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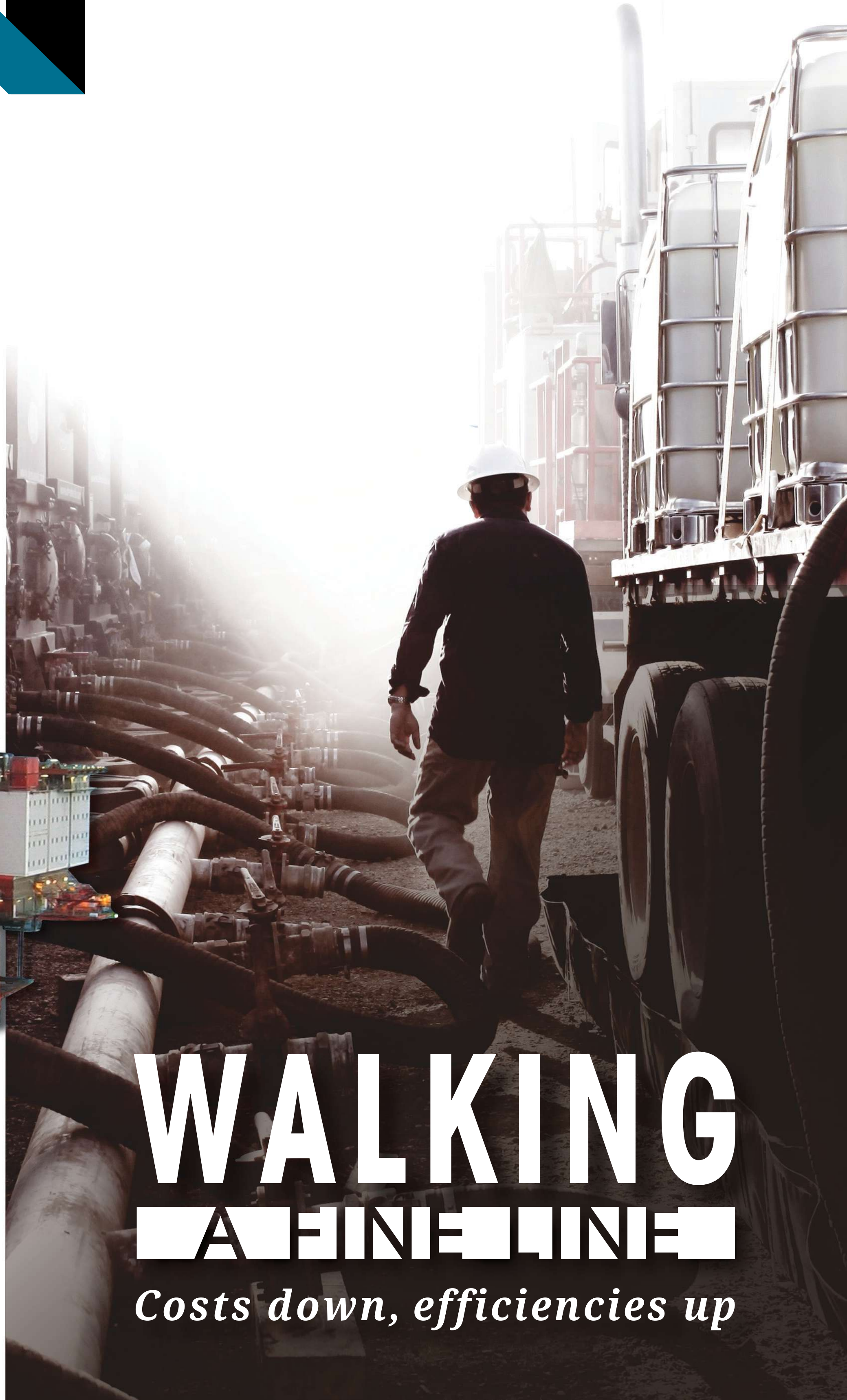

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FEBRUARY 2016
VOLUME 89 ISSUE 2

E&P

A HART ENERGY PUBLICATION

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Conference Agenda

Wednesday, March 9

5:00 pm Opening Reception

Thursday, March 10

7:30 am Registration, Breakfast & Networking

8:30 am Welcome & Opening Remarks

8:35 am Opening Keynote: Optimizing The Bakken & Niobrara

- **Jim Volker**, *Chairman, President and CEO,* ***Whiting Petroleum Corp.***

9:00 am OFS Spotlight: A View Of The Lower 48 From An International Perspective

- **HC Freitag**, *Vice President, Integrated Technology,* ***Baker Hughes Inc.***

9:20 am Panel: Bringing Down Breakeven Costs

- **Chris Wright**, *CEO,* ***Liberty Resources LLC***
- ***Synergy Resources Corp.***, Speaker TBA

10:00 am Networking Break

10:40 am Operator Spotlight: Wattenberg Evolution

11:00 am Operator Spotlight: Rockies Returns– From Gallup to Piceance to Bakken

- **Clay Gaspar**, *Senior Vice President and Chief Operating Officer,* ***WPX Energy Inc.***

11:20 am A&D Panel: Capturing Opportunities

- **Grant Butkus**, *U.S. Head of A&D Advisory,* ***Macquarie Capital***

12:00 pm **Featured Keynote Luncheon Speaker**

- **Karl Rove**, *Former Deputy Chief of Staff and Senior Advisor to President George W. Bush, Political Strategist and Bestselling Author*

1:30 pm Operator Spotlight: Vertical Integration Strategy

1:50 pm Infrastructure Panel: Moving The Rockies' Bounty

- **Sam Margolin**, *Director, Equity Research, Energy,* ***Cowen & Co.***
- ***Tallgrass Energy Partners LP***, Speaker TBA

2:40 pm Midstream Operator Spotlight

3:00 pm Networking Break

3:30 pm Roundtable: Technology Solutions

- **Heath Mireles**, *Manager, Resource Development, Northern Region,* ***Continental Resources Inc.***
- **Nathan Fisher**, *Vice President, U.S. Development & Geosciences,* ***Enerplus Resources (USA) Corp.***
- **Garrett Frazier**, *Director,* ***Magnum Oil Tools International Ltd.***

4:10 pm Closing Keynote: Out-Stripping The Type Curve

- **Greg Hill**, *President and Chief Operating Officer,* ***Hess Corp.***

4:30 pm Networking Reception

Friday, March 11

7:30 am Registration, Breakfast & Networking

8:30 am Welcome & Opening Remarks

8:35 am Opening Keynote: Oil In The Bank

- **Taylor Reid**, *President and COO,* ***Oasis Petroleum Inc.***

9:00 am Panel: Private Operators: Staying The Course

- **Ward Polzin**, *CEO,* ***Centennial Resource Development LLC***
- **Jack Vaughn**, *Chairman and Chief Executive Officer,* ***Peak Exploration & Production LLC***
- **Ben Burke, PhD**, *Senior Geologist,* ***Fifth Creek Energy LLC***

10:00 am Networking Brunch

10:30 am Panel: Returns & EUR Case Studies

11:30 am Closing Keynote: U.S. Crude Exports & The World

12:00 pm Conference Adjourns

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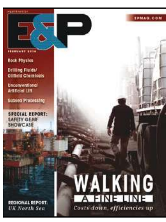
DEPARTMENTS AND COMMENTARY

COMING NEXT MONTH The March issue of ***E&P*** will focus on new advances in drilling and downhole technology. Other features include time-lapse seismic, coiled tubing drilling and tools, emissions management, and deepwater facilities, and the regional report will focus on Australasia. 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 Service company pricing is near a low ebb, completion costs have gone down and efficiencies have gone up dramatically, but the industry faces a limit. This hydraulic fracturing spread shows an austere view of today's service industry. Left, the U.K. North Sea will be hard-pressed to increase output in 2016 in a lower-for-longer oil price world. *(Cover image courtesy of Liberty Oilfield Services; left image courtesy of Simon Pedersen, Shutterstock.com; cover design by Carleigh Pearson)*

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Zohr discovery may overlay additional field in North Port Fouad Block

The recent Zohr gas field discovery in the Shorouk Block in Egypt's Nile Delta could be overlying another potentially giant field that might extend into the adjacent North Port Fouad Block.

EOG's Codell discovery produces 602 bbl/d of oil

EOG Resources Inc. made a horizontal Codell discovery in the Denver-Julesburg Basin in Laramie County, Wyo. The #517-2932H Hillsdale flowed 602 bbl/d of 36.3°API-gravity oil, 12,374 cu. m/d (437 Mcf/d) of gas and 1.51 Mbbl/d of water.

Two BHP-Phantom field discoveries reported

BHP Billiton Ltd. has released results on its two horizontal Phantom Field-Wolfcamp completions in Reeves County, Texas, in a portion of the Delaware Basin. The #1H State Camp 56-T2-14X11 flowed 47,402 cu. m/d (1.674 MMcf/d) of gas, 265 bbl of 49°API-gravity condensate and 750 bbl/d of water. The #2H Hill & Meeker 56-T2-22 flowed 1,102 bbl of oil and 93,445 cu. m/d (3.3 MMcf/d) of gas.

AVAILABLE ONLY ONLINE

Report: offshore areas among untapped energy sources for US

By Velda Addison, Senior Editor, Digital News Group

Offshore development was among the areas mentioned for potential in terms of production, jobs and economic growth in an oil and gas association's report on the status of the U.S. energy sector.

Oil, gas sector keeps eyes on Iran, Saudi conflict

By Velda Addison, Senior Editor, Digital News Group

The conflict between Iran and Saudi Arabia has not significantly rattled the oil market, but analysts say the potential for market and supply disruptions exists.

Forecast shows more E&P spending cuts worldwide

By Velda Addison, Senior Editor, Digital News Group

A survey of 450 companies forecasts double-digit spending drops in North America, Latin America, Asia-Pacific, Africa and Europe. But the Middle East and Russia appear to bucking the trend.

Taking a bite out of the big Mac

By Gareth Quinn, Hart Energy

Some industry observers have likened the McArthur Basin in Australia to the Haynesville Shale in Louisiana, where production peaked at 2.8 Bcm/d (100 Bcf/d).

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Delayed production means only one winner

With analysts vying to pronounce ever-gloomier predictions, beyond the decimated spending plans lurks a seemingly ever-present fact of life.

A dose of doom and gloom is never a great way to start the year, but that summed up January for most of us.

According to Wood Mackenzie, about $380 billion of full-life capex (real terms, excluding abandonment) associated with 68 delayed major projects has been deferred. That's $180 billion more than they thought it would be just six months earlier (representing 22 more impacted projects).

With the oil price continuing to struggle, the list will keep growing, WoodMac warned, with $170 billion more at risk from 2016 to 2020. "With oil prices below $35/bbl, oil and gas companies will be forced to go into survival mode in 2016. Further project delays and cuts to discretionary investment are highly likely." There are some encouraging signs, according to WoodMac, with operators reevaluating how they can profitably develop large, high-cost conventional resources in a low-price environment with a genuine push toward more standardization and a higher level of innovation.

But the elephant in the room is future production—or rather, the lack of it. Countries with the largest inventory of delayed oil projects include Canada, Angola, Kazakhstan, Nigeria, Norway and the U.S. These hold nearly 90% of all the deferred liquids reserves resulting from the delayed 68 projects, which include oil sands, onshore, shallow-water and deepwater assets.

This represents 27 Bboe of commercial reserves delayed from the identified 68 major projects. For liquids alone that equates to 1.5 MMbbl/d in deferred volumes in 2021 and 2.9 MMbbl/d by 2025.

The industry knows that it has been here before—when Brent hit $46.50/bbl in November last year, it was compared to the January 1990 level of $23.73/bbl. Applying the U.S. inflation index equates that 1990 price to $43.20/bbl, a level similar to today.

According to Barclays' latest analysis, the Middle East remains the only market set to see 2016 capex grow (by 6%). This includes the world's largest national oil company, Saudi Aramco, which will hike its spending 5%. OPEC (mainly Aramco) has a high pain threshold—despite Saudi Arabia's fiscal breakeven being just below $100/bbl, it has $750 billion in cash reserves to help it deal with a weaker oil price for years (Kuwait at $47/bbl and the United Arab Emirates at $69/bbl also are pretty well placed). This allows OPEC to maintain its activity levels and stay committed to a production strategy of 31.5 MMbbl/d.

The end result is that the (mostly) Western industry's need to survive today by deferring production across the board will result, inevitably, in OPEC eventually being back in charge when the long-awaited industry upturn comes. Thus has it always been. E&P

Mark

Delivering effective commercialization

Aligning horizons across R&D organizations will enable successful commercialization and deployment.

Crispin Keanie, OTM Consulting

The disconnect between technology innovation and technology deployment is long-standing but perhaps comes into sharper focus in the context of low oil prices. As the availability of "easy oil" becomes scarcer, there is broad consensus that technology must be pivotal in increasing recoverable oil in existing areas, helping identify and harvest oil in less accessible areas and driving down costs in general.

The oil price downturn has impacted spend on R&D and innovation projects. As well as absolute R&D spend, return on R&D/technology investment is being questioned across the industry. A key area under the spotlight is deployment and commercialization. Whereas companies tolerated underperformance during the good times, they are now coming under fire, and greater efficiency and effectiveness are being demanded.

Figure 1 shows the key to being a highly successful commercialization organization. It tackles the right R&D and technology that satisfies its key stakeholders; it ideates, innovates and develops, maturing through R&D funnel de-risking technically and commercially in a timely fashion. It then flawlessly and rapidly monetizes through trials and widespread application and has the right internal capabilities combined with adequate and consistent funding as well as the right external partners aligned and incentivized to innovate.

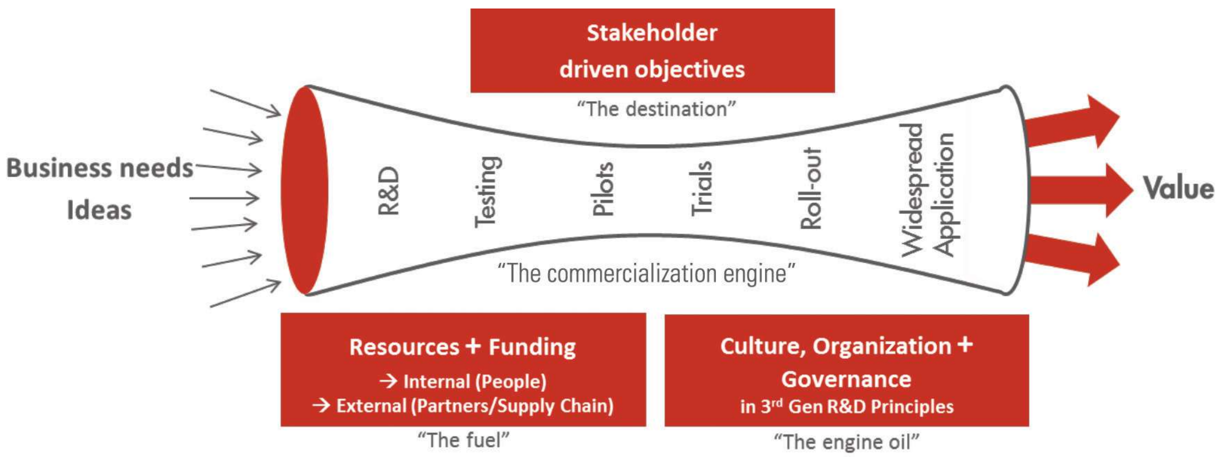
And gluing everything together, it has culture and governance that creates partnerships, optimizes value, creates the right horizon view and delivers the appropriate appetite for innovation risk aligned to the company's objectives.

It will come as no surprise that obtaining simultaneous excellence across all these areas is incredibly hard to achieve. And failures become more apparent in times of greater scrutiny and demand for clearly demonstrated value.

Three key areas that need to be tackled within the industry are highlighted, potentially with game-changing solutions, all under the theme of aligning horizons where time and value-creation horizons in portfolios are considered, corporate objective horizons are identified in first deployments and aligned end-game horizons with external partners are optimized.

Aligning horizons in R&D portfolios

Questions are rightly being asked about what it means to operate in a long-term low oil-price environment in terms of R&D and long-term innovation. OTM's research indicates that technological leaders seldom are the most efficient operationally; more typically,



The commercialization engine drives a highly successful commercialization organization. It tackles the right R&D and technology that satisfies its key stakeholders. (Source: OTM Consulting)

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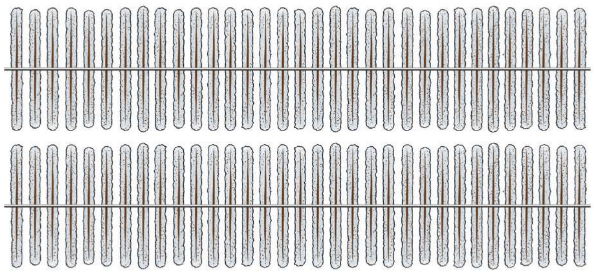

Predictable, verifiable, and repeatable frac spacing and propped volume eliminate key unknowns to facilitate formation-specific, well-to-well optimization across entire fields.

Recorded downhole data describes every frac

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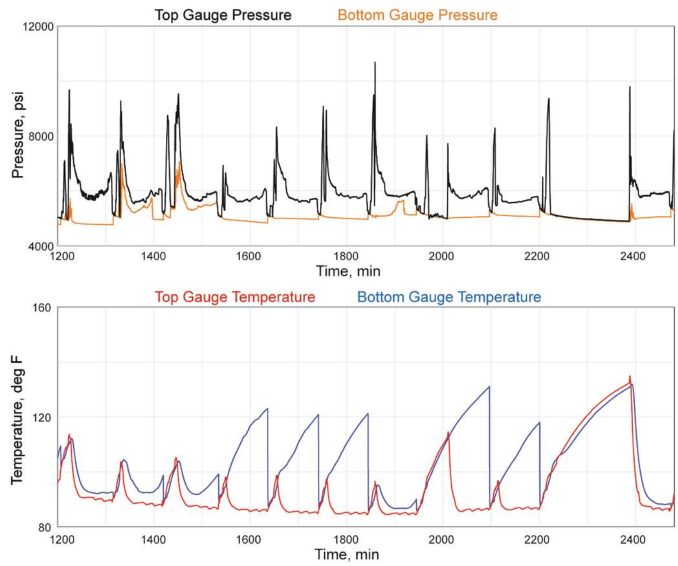
The combination of consistent frac placement and downhole data is your best and fastest route to truly optimized completions and field-development strategies. Learn more at ncsmultistage.com.



These charts show pressure and temperature above and below the isolation assembly for ten stages. The data reveals and describes any interstage communication and important frac and formation characteristics.

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Aligning enabling R&D technology is where companies should be focusing rather than short-term fixes. (Source: totojang1977, Shutterstock.com)

leaders are pushing industry boundaries in terms of resource access (which in itself is often more expensive to develop).

While technology has a role to play in short-term cost reduction, for example, data analytics for operational efficiency and accelerating learning curves (see BP's Technology Outlook, November 2015), its impact in the short term will be smaller than supply chain efficiencies. Understanding the future business scenarios and aligning enabling R&D/technology is instead where companies should be focusing rather than shifting portfolios to short-term fixes.

Aligning horizons in corporate drive

Technology early-application "valleys of death" are being exacerbated, resulting in delayed and slowed innovation. The cost and risk associated with being the first asset manager to apply or trial a new technology in his/her well/field is often too high to be taken in isolation. In fact, it is the corporation as a whole that will benefit from successfully proven technologies that can be leveraged over a global asset base.

Companies need to find new ways (or revisit old ways) of motivating the early uptake of technology and instilling a culture of innovation, particularly when the full benefit of the technology will be realized in subsequent applications and ultimately from applying it throughout the organization. By correctly understanding value generation early in development, companies are then able to ensure it is secured through commercialization as well as deployment.

Aligning horizons in external relationships

In a downturn, particularly an anticipated long, deep one, the pressure always comes to outsource more R&D and technology development. Indeed, we've seen an upturn in technology and research strategic alliances between oil companies and service companies in the last 12 months as an indicator of this. However, a simple corporate mandate can become increasingly difficult to implement effectively to deliver significant value back to the company via innovation in a timely manner.

Strategic bridging roles within procurement departments are now appearing; these are needed to be able to implement effectively as it is often now too complex for R&D to handle on its own. The critical component to success is to think strategically about relationships and about how the "end game" with external relationships will play out.

With R&D and technology considered invaluable for future success and yet under pressure to deliver increased value, aligning horizons in 2016 across R&D organizations will be the key to successful commercialization and widespread deployment. That is the only way for R&D and technology investments to actually realize their value. E&P

Leading with Lean

Through a radical shift in thinking, one company finds that success is repeatable with its 'army of problem solvers.'

Jennifer Presley, Senior Editor, Production Technology

It is one of the many 800-lb gorillas that always finds a way to be in the way. Accounting for it has become the norm in scheduling any type of work, be that punching up a spreadsheet, pushing a broom or turning a wrench. It is the wasteful product of inefficiency and poor planning. It is nonproductive time (NPT), and the challenge of eradicating it from the development of oil and gas resources has long been considered an impossible one.

But that view was challenged in 2014 when, through its use of Lean manufacturing, Hess Corp. attained zero NPT on an exploratory well offshore West Africa.

"One of the things I'm most proud of is our use of Lean principles in a deepwater drilling campaign in West Africa," said Greg Hill, COO of Hess Corp. "We had 10 exploration and appraisal wells to drill offshore Ghana. Seven of those 10 wells were by far among the best wells drilled by the industry in West Africa. In particular, the last well had zero NPT. I've never, in 32 years of my being in this business, ever seen that anywhere on the planet."

The company's success in Ghana did not come overnight, but through the culmination of lessons learned over the last six years in its onshore and offshore operations. Hess' shift to Lean—a manufacturing approach developed by Toyota that set the automotive world on its ear—started in 2010 in its Bakken program with the goals of reducing well costs and optimizing well productivity.

Greg Hill joined Hess Corp. in 2009. (Source: Hess Corp.)

The company has since experienced a 62% improvement in spud-to-spud drilling performance in the Bakken—down from 45 days in first-quarter 2011 to 17 days in third-quarter 2015. It has seen a similar improvement in its reduction of drilling and completion well costs by 60%, from $13.4 million in first-quarter 2012 to $5.3 million in third-quarter 2015, according to the company.

For all of the initial success the company had in its Bakken program, the lingering question was could that success be replicated elsewhere? In transferring the principles over to its Utica operations, the company reported that it reduced drilling and completions costs by 41% and 43%, respectively, since application of Lean began there in 2013.

Having found success onshore, the processes have demonstrated similar returns offshore. In those efforts, the company has realized a 40% reduction in lifting and hoisting incidents over two years, a 50% decrease in the turnaround time in Equatorial Guinea, along with zero safety incidents and a significant reduction in construction time at its Stampede project in the Gulf of Mexico.

"For the Stampede project, we have a whole team applying Lean principles on it," Hill said. "One of the major items to construct is a blast wall to protect the workers in the event of a process safety explosion. The team applied the Lean principles and realized a 40% reduction in the construction time.

"Stampede is a $6 billion dollar project, gross. If I can get a 10% or 20% improvement, these are huge numbers," he said. "It actually more than offsets anything done in the Bakken because it has such a huge starting point."

What is Lean?

Being "Lean" carries many definitions, but essentially it is a systematic method for the elimination of waste within a manufacturing system. Hill sees it as the art of doing work efficiently and something more.

"Basically, it's about building a culture of problem solvers or, as we call it, an army of problem solvers," he said. "One of the tenets of Lean is that leadership behaviors are everything. For example, a typical Western model of leadership is, 'I'm the leader. You bring me problems. I solve them because that's what I do. I'm the leader.'

