy and repeatability in parameters that can be directly measured. This inherently leads to complexity, human intervention and validation-hungry systems.

To address these weaknesses, cumbersome and expensive test separators remain in operation, but they provide only piecemeal or fragmented information that rarely delivers more than limited value. So while oil and gas companies seek the benefits of access to data, they've been consistently unable to access lower-cost, reliable and reproducible information sets.

Quantifying change

There is no doubt the industry needs to spend less per barrel. It is a theme that is coming straight from the top: How can the industry reduce its biggest costs? Can technology stop the industry's salary graph from going up and its production graph from going down?



The carbon fiber construction of an M-Flow metering system makes it possible to deploy sensor systems fully protected from aggressive oil well fluids. (Source: M-Flow)

In the onshore industry where the costs are often well-driven, operators that want to reduce expenditure have generally cut people or workovers. That is where the greatest costs are found. However, eliminating workovers will lead to trouble later on. Workovers and other well interventions need to be done at some point, and once completed, it is important to know what worked best to determine future strategy. Without measurement, it is difficult to get a clear picture of what has been effective. Continuous well-by-well data will deliver significant improvement on this front.

Meters at every well would be a best practice if it was cost-effective, and it is a reality today with M-Flow. Operators can manage an oil field without having to amend the operational pattern every time something changes. But as with other process industries, this will involve smart monitoring systems throughout the upstream production chain.

One factor that will govern the future price of oil is the extent to which the standardized, manufacturing-like processes that characterize tight oil production are implemented across the industry. For example, best practice in the U.S. shale plays has transposed swiftly between operators and operations (e.g., pad drilling, high-volume completions and tighter well spacing). All have made statistically visible differences in costs and how quickly and successfully projects are brought to commercialization.

At the heart of this is the requirement for reliable data to improve performance through the reproducibility and tight process control that delivers the marginal gains that compound into improvements.

Removing statistical doubt

In rethinking the challenges that have inhibited the growth of multiphase data for the production optimization market, a technology that provides confidence at the wellhead was developed.

M-Flow focuses on understanding well performance through phase fraction measurement because this system delivers through direct measurement the key parameters that quantify and signal production change. It can be combined with other measurement systems and datapoints to provide more complex understanding.

M-Flow's carbon fiber construction creates a transparent window on the pipe flow and makes it possible to deploy sensor systems fully protected from aggressive oil well fluids. The company's meters experience none of the harsh fluids induced degradation or calibration changes that are the main drivers for multiphase flow-meter intervention.

In contrast to traditional meters, the company's new carbon fiber multiphase meters require minimal manpower, lower capex and almost zero opex. Costs for the five-year life-cycle meter are on average 20% of traditional multiphase flowmeter costs.

By delivering directly measured, constant data on water cut and gas fractionation in a discreet, packaged and valuable dataset, M-Flow has shifted focus to moving dialogue within the multiphase market away from the meter and onto the impact of accurate and reliable data to redefine upstream operations.

Reliable data form the foundation of the modern oil field. Unless the information that is derived at the wellhead is consistently reliable and replicable, the challenges of

today and tomorrow will not be solved.

There is broad recognition that digging into a well-managed dataset reveals insights, trends and patterns that will help increase return on investment, decrease HSE incidents and create the foundation for future achievement. In this environment, data trust is a competitive advantage. Success is built upon actionable insights and that starts with credible data. **ESP**



The M-Flow multiphase meter accurately identifies water cut, gas breakout or rapid changes in fluid fractions as they occur. (Source: M-Flow)

BRIGHT FUTURE

New projects keep subsea flowing

Jennifer Presley, Executive Editor



The 24,000-tonne topsides for the *Aasta Hansteen* gas platform was floated over and connected to the floating vertical hull in December 2017. (Photo by Olaf Nagelhus/Worldcam, courtesy of Statoil)

After three years of contending with formidable market conditions, upstream companies have begun the arduous task of getting back to what they do best: finding and producing oil and gas. While the offshore sector certainly felt the impact of the price crash, it did not leave it comatose. One need only look at the last months of 2017 to see the promise of 2018.

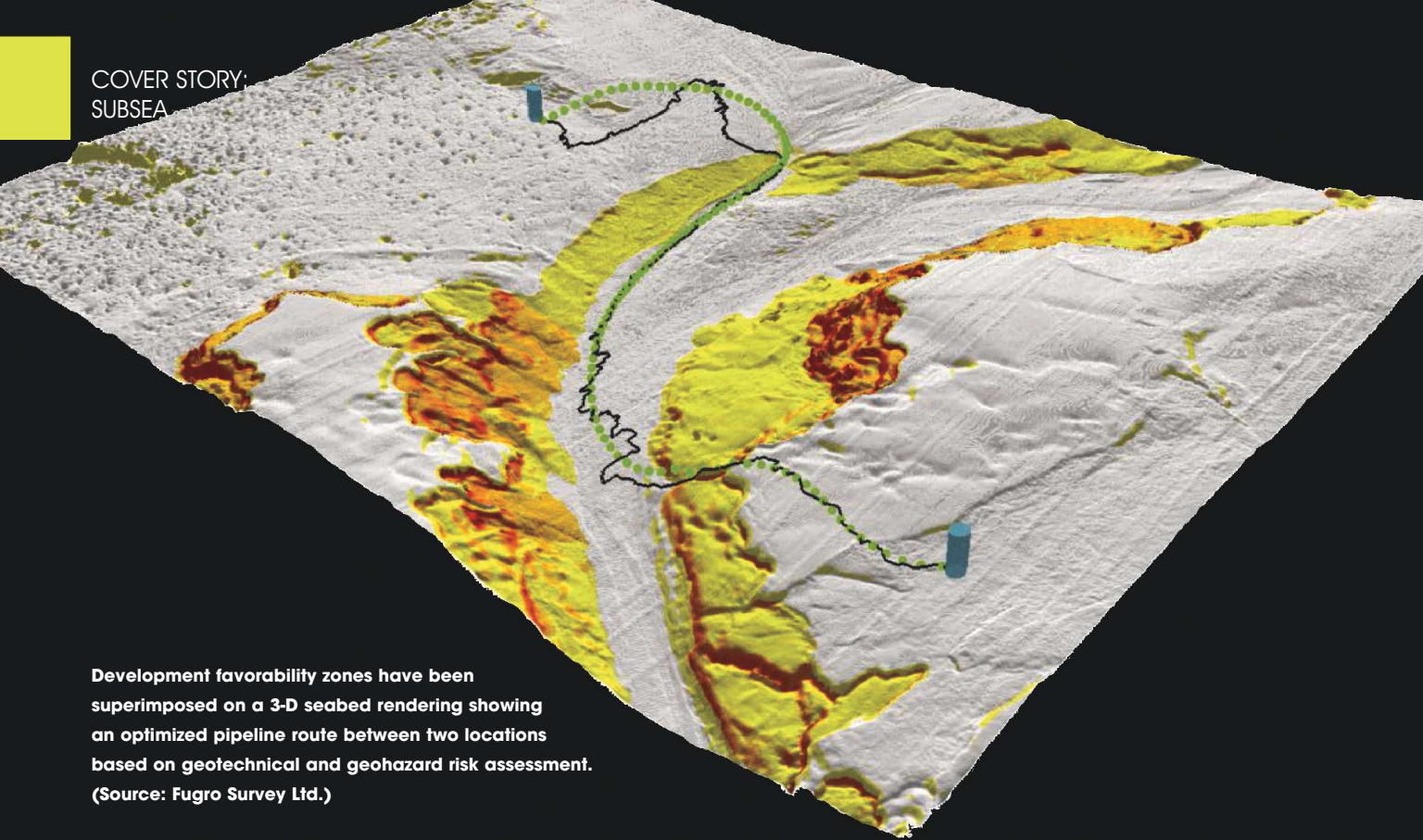
Take, for example, new discoveries announced off the coasts of Equatorial Guinea, Guyana, Russia and Trinidad, which show that exploration is not dead. A flurry of field development proposals were submitted to the Norwegian Petroleum Directorate (NPD) for consideration. The seven plans submitted to the NPD represent a total value of more than \$12.5 billion in green-field capex, according to a report from Rystad Energy.

In December 2017 a 46,000-tonne floating vertical hull received its topsides crown to become the world's largest spar FPSO unit. That spar will be located in the Aasta Hansteen gas field located in

the deep waters of the Norwegian Continental Shelf about 300 km (186 miles) from Bodø.

Subsea will play a significant role in the success in these future or current fields. Like all in the industry, subsea players face a new future where lessons learned from previous projects and standardization are helping to ensure long-term growth.

This month *E&P* takes a step back to the basics with a look at how operators are identifying the best locations to place subsea equipment during the field development phase. Other stories include a dive into the considerations made during the design and selection process of subsea production systems. Also covered is a new digital platform that integrates robotics, artificial intelligence and original predictive analytics to advance subsea inspection services. The section wraps up with an overview of how operators are bringing together current infrastructure with future subsea projects. **EXP**



Development favorability zones have been superimposed on a 3-D seabed rendering showing an optimized pipeline route between two locations based on geotechnical and geohazard risk assessment. (Source: Fugro Survey Ltd.)

Back to basics on seabed surveys

Before deploying subsea development strategies, operators need to know where their equipment is going.

Rhonda Duey, Senior Editor, Exploration

S seabed images tend to depict the ocean's floor as a flat, sandy environment. This is not always the case. In fact, companies that want to install a subsea development scheme spend a lot of time and money characterizing the seabed before the first item of kit is installed.

E&P recently spoke to Brian Mackenzie, service line director of Marine GeoConsulting, Europe & Africa, at Fugro Survey Ltd. about the concerns that operators face when planning a subsea development.

***E&P*:** What are some of the main considerations when conducting a seabed survey?

Mackenzie: We would always start with the end-goal of working with our client toward the successful design and installation of seabed infrastructure.

Implicit in 'successful design and installation' is its safe and reliable operation and assured asset integrity over its design life. With that in mind, considerations would include what the client is planning to build. The layouts associated with subsea and offshore projects can be complex, and also the shape, size and weight of the installed equipment affect its interaction with the seabed and determine the coverage and type of survey required.

Often the layout, or indeed the equipment to be installed, may not be known at the time of the survey. This certainly makes things interesting because, rather than surveying to a known pattern or layout, we would try to characterize some overall volume of seabed, and from that we would be able to help the client identify the optimum development site within the overall notional project area.

Our first question when receiving an inquiry from a client about a survey is, 'What is it for?' Then we start to think about the seabed itself, with the most fundamental question being, 'What's the water depth?', because

that would determine the choice of platforms available from which to conduct the survey as well as driving the development concept on the client side.

Once we know the client's development plans, location and water depth, the next consideration is the seafloor and the sub-seafloor itself as well as its features and ground conditions.

We aim to identify the constraints and hazards that might be posed to the development (for example, any adverse ground conditions). This could simply be excessively soft or sensitive sediment that can't support infrastructure or, conversely, hard ground or buried rock that poses installation risk. Then there could be a whole host of hazardous features such as faults, steep slopes or gas expulsion features to be taken into consideration.

These are static features that can sometimes be readily identified simply by examining the bathymetry, but it's also necessary to consider dynamic features such as a mobile seabed. This is something that tends to be talked about more in the offshore renewables sector rather than in oil and gas field development. For example, there is a wind farm development off the U.K. coast that has been built on what turned out to be a mobile sandbank, so the ground is actually shifting.

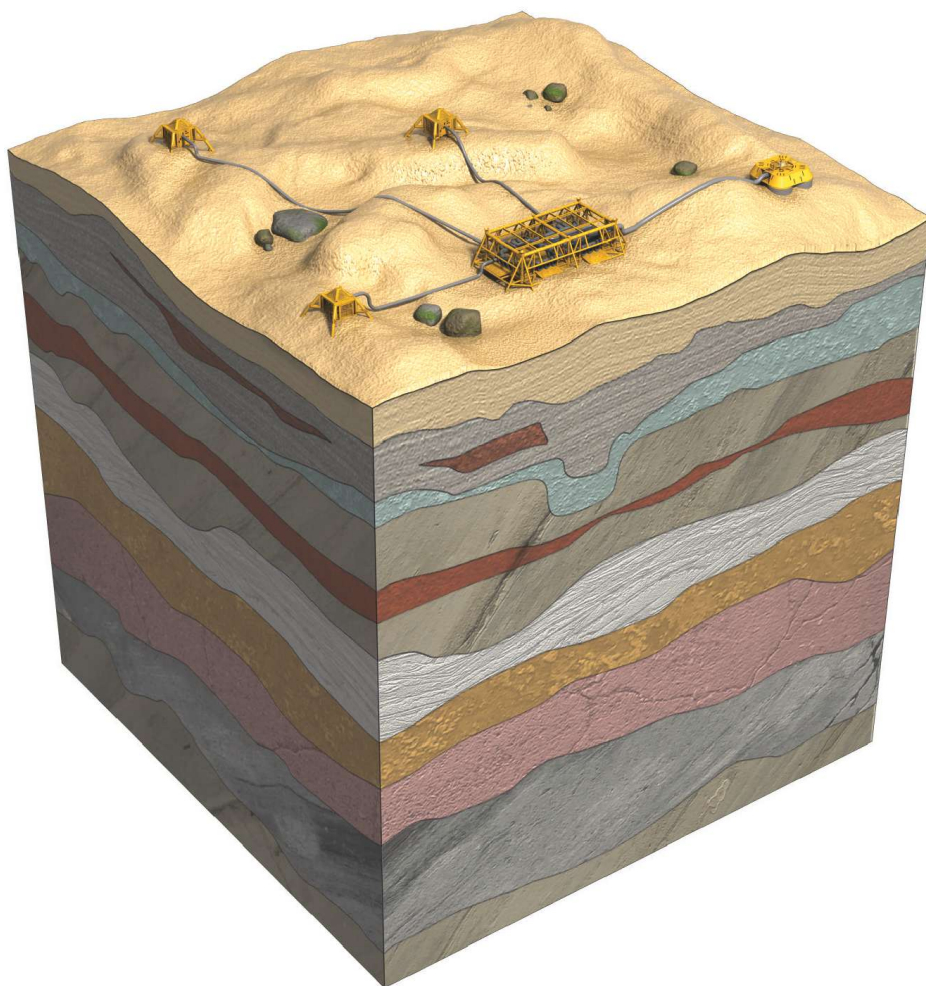
These are dynamic hazards that you wouldn't necessarily see in a snapshot survey. And in the so-called 'frontier developments' around the world, there may be other dynamic geohazards. The classic threats in such environments include steep unstable slopes characterized by very soft sediment and earthquake-prone environments. These can trigger instability, essentially a soil avalanche developing into a debris flow, with huge amounts of energy and the ability to cause a lot of damage if not destruction. Such geohazards are a crucial consideration in a seabed survey.

Another important point is that in such circumstances the threat to the subsea development can actually originate some distance from

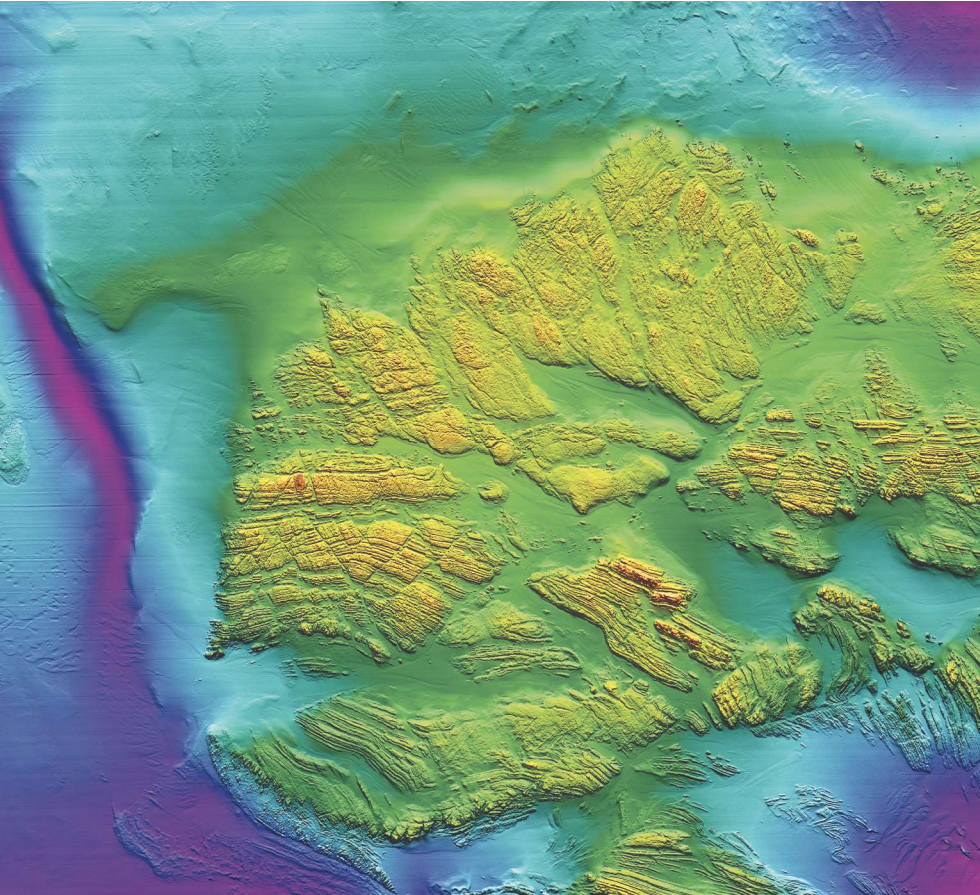
the development itself. It could be tens of kilometers away, so in considering and planning the survey, not only are we interested in where our client is going to build, but we may also be interested in the surrounding seabed terrain and the source of threats to the development.

Once the inherent hazards have been examined, we investigate the actual engineering properties of the seabed itself such as the characteristics that tell us, for example, what load it can support, whether its strength might degrade over time and what foundation settlement might be expected. Those engineering properties feed directly into the design process, so they drive the foundation sizing and configuration as well as the selection of installation equipment and therefore any direct financial consequences relating to the characterization.

In the wider context of marine site characterization the environmental habitat conditions are also important,



This sub-seabed visualization has been enabled by integrating geophysical and geotechnical survey data. (Source: Fugro Survey Ltd.)



This high-resolution seabed image highlights terrain challenges facing marine infrastructure design and installation. (Source: Fugro Survey Ltd.)

so we can assess the impact of a development against those baseline conditions. Metocean conditions are also important, as waves and seabed currents will determine the load on what the client builds.

E&P: What are some of the technologies that are used for these surveys? What information do they provide?

Mackenzie: Fundamentally there are two main types of methods used to characterize the seabed.

The first is geophysics. That's using an acoustic source and reflections, so it's a nonintrusive means of investigating the seabed, and it uses the same overall method used for prospecting for oil and gas, just with a shallower focus for subsea developments.

The other fundamental option is geotechnical investigation. That involves drilling into or otherwise probing a sampling device or form of instrumentation into the seabed, so it's an intrusive process. In a full borehole program we extract high-quality samples from

the sub-seabed and then undertake a range of further examinations. Obtaining samples from the seabed isn't exactly straightforward.

In terms of what the two methods produce, geophysics gives a spatially continuous picture of the investigated area. It provides the bathymetry and the subsurface layering, so it is great at picking up variability across the site, but what it doesn't provide is the actual engineering properties of the soil, so it's not advisable to design on the basis of geophysical information alone. In the field of geophysics there is quite a technological drive for increased resolution, being able to pick up smaller and more detailed features. Of course there is also a technological drive to make the process less weather-sensitive.

Having said that, geophysics doesn't give engineering data; there is a further technological drive in the industry to improve upon this and, by using innovative interpretation methods, to try to derive more engineering properties from geophysics. Ultimately, it will rely on calibration with ground-proving geotechnical data, so in effect it requires a marriage between the two technology types.

Conversely, the result of geotechnical investigations is a very detailed characterization with soil samples in our hands to test but only at discrete points on the seabed. They offer a continuous depth profile of all the governing properties needed to design the foundations for a subsea development. A technological drive on this side is for enhanced quality sampling to be able to extract the sample from the sub-seabed, which is as close to its *in situ* state as possible. This again involves reducing the weather sensitivity of the drilling and sampling process.

The overall objective of a reliable seabed survey is to combine the data from both the geophysics and the geotechnics to deliver the detail, continuity and spatial extent, resulting in a state of knowledge that is known as a ground model.

E&P: What are some of the main considerations when it comes to subsea installations? Do you have examples where operators have had to work around a particularly difficult environment? Or were they surprised by the difficulty of the subsea environment?

Mackenzie: Overall, the considerations are the same as when planning a survey because the objective of the survey includes enabling a good installation.

More specifically, when you talk about subsea installations, you are describing the placement of equipment on the seabed—undertaking the construction work having done the design. An initial consideration would simply be the levelness of the seabed and any obstructions on it. And for design purposes, the soil strength is a key consideration, or more specifically its resistance to foundation installation. There are various ways of installing foundations into the seabed, including pile driving using a hammer or the penetration of skirts around a seabed structure, which relies on the structure's self-weight pushing the skirts in. It also could be suction installation, which is a concept that is widely used for subsea oil and gas. These all rely on us enabling the operator to predict the soil resistance, and that includes any buried obstructions such as boulders.

There are indeed examples of operators having difficulties. Sometimes they are manmade, such as unexploded ordnance that can be detected using geophysical methods and therefore managed. Another classic man-made example is the legacy of previous drilling activity before the development. For example, drilling and cementing of wells can complicate things because they result in a seabed that is harder to manage than in its original state.

The weather and tidal and current conditions can also cause difficulties with equipment placement. As a site investigation contractor we experience difficulties, and it is likely that the same difficulties will be experienced when it comes to building on the seabed. We are often a good barometer for potential construction difficulties.

There are also countless examples of operators having to work around difficult ground conditions, sometimes anticipated and sometimes not. Ideally the surprises are discovered in the seabed survey—that's the point of it, but it doesn't always happen. Sometimes surveys are insufficiently specified or just don't cover the extent of the development area. Things change; layouts change. The industry still often faces difficulties due to unforeseen ground conditions.

Where ground conditions are not adequately revealed by the survey, there are inevitably surprises. Where ground conditions have been adequately revealed by the survey, there should not be surprises, but there can still be unfortunate outcomes against an acceptance of residual risk. In hard ground with boulders, for example, there will be differing levels of risk associated with

different foundation designs and installation methods. Even with knowledge of the ground conditions, such difficulties can manifest themselves in pile driving damage and refusal that requires quite extensive mitigation.

A reliable survey is all about identifying risks for a range of development and foundation design options, mitigating them and quantifying the residual risk, which enables the operator to make the best decisions in terms of mobilizing the appropriate equipment to deal with challenges. Hence, if the survey shows a hazardous environment, it still puts the operator in a better place, proving that knowledge is power.

ESP: Are there areas where subsea developments simply don't make sense? Does the subsea environment ever dictate an operator's choice of development scheme (i.e., floating production, jackup, spar, etc. versus subsea)?

Mackenzie: Yes, absolutely. Water depth is a great fundamental driver of the choice of the scheme. Different concepts have different economic suitability based on water depth, or in some cases a technical cut-off. For example, the biggest jackups would operate in a water depth of something like 120 m [394 ft] but are wholly incompatible with a deepwater development. In the past some pretty tall fixed structures have been built, probably because at the time they were considered the most economical solution. Hence, there are some rather tall fixed platforms in the Gulf of Mexico. Since then floating production technology has advanced along with pure subsea solutions with an export to shallower waters or ashore. A development's proximity to existing infrastructure will also dictate the export scheme.

Considering the seabed itself and the soil condition aspects of the subsea environment, these are less likely to drive the overall development concept, but they are certainly likely to drive the foundation concept needed to make the development successful. If an operator has done all its economics and has decided that a floating production system is preferable to a fixed platform, the decision between the two alternatives is unlikely to be the result of considering the soil strength or detailed seabed conditions.

However, the foundation concept needs to support the chosen solution. For example, a floating production system needs anchoring, and the foundation design will be wholly dictated by the seabed conditions.

If the seabed conditions are ignored, the foundation design will not be reliable, and this could compromise the asset integrity irrespective of the choice of overall development scheme. **ESP**

Optimizing system design and field architecture

An integrated SPS/SURF and alliance approach delivers sustainable improvement in field development value.

Marcial Vilchez, OneSubsea, a Schlumberger company, and **Karim Jan**, Subsea 7

An industry trend to engage early on with contractors for subsea production systems (SPS) and subsea umbilicals, risers and flowlines (SURF) during the early phases of a project is rewarding early adopters with significant benefits. These operators are witnessing added value from reduced costs, improved schedules, risk mitigation, improved interface management and more predictable delivery outcomes, combating the industry's challenge of increasing cost and diminished returns. An aligned SPS and SURF approach is helping to address issues of suboptimal processes, cost inflation, nonstandard specifications and under-recovered resources.

Traditional engagement strategies create a significant number of possible permutations and combinations during project execution, making it difficult to deliver complex projects at a viable cost. There are areas within the process that create gaps associated with interdependency and interaction of technical and commercial processes.

The integrated approach to SPS and SURF collaboration in the field development phase and throughout subsequent execution phases offers opportunities to close those gaps and efficiently reduce costs, improve schedules and maximize overall returns.

Potential benefits during field development phase

In addition to these benefits and improvements, early engagement with SPS and SURF contractors can result in enhanced system performance that offers potential for enhanced overall production recoveries; access to the most current available technologies that are often economic and technical enablers; optimization of development costs based on the aligned SPS and SURF interfaces; and accurate and current benchmarks to derive a robust cost estimate, execution schedule and risk evaluation.

Typical evaluation criteria include estimated cost, expected field production and recovery, operability and flow assurance, delivery schedule, and technology readiness. Applicability of an early, aligned approach depends on the specifics of each project or field prospect.