"Actually, Lean turns that upside down. It says, 'The role of the leader is actually to facilitate the problem-solving process with his team of workers' because the best person who knows how to fix something is the person doing the work; very rarely is it the supervisor. That's as much about a leadership model as it is about anything else," he explained.

"It's all about creating that culture that allows the workers to feel like they can contribute their ideas, and they're involved in improvement. That's why when you decide that you're going to implement Lean, it takes a long time because it truly is a cultural journey. It's not just picking up a book and training everybody in tools. If you don't have the leadership culture behind that, it will fail. It's only a question of when," he cautioned.

"There are principles to follow. It also is a culture of continuous improvement where everybody works to eliminate waste from the process. Waste is public enemy No. 1," he said.

"A big part of it also is a standard of work with an emphasis on transparency in measurement. We measure safety, quality, delivery and cost," he said. "It's great to measure it, but you need a rigorous management process to look at those measurements to find areas of improvement in that standardized process."

Through Lean manufacturing processes, Hess is continuing to increase efficiency and in turn bring down drilling costs in the Bakken. Pictured is the Nabors B06 Rig drilling a Hess well in December 2015 just south of Tioga, N.D. (Source: Hess Corp.)

Establishing standards, gaining efficiencies

The need for standardization and collaboration are just two of the many drums being beaten currently by the industry in this "lower for longer" market climate. Lean, with its emphasis on both, is a natural fit to meeting these needs. It is through the standardization of processes, systems and components that the greatest efficiencies are found.

"I believe one of the Achilles' heels of the oil industry is that everything is bespoke. You talk to our contractors, and they will say that one of their biggest frustrations is that there's just not much standardization in our business," Hill said. "The only way that Lean manufacturing can work effectively is through standardization of the work. Only then can you improve upon a standard."

According to Hill, for the industry to realize across-the-board efficiency gains, a much higher level of standardization is needed.

"My hope is that is that the industry uses this downturn as a means to really focus on the inefficiencies that have been built into this business as a result of a rapid upturn caused by the U.S. onshore," he said. "There was a lot of inefficiency that crept into the system. Lean is one way to address it. It is the way Hess is doing it because it works extremely well."

Through Lean, Hess found a way to survive the lean times present during a market downturn. The company's willingness to endure a journey of cultural change should contribute to its future longevity. It is a journey that experts have said takes years. For those daring enough to take the first step on their own journey, Hill offered the following advice.

"Don't underestimate the challenge. Focus, at least initially, on the company leadership. Are they wired to thrive in a Lean environment?" he said. "Stick with it as it will be frustrating. But you will be shocked, amazed and surprised at the level of improvement that can be accomplished." E&P

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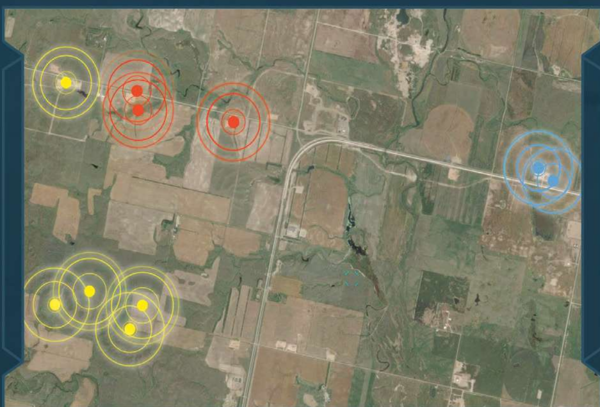

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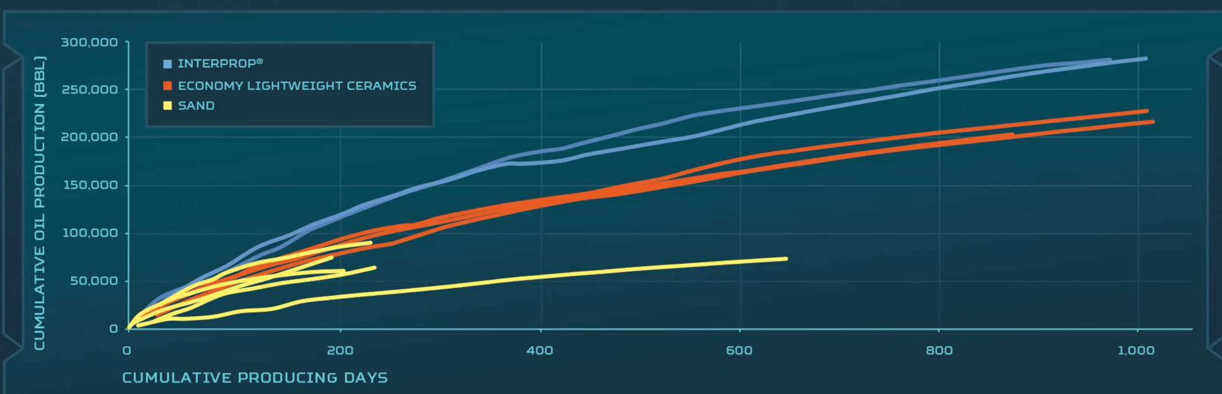

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A Permian Basin primer

Although Permian Basin oil services work has held up better than other markets, contractors in all service lines foresee tougher conditions in 2016.

Richard Mason, Chief Technical Director

The good news is that unconventional oil and gas activity has held up better in the Permian Basin than in any other market. The bad news is that industry indices such as the Baker Hughes rig count show activity down more than 50% from the fourth-quarter 2014 peak.

Utilization for drilling rigs regionally fell to 36% at year-end 2015, and drilling contractors' mindsets are acquiescing to the potential reality that the market for land drilling rigs might not improve meaningfully in 2016. Average rig rates dropped $1,000 per day in just 90 days at year-end 2015 to $16,000 for the benchmark 1,500-hp AC-VFD Tier I drilling unit. Hart Energy surveyors found some contractors quoting spot market rates of $15,000 but finding few takers. Many Permian oil and gas operators are not willing to drill at the moment, regardless of pricing. Work, when available, is on a well-to-well basis, though there are a few contracts remaining with terms that run a few months.

- **Vertical well drilling gains share in a softening market**
- **Permian operators experimenting with refracks**
- **Survival an issue as weakening demand impacts regional workover and pressure pumping firms**

Similarly, there is little rest for weary well stimulation service providers in the Permian Basin. The outlook among well stimulation service providers was mixed at year-end 2015, according to those participating in the Hart Energy field service surveys, with half of respondents expecting little increase in demand during first-quarter 2016 while the other half expects demand for well stimulation services to fall further. The main culprit in sentiment erosion is the continuing and unexpected drop in commodity prices. Some well stimulation providers indicate the current climate will hasten issues of survival for cash-strapped regional pressure pumpers.

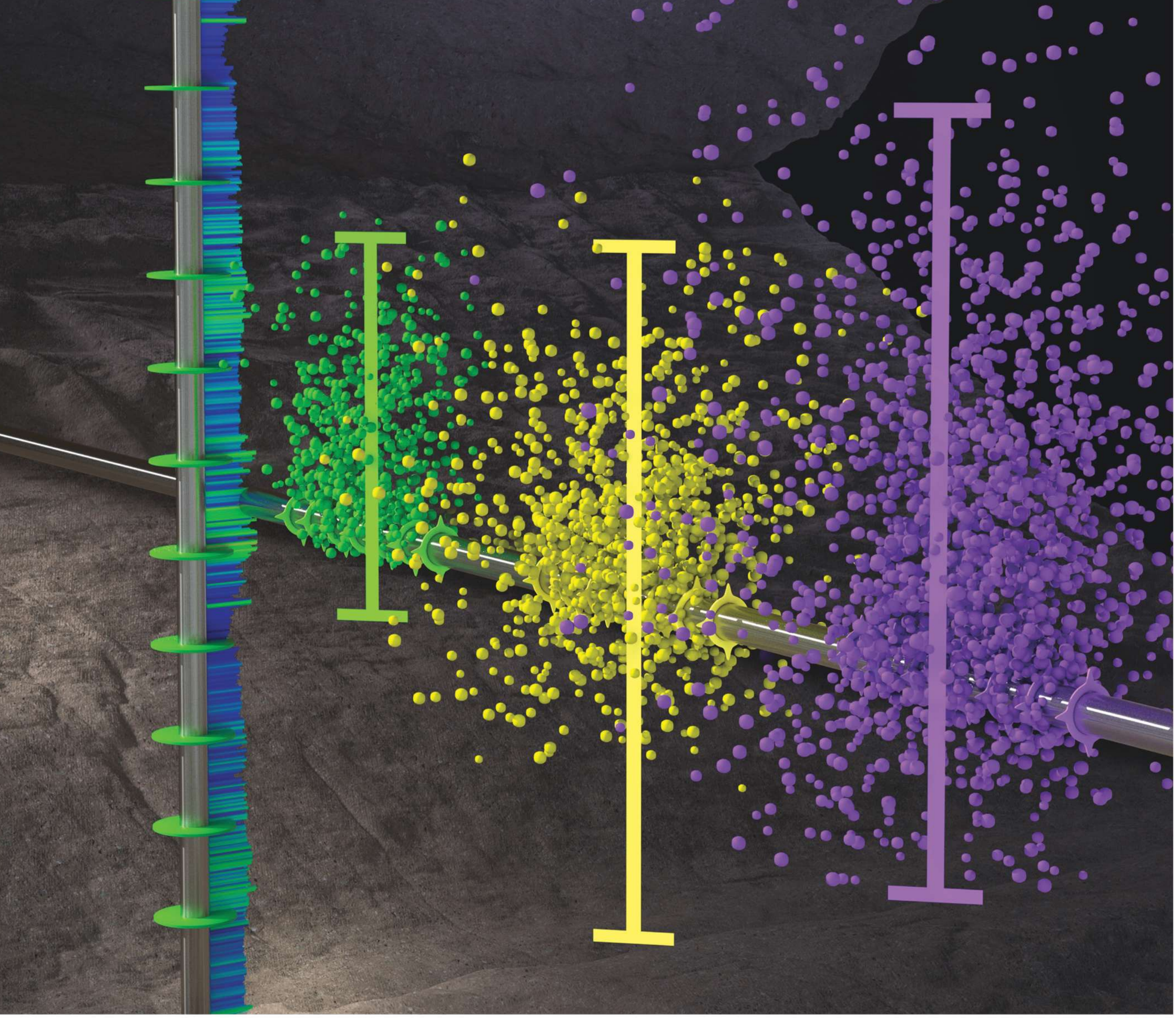
The job mix in fourth-quarter 2016 finds a few operators shifting back to vertical wells to keep costs down and cope with the low-price environment. The average price per stage has fallen to $34,000, although average Permian Basin pricing incorporates lower cost work for vertical wells. Operators are drilling fewer wells and completing those one well at a time while pressuring service providers for additional cost cuts. The evidence is found in the fact that zipper fracks, as a percentage of all completions, fell to 42% of wells among those surveyed at year-end 2015, down from 56% of completions at the end of third-quarter 2015. Zipper fracks are a proxy for batch completions, and this suggests the backlog of drilled but uncompleted wells continues to rise in the Permian.

Operators have settled on "tried and true" practices for downhole completions, which entails slickwater fracks, stage spacing of 76 m (250 ft) and plug-and-perf methodology. Proppant use remains high at 7.9 million pounds per lateral on average, down incrementally from the 9 million pound average at the end of third-quarter 2015 but likely reflecting interview sampling weighted to the Midland Basin. That switch in interview sampling also revealed a growing component of vertical wells, which represent 26% of wells drilled among survey respondents vs. the 74% that employ enhanced completion technology.

Well stimulation service providers pointed to experimental work on Permian Basin refracks, with operators trying different mechanical approaches. However, refrack marketshare is still low.

Sentiment among Permian Basin workover contractors reflects that of their colleagues on the drilling side. Survey participants see demand for workover services getting weaker in first-half 2016. Operators are reducing spending to adjust to a cash flow neutral world, with more spending cuts coming in first-half 2016. Routine maintenance accounted for more than 70% of job mix at year-end 2015 compared to 60% in third-quarter 2015. Meanwhile, a price war has broken out for the shrinking workover pie between the larger public and smaller privately held well service providers.

Contractors intend to stay lean until 2017. E&P



Keep it simple, stupid

What might the next-generation marine vibrator include? Try a servo motor and a radial tire.

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Read more commentary at
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Despite studies that suggest that airguns have little impact on marine mammals, government regulations worldwide continue to get more stringent. This has spurred interest in a more benign marine source: the marine vibrator.

Marine vibrators are not a particularly new concept, but the ones that have been developed to date are nowhere close to replacing airguns in marine seismic surveys. Why? According to James Andersen, president and CEO of GPUSA Inc., it's because developers are overthinking the problem.

Andersen displayed his alternative system at the recent Society of Exploration Geophysicists conference and met a woman from a major oil company who had been sent to the show to analyze the progress on marine vibrators. "She told me, 'I've looked at what they're doing, and they just don't seem practical,'" he said. "I agreed, and I showed her what we're doing. She said, 'That's so simple. I really think that's the way it ought to be.'"

The MV-24 uses opposed piston transducers run by a 6.3-hp motor that can drive the transducer from 0 Hz to 100 Hz at sweep rates from 3 sec to 30 sec in length. (Source: GPUSA)

Andersen's background as a naval engineering officer, which led to jobs at companies like Westinghouse and Litton, made him quite familiar with the technology being used to build marine vibrators. "When I heard there was interest in marine vibrators, I looked into it," he said. "I realized that this was the same technology that we were using in the '80s."

So Andersen tried a different approach. Rather than using magnets and ceramics to create the vibration, he's using a servo motor, common in automated factories, to drive pistons. The housing actually is a radial tire with flexible sidewalls to be able to accommodate the motion.

"What we're doing is just so simple," he said. "When we explain it to people, they say, 'How is it possible that nobody's ever done this before.'"

Another interesting facet is the fact that Andersen is trying crowd funding for his project rather than chasing venture capital. He got the idea from a Forbes Online article that predicts that crowd funding will outpace venture capital by year-end 2016.

Just before press time, an investor who contacted him through the site had agreed to fund the entire amount.

"Life is great, isn't it?" he said.

Ironically, the first test of the system will likely be on land. Andersen said that operators running vertical seismic profiles (VSPs) in areas where vibrator trucks aren't practical will dig a pit, line it, fill it with water and put in an airgun for the source. Not surprisingly, this is a rather messy procedure since the airgun tends to blow the water out of the pit. It's also not a particularly repeatable source.

"When they do a VSP with a Vibroseis truck, they'll do it over and over to get the best signal-to-noise ratio," he said. "An airgun is different each time, so they can't really stack the data.

"One company is interested in putting our system in the tank and running it 10 times. They've told me they'll get beautiful images."

Obviously Andersen is a long way from commercial production. But it's interesting to see a company approach a problem in a completely novel fashion. E&P

Rhonda

Too much supply, not enough demand will drive 2016 E&P spending

The average U.S. onshore rig count will fall by 29% in 2016 and will exit the year at 660 rigs.


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The end of the natural gas storage injection season was marked Nov. 20, 2015, with a new record for natural gas storage of slightly more than 113 Bcm (4 Tcf). With El Niño disrupting usual weather patterns, the warmer winter will likely end with a record amount of natural gas still in storage when the next injection season begins.

At the end of December 2015, total U.S. crude inventories were at 487.4 MMbbl, slightly below the record level of 490.9 MMbbl set in April 2015. Storage in Cushing, Okla., set a new record of 63 MMbbl, which was 800,000 bbl above the previous record reached in April 2015.

Supplies of natural gas and crude oil are outdistancing demand. Uncertainty in the Middle East and continued maximum production by Saudi Arabia exacerbate the problem.

In its 34th annual study of oil and gas companies' E&P capex issued Jan. 4, 2016, Cowen & Co. concluded, "the sharp declines in 2015 E&P spending will continue in 2016 both in North America and internationally. This will result in the largest two-year declines in spending since we began our survey [in 1982]."

Companies will have to batten down the hatches to survive a rough 2016. The Middle East is the only region expected to show a slight increase in spending. (Source: Corlaffra, Shutterstock.com)

Cowen's "Original E&P Spending Survey" estimated that "2015 global E&P capital expenditures will fall by 17% in 2016 to $447 billion. We would caution that the average price that these budgets are based upon is $48.50 per barrel WTI [West Texas Intermediate]. With current prices in the mid-$30 per barrel area and futures prices in the low $40s, there is downside risk in these budgets."

This year's survey was based on interviews of 450 companies, one of the largest surveys ever. The 185 companies surveyed in the U.S. plan to decrease upstream capex by 24% to $89.6 billion. In Canada, the 103 companies that were surveyed are budgeting a 22% decline.

"The cuts in U.S. E&P spending are broad-based and driven by reduced cash flows and uncertain economics," said Jim Crandell, senior research analyst covering oilfield services and offshore drilling at Cowen.

Marc Bianchi, an analyst covering oilfield services at Cowen, said that under a 24% decline in spending, this "scenario would result in a year-end 2016 rig count of about 660 vs. 685 today and an average 2016 rig count of 666—down by 29% vs. calendar 2015. The difference is increased capex per rig.

"We expect international E&P spending will decline by less in 2016 than North American spending. The outlook varies considerably by region, with companies based in Russia (-1%) and the Middle East (+1%) holding up well, and Latin America (-27%), Asia-Pacific (-21%), Africa (-18%) and Europe (-17%) being the weakest regions," he continued.

Companies that can navigate these rough seas will reap the benefits when the tide turns. E&P

Scott

Another piece placed in the production puzzle

A field trial of a new artificial lift approach delivers promising results in the Mississippi Lime play.

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Solving the puzzle that is unconventional production began more than 60 years ago with the setting of the hydraulic fracturing corner piece. Over time, advancements in technologies like directional drilling and the chemistries of fracturing fluids helped to fill in a few more gaps. New approaches to seismic acquisition and interpretation and drilling and completions optimization delivered greater initial returns. While work continues to fill in those areas of the puzzle, focus has turned more to increasing production over the life of the well.

Enhancing artificial lift systems is one of the many areas currently under examination. Two examples of such work are included in this month's unconventional artificial lift feature. One features a horizontal

The LEAP system is designed to adapt to the dynamic production profiles typical in most unconventional wells. (Source: Baker Hughes)

gas lift system that addresses the challenge of getting more with less, and the other explains how permanent magnetic motors can offer a huge cost savings when used in electric submersible pumps.

A third example was announced last month when Baker Hughes shared the results of a field trial of its new LEAP Adaptive Production System. The system was installed Dec. 12, 2015, at a depth of 1,585 m (5,200 ft) in the Mississippi Lime play in Woods County, Okla., for SandRidge Energy.

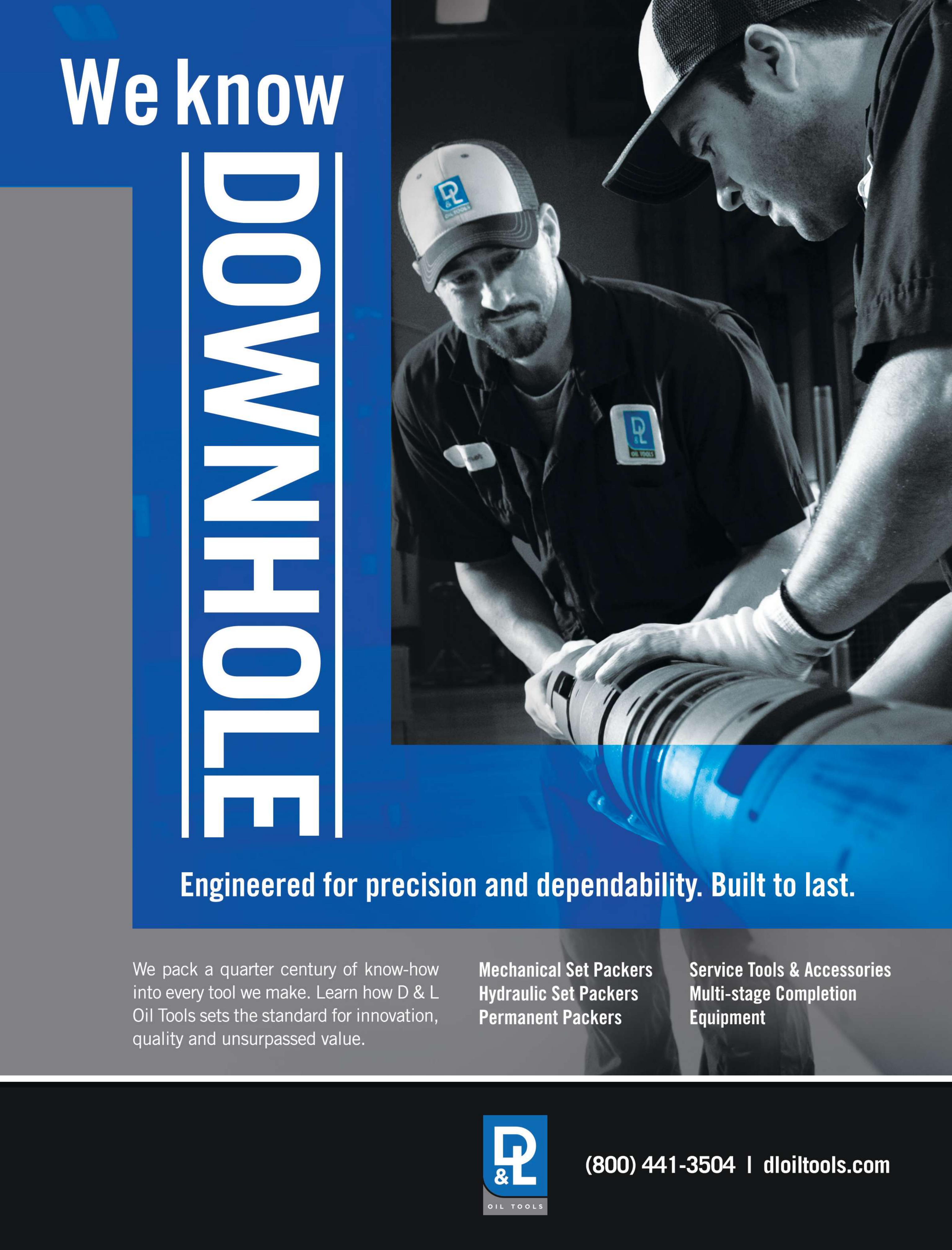
The entirely new approach to artificial lift delivered 300% greater oil production and 200% greater natural gas production at the trial compared to a previous artificial lift solution, according to a press release. In continuous operation since its installation, the system was seamlessly deployed through the deviated section of the wellbore and started on its first attempt with no issues.

"Until now, operators have had to use 100-year-old technology that was never intended to operate in deep horizontal wells or to handle the rapidly declining production rates and high gas volumes typical of unconventional reservoirs," Wade Welborn, vice president of artificial lift systems at Baker Hughes, said in the release. "As the first artificial lift technology designed specifically for these unique production challenges, the LEAP adaptive production system represents a step change in artificial lift technology."

The downhole system consists of a positive displacement pump, which can be installed to sit deeper in a well than traditional rod pumps; a submersible linear electromagnetically actuated motor, which drives the pump and eliminates the need for the long rodstring; and a sensor, which provides pressure and temperature data to help ensure the highest level of production optimization and system longevity, the release stated.

In addition, proprietary software built into the LEAP system surface variable speed drive integrates with downhole electronics to allow remote adjustments to the pumping system speed and stroke length as production rates change.

Time, effort, ingenuity and dogged persistence keeps the industry moving forward in its quest to solve the 100,000-piece jigsaw puzzle that is production from unconventional reservoirs. E&P



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Storm clouds gather over UKCS

Iona has become the first casualty of 2016, but many more North Sea companies are under threat from the plummeting oil price.

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EPmag.com

It has been a turbulent start to 2016 for the U.K. Continental Shelf (UKCS), with storms battering infrastructure and dark clouds hanging over dozens of companies operating in the region.

A fierce storm hit vessels and platforms at the beginning of January, causing the *Petrojarl Banff* FPSO vessel to lose tension in five of its 10 anchors and drift up to 250 m (820 ft), while Shell's Brent Delta platform also was damaged.

But it is the sinking oil price—which was hovering around the \$33/bbl mark at the time of writing—that is really wreaking havoc in the region and already has claimed its first victim of the new year.

Only six exploration wells are planned on the UKCS this year. (Photo by Harald Pettersen, courtesy of Statoil)

Iona Energy's U.K. subsidiaries, Iona Energy Co. (U.K.) and Iona UK Huntington, which were developing the Orlando Field in the U.K. Northern North Sea as a subsea tieback to the Ninian platform, have been forced into administration.

There are many other companies under threat. The struggling Norwegian Energy Co.'s U.K. subsidiary has been made to give up its stake in the Huntington license to partners E.ON UK and Premier Oil after failing to keep up with payments for costs.

First Oil, which has a 15% stake in the Kraken development, has reportedly been put up for sale, while the U.K. North Sea's largest independent producer, EnQuest, has seen its share price halved in the past year and is struggling with \$1.6 billion of debt.

Some 65,000 jobs already have been lost in the U.K. sector as a result of the oil price crisis, and this could be the tip of the iceberg.

Warnings emerged toward the end of last year when oil prices were about \$50/bbl that one-third of companies operating in the U.K. North Sea are at risk.

Another threat hanging over the region—that of strike action by members of the Offshore Contractors Association (OCA) who provide critical maintenance across installations on the UKCS—seems to have been avoided, though.

OCA members voted in a ballot to accept improved holiday entitlement and a joint review of the "three and three" equal time shift rotations. The agreement ends a prolonged dispute.

Unite Regional Officer Tommy Campbell said, "What our oil and gas sector urgently requires now is genuine cooperation between government, industry and the offshore trade unions to respond to this ongoing crisis, alleviating the pressure on the industry while protecting employment rights. This is the only way we can begin to build a safe and sustained recovery for the U.K. offshore sector."

The biggest threat of all, however, is likely to come from a lack of investment in exploration drilling because of the low oil price.

Only six exploration wells are likely to be drilled on the UKCS this year, the lowest hit rate since prospecting began back in 1964. This follows on from just 13 wells drilled last year.

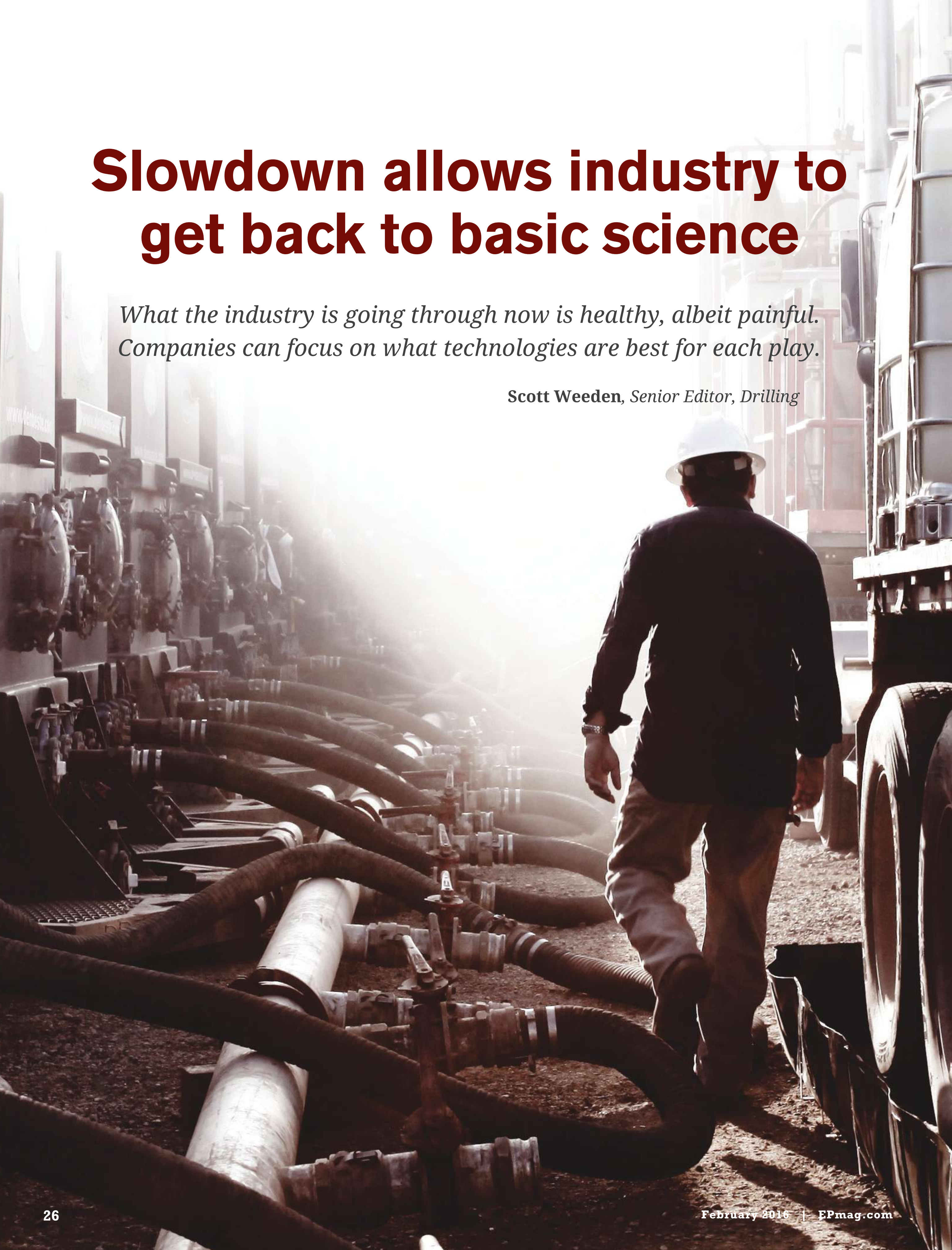
Without exploration to build on, the future is looking very bleak indeed. E&P

John

Slowdown allows industry to get back to basic science

What the industry is going through now is healthy, albeit painful. Companies can focus on what technologies are best for each play.

Scott Weeden, *Senior Editor, Drilling*



The hydraulic fracturing and horizontal completion business has been almost too successful for its own good. The advance in pad drilling that resulted in more efficient drilling in fewer days is just one example of why oil and gas production has remained high even with lower oil prices.

"In my opinion, most of the completion techniques continue to advance. They're getting better and better. And that is actually one of the problems in our industry. As we keep making better and better wells out of fewer and fewer wells drilled, that creates more gas and more reserves, which make prices economically stay down," said Glenn Hart, president and CEO, Laredo Energy.

"We were joking at a Christmas party, saying, 'Hey, why don't you stop drilling and fracturing, and I'm going to keep on doing mine,'" he laughed. "We're causing our own problems, in a way, with our success."

Ryan Hummer, executive vice president, strategy, NCS Multistage, agreed. "Obviously we can't predict the future, but we think this current low-price environment is likely to persist for a while. We're not going to be able to wait for prices to bail us out. Our conversations with our customers indicate that they are thinking the same thing. To cope with and make money in this current environment, they really need to continue to optimize completion designs and maximize how efficiently they can deploy capital."

Hart and Hummer were part of a roundtable teleconference *E&P* held to discuss the status of hydraulic fracturing, where the technology is headed and what technologies would be game changers for the industry in this price environment. The panel also included John Ely, president, Ely and Associates; Ted Randolph, fracturing engineering manager, NCS Multistage; Don Conkle, vice president, marketing and sales, Carbo Ceramics; and Joel Gay, president and CEO, Energy Recovery.

Q: *E&P: Is there a lower price limit in this environment? Is $35 oil about as low as prices can go?*

A: ELY (Ely and Associates): We have customers that are going ahead with completions but are a little nervous about getting much below $40, but very successful with $40 oil. When you get into the Bakken, some of that was questionable at $80 or $90. It depends on the reservoir and the capability of the reservoir to produce.

We're going to see substantial downturns if we stay at $36 or whatever it is today. There are so many of the reservoirs that we deal with where it's just not economic. The service company pricing is about down to a low ebb, completion costs have gone down and efficiencies have gone up dramatically, but there's a limit. I think we're getting there very quickly.

CONKLE (Carbo Ceramics): Let's hope it does not get much lower. The resiliency of the industry and operators in general has proven itself over the decades. Economics are normalizing as service costs come down with commodity prices. Most operators are refocusing on completing the best part of their reservoirs and spending more time evaluating the completions performed over the past few years as they now have more time with less activity. Every dollar they spend is important now as economics are slim. More engineering is being performed with solid evaluation to optimize completions. This makes the phase that we're in very exciting. It's not the best financial time for any of us, for sure, but it's a great time of learning and reflecting.

HART (Laredo Energy): The [lower limit is] an ever-moving target. Costs are changing constantly. Price is changing constantly. Certainly there are things that don't work economically today that worked a year or two ago, but there are still things that actually do work.

We are really rate-of-return-driven. If we can make a good enough return, with the cost being lower and yet the price being lower, we'll continue to do so.

THE PANEL

John Ely, President, *Ely and Associates*

Don Conkle, Vice President, Marketing and Sales, *Carbo Ceramics*

Glenn Hart, President and CEO, *Laredo Energy*

Ryan Hummer, Executive Vice President, Strategy, *NCS Multistage*

Joel Gay, President and CEO, *Energy Recovery*

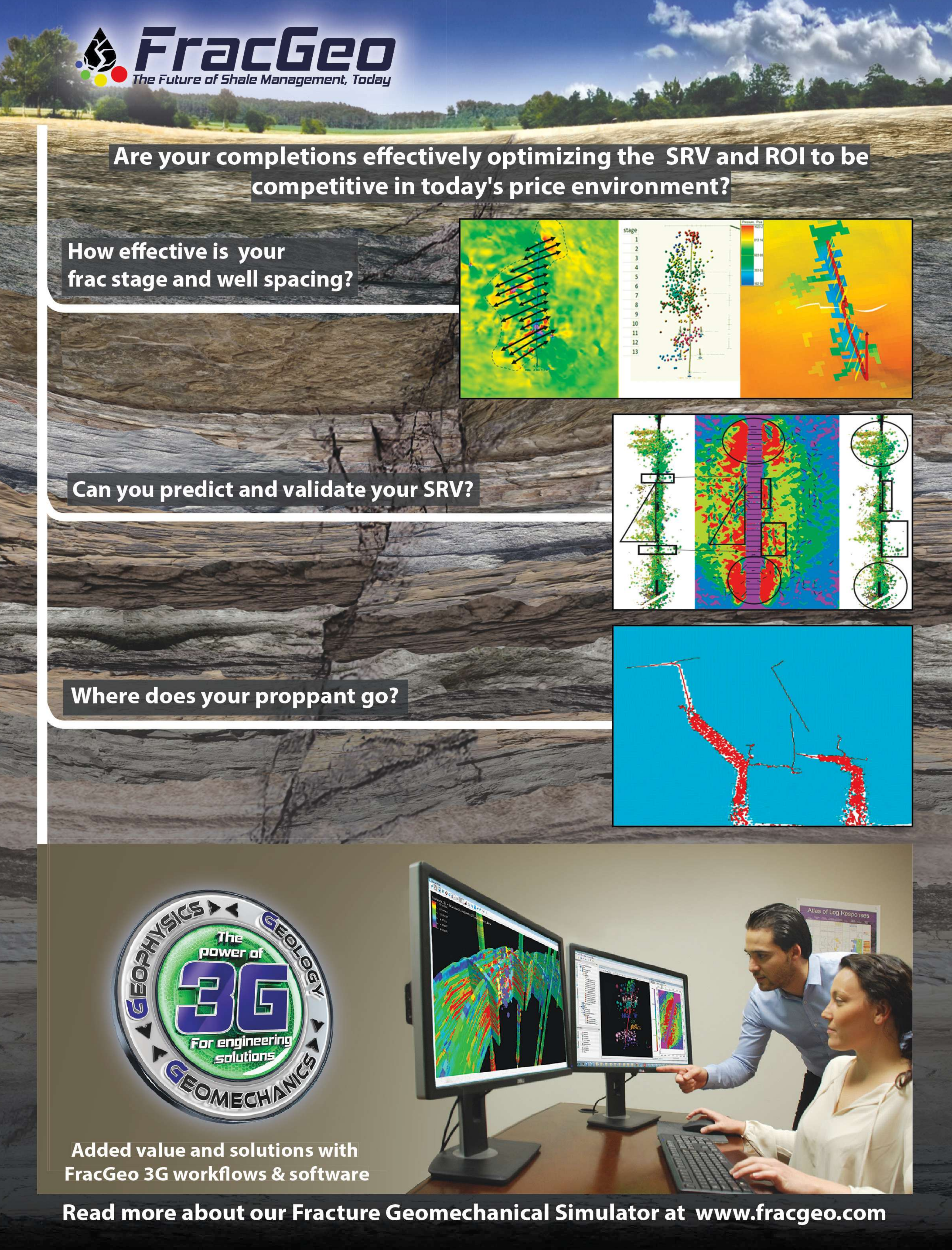
Ted Randolph, Fracturing Engineering Manager, *NCS Multistage*

It is another place I'd take Wall Street to task, where they make these broad-brush statements like the entire breakeven of the Bakken is 'x' dollars per barrel or the entire Permian Basin. That one really gets me. It is like, 'How many different horizons are out there in the Permian?' Come on! There are still economically attractive things even at today's prices. Though I'll grant you there are far fewer than there were a couple of years ago.

HUMMER (NCS Multistage): I've been amazed with how quickly the economics have adjusted, even as pricing has come down. Specifically in the Permian, there have been significant strides in lowering breakeven costs given the short amount of time that we as an industry have been pursuing horizontal wells there.

I think there's still work to be done. There's not necessarily a magic number. It is a moving target. As we do introduce technologies and learn more, certainly as an industry, we'll become more and more efficient producing hydrocarbons in the lower price environment.

Long-term I'm still bullish on North American unconventionals. What we're going through now is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healthy. We've probably learned more as an industry in the last 15 to 18 months than we have in the previous several years where the activity was so high there wasn't as much focus on costs.

Now everyone is laser-focused on making every improvement we can make, whether it's on the completion side, on the drilling side or reducing operating costs. It's actually an exciting time for the industry as we go through this, even though it's painful certainly for the services industry and painful for our customers as well.

GAY (Energy Recovery): One of the positive externalities of the energy depression has been a rejuvenation of operational efficiency as E&Ps, pressure pumpers and service providers alike attempt to streamline their cost structures such that they can continue to complete wells and generate revenues and ultimately cash flows in very challenging economic circumstances.

When we think about to what extent all of these new and exciting technologies can drive down the cost per barrel to fracture a well, we are not aware of any technology that even approaches a dollar, let alone $4 to $5 per barrel.

Q: ***E&P: What do you see as the current status of hydraulic fracturing?***

A: **ELY:** We're in a very interesting time, and it's been going on for several years, movement away from the more conventional fracturing crosslinked gel, viscous fluids. We're primarily using slick water or what I call pseudo-hybrid systems. We typically run some slick water, and for deeper reservoirs we use some very unstable crosslink fluids.

We've moved tremendously toward smaller sand. The dominant proppant in the market now is 40/70 and 30/50 proppant. But very rapidly, 100 mesh or very small 70/140 sand has moved into the forefront with success even in oil reservoirs. Much of this is counter to classical fracture theory, but it has led to success.

HUMMER: Things are changing on the fly a lot, as John [Ely] had mentioned. I think we're early in really optimizing unconventional development and improving resource recovery. How do we get more than 5% of the resource out of the ground? Obviously when we were in an $80 or $100 per barrel oil environment, prices covered up a lot of inefficiency.

There were high levels of activity that really drove a focus on the logistics of the completion as opposed to doing what was right for the reservoir. John mentioned a lot of the changes that customers are making to optimize. It's changing the completion designs, the fluid systems, tighter stage spacing, tighter cluster density and higher proppant concentrations.

We think there's still a long way to go, especially to learn about the reservoir and to get information to help us do things better. We're still in early innings, and we'll continue to make improvements. I think obtaining downhole information and utilizing it to drive optimization decisions are keys to accelerating those improvements.

CONKLE: The engineering of hydraulic fractures continues to evolve, driven by technology as well as better understanding of the more important parameters that drive production and recovery in each reservoir. Many operators have seen significant success by utilizing data-driven models that incorporate reservoir parameters with completion design to optimize both production and EUR. Operators have found that the four consistent parameters that are impacting production and recovery the most in low-permeability reservoirs are hydrocarbon content in the mud logs; effective permeability; propped hydraulic fracture contact with the reservoir; and conductivity of the fracturing, especially near-wellbore. Technology is quickly evolving,

A significant impairment to operators' lease opex and production is damage caused by scale, paraffin and other production-related problems. Proppant-delivered chemistry has prevented scaling for nearly two years in wells without any wells forming scale. (Source: Carbo Ceramics)

allowing the ability to impact the entry points at the wellbore as Ryan [Hummer] mentioned. It also is evolving to provide increased conductivity through the use of KRYPTOSPHERE or ultralow density proppants such as CARBOAIR, which help to prop the total height/length of the fracture area. We are likely in the fifth inning in understanding optimized completions, and with many reservoirs having only 5% to 10% recovery factors, there is great opportunity to maximize recoveries through proper completion design.

A new missile developed by Energy Recovery could cut the cost of hydraulic fracturing by an estimated $4 to $5 per barrel. Liberty Oilfield Services conducted a field test of the VorTeq missile in December 2015. (Source: Energy Recovery)

Q: ***E&P: What do you see as the current status of hydraulic fracturing from an operator's point of view?***

A: **HART:** I would say continually advancing technology. I think what we see is a little bit of a pause and a slowdown. Everybody's had an opportunity to go back and reexamine things pretty thoroughly. Now we have the benefit of a lot of completions where we can start to see what parameters matter. For example, that's where I see not so much new things but optimizing of things.

Q: ***E&P: What would be a game changer for hydraulic fracturing in this environment?***

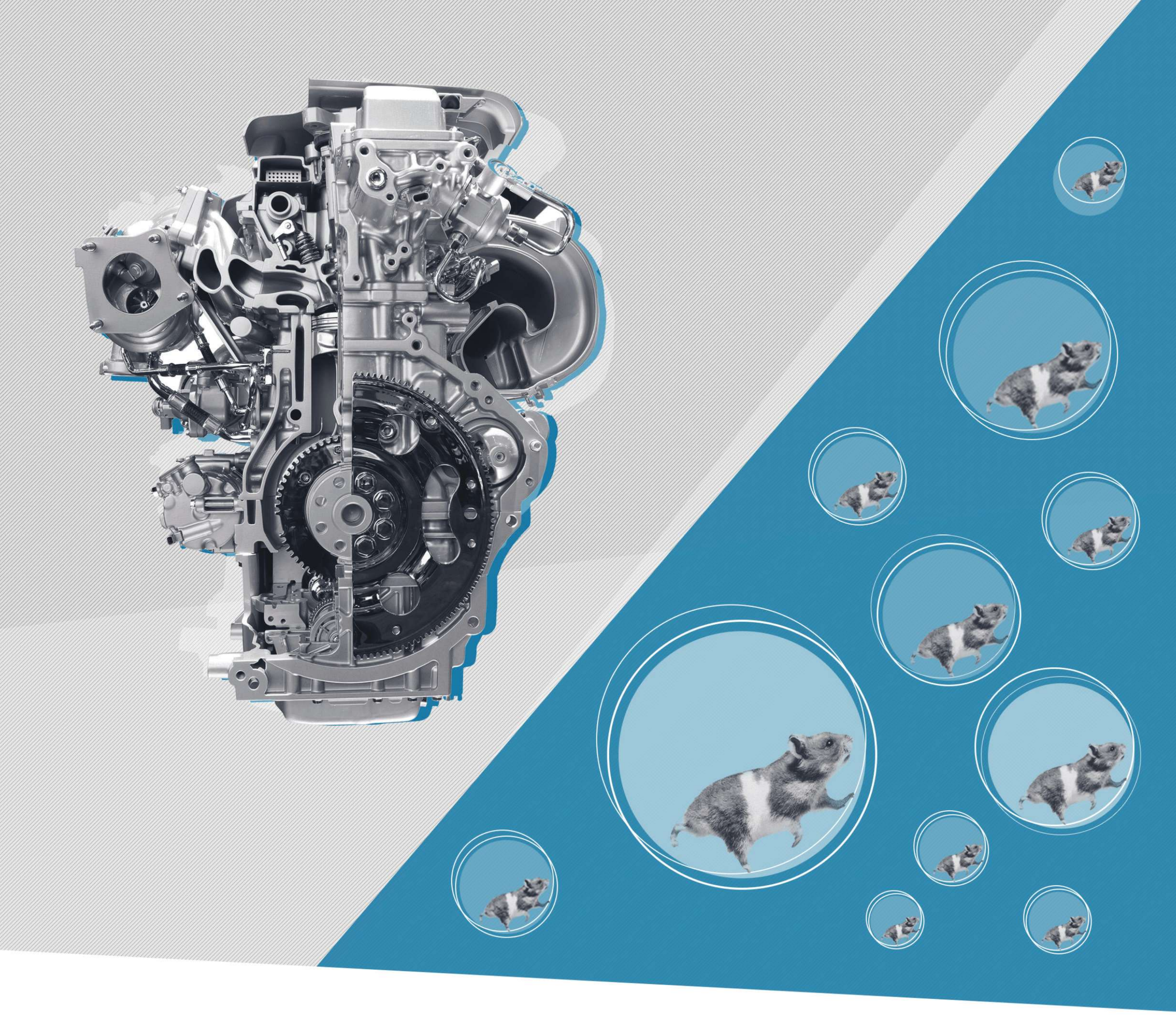
A: **ELY:** For me with EMP [electromagnetic producing] technology, it's a company called Deep Imaging Technologies. I think it's in very early stages, but it should be able to tell us where the fluid is moving and where the proppant is in the reservoir. That's exciting; that's a game changer. That will drive all the modelers crazy if we really know where everything is. If we know where the proppant is, we can spot our wells. We're not going to drain anything in these ultratight reservoirs that we don't prop open and create massive surface area.

Laredo Energy continues its operations in Webb County, Texas. Glenn Hart, Laredo president and CEO, said if the company makes a good enough return, even with the cost being lower and the price being lower, it will continue to do so. (Source: Laredo Energy)

CONKLE: Technologies that aid operators in decreasing their F&D [finding and development] cost/boe for each well and their field in general are critical in today's environment. As hydraulic fracturing is a significant cost to the operator, understanding the length and height of your propped fracture volume or propped reservoir volume will allow a better designed field development plan, potentially allowing significantly fewer wells to be drilled to develop a field. A proppant that is detectable will be critical to achieve this. Development is ongoing with CARBO in this area, with positive tests already witnessed.

Another significant impairment to operators' lease operating expenses and production is damage caused by scale, paraffin and other production-related problems in the near wellbore area and within the tubulars. Placing proppant-delivered chemistry within the fracture, which can dissolve slowly from the proppant grain for multiple years, is having a significant impact on operator's opex budgets. The CARBO GUARD technologies have prevented scaling for nearly two years in wells without any wells forming scale with more years expected.