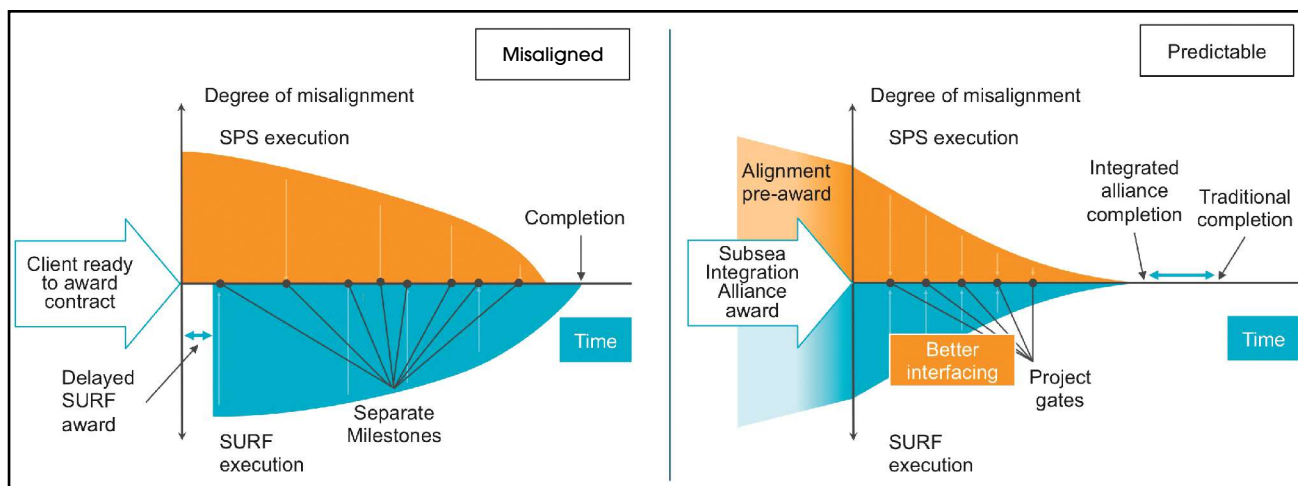


FIGURE 1. The left graphic is a traditional model showing SPS and SURF working separately and misaligned. The right graphic is an integrated model showing SPS and SURF working together, aligned, with a predictable outcome. (Source: Schlumberger and Subsea 7)

Optimizing field architecture

Examples of how the integrated SPS and SURF approach can make a difference in project planning and execution might include the following categories: system operability, reservoir performance and pressure management. The capability to evaluate the operability of a proposed development in accordance with the design and flow assurance philosophy of the project is a key aspect of the integration of flow assurance in the SPS and SURF concept workflow.

When it comes to reservoir performance, the asset models typically in use are often a representation of reservoir production potential using data from a reservoir forecast. However, the reservoir is dynamic and the response is affected by the drawdown from the surface network. Establishing a strong link between SPS and SURF contractors and the operator can result in building an asset model that adequately captures reservoir dynamics and the performance of the surface network. This type of model can accurately predict the degree to which any newly proposed wells would choke production from existing wells. This has a direct impact on the feasibility of any development concept and selection of field architecture.

Most fields exhibit a rapid decrease in pressure as the reservoir is depleted. Water cut increases and the natural production diminishes. Therefore, pressure enhancement in the form of artificial lift is often needed to lighten the fluid column, boost the flow rate and improve field economics. Integration of an SPS and SURF work scope helps fine-tune the field architecture to optimize system design, resulting in significantly increased revenue and an improved revenue stream. The diameter of flowlines can be smaller, which reduces capex. Also, hydrate issues can be avoided and chemical injection requirements streamlined. For long step-outs, production enhancement can eliminate terrain slugging at the riser.

Installation aspects

Following determination of the subsea tophole location on the seabed and control system optimization at the drill center, a benefit of an integrated approach to SPS and SURF is to simplify the interface between designers and installers of SPS elements by improving understanding of drivers and constraints of each party. The traditional method of issuing SPS elements as “company provided” items to installers often can lead to interface issues, misunderstanding, increased complexity and imperfect solutions. A contingency cost is generally needed to cover the inherent risk.

Another way to minimize costs is to allow influence on the design of subsea structures so they can be

installed with the most cost-effective and suitable vessels. For example, some heavy subsea structures could be split into modules to allow separate installation of each subsea module with a lighter intervention vessel. A subsea separation unit could be installed in several lifts by having several modules installed one after the other.

Alternative installation methodologies and system configurations also can be considered. An integrated approach would greatly facilitate resolution of challenges and careful assessment of system design to ensure a positive impact on the overall project.

Additionally, umbilical packing considerations can contribute significant costs. Having long sections of umbilicals on the field may end up with the installation vessel having to transit to the umbilical factory to load out the product in a carousel; having the umbilicals on reels allows much more logical flexibility as they can be transported on a heavy-lift vessel.

Project execution synergies

Recent lessons learned from projects that were considered successful showed that additional costs to manage gaps in the consideration and execution of SPS and SURF can potentially be 5% to 10% of the overall SPS and SURF contracts with associated schedule impacts of three to six months. On projects where interface issues are poorly defined and executed, the impact overall can lead to significantly higher cost and schedule overruns.

Three main success factors to deriving benefits from an integrated SPS and SURF project include goal alignment, convergence management and rationalization (Figure 1).

Risk and schedule assurance

An industry report by EY found that nearly two-thirds (64%) of multibillion-dollar technically and operationally demanding megaprojects exceeded budgets with nearly three-quarters (73%) missing project schedule deadlines. The previous method communicated in this report resulted in challenges to deliver complex projects and decrease continuity and familiarity with project goals. It also failed to address new problems and challenges bespoke to a specific development.

Building a more integrated approach to SPS and SURF delivery that is repeated on several projects concurrently in an ongoing collaboration greatly increases the potential for repeatable and more reliable subsea system delivery. The combination of early engagement, technical optimization and integrated project execution can reduce costs, mitigate risks, improve interfaces and deliver more predictable outcomes for operators. **ESP**

Making the most of offshore infrastructure

Operators find subsea success by using existing infrastructure off the Norwegian coast.

Steve Sasanow, Contributing Editor

In the years before the oil price crash of 2014, the offshore industry spent bucketsful of money building infrastructure while the price of oil was high and looked like it was never coming down. It was the oil and gas version of making hay while the sun shines. It would be easy to say “who knew?” in relation to the price crash because not many analysts and observers expected to see such a precipitous and sustained drop in the price of a barrel of crude causing a significant collapse in development activity.

Since then license groups in offshore sectors around the world have struggled for the most part to find a way to

bring new production onstream at a price that made the investment of new capital worthwhile. Many in the service and supply sectors trimmed personnel, reduced the size of construction vessel fleets and curbed new capex to match the reduced demand for project support.

Approval of new projects—with water depth not appearing to be a major factor in deciding what would and would not be developed—has dropped from the heady days of five years ago. But it was not quite the fall from the cliff edge that some have suggested.

Weighing Norwegian opportunities

A look at what fields are due to soon come onstream and what fields were either already approved or near to what is now the Holy Grail—the final investment

decision (FID)—suggests the industry has not exactly been sitting on its hands for the last three years (Table 1). The industry has weighed up its offshore opportunities in a measured fashion while watching the cost of development come down to a level where money can be made even with the barrel of oil now finely balanced in the \$50/bbl to \$60/bbl range.

Nowhere is this truer than in Norway. Traditionally viewed as a high-cost sector, it has been perceived as an indigenous company sector once Statoil took over Mobil's assets in the 1980s. Before Statoil absorbed its compatriots—Saga Petroleum and Norsk Hydro—these three companies dominated the sector. Most of the very big fields, such as Åsgard, Kristin, Ormen Lange, Oseberg, Snorre and Troll, were developed by the Norwegian companies with a major emphasis on deploying new technology often developed in-country. The sector was certainly seen as one where almost anything could be tried with the support and encouragement of the authorities and technology organizations.

GLOBAL SUBSEA PROJECTS		
LOCATION	FIELD	STATUS
Africa	Coral FLNG	FID announced June 2017
	Egina	In development, 2018 startup
	Fortuna FLNG	Waiting for FID
	Moho Nord	Onstream 2017
	Tortue	Pre-FEED
	West Nile Delta	Onstream 2017
	Zohr	Onstream 2017
Australia	Ichthys	In development, 2018 startup
	Prelude	In development, 2018 startup
	Persephone	Onstream 2017
	Greater West Flank 2	In development, 2019 startup
South America	Libra	Onstream 2017
	Liza	FID announced June 2017
	Lula Extremo Sul	In development, 2018 startup
India	KG-D6 block	Development plan submitted, 2022 startup
	MJ-1	Development plan submitted, 2021 startup
Norway	Aasta Hansteen	In development, 2018 startup
	Johan Sverdrup	In development, 2019 startup
Gulf of Mexico	Appomattox	In development, late 2019 startup
	Buckskin	In development, late 2019 startup
	Kaikias	FID announced February 2017
	Mad Dog 2	In development, late 2021 startup
	Stampede	In development, 2018 startup
	Thunder Horse South	Onstream 2017

TABLE 1. Offshore opportunities have kept E&P companies busy weighing development options for their fields since 2014. (Compiled from industry reports)

New international players have emerged, as well as some new domestic players seen as replacements for Saga and Norsk Hydro, that like the opportunities in and the proximity of Norway to their home countries. Companies like Swedish firm Lundin, German entities Wintershall, VNG and DEA, Centrica out of the U.K. and domestic operator Aker BP have worked their way into the Norwegian scene. These companies, including Statoil, are taking advantage of Norway's big portfolio of platforms to bring a raft of smaller finds into production and give them a new profile on the Norwegian Continental Shelf.

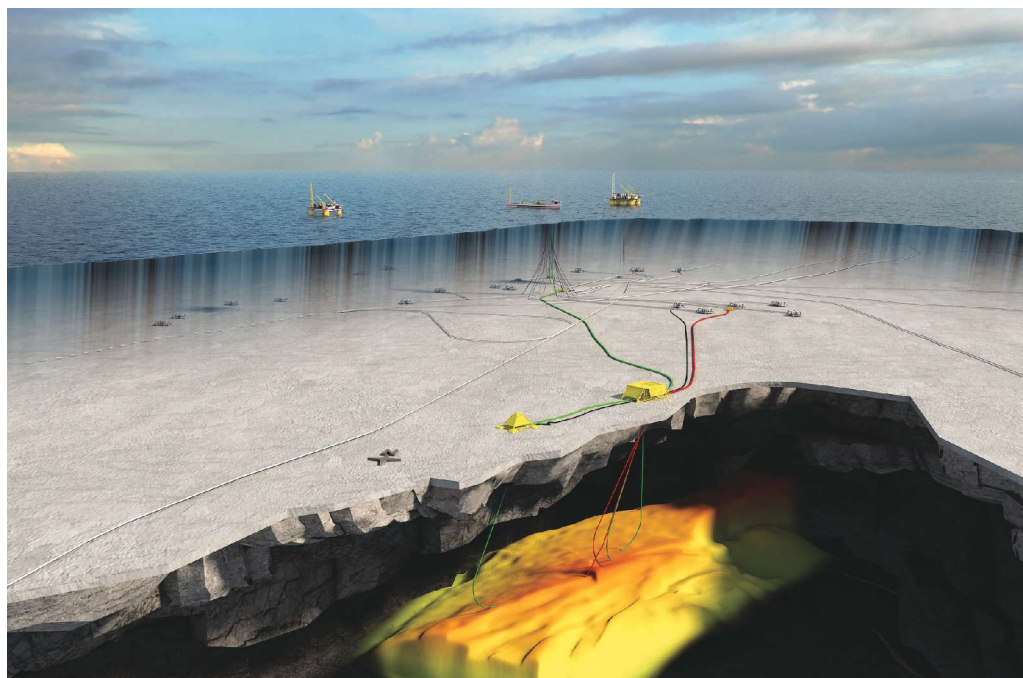
Developing fields

Wintershall has been making its move into the Norwegian North Sea for a number of years. It first acquired the Brage asset to cut its teeth on offshore operatorship and has now completed its first development at Maria (6406/3) in the Haltenbanken area of the Norwegian Sea. This project exemplifies what can be done with relatively small reserves (29 MMbbl and 2.3 Bcm [81.2 Bcf]) in the midst of a well-developed offshore sector.

The company is taking full advantage of its field's proximity to three Statoil platforms in the area. The fluids from the subsea field flow 20 km (12.4 miles) to the *Kristin* semisubmersible unit and then onward to the *Åsgard C* floating storage unit. The field also will have production support of gas lift from the *Åsgard B* semisubmersible unit through a seabed template on the Tyrihans Field and water injection from the Heidrun tension-leg platform (TLP).

In roughly the same area is DEA's Dvalin subsea gas project with 18 Bcm (635 Bcf) in reserves. The company is making use of the Heidrun facilities located 15 km (9.3 miles) away. It will have four wells on a single template feeding gas to the TLP and then onto the Polarled pipeline installed to handle gas from the Aasta Hansteen Field located another 7.5 km (4.6 miles) away.

VNG is yet another German company getting into the Norwegian sector. It is bringing together three finds—Pil, Bue and Boomerang—under the banner of Fenja. Located 32 km (20 miles) from the Njord Field, the field will include two seabed templates with production



The Trestakk Field in the Norwegian Sea is located about 20 km south of the Åsgard Field and will consist of one subsea template with four well slots and an additional satellite well. The subsea installation will be tied back to the Åsgard A facility for processing and gas injection. (Source: Statoil)

wells as well as water and gas injection wells. This complex of fields will come onstream in 2020 to coincide with the redevelopment of the *Njord A* semisubmersible unit. Operational since 1997, it underwent a major life extension program in 2012 to enhance production life and to accommodate production from the Hyme and Njord Northwest Flank satellites. The production semisubmersible unit was towed to shore in 2016 for major modifications for life extension and to facilitate development of the Bauge satellite field.

Another subsea satellite brings another merger and another German company into a new development. Centrica of the U.K. and Bayerngas Norge have merged to form Spirit Energy. The company's first project will be the Oda Field, formerly Centrica's Butch prospect, with reserves of 48 MMboe. The field was discovered in 2011 in the southern part of the Norwegian North Sea about 13 km (8 miles) east of the Ula Field. When it comes onstream in 2019, it will produce 35,000 bbl/d from two subsea wells tied back to the Ula platform and one seawater injection well for pressure support, per the plan and development operation (PDO) submitted to the Norwegian Petroleum Directorate (NPD).

Aker BP submitted three plans for development, two of which are subsea, to the NPD in December 2017.



The heavy transport vessel *Dockwise White Marlin* transported the 24,000-tonne topsides for the future the *Aasta Hansteen* spar FPSO unit from the Hyundai Heavy Industries' shipyard in Ulsan, South Korea, to Ølsvåg, Norway, in late 2017. (Photo by Espen Rønnevik/Worldcam, courtesy of Statoil)

The Skogul Field is the smallest of the two subsea projects submitted. It will be developed as a subsea tieback to the *Alvheim* FPSO unit. Aker BP estimates recoverable reserves of the field to be about 10 MMboe.

The larger development of the two is at the *Ærfugl* Field in the Norwegian Sea. The plan calls to develop two deposits—Snadd and Snadd Outer—in two phases as a subsea tieback to the *Skarv* FPSO unit. Aker BP estimated remaining reserves of the *Ærfugl* Field to be at about 275 MMboe. The first phase, due onstream in 2020, will include three new subsea wells plus the already drilled A-1H well. A second phase that will require more work to confirm could be onstream in 2023.

Sailing forward

As the biggest player in the sector, Statoil would hardly want to be left out of all of this satellite activity. More than five years ago, the Norwegian state company launched its “fast-track” initiative to bring as many of its small finds onstream as quickly as possible while infrastructure was still in place. The intention also was to keep project teams together so that they could improve upon their performance and aim to reduce the costs of developing fields with small reserves.

The first field to come into production under this scheme was Visund South in 2012, and it appears that Gullfaks Rinfaksdalen was the last in the summer of 2016, although Statoil would not confirm this. This initiative, having covered at least 20 projects, was quietly closed for reasons undisclosed by Statoil.

With the installation of a new NOK 1 billion (US\$125.5 million) gas processing module onto the unit, the *Troll C* semisubmersible unit will be not shut down any time soon. The upgrade is to improve the efficiency of production from the Fram Field. In addition, the Byrding Field will be developed with a single multilateral well linked into the Fram Field pipeline infrastructure at the Fram H-Nord template.

In 2017 Statoil filed a PDO for the Trestakk Field that will be a large satellite field adding an estimated 76 MMboe to the Åsgard complex. A subsea template will have three new oil production and two gas injectors and tie into an existing producer.

These fields fit into the mold of small subsea projects but Snorre 2040 does not. The field was first developed by Saga in the early 1990s with a TLP and a 20-slot seabed template. Initial reserves were put at 750 MMbbl, but extensive drilling and the addition of a production semisubmersible unit have seen that figure rise to more than 1.7 Bbbl. Current production is more than 80,000 bbl/d, boosted by three recently drilled producers that were drilled at a cost similar to a single earlier well and added 30% more fluids.

This latest expansion will add at least 200 MMbbl to that total. Originally to be based around a new production facility, Statoil is now opting for a full subsea development with six seabed templates and at least 24 new wells. This new scheme will see capex on this field extension plan fall by 30% to 40%. The FID remains to be made at this writing. **ESP**



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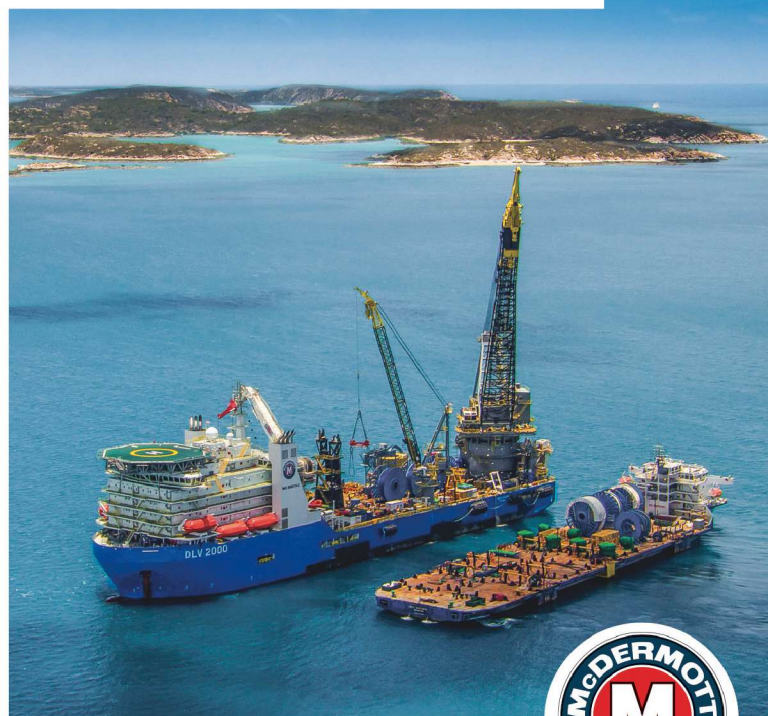
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Brad Tomer, Avitas Systems

Industrial inspections are typically labor-intensive and conducted on a time-based schedule. The collection of data is generally manual, time-consuming and involves humans being exposed to high-risk environments. For example, ropes teams hang from high places, inspectors enter confined spaces and workers often are exposed to severe elements. These inspections result in suboptimal data collection based on a human's ability to work in such environments.

Data collection is subjective, inconsistent and prone to human error. Inspections are conducted on a periodic basis, and sometimes the find rate of time-based inspections is less than 2%, making more than 98% of the inspections unnecessary. In other instances, the inspection interval is too long, and adverse incidents occur as a result. For example, to inspect some assets in the oil and gas industry, such as flare stacks, operators must take them out of service, causing lost revenue.

Once inspection data are collected, value must be extracted from it. This process also is manual and not integrated, leaving findings disorganized and subject to interpretation. These findings can vary from inspector to inspector or even from one day to the next. In the process of transferring and communicating inspection results for paper or PDF reports, data can be lost. Additionally, firms often delete much of the data after the report is finished, which limits the ability to learn from historical records. Overall, reporting can take six months or more after the inspection is completed.

Platform detects anomalies, generates alerts

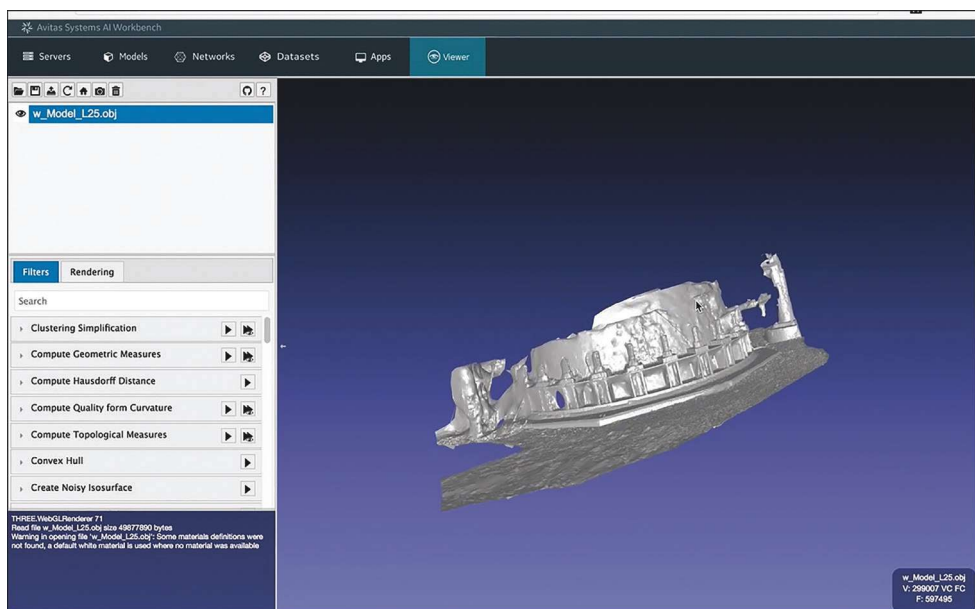
To address these challenges, some companies are using unmanned aerial vehicles (UAVs) or AUVs. During a subsea inspection, for example, many companies require a support vessel and crew to command ROVs. This process is usually expensive and weather dependent. During aboveground inspections, UAVs can collect thousands of images, but inspectors need to manually examine these data to develop a report, which

doesn't save much time.

The true benefits of robotic inspection derive from the ability to efficiently maximize the added data that are collected over time with a smaller logistical footprint.

Avitas Systems, a GE Venture, is taking a more systematic approach to inspections by collecting data autonomously and fusing those data into an advanced analytics platform, where artificial intelligence (AI), physics models and algorithms combine to automatically detect asset anomalies and generate alerts.

To develop these solutions, Avitas Systems brings together a team of subject matter



Inspectors can select exact POI on digital 3-D models of entire assets. (Source: Avitas Systems)

experts across diverse technologies and businesses, including engineering, analytics, computer vision, flight operations and GE's Global Research Center for the customization of these technologies.

Avitas Systems uses a variety of robotics, including UAVs, AUVs, surface robots such as crawlers and customized sensor technology, to make its services cross-industry, targeted and thorough. By incorporating robotics in data collection, the company can prevent inspectors from performing high-risk tasks and provide more consistent inspections to better detect asset defects earlier and faster, which means communities surrounding industrial assets are safer, too. All the while, minimal machine downtime is required, so companies don't have costly turnaround time.

Advanced 3-D modeling, AI

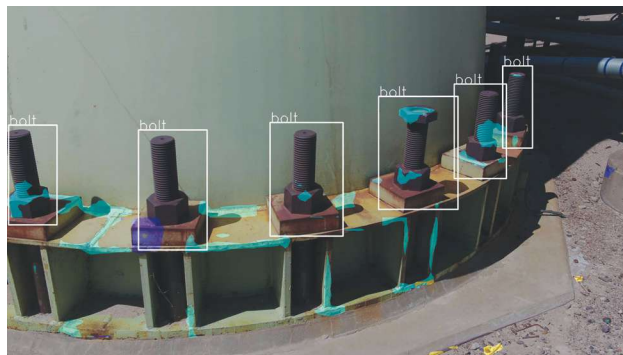
What makes robotic data collection with Avitas Systems more efficient is the company's advanced 3-D modeling and unique integration of AI to enable its analytics. The company's data collection process improves the quality and consistency of inspection insights, which customers often can see livestreamed. Inspectors can select exact points of inspection (POI) on digital 3-D models of entire assets.

Users simply select POI on the model, change the perspective of the model to define the sensor angle and indicate the size of the resolvable defect by extending the POI, which translates into a robot's standoff distance. This point-and-click method reduces the inspection planning time from hours to minutes, with a more targeted approach. Avitas Systems autonomously converts this 3-D modeling, integrated with existing customer requirements such as no-fly zones, into safe and precise paths that robots follow for data collection.

These paths can be repeated, which allows increased efficiency and the ability to detect changes in an asset over time. Change detection produces historical data in the form of images that sensors capture, including RGB, infrared and ultraviolet imaging, stored on the company's digital, cloud-based platform. The platform centralizes the data, unlike many other companies, and allows archival searches of inspection records as the data grow.

Predictive analytics

In addition to data warehousing, the platform notably includes predictive analytics so inspections can be planned according to risk, as opposed to time intervals. Risky assets receive increased attention, thus improving safety. Avitas Systems fuses manual and autonomous inspection data, existing asset performance data, external data sources (e.g., weather) and new inputs from



Deep learning models are stored on the original Avitas Systems AI Workbench. (Source: Avitas Systems)

subsequent inspections. Advanced algorithms then detect asset defects and anomalies automatically. Defects and anomalies vary across the industry, including flare stack damage or subsea gas bubbles.