RANDOLPH (NCS Multistage): In earlier days of vertical well completions, it was all about connectivity with the reservoir and focusing the treatment for the reservoir, whether it was more fluid or higher proppant concentrations. Once we had geological information up front, we could make decisions and start optimizing designs. Then we could



Drilling and fracturing multiple wells from a single pad improved the efficiency of drilling and completion operations. Technology advancements continue to increase both production and EURs. (Source: Liberty Oilfield Services)

come back, evaluate it and make sure that all of our upfront assumptions were right.

It was always about doing what was right for the reservoir. I think we lost a little bit of focus on that as we went into horizontal wells. I think we started focusing on fracture designs around the completions as opposed to the reservoir. I think we have an opportunity to refocus and start thinking about how can we do things better—we can get back to doing what's right for the reservoir. Game-changing results in horizontal wells will come from utilizing technologies that would economically get not just upfront reservoir information but also downhole data during completions operations to allow us to customize completion designs and better optimize based on reservoir characteristics and responses.

GAY: We believe that the VorTeq technology that we recently licensed on an exclusive basis to Schlumberger will be one of the greatest breakthroughs. However, we don't expect commercialization until 2017. Pump failure is the greatest pain point in that industry and certainly causes operators the most heartache, resulting, of course, in inordinate operating and capital expenditures.

There's been a tremendous amount of research over the last 10 years on rotating equipment and hydrodynamics to extend the life of the reciprocating positive-displacement pumps. Now, unfortunately, the existing pumping technology is 40 to 50 years old, and the R&D efforts are best described as marginal.

The VorTeq allows the complete isolation of the pumping technology from the proppant, which we believe represents a step change. As we think about the current fracture ecosystem, you've got a tremendous amount of horsepower at any given wellhead. Our VorTeq missile allows the transformation of that fracturing ecosystem where you could at some point reduce the number of pumps required from 20 down to three or four large centrifugal pumps. In addition to an economic value standpoint, there's also a tremendous safety and carbon footprint advantage to the VorTeq as well as the savings associated with that, specifically in the depreciable expense and the R&M [repair and maintenance] associated with these centrifugal pumps. We believe that we can drive down the cost per barrel to fracture a well by $4 to $5.

Editor's note: The interview continues on epmag.com.

Maintaining well productivity with effective multistage refracturing

Degradable diverter offers another option in zonal isolation and diversion.

Andrew Babey and **David Arnold**, Weatherford

Technology advances for horizontal drilling, fracturing and multistage completions have contributed to the 65% growth in U.S. oil production in the last five years, with a significant portion of this increase coming from shale plays. However, operators in shale plays often struggle to sustain IP rates, which can decline by up to 80% within the first year. Operators have traditionally resorted to drilling more wells to offset the drop in production. As the current economic climate forces the industry to identify more time- and cost-effective methods for prolonging the productive life of shale wells, refracturing is quickly becoming the preferred alternative, especially for wells with completion inefficiencies that hinder production or leave significant untapped hydrocarbon reserves.

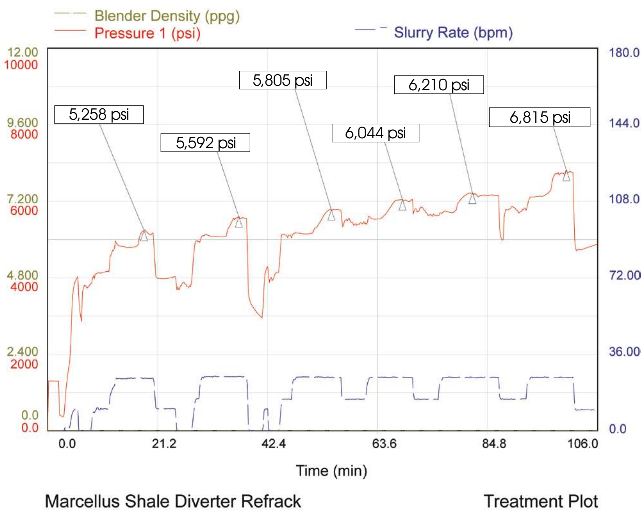
The agent has a pellet-like appearance at the surface but, once in place downhole, transforms to create a wall that separates individual fracturing stages or seals existing perforations. This barrier is much less permeable than traditional degradable diverters; withstands higher treatment pressures; and dissolves only at a precise, preplanned time. (Source: Weatherford)

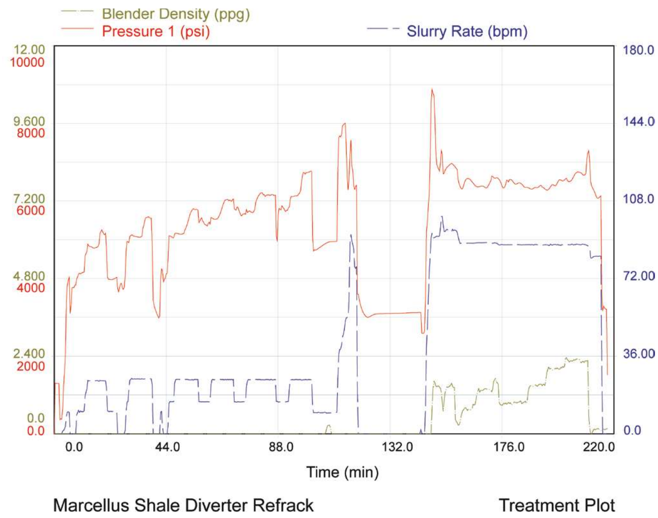
Limitations of traditional refracturing techniques

There are three approaches for refracturing wells: treating existing unproductive perforations, sealing existing perforations and targeting new or previously bypassed pay zones, or using a combination of these approaches. There are several methods to do this, but some have drawbacks, particularly in multistage fracturing operations. Sliding-sleeve completion systems are highly efficient and accurate but costly. Although sophisticated zonal-isolation tools can be installed using coiled tubing (CT), the small inside diameter of CT results in low rates and proppant concentrations and limits the treatment design. Additionally, CT can be costly and may have availability issues. A perforation squeeze can be performed during which cement is used to seal existing perforations, but this can eliminate all existing perforations and can damage producing fractures.

Alternatively, degradable mechanical diverters can be used to isolate zones and to direct stimulation fluids on a temporary basis at a lower cost without logistical limitations and with minimal formation damage. Mechanical diversion is a well-known and increasingly popular method of refracturing wells because of its simplicity. This approach involves pumping a diverter downhole in fracturing fluid, where it then forms a seal over existing perforations or directs fracturing fluid to new zones. By dissolving downhole, degradable diverters eliminate milling, reduce wellbore cleanup and save time, all of which helps to decrease operational costs.

However, traditional degradable diverters—such as balls, degradable ball sealers, rock salt, dissolvable flakes and high concentrations of sand—are unreliable for multistage fracturing operations because they do not provide the optimal level of zonal isolation, nor do they maintain an intact seal for the periods of time necessary for treatment. Balls or degradable ball sealers unseat from perforations without a constant application of pressure, rendering them ineffective if a refracturing operation needs to be halted. Rock salt and flakes have a short lifespan—as low as a few hours—before dissolution, which is usually not enough time to refracture an entire lateral.





These pressure plots show the results of the agent deployed as part of a Marcellus Shale refracturing operation. The left plot shows the results of pumping and displacing six batches of the TBlockSure agent, which increased pressure to more than 6,500 psi and initiated treatment of new perforations. The right plot provides an overview of first-stage fracturing treatment with the TBlockSure agent as it seals existing perforation clusters. (Source: Weatherford)

Evolution of degradable diverters

As horizontal multistage fracturing becomes commonplace, there is an increased need for longer lasting, more reliable diverting technologies such as advanced degradable diverters. The Weatherford TBlockSure diverting agent and stimulation enhancer is a solid material—made of a proprietary degradable mesh—that provides superior isolation and diversion compared to traditional diverters.

Degradable diverters can be deployed easily and with minimal equipment requirements, which is beneficial from a cost-reduction standpoint. The only equipment required at the well site is the agent and a dedicated pumping unit that can be easily installed at the wellhead. Although the agent is compatible with standard pumping equipment, using the specialized separate pumping unit prevents the agent from contaminating other equipment in the fracturing fleet by remaining in the valves and seats in the fluid ends of fracturing pumps.

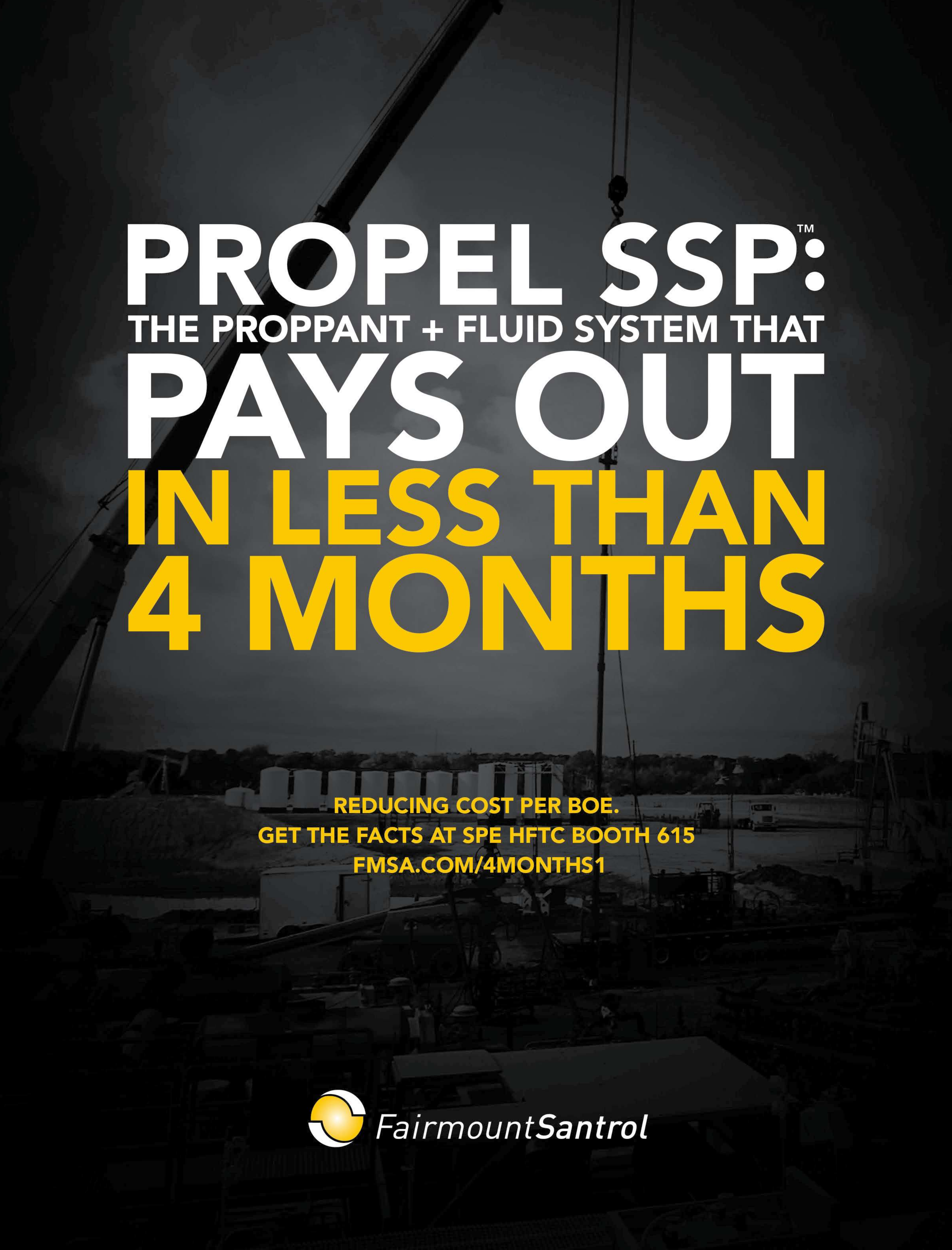
The agent is then simply pumped downhole using either slick water or, more commonly, a viscous fracturing fluid. It can be deployed in any well regardless of borehole size, geometry or the original fracturing method used. Additionally, the TBlockSure agent is available in a high-temperature version for environments between 82 C and 149 C (180 F and 300 F) and a low-temperature version for environments between 54 C and 82 C (130 F and 180 F).

Once in place, the agent creates an enhanced zonal barrier or perforation sealant that withstands high treatment pressures. Only at a predetermined time—depending on the bottomhole temperature, the duration of exposure to the temperature and the pH—the mesh dissolves into liquid form to reopen fractures or perforations and to enable flow. No secondary treatment is required to start the degradation process. However, chemicals such as breakers or pH-adjusting agents can be added to the TBlockSure agent to control how quickly or slowly the material degrades. Although the degradation process requires shut-in time, this time can be used to prepare production facilities and should not cause a significant delay to operations.

Case study

A Marcellus Shale operator used the agent to refracture a 1,981-m (6,500-ft) horizontal gas well with a measured depth of 2,865 m (9,400 ft) and bottomhole temperature of 49 C (120 F). The operator initially screened out existing perforations with high concentrations of sand and, using the plug-and-perf method, created new perforations between the existing perforations. There were 26 existing clusters with 312 perforations and 24 new clusters with 192 perforations. The operator sought a more robust solution for isolating existing perforations and for diverting stimulation fluid to new perforations more effectively.

Weatherford pumped the agent downhole in six batches at a rate of 25 bbl/min. After the sixth deployment of the agent, a sharp spike in the treating pressure to more than 6,500 psi indicated that the existing perforations were sealed. At this point, the new perforations could be targeted with stimulation fluid and the first fracturing stage begun. The agent withstood treatment pressures needed to break into the zones. E&P



A Safe License to Operate

The safety of E&P employees is the top priority.

The industry's occupational safety record has improved greatly in recent years, with standards, processes, training, equipment and materials constantly evolving. An estimated 1.5 million people are engaged in oil and gas E&P activities around the world.

Recent analysis of annual company data and reports by DNV GL show a tenfold reduction in reportable incidents per 200,000 man hours over the last 20 to 30 years when lost-time injuries are excluded.

DNV GL noted organizations such as the International Regulators Forum along with industry bodies such as the American Petroleum Institute, Norwegian Oil & Gas Association, International Association of Drilling Contractors and the classification societies take an active role in sharing information and trends that help improve global safety. The new OGP (International Association of Oil & Gas Producers) 456 Recommended Practice on process safety is another recent example of such collaborative efforts.

Having the best available equipment, training, clothing and accessories to help protect employees makes these safety improvements possible. On the following pages, a sampling is provided of companies and their products that enable operators and service providers to employ best industry practices in their pursuit of exemplary safety records.

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

Footwear prevents chafing and offers comfort, slip resistance

Ansell has released its DuraPro footwear that provides workers' safety and comfort through many product features. These include a sloped comfort top rim that prevents chafing and reduces discomfort when walking, bending and kneeling; a 360-degree pull tab for easy donning; a larger circumference at the top that makes it quick and easy to pull the boot on; superior shock absorption, support and comfort from the specially designed DuraPro insole; a honeycomb design molded inside the heel to reduce impact when walking; an ergonomically designed foot-bed to provide better underfoot support; and protective bumpers at the rear of the boot to prevent premature wear/puncture. *ansell.com*

Women's work wear features moisture management

The Ariat FR Polartec Powerstretch Jacket for women features flame resistance, greater arm mobility and moisture management technology to keep workers cool and dry. (Source: Ariat)

Ariat provides Western apparel that now includes flame-resistant (FR) work wear for women. The company has released its first Ariat Work FR line specifically designed for women with premium technology and safety features for hazardous work environments as well as style, fit and comfort. Similar to its male counterpart, the Ariat FR Polartec Powerstretch Jacket for women features permanent National Fire Protection Association (NFPA) 2112 and NFPA 70E flame resistance, greater arm mobility and moisture management technology to keep workers cool and dry. Ariat also made specific design choices that flatter every body type and help avoid the look of traditional boxy work wear. The jacket also provides a dual-hazard compliant fabric. *ariat.com*

FR jeans provide dual-hazard protection

Carhartt's new FR Rugged Flex jeans include triple-stitched main seams and are 99% cotton. (Source: Carhartt)

Carhartt FR is designed to help keep crew protected and comfortable. Carhartt's new flame-resistant (FR) Rugged Flex jeans' stretch technology provides for ease of movement and dual-hazard protection. The pants' traditional fit sits at the waist with a slim seat and thigh. The arc-resistant button closure at the waist and the brass zipper fly with Nomex FR zipper tape provide complete FR protection. This product is made of 12.5-oz. FR denim and is 99% cotton and 1% spandex. Other features include triple-stitched main seams and two back pockets. The garment is washed for a soft finish. This meets the performance requirements of National Fire Protection Association (NFPA) 70E and is UL classified to NFPA 2112. *carhartt.com*

Flame-resistant shirt increases wearer mobility

The Bulwark iQ Series Comfort Woven flame-resistant shirt is designed to increase comfort and performance. As light as sportswear, the iQ Comfort Woven shirt increases wearer mobility through functional design elements like stretch-woven mobility panels on the back and full-side seam gussets. Concealed and side-zip Napoleon pockets also provide extra storage. The shirt is National Fire Protection Association 2112 compliant. *bulwark.com*

The Bulwark iQ Series Comfort Woven flame-resistant shirt features concealed, side-zip pockets. (Source: Bulwark)

Performance work wear is based on a layering system that allows for quick adjustments for activity level and changes in environment. (Source: DragonWear)

FR protection cannot be worn away or washed out

DragonWear offers a full line of comfortable flame-resistant (FR) performance work wear based on a unique layering system that allows for quick adjustments for activity level and changes in environment. The FR properties of the fabrics utilized are not chemically treated but are inherent within the fiber, which means protection cannot be worn away or washed out. DragonWear's new FR and arc-rated Cold Warrior convertible balaclava protects against punishing temperatures and the hazards of the job. The top has high/low interior grid construction that maximizes warmth yet promotes breathability, while the bottom has a wind-resistant outer surface with a lofted fleece interior to retain body heat. The company's Elements flak jacket is a fusion of Polartec's Wind Pro and the new patented HardFace FR fabrics. This garment provides weather protection and rugged usability. This dual-hazard hooded hybrid has CAT 2 protection and combines the best features of a versatile hooded outer layer with a built-in fleece balaclava. The jacket is designed to transition a worker through the daily hazards of the job to the most rigorous off-duty adventure. *dragonwear.com*

Company offers variety of safety courses

EnerSafe boasts that it uses the best talent in the industry and the latest learning conventions to deliver an outstanding training experience. The company's trainers are certified professionals who can provide a variety of safety courses. They specialize in hydrogen sulfide (H_2S) courses based on ANSI z390.1; these include an H_2S initial course, H_2S refresher course, H_2S man-down training drills and the new PEC H_2S end-user training as well as respirator fitting. EnerSafe teaches confined space, fire safety and core courses including back safety; bloodborne pathogens; electrical safety; Globally Harmonized System/hazard communication; incident investigation/workers' comp; personal protective equipment and respiratory safety as well as slip, trip and fall (working surfaces) training. Additionally, equipment safety services include excavation/trenching safety and man-lift safety as well as crane, forklift, backhoe and trackhoe safety courses. *enersafe.com*

EnerSafe offers hands-on CPR and general first-aid training. (Source: EnerSafe)

Foot-warming pack for workers on the cold shift

Ergodyne has released the N-Ferno Disposable Foot Warmer (Model 6995). This one-size-fits-all foot-warming pack helps workers do their job well and comfortably at any indoor or outdoor jobsite where the thermometer knows only one reading: cold. The foot warmer's all-natural ingredients heat up quickly as soon as they come in contact with oxygen and can warm feet for up to 7 hours. Plus, they can be sealed in a plastic bag and reused the next day. *ergodyne.com*

The N-Ferno Disposable Foot Warmer can be sealed in a plastic bag and reused. (Source: Ergodyne)

Gas detection monitor communicates alarm status in real time

GDS Corp.'s GDS-58NXP Sample Draw Monitor provides highly reliable gas detection, easy installation and maintenance, and an ultrabright color screen that communicates alarm status in real time. The GDS-58NXP includes a GASMAX CX gas monitor, sample pump, visual flowmeter and low-flow warning switch in a single convenient package. The GDS-58NXP can be installed up to 152 m (500 ft) from HVAC air ducts, sumps, cabinets and other hard-to-access locations, eliminating the need to install sensors in hard-to-reach, hard-to-calibrate or easy-to-forget areas. The GDS-58NXP Sample Draw Monitor can detect one or two gases simultaneously and features standard 4-20mA output as well as RJ-45 Ethernet with MODBUS/TCP and a built-in web server. Relays and dual serial MODBUS also are available. *gdscorp.com*

The GDS-58NXP Sample Draw Monitor provides gas detection and an ultrabright color screen that communicates alarm status in real time. (Source: GDS Corp.)

BW Technologies portable gas detectors feature compact size; simple-to-use, one-button operation; and reliable performance in extreme environments. (Source: Honeywell Analytics)

Gas detectors pack new technology into small footprint

Honeywell's BW Technologies portable gas detectors are designed to keep workers safe and productive. In addition to the characteristic canary-yellow housing, these detectors have many distinguishable features: compact size; simple-to-use, one-button operation; reliable performance in extreme environments; and affordability in both single-gas and multigas formats. Recently, many technological innovations have been built into this detector line by Honeywell's global engineering team. Depending on model, choices might include extended battery runtime; high-performance oxygen sensors; IntelliFlash visual compliance check; and compatibility with IntelliDox instrument management system for extremely quick bump tests, bump test tracking, adjustable set points and more. The BW Clip is a new single-gas detector that delivers up to three years of personal protection with no need for calibration, sensor replacement, battery replacement or battery charging. GasAlertMicroClip X3 is a new four-gas monitor that features an all-new oxygen sensor with a five-year life expectancy, an ingress protection rating of 68 for multigas units and a three-year warranty. *honeywellanalytics.com*

Docking station maintains, monitors gas detectors

The DSX Docking Station is a new gas detector maintenance and record-keeping station from Industrial Scientific. The DSX easily maintains the gas detectors that keep people safe in hazardous oil and gas environments. The docking station is designed to ensure that instruments are always ready for use without the burden of manual bump testing and maintenance routines. Users no longer need to worry about calibration gas; the DSX monitors and orders replacement gas cylinders when needed. Users can effortlessly manage

The DSX Docking Station helps maintain gas detectors. (Source: Industrial Scientific)


ORHD®
THERMAL
KNIT
CR3
CUT LEVEL 3
The ORHD® Thermal Knit features 10-gauge thermal acrylic insulation for cold conditions and delivers CE level 3 cut resistance to the palm and fingers.
EN 388
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3342
ORHD®
CUT RESISTANCE
IMPACT PROTECTION
ORHD®
KNIT
CR3
CUT LEVEL 3
The ORHD® Knit CR3 features a 13-gauge outer that form fits the hand and delivers CE level 3 cut resistance to the palm and fingers.
EN 388
CE
4341
ORHD®
KNIT
CR5
CUT LEVEL 5
The ORHD® Knit CR5 features a 13-gauge outer that form fits the hand and delivers CE level 5 cut resistance to the entire hand.
EN 388
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Women can now have safety on the job without the inconvenience of wearing men's or unisex-sized uniforms. (Source: LAPCO FR)

FR clothing for the modern working woman

LAPCO FR has released its new ladies flame-resistant (FR) clothing line, which includes FR Advanced Comfort Uniform shirts and pants and FR Classic Fit and Modern Fit jeans, made to fit and flatter all women. Women can have safety on the job without the inconvenience of wearing men's or unisex-sized uniforms. All are available in misses and women's sizes. All items in the line are UL classified to National Fire Protection Association (NFPA) 2112 and ASTM F1506 and are compliant with NFPA 70E to meet the needs of women in various industrial fields. *lapco.com*

FR denim fabrics mimic everyday denim

Westex Indigo offers FR denim flex fabrics to enable workers to move, bend and climb freely as their job requires. (Source: Milliken)

Safety, comfort and ease of movement are critical for today's workers, and comfortable flame-resistant (FR) denim is increasingly becoming workers' fabric of choice. Westex by Milliken's new Westex Indigo offering features FR denim fabrics for FR denim jeans and work shirts that provide flash fire and arc flash hazard protection. The Westex Indigo denim line includes a range of weights, constructions and shades in 100% cotton and cotton/synthetic fiber blends matching the comfort and styling of everyday casual wear. The Westex Indigo line also features FR denim flex fabrics to enable workers to move, bend and climb freely as their job requires. The result is safety, comfort and ease of movement to help workers be as productive and as safe as possible. *westex.com/fr-fabric-brands/indigo/*

Portable gas detector designed to save time, calibration gas

The ALTAIR 2X line of portable gas detectors incorporates XCell sensor technology. (Source: MSA)

The ALTAIR 2X line of portable gas detectors from MSA offers the first one- or two-gas detector that incorporates XCell sensor technology. Stability, accuracy, repeatability and fast response have characterized the MSA XCell sensors. The ALTAIR 2X Platform delivers unparalleled performance while drastically minimizing total cost of ownership, increasing durability and delivering enhanced worker safety, compliance and traceability. Built with XCell Pulse Technology, this platform includes the new ALTAIR 2XP Detector, which introduces the world's first standalone bump test that does not require calibration accessories or bottled gas to complete a daily bump test. Workers will spend less time at the bump station, which means less down time, giving them more time to be productive. *MSAsafety.com*

Software collects, analyzes safety data

SafetyNet is a leading safety management system for saving lives by predicting workplace injuries. The Safety Net system helps users collect and analyze safety data, enabling them to predict and prevent injuries. It is the only software solution in the world that can answer the question, "Will I have an incident tomorrow?" *predictive-solutions.com/safetynet*

Gloves offer impact protection for hand safety

The R-160 and R-161 gloves offer impact protection and allow workers to get into limited spaces without sacrificing protection. (Source: Ringers Gloves)

Ringers Gloves, provider of hand safety solutions for the oil and gas industry, has expanded its light-to-medium-duty product lines to heighten dexterity for certain tasks and applications. The R-160 and R-161 gloves address the needs of mechanics, supervisors and technicians who need to stay compliant by wearing a glove with impact protection but also need to be able to get into limited spaces without sacrificing protection. *ringersgloves.com*

SRP Environmental can create an environmental safety training program suited for specific business needs. (Source: SRP Environmental)

Training employees on how to use, wear safety products

SRP Environmental safety consultants provide active training so employees will be able to properly utilize the safety skills learned in a real-world setting while meeting Occupational Safety and Health Administration safety training mandates. The company offers HSE training to educate both employers and employees. The certified safety training instructors use a combination of audiovisual presentations and equipment to produce real-life on-the-job scenarios and hands-on real-life situations to provide each individual with a better understanding of safety on and off the job. *srpenvironmental.com*

Antimicrobial and odor protection for clothes, equipment

Microbes such as bacteria and fungi thrive in moist conditions like boots, gloves or under work uniforms. Commonly found microbes on industrial sites or in industrial living quarters include athlete's foot, Methicillin-resistant Staphylococcus aureus and E. coli. SRP SilverClean uses its patented SilverClean technology to provide antimicrobial and odor protection to socks, t-shirts and towels. This is accomplished by harnessing the antimicrobial power of nano silver. SilverClean products continuously kill microbes at the source and are ideal when laundering services aren't readily available or when working in unsanitary conditions. *srpsilverclean.com*

SRP SilverClean provides antimicrobial and odor-eliminating products that are infused with nano silver. (Source: SRP SilverClean)

Boots provide underfoot comfort and are easily removable

Steel Blue boasts that its Argyle Zip boot is one of the safest and most comfortable boots available. Getting in and out of boots is easy with the conveniently located zip release. Steel Blue boots offer superior underfoot comfort with their patented Tri-Sole Comfort Technology. The company claims that the boots reduce fatigue and lost-time injuries while increasing employee productivity. Breaking in isn't needed. The company offers a wear trial, with a 60-day 100% comfort guarantee. *steelblue.com*

Getting in and out of the Argyle Zip boots is easy with the conveniently located zip release. (Source: Steel Blue)

Tool provides real-time wireless communication

Sunnyside Supply's Spotter Buddy can reduce injury to workers and damage to equipment as it allows the spotter and driver to communicate in the field along with keeping the spotter out of the dangerous pinch zone. The product comprises a transmitter and a receiver. The drivers will have a portable receiver box mounted to their mirror frame with a red light and audible to signal the driver to stop, a green light that allows the driver to back up slowly, and right and left turn signal arrows. The spotter will have a transmitter with a button pad that will send radio frequency signals to the driver's receiver box. The spotter will engage an emergency stop switch (ESS) on the transmitter, which will activate the green light on the driver's receiver box. If the spotter were to fall, the transmitter would disengage the ESS and activate the red stop light/beeper on the driver's receiver box, signaling the driver to stop. *sunnysidesupply.com*

Spotter Buddy allows the spotter and driver to communicate in the field along with keeping the spotter out of the dangerous pinch zone. (Source: Sunnyside Supply)

Choosing the correct hand protection

The TenActiv anti-impact, high-visibility glove is made with Black Widow grip micropore nitrile. (Source: Superior Glove)

More than 60% of injuries reported by oil and gas workers occur to the hand. According to the latest data from the National Safety Council, the average cost of a single hand injury is $21,918 (for both indemnity and medical costs). Since most "general purpose" gloves won't fully protect hands against all types of hazards, workers should choose gloves that are specifically designed for the oil and gas industry and its corresponding risks—such as one of Superior Glove's many TenActiv anti-impact styles. *superiorglove.com*

Portable measurement device provides traceability of torqued connections

The E-Wrench is a portable torque measurement device designed to ensure threaded connections are torqued to spec. (Source: Thru Tubing Solutions)

Thru Tubing Solutions' (TTS) E-Wrench is a portable torque measurement device designed to ensure threaded connections are torqued to spec. Incorporating a jaw-locking mechanism to secure the E-Wrench to the tools being torqued reduces the number of required personnel near the wellhead. TTS designed the E-Wrench to reduce the exposure of personnel working under overhead loads, to provide traceability of every torqued connection and to provide accuracy, thus reducing the risk of damaging tool joints and/or leaving a fish downhole. *thrutubing.com*

FRC repels insects

Biting insects present a significant challenge for outdoor oil and gas workers. Complicating the issue, many insect repellents are flammable and should never be used with flame-resistant clothing (FRC). Tyndale offers exclusive FRMC (flame-resistant modacrylic cotton) garments with durable Perimeter Insect Guard, a nonflammable repellent that is safe for use with FRC and repels insects for 50-plus launderings. Perimeter technology has been used by the U.S. Army for more than 20 years and as standard issue for the Marines since 2007. It's approved and recognized by the Environmental Protection Agency and Centers for Disease Control and Prevention as a safe and effective method of preventing insect-transmitted diseases. *TyndaleUSA.com*

Tyndale offers exclusive FRMC garments with durable Perimeter Insect Guard. (Source: Tyndale)

Gloves help reduce hand injuries prevalent in oil, gas environments

Wells Lamont Industrial, a U.S. manufacturer of hand and arm protection, has released the FlexTech I2459, an ANSI Cut Level 5 palm-dipped impact glove. The I2459 provides an extra level of protection to the back of the hand and fingers. The soft and flexible thermal plastic rubber pads protect hands from impacts and blows. Additionally, the sandy nitrile palm coating enables a firm grip in wet and oily applications. Manufactured using a unique blend of high-performance fibers and stainless steel, the glove delivers protection in a form-fitting, comfortable machine-knit shell. Made to withstand repeated wear, the I2459 stands up to the harsh conditions of oil and gas, mining, and heavy construction. Its orange pads promote greater hand visibility compared to competitive styles. I2459 is available in sizes small to XXL. *wellslamontindustrial.com*

The FlexTech I2459 gloves were made for tough environments where hand and finger injuries are most common. (Source: Wells Lamont Industrial)

Ultralightweight FR clothing offers more comfort

Workrite Uniform Co. Inc. has released its flame-resistant (FR) product line featuring 5.3-oz. GlenGuard fabric. The new Workrite FR GlenGuard 5.3 line offers one of the lightest-weight category 2 fabrics available. Produced by Glen Raven, the GlenGuard fabric offers an arc thermal performance value of 9.5 cal/cm2 and is UL certified to National Fire Protection Association 2112. This new line aims to increase wearer compliance by providing an unprecedented level of comfort and protection. "Unfortunately, some FR garments can be heavy or

The new GlenGuard 5.3 FR clothing line features one of the lightest-weight category 2 fabrics available on the FR clothing market. (Source: Workrite Uniform Co. Inc.)

cumbersome, prompting workers to increase their comfort level by rolling up their sleeves or untucking their shirts—exposing them to greater risk or injury," said Mark Saner, Workrite Uniform technical manager. The new Workrite FR line includes coveralls, shirts and pants in a variety of colors. The garments also offer moisture management, durability and exceptional colorfastness. *workrite.com*

FR jeans offer comfort, durability and protection

Wrangler has released the Wrangler Flame-resistant (FR) Advanced Comfort jeans, the newest extension of the brand's performance apparel featuring four-way flex technology. Wrangler partnered with Westex by Milliken to engineer the Wrangler FR Advanced Comfort jeans. Milliken provided the latest advancements in FR fabric development with Westex Indigo, a new line of denim. The fabric, which is made of a unique blend of fibers designed to increase mobility, durability and comfort, allows workers to be productive while exceeding FR requirements from protection agencies. The Wrangler FR Advanced Comfort jeans feature "room2move" technology in a regular and relaxed fit with gusseted construction, reinforced back pockets for increased durability and extra-deep front pockets for added functionality. The Wrangler FR Advanced Comfort jeans will be available in March 2016. *wrangler.com* E&P

Wrangler FR Advanced Comfort jeans feature four-way flex technology that allows the jeans to move with the wearer for maximum comfort. (Source: Wrangler)

Higher level of perforating safety and efficiency

New perforating system greatly reduces the threat of a misfire.

Thilo Scharf and **Ned Galka**, DynaEnergetics

The complexity of completing a modern oil and gas well increased dramatically with the rise of unconventional plays. Wellsite operations employ a large variety of equipment, often working on multiple wells. Simultaneous operations and communications are essential to working efficiently and cost-effectively but pose safety risks that must be effectively managed.

Most horizontal wells use plug-and-perf (PNP) completions involving multiple stages and 12 or more perforating guns per stage. More than 12,000 horizontal wells with an average of 20 or more stages per well were expected to be completed in the U.S. during 2015. Because each gun in each stage uses its own switch and detonator, the number of detonators used has grown dramatically.

Despite the increasing complexity, many companies still use detonating technology invented more than 50 years ago. These resistorized detonators are low-cost and reliable, but they can initiate with any potential difference higher than the no-fire current of the detonator's fuse. Wireline companies have well-established safety procedures and training programs to address potential issues and ensure worker safety when using resistorized detonators.

Nonetheless, the potential for human error and wiring failures remains. Surface detonations still occur because this technology is not intrinsically safe—it does not fail safely and will initiate a perforating gun that can injure or kill oilfield workers. Unfortunately, a small number of fatalities and injuries occur each year at oilfield operations around the world.

Selective perforating

The majority of PNP operations still use pressure diode switches and resistorized detonators. These switches depend upon the successful initiation of one perforating gun to create an electrical connection with the next gun. Radio silence is required, so simultaneous operation is typically prohibited. If the wireline cable is powered, there is a direct electrical connection to the detonator, and the gun will initiate. The current from a cable electrical insulation tester also can initiate the detonator if mistakenly applied to a gun string.

Electrical switches are an alternative. Standard electrical switches require wireline service companies to manually wire the switch to the detonator. If a wire is pinched, damaged, miswired or comes loose, the wires on the detonator can operate like an antenna. If resistorized detonators are used, enough energy can be generated around the well site to risk an unintentional initiation.

A PNP gun string is surface-tested prior to connecting the cable head. (Source: DynaEnergetics)

As a next step, the industry introduced radio-frequency (RF)-safe detonators to ensure safety and allow uninterrupted communications. They are immune to being initiated by the energy from high-frequency communication devices. With RF-safe devices, maintaining radio silence is not required when a perforating gun string enters and exits the well.

While the industry has put great effort into ensuring RF safety, oilfield studies from the last two decades have shown that direct voltage on the wireline and human error are the primary causes of unintentional detonations. A still higher level of safety is necessary to ensure every oilfield perforator is safe at the end of each shift.

Design optimization for safety

Intrinsically safe integrated switch detonators have been used in PNP applications for the past four years. These systems incorporate microprocessors and a multistep logic sequence to establish communication and to arm and enable the detonator prior to initiation. Intrinsically safe systems are fail-safe so that a surface detonation cannot occur. DynaSelect and the DynaStage detonator are examples of such devices.

Using rigorous design techniques, the microprocessor elements can be integrated into the detonator to form a single compact device. This eliminates manual wiring between the switch and detonator, and the connection between the components is verified during manufacturing. Reliability and safety are markedly improved.

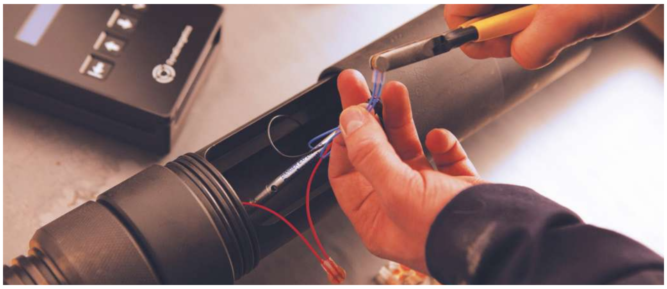
The firing logic incorporates four steps (power up, arming, enabling and initiation). Each circuit component is separated by a normally open logic gate. A unique and progressively more complex digital code is required for each gate, and the probability of an unintended initiation of an integrated switch detonator is 1.38 by 10^{-17}.

Any wrong code will reset the detonator to its normally open state, and the entire sequence must be rerun. If power is interrupted, any energy stored in the system is discharged to a safe level below the required initiation voltage. A high voltage or current spike will destroy the main logic unit, thereby disabling transmission of the digital codes required to initiate the detonator.

Extensive testing verified the intrinsically safe integrated switch detonator is RF-safe and will not initiate due to stray or induced current and voltage. The following tests results were validated by three different independent test laboratories:

- Safely-tested at 50 V and 20 A;
- Protection ensured against maximum static electricity of 2,500 PF, 30 kV;
- Burst-tested to a maximum of 4.4 kV;
- Surge-tested to a maximum of 6.6 kV and 2,500 A; and
- Immune to a maximum frequency of 4 GHz and 300 V/m.

These results exceed the most extreme conditions encountered at a well site. The burst test voltage is 4.4 times greater than the maximum output of a Megger tester. Similarly, RF-safe performance is assured through maximum frequency results five to 10 times greater than the RF energy emitted by a mobile phone or two-way radio. Intrinsically safe devices ensure workers are protected from electrical hazards associated with test equipment, generators, telecommunications, high-voltage power lines and indirect lightning strikes.



A worker wires a DynaSelect intrinsically safe integrated switch detonator into a perforating gun. (Source: DynaEnergetics)

Improved operational efficiency

Intrinsically safe integrated switch detonators provide the highest level of safety while enabling an operational protocol that reduces the cost of completions. Radio silence is not required, so simultaneous perforating and frack activities can be performed. On a three-well, 25-stage-per-well pad, this can shorten the time it takes to carry out completion operations by more than a day.

A surface tester verifies communication with each integrated switch detonator in the gun string prior to running in hole. The tester is a low-power device and cannot initiate any detonator. Surface testing can be conducted without risk to worker safety, and lost time is minimized by screening for errors at the earliest possible point.

The firing panel communicates with all the devices in a gun string without arming any of the RF-safe circuitry. The gun string can be continuously verified as it travels downhole without concern of an off-depth perforation. When at depth, the guns can be selectively armed and initiated. A gun can be skipped in the event of an issue, and perforation can continue without gun string retrieval and a second trip downhole. This can save 3 to 4 hours of downtime and several thousand dollars in operating costs.

Real-world results

Intrinsically safe integrated switch detonators have been employed for PNP applications in the U.S., Canada, Europe and China. These devices have established a proven safety record with more than 300,000 detonations without a single safety incident.

Several wireline service companies employ intrinsically safe integrated switch detonators in wireline operations in the Bakken, Eagle Ford, Permian Basin, Marcellus and other plays. In addition to the safety record, a notable improvement in operating efficiency was achieved.

Prior to implementation, the wireline runs-to-misruns ratio neared 25. With the introduction of the intrinsically safe integrated switch detonator, this ratio improved more than fourfold to a ratio ranging from 100 runs to more than 300 runs—a benefit delivering hundreds of thousands in savings to E&P operators from improved operating efficiencies from reduced frack standby times and the associated reduction in the cost of operations. E&P

Shift in downhole sand control

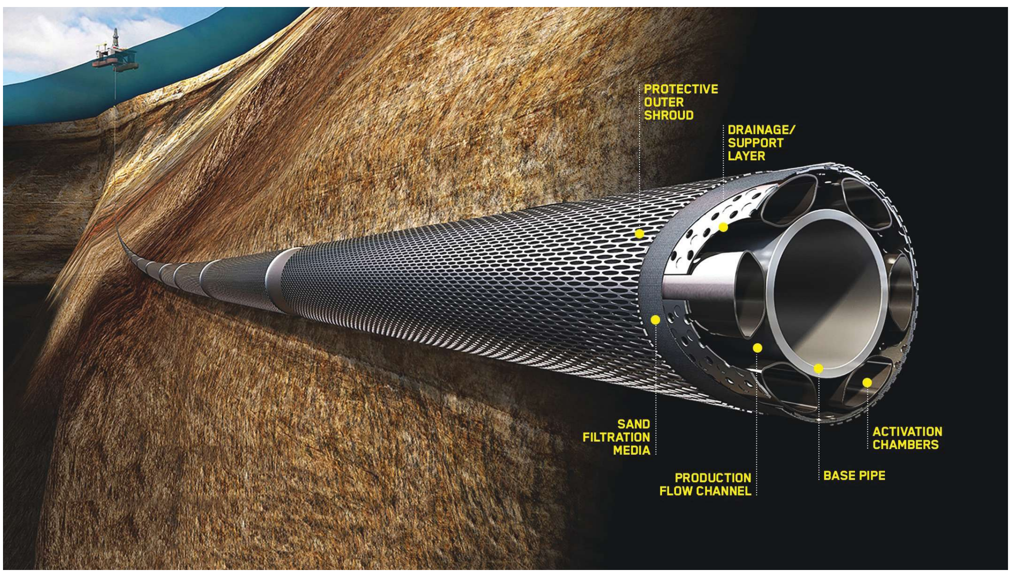
Hydraulic screen technology efficiently completes sand-plagued wells.

Keith Oddie, Darcy

With an estimated 70% of mature and deepwater oil and gas wells requiring sand control and experiencing costly challenges, there is global interest in finding new, efficient solutions to downhole sand control.

Achieving sand-free flow performance in openhole completions often requires removal of the annular gap between the screen section and wellbore. For the first time in the industry, patented hydraulic screen technology has been used to overcome the challenges associated with the high failure rate of traditional gravel packing methods, which are time-, labor- and logistically intensive and costly.

Darcy developed the hydraulic screen technology installed in Statoil's Statfjord oil field in the Norwegian Sector of the North Sea. This openhole application, in a wellbore faced with continuous reservoir pressure depletion, contributed an approximate 30% reduction in overall completion time compared to traditional methods. The technology is suitable for a range of applications, including mature and low-pressure reservoirs, HP/HT conditions, deepwater and shallow reservoirs, injector wells, horizontal and multilateral wells, and in oil fields with heavy and viscous oil.



The hydraulic screen technology removes the need for pumped sand control. (Source: Darcy)

Gravel packing challenges

Gravel packing is a proven practice and has been a method used by the oil and gas industry for many decades. It provides a downhole filter designed to prevent the mobilization of formation sands.

The wellbore is supported and formation sand is held in place by a gravel pack that is pumped downhole from the surface; a screen is first deployed across the reservoir interval and sized to retain the gravel being pumped. The particle size distribution of the formation sand is analyzed to determine the gravel size to prevent unwanted sand production while achieving the desired production or injection performance.

The gravel pack method is time- and labor-intensive and operationally challenging; it typically requires a crew of more than 10 people for an average operation, with extreme demands placed on HSE and logistical planning, especially offshore or in remote locations.

While gravel packing has historically proven to achieve excellent results in many environments, the industry is increasingly faced with marginal economics combined with reservoirs and applications where technical difficulties occur when pumping the gravel pack. One particularly challenging area is mature low-pressure environments where successful placement of a gravel pack depends on the ability to maintain circulation without excessive losses occurring to the reservoir formation. If losses are too high and circulation cannot be maintained to place the gravel, there is an increased risk of incomplete packs resulting in compromised well performance and/or well failures.

An unsuccessful gravel pack fails to remove the annular gap between the screen and wellbore, leading to a risk of sand being free to travel as the well is opened to production (or injection). This mobilization of sand can result in erosion of downhole equipment and/or plugging of the completion, which ultimately can lead to severely impaired well performance, loss of equipment integrity or complete completion failure.

Alternative sand control

Hydraulic screen technology was developed to set a new benchmark in operational efficiency by removing the need for pumped sand control, greatly reducing the associated time, labor, and operational and logistics costs. Hydraulically activated from the surface, a maximum crew of two is required offshore for an operation using standard rig practices.

The screens are designed to integrate fully with standard completion equipment and rig handling operations. After deploying to setting depth, the hanger and screens are set by surface-applied pressure from the rig cementing unit; this operation typically only takes 1 hr. Once set, the screens extend radially to close the annular gap and provide positive wellbore support. The technology suits well designs with 8.5-in. drilled openhole reservoir sections and extends to a maximum range of 10-in. wellbore diameter. The hanger packer is set and reservoir isolation barrier closed in the same trip, providing testable barriers prior to displacing the well for upper completion operations.

Rig time is greatly reduced with the removal of steps from the well program for circulation and displacement of specialist fluids for gravel pack pumping operations. The screen design provides mechanical strength and high collapse resistance for applications where severe geomechanical changes might occur or where extreme production conditions exist.

The strength of the completion is therefore maximized, its large internal diameter retained throughout to ensure life of well operational efficiency; well intervention functionality; and options for selective production, injection and internal and external isolation and shutoff.

Applications

The screens are suitable for all sand control applications but are particularly suitable for offshore, remote or environmentally challenging locations.

The recent Statoil installation involved a mature offshore environment faced with continuous reservoir pressure depletion. The producer well was drilled to 2,580 m (8,465 ft) at a maximum deviation of 30 degrees and at a temperature of about 80 C (176 F).

The technology is designed to complete complex wells with less risk such as horizontal and multilateral wells. Extended-reach drilling also poses an issue when the operator may want to step out to reach a pocket of the reservoir. This can create a challenge to pump and circulate a gravel pack and increase risks and costs associated with excessive tripping in time.