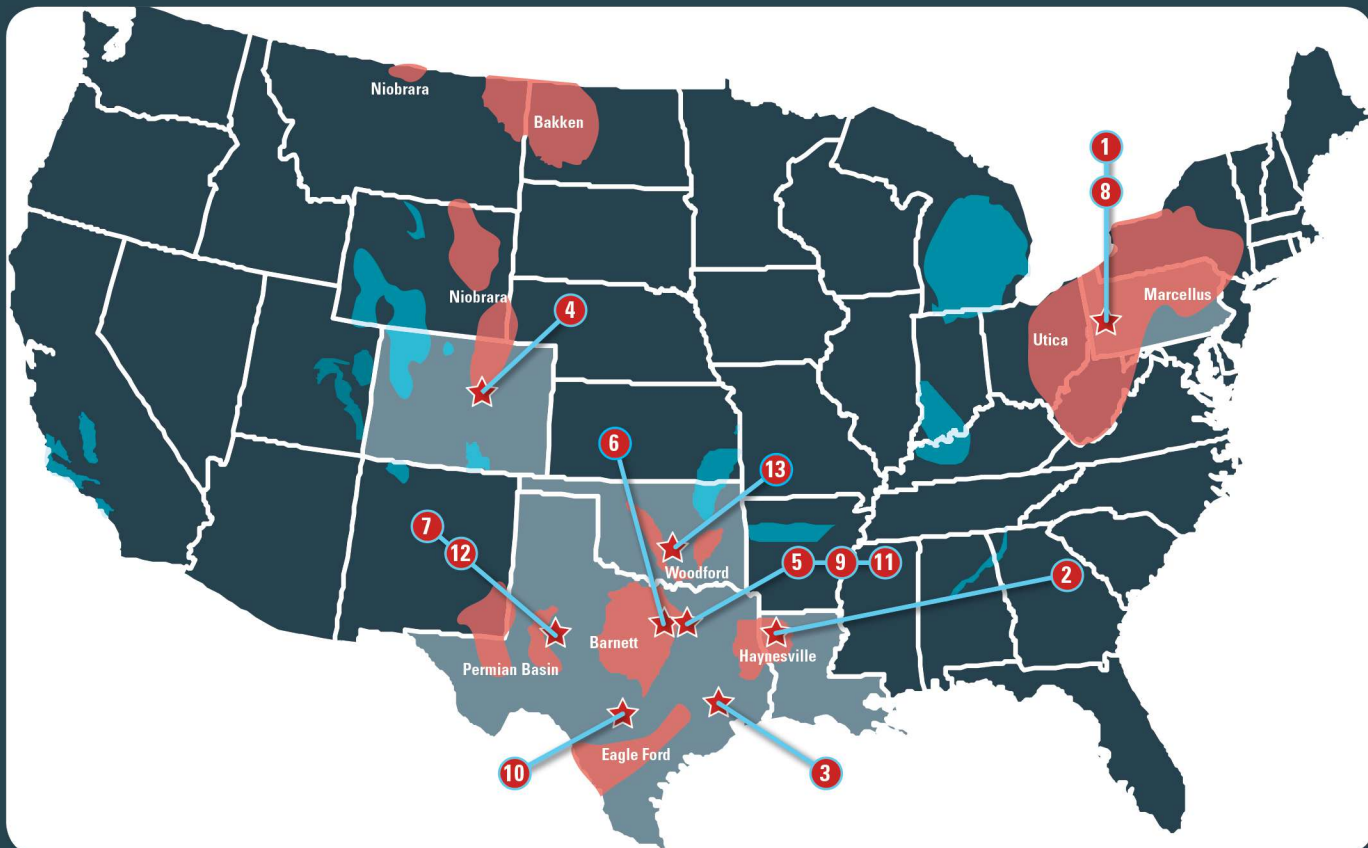
Avitas Systems can quickly and more accurately determine the likelihood a defect will lead to failure in a few hours instead of several weeks and at a reduced cost. Automated defect recognition means inspectors no longer need to manually peruse disparate datasets across different teams. As more data are ingested from diverse sources, the deep learning models stored on Avitas Systems' original AI Workbench retrain for smarter actionable insights.

The platform uses predictive analytics to recommend targeted inspection scheduling and planning, which significantly improves accuracy and enables earlier resolution of potential issues. The recommendations and networkwide risk maps for assets are displayed in the company's customer-focused, web-based interface with accessible dashboards based on user type. The advanced reporting tools available in the interface integrate with existing management and reporting systems.

Partnerships

With the company's hybrid of technologies, human perspective complements the dexterity of advanced robotic technology and analytics. Avitas Systems is making inspectors' jobs easier and more efficient. This first inspection-as-a-service solution and the fundamental algorithms it involves can apply to multiple industries, including oil and gas, electric power and transportation. Avitas Systems is partnering with market leaders in robotics and AI to expand its platform globally. By partnering with Kraken Robotics, for example, Avitas Systems will be able to incorporate sensor technology for subsea inspection across the oil and gas, offshore renewable energy and shipping industries. **ESP**

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Pittsburgh, PA

2

DUG
HAYNESVILLE

Feb. 20 – 21
Shreveport, LA

NEW IN 2018

3

DUG
EXECUTIVE

Feb. 26
Houston, TX

NEW IN 2018

4

DUG
ROCKIES

April 24 – 25
Denver, CO

5

energycapital
CONFERENCE

May 7
Dallas, TX

6

DUG
PERMIAN BASIN

May 21 – 23
Fort Worth, TX

7

MIDSTREAM
TEXAS

June 5 – 6
Midland, TX

8

DUG
EAST

June 19 – 21
Pittsburgh, PA

9

A&D STRATEGIES AND OPPORTUNITIES
Conference & Workshop

Sept. 5 – 6
Dallas, TX

10

DUG
EAGLE FORD

Sept. 19 – 21
San Antonio, TX

11

MIDSTREAM
FINANCE CONFERENCE

Oct. 22 – 23
Dallas, TX

NEW IN 2018

12

EXECUTIVE OIL
CONFERENCE

Nov. 5 – 7
Midland, TX

13

DUG
MIDCONTINENT

Nov. 13 – 15
Oklahoma City, OK

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NEW



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DUGHaynesville.com



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Pittsburgh, PA
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San Antonio, TX
DUGeagleFord.com



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Managing well development with a manufacturing mindset

The upstream oil and gas industry has managed its operations the same way for decades because ‘We’ve always done it that way.’

Brad Thompson, Epex Solutions

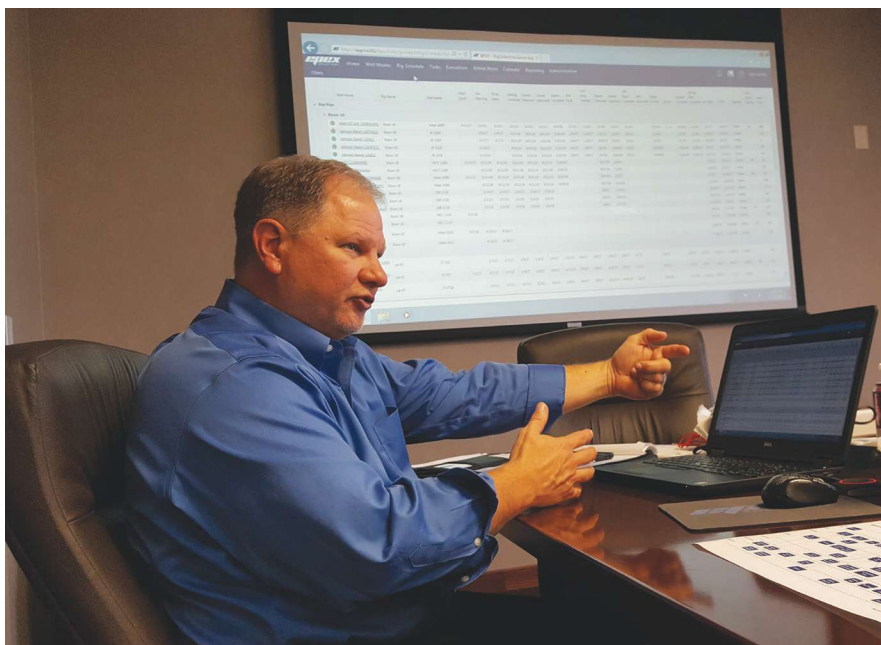
Anyone who has tried to introduce change within the oil and gas industry has heard the phrase “We’ve always done it that way” more than a few times during their career. It is the expected response from oil and gas executives and managers who have run their operations the same way for decades. While they have continually implemented new and effective technologies in the field and downhole and worked with other industries in developing and advancing things like geosteering, fracturing and countless other elements of drilling and upstream field operations, there is one area that has not really changed since the industry began shifting from an exploration mindset to large-scale development activities in the early 2000s. That area is the repetitive processes of new well development driven mostly by the move into unconventional oil and gas plays.

Some innovative industry leaders have shifted to a new mindset regarding operational management. Moving from an approach that manages new well development programs as if all wells are unique exploratory wells to one that only needs a manage-by-exception approach for all wells in an asset is much easier than it seems.

Williston Basin

In 2011 an executive commissioned a project to find a better way to manage his company’s large capital programs. This executive was about to take over operations of an acquisition that would require the managing of 15 full-time rigs in the difficult and expensive Williston Basin. As the project began, his statement was simple. He said, “It seems crazy that I can order a pizza online and see exactly where it is in the process, but I have no way to know where our \$10 million wells are in their development process. There has to be a better way to manage this process than the way we have always done it.”

Exploration wells are unique items with unique qualities and attributes and should be managed as if they are a “custom” well. Development wells, on the other hand, look more like cars coming off of today’s assembly lines. Once a car’s options have been selected and it has been given its place on the schedule, the manufacturing processes and systems take it from there. Likewise, once a well’s attributes have been selected and it is placed on the rig schedule, that well should move through its capital life cycle without much intervention unless for some reason it becomes an exception. This mindset shift from “manage everything” to “manage the exceptions” takes the right technology and management approach to become institutionalized.



President of Epex Solutions Brad Thompson talks to a completions group to modify and optimize their completions process. (Source: Epex Solutions)

Assembly line drilling

Just like stopping an assembly line in Detroit, stopping the assembly line of drilling and completing new wells is very costly. In 2011 a single day of idling a drilling rig in the Williston Basin could cost more than \$100,000. With the price of oil at more than \$100/bbl at the time, shortening the time to market (TTM, defined as the time from the beginning of drilling operations to the time of first sellable oil) made an enormous improvement on the return on investment. And with the climate challenges presented in North Dakota, having to build a well pad through the freeze of the winter could sometimes triple the cost of construction.

It was, and still is, very common to see weekly planning meetings in standing-room-only conference rooms for an hour or two to discuss all of the wells, their attributes and when they will be drilled across a given asset. Since software tools like Microsoft Project and Excel are commonly used to gather and track data, each functional group within the process maintains its own files to track and monitor its workloads.

Data can exist in multiple places, which causes confusion and errors. Lack of a single data source also makes the reporting process consume very costly employees who spend their time trying to develop informational reports that could otherwise be visible in real time.

It sometimes takes an enormous amount of time for a very talented spreadsheet guru to develop an extremely large file loaded with macros just to produce simple statistical reports. These files usually consume an entire full-time resource, and the company is exposed to tremendous risk if that person becomes unable to work or leaves the organization. Every time a task in the process of the well's life cycle is completed, the person completing the task has to notify several individuals, and each of them has to keep their own spreadsheets updated.

It is very common to have geologists, engineers and other staff start working on their individual parts of the well only to find out that the prerequisite tasks before them are not complete. They then must move on to other tasks, usually having to completely restart that previous effort at a later day.

By comparison, new cars move down an assembly line from station to station in an order that allows

each station to add specific components to the build without having to ever revisit that car to finish up that task. In most automotive assembly lines the car doesn't even come to a stop while the task is being performed. Parallel processes are synced to make sure that components are ready at the proper time and that they are configured to exactly meet the car for which they are designed. Everyone is using the same data to build the same car and understands how their specific task fits into the flow of that car's capital life cycle. Automakers today build better products with tighter tolerances and control costs better than they ever have before.

Managing by exception

To compete in a global market with crude prices at their new adjusted levels, operators must adopt some of these same techniques to reduce their costs and streamline their organizations. When a manage-by-exception approach is used, more time is spent by valuable engineers performing technical tasks and less time is spent churning out reports, sitting in meetings and starting and stopping the development of programs and plans. Wells with lower TTM durations are more profitable wells. With schedules visible to all, better coordination between operations and supply chain reduces material wait times and allows more negotiating power when product demand is based on a predictable schedule.

Epex Solutions has used its experience with the upstream industry optimizing manufacturing environments and its technical expertise to build a technology platform being used by some of today's most efficient upstream operators. Its electronic assembly line is customized to each operator's process flows and nomenclature, and its centralized database allows endless reporting and evaluation opportunities, which reduces and virtually eliminates costly mistakes during the capital development process. Epex clients have seen teams strengthen and their drilling programs become easily scalable. **ESP**

This mindset shift from "manage everything" to "manage the exceptions" takes the right technology and management approach to become institutionalized.

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

Unlocking the world's smaller offshore gas assets

A concept using small FLNG vessels for stranded fields will save the industry billions of dollars.

Eduardo Robaina, Add Energy

Companies traditionally have spent significant amounts of time and money in defining the capabilities of gas field development sites. This process, involving the identification of components required to develop and operate a field, can take up to five years before the delivery phase can even begin.

International energy consultancy provider Add Energy, partnering with Transborders Energy (TBE), has created a step change in the way smaller and stranded gas field development is executed.

This business model for the FLNG industry is intended to free up small-scale stranded resources around the world and establish a new concept in global gas field development.

The challenge

By 2040 it is forecast that global energy demand will increase by 30%, with natural gas demand growing by 50%. Based on its mobile nature, LNG will facilitate the global integration of gas markets as supply sources increase.

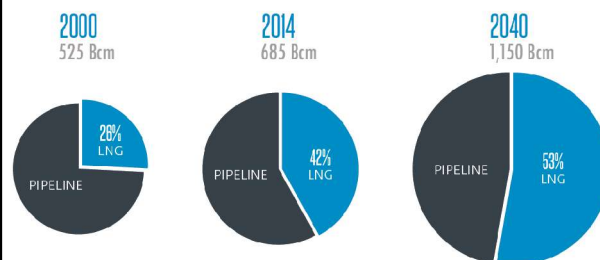
Nonetheless, the LNG market is oversupplied. LNG development is focused on fields with large-scale volumes between 141.5 Bcm and 283 Bcm (5 Tcf and 10 Tcf). However, a supply shortage in LNG is expected from mid-2020 due to demand growth and a failure to proceed with new megaproject developments.

Large-scale LNG projects typically involve up to five years of FEED work and a further six years for engineering, procurement and construction (EPC) activities, but new projects need to progress now to capture this upside.

With key forces driving commoditization in the LNG industry, the potential is ripe for industry stakeholders to grab and capture smaller opportunities in the changing business landscape.

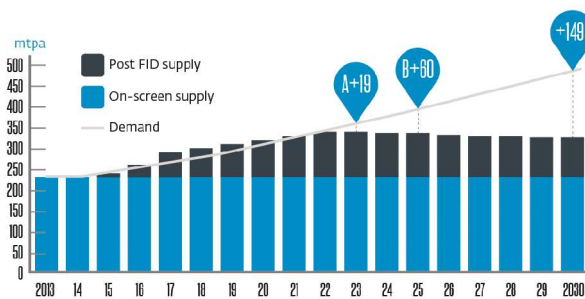
Moving into its most significant expansionary phase to date, the LNG industry is seeing supply racing ahead of demand in the short term, but this picture is expected to change dramatically as demand for LNG, particularly in Asia and led by China, is forecasted to grow.

GLOBAL NATURAL GAS DEMAND



Source: IEA World Energy Outlook 2016

GLOBAL LNG SUPPLY & DEMAND BALANCE



Source: BP Statistical Review, Energy Insights' Global Gas Model & Global Energy Perspective Model

Global natural gas demand is expected to grow by 50%, and LNG will facilitate the global integration of gas markets as supply sources increase. (Source: Add Energy)

A significant number of smaller stranded and previously uneconomic gas fields exist globally. New technology and innovative business models have enabled the economic exploitation of these resources to ensure that global supply will be able to meet the increase in LNG demand in the next decade.

The solution

TBE, with partners Add Energy and TechnipFMC and technical adviser for feasibility and technical study MODEC, is hoping to use emerging but proven technologies and stranded gas resources to carve a niche in global energy markets.

The four companies are targeting a stressed market with the view to position themselves in a strong gas delivery position by 2023. They plan to select an undeveloped field this year, with a final investment decision (FID) by 2020 and first gas by the mid-2020s, paving their way into the commoditized industry.

The team will generate a step change in industry value creation through these steps:

- Deploying its predetermined low-cost small FLNG concept;
- Selecting already discovered but stranded resources that fit the concept;
- Implementing innovative financing and commercial structures;
- Differentiating the value proposition to LNG buyers;
- Delivering with a small-focused, high-caliber team; and
- Replicating the concept on multiple resources.

Although the move to a FID by 2020 is ambitious, the team sees the schedule accelerated with the support of upfront concept selection rather than finding a resource and trying to develop a production solution based on that.

The driving force behind the new business model is recognition that the trend for large-scale LNG megaprojects may have run its course. In financially challenging environments such large, capital-intensive projects are challenged by FIDs, and although that will hamper a growth in supply, demand will continue to grow.

To combat this, the team has opted to avoid “going big” and chasing the fantasy of efficiencies of scale and instead has opted to “go small” to maintain a feeling of being lean and in control.

The concept enables the development of smaller, previously uneconomic resources at a much faster pace than that of megaprojects and will help feed the growing demand for energy, initially in Asia and elsewhere.

A new business model

The new business model targets discovered gas resources of about 14 Bcm to 57 Bcm (0.5 Tcf to 2 Tcf) of gas that have little value to their current owners because they are either in remote locations where tieback is capital-intensive or lack an economically viable development concept.

Key to the model is the deployment of an innovative small-scale FLNG vessel. Rather than investing up to five years in identifying a gas resource, understanding its size and potential and creating a bespoke development concept, the new model establishes a predefined concept incorporating the use of an ≈1-million-ton-

per-annum FLNG vessel and applies it to fields that fit the concept.

This low-cost concept represents a radical change in gas field development and could unlock many of the world’s previously uneconomic smaller natural gas plays, generating billions of dollars in the process.

TBE Managing Director Daein Cha explained, “The economies of scale pursued by megaprojects have not eventuated. They are too capital-intensive and risky in terms of resilience and flexibility for what is a commoditizing business.

“However, the deployment of this predetermined low-cost small-scale FLNG concept on already discovered but stranded resources with innovative financial and commercial structures delivered by a small but high-caliber team establishes a new value proposition to the resource owners and LNG buyers.”

The plan

TBE has identified 16 appraised assets in Australia containing about 566 MMcm (20 Tcf) in total. The company believes it could support a development within the Bonaparte, Browse and Carnarvon basins, and negotiations are ongoing to secure an operated position among its shortlisted assets.

“Instead of starting from the resource and optimizing the facilities to monetize that resource, we have developed a low-cost facility, and based on that, we are looking at resources that fit that concept,” Cha said.

Add Energy will be responsible for the drilling operations, maintenance, safety and risk management of the projects and is the exclusive partner to engineer, procure, drill and operate the wells.

TechnipFMC is the exclusive partner for TBE to EPC and install (EPCI) the subsea umbilicals, risers and flowlines and the FLNG vessel.

MODEC is the technical adviser for the EPCI of the hull, LNG tank and turret mooring system of the FLNG vessel together with the operations and maintenance of TBE’s FLNG vessel.

Offshore Australia has been identified as suitable for an initial pilot project, with a target resource to be confirmed in 2018 and the project to reach a FID by 2020. TBE is also in discussion with resource owners of other jurisdictions to pursue global opportunities. **ESP**

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

Harnessing the true potential of IoT

Predicting equipment downtime through IoT solutions can save operators time and money.

Dave McCarthy, Bsquare Corp.

Unplanned downtime is a phrase that can strike fear in any upstream operator. A single unexpected pump failure can cost hundreds of thousands of dollars every day, not to mention the expense of emergency repairs. No matter where it occurs in the supply chain, unplanned downtime seriously impedes the efficient, dependable retrieval and distribution of petroleum products and services. So how can operators address such an expensive problem if they do not know how to see it coming?

The answer is Internet of Things (IoT) technology. Using machine learning and device sensors, IoT solutions can analyze the enormous datasets produced by assets in the field, model how those pieces of equipment work and interpret the myriad intertwined factors that influence their behavior. Operators can use this information in multiple ways to cut down unplanned downtime and improve productivity:

- **Error prediction:** Understanding the leading indicators of a failure event makes it possible to monitor for at-risk conditions as well as take proactive action

to fix a problem or limit damage if the signs appear before a failure occurs;

- **Error diagnosis:** Failure prediction provides contextual data and models that are directly applicable to identifying the corresponding root causes as well as the steps and parts needed to make repairs faster, which enables quicker returns to production while lowering service costs; and
- **Operation enhancement:** These same data models also can help create optimal performance baselines for each asset. Comparing this to real-time operations makes it possible to identify potential problems and prescribe solutions more accurately, enhancing productivity.

Predicting equipment failures

The use of technology is not new in oil and gas, but historically much of the focus has been on hydrocarbon identification and extraction or managing individual assets. With the drop in oil prices over the past several years, upstream operators are working to improve recovery rates using methods and equipment that makes E&P more complicated and introduces more points of failure. Electric submersible pumps (ESPs) used for arti-

ficial lift are a perfect example. They allow increased flow rates for greater well productivity, but downhole failures result in expensive well intervention operations and lost production. It is critical for operators to understand how equipment is performing and the interactions that happen with it before a failure.

Data provided by connected ESPs and other



When operators partner with solution providers that can help them analyze the vast amount of data available to them and link them to related areas of the business, it leads to a successful outcome. (Source: Bsquare Corp.)

business-critical equipment is the key to predicting failures, but the geysers of data coming from machines can quickly overwhelm the people trying to make sense of them. Workers tasked with analyzing equipment data can spend anywhere from two-thirds to three-fourths of their time on nonproductive tasks like simply trying to find the right data to analyze to find a problem. With that approach, it can often take weeks or months to get to the root cause of a single problem.

IoT can help by applying advanced analytics and machine learning techniques to this torrent of data to rapidly recognize patterns and anomalies. It can parse through endless streams of noisy, irrelevant data to detect small pattern deviations that may indicate changes in a machine's state. Subject matter experts (SMEs) can then spend their time examining data more likely to be relevant to determine if the condition requires corrective action.

Over time, the system looks at the state of each individual machine from its first in-service date to its last along with error conditions and failures that occur during its lifetime. This process of mapping individual and groups of machine states and patterns and how they relate to each other enables the creation of digital models, or twins, of each machine. The models can be asked about the state of the machine and the probability of state changes that may foretell a failure. Time ratings can then be assigned to the state changes, effectively calculating a predictive failure scenario and giving the operator the ability to plan for repairs before the failure occurs.

Diagnosing problems

Once an operator is able to get better insight into its equipment and is receiving alerts of impending failures, the next step is to pull in contextual data that can help determine exactly what is causing the problem and the best way to correct it. Awareness of a potential failure and performing repairs on time with the correct replacement parts on hand ensures continued production with minimal interruption.

IoT can tap into external data that add context to error codes, from environmental conditions (e.g., was there a period of extreme cold at the location?) to engine specifications and maintenance records (e.g., was a part recently replaced that might be bad?).

This added information narrows down the root cause of failure and helps identify the part or parts that need repair. Further linking to other information sources such as enterprise asset management systems can help locate parts quickly and automate inventory management. Detailed repair plans can be created that allow technicians to arrive

onsite with the correct parts and step-by-step instructions that greatly improve the odds of a first-time fix.

Optimizing equipment

Some equipment operates better than others. This could mean it lasts longer, has fewer failures, is more energy-efficient or has better output. Given a particular set of conditions, whether environmental, geothermal, aboveground/below ground or offshore/onshore, it is possible to accurately tune and calibrate equipment so that it is operating at its peak.

An IoT system can compare a group of like equipment to not only understand variations but also what drives those variations and provide prescriptive recommendations. For example, increasing pump rpms could remediate a drop in performance without any detrimental effects. The system can alert the operator and recommend parameter changes to increase those rpms.

As the operator reacts and makes decisions on actions, the system can learn to perform actions based on past responses and become more automated. This progressive approach allows operators to guide responses and understand cause and effect while ultimately becoming more proactive as the system becomes more intelligent. Using digital models, an optimized baseline is created that can be compared to equipment in the field to prescribe actions that elevate performance and increase productivity.

Partnering for success

Many operators are interested in improving their business with IoT but lack the skill sets and experience to be successful, especially since these concepts are not traditionally a core competency in this industry. It is important to understand that adopting IoT is a progression that involves readiness at the organizational level and the involvement of SMEs to guide the application of analytics, machine learning and modeling behavior as well as ties into other sources of enterprise information.

Advances in software can provide much of the heavy lifting of data analysis and free up operator experts to apply their knowledge to operationalizing the data back into the business. The most successful initiatives occur when operators partner with solution providers that can help analyze the vast amount of data available and then link to related areas of the business. This approach can generate significant, tangible business benefits, including optimized asset efficiency, valuable real-world feedback for R&D and substantially improved uptime, driving toward that holy grail of zero unplanned downtime. **ESP**

Accurately representing fracture flow in reservoir simulation

Intuitive analysis helps prevent slow or inaccurate predictions.

Daniel Rings, Emerson Automation Solutions

Whether through advances in parallel computing and greater simulation performance or enhanced history matching capabilities and a more integrated workflow from geosciences through to production, reservoir simulation and the technologies and tools around it have advanced dramatically over the last few years.

Reservoir simulation stands as a crucial element of the reservoir management workflow—mitigating risk, improving decisions and ensuring more productive and profitable fields. Yet for all its advances, one area that reservoir engineers have struggled to incorporate into their workflows is that of fractures.

Importance of fractures

Fractures have a direct influence over fluid flow behavior, greatly enhancing the permeability of rocks and changing the distribution of flow in the reservoir.

Decades before fracturing became prevalent in unconventional reservoirs, inducing fractures around wells to enhance fluid flow was a common technique. This was achieved by injecting a mixture of fracturing liquid and proppant into the well at high pressures to create a set of (usually) vertical fractures propagating from the wellbore into the surrounding rock.

Because of the proppant, these fractures remained open even after the injection ceased, effectively expanding the influence region of the well and enabling increased production without the need to drill new wells.

Yet, despite the importance, influence and popularity of fractures, existing reservoir simulation workflows have struggled to incorporate well fractures either efficiently or accurately into the calculation of reservoir fluid flows.

Reservoir simulation advances

When trying to incorporate fractures into the workflow, reservoir simulation software has tended to be either overly simplistic—limiting the sureness of its predictions—or has tried to gain accuracy by using a fine-grained discretization of the reservoir around the fractures. However, fractures are regions of small volumes with high flows. This makes the modeling of fractures through conventional numerical techniques a challenge, impacting reservoir simulation performance.

It is with these issues in mind that Emerson has developed a new method to quickly and accurately model well fractures within its Roxar Tempest MORE reservoir engineering software.

The method forms part of a workflow, from well fracture planning to results visualization, and is designed to let reservoir engineers gain deeper insights into the effect of well fractures on their reservoirs.

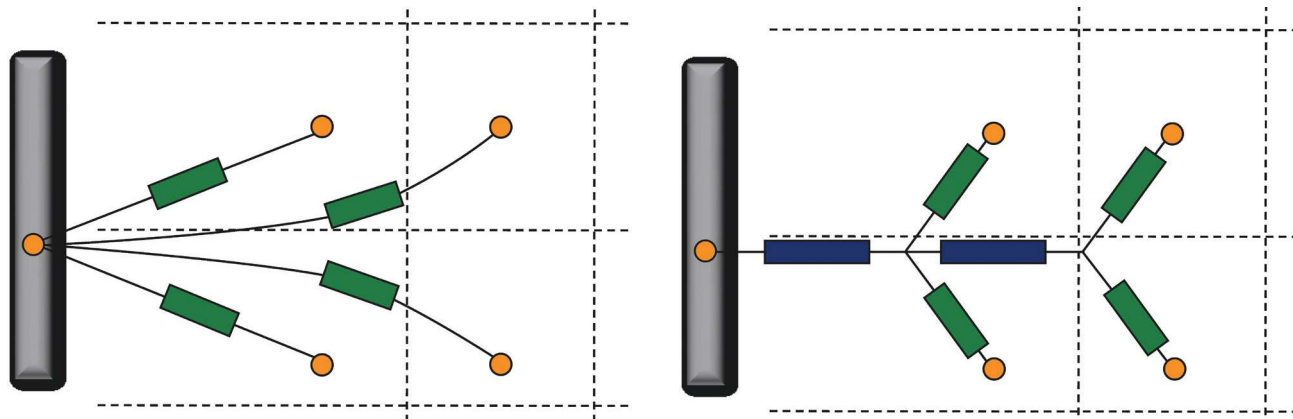


FIGURE 1. This model depicts traditional (left) and enhanced (right) fracture-well connections. (Source: Emerson Automation Solutions)

How it works

The new fracture modeling feature handles the physics of the fracture-to-well connection and the multiphase flow within the fracture. It enhances previous tools that model fractures as a set of two-point flows as depicted in the left-hand sketch in Figure 1.

Although simple and fast, the approach ignores cell pressure variations along fractures, tends to overestimate inflow and does not allow direct crossflow between cells through the fracture. To address these issues, an enhanced approach has been developed with fractures modeled separately as 2-D grids intersecting the 3-D reservoir grid (Figure 2).

The simulator solves the pressure field inside each fracture and subsequently calculates the component flows from the reservoir into and along the fracture to the wellbore. This requires the solving of only a small linear system of equations, thereby avoiding separate fracture solver iterations inside the well solver and thus adding to the overall robustness and performance of the model.

How it looks

Setting up the fractures is straightforward using simple data entry forms that allow the user to define the fracture properties, including height, length, conductivity and geologically consistent direction.

High-quality visualization and plotting capabilities then offer a quick and clear understanding of the fracturing effect as shown in Figure 2. The figure shows a 3-D visualization of a reservoir with two types of well fractures: along vertical trajectories and across horizontal trajectories. The fracture grid coloring illustrates the pressure inside the fractures.

Fluid flows also are reported for each fracture rather than for the individual fractured grid cells (Figure 3). This makes it simple to see the effect of individual fractures and keeps data volumes manageable.

In summary

Hydraulically fracturing wells is a common engineering technique to enhance well productivity but has been awkward to simulate in the past and has led to slow or inaccurate predictions. This new technique scales to large reservoir simulations with hundreds of wells and

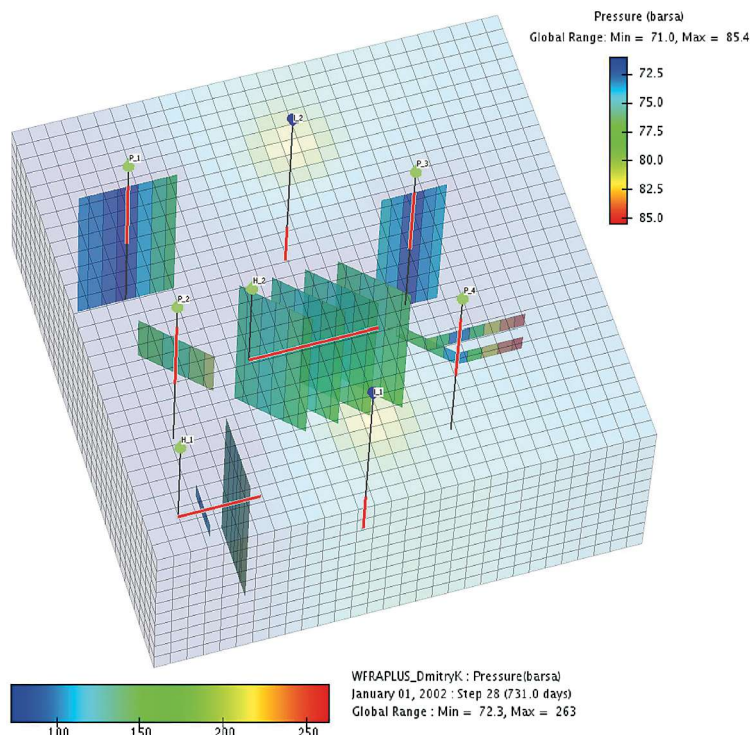


FIGURE 2. Visualization and plotting capabilities depict fractures on the reservoir grid. (Source: Emerson Automation Solutions)

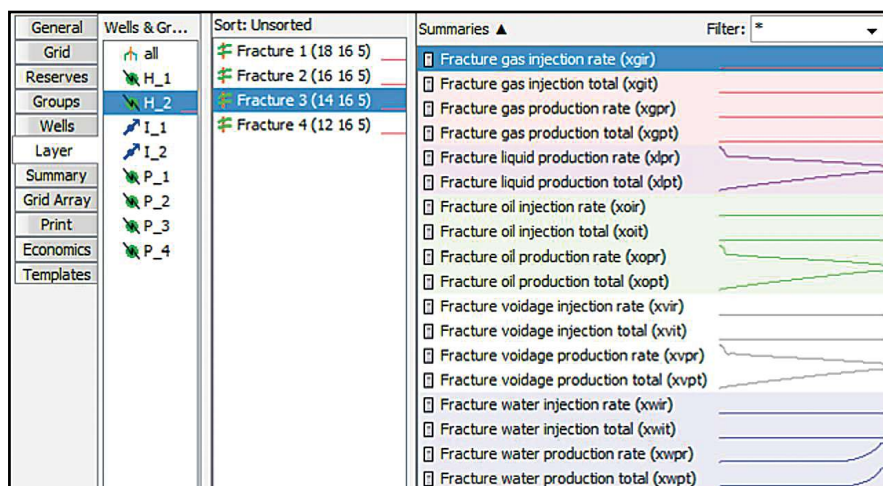


FIGURE 3. This graphic depicts fluid flows by fracture. (Source: Emerson Automation Solutions)

provides easy setup and intuitive analysis tools. In turn, this allows more effective risk mitigation and decision support, especially when embedded in Big Loop uncertainty analysis workflows.

Following the recent Emerson acquisition of Paradigm, the combination of Emerson and Paradigm technologies will accelerate the launch of exciting geoscience and reservoir engineering solutions over the coming months. **ESP**

Facies-based inversion through the asset life cycle

A research study indicated that a facies-based seismic and CSEM inversion provides useful information.

Michel Kemper and Kester Waters, Ikon Science Ltd.

Seismic lacks low frequencies, so for an absolute seismic inversion a low-frequency model (LFM) is required. Starting from an empty LFM, interpreters would like to post sand velocity values where there is sand, shale velocity values where there is shale, etc.

But unless there are very favorable circumstances, interpreters don't know in any great detail where the facies differentiations are located in the subsurface. Therefore, an LFM is typically compromised, and during the inversion the seismic cannot "fix" a compromised LFM because it lacks low frequencies.

Facies-based inversion

An advanced approach to a better LFM is to input an LFM for each of the facies expected and to let the inver-

sion decide what the ultimate LFM is. In other words, the LFM used is an output, not an input.

This new inversion involves two steps:

- Invert the seismic for impedances given the facies; and
- Invert the impedances for facies.

The two steps help one another. Clearly, better impedances lead to a better facies estimate. The reverse is also true because in each execution of the impedance inversions, the LFM is recreated based on the facies estimate.

The implementation is a Bayesian one. Therefore, multiple equiprobable facies realizations can be generated for subsequent uncertainty analysis.

Application from exploration to production

The parameterization of facies-based inversion changes from exploration to production. In exploration the inversion window is usually quite large and

the number of zonations in that window are quite small, so the number of facies inverted will be small as a result. In production the reverse is true: a small inversion window targeted on the reservoir, many zonations and a larger number of specific facies (Figure 1a).

In one exploration case study Ikon inverted the Willem survey offshore Northwest Australia. The dataset consisted of 2,400 sq km (927 sq miles) of seismic (four partial angle stacks) with only two wells with elastic logs (and a further three wells without elastic logs and one well, Pyxis-1, which very little was known other than it was a gas discovery).

Figure 1b (top) shows the facies-based inversion result (impedances are not shown are the discrete facies) on an arbitrary line through the Pyxis-1 discovery. For the sake of comparison, the company also ran a model-based simultaneous inversion, which requires an LFM as an input. This, however, only gives impedances, and so

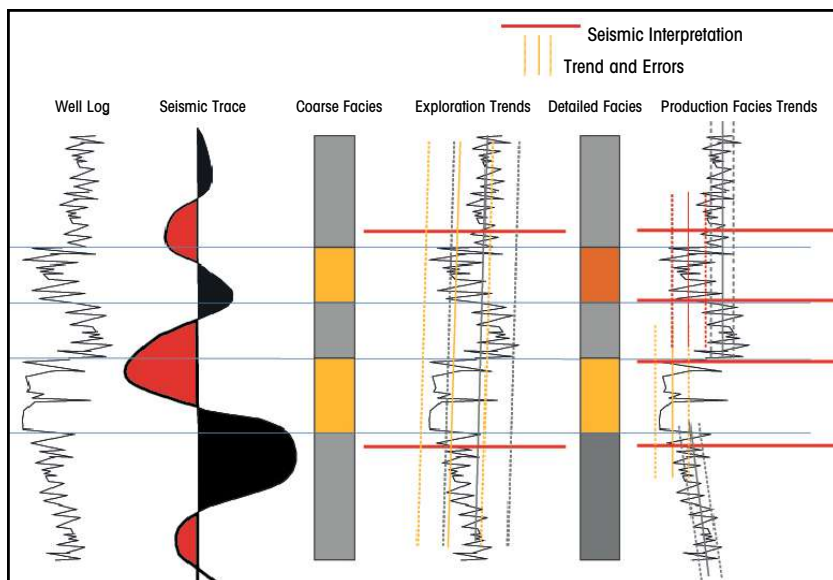


FIGURE 1a. Left, the log and seismic traces are shown at the well location. The middle trace shows an exploration inversion, in which the interpreter may decide on only two facies (sand and shale), the trends/LFMs of which are shown. Note there are three zonations. Right, in a development or production setting, interpreters may decide on only four facies: clean sand, dirty sand, soft shale or hard shale. (Source: Ikon Science)

FIGURE 1b. The facies-based inversion (top) and model-based simultaneous inversion followed by Bayesian classification to facies (bottom) of the Willem 3-D survey are shown. Grey is shale, yellow is water-bearing sand, red is gas-bearing sand, blue=limestone and purple is marl. (Source: Ikon Science)

interpreters subsequently derived facies using Bayesian inversion (Figure 1b/bottom).

The facies-based inversion result looks more credible. This can be substantiated by 1) inspecting the two ellipses (the facies-based inversion identifies a gas-water contact) and 2) looking at the two arrows. The facies-based inversion images a continuous gas-bearing sand and predicts an 18.2-m (60-ft) gas column at Pyxis-1, and later the interpreters learned that they were only 1 m (3 ft) short. Simultaneous inversion followed by Bayesian classification does find the gas leg, but it is broken up, has water-bearing sand (yellow) above and below the gas-bearing sand (breaking hydrological rules), and the gas column is too small.

Production setting

In the mature Forties Field the objective of seismic inversion is to assist in locating untapped hydrocarbons (bypassed pay, undrilled fault blocks, etc.). The first 3-D survey was shot in 1988 and forms a baseline for 4-D studies. Five monitor surveys have been acquired, the last of which was in 2013.

Facies-based inversion as discussed so far is a 3-D inversion, and therefore this technique was applied to the 1988 and 2013 surveys individually. Figure 2 shows a map view of the facies distribution in 1988 (top) and 2013 (bottom).

The massive sweep signature to the southwest is evident, but detailed analysis shows finer details also (e.g., “halos” around water injectors).

Look ahead

Facies-based seismic inversion is powerful because facies typically have distinct elastic properties, but they usually have distinct resistivity, too. Therefore, a facies-based seismic and controlled-source electromagnetic (CSEM) inversion makes sense.

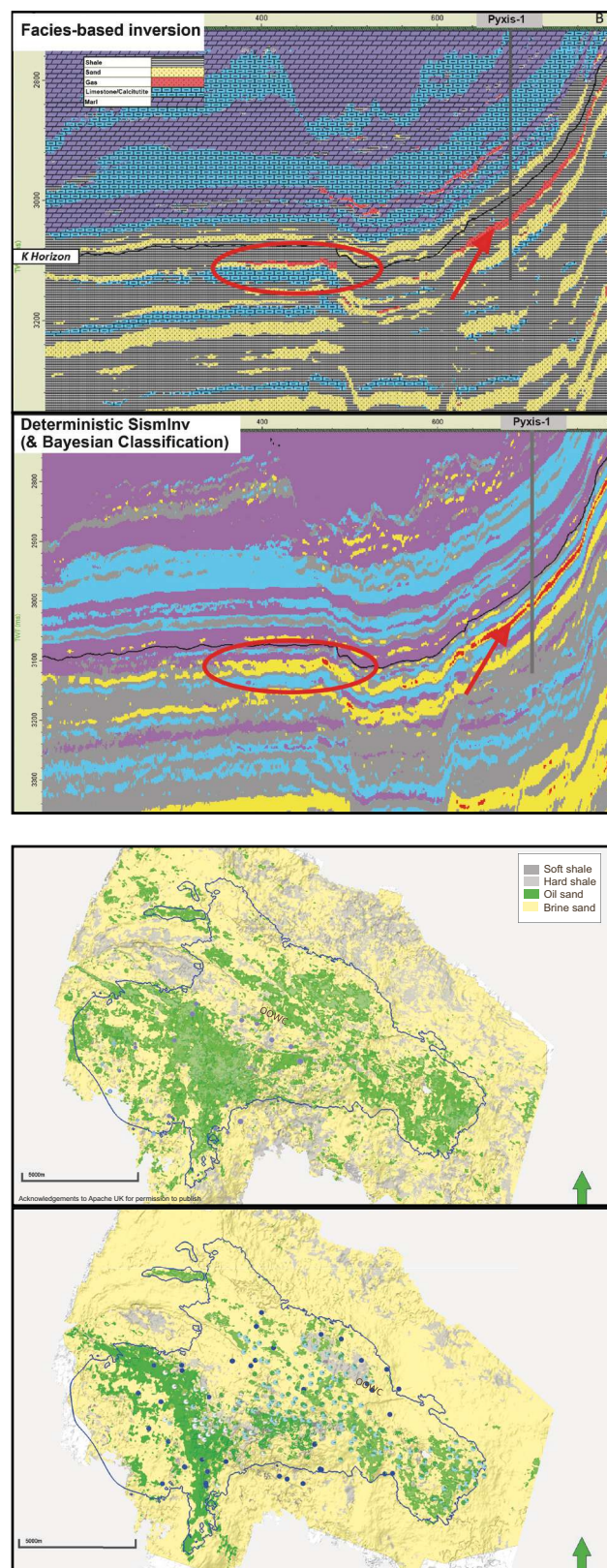
The industry has seen a rapid adoption of facies-based inversion over the full life cycle of an asset since it opens the door to new subsurface workflows. Facies-based seismic and CSEM inversion as well as facies-based 4-D inversion and facies-based anisotropic inversion have been successful, and more are in the pipeline. **ESP**

References available.

Acknowledgment

Ikon Science thanks Tullow Oil Plc and CSIRO for their cooperation.

FIGURE 2. This facies image shows the top 20 m (66 ft) of the Forties reservoir in 1988 (top) and 2013 (bottom). (Source: Ikon Science)



Simulating relative permeability

A new software program helps operators model multiphase flow.

Rhonda Duey, Senior Editor, Exploration

Those who attended the Abu Dhabi International Petroleum Exhibition and Conference (ADIPEC) in 2017 might have had a chance to hear Exa and BP present a paper on a multiyear data study showing results of the industry's first relative permeability software solution. The DigitalROCK software is intended to get petrophysicists out of the laboratory by enabling them to evaluate rock formations and assess relative permeability to accurately assess reservoir output. *E&P* recently talked to David M. Freed, vice president of Exa's Oil & Gas Division, about the potential for this technology.

***E&P*:** Please share a brief background about the company.

Freed: Exa was founded in 1991 and for the past 20 years has been in the business of providing an accurate

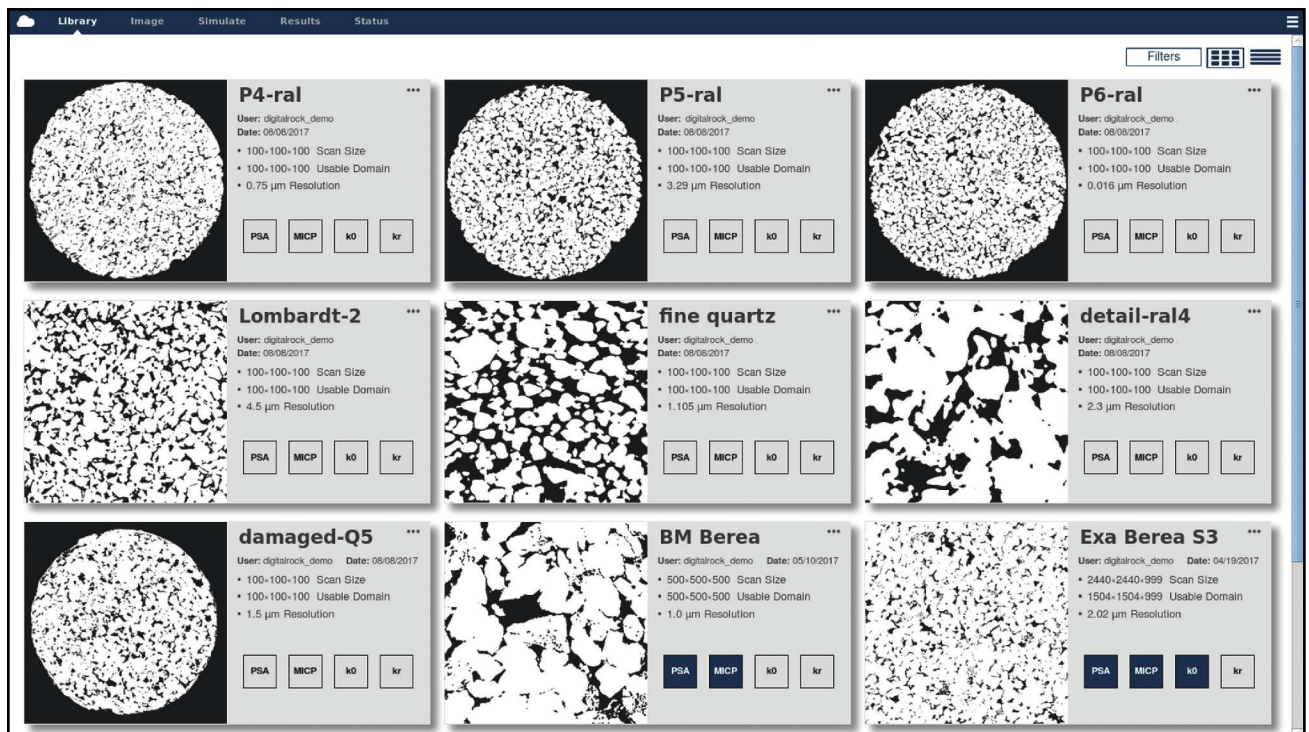
computational fluid dynamics solver for automotive aerodynamics and related applications. It's a revolutionary way to do fluid flow simulation based on this technology called the Lattice-Boltzmann [LBM] method.

Exa was the first company to build a business from commercializing LBM. So having built up market leadership and a core business in fluid flow related to cars, trains, airplanes, heavy equipment and related applications, at some point we recognized that our technology could be ported over to the oil industry.

We always knew that we had a unique technical advantage for multiphase flow, but we didn't use it until we started working on this DigitalROCK application. Over the last five years we leveraged our technology foundation to develop the DigitalROCK capability.

***E&P*:** Can you explain how LBM works?

Freed: Let me first say a few words about how fluid dynamics is usually done on a computer. Historically,



DigitalROCK allows users to isolate more rock types to identify lithotypes. (Source: Exa)

people have taken what they call the fluid flow equations and tried to solve those directly on the computer, and that's a fine thing to do, but it does run into limitations. There are times when the computer has to deal with a very large numerical simulation, and it becomes harder to scale.

With the LBM approach you're taking the point of view of the particles. But you don't follow each individual particle. You follow what we call groups of particles or particle distribution. You can think of it as a bottom-up approach. By taking this approach and being very precise in how you track the movement and interaction of particles, you can perform complex fluid flow situations in a more natural way that lends itself well to dealing with very large or very complex flow systems.

E&P: Exa recently co-wrote an ADIPEC paper with BP. Can you go into a few details about that company's interest and why it chose to undertake this project?

Freed: BP had been working on DigitalROCK for a long time and had gone quite far with it. Their scientists had developed world-class imaging capabilities. By imaging, I mean the ability to use a microcomputer tomography scanner to create a 3-D tomographic image from which you can then discern the actual pore space of a rock sample and use that pore space geometry as the basis of various rock property analyses. So the company was already a leader in the imaging and image processing, and it can do several kinds of analyses to determine important geophysical and petrophysical properties of the rocks.

But what BP really wanted to do was to be able to do multiphase flows to calculate the relative permeabilities, for example, water and oil or oil and gas flowing together. In real reservoir rock you always have a mixture of fluids.

At some point BP ran into us, and we were already pretty far along in developing a multiphase flow simulation capability. We realized that by partnering we would be able to take it all the way.



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At this point Exa didn't have much of an oil and gas background. It was our first entry into the industry, so we needed a partner that would provide that domain expertise and have physical test data to compare the simulation results to. BP needed a partner that had the fundamental technology to do the multiphase flow simulation. By joining forces over the course of a few years, we were able to take the solution all the way through to being tested and validated against high-quality physical lab test data.

E&P: What kind of a learning experience was that for you?

Freed: It was pretty epic. I think it was one of the most amazing journeys of my career to work with the really brilliant and visionary people at BP, [who are] technically very capable people, and to work together as a team, solve this problem and work through all of the challenges that come up when you're trying to compare computer simulation predictions to real-world physical lab tests. It was an incredible experience to bring those different domains of expertise together to solve this problem.

We were working with a dedicated interdisciplinary team, a DigitalROCK group. It was composed of people with a reservoir engineering background but also with imaging expertise and expertise in relative permeability and multiphase flow in reservoir rocks.

E&P: Why do you think your solution is better than some of the others that are out there?

Freed: We didn't invent the idea of DigitalROCK. It was already around, and there were already researchers and companies working in this space. And I think a lot of them got pretty far. I think that you can already get some value out of the images, see things that help you understand your rocks. People also got pretty far with being able to look at porosity and do single-phase flow, which gives you the absolute permeability.

What the industry really needs, though, is the multiphase flow [and] the relative permeabilities. And I think that's where the other companies and researchers in this field fell short. There really wasn't an accepted or credible multiphase relative perme-

ability prediction capability out there before. We're really the first to crack that nut in a robust and credible way.

E&P: There's always the scaling issue if you're taking something at a microscopic level and trying to expand it out to reservoir level.

Freed: With DigitalROCK, with the digital version of the lab tests, you can do many more samples because it's so much faster. And not only that, you can really isolate each rock type. You do a little geology ahead of time to identify the rock types and lithotypes. And then you want to get some reasonable number of samples for each of those lithotypes. Then you're able to characterize each of the lithotypes independently and feed that set of information into your reservoir simulator.

I think that the big take-home benefit, if I had to name just one, is the much faster analysis time for the digital instead of the physical lab tests. Because of that faster time there are many things you can do, [such as] what-if studies and really understanding sensitivities to different flow and rock system parameters. I think those are the key benefits of the technology, and Exa is committed to help the industry leverage this technology to really be a game changer in terms of better field characterization and production optimization.