In regions such as the Gulf of Mexico, where deepwater fields with shallow reservoirs exist, gravel packing is particularly challenging since wells have a small window between the pore pressure and fracture gradient. These geologically young formations make it more difficult to circulate the gravel into position due to the risk of fracturing the formation and resultant loss of fluid leading to an incomplete gravel pack.

In HP/HT wells, the screen's strength is maintained and risk of mechanical failure is reduced despite high reservoir depletion pressures and geomechanical loading of the openhole screen completion. In all cases, the screen technology closes the annular gap without weakening the original mechanical properties of the screen.

In injector wells, the screens maintain positive borehole support and near-wellbore stability at all times throughout injection and shut-in cycles, providing protection from water hammer effects. The technology prevents problematic resorting of sands and protects injection performance from the outset by effective placement of filter cake treatment before screen activation. It offers additional benefits through effective zonal selectivity as well as ease of well intervention.

Artificial lift in heavy and viscous oil applications stresses the reservoir and is more likely to draw in formation sand. The screens offer positive wellbore support and completion strength, ensuring sand integrity when greater drawdown loadings occur.

Future of sand control

The production of sand into a wellbore and its effects on well productivity, completion and surface equipment is one of the oldest problems facing the oil and gas industry. In a climate of increasing cost pressures, the development of reliable sand control technology that delivers efficiencies is a growing priority. Using hydraulic screen technology as an alternative to gravel packing methods removes reliability issues in wells where annular gap removal is needed. Elimination of operations, planning and logistics required for heavy pumping equipment and a pumping crew greatly reduces costs and minimizes risks. E&P

Single bit/BHA drilling in Eagle Ford wells reduces time, costs

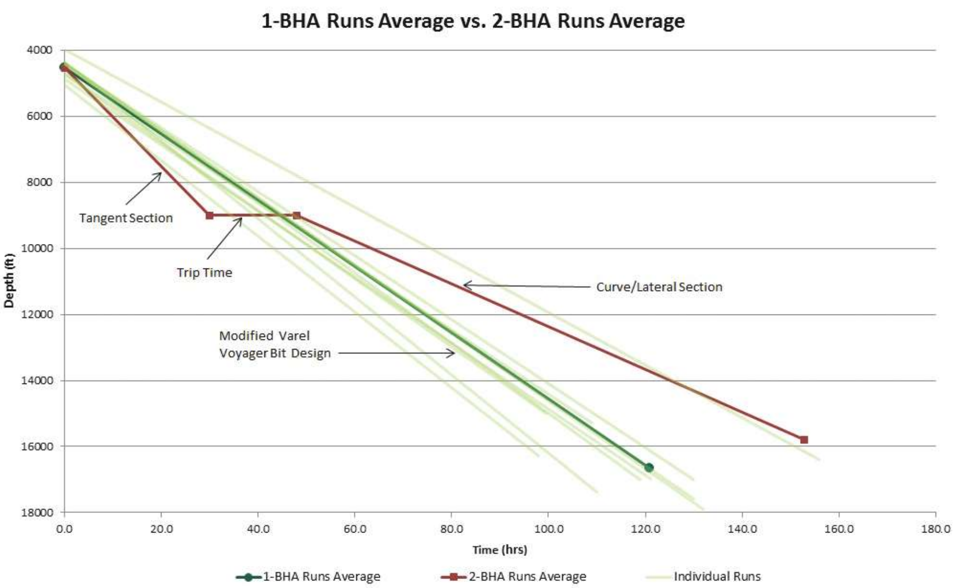
The bit was designed to drill the tangent, curve and lateral sections in one run.

Tim Anderson and **Steve Drews**, Varel International

A fixed-cutter bit designed to drill tangent, curve and lateral sections in a single run is improving the economics of Eagle Ford wells by cutting trips and bottomhole assembly (BHA) costs. Wells in Atascosa and McMullen counties, Texas, typically require multiple bits plus changes in motor and MWD components to drill all three sections. The costs can be significant. In addition to BHA expenses, a single round trip takes about 18 hours.

A bit was needed that could drill all three sections in a single run using one BHA. A Varel Voyager bit designed for directional drilling was optimized for the task by precisely balancing speed and durability demands in each of the three sections.

In addition to significant time and cost savings, the bit is achieving true “factory drilling” consistency in both drilling time and wellbore quality.



Designing a Voyager bit to drill tangent, curve and lateral sections in a single run cut trip time in Eagle Ford wells. (Source: Varel International)

Drilling three sections in one run

While the low compressive-strength sands and shales in the Eagle Ford make minimal demands on bit durability, changes in formation and hole geometry create unique requirements. Drilling the tangent, curve and lateral sections typically requires trips for at least two bits and BHA, which adds considerable time and expense to each hole.

In offsets, an average 1,359-m (4,457.7-ft) tangent section was drilled in 29.8 hours at 45.6 m/hr (149.58 ft/hr) ROP; the average curve/lateral section of 2,067 m (6,780.6 ft) was drilled in 104.9 hours at 19.7 m/hr (64.63 ft/hr). The three combined sections (3,426 m [11,238.3 ft]) were drilled in an average 134.7 hours at 25.4 m/hr (83.4 ft/hr), but the addition of an 18-hr round trip resulted in an overall offset average of 152.7 hours and an overall ROP of only 22.4 m/hr (73.6 ft/hr).

Eliminating the trip plus BHA costs had a significant impact on performance. The first 10 runs of the Voyager bit used a single bit and BHA to drill all three sections for an average 3,697 m (12,125.4 ft) drilled in 120.8 hours at 30.6 m/hr (100.38 ft/hr).

Balancing demands

Eliminating a trip or two and the associated BHA costs required development of a bit that could effectively drill all three sections in a single run. The inherent challenge was balancing each section's different formation characteristics and wellbore geometry demands to produce a bit that would optimize overall performance.

Varel used proprietary modeling and design software to determine the best combination of bit features and characteristics for the one bit/one BHA application.

The design started with a 7 7/8-in. Voyager V513GH fixed-cutter bit developed for directional drilling applications. The model is designed to support modifications that optimize performance for the specific application. Its basic design includes additional nozzles and contoured blades to support increased hydraulics and minimize erosion.

The bit also features thermally stable polycrystalline diamond elements throughout the gauge to enhance durability. Three different gauge configurations provide options for modifying directional behavior, which makes the bits broadly compatible with various directional drive systems.

For the single-run Eagle Ford wells, the objective was to balance the speed and durability required in the tangent and lateral sections with the demand for speed and steerability in the curve section. In this application, the curve is the most demanding section and requires the most specific bit design. Durability in the tangent/lateral section had to be optimized within the requirements of drilling the curve section.

Design changes ranged from modifications of the basic cutting structure to fine-tuning that altered back rake, side rake and torque limitations. Changes included varying cutter exposure to limit torque fluctuations and improve toolface consistency. Gauge requirements, which vary dramatically in each of the hole sections, also were modified, along with the cutting structure.

Modifications to the Voyager V513GH bit included changes to the cone design (three blades to center) to further enhance durability. (Source: Varel International)

Modeling software solution

Proprietary bit modeling software was used to determine the optimal gauge selection based on directional objectives. Voyager gauge options provide alternatives for conventional, rotary steerable, positive displacement motor and point-the-bit rotary steerable system (RSS) assemblies as well as push-the-bit RSS and push-the-bit, high dogleg severity (DLS)/3-D sidetracking RSS.

The modeling software allowed designers and field engineers to specifically address the multiple formations encountered in the single-run application. The program employs advanced algorithms, rock analytics and extensive field operating and performance data to determine how changes in bit features and dimensions will affect a range of characteristics—including steerability, bit walk, DLS capability and vibration control—for a particular well trajectory and BHA.

Proprietary SPOT design software was used to lay out the cutting structure so that torque values were optimized based on the various formation and drilling characteristics. The software improves design flexibility by modeling the cutting structure to improve steering control by finding the optimal balance between speed and stability.

Geoscience rock analytics used in this process model bit behavior in various rock types. This was fundamental to predicting bit wear when drilling the multiple formations encountered in the single-run application.

Field operations

The first two modified 7 7/8-in. V513H bits successfully drilled the tangent, 90-degree curve and lateral sections. The first bit drilled 3,680 m (12,072 ft) at 30.5 m/hr (100 ft/hr), while the second bit drilled an outstanding 4,121 m (13,517 ft) at 31.2 m/hr (102.4 ft/hr).

A second design iteration done to toughen the bit added more cutters and diamond elements in the gauge. This version successfully completed its tangent, curve and lateral to total depth (TD), drilling 3,955.8 m (12,975 ft) at 36 m/hr (118 ft/hr), which still stands as the best run. Wear conditions were very good with a dull grade of 1-0-WT-N-X-In-NO-TD.

Drilling performance enhancement

Ten Voyager bit runs have been made to date. The bits have drilled an average 3,696 m (12,125.4 ft) at an average ROP of 30.6 m/hr (100.38 ft/hr), spud to TD. The performance of the design enabled a process change that eliminated multiple trips for bit and BHA changes in tangent, curve and lateral sections.

By balancing durability and steering requirements, the Varel bit enabled drilling the entire well with a single bit and BHA, eliminating a trip and associated BHA costs.

In addition, consistency in drilling time and hole quality was improved, benefiting the overall efficiency of the pad drilling operations. E&P

Adding value through reprocessing, facies-based inversion

Despite having little well data, a new workflow shows continued promise in the Carnarvon Basin.

Mark Sams and **Ebrahim Zadeh**, Ikon Science; **Shane Westlake**, Finder Exploration Pty. Ltd.; and **Josh Thorp**, Searcher Seismic Pty. Ltd.

The open file 2,700-sq-km (1,042-sq-mile) Willem 3-D seismic survey adjacent to the giant Io/Jansz, Wheatstone and Pluto gas fields in the Carnarvon Basin on the northwest shelf of Australia has been reprocessed and inverted to provide a significantly improved dataset to reduce the risk of the presence of hydrocarbon charge and top seal leakage in an underexplored yet prolific hydrocarbon area. The seismic survey was originally acquired and processed by Woodside Petroleum in 2006. The Urania-1 gas discovery and northern extent of the Pluto Field were detected on the original data. Despite a high chance of success driven by 3-D seismic data and an amplitude vs. offset- (AVO-) rich area, some wells within the survey failed to encounter hydrocarbons when testing seismic amplitudes that were subsequently found to be caused by the tuning effect on the edge of the local depositional center (e.g., Ixion-1). Improvements in seismic processing, including broadband technology and prestack depth migration as well as improvements in quantitative interpretation through facies-based inversion, suggested that significant value could be added to the dataset for a fresh look at areas previously passed over.

Reprocessing

The original processing was regarded as good for the time; however, a number of limitations were clear: poor imaging, amplitude attenuation, multiple energy and signal-to-noise (S/N) drop below the Cretaceous. The causes of these problems also were clear: the strong bathymetric relief, the complex overburden and shallow anomalies associated with potential leakage features. The reprocessing was designed to address all of these issues. A key element of the workflow was the use of broadband de-ghosting that has now become a common tool for conventionally shot streamer data. The de-ghosting improved the de-multiple sequence by having a zero phase wavelet with minimal sidelobes. Surface-related multiple elimination worked quite well, and having a better understanding of the phase allowed for a tighter premigration radon. Integrating regional geological knowledge early improved the initial velocity analysis. Furthermore, going into the velocity modeling, there was less ambiguity of the events in the overburden, which allowed for significant additional detail in the velocity model. Having reduced tuning effects/constructive interference on the flanks of channels and thin beds, the tomography could accurately define the velocity contrasts and helped account for the ray path distortion seen on the far offsets of the original dataset.

Depth migration consisted of five iterations of constrained global tomography to generate a final velocity model and two anisotropic updates. Emphasis was placed on properly resolving the channel features. Resolving the deeper complex features aided in identifying shallow anomalies. The anisotropic model was layer-constrained using regional lithological knowledge and quality-controlled, partly through a focus on the deep AVO response on the far offsets. The detailed interpretation resulted in high-resolution velocity and anisotropy models. Post-migration, the detailed velocity model allowed for a more effective de-multiple as tighter constraints could be applied and the anisotropic imaging ensured a stable offset response for stacking. The data were stacked into partial angle stacks for simultaneous inversion.

Inversion

Inversion was carried out to improve the interpretability of the seismic data. The type of inversion chosen was a deterministic facies-based simultaneous inversion. That is, the partial angle stack seismic data are simultaneously inverted to elastic rock properties and a most likely facies model. There are a number of reasons for selecting such an inversion. First, simultaneous inversion combines the well-known benefits of inversion with the AVO in the seismic to produce, at least, acoustic and shear (S) impedance models of the subsurface, which when combined allow for a better definition of lithologies and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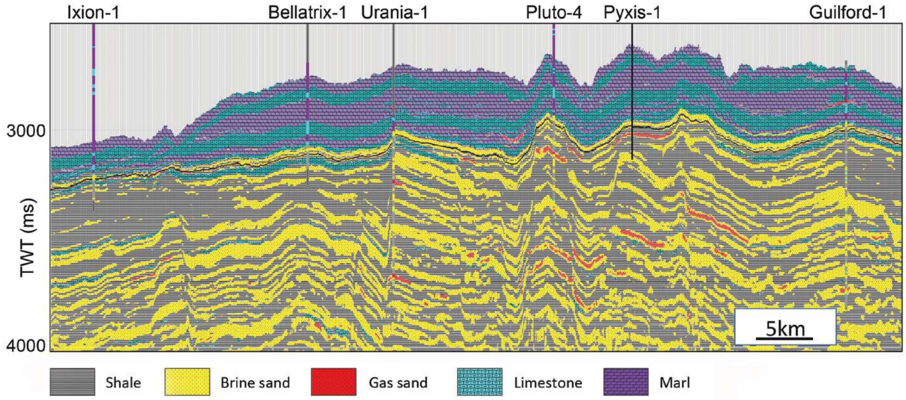


The inverted facies are shown along a traverse that passes through each of the wells. (Source: Ikon Science)

fluids. Second, combining simultaneous inversion with a facies inversion removes the requirement for an initial low-frequency model and introduces constraints that potentially improve the definition of thin and thick beds. The lack of a requirement for a low-frequency model is important in this case as there is limited well control within a very large geographical area. The simple interpolation/extrapolation of a few wells across such a large area would be meaningless.

Including facies within the inversion limits the required input to time-dependent rock physics relationships for each of the chosen facies complete with an assessment of uncertainty. Of course, the assumption is that these rock physics models are applicable over the entire area and can be extrapolated to depths greater than the well control. The low-frequency components of the resulting absolute elastic property models are determined by the predicted vertical distribution of facies and the trends associated with those facies.

The facies chosen for inversion were based on five open file wells: Ixion-1, Bellatrix-1, Urania-1, Pluto-4 and Guilford-1. Five facies were selected based on the geological sequence and upscaled elastic properties as the facies must have some degree of separation in the elastic domain to allow the seismic reflectivity to drive the final distribution. These facies were brine sand, gas sand, shale, limestone and marl. The rock physics models were defined by only two wells with a complete suite of elastic logs: Bellatrix-1 and Urania-1. The rock physics models consist of time-dependent trends of compressional (P)-velocity and relationships between P-velocity and S-velocity and between P-velocity and density. The additional inputs to the inversion are wavelets for each angle stack, S/N estimates for each stack and prior probabilities for each facies.

Results

The results can be assessed by the conformity of the facies distribution to geological expectation and the match at all of the wells. Given that the rock physics models were based on only two wells where S-sonic was measured, the prediction of facies at all the wells is very encouraging (see figure). It is interesting to note that although no Cretaceous gas sands were available for input into the rock physics model, the prediction of the gas sand in the Guilford-1 well is accurate. It is also interesting to note that at the two wells where no gas sands were encountered, although they had originally been drilled based in part on seismic amplitudes, the inversion predicts that there are no gas sands.

The Pyxis-1 discovery by Woodside Petroleum was announced a very short time before the inversion part of the project was initiated. Only the well location and the fact that gas had been discovered were known; neither the depth nor the stratigraphic level of the find were known. A gas sand was predicted at the Pyxis-1 well location within the Upper Jurassic, possibly Tithonian interval. The discovery is of significant size, covering an area of about 20 sq km (7.7 sq miles), and the inversion has provided a clear definition of the dimensions, including the prediction of a very thin gas leg separated from the main accumulation by a small graben. The inversion predicts a gas-bearing sand with a thickness of about 18.3 m (60 ft) at the well location, which compares favorably with the 19.5 m (64 ft) announced by Woodside Petroleum.

Acknowledgements

The authors would like to thank Searcher Seismic for allowing access to the data and permission to publish the paper; Finder Exploration, which provided the interpretation; and Ikon Science, which provided the facies-based inversion. This article is an abridged version of an article that ran in the January 2016 issue of The Leading Edge. *The Society of Exploration Geophysicists owns the copyright and has granted permission for its reprint. Mark Sams, Shane Westlake, Josh Thorp and Ebrahim Zadeh (2016). "Willem 3D: Reprocessed, inverted, revitalized."* The Leading Edge, *35 (1), 22-26. doi: 10.1190/tle35010022.1.* E&P

Interactive rock physics in multiwell studies

Modeling combinations can be presented in an interactive way to other geoscientists while keeping the rock model fundamentals untouched.

Paola Vera de Newton, **William Marin** and **Fady Hanna**, Rock Solid Images

Quantitative interpretation of geophysical data requires rock physics as the bridge that links rock property heterogeneity observed at core and well scale to observations away from the well control. As wells become available, they can be incorporated into reservoir characterization studies for possible rock property calibration of zones of interests. If no other information is available, the modeling of probable reservoir quality zones can be done via pseudo-modeling exercises. This step might include empirical, theoretical or more sophisticated rock physics modeling techniques. It also assumes that an in-depth petrophysical model is available and proper well log data conditioning has been applied to the data.

The prediction and sensitivity analyses of rock properties are a fundamental phase in E&P and appraisal cases. It allows geoscientists to understand reservoir heterogeneity and possible facies scenarios due to changes in the elastic and electrical domains. By perturbing the rocks using a suitable rock physics model, explorationists can interpret key changes that might relate to a specific geophysical response.

Identifying a rock model accurate enough to represent rock type and its microstructure can be an exhausting task when performed in multiple reservoirs and wellbores. One common challenge is that teams will require constant input from rock physicists to first calibrate such a model and, most importantly, to constantly generate iterations that cover those possible scenarios that might explain the geophysical signature in question. The idea of a more interactive rock physics modeling approach is presented as a way to freeze the rock modeling phase and make it available to other geoscientists without generating unrealistic cases that are not supported by the rock physics diagnostics. It also allows interpreters to see these results in real time.

Multiwell studies

This concept can be applied to any size project, but it proves to be extremely convenient when dealing with multiwell studies or large areas including multiple well control points. Exploration efforts in areas such as the Gulf of Mexico (GoM), for example, have been ongoing for many years, and more areas have regained interest within and outside U.S. waters. Deepwater protraction areas such as Walker Ridge, Mississippi Canyon, Green Canyon, Alaminos Canyon and Keathley Canyon have continued to prove highly prospective over time. More than 540 wells have been included in rock physics studies; however, in the Alaminos Canyon area the interactive rock physics approach was applied to discovery wells drilled on the Trident, Silvertip and Great White prospects.

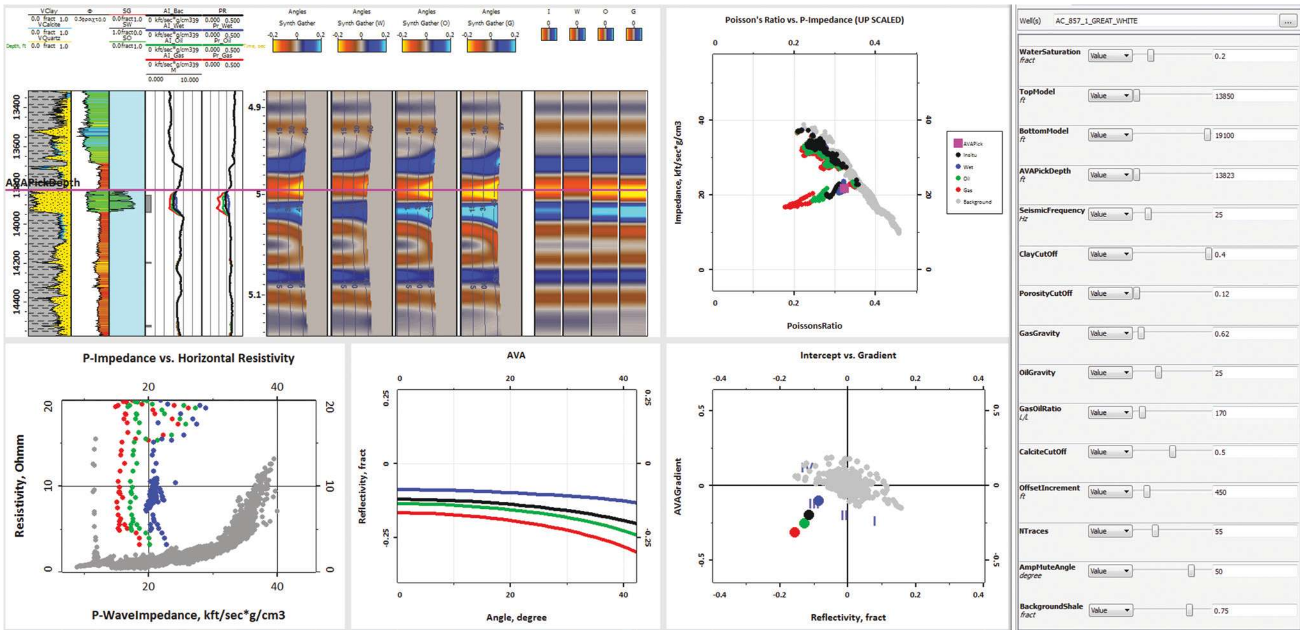
The modeling results for this example have been provided using a real-time modeling and visualization tool called rockAVO. Given the nature of these rocks, the base type of modeling is fluid substitution followed by calculation of the resulting synthetic seismic signatures. Fluid substitution modeling can provide a good understanding of amplitude vs. offset (AVO) response to fluid phase change for a given rock. In addition, matrix changes are performed so that the effect of changes in porosity and mineralogy of the reservoir can be observed instantaneously. Finally, fluid property modeling may be conducted to assess the AVO response to changes in oil gravity, gas gravity, gas-oil ratio, etc.

In summary, the overall objective of this approach is to encapsulate the underlying rock physics modeling methodology so users can interact with the data without the need to be a rock physics expert and without violating physical bounds defined during the rock physics diagnostics stage.

Workflow

The workflow is divided as follows:

- Step 1: All well data must be processed through a rigorous well log conditioning phase, which is termed Geophysical Well Log Analysis, and it includes the Rock Physics Diagnostics phase, which ensures that all logs are corrected (if needed) in a consistent manner. In this step, a rock model or combination of models are identified for reservoir quality rocks. This model will be used as a proxy for perturbational modeling purposes.
- Step 2: Based on the previous rock model, the reservoir



In this dynamic deliverable in rockAVO for the AC857-1 well in Alaminos Canyon, elastic attributes (compressional or P-impedance, Poisson's ratio and resistivity) are displayed after fluid substitution cases (80% gas in red, 80% oil in green and 100% brine in blue). From left to right, ray-traced synthetic gathers and stacks are shown for in situ, brine, oil and gas cases. The P-impedance and Poisson's ratio plot (upper right) shows the upscaled response within the zone of interest and sand response (magenta square). The P-impedance vs. horizontal resistivity plot (lower left) shows the same sensitivity combining elastic and electric domains. The lower right plots show the reflectivity response at the depth indicated by the magenta line. The workflow panel to the right shows the parameter controls the user can interactively change while using rockAVO. (Source: Rock Solid Images)

is perturbed for variations in fluid, porosity and dominant mineral content as the main changing variables. Since the aim of the integrated result is an understanding of the theoretical geophysical responses to changes in reservoir properties, synthetic seismic and/or electromagnetic modeling also is incorporated into the workflow so that geoscientists can visualize the effect of changing these properties on post-stack and prestack seismic response and, ultimately, controlled-source electromagnetic data.