E&P: It seems like your approach has more of an EOR focus.

Freed: Well, I think EOR is a good example of a use case where you really have to be talking about multiphase relative permeabilities or multiphase capillary pressure prediction. That's what makes all the difference. If you're going to run a waterflood or add a surfactant, is that going to change your relative permeability? Is it going to change your endpoint, which is the residual oil? That's the whole name of the game. Porosity and single-phase permeability can already help you with your reservoir characterization. But then the multiphase capabilities take it to the next level around whether an EOR technique is going to be feasible and economic on a particular set of rock types. **E&P**

The LBM
approach takes
the point of
view of
the particles.



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A critical element for understanding the subsurface

An understanding of rock physics is crucial for reservoir characterization.

Larry Meckel, L. Meckel & Co.

The industry has amazingly good methods to quantify rocks in the subsurface, and they are constantly improving. The main ones are downhole well logs of various kinds and seismic. They measure properties on two very different scales, but both are valuable for understanding the subsurface.

The industry's ability to relate these measurements to the actual subsurface rocks is critical for E&P. However, the physical measurements alone commonly do not give a unique answer as to what the actual rock-fluid system actually is. So the challenge is to properly interpret those data, and doing so requires a calibration of those measurements with good rock data. The rock data are usually in the form of whole cores, sidewall cores or cuttings (available for virtually every well). In some cases,

nearby outcrops (as with the Eagle Ford Shale) can be very instructive. The real objective is to reduce risk.

The most common phrases used to describe this are "rock physics" or "reservoir characterization." These words embody both the 3-D geometry of the reservoir (best with seismic) and the internal attributes of the reservoir (mostly from logs).

Historical context

The first application of rocks physics came in the '50s and '60s to tie downhole well logs to rock data, mostly for the conventional clastic and carbonate reservoirs the industry dealt with at that time. With the advent of true amplitude seismic data in the '70s the industry realized there was valuable rock-fluid information encoded into amplitudes, frequencies and phase properties of the seismic, but it needed calibration with real rock data.

As the industry moves into unconventional resource plays where the reservoir is even more complicated, the need to calibrate the engineering data with rock information is more critical as the lithologies, pore systems and flow properties are more complicated. The industry also deals with mechanical properties like brittleness, which is so critical to create the fractures to make these plays economical.

A check of most any E&P office will show that most workers are fixed on screens manipulating various forms of data. Many companies have deserted the train-

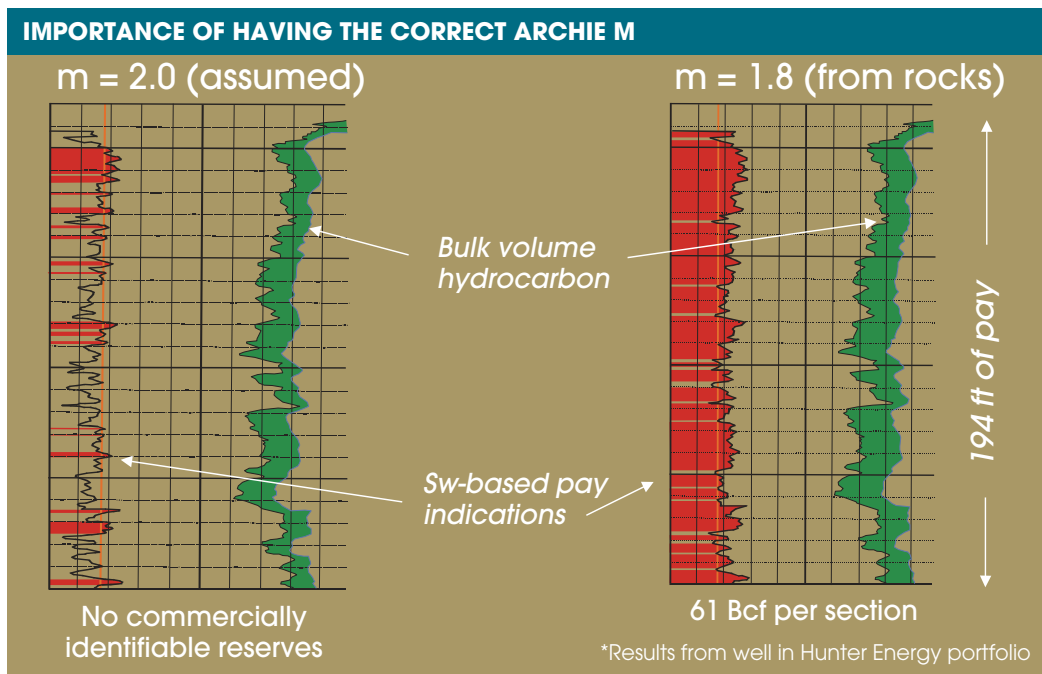


FIGURE 1. An assumed m of 2.0 gave a marginally productive pay zone (left). Once calibrated with rock data, the new m of 1.8 gave 59 m (194 ft) of pay (right) and large recoverable reserves. (Source: L. Meckel & Co., courtesy of K. Stølper, personal communication)

ing that earlier geologists had—namely, to carefully look at and describe the rocks.

What do rocks provide?

The main items we get directly from the rocks are:

- Lithology;
- Mineral composition;
- The mix of lithology and mineral composition (i.e., the degree of heterogeneity that is being averaged by the measuring tool);
- Porosity type and value;
- Permeability;
- Brittleness;
- Cementation exponent (m);
- Specific minerals that create log anomalies that complicate normal interpretation; and
- Various special core analysis measurements that impact petrophysical models, reservoir engineering parameters and well completion designs.

Examples

Two recent examples illustrate the value of good rock data because in each case the initial interpretations from good engineering data alone indicated non-commercial or water-wet units. When rock data were added to calibrate the log data, the units were all economical pays.

Establishing the correct m . A correct m is essential for establishing an accurate water saturation calculation and thus establishing what is pay. A value of 2.0 is commonly assumed. That value can in fact vary from 1.5 to 2.5. By looking at the rocks, the correct value for m can be established rather quickly and inexpensively. A correct m can result in testing units that would otherwise appear wet using an existing assumed value. Figure 1 shows how a marginally productive zone (left) was converted to one that has about 1.7 Bcm (61 Bcf) of recoverable gas per section (right) by obtaining a correct m from cuttings.

Identifying low resistivity, low contrast pays. Low resistivity, low contrast zones are commonly overlooked or considered wet due to their low resistivity values. This is because 1) there is usually a mineral or lithology that suppresses the resistivity enough to indicate the

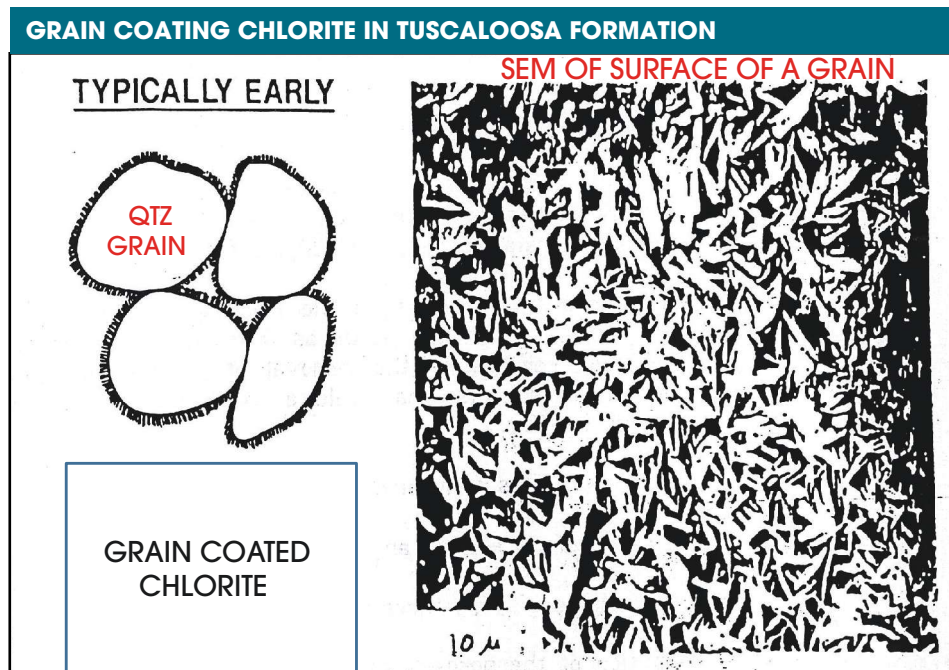


FIGURE 2. This unit had very low resistivity and was considered wet. When calibrated with rock data (right image), it was realized that the sand was a low resistivity, low contrast pay and was not water-wet. The low resistivity was due to the pore lining chlorite that had abundant micropores filled with nonmovable water. (Source: L. Meckel & Co.)

unit is wet, 2) the reservoir may be thinly shale-laminated, which cannot be resolved with the available log suite, and 3) the grain size and pore throat distribution may be small enough that nonproductive water is trapped.

For example, in part of the Gulf Coast Tuscaloosa trend one can get water-free oil production at less than 2 ohm-meters, a resistivity value normally considered wet. Available cores (cuttings will work fine) show that where this occurs, the quartz grains are coated with a diagenetic bladed chlorite that contains lots of micropores filled with water (Figure 2). Therefore, the electrical current goes through these thin wet rims on the grains and bypasses the resistive hydrocarbons in the main pore system. The units thus have a low resistivity indicative of being wet, when in fact they will produce water-free oil.

If maximizing the value received from well-acquired and expensive engineering tools like logs and seismic is desired, it is critical that the data be calibrated with real rock data. Good rock physics data provide a better interpretation of the subsurface, thereby reducing the risk associated with this business. **ESP**

References available.

Answering borehole stability challenges in difficult shale

Formate fluids help slow pressure transmission in the wellbore.

Siv Howard, Cabot Specialty Fluids

Shale-related problems continue to be one of the largest sources of nonproductive time and trouble cost during well construction. Operational problems range from bit-balling and cuttings dispersion to full-scale stuck drillstring and casing events because of wellbore caving and collapse. Problems manifest themselves mostly when using water-based muds (WBM) and can often be sidestepped by using oil-based mud (OBM) and synthetic-based mud (SBM).

The latter, however, come with their own set of drawbacks, including complicated offshore skip-and-ship operations, difficulties obtaining electrical/resistivity logs, high waste disposal costs, a low threshold for lost circulation through induced fractures, incompatibility with Portland cement, etc. Moreover, these muds do not perform well on fractured shale formations. It is therefore still highly desirable to identify water-based alternatives to OBM/SBM.

Naturally compatible

Both field experience and research show that fluids based on cesium and potassium formate brines are among the best shale-compatible water-based drilling and completion fluids available. Unlike other water-based drilling and completion fluids, the shale-stabilizing properties of formate fluids are attributable to the inherent properties of the formate brine itself, rather than to additives. This has the great advantage that the shale-stabilizing properties do not deplete with time, and no complicated and/or expensive additive maintenance is required.

First, cesium (and to a lesser extent potassium) ions have a low level of hydration in solution, and the effective “shell” of water molecules they carry around them is easily removed. When such ions exchange at clay sites in shales, they can effectively shield the water-structuring negative potential of the clay platelets, while at the same time avoiding ion hydration/solvation stress buildup.

This allows these “inhibitive” ions to heavily reduce the swelling pressure acting in the clay fabric, delivering

important benefits that range from the ability to avoid bit-balling and cuttings disintegration all the way to preventing clay swelling and fines mobilization in hydrocarbon-bearing reservoirs.

Stabilizing effect

Cesium and potassium formate fluids exhibit remarkable qualities for stabilizing wellbores in shale formations as confirmed by both detailed laboratory studies as well as field applications. Contrary to popular belief, wellbore instability has little to do with clay swelling.

Wellbores typically destabilize, irrespective of mud type and formulation, when the wrong mud pressure is applied. However, even when the correct mud pressure is used shale formations may still destabilize over time due to mud pressure transmission driven by mud overbalance. Pressure transmission “charges” the near-wellbore pore pressure in shale rocks, creating instability in near-wellbore zones with associated borehole caving and enlargement over time, and a plethora of knock-on problems that include stuck pipe, poor casing runs, poor cement displacement causing poor cement jobs and insufficient zonal isolation.

Formate fluids offer two main mechanisms to slow down—and in some cases even avoid—pressure transmission. First, concentrated formate solutions have high filtrate viscosity. This slows Darcy flow into the shale that causes the detrimental near-wellbore pore pressure elevation. Second, concentrated formate solutions generate high osmotic pressures opposite shales with lower-salinity pore fluids, allowing hydraulic flow into the shale to be offset by osmotic flow out of the shale if the shale acts as an osmotic membrane.

Offshore shale case study

How good the shale-stabilizing qualities of formate fluids are in comparison with other muds was shown recently in a comparative mud evaluation conducted on behalf of Maersk Oil. The company had been suffering from time-delayed wellbore instability problems in the Lark/Horda shale formation that was intersected while drilling Tor/Ekofisk wells in the Danish sector of the North Sea.

Drilling with either conventional WBM or OBM resulted in a limited trouble-free openhole time of only three to five days before the well started to cave and wellbore enlargement commenced. This resulted in operational problems ranging from trouble backreaming out of the hole and running casing to irreversible stuck pipe and necessity to sidetrack.

In a series of competitive tests, a 13.5-parts-per-gallon-mixed cesium/potassium formate fluid showed minimum shale accretion and excellent cuttings integrity in dispersion testing. The fluid distinguished itself in particular, however, during pressure transmission tests and borehole collapse tests where it stood apart from all other muds, including new commercial high-performance WBM (HP-WBM) formations and modified OBM formulations.

Formates can osmotically pull water from shales, creating a lubricating layer that prevents shale from sticking to bit cutters.

Figure 1 shows the comparative pressure transient testing results, showing the formate fluid to be in a league of its own in its ability to delay the onset of instability caused by pressure transmission, with delay factors that

were more than five times larger than those observed for the best HP-WBM systems. The formate fluid also delivered the strongest wellbore during the borehole collapse tests.

Faster ROP with formate fluids

These results are fully validated by field experiences with formate fluids. Wells drilled from the late 1990s by Agip, Statoil, Kerr McGee and others all have shown excellent wellbore integrity in shales after extended periods of openhole time.

These operators also observed a significant increase in ROP when comparing formate fluids to both conven-

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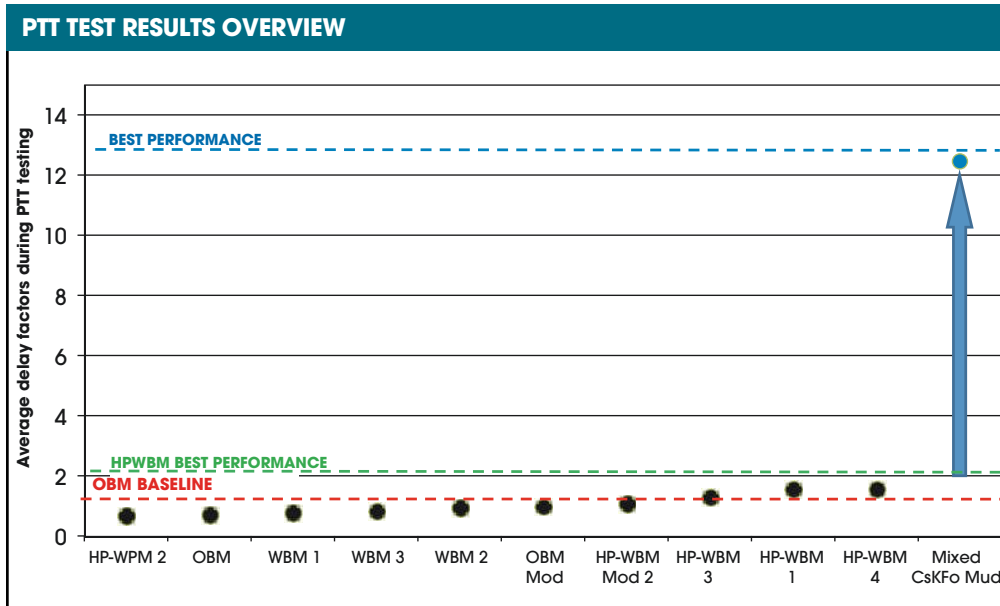


FIGURE 1. An overview is shown of absolute delay factors recorded during pressure transient testing by Maersk Oil for various mud systems indicating baseline performance by OBM and previous best HP-WBM performance by HP-WBM 1 and HP-WBM 4. The blue arrow indicates the step-change improvement observed with cesium/potassium formate fluid, which is clearly distinguished from the other results. (Source: Cabot Specialty Fluids)

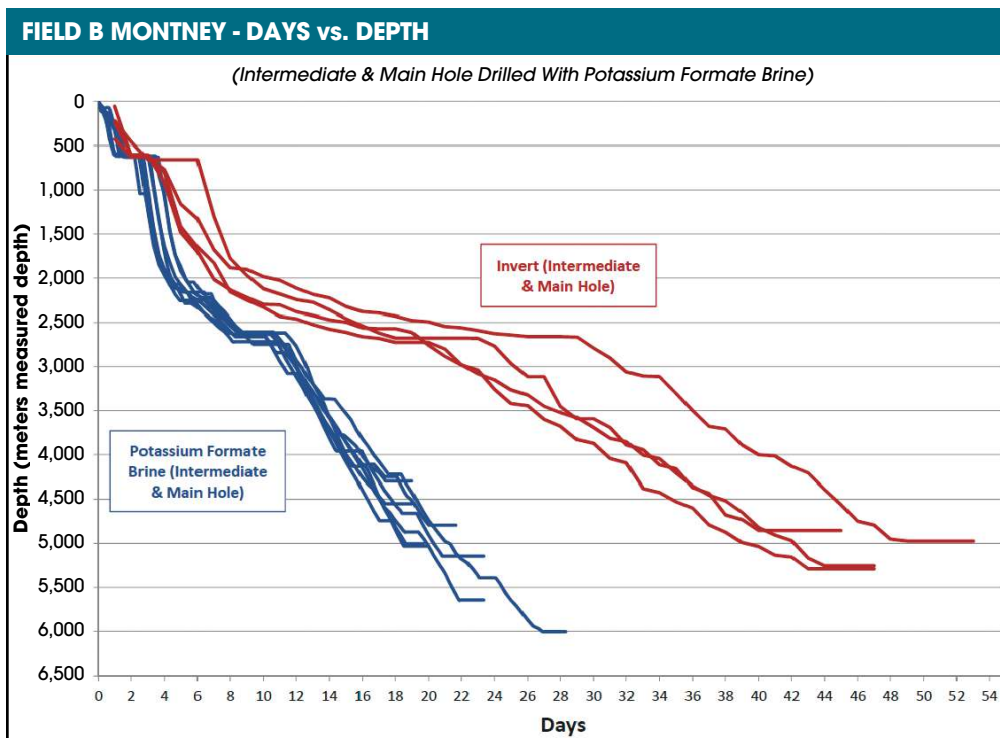


FIGURE 2. Potassium formate brine drilling performance (blue) in days versus depth compared to invert OBM (red) in Montney Field B clearly shows the acceleration in drilling performance facilitated by the formate fluid. (Source: Cabot Specialty Fluids)

tional WBM systems as well as OBM/SBM systems. This was most clearly demonstrated by a large number of wells drilled by Encana and others in the Montney Shale in Canada, where a potassium formate fluid drilled on average 30% to 40% faster in the shale than OBM systems (Figure 2).

The hole-making benefits of formate fluids are derived from two mechanisms. First, it is possible to formulate higher density fluids with the brine by itself, resulting in low-solids/solids-free fluids that reduce chip hold-down. Second, as indicated, formates can osmotically pull water from shales, creating a lubricating layer that prevents shale from sticking to bit cutters and allowing better hydraulic cleaning of the bit face.

Additional benefits that come into play when using formates are excellent lubricity on steel and shale formations, low hydraulic frictional pressure losses, excellent HP/HT stability, ability to obtain exceptional resistivity/electrical logs and not having to adopt zero discharge waste management in offshore operations. These advantages, in combination with the aforementioned shale stability benefits, make formate fluids excellent candidates for performance drilling applications. **EP**

References available.

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The Kronos drilling fluid system delivers solutions for drilling challenging deepwater wells in the GoM. (Source: Lukasz Z, Shutterstock.com)

Flat rheological fluid system safely achieves drilling objectives

A drilling fluid system combines chemistry, software and logistics to deliver solutions for challenging deepwater wells.

Andrew Seefield, Jan Baggerman and Matthew Kratzer, Newpark Drilling Fluids

Gulf of Mexico (GoM) deepwater wells present the potential to encounter a variety of drilling-related challenges, including gas hydrates, wellbore instability, ROP, lost circulation and pressure control. Management of these challenges is paramount toward execution of a strategy to reduce nonproductive time (NPT) and to safely achieve drilling objectives and project economics. Additionally, operational activities in the GoM are conducted within the regulatory framework of the Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement.

Newly implemented regulations for offshore drilling in the GoM increased focus on the physical properties of drilling fluids to ensure adequate pressure control is maintained. Pressure control is particularly important in deepwater operations where a narrow window exists between the pore pressure and the fracture gradient. These narrow margin wells are abnormally pressured, and the design characteristics of drilling fluids for deepwater wells are unique and can differ significantly compared to the requirements for normally pressured wells.

Deepwater drilling fluid design challenges are exacerbated by the operational conditions typically encountered in the execution of drilling operations. The cooling effects of the water column opposite the

riser creates a negative geothermal gradient, where static temperatures are often reduced to as low as 4 C (40 F) at the seafloor. The geothermal gradient then increases with increasing depth, with bottomhole static temperatures in excess of 149 C (300 F) frequently encountered. Increasingly, the fluids of choice by operators in the GoM deepwater operations are characterized as flat or constant rheology fluids designed to achieve drilling performance objectives and manage risks inherent to drilling in a narrow pressure environment.

Newpark's Kronos is a flat (constant) rheology system designed specifically for use in challenging deepwater wells. It is an environmentally sound nonaqueous drilling fluid with the flexibility to address a broad range of operational requirements.

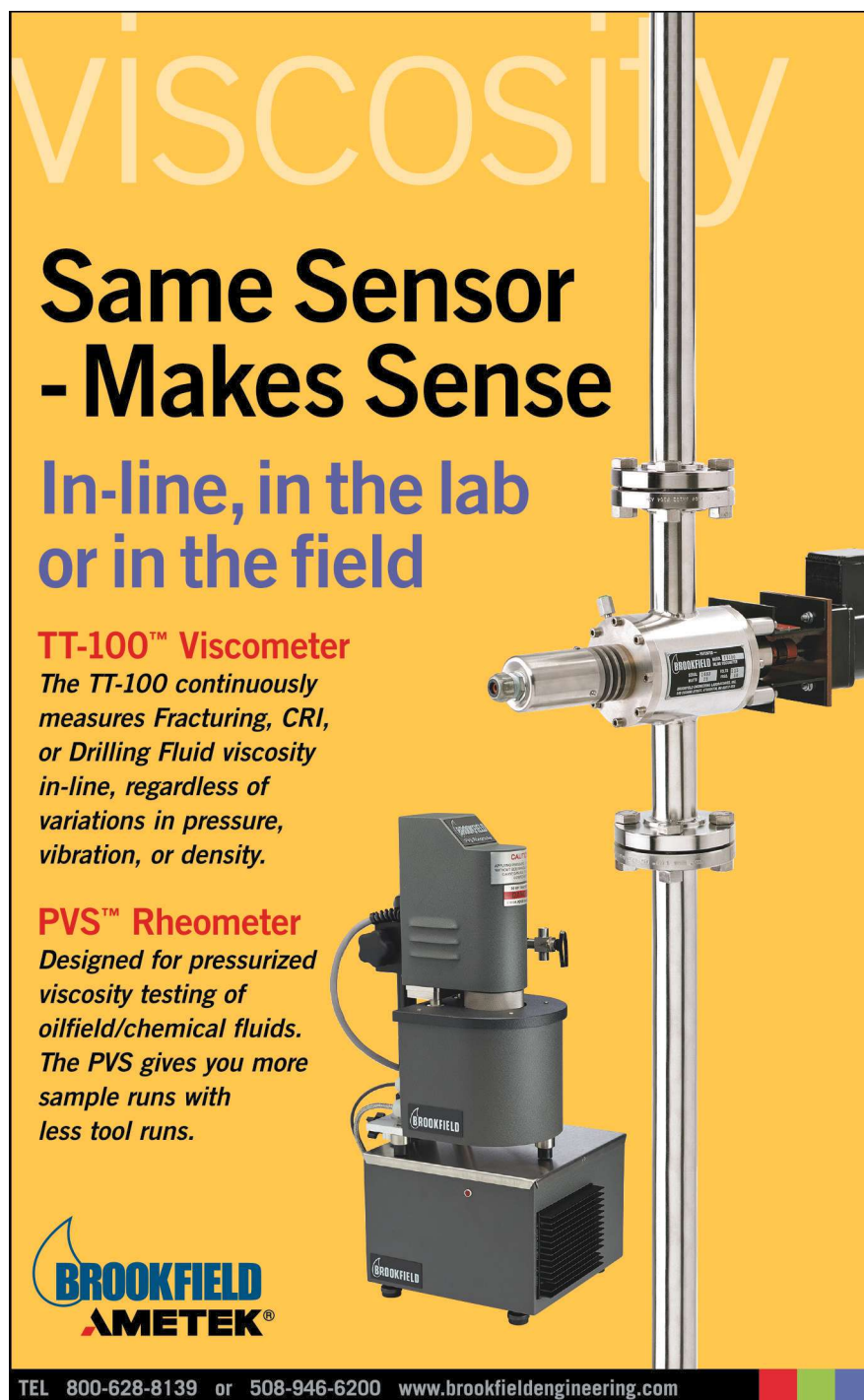
More than a fluid

The Kronos drilling fluid system can be readily formulated with a variety of synthetic-based fluids, grades of barite and type of brines. Robust fluid formulations are built through use of novel and proprietary emulsifiers, rheological modifiers, suspension agents and fluid loss additives. The system is nearly independent of changes of temperatures and pressures typically encountered in deepwater drilling operations.

Variations in rheological properties such as plastic viscosity, yield point, as well as viscometer dial readings of 3 rpm and 6 rpm and gel strengths, are minimized in Kronos to safely achieve drilling, tripping and casing running objectives without incidents of fluids-related NPT.

The benefits of the Kronos flat rheology system are further enhanced through use of the HyCalc engineering software platform by allowing greater operational efficiency while also reducing the potential for lost circulation. The HyCalc software is extensively used in prewell planning operations. During the planning stage, the software is used to model the operational environment

and to ensure that hole cleaning, barite sag, equivalent circulating density (ECD) management and swab/surge objectives are satisfied prior to commencement of drilling activities. The use of the HyCalc system continues during the wellbore construction process. Surface fluid



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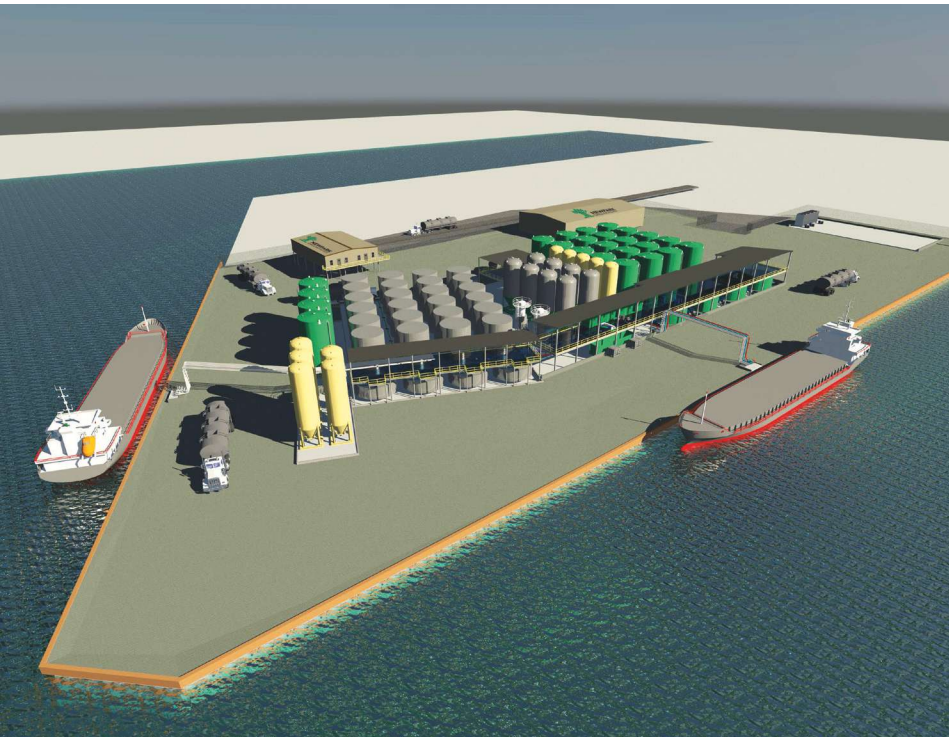
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The Newpark Drilling Fluids Port Fourchon facility underwent a major expansion in 2015 to meet the growing needs of the deepwater market. (Source: Newpark Drilling Fluids)

properties and operating conditions are frequently updated to predict downhole hydraulic-related annular profiles. Internal knowledge of the Kronos system's HP/HT properties coupled with a rheology calibration procedure enhance HyCalc's ability to accurately predict ECD values in comparison to downhole measured values.

Another key enabler in the drilling fluids value chain is facility placement, capability and capacity. Operators leverage best-in-class distribution and logistics provided by offshore supply bases to improve project efficiencies and economics. Understanding the logistical and operational challenges associated with deepwater projects, Newpark Resources invested in an offshore supply base in Port Fourchon, La. Able to address the growing deliverability requirements for the GoM deepwater market, the supply base can manufacture and simultaneously offload large volumes of drilling fluids to multiple supply vessels at rates surpassing competitive facilities, leading to a more cost-effective solution.

Precise, real-time metering with monitoring and control abilities allows the plant operators to be well-informed while keeping the important process decisions simple, timely, accurate and reliable. A rapid salt delivery system and improvements in mixing and shearing techniques, along with reconfigured piping and pump arrange-

ments, have allowed parallel processing and advances in both lead time and capacity.

Overall faster turnaround in loading and unloading boats also was achieved. Upgrades to mixing equipment have produced a more stable fluid, which ensures the rheological quality of the drilling fluid is maintained between offloading and utilization at the rig site.

Case study

Newpark recently demonstrated its ability to integrate and leverage its Kronos flat rheology system for a multinational company in a GoM deepwater well in more than 1.6 km (5,500 ft) of water. The system was chosen following a rigorous and demanding approval process. Key operational parameters in the prewell planning phase included displacement efficiency, contamination, tight tolerances and management of static and dynamic barite sag. A Kronos fluid was designed and tested at the Newpark Technology Center over several weeks. Laboratory testing ensured that all rheological, filtration control,

emulsion stability and barite sag design parameters were optimized in advance preparation of the Kronos system at the Port Fourchon supply base.

The rheological and emulsion stability properties of the Kronos flat rheology fluid were optimized at the supply base through use of an inline shearing device. Placement of the shearing device in the Kronos design process ensures delivery of a robust and fit-for-purpose fluid upon delivery, eliminating the need to circulate and shear through the drillbit. The performance of Kronos on this well met the performance expectations of the company.

The system proved to be robust and easy to maintain within specifications in all phases of the operation. A true measure of robustness of nonaqueous fluids is the ability to handle interfaces and contaminants, such as seawater and cement spacers, and the Kronos system was able to maintain a flat rheological profile despite encountering these contaminants. The ability of the Kronos fluid to manage barite sag was best observed when the standby Kronos fluid was offloaded following completion of the campaign. This contingency Kronos fluid was stored on the supply vessel for 44 days. Settling or sedimentation did not occur despite being subject to slow and continual motion on the vessel. **ESP**



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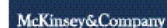
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Improving well economics with advanced proppants

Altering the surface chemistry of resin-coated proppant delivers improved oil flow rates in the Eagle Ford Shale.

John M. Terracina and Adam K. Harper, Hexion Inc.

Typical proppant selection factors of size, strength, density and baseline conductivity do not accurately predict how proppants perform in a fracture at downhole conditions of temperature, closure pressure, moisture and high flow rate. Additional proppant selection factors that affect the results of fracturing treatments are proppant fines generation and migration, effective conductivity, proppant flowback, proppant embedment, proppant pack cyclic stress and proppant scaling or diagenesis.

The wettability of the proppant is another factor that should be considered for fracturing treatments in oil and liquids-rich reservoirs. Traditional proppants are hydrophilic in nature and attract water to the surface of the proppant. This water can block pathways for oil to flow, resulting in underperforming wells. In addition, if a proppant's surface is entirely oleophilic, it would

attract oil to the surface and a clear production pathway would not be achieved.

By altering the surface chemistry of the proppant, it is possible to create a proppant that is not inherently hydrophilic or oleophilic. The neutral wettability allows an increase in relative permeability to oil in the proppant pack. A surface-modified resin-coated proppant (RCP) was developed that demonstrates improved oil rates in laboratory testing. These results were confirmed by field production studies throughout North America.

Laboratory research

To test the effect of proppant surface wettability, a laboratory test was developed at Hexion's Oilfield Technology Center. The process was as follows: proppant was packed in a glass column and saturated with water. Laboratory oil was then added and gravity was used to displace the water that was in the proppant pack. Once

the water was displaced by the oil, the oil flow rate through the proppant pack was recorded. The oil flow rate was calculated from the volume of laboratory oil collected over time. Measurements were taken to determine how much was retained by the proppant pack. Care was taken to ensure that the median particle diameter of the proppant was consistent for all tests.

Several curable resin systems were designed and tested. Oil flow rates were compared to conventional RCPs. OilPlus proppants (Figure 1) were the result of this research and are the first proppants specifically designed for fracturing treatments in oil and liquids-rich reservoirs. These proppants have shown almost double (91% increase) the oil flow rate of conventional RCPs in laboratory testing.

This resin system increases the relative permeability of oil in the proppant pack resulting in higher oil production compared to conventional proppant. These advanced RCPs have all the benefits of curable RCPs including increased proppant flowback control, reduced proppant embedment, reduced proppant fines, decreased



FIGURE 1. Hexion's OilPlus proppants increase the relative permeability of oil in the proppant pack. (Source: Hexion Inc.)



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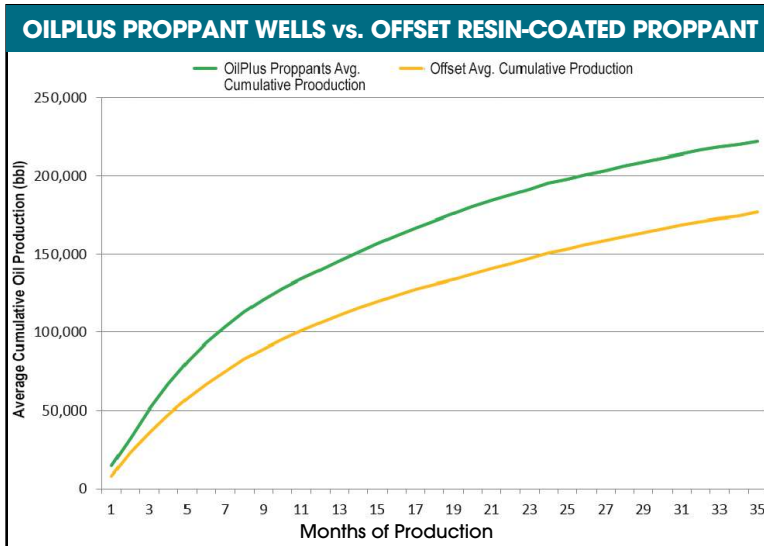


FIGURE 2. Cumulative production from OilPlus proppant wells shows a 25% average increase in production over three years per well as compared to conventional RCP wells. (Source: Hexion Inc.)

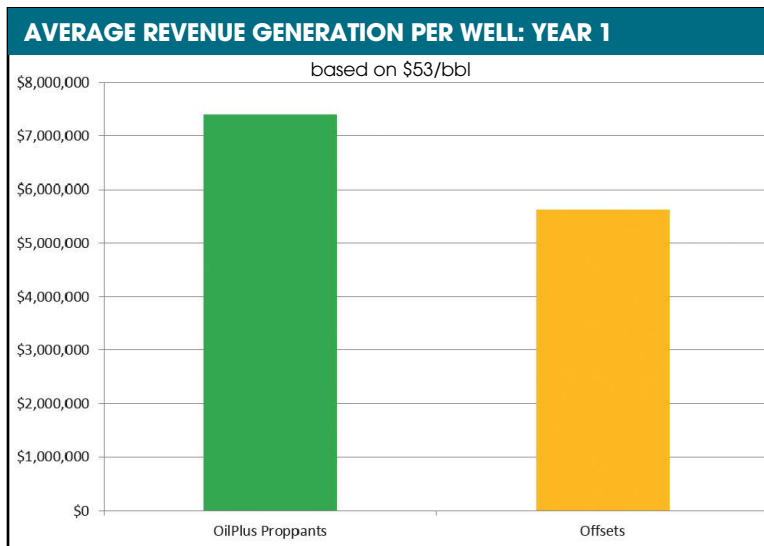


FIGURE 3. Revenue from OilPlus proppant wells averaged higher than revenue from conventional RCP wells in the first year of production. (Source: Hexion Inc.)

proppant scaling and higher effective conductivity compared to uncoated proppants.

The advanced resin technology has yielded years of enhanced oil production in all the major shale formations of North America. It provides higher flow rates compared to traditional RCP, ceramics and uncoated sand. This technology increases proppant pack relative permeability to oil. With the new proppant technology, water does not cling to the surface of the proppant.

This allows a clear path through the proppant pack, resulting in increased hydrocarbon flow compared to traditional proppants.

Case study

An operator in South Texas was challenged to increase oil production while reducing the cost per barrel of oil. The dataset in this case study contained 27 wells, including 10 OilPlus proppant wells and 17 direct offset wells with another curable RCP.

All wells were completed by a single Eagle Ford operator in Karnes County, Texas, and were drilled to 3,505 m (11,500 ft) true vertical depth with a 1,311-m (4,300-ft) horizontal length. The operator used 5 million pounds of 30/50 mesh proppant and 40/70 mesh proppant with a 15% tail-in of OilPlus proppants or conventional RCP in all wells. Slickwater/crosslinked hybrid fracture fluids were used in all wells.

A 25% average production increase over three years per well was achieved utilizing the advanced RCP compared to conventional RCP (Figure 2). When looking at the cumulative production in Figure 2, the differential gap between the advanced RCP wells and offset wells widens over time, indicating that the advanced RCP continues to work after several years. Based on a \$53/bbl oil price, the advanced RCP wells produced an average of \$1.7 million more in revenue per well over the first year compared to the conventional RCP offset wells, as shown in Figure 3. If the operator had used the advanced RCPs in the offset wells, an additional \$28.9 million in revenue would have been realized in only the first year.

Conclusion

The challenge for operators is how to operate effectively in a low oil price environment. Oil-Plus proppant provided higher oil flow rates in laboratory testing and in the field. This advanced resin technology increases the proppant pack's relative permeability to oil, resulting in increased flow of hydrocarbons. This advanced RCP has helped yield three years of enhanced oil production in the Eagle Ford Shale as compared to a conventional RCP used in direct offset wells. **ESP**

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EnerCorp Sand Solutions' patented 5,000-psi dual horizontal sand filtration unit is in operation in Ohio. (Source: EnerCorp Sand Solutions)

Managing sand production during a downturn

As usage grows, technologies emerge to face new completion production challenges.

Gareth Young, EnerCorp Sand Solutions

The term “downturn” is one that most oilfield services companies know all too well. However, for two companies based 3,218 km (2,000 miles) apart, it means something more. It was during the lowest activity and commodity price levels of 2016 when Energes Oilfield Solutions and Dynacorp Energy Services developed a business partnership that would not only eventually unite them into a single company, EnerCorp Sand Solutions, but also bring production systems to operators through innovation and service.

“The opportunity to introduce new technology to the market was timely in this downturn as costs were being scrutinized at every level in the well life cycle,” said EnerCorp CEO Justin Morin. “E&P companies were looking to maximize production more efficiently, safely and without equipment failure due to sand erosion.”

Sand usage per well has been the hottest growth segment for the completions industry during the past

couple of years as operators increase lateral lengths and push proppant per lateral foot well above historic levels. The largest wells now consume upward of 5,500 tons of sand per well, which is up from 1,500 tons just a few years ago. Credit Suisse projections of more than 2% sequential growth through 2018 means demand will grow from 33 million tons in 2016 to 60-million-plus tons in 2017 and 75 million tons to 90 million tons this year, with a sand usage per well growth of 15% to 20%.

U.S. Silica projects the usage could even go as high as 147 million tons in 2018. This increase in sand usage has presented production and midstream facility challenges that have never before been seen in the industry.

Managing increased sand

Traditional gravity-driven sand separators were the only option on the market to combat sand returns and still remain a staple for most completions and production groups. However, with the above-mentioned increase in sand usage, sand returns have increased sequentially. To

address this, the company then known as Energes introduced a proprietary dual cyclonic sand separator with engineered inserts for second-stage solids separation.

Even with the increased efficiencies of the dual cyclones, the field tests that were conducted using acoustic monitoring sensors downstream of the sand cyclone separators were registering that 10% to 25% of entering sand was still carrying over. Most would assume that this sort of efficiency is good enough. But 10% to 25% of a well flowing back 10 lb to 65 lb of sand per hour accumulates to a significant amount of sand over weeks and months of production, which in turn leads to excessive damage of piping and components at facilities.

In addition to the accumulating sand volumes building up at the production facilities, some E&P operators also were finding they were unable to drive strong well IP due to sand returns limiting their ability to run aggressive choke schedules. These growing challenges led the company then known as Dynacorp to introduce its patented sand filtration system that already had garnered success in the Canadian market.

On the first trial job of a Delaware Basin well—through the introduction of the filtration unit—the team enabled the operator to open the well up to a 41/64-in. choke, where previously it was limited to a 17/64-in. choke due to increasing sand issues in the production facility. Oil production increased by 200 bbl/d due to the increase in choke size, and gas production increased from 28 cu. m to 51 cu. m (1 Mcf/d to 1.8 Mcf/d).

Energes' sand monitoring system showed only minute traces of sand downstream of the filtration unit, sending clean production to the facilities. A second operator was facing a very different issue with pump seals being destroyed on a daily basis at its central battery system. The operator was attempting to redesign how it managed production facilities and had found a more cost-effective and operationally efficient design but was unable to manage the hourly returns of 30 gal to 65 gal of sand it was seeing. Since sand filter installation, after 120-plus days, candidate wells were opened to 64/64-in. choke and had no pump seals damaged.

Continuing innovations

The need to remove and reinstall the screen for cleanings presented an HSE concern due to the size and weight of the screens. Overhead gantry systems were designed and installed on the units to ensure the elimination of any bodily strain on the field operators managing the filter system. The Dynacorp engineering team also has developed self-cleaning screen applications to

eliminate the need for screen removals. This not only eliminates HSE exposures but also drives down personnel costs to the operator.

Sand monitoring is another challenge facing the industry. Operators want to know what their sand volumes are entering the various sand management systems, how much sand is being removed from each stage, and how much sand is being passed through each system and into their production facilities. Various technologies on the market can provide data on solids intensity, but nothing had been developed showing accurate sand measurements in a live flow environment. This led EnerCorp to develop proprietary software using commercially available ultrasonic flow measurement equipment.

The inclusion of weight scales as a redundant and secondary backup has enhanced the accuracy of the data the ultrasonic sensors provide for E&P companies and operators to know when to clean and what volumes of sand are being made. The teams are further developing new technology to ease the maintenance, cleaning and time operators are required to be at the site. The self-cleaning screen system will provide operators the ability to wash down the accumulated sand inside the pressure vessel with high-pressure water while maintaining continuous flow. The concept to commercialization of the cleaning system is underway and is expected to be in full operation and mass production in first-quarter 2018.

Continued innovation with the cyclone design also has improved efficiencies. Through computation flow dynamic software flow modeling and engineering, EnerCorp developed multiple cyclone inserts to achieve the maximum efficiency of sand separation inside the pressure vessel with 100 μ sand. The teams learned the well parameters played an integral role in sizing the cyclone inserts. With the software the companies can model the conditions in which the well would flow through the cyclone and what efficiency it would achieve. **ESP**



Pictured is EnerCorp Sand Solutions' 15,000-psi dual cyclonic sand separator. (Source: EnerCorp Sand Solutions)

Getting a handle on sand production

Sand-handling technologies protect equipment and reduce costs.

Mark Wolf, Craig Hofmeister and Claire Kennedy Platt, NOV; **Norman Glover,** Enerplus Corp.

The recent boom in the North American shale plays from hydraulic fracturing depends on pumping large volumes of sand and water into horizontally drilled wells. Operators have optimized fracturing techniques the last two years, lengthening well laterals and doubling the volume of sand used per foot. A typical fracture job uses from 1.5 million pounds to 6 million pounds of fracture sand. Daily sand production rates can range from 50 lb to 1,600 lb produced during flowback and early production, posing significant problems for production equipment downstream.

Sand accelerates wear on pumps, chokes and valves designed to handle fluids, leading to increased maintenance, early equipment replacement and increased downtime. High sand content also settles and accumulates in separation vessels and water storage tanks, requiring additional cleanouts.

Filters serve as a standard solution to these challenges, but they can create additional problems. Frequent filter change-outs incur significant labor and disposal costs. Systems such as the Tore Trap cyclonic desander from National Oilwell Varco (NOV) operates in solids management in oil and gas production. The Tore

Trap can be installed without filters or combined with high-efficiency filters to meet demanding water quality specifications while minimizing the time and costs associated with frequent filter changes.

The equipment combines high-efficiency, solid-liquid hydrocyclones with the Tore solids fluidizer to enable removal of solids from water without disrupting flow. By reducing the concentration of solids in fluid upstream of a filter, the Tore Trap contributes to a significant reduction in the frequency of filter changes and improves the condition of filter elements. Operation at a consistent differential pressure enables better protection of downstream equipment and simplifies management of solids removal.

The ceramic cyclones within the Tore Trap cause the sand to disengage and deposit into an accumulation section. The sand-free fluids exit via the cyclone overflow and continue to the remainder of the process equipment. Once the sand has reached a high level within the accumulation section, the Tore solids transportation device activates to discharge the solids without disrupting flow through the ceramic cyclones. The Tore Trap has the ability to handle a high concentration of inlet solids of up to 1% by volume. The fluidizer can discharge the accumulated solids in 10 minutes or less with minimal operator involvement.

The same Tore fluidizing technology may be used for online vessel desanding. NOV has successfully applied this method to remove solids from the bottom of production separators, crude oil treaters, free water knockouts and tanks. The technology fluidizes solids without disturbing the separation process. Similar to the Tore Trap, this method also allows solids to be removed from critical production equipment without shutting down and eliminates carryover of solids to downstream equipment.

The following case studies examine how the technology has contributed to successful solids management, reducing filter changes and vessel cleanout removal and, in some cases, eliminating the need for filtering.

Produced water treatment

Alberta-based operator Enerplus Corp. experienced challenges with high sand content, which led to filter replacements every 45 minutes on one of its well sites. This operational inefficiency caused increased mainte-



The Tore Trap skid from NOV desands up to 18,000 bbl/d.
(Source: NOV)

nance hours, wasting time and increasing costs. Enerplus worked with a team of sand management experts from NOV, conducting a four-month trial of the Water-Wolf Dynamic Oil Recovery system and the Tore Trap desanding skid. During this trial Enerplus found that the technology behind the desanding skid allowed the best addition to its production stream. The equipment created a dramatic reduction in sand content, decreasing the filter replacement rate from every 45 minutes to once a day. Enerplus continues to see positive results using the technology. The company used the equipment as a key component of its newest waterflood project, crediting the small footprint, service and technical expertise as an ideal production solution.

Saltwater disposal facility

At a centralized processing facility in Oklahoma, solids had accumulated in offload tanks, gun barrel separators and clean water tanks, requiring subsequent unplanned tank shutdowns to dig out solids. To alleviate these issues, the facility required a more efficient separation system. The facility installed a Tore Trap, which pumped fluids through the solid-liquid cyclones. The system helped reduce the solids entering the facility. The inlet fluid entered the Tore Trap and exited nearly free of solids. A significant mass of solids from the inlet had been clearly trapped in the system.

The laser particle size analysis also highlights the effectiveness of the unit. Samples from the water inlet indicated that particles ranged from 1 μ to 350 μ , with a mean of 12.3 μ . The water outlet sample indicated that most particles greater than 10 μ and many particles from 4 μ to 10 μ were removed. The mean particle size in the outlet sample was now 1.5 μ . The equipment effectively removed solids from the facility's received fluids, aiding in the overall operability of the facility, minimizing fine solids carryover, downstream accumulation in tanks, and pump and well maintenance issues.

Water tank cleanout

In 2016 a Permian Basin operator observed a significant buildup of solids in water tanks at one facility. To assist in cleaning the tanks, the operator rented a Tore Trap and connected it to the bottom nozzle of a solids-filled tank. The pump circulated the solids-laden tank water through the cyclones. The operator directed discharge water from the equipment through a hose into the thief hatch of the tank and used the stream to stir the tank bottom. The tank-cleaning exercise helped the operator avoid calling an environmental cleaning company to remove the tank bottom with vacuum trucks and elim-

inated the need for a cleaning crew to enter the tanks, saving thousands of dollars.

Online sand removal from a separator

An operator experienced an ongoing problem of solids separation and accumulation in separators. The sand reduced the vessel's fluid-holding capacity and minimized the fluid retention time, resulting in poor gas, oil and water separation. The sand impacted the vessel's level instrumentation and carried over into downstream equipment. Dump valves on the separator experienced severe erosion, requiring regular replacement. NOV installed the ToreOVD system to remove the sand online, as it accumulated without affecting the separation process. The system enabled daily sand removal, allowing the separator to now effectively separate gas, oil and water as designed. The equipment also eliminated problems with level instrumentation and erosion of the control valves.



Pictured are a water inlet sample to the Tore Trap (left) and a desanded water outlet sample (right). (Source: NOV)

Conclusion

As hydraulic fracturing and sand volumes increase, operators will need more effective sand removal solutions to conquer sand production challenges. Removing sand from a process fluid stream prevents the sand from causing erosion of downstream equipment and accumulating in separators, heater treaters and tanks. The Tore Trap allows online sand separation and transfer of the captured sand while remaining online. By removing sand from oil and gas production, the system minimizes overall maintenance, labor and operating expenses. **ESP**

Improving safety through advanced composite technology

Novel approach saves time and reduces risk for offshore casing installations.

Judy Murray, Senior Contributing Editor, Offshore

A unique landing string buoyancy design has introduced an improved system by leveraging composite technology. This system, built with 100% composite materials, improves safety in a number of ways. By looking at the challenges presented by offshore casing installation from a new perspective, engineers were able to introduce a technology that shortens the time needed to carry out this stage of the drilling program and allows the installation vessels to work without exceeding their maximum capacity.

History of composites application

Although the oil and gas industry has not been at the leading edge of applying composite solutions, other industries have used composites for decades to improve performance and safety. Among these is the aerospace industry, which has seen the use of composites double every five years since 1987. Composites have changed the landscape of the industry, allowing reduction in airframe weights, better fuel economy and lower operating costs.