- Finally, all results are merged into the rockAVO visualization tool as a delivery mechanism, enabling users to effect and view changes in real time without changing the core rock physics of the methodology.

An example of the fluid sensitivity results for the main oil sand in the Great White well (AC857-1) is shown in the figure. The usage of interactive rock physics enables users to, for example, understand the theoretical variation of AVO signatures in the field using rock model constraints wrapped into the workflow panel. Quick quality control of AVO anomaly changes from Class III to Class II can be determined as a function of sand facies change. Lithoclasses in the area range from blocky oil sands to silty and shaly sands with residual oil saturations. Simultaneous changes to this particular example included API gravity, dissolved gas, water salinity and seismic geometry.

Rock modeling also can be used to build a template for efficient reservoir characterization so that numerous rock property scenarios can be modeled when interpreting geophysical data. This common technique allows us to understand reservoir property signatures with the principal objective of minimizing uncertainty and risk. For multiwell studies such as the GoM case, a rock physics template can be built upon the existing modeling conducted as part of the regional rock physics atlas for a specific location.

The panel presented in this case simplifies one of the many modeling combinations that can be presented in an interactive way to other geoscientists while keeping the rock model fundamentals untouched. It provides intuitive access to common rock physics practices that often are unavailable in multidisciplinary teams. The application of integrated workflows also ensures higher confidence in the modeling criteria when dealing with a larger number of well log datasets and a common source of rock physics modeling results. E&P

References available.

New-age approach to an age-old problem

A novel surfactant/oxidant system provides a single-step treatment for oil-based filter-cake removal.

Jen Holcomb, EthicalChem

The adage "time is money" is never more true than in production of a commodity such as oil. Reducing the time between well development and oil production while enhancing production efficiency has recently become an area of opportunity with respect to a key step in the well completion process—removal of residual filter-cake buildup.

Conventional oil-based filter-cake cleanup methods consist of multiple chemical injection steps including enzymes, chelating agents, reactive mineral acids, oxidizers or a combination of these chemicals. These methods are also typically preceded by various pretreatments to alter surface wettability from oil-wet to water-wet. Given the current crude oil market dynamics, the timing seems right to utilize a single-step, lower cost approach for wellbore cleanup.

EthicalChem saw the industry need for an easier, affordable, single-step process to remove filter cake. "The MudOut single-step approach not only reduces cost spent on injection equipment, labor hours and overall chemical volume but also allows the well to become a production well faster," said Dr. Betty Felber, chemist formerly with Amoco, Core Labs and the U.S. Department of Energy as well as one of five 2014 Society of Petroleum Engineers IOR Pioneer Award recipients.

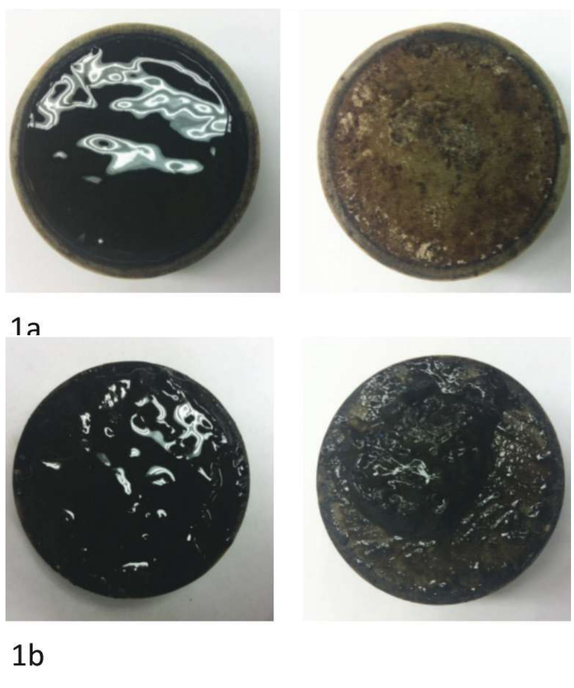


FIGURE 1. Filter cake (1a, top) is shown before (left) and after (right) MudOut treatment. The filter cake (1b, bottom) can be seen before (left) and after (right) formic acid treatment. (Source: EthicalChem)

Drawing on years of experience with surfactant-oxidant chemistry, EthicalChem formulated a product that would address both the organic and inorganic components of filter cake while eliminating the need for pretreatment steps to alter surface wettability.

Following extensive R&D in collaboration with the Harold Vance Department of Petroleum Engineering at Texas A&M University, EthicalChem announced the release of its new patented product, MudOut, in mid-2015.

MudOut disperses oil-based filter cake and removes internal damage without causing significant corrosion impacts on steel and without a series of pretreatment stages. In laboratory testing at Texas A&M under a variety of temperature and brine conditions, MudOut consistently removed 98% of filter cake.

In a head-to-head comparison with formic acid (9% solution by weight) MudOut removed 95% of filter cake after 4 hours, whereas formic acid removed only 78%. After 20 hours, MudOut had removed 98%, while formic acid removed 92%.

Figure 1a shows the effect of 8 hours of MudOut treatment on filter cake. No filter cake or residue is observed, and experimentally 97% of the filter cake was removed. Figure 1b shows the effect of 8 hours of formic acid treatment on filter cake. A substantial amount of filter-cake residue remains visual after the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Filter cake removal by MudOut and formic acid		
Hours	MudOut	Formic Acid
4	95%	78%
8	97%	85%
20	98%	92%
Final Permeability Ratio	2.1	1.2

TABLE 1. Removal efficiency and permeability ratios show the comparison between MudOut and formic acid. (Source: EthicalChem)

formic acid treatment, and experimentally only 85% had been removed.

In addition to the clear performance advantage in terms of filter cake removal, the retained permeability shows that there is some stimulation effect from the MudOut, with a permeability ratio (k_f/k_i) of 2.1. In comparison after treatment with formic acid, the permeability ratio was 1.2 under the same test conditions.

Table 1 shows the removal efficiencies of MudOut and formic acid after 4 hours, 8 hours and 20 hours of treatment along with the final permeability ratios. Results show that MudOut outperformed formic acid at each time interval and resulted in a higher permeability ratio, indicating improved permeability.

Dr. Hisham Nasr-El-Din, Texas A&M University professor and holder of the John Edgar Holt Chair, who oversaw product testing at Texas A&M, said, "We were pleased to test the MudOut product. It truly represents a significant advancement in filter-cake removal technology in terms of both filter-cake removal performance and elimination of costly steps required by conventional treatment approaches."

How it works

The key to the MudOut price/performance advantage is the innovative patented surfactant and oxidant system, which works to address both the organic and inorganic components of filter cake. The plant-based surfactant, which was selected in part for its ability to provide stability to the oxidant, solubilizes and emulsifies the hydrocarbons while the oxidant addresses the polymers.

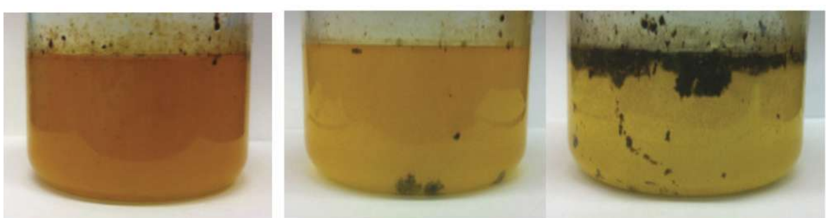
Additionally, decomposition products drive the pH to below one, creating temporary acidic conditions at the tail end of the process, which dissolve inorganic components of the filter cake such as calcium carbonates. The MudOut oxidant includes multiple coated oxidants that can be varied to create well-specific formulations, which ensure controlled, uniform reactions, thereby preventing partial filter-cake removal or wormholes.

Figure 2a illustrates how MudOut surfactants and oxidants dissolve and solubilize filter cake, which enables easy removal through pumping. Acid treatments, which primarily only address inorganic components, result in incomplete breakdown into large masses and incomplete removal as shown in Figure 2b (formic acid treatment).

The MudOut blend can be formulated for well-specific conditions with, for example, a longer lasting, more durable blend used under harsh conditions (high temperatures and high brine) and a faster acting blend used for lower temperatures and lower brine.

"Now is the right time for oil services companies and producers to embrace new technologies such as MudOut, which can significantly lower costs while bringing wells into production faster," Felber said. E&P

2a



2b

FIGURE 2. MudOut surfactants and oxidants dissolve and solubilize filter cake, which enables easy removal by pumping. After 4 hours, 8 hours and 20 hours of treatment, the top row (2a) shows MudOut filtrate with the filter cake ready for pumping, while the bottom row (2b) shows results with formic acid (9% by wt). (Source: EthicalChem)

Fluid conditioner, HPDE cut lubricant costs, improve ROP

Using a fluid conditioner and applying HPDE through a steady stream, an operator in the Bakken experienced reduced motor wear and used only one bit to drill a 3,201-m Three Forks lateral.

C.S. Jones and J. Shipman, Newpark Drilling Fluids

Operators in North Dakota drilling in the Bakken Formation wanted to explore possible cost savings without sacrificing quality. The operators, who were drilling long laterals, communicated a need for improved efficiencies to minimize their drilling fluid costs.

To one operator, Newpark proposed two changes to drilling practices: using a fluid conditioner and changing the application method of the high-performing drilling enhancer (HPDE). The benefits were presented to a second operator, which also implemented the practices and realized substantial results. The following discussion summarizes drilling practice modifications and then outlines both operators' results.

Using fluid conditioner

The first operator outlined concerns about using the current fluid system more efficiently. The most obvious concern was that the fluid's lubricity diminished after it was circulated over the solids control equipment. This is a common challenge with most lubricants. Newpark suggested additions of EvoCon II, a high-performing fluid conditioner, to best optimize the fluid so that the lubricant coexisted with the cuttings more synergistically.

The fluid conditioner allowed cuttings removal so that the drilling fluid had the lubricant intact. Newpark was given the opportunity to measure the effectiveness of the fluid conditioner on lubricity and fluid costs savings.

Changing HPDE application method

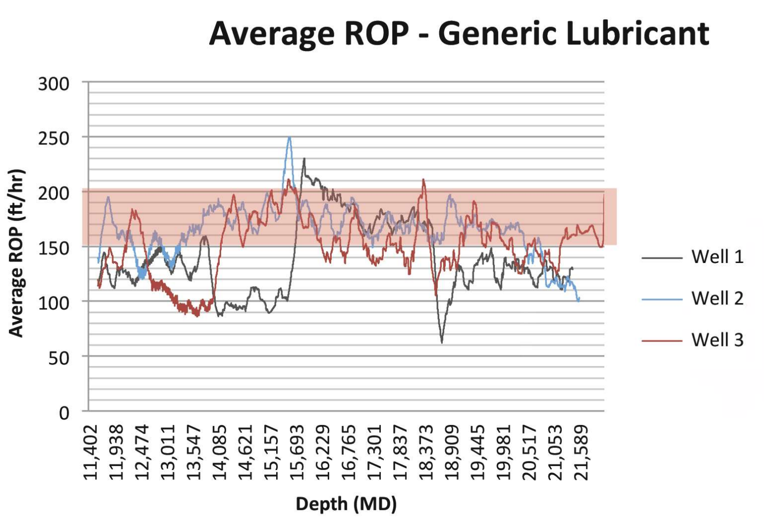
Continuing its quest for improved efficiencies, the first operator wished to explore lubricant application options, perhaps with an option that was not conventional. To increase drilling fluid lubricity, two conventional HPDE application methods dominate: maintaining a constant lubricant concentration and running lubricant sweeps.

Maintaining a constant concentration can be difficult because real-time measurement of lubricant concentration throughout the wellbore remains a challenge. A relative concentration might be approximated from the fluid's lubricity coefficient, which is measured with an extreme pressure and lubricity meter.

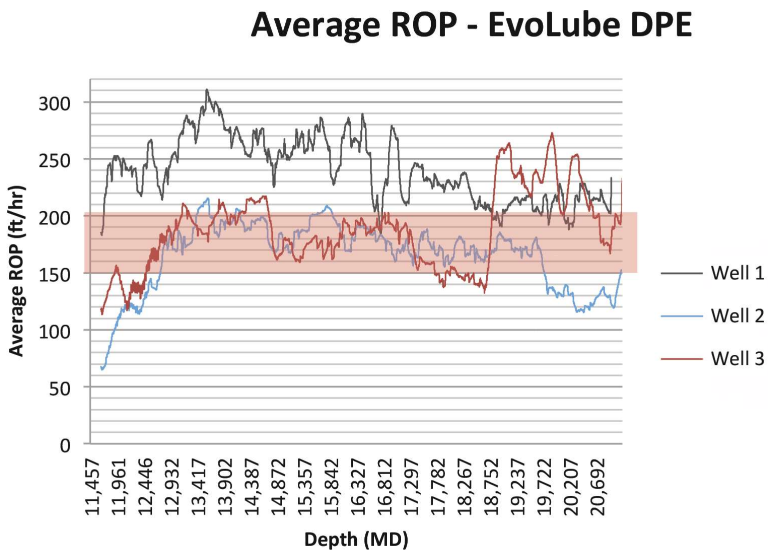
The other method, running lubricity sweeps, involves adding a higher concentration of lubricant into a small volume of drilling fluid. The sweep is applied by circulating this small volume downhole so the high concentration of lubricant inundates the drillstring. The sweep is followed by a regular regimen of fluid. This technique of lubricant application is short-lived. In particular, this method typically results in high torque and drag, which can be detrimental to operations.

To address this issue, a steady but small stream of EvoLube DPE was flowed into the drilling fluid as it was going downhole. This modification required close monitoring of the flow from a tote to the pit near the outlet line.

The ideal flow rate was determined by measuring the fluid's relative lubricity coefficient by an extreme pressure and



ROPs measured on rigs using a generic lubricant were lower than the operator's expectations (range highlighted in pink). (Source: Newpark Drilling Fluids)



ROPs measured on drilling sites using the HPDE were higher than the operator's expectations (range highlighted in pink). (Source: Newpark Drilling Fluids)

lubricity tester, modifying the flow so the fluid maintained a target value of less than 0.2.

Results

To validate the effect of the fluid conditioner, Newpark measured the lubricity coefficient of the active system and the lubricity coefficient of the effluent (the fluid removed by the solids control equipment).

Prior to fluid conditioner treatment, the lubricity coefficient of the effluent was more than twice that of the active system. After treatment, the two coefficients closely aligned, with only a slightly higher rate in the effluent. This demonstrates that fluid conditioner use allows the lubricant to remain in the fluid so that it may be circulated again with minimal additions.

This operator saved an average of 17% in fluid costs when compared to applications without the fluid conditioner. Additionally, the rigs that implemented the "steady stream" of HPDE to the fluid experienced a lubricant savings of 28.3% compared to drillsites that used fixed-percent and sweeps methodologies.

This operator compared lateral drilling days of wells drilled using the novel approaches to wells drilled with $CaCl_2$ brine and with oil-based fluid (OBF). The Newpark Drilling Fluids' Evolution High-performing Water-based Fluid System (HPWFS) averaged a total drilling time of 13.7 days. The brine and OBFs averaged total drilling days of 25 and 24.7, respectively. ROPs for the brine, OBF and HPWFS were measured to be 266.5 m/d (873.3 ft/d), 202 m/d (663.7 ft/d) and 706 m/d (2,315.3 ft/d), respectively.

The second operator, who was new to Newpark, implemented these two changes, realizing additional benefits. This operator experienced reduced motor wear. For one well, the operator used only one bit to drill a 3,201-m (10,500-ft) lateral through the Three Forks Formation. On average, the operator observed a 136.3% increase in constant differential pressure in comparison to offset wells.

This differential pressure, which remained relatively constant throughout the remainder of the drilling process, transferred into increased weight on bit (WOB). The increased WOB resulted in an average 20% increase in ROP. Compared to a competitor's lubricant and methodology on surrounding wells, the operator saw an 18% decrease in rotational torque spikes (calculated as a standard deviation). Lubricant costs were 51.3% lower using the Evolution system and these methodologies in comparison to the operator's other wells in the vicinity.

Lessons learned

Collaboratively working with the operator, Newpark changed fluid properties by product additions and method application to everyone's advantage. Evolving from previous knowledge and then continuing in that progression allowed the drilling fluid to perform more efficiently.

This occurs when the operator is open to suggestions and change and if the service company is experienced enough to offer the recommendations. The outcomes of these implementation changes resulted in a reduction of drilling days for the lateral, reduction in trips for motor failures and a notable improvement in sliding for directional drilling. E&P

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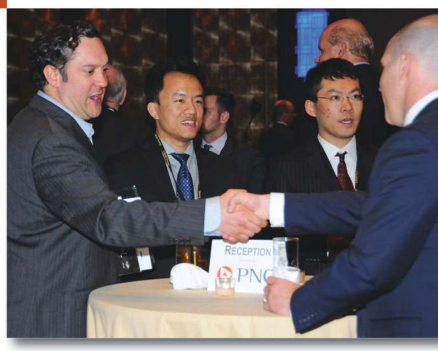

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Addressing artificial lift predicaments

The challenge is to get more with less.

Dave Kimery, **Camille Jensen** and **Jeff Saponja**,
Production Plus Energy Services Inc.

When oil prices are low, the industry is challenged to seek opportunities to optimize every producing asset. On the production side, it is the production engineer's mission to design the most cost-effective means to recover the greatest amount of production from a well in the shortest amount of time. Conventional artificial lift practice often transitions a horizontal well through multiple artificial lift systems in a strategic attempt to balance lifting reliability and maximize drawdown, all while trying to achieve the lowest possible operating costs. The artificial lift predicament is this challenge to simultaneously maximize drawdown and achieve reliability.

Gas-lift limitations

Once horizontal wells expend their phase of natural flow and an artificial lift system is required, they are known to have production challenges associated with downhole pump gas interference and solids issues. Gas lift often is implemented as a transitional artificial lift solution since it is solids-tolerant, can handle high decline rates and can manage sluggy flow conditions inherent to horizontal wells. Producing fields with gas infrastructure frequently default to this option to capitalize on existing equipment but knowingly sacrifice longer term production and reserves from the limitations of gas lifting.

In the artificial lift predicament, gas lift addresses reliability, but its downfall and limitation is the difficulty of achieving a low producing bottomhole pressure (BHP) to maximize drawdown. To complicate the challenge, gas lift is a highly inefficient process, and the deeper the well, the more limited drawdown becomes.

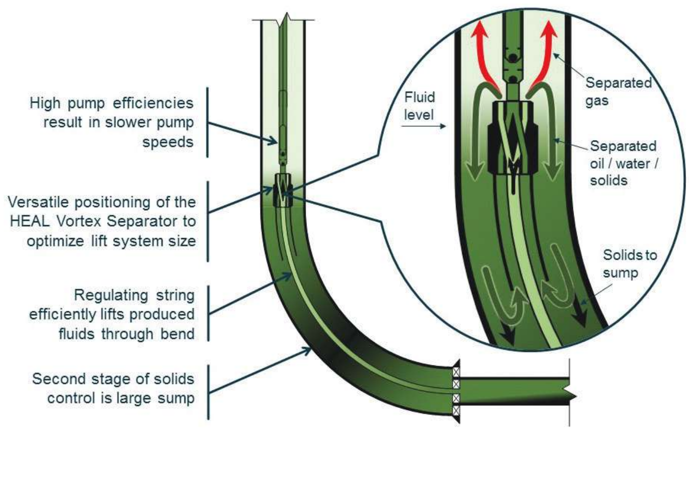


FIGURE 1. The cyclonic effect of the vortex separator efficiently separates gas and solids from the liquid and protects the pump from damage. (Source: Production Plus Energy Services Inc.)

For example, in a typical 2,000-m (~6,500-ft) true vertical depth (TVD) horizontal well, the lowest producing BHP a gas-lift system can achieve is about 750 psi. Limiting producing BHP to 750 psi results in the well not being produced to its full potential. At some point in the life cycle the well will be forced to move from gas lift to another artificial lift solution such as rod pumping to further increase drawdown and produce at a rate that can economically access the remaining reserves.

Reliability and drawdown

Rather than finding the trade-off balance between reliability and drawdown, consider a way to drive both. Production Plus Energy Services Inc. took on this challenge and identified the root cause of the reliability drawdown trade-off: sluggy, inconsistent messy flow from the horizontal. Traditional artificial lift systems struggle when faced with horizontal wells that present rapidly fluctuating fluid rates and surges, solids issues and gas interference. The consequences of this messy flow are poor runtime, excessive workover costs and inadequate drawdown.

Researchers discovered that the key to the artificial lift predicament in horizontal wells is to smooth flow. The company developed the patent-pending Horizontal Enhanced Artificial Lift System (HEAL) to complement existing artificial lift systems. It settles the messiness of horizontal flow and reduces fluid density to lift fluids up to the vertical where a pump can operate reliably. The system controls solids and gas interference to protect the pump while operating at very low producing BHPs.

The system itself is a mechanical system comprised of a seal, a sized regulating string and a highly efficient vortex separator. To minimize operational risk, the system was designed with no moving parts and does not extend into the horizontal.

Production from the horizontal is conditioned up the sized regulating string, smoothing flow and reducing density, which results in increased drawdown. Flow from the sized regulating string is discharged to the well's annulus by the vortex separator, which is placed near or above the kickoff point. The cyclonic effect of the vortex separator efficiently separates gas and solids from the liquid, protecting the pump from gas interference, damage or seizing from solids (Figure 1).

Smooth, even flow of liquid to the pump creates the possibility for exceptional reliability. Reliability is directionally proportional to higher pump efficiencies at slower pump speeds and reduced pump loads—a combination that sets the stage for resolving the predicament of reliability and maximized drawdown.

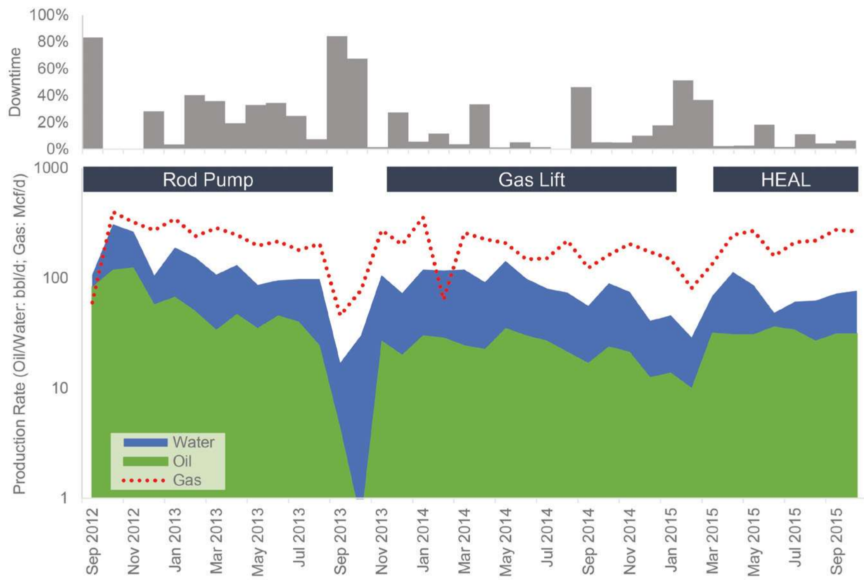


FIGURE 2. Applying the HEAL System to a well in Alberta increased its production rates. (Source: Production Plus Energy Services Inc.)