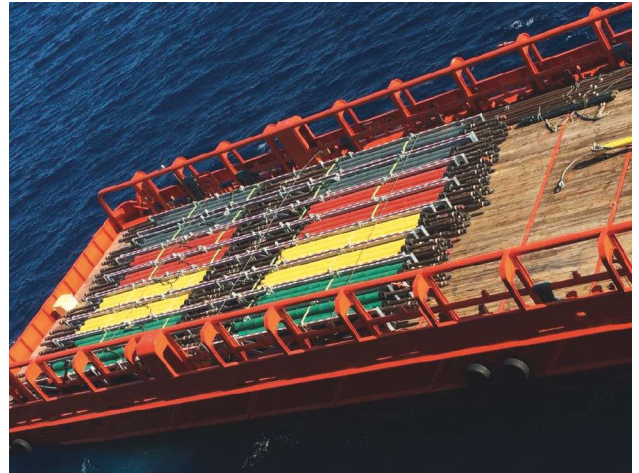
The same goes for the marine industry, where more than 90% of the hulls are composite, and the automotive sector, which boasts greater than 90% composite construction on heavy trucks used for long-haul transportation.

Composites are a top choice for construction across industries because of a number of desirable characteristics:

- Flexibility;
- High-impact resistance;
- Lightweight (with weight reduction ranging from 20% to 50%);
- Long field life;
- Low maintenance;
- Resistance to conductivity, corrosion and fatigue damage;
- Thermal stability; and
- Tolerance to damage.

Composites in offshore solutions

Landing String Solutions (LSS) LLC came up with the idea of using composites in its landing string system at



Dressed landing string joints, which were made up in a controlled environment onshore, arrived to the drilling vessel ready to be deployed. (Source: Landing String Solutions LLC)

a time when no company in the oil and gas sector had taken this approach to buoyancy for a landing string.

According to Chris von Eberstein, vice president of LSS, “We wanted to provide an option to improve safe rig operations, optimize critical path time and significantly cut cost by reducing the hook load while running heavy casing.”

Part of the reason no one had tried it was because of the requirement to have a product that could contend with wellbore fluid. Nearly all composites used in drilling and production applications had been designed for use in seawater. Drilling mud is a different medium, with varying chemical components and temperatures. The challenges in coming up with the right material were considerable, but von Eberstein was convinced it could be done.

Antony Croston, business group director at Trelleborg, said his company applied its 40 years of experience in buoyancy systems and an understanding of how environments affect them to identify the mix of materials, additives and treatments to produce the best composite solution. “We looked at how each material failed and how it was degraded during testing to find a material we believed would work, then we set up experiments to test it.”

Trelleborg manufactures raw materials that include hollow glass microspheres that in their original form look like talcum powder but are, in fact, a high-strength glass bubble, Croston said. “It is the same type of composite used in high-performance aerospace applications, and in combination with other components in its finished form, the heart of the landing string system is essentially an extreme service buoyancy syntactic covered by a polyurethane skin.”

Croston explained that exposure tests were carried out on the composite in drilling fluid at specific temperatures and pressures, with the weight of the sample measured before and after. The results were measured against predetermined pass/fail criteria. Cyclic tests followed.

“We would pressurize it for a time and take it out, repeating over time to evaluate cyclic loading,” he said.

When tests results showed the right material had been found, developers knew they had found a solution that when implemented would introduce significant safety advantages in a novel way.

According to von Eberstein, it is important to understand that the composite is the enabler for this system.

“Operators would be reluctant to use a system deployed inside the riser if it had any metal parts because even a small piece of metal falling into the wellbore can do a huge amount of damage,” he said.

“In this particular application, this isn’t a better mousetrap. It’s not a step change. This is a new trap altogether,” Croston said. “This is an enabling technology.”

Advancing safety

Safety was the impetus for developing this tool, von Eberstein said. The composite was the essential element needed to create a system that could work inside the riser without introducing risk of damage to the subsea wellhead system and casing, but the overarching goal was to address the risk of the rig exceeding its maximum designed hook load.

“We wanted to provide a tool to keep rigs working within safe design parameters,” he said.

Operators contracting vessels to set casing have to consider the specifications required for each installation. The weight of the casing combined with the landing string weight and the depth of the installation are the primary considerations when determining the necessary hook load, but sea state also is a factor.

The composite-based system creates buoyancy once the casing/landing string is in the riser, which reduces the hook load, decreasing the risk of the vessel exceeding its maximum hook load rating.

“This gives a smaller and cheaper rig the opportunity to do the job safely,” von Eberstein said. “It also means potentially eliminating liner tiebacks and running longer casing strings.”

Continuous operation cuts downtime, which not only improves safety by decreasing the amount of time workers are actively carrying out an operation, but also delivers efficiency gains in terms of contract length.

According to Croston, safety begins with the construction of the composite components in Trelleborg’s controlled manufacturing environment. The individual buoyancy elements and securing clamp components arrive at the LSS site for assembly onto the landing string joints by a LSS specially trained crew. The dressed landing string joints are loaded into transport baskets and delivered to the drilling vessel ready to be deployed in exactly the same manner as traditional landing string pipe. By using quality materials and individual system components and following a controlled assembly procedure at the LSS facility, von Eberstein said, it is possible to ensure consistent results over multiple deployments.

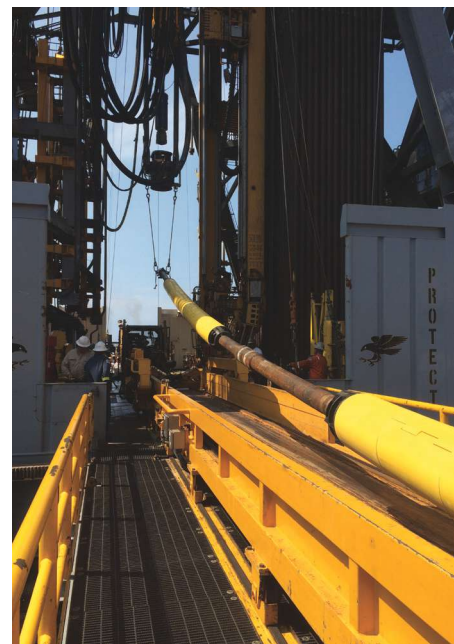
Moreover, they reduce the risk of injury to offshore workers because the units are relatively light. Physically placing them on the landing string requires no heavy-lifting equipment.

“It can be accomplished in one man-lift,” Croston said.

Von Eberstein said this product is among those the company considers essential for reducing equipment failure and significant safety incidents in deep water.

“It is extremely difficult to accurately calculate dynamic loading effects when running/lifting casing strings,” he said. “By using our system we can provide a means by which a rig can maintain its margin of safety.”

As the LSS system has proven itself in offshore operations, the team is looking ahead to identify other applications for composites that will make it possible to improve offshore safety through reduced weight, increased wear and improved buoyancy. **ESP**



A double stand of casing outfitted with the composite buoyancy system was picked up before being run into the hole. (Source: Landing String Solutions LLC)

Flow assurance evolves

Improved products and expanded services deliver gains for subsea production.

Judy Murray, Senior Contributing Editor, Offshore

Making sure oil and gas flow freely through long, complex tiebacks is one of the critical challenges of production facilities. Many things can inhibit flow, including hydrates, paraffins, scales and asphaltenes, and these impediments can affect producing wells, flowlines and production facilities.

This problem impacts both onshore and offshore developments. Onshore, it is easier to deploy equipment and address flow issues, but offshore flow assurance challenges are somewhat more complicated because intervention costs increase with the distance from shore and the length and depth of flowlines. Temperature also can present a challenge because temperatures in deep water often are near or below 4.5 C (40 F).

Many companies have invested in R&D to develop ways to improve flow assurance, investigating such techniques as insulating pipelines or electrically heating lines to manage temperature and introducing chemicals to control wax and anti-agglomerators to prevent hydrates from forming plugs.



The CT-deployed CoilTac tool has been used to distances in excess of 1,219 m to remove paraffin, hydrate plugs, asphaltenes, scale and other blockages to the full ID of the pipeline. (Source: Superior Energy Services)

Flow assurance

There are multiple ways of remediating blockages. Flow can be modified so a specially designed pig can be deployed to cut through flow-restricting buildup and help improve throughput. The line can be heated, hot fluid can be circulated through the line, and coiled tubing (CT) can be inserted through a lubricator on the surface to deliver inhibitors like glycol or methanol into the face of the blockage.

A paper presented by FMC Technologies at the Offshore Technology Conference a few years ago identified and evaluated 30 flow assurance solutions, dividing them into five categories. Under “thermal solutions,” the authors included insulation, direct heating, electrically heated pipe-in-pipe, cold flow and phase-changing materials. Nine “chemical solutions,” ranging from thermodynamic hydrate inhibitors and low-dosage hydrate inhibitors to defoamers, H₂S scavengers and drag reducing agents, were included, as were “operating solutions,” such as pigging, flushing, depressurization and gas sweeping. There were “evaluations” of nearly a dozen “hardware solutions,” including subsea separation, boosting, compression and cooling as well as acoustic sand and leak detectors, desanders and CT tractors. The final category identified software that can evaluate impediments to flow and provide treatment options.

Hardware in the line

Warrior Energy Services, a fully owned subsidiary of Superior Energy Services, offers a CT tool called CoilTac, a thruster designed for cleanout operations in pipelines with an inside diameter (ID) of 3 in. and larger. It has been used to distances in excess of 1,219 m (40,000 ft). The thruster removes paraffin, hydrate plugs, asphaltenes, scale and other blockages to the full ID of the pipeline. Operations can be performed from liftboats, deepwater vessels, platforms or on land. The system provides jetting ahead of the thruster while applying thrust force as it moves down the pipeline.

Simultaneously thrusting and jetting ahead of the tool with treatment chemicals applied directly to the pipeline obstruction allows the thruster system to clean farther than conventional CT applications. The tool sends data as it progresses through the line, providing a snap-



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shot of current conditions. The company believes this technology also could impact future pipeline construction design by extending the reach of subsea tiebacks.

GATE Energy's eelReel is another CT-deployed tool that has been used to resolve blockages, including hydrates, scale, paraffin and asphaltenes, as well as prejob stimulation, production enhancement, flowline abandonment and stuck pig retrieval. The tool is attached to CT and loaded into the flowline through an injector head positioned above the tree.

Power fluid (e.g., produced oil, diesel, chemical or water) enters the tool through the screen and pushes the tool through the line. High-pressure jets dispense the power fluid to remove debris, which enters through the tip and is extracted to the surface through the CT. The reverse screen subs on the front of the tip prevent debris from plugging the CT. According to GATE, eelReel jets clean the flowline to the original pipe ID.

Science and art

Because oil and gas is a data-driven industry, there has been a shift toward using modeling software that can evaluate a range of parameters that affect hydrocarbon flow. Instead of providing discrete solutions, oilfield service companies are developing systems that use data specific to the individual field to model hydrocarbon flow, determine where flow is likely to be inhibited and provide a range of solutions for restoring movement. Managing flow assurance has become both a science and an art that takes into account pressure and temperature profiles and uses a broad range of data to model hydrocarbon flow throughout the production system.

Production challenges are being simulated in laboratories, where hydrates, paraffin, asphaltene, emulsions, scale and corrosion can be studied in the context of a system. Using fluid flow software packages, engineers can evaluate the thermal hydraulic behavior for a wide range of systems and choose from an assortment of solutions.

Assured Flow Solutions LLC is one of the companies that offers a range of fluid flow testing capabilities to identify the multiphase flow challenges that are likely to occur during specific operating scenarios and provide a solid understanding of the transient behavior in a system. With this information in hand, engineers integrate reservoir, flowline/pipeline, riser, facilities, material and operational constraints to deliver a complete flow management system.

Having more data in hand to make decisions for improving system fluid flow is crucial to an appropriate life-of-field design; so it is not surprising that a number

of companies are offering modeling as the foundation for understanding flow assurance issues and using the results to deliver solutions.

Schlumberger's PIPESIM is one of these. It is a steady-state multiphase flow simulator that offers workflows for both front-end system design and production operations. The PIPESIM simulator often is used to identify situations that require more detailed transient simulation such as shut-in, startup, ramp-up, slugging, hydrate kinetics and wellbore cleanup. Advanced simulation is carried out using the OLGA multiphase flow simulator, which enables key flow simulation applications, including liquids handling, sizing separators and slug catchers, solids management, and pigging modeling for contingency planning. By identifying areas prone to slugging, corrosion and solids formation, engineers are able to pinpoint solutions appropriate to each particular flow challenge.

Halliburton's SureStream flow assurance services, which the company refers to as "integrated flow optimization capability," is another broad offering of flow assurance solutions. Through the SureStream suite of services, engineers provide analysis and assessment of an extensive range of parameters that impact the free flow of production and offer a range of chemical, mechanical and thermal cleaning programs as well as maintenance management support.

Baker Hughes, a GE company (BHGE), addresses flow assurance issues with FORSA flow assurance chemical solutions. BHGE uses what it calls a total systems approach process to analyze field conditions from the reservoir to the wellhead up to the surface storage tanks with the goal of identifying flow challenges and formulating the optimal mitigation option. After pinpointing potential threats, BHGE engineers can offer a solution from options that include scale mitigation treatments, paraffin control, asphaltene treatments and hydrate inhibition.

Tools for tomorrow

There is a lot at stake when hydrocarbon flow is curtailed. Not only does restricted production impact profitability, it can result in compromised or damaged equipment that can threaten the environmental integrity of operations.

As operators focus on improving safety and minimizing the footprint of offshore production, longer tiebacks and more subsea systems will be the norm. More real-time production data will be available, and creative engineers will mine that information to find even better ways to improve flow assurance. **ESP**

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Haynesville continues its climb

This region's gas production equals predownturn levels.

Contributed by Hart Energy Mapping & Data Services

The Haynesville is continuing its climb back, one that shouldn't be considered a slow climb either. According to the December 2017 U.S. Energy Information Administration (EIA) Drilling Productivity Report, gas production in the Haynesville region has reached predownturn levels—215 Mcm/d (7.6 MMcf/d). Those production amounts haven't been seen in the Haynesville since June 2013, when the region was producing 220 Mcm/d (7.8 MMcf/d), according to the EIA.

Although the Haynesville is still the third highest-producing shale play in North America behind the Permian Basin and the gas-producing behemoth Marcellus-Utica, its production is growing at a faster rate than the Marcellus.

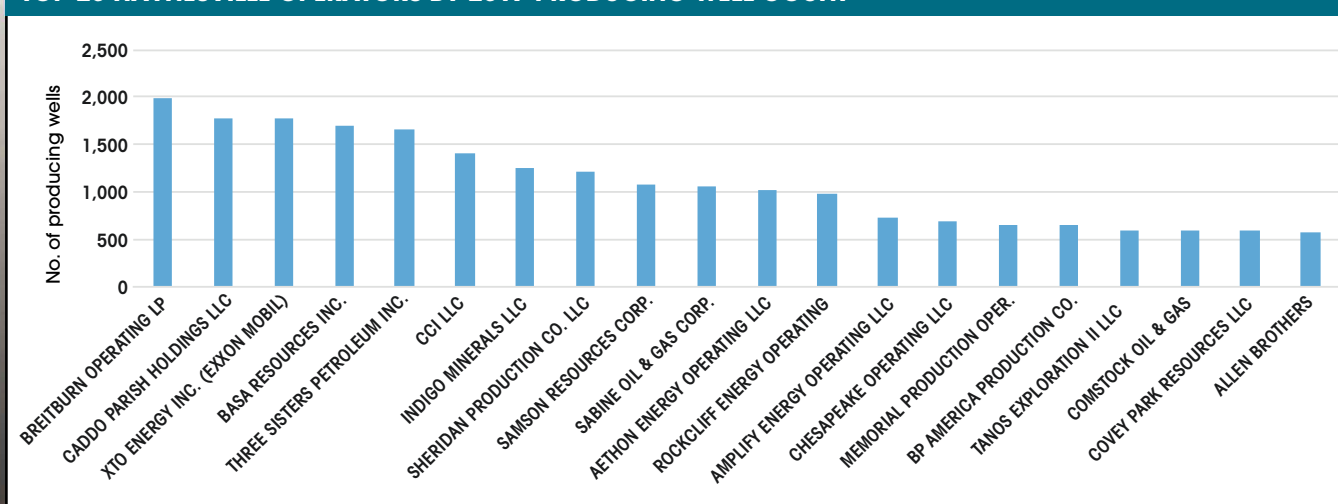
Between January 2016 and January 2018, the Haynesville's gas production increased 25%. Meanwhile, the Marcellus' production has increased

20% during that span—although it produces almost 566 Mcm/d (20 MMcf/d) more. Production growth in the Haynesville is stemming in part by efficiency gains. The region's rig count has held steady since spring 2017, averaging in the mid-40s each month through year-end 2017, but has tripled since a low of 16 operating rigs in April 2016, according to the EIA.

The rigs currently in operation continue to slightly improve their per-day output, producing about 226.5 cu. m/d (8 Mcf/d), up from 218 cu. m/d (7.7 Mcf/d) in January 2018. The Haynesville slightly increased its month-over-month total production by 4 cu. m/d (148 cf/d) from December 2017 to January.

The steady growth the Haynesville experienced in 2017 comes on the heels of a study by the U.S. Geological Survey (USGS) released in April that reported the Bossier and Haynesville formations contain an estimated 4 Bbbl of oil, 8.6 Tcm (304 Tcf) of natural gas and 1.9 Bbbl of NGL. The updated estimates represent the largest continuous natural gas assessment the USGS has conducted. **ESP**

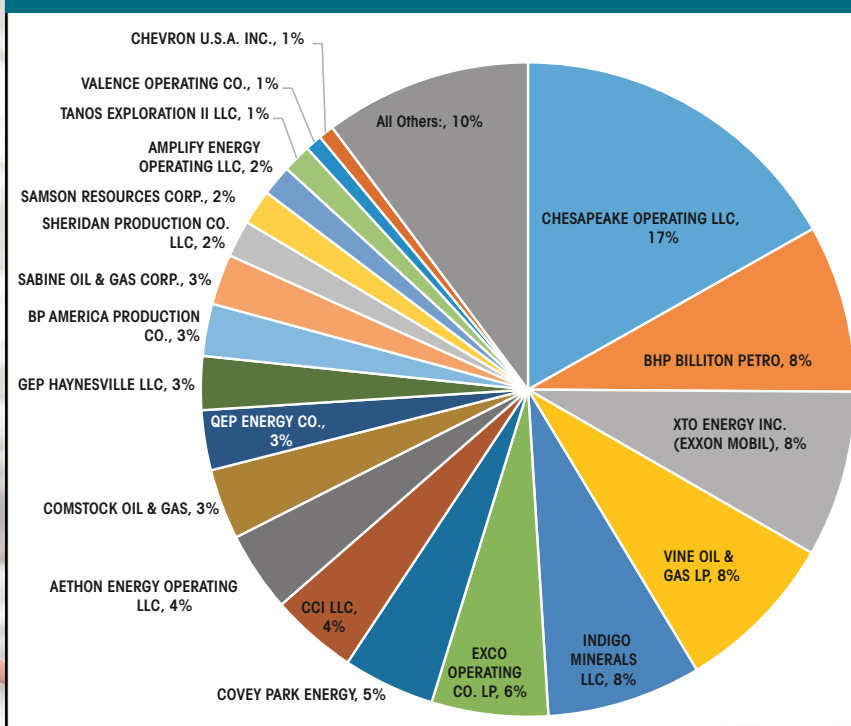
TOP 20 HAYNESVILLE OPERATORS BY 2017 PRODUCING WELL COUNT



Breitburn Operating LP owns nearly 2,000 operating wells in the Haynesville, most of any company in the region. (Source: Hart Energy Mapping & Data Services)

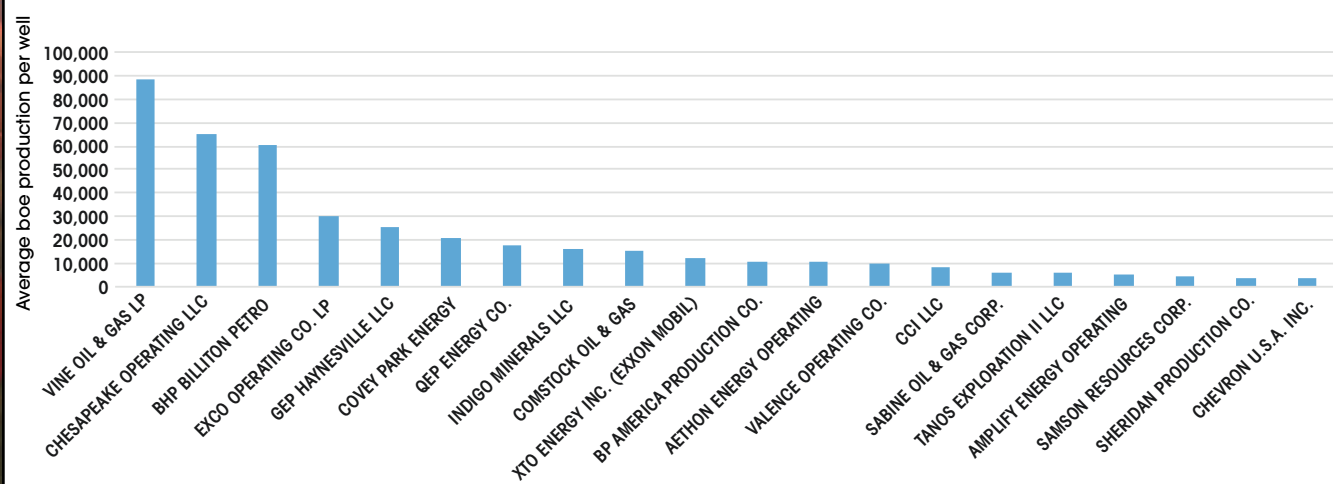
(Photo by Tom Fox, courtesy of Oil & Gas Investor)

TOP 20 HAYNESVILLE OPERATORS BY 2017 BOE PRODUCTION



Chesapeake Energy is the leading producer in the Haynesville, amassing 17% of the region's total production. Through November 2017, Chesapeake produced more than 44 MMboe. (Source: Hart Energy Mapping & Data Services)

TOP 20 HAYNESVILLE OPERATORS BY AVERAGE BOE PRODUCTION BY WELL COUNT



Vine Oil & Gas LP averages 88,221 boe production per well. (Source: Hart Energy Mapping & Data Services)

A highlight in carbon reduction

A new photocatalytical process promises to reduce greenhouse gases.

Elvis Cao, Cornell University

Charles Dickens once wrote, “It was the best of times; it was the worst of times.” According to the annual Greenhouse Gas Bulletin issued by the U.N. World Meteorological Organization, the atmospheric concentrations of CO₂ reached 403.3 ppm in 2016, setting an 800,000-year record. A multidisciplinary team of engineers at Cornell University in Ithaca, N.Y., are working to convert waste carbon emissions into fuels and feedstocks that power the economy and fit into a planetary carbon cycle through the HI-Light reactor being developed at the school.

HI-Light is a solar thermal chemical reactor technology for converting CO₂ to fuels. Creating high-value products from CO₂ by using energy from all parts of the solar spectrum to photocatalytically produce renewable fuels will make CO₂ capture and conversion economical. Similar to fiber optics in telecommunications, the wave-guide technology will enable the light to be distributed evenly within the reactor so as to increase reaction rate, decrease capital cost and increase operation outcomes. The claim of the reactor design derives from the concurrent optimization of light-coupling and catalyst availability.

How it works

By using built-in waveguides inside a scalable reactor, the Cornell team is developing a new approach to turning CO₂ into useful products and fuels. The HI-Light reactor is trying to do what nature has already done with photosynthesis systems but with materials and technologies nature has not had access to. The basic chemistry and idea is the same: to convert CO₂ and energy as input into something energetically more useful. In nature plants absorb CO₂, water and sunlight and then convert those things into the food that helps the plant grow. HI-Light is a photothermalcatalytic reactor that acts like a leaf. With this technology CO₂ is converted into fuels and feedstocks that could serve as the building blocks for products that humans use every day.

This process begins with a massive source of carbon waste; for example, the exhaust system of an electric power plant. The idea is to channel that waste CO₂ gas into a large reactor. Within the reactor there are a bun-



Optical waveguides glow as they transfer light into the reactor's shell. (Source: Cornell University)

dle of rods coated with a photocatalyst. The rods will guide the light to the inside of the reactor, and CO₂ gas will react with the catalyst to form different products, depending on how the catalyst is designed.

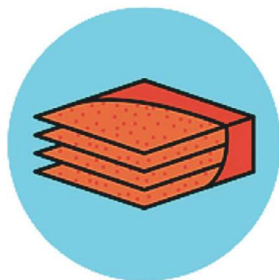
Impacting climate change

The HI-Light reactor deals with carbon emissions. The vast majority of industrial processes emit CO₂ as a waste product, and nature has a built-in system for handling these emissions. The carbon gas released by burning goes into the atmosphere and is then taken back up by plants that recycle the energy. But the cycle has gotten completely out of whack. There is more carbon being released into the atmosphere than the world's plants can handle, and the excess is playing havoc with the Earth's climate.

Capturing CO₂ to keep it out of the atmosphere is a promising strategy to fight climate change. To combat this problem, the Cornell team hopes to use this ultracompact reactor that is powered by the sun and converts CO₂ to higher value fuels. This easily scalable technology is a three-way win: It runs on solar, captures CO₂ and yields a valuable solar fuel. The Cornell team also is partnering with Dimensional Energy to develop green solar fuels for commercialization.

Next steps

The team started from building a laboratory scale reactor, for which it was testing different catalysts and trying to optimize the reaction parameters to achieve the maximum conversion rate. After showing proof of concept by the small reactor, the team is working to scale up the reactor. The most difficult problems are related to



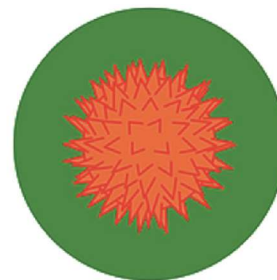
Waveguides direct sunlight to nano-engineered catalyst.



Catalyst bends CO₂ molecules, making it more reactive.



At this point the reaction needs only sunlight and water.



Water CO₂ is converted to solar fuels and feedstocks.

(Source: Cornell University)

guiding the light and heat more evenly in the reactor and figuring out the photocatalyst with the best performance for specific photoreactions.

The next steps include further increasing the conversion rate and scaling up this technology eventually to the industrial scale. The potential is to transform the CO₂ into different sorts of chemicals depending on how the catalyst

is designed. Currently, the team is concentrating on things that could replace natural gas as a fuel source. **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.



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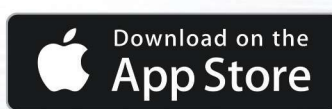
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Conical element cutter block increases tool stability

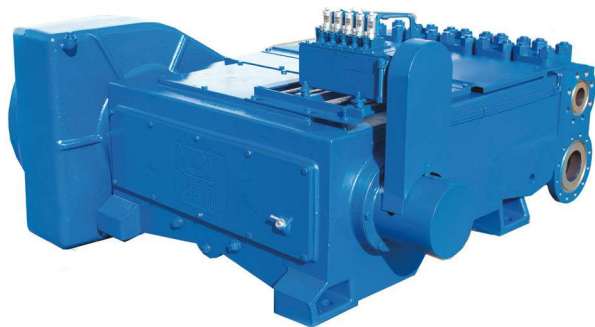
Schlumberger's StingBlock cutter block features Stinger elements for enhanced durability and a staged-gauge pad design that substantially increases tool stability, according to a recent product announcement. Developed for the Rhino integrated borehole enlargement system, the StingBlock cutter block is designed for hard and interbedded applications that pose a high risk of vibration to the bottomhole assembly and high-impact damage to conventional cutter blocks. A staged gauge pad increases stability and the Stinger conical diamond elements are incorporated along the block for enhanced impact resistance. Field tests using this cutter block demonstrated up to a 29% increase in ROP and a 56% increase in footage as compared with benchmark results in the Gulf of Mexico, the release stated. *slb.com*

Shaped cutter drillbits designed to increase control

Halliburton has released its Geometrix 4-D shaped cutters, a line of four distinct geometric profiles to help improve cutting efficiency and increase control to reduce drilling costs, a company press release stated. Each cutter is tailored for specific applications. In a recent offshore job in Mexico where an operator was drilling a limestone-shale formation, the Geometrix bit doubled the ROP over a 700-m (2,296-ft) section, which saved the operator three days of drilling time compared to offset wells. *halliburton.com*

Reciprocating pump designed for saltwater disposal, water injection challenges

National Oilwell Varco (NOV) has released the new 415Q reciprocating pump to its line of high-pressure positive displacement pumps. The 415Q reciprocating pump is designed to address the challenges of the salt-



The 415Q pump has an enhanced power frame and redesigned liquid end. (Source: NOV)

water disposal and water injection markets. The pump enhances the application capabilities of the existing 5-in. stroke models while providing increased volume opportunities and maintaining high levels of reliability and performance. The 415Q pump available in aluminum bronze and with cast duplex stainless steel fluid ends also has an enhanced power frame and redesigned liquid end. *nov.com*

High-resolution subsea actuator enables increased production

Master Flo Valve Inc. has released a new high-resolution subsea actuator that enables operators to increase production utilizing its existing subsea infrastructure. Based on the hydraulic stepping actuator design that has been proven in subsea applications for more than 20 years, the SL3 provides three times the number of opening set points of previous actuators, a press release stated.

When bringing new production online, this combination of reliability and higher resolution delivers the precision required to reduce the downhole pressure drop and surge experienced at each step, and thereby decreases the likelihood of reservoir damage, sand production and debris. On existing wells the SL3 can open subsea chokes to the sand breakthrough point in smaller steps to safely increase production. The SL3 is backward compatible with existing subsea chokes and utilizes the installed electrohydraulic infrastructure. According to the company, this makes it a more cost-effective option than switching to electric actuators, which typically require modifications such as implementing battery power banks or additional power umbilicals. *masterflo.com*



Master Flo's new high-resolution subsea actuator is designed to help increase production while utilizing existing subsea hydraulic architecture. (Source: Master Flo Valve Inc.)

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RGU launches world-first decommissioning simulator

Aberdeen's Robert Gordon University (RGU) has released a decommissioning simulator. The simulator and the associated software will be used to support decommissioning activities in the U.K. and other parts of the world, a press release stated. RGU, in collaboration with funding partners The Oil & Gas Technology Centre, KCA Deutag and Drilling Systems, with technical support from Baker Hughes, a GE company, has established the simulator to focus on well plugging and abandonment (P&A). P&A is an area that is forecast to cost the U.K. more than £8 billion (US\$10.7 billion) over the next decade, with about 2,500 wells expected to be decommissioned across the U.K., Danish, Dutch and Norwegian continental shelves. The simulator can support oil and gas operators and service companies with the planning and preparation for well P&A, in a similar way pilots get trained and tested on flight simulators. The simulator has the potential to significantly enhance the safety, improve the efficiency and reduce the cost associated with decommissioning oil and gas wells. RGU's partnership with The Oil & Gas Technology Centre also will create new opportunities to develop and test technologies. rguoilandgasinstitute.com

Operational risk management and asset integrity solution for FPSO units

Bumi Armada Berhad has selected RiskPoynt Barrier Model as its operational risk management and asset integrity solution, a press release stated. The company is working with MDI Enterprises to launch cloud-deployed RiskPoynt at FPSO units in the North Sea and across Asia and Africa. Bumi Armada tapped RiskPoynt after searching for a software tool to improve its process for managing upstream operational risks across its portfolio of FPSO units. The company required an operational risk management application that could meet and exceed new EU regulatory and reporting standards and provide operations and senior executives with clear visibility over the operational health of its global assets in real time. riskpoynt.com

System optimizes performance of reciprocating machinery

Windrock, a Dover Energy Automation company, has released its new Spotlight Monitoring System, an automated, real-time technology that leverages Industrial Internet of Things principles to deliver insights into the health and performance of critical assets, a press release stated. The system continuously monitors, diagnoses and

optimizes equipment health. The system also cost-effectively collects and analyzes performance data from assets in the field and transfers it to the palm of the user's hand in real time. The system is a plug-and-play tool that utilizes edge hardware, called Spotlight PUC, to acquire high-speed rotating data. The Spotlight Controller then sends these data to a Microsoft Azure-hosted cloud via gateway, where Windrock Enterprise, an intuitive data visualization software proprietary to Windrock, provides actionable insights and uncovers trends concerning the health of the entire fleet of assets. In addition, the Spotlight Monitoring System allows tiered services to enable digital transformation. The monitoring tier allows users to get complete visibility and then augment it with algorithmic analyses from Windrock Enterprise. iot.windrock.com/spotlight

Drone completes 100-km flight for oil, gas market

SkyX Systems Corp. has successfully completed an unmanned data collection flight of 100 km (62 miles), one of the longest journeys in its class, a press release stated. The firm successfully flew its SkyOne unmanned aerial system on an autonomous data mission over more than 100 km of gas pipeline in Mexico. The robotic flight was programmed and monitored remotely from the company's Greater Toronto Area SkyCenter mission control, with a support crew of engineers on the ground in Mexico. Using high-resolution imagery, the longest of multiple flights identified more than 200 potentially significant anomalies along the remote pipeline, ranging from unauthorized buildings and cultivation to a fissure possibly caused by seismic activity. The flight gathered data in a little more than 1 hour, which would have taken a person well over a week. The mission also identified more than 200 georeferenced anomalies the customer was unaware existed, pinpointing precise coordinates for rapid investigation and remediation. skyx.com **ESP**

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



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1 US

Continental Resources Inc. has completed two Woodford producers in the Scoop play at an increased density pilot project in the Anadarko Basin in Stephens County, Okla. IHS Markit reported #7-6-7XH Sympson, Section 6-2n-4w, was tested on a 40/64-in. choke flowing 603 Mcm (21.3 MMcf) of gas, 472 bbl of 61-degree-gravity condensate and 2.088 Mbbl of water per day. The 7,877-m (25,843-ft) venture was drilled to the south with a true vertical depth of 4,473 m (14,674 ft). It bottomed in Section 7-2n-4w and was acidized and fractured at 4,740 m to 7,824 m (15,550 ft to 25,668 ft). About 3 km (2 miles) to the south in Section 18-2n-4w, the #4-7H Sympson produced 467 Mcm (16.5 MMcf) of gas and 276 bbl of 57-degree-gravity condensate. It was drilled to 5,917 m (19,413 ft [or 16,085 ft true vertical]), and production is from an acidized and fractured zone at 4,908 m to 5,894.5 m (16,102 ft to 19,339 ft). Both ventures are deferred completions of wells first drilled by Continental in 2015.

2 Mexico

Eni completed #2-Tecoalli, a well in Campeche Bay offshore Mexico. The well was drilled in 33 m (108 ft) of water and reached a final depth of 4,420 m (14,501 ft). It hit about 40 m (131 ft) of net oil pay in Orca with excellent quality sandstone reservoirs. The well was then deepened to the Cinco Presidentes exploratory target and encountered an additional 27 m (88.5 ft) of net oil pay. A production test will be executed, and the well will be temporarily abandoned. The find is in Area 1 between Tecoalli Field and Amoca Field. The discovery increases the in-place hydrocarbon estimate from 1.4 Bbbl to 2 Bbbl, of which about 90% is oil and the

remaining is associated gas. Eni is working on a development plan, and first production is expected in 2019.

3 Colombia

GeoPark drilled and tested appraisal well #4-Tigana Norte in the Llanos 34 Block in Colombia. The Tigana Field well was drilled to 3,575 m (11,730 ft) and had oil shows in Guadalupe and Mirador. A production test conducted with an electric submersible pump in Guadalupe flowed 1.9 Mbbl of 14.1-degree-gravity oil, with a 1.8% water cut. It was tested on a 34/64-in. choke, and the wellhead pressure was 178 psi. Bottomhole pressure recorders from the latest tests performed indicate a producing drawdown of about 30%. GeoPark is drilling #5-Tigana Norte 5 to a bottomhole location that is farther down-dip of the #4-Tigana Norte well to further delineate the northeastern boundaries of Tigana Field.

4 Uruguay

Petrel Energy has spudded exploration well #1-Cerro de Chaga as part of an exploration program in Uruguay's Norte Basin. The Salto Basin venture will test a four-way dip closure in Devonian source rocks including Mangrullo Shale. The organic-rich Mangrullo Shale is similar in age to the Bakken Shale. According to the company, #1-Cerro Padilla was drilled to 845 m (2,772 ft) and hit 2 m (6.5 ft) of oil in a saturated sand zone at 793 m (2,601 ft).

5 Gambia

A study conducted by FAR Ltd. for two Gambia blocks, A2 and A5, indicates a potential for 1.1 Bbbl of oil with an unrisksed, recoverable net estimate of 926 MMbbl. Blocks A2 and A5 are within the emerging Mauritania-Sen-

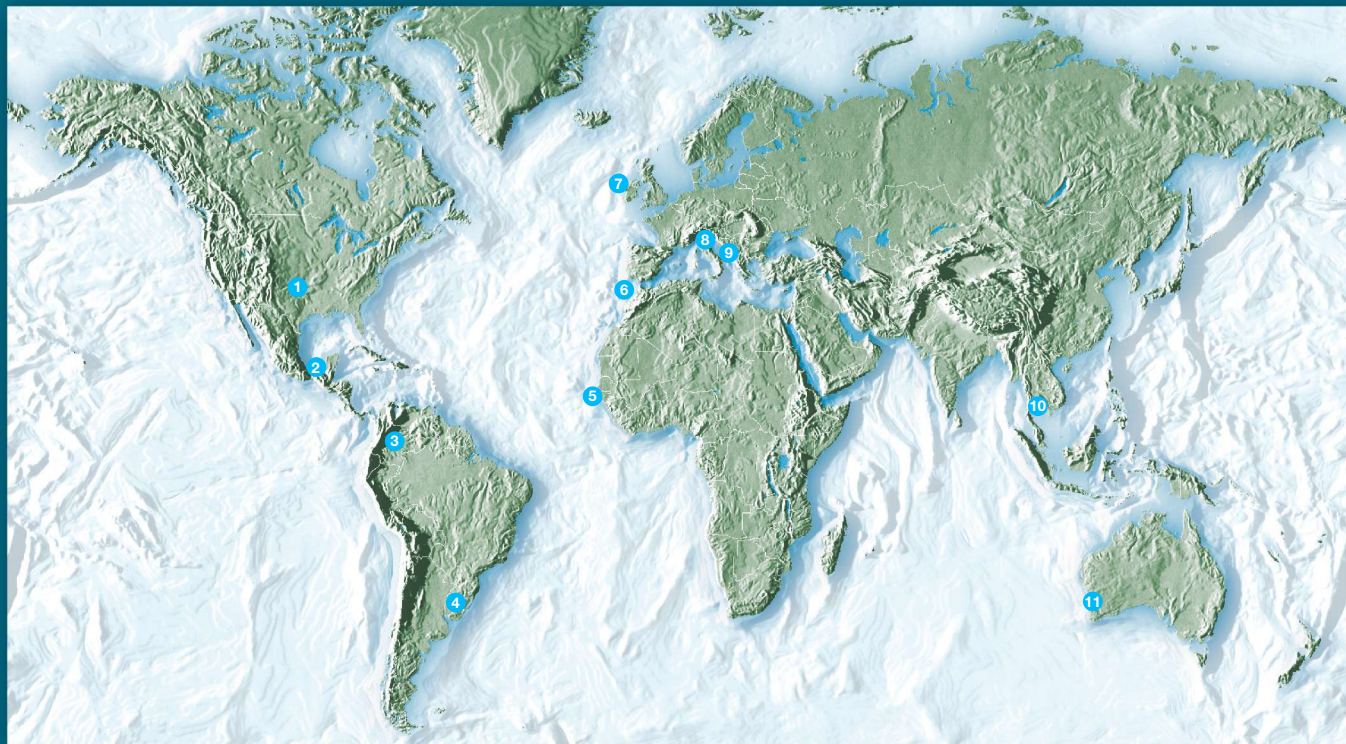
egal Guinea-Bissau Basin and are on-trend with the recent offshore Gambia discoveries by Cairn Energy. Two drillable prospects have been mapped at prospects Samo and Bambo. The Bambo prospect has been identified following recent mapping of the 3-D seismic and targets a separate reservoir objective on the same structural trend as the Samo prospect.

6 Morocco

Eni and Chariot Oil & Gas have scheduled an exploration well in the Rabat Deep Offshore Block of Morocco. Eni plans to spud #1-Rabat Deep (RD-1) well on the JP-1 Prospect in 2018. The JP-1 Prospect is a large, four-way dip closed structure of about 200 sq km (77 sq miles) in areal extent, with Jurassic carbonate primary reservoir objectives. An independent estimate of the gross mean prospective resource is 768 MMbbl of oil. According to Chariot, the Rabat Deep permits have an additional six leads in the same play that have the potential to be de-risked by #1-Rabat Deep.

7 Ireland

A study commissioned by Europa Oil & Gas for offshore Ireland's Slyne Basin indicates several significant potentially gas-bearing structures. The study is based on legacy 3-D seismic data and data recently released from exploration well #18/20-7 that was drilled in 2010 into Corrib North, a Triassic sandstone reservoir prospect on LO 16/20. According to the company, the prospective resources estimate is 39.6 Bcm (1.4 Tcf) of gas in place. Log data from the exploration well suggest the presence of gas at Corrib North, which is a separate anticline north of the Corrib gas field. Based on mapping, Europa believes the full gas column at Corrib North has the potential to be 170 m (558 ft) thick.



8 Italy

Logging results from a Selva Field directional test in northern Italy's Po Valley indicate a gross gas pay zone of 53 m (174 ft). The venture, #1-Podere Maiar by Po Valley Energy, is in the Podere Galina Block in Bologna, Italy. The well was drilled to 1,330 m (4,363.5 ft) and was targeting Pliocene. Plans call for casing, perforating and installing downhole production equipment in early 2018.

9 Montenegro

A report by Netherland Sewell & Associates for Energean Oil & Gas indicates the combined net, unrisks prospective recoverable resources for two offshore Montenegro blocks contain 50.9 Bcm (1.8 Tcf) of gas and 144 MMbbl of liquids. Energean is the sole operator

of the Adriatic Sea blocks 4218-30 and 4219-26, with 100% working interest. The blocks cover a surface area of 338 sq km (130.5 sq miles) in shallow waters.

10 Thailand

Mubadala Petroleum announced results from an exploration well in the Gulf of Thailand at #6-Manora in the G1/48 concession. The operator reported that the well was drilled to a true vertical depth of 2,412 m (7,913 ft), and it was targeting the L fault block prospect. Interpretation of the LWD data indicates a 5.8-m (19-ft) oil column in the primary reservoir section at a depth of 2,229 m (7,313 ft). Based on these results, a sidetrack, #6ST-Manora, was drilled to test the M prospect. The sidetrack was drilled to 2,387 m (7,831 ft) and LWD data indicated 5.9 m (19 ft) of oil in three separate reservoir sand-

stones, each of which exhibited evidence of an oil-water contact.

11 Australia

Australia Worldwide Exploration announced results from flow testing at #4-Waitsia in the Waitsia gas field in onshore Western Australia. The well flowed gas at an instantaneous maximum rate of 2.54 MMcm/d (90 MMcf/d) and an average of 2.53 MMcm/d (89.6 MMcf/d) during testing on a 96/64-in. choke with a flowing well pressure of 2,395 psi from Kingia Sandstone. The well hit a 50-m (164-ft) zone between 3,370 m and 3,420 m (11,056 ft and 11,220 ft). **ESP**

For additional
information on
these projects
and other global
developments:



PEOPLE

Long-time executive **Jerry D. Dumas, Sr.**, 82, passed away in December 2017. Throughout his career at Flotek Industries Inc., he was board chairman, CEO and president. In addition, **William H. York** was named Flotek's chief administrative officer in January.



DEA Deutsche Erdoel AG appointed **Maria Moraeus Hanssen** (left) CEO and chair of the board of management, succeeding **Thomas Rappuhn**.

Parsley Energy Inc. announced **Bryan Sheffield** will step down as CEO and become executive chairman in 2019. **Matt Gallagher** will be his successor.



Steve Paulsen was promoted to PG Flow Solutions' CEO.



Christina Verchere resigned from BP Plc to become OMV Petrom's CEO and executive board president, positions she will assume in May.

Lance Ugglä was selected as chairman and CEO of IHS Markit when **Jerre Stead** announced his retirement in December 2017.

Akastor ASA has selected **Karl Erik Kjelstad** as CEO, succeeding **Kristian Røkke**, who will assume the position of chief investment officer at Aker ASA.

Gulfport Energy Corp. appointed **Donnie Moore** COO.

EOG Resources Inc. promoted **Lloyd W. "Billy" Helms, Jr.** to COO and **Ezra Y. Yacob** to executive vice president of E&P.

Éric Lachance was appointed senior vice president of corporate affairs and CFO of Énergir LP, succeeding retiree **Pierre Despars**.

PDC Energy Inc. appointed **R. Scott Meyers** CFO, and **Christina M. Ibrahim** was appointed board director.

Geoffrey Wagner has been selected as executive vice president and chief commercial officer of Helix Energy Solutions Group Inc.



David Cedro (left) has joined Danos as vice president of finance and

administration. In addition, **James Callahan** (right) has been named vice president of project services.

Seadrill Ltd. selected **Harald Thorstein** as director of the company.



EM&I appointed **Neil Woodcock** regional general manager for the Europe Africa region.



Aminex named **Brian Cassidy** (left) company secretary. Former

company secretary **Max Williams** (right) will continue in his role as director and CFO.

U.S. Silica Holdings Inc. promoted **Billy Ray Smith** to senior vice president and president of Oil & Gas Proppants, succeeding retiree **Don D. Weinheimer**.



KCA Deutag named **Albert Allan** senior vice president of its RDS business unit.



Stephen Bell of Opportune LLP has been promoted to managing director.

Omur Izgili was appointed country director for VIKING's Turkey, Greece, Bulgaria, Romania and Lebanon sectors. He succeeded **Yasin Kasa**, who has been appointed senior commercial director for VIKING Asia.

Chris Ong Leng Yeow joined the board of directors as a nonexecutive director at KrisEnergy Ltd., replacing **Michael Chia Hock Chye**.

Senex Energy Ltd. appointed **Andy Zhmurovsky** nonexecutive director. **Yanina Barila** has resigned from the board of directors.



Subsea North East's **Bruce Heppenstall** has been appointed regional chairman, succeeding

Andrew Hodgson.



The Energy Industries Council appointed **Louise Ledgard** (right) and **Duncan Reed** (left) to its board of directors.

EnQuest Plc's board of directors named **Laurie Fitch** nonexecutive director.

Subsea UK has named a new board for 2018-19: **Bill Edgar**, **Neil Gordon**, **David Rennie**, **Bill Catnach**, **Mark Richardson**, **David Sheret**, **Nicky Etherson**, **Zander Bruce**, **Geoff Lyons**, **Peter Blake**, **Tim Sheehan**, **Cameron Mitchell** and **Phil Simons**.

COMPANIES

C-Innovation LLC has formed a turn-key subsea projects group in Houston.

Westerton, an Aberdeen offshore specialist of high-precision downhole



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tools, opened a Houston-based office and workshop in January.

Delmar Systems Pty Ltd. purchased a new storage facility in Western Australia.

Siemens opened a new digitalization and energy-focused MindSphere Application Center in Berlin.

TAM International opened a new manufacturing facility in Obninsk, Russia.

Dynacorp Energy Services and **Energes Oilfield Solutions LLC** have merged. The new company is named **EnerCorp Sand Solutions**.

America Inc., **Horizon Marine Inc.** and **Woods Hole Group Inc.** completed its merger in January. The new company retained the name **Woods Hole Group Inc.**, specializing in offshore oceanography for the

energy industry and providing environmental services.

Fairmount Santrol Holdings Inc. was sold to **Unimin Corp.** in a cash-and-stock deal, which is expected to close by mid-2018.

Drillinginfo acquired **Pattern Recognition Technologies**, a provider of energy forecasts, in December 2017.

Oil States International Inc. acquired **GEODynamics Inc.** in January.

Stallion Oilfield Services Ltd. acquired **Basin Wastewater Solutions LLC**.

McDermott International Inc. and **CB&I** announced in December 2017 their transaction to create a fully vertically integrated onshore-offshore company. The transaction is expected to be completed in second-quarter 2018. **ESP**

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AI shaping the future of oil and gas

Four critical automation areas are paving the road for longer-term AI.

Shiva Rajagopalan, Seven Lakes

Employee layoffs, dwindling investments and limited budgets are the result of falling oil prices. The oil and gas industry is being challenged to adapt and optimize performance in every way possible to maintain profitability.

Every oil and gas company is looking to increase production without increasing resources. And every oil and gas software-as-a-service vendor is looking to provide the latest in production optimization software. Although both parties have heard of artificial intelligence (AI) and its promise to expedite processes, this modern technology is just beginning to graze the surface of what's possible.

The four biggest areas that lease operators will benefit from near-term automation and longer-term AI are: well service, mobile work orders, compliance and run tickets.

Well service

It does no good to count the number of stops a pumper makes or to measure the distance between them. That simply measures what needs fixing or adjusting, where those tools are and how long it will take a crew to get from the last broken well to the next one.

Automated intelligence algorithms apply field intelligence that prioritizes well visits to significantly enhance pumper productivity. For example, pumpers allocate their time to wells demanding high-priority assistance with event-based algorithms and location awareness aids.

Oil and gas companies that have embraced technology are presenting strategic recommendations for specific well sites requiring immediate attention. Without this dynamic awareness of well health and location, pumpers end up treating all wells the same.

Mobile work orders

The traditional method for drafting and completing work orders entailed pumpers to head to their office, print and fill out a form, and send it in to headquarters.

This paper process lacks efficiency and involves too many platforms creating fragmented and outdated data.

Automation enables operations staff to monitor results and report from the field via mobile work orders. The use of data and automation of information on pumps permits performance optimization. Automation minimizes errors by housing all data in a centralized location.

Compliance

Before automation efforts, companies faced important reporting obligations while producing oil and gas. This required operations staff to spend a large portion of their day collecting data in multiple systems, resulting in high overhead costs and difficult-to-locate information.

Automation empowers companies to generate compliance reports without the need for extra personnel because gathered data are in a centralized location within the platform. Siloed information housed in various places

is no longer acceptable. Automation is the new highest standard for field operations in the oil and gas industry, partly because it makes searching for reports simple.

Run tickets

The industry runs on tickets. Sometimes simple data entry mistakes can have a huge impact. These run tickets are checked manually, making it a ripe opportunity for automation.

Seven Lakes can equip pumpers with a simple way to photograph their run tickets and automatically translate and upload those data with 99% accuracy. No more manual entry is needed. Users get much better data quality, better accounting and more speed. To do this, users need more than simple character recognition software. Using the TensorFlow technology, each ticket learns from the first and applies that knowledge to the next.

Leading E&P firms realized that antiquated systems or processes severely restrict their ability to cut costs effectively. Given the significant cost savings that can result from automating processes by adopting field intelligence software makes sense from a functional and financial perspective. **ESP**

AI is just
beginning to
graze the
surface of
what's possible.



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

More stages per well

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

- 155 stages (Bakken)
- 135 stages (Cardium)
- 147 stages (Permian)
- 125 stages (Duvernay)
- 145 stages (Montney)
- 116 stages (Marcellus)

More sand per well

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

- 16.2 million lb @2,190 lb/lateral ft (Montney)
- 15 million lb @1,711 lb/lateral ft (Duvernay)
- 14.9 million lb @1,825 lb/lateral ft (Montney)
- 14.2 million lb @1,973 lb/lateral ft (Permian)

Faster execution

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

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

Fewer coiled tubing trips. Almost 90% of NCS Multistage jobs are performed in a single coiled tubing trip. As many as 155 sleeves have been fraced without tripping out of the hole.

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