Case study

The Western Canadian Sedimentary Basin is no stranger to the artificial lift predicament, including a west-central Alberta well in the Montney zone. This horizontal multistage fractured well had a total measured depth of 4,202 m (13,786 ft) at a TVD of 2,441 m (8,008 ft). The well had a high gas-liquid ratio, starting at 34 cu. m/bbl (1,200 scf/bbl) and rising to more than 99 cu. m/bbl (3,500 scf/bbl) as production proceeded.

Initially, the operator installed a rod pump that was plagued by runtime challenges and inefficiencies caused by gas interference, averaging monthly downtime of 25%. Gas lift was installed with the expectation of higher production runtime. Gas lifting did provide a solution for reliable production runtime (Figure 2). It reduced the average monthly downtime to 12%. However, drawdown was significantly compromised so that instantaneous production rates diminished by 10% to 15%. Higher runtime realized from gas lift offset the production decrease to keep total fluid rates from the well on trend with earlier rod pump production. The operator was caught in the predicament of balancing reliability against the quest for more drawdown by achieving a low producing BHP.

Beyond the artificial lift predicament, the cost of achieving additional runtime was substantial. The operator had to install the gas-lift equipment and support increased operating costs. Monthly operating cost for gas lift are typically $20,000, while rod pumping operating costs are about $8,000 per month.

The HEAL System was introduced to replace gas lift and return the well to rod pumping. The system was placed downhole below the rod pump in the bend section of the horizontal. Placing the system in the bend allowed the pump to be placed above the kickoff point and into the vertical part of the wellbore, requiring a smaller pumpjack. A conventional installation in this field would require a larger pumpjack and rodstring to achieve the same production rates that the system achieved with the smaller pumpjack.

Produced fluids were efficiently lifted through the bend, achieving lower producing BHPs at greater reliability than previously realized with earlier artificial lift systems installed in this well. The production and value-add benefit to the well continues to be substantial.

Changing the mindset

As the price of oil is remaining low for the foreseeable future, it is becoming increasingly difficult for operators to retain operating margins and to reconcile the artificial lift predicament. In this case study the operator was able to realize the well's potential by shifting out of the traditional artificial lift approach. With the installation of the HEAL System, the operator was able to complement a current system and capitalize on existing equipment as well as create a situation where the well reliably maximized drawdown and lowered operating costs simultaneously. E&P

Driving from downhole

The 15% savings that PMMs offer over induction motors translates to a staggering potential cost savings in the region of $1.5 billion to $2 billion a year if there was universal adoption.

Keith Russell, Borets

The electric submersible pump (ESP) industry is significant in size, with about 150,000 ESPs operational in the world today. Borets' dedicated R&D department has focused its resources on the global land market, paying particular attention to unconventional shale plays. A focused team of engineers at the company is devoted to developing a whole new range of ESP technology centered on the concept of driving artificial lift from downhole rather than from surface. The team has developed a radically different platform based on the company's permanent magnet motor (PMM) technology.

PMM

A decade ago, company engineers developed the concept of the PMM and have developed it into the mature product it is today. PMMs offer an alternative to the older and more established induction motor concept.

PMM and induction motor stators are similar: Both have three-phase armature winding, which generates a rotating magnetic field. Both have housings, heads and bases, shafts and bearings that are similar. However, PMM and induction motor electromagnetic processes, which participate in energy generation, have significant differences.

PMMs are about 15% more electrically efficient than induction motors, meaning that billions of dollars in savings could be achieved if PMMs were to be adopted industrywide and millions of megawatts of unnecessary power use could be avoided. In Europe in particular the adoption of PMMs would qualify a company for the award of carbon credits and reduce its environmental footprint considerably.

Because the PMM has much greater power density than the induction motor, considerably higher horsepower can be harnessed in a shorter component. For example, the company's 5.62-in. diameter motor can deliver 1,000 hp in a single motor section. Currently, three sections of induction motors, 27 m (90 ft) long, are required to generate the same as one 9-m (30-ft) long PMM section. Therefore, PMMs are ideally designed for future use in offshore wells, where the absolute highest horsepower possible in the shortest package is advantageous.

Offshore wells and unconventional land wells often are deviated; therefore, shorter units can more successfully navigate these geometries. Additionally, in an offshore environment a 27-m motor will need to be handled and assembled in three pieces, resulting in more points of potential failure and increased time spent rigging up in an expensive offshore environment. Several large research projects aimed at exploring deepwater high horsepower applications are ongoing.

Borets has more than 7,000 PMMs sold into the oil field today, and the uptake of this technology in the industry is growing significantly.

New technologies based on PMM platform

Developed on the platform of already-operational PMMs are a number of new technologies applicable to the unconventional land market. One is the PMM progressive cavity pump (PMPCP).

Traditionally, when using a PCP, companies drive the pump from the surface with a drive head

The use of PMMs in PCPs allows operators to drive artificial lift from downhole rather than from the surface. (Source: Borets)

and drive rods. In highly deviated or crooked wells, this becomes the key wear point and main mode of failure in the system. The only truly effective way to run a PCP in a deviated well is with a downhole motor as opposed to a surface motor. Borets uses the PMM motor to turn at an acceptable rpm for a PCP pump without the need for a downhole gear box to reduce the speed of the motor, which has proven to be the least reliable component in previous bottom-driven PCP systems.

The concept of using a PMM to drive artificial lift from downhole rather than from the surface is a new idea made possible with PMM technology.

The PMPCP is essentially a PMM that is constructed in a way that allows it to rotate at a slow speed (in the 500-rpm to 700-rpm range) and that allows connection to a conventional PCP. It can be used in wells that are too deviated to accommodate traditional PCPs, which rapidly wear out in such environments. By operating the pump from downhole, the PMPCP eliminates multiple well workovers over the course of a pump's lifetime.

Also recently launched into this suite of technology is a new variable speed drive (VSD) that works in conjunction with the PMM, known in the industry as AXIOM II. A unique aspect of the AXIOM II is that it is capable of running both an induction motor and the PMM. It offers unique functionality that provides operators the flexibility to use PMMs and apply a VSD solution to optimize production while not creating inventory or training issues with existing equipment.

Components for the WR2 system are manufactured through metal-injection molding, allowing engineers to use geometries in design that cannot be economically produced in a foundry. (Source: Borets)

High-speed WR2 system

Another technology recently launched by the company is the high-speed wear-resistant/wide-range or "WR2" system. The system includes a high-speed pump, a PMM and a monitoring package. The manufacturing of the WR2 system uses metal-injection molding. This method was previously used on very small parts such as those found in medical devices. It has been scaled to a size large enough to be deployed in downhole oil and gas applications. The new method of pump manufacturing enables the development of unique hydraulic designs and new materials for stage manufacture.

The new patent-pending processes involved in metal-injection molding allow engineers to use geometries that cannot be economically produced in a foundry. Because the geometry is different to what can be made in a sand cast, it has a unique geometry that cannot be recreated in a conventional pump, resulting in better gas handling. When finished, the mold is close enough to the desired finished form and at the required tolerances that minimal machining is required. Therefore, a very hard material can be used, close in hardness to a ceramic bearing, enabling it to handle sand flowback yet survive for an acceptable runlife.

The WR2 system is a complete system built in combination with a PMM. As a result of the PMM and the way the pump is designed, it can be turned at a very high speed. Conventional ESPs run between 3,500 rpm and 3,600 rpm, but the WR2 system can run at 6,000 rpm. In pump terms, this means everything can be made shorter and more efficient, resulting in a much-improved tool for navigating deviated and horizontal wells. Its improved energy efficiency also results in lower power costs.

Eleven WR2 systems have been run outside North America so far and five within North America. The initially released pump has an efficient pump range from 400 bbl/d to 1,900 bbl/d and covers a wide range of operation at a high efficiency.

In the current industry climate of cutbacks and money-saving initiatives, completing a well now with a system that will use 15% less energy over its lifetime represents a significant saving, making it an appropriate time to transition to PMMs for new wells. The efficiency of the WR2 system allows clients to optimize their financial return in the early period of the well when they are looking to pay back the investment in the fastest way possible. E&P

Bringing seabed processing into mainstream

The subsea processing industry is at a pivotal point as it transitions from mostly niche 'one-off' projects to mainstream field developments, where its value is now largely accepted.

Alisdair McDonald, GE Oil & Gas

The ethos of subsea processing has always been about moving as much of the conventional processing capabilities from the surface to the seafloor—helping to debottleneck topside facilities and subsea pipelines, increasing recovery rates and, in some cases, creating new possibilities for profitable field developments.

Technological development has accelerated in recent years, with core technologies such as boosting, separation, power and compression now routinely considered as part of new development scenarios. They also are seen as an opportunity to improve return on investment on aging brownfield projects.

GE Oil & Gas, having worked in the subsea processing space for more than 20 years, has its inventory of knowledge and technology contained in what is called the "GE Store," which allows it to tap into different technological areas.

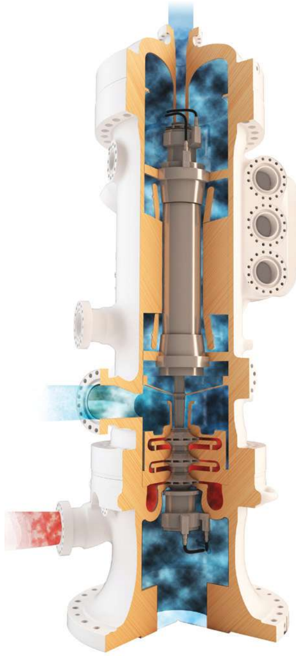
For the subsea sector, this means leveraging its capabilities in rotating equipment, flow assurance, subsea production, water treatment, power systems, and advanced monitoring and diagnostics.

Gas compression

Subsea gas compression is one emerging technology that can significantly improve the economics of many mature gas fields. By placing such systems on the seafloor, the E&P industry can accelerate production while eliminating the need for costly topside facilities.

GE's Blue-C technology is at the heart of both its subsea dry and wet gas compression system. Initially designed for dry gas, a wet gas version of the compressor that can handle up to 5% liquid has now been developed, eliminating the need for a subsea separator and resulting in a more compact and lower cost system.

The Blue-C is a high-capacity centrifugal compressor designed for maximum reliability that has undergone exhaustive testing in a submerged environment to ensure full optimization for subsea operation. It can be configured to run from 4 MW to 20 MW, providing the flexibility to deliver systems for use in both small and large fields or to run with a single compressor or more than one compressor in parallel.



A schematic of GE's Blue-C compressor is shown. (Source: GE Oil & Gas)

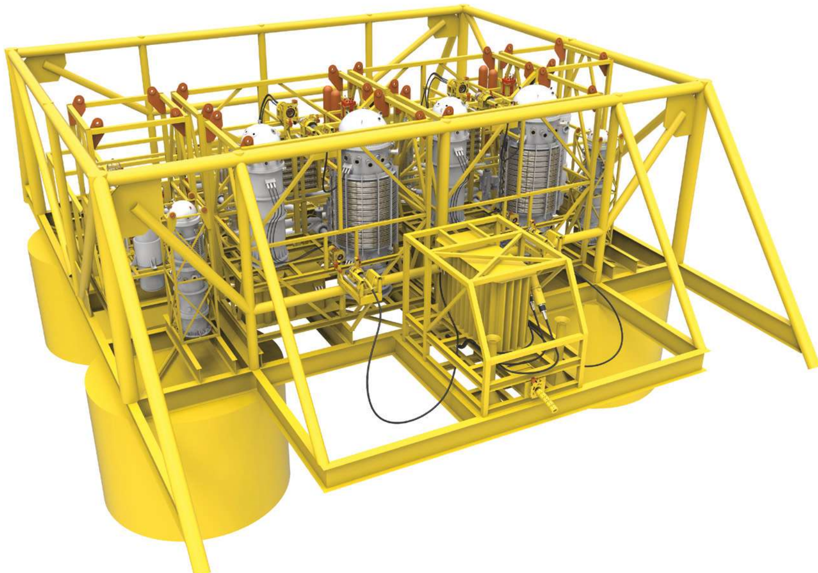
Subsea boosting

Even in challenging environments such as long-distance tiebacks, low-pressure reservoirs or wells with difficult flow assurance conditions, subsea boosting can be used to unlock and enable access to these assets.

GE Oil & Gas has drawn inspiration from its GE Aviation sister business to explore a new boosting system approach that has the potential to fundamentally change and simplify subsea boosting. The company is collaborating closely with leading operators to build a demonstrator test unit aimed at confirming its ability to handle a variety of flow rates and fluid compositions.

The system can be configured with either centrifugal or helico-axial stages, with each system again designed for high reliability. Key benefits include life-cycle cost reduction, operational flexibility, and reduced topside and subsea footprint compared to conventional subsea boosting.

In addition to the existing market for subsea boosting, this new concept provides the potential to unlock additional barrels in many brownfield applications where there is either not enough space topsides to accommodate the equipment associated with conventional boosting systems or where the cost of conventional systems is prohibitive.



GE's subsea compression system eliminates the need for costly topsides facilities. (Source: GE Oil & Gas)

Seawater treatment, injection

One of the remaining subsea processing building blocks still to be fully developed is seawater treatment for injection.

Produced water can be directly reinjected into the reservoir, but seawater requires treatment prior to injection to remove sulphates and other divalent ions that can cause souring and scaling of the reservoir. This is typically done topside on a platform or FPSO vessel using large processing facilities that use membranes. The treated water is then injected into the reservoir through high-pressure risers.

By tapping into another of its sister business' expertise, focused on the power and water sector, GE Oil & Gas has explored the feasibility of a seabed seawater treatment solution using a combination of nano-filtration and ultrafiltration membranes.

This system has been designed for minimal intervention, with the membranes to only need replacing every five years. Although subsea seawater injection will not make sense in all business cases, it can be very attractive for deepwater assets, long-distance step-outs or where topside footprint or weight is constrained.

Subsea power enabler

Subsea power is still seen by many as the most critical enabler for subsea processing, and there has been intense focus by the industry in recent years to develop the core building blocks and enable subsea alternating current (AC) power supply, transmission and distribution systems—commonly known as "type-3" systems. These systems are key enablers for longer step-outs and for multiple loads such as distributed compression and boosting systems.

GE has qualified a complete type-3 AC power system that includes subsea variable speed drives, uninterruptable power supply, and subsea switchgear and high-voltage connectors.

For longer step-outs beyond 150 km (93 miles), there might be the need to consider low-frequency AC, while direct current (DC) transmission is seen as the only potential solution for ultralong distance step-outs of more than 500 km (311 miles). However, it is widely accepted that there are still some major technical challenges to low-frequency AC systems, while significant resources and time also would be required to develop a DC system.

GE already has completed significant preliminary R&D on DC topologies including ongoing work on a high-voltage DC connector under a Research Partnership to Secure Energy for America program and will be ready to support the development of DC solutions when the business case becomes clearer.

Continuing the evolution

The offshore industry has come a long way over the last 15 years or so, tackling and solving some of the major challenges presented by subsea processing.

Some of these achievements would not have seemed possible before—from the world's first subsea separation and injection system in 2001 to the world's first subsea gas compression system in 2015.

It is now at the point where it has the technology at its disposal, has developed the project execution experience and built a global pool of subsea processing experts. To continue this evolution, the industry needs to intensify collaboration, push the boundaries of what is possible and be prepared to do things differently. In this way, it can take the lead in making efficient and integrated subsea processing systems a new standard for the offshore sector. E&P

Back to the future for subsea control fluids

As the boundaries of subsea operations continue to be pushed, one question to be asked is 'Should we be looking back to the future for the next generation of subsea control fluids?'

Tony Globe, Castrol Marine & Energy Lubricants

Back in the 1960s the first subsea systems were simply waterproofed surface systems placed on the seabed next to a platform in shallow water. These systems were operated remotely using a normal hydraulic system with conventional mineral hydraulic oil. As the oil was returned to the platform via the umbilical hose, the product did not leak into the sea (unless something burst), and therefore the associated environmental impact was minimal.

With time, subsea wells moved gradually farther away from the platform. As conventional hydraulic oils are quite viscous, this increased distance necessitated the development of new water-based fluids as they are much thinner. The advent of water-based products also removed the need for the hydraulic fluids to be returned back to the platform via a circulating system—they could now be discharged directly into the sea within discharge limits agreed upon with environmental regulators and based on environmental impact assessments.

One of the subsea templates being installed on Statoil's Åsgard Field offshore Norway is shown. As subsea operations further extend into more remote and challenging environments, the need for alternatives to water-based subsea control fluids will increase. (Source: Statoil)

Water-based challenges

Despite certain benefits, these water-based products also brought certain challenges. Inhibitors are required to prevent corrosion, glycol must be added to prevent it from freezing at low temperatures and, as the product is discharged into the sea, not only must it be cheap enough to "throw away," but the aforementioned environmental legislation also has steadily become more stringent.

The electro-hydraulic multiplex (EH-Mux) subsea control systems that followed were based on avionics control technology and used synthetic fluids such as Castrol's Brayco Micronic subsea control fluids derived from those used in military aircraft, guided missile systems and even spacecraft. The EH-Mux system concept reduces the impact of fluid viscosity on system response time, allowing control over much longer distances. This also facilitates the use of a closed-loop configuration, where hydraulic fluids are returned back to the platform. At this time, the majority of operators did not transition to this new system, which also meant that they continued to use the standard water-based fluids and discharge them into the sea.

Operators have embraced the transition to EH-Mux subsea control systems. However, there is still a reluctance to return to synthetic fluids to support those systems as this requires a circulating system and return line to the platform, which is considered more expensive in the short term. There is also a perception that today's fluids are still "oil vs. water" from an environmental perspective, when actually most current environmental legislation refers to individual chemical components and the impact they have on the environment and doesn't differentiate between oil- or water-based products.

Fundamentally, a fluid is either compliant with the appropriate legislation, or it's not.

11-million liter global fluid market

The global subsea control fluid market consumes in the order of 11 million liters (2.9 million gallons) annually, and currently this is almost all being discharged into the sea.

From an environmentally sustainable perspective, it is likely that—in the medium to long term—environmental legislation and a desire for continuous improvement will encourage operators to stop discharging products into the sea rather than continually developing less harmful products.

Operations in deep water, remote areas, extreme climates, tieback to shore, HP/HT systems and environmentally sensitive locations each bring unique challenges. As these more challenging operating conditions continue to push the limits of water-based products, an alternative approach should be considered.

Basic chemistry dictates that if a subsea fluid is going to remain stable under extremely adverse conditions, then it must have strong chemical bonds. And a product with strong chemical bonds is unlikely to be biodegraded by marine life when released into the sea.

The industry needs to invest in R&D for a new generation of products that are likely to only be used in a small part of very few systems but are capable of confidently meeting the requirements of next-generation subsea systems. The cost of meeting this challenge effectively is likely to create a product that is too expensive for use in the entire system or to be discharged into the sea.

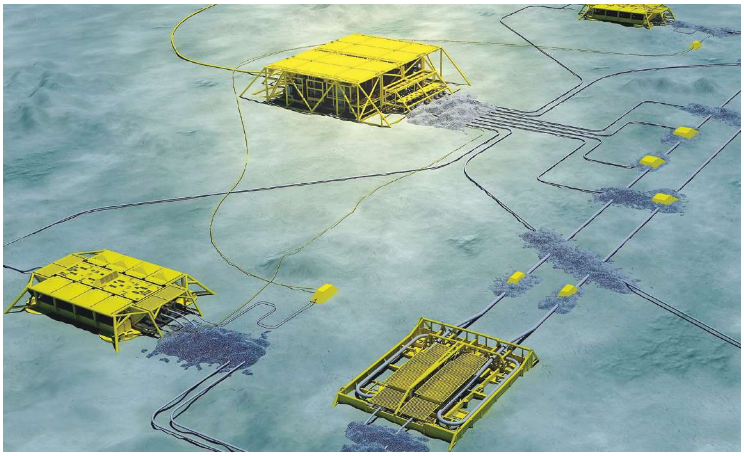
So shouldn't the industry instead consider reverting back to a closed system using synthetic fluid technology, which can provide much greater inherent stability under these extreme conditions?

High-performance synthetics

Synthetics have a proven track record, and there are evolving technologies at an advanced stage that can deliver high performance in these extreme conditions. It is possible. For example, the Ormen Lange Field, which is more than 100 km (62 miles) offshore Norway, is tied back to the coastline with the subsea control system running on Castrol's Brayco Micronic control fluid.

The case for change is not black and white, and there is a need for compromise. There are two relatively distinct areas within the subsea production hydraulic control system, the first being the high-pressure system, which operates in well equipment such as the subsurface safety valve well. This is where the equipment also is subjected to very high temperatures by the raw hydrocarbon flow.

Secondly, the low-pressure system operates valves mounted on the christmas tree. This requires higher volumes of control fluids in a total-loss system but represents a relatively benign environment as the hydraulic actuators are immersed in seawater and so are exposed to lower temperatures.



Shell's Ormen Lange Field, more than 100 km offshore Norway, already employs synthetic technology, with the development's subsea control system running on Castrol's Brayco Micronic synthetic hydraulic fluid. (Source: Statoil)

Simultaneous use of different fluids

At present, a standard water-based hydraulic fluid is generally used throughout the entire system. But could the two nearly separate systems operate autonomously using two different control fluids, each more suited to the operating conditions? This would enable operators to use synthetic products in the high-pressure area and continue to use cheaper water-based products in the low-pressure area.

There are certain technical challenges that will need to be overcome. The differences between the physical characteristics of the two types of fluid need to be taken into consideration when designing the system, and the most frequently quoted argument for maintaining one single total loss system is human error (e.g., if someone puts the wrong fluid in the wrong tank).

But that is something of an unjust appraisal of the ability of subsea operators as their counterparts on surface production facilities are expected to deal with up to 700 lubrication points and about 40 different lubricants.

As subsea production moves into new areas of operations, the industry must be ready with fresh innovations to support successful and reliable operation of such assets in new territories. A collaborative approach between equipment vendors and lubricant manufacturers is essential to ensure the development of new subsea technologies that are reliable and fit-for-purpose.

The technology exists to meet the increasing challenges of the subsea operating environment, but this technology is synthetic rather than water-based, which will require lateral thinking in terms of system design and architecture. E&P

Quest for success in Vaca Muerta

Like in many shale plays around the world, players interested in the Vaca Muerta Formation must overcome steep learning curves and find adequate financing. But the prize is there.

Global Business Reports

Vaca Muerta is home to most of Argentina's 27 Bbbl of unconventional oil and 23 Tcm (802 Tcf) of unconventional natural gas. When asked whether Vaca Muerta's development will come at the expense of other unconventional plays in Argentina, Ernesto López Anadón, president of the Instituto Argentino de Petróleo y Gas, responded, "Yes. Except for a couple of wells that have been drilled in the San Jorge Basin in the D-129 Formation, the bulk of shale exploration and development has been in the Neuquén Basin, specifically in the Vaca Muerta Formation."

A comparison with other unconventional resource plays explains why Vaca Muerta has so much potential. Like the Marcellus Shale in the U.S., which has a total organic carbon (TOC) of 2% to 12%, Vaca Muerta has a TOC of 3% to 10%; like the Wolfcamp play, whose thickness ranges from 200 m to 300 m (656 ft to 984 ft), Vaca Muerta's thickness ranges from 30 m to 450 m (98 ft to 1,312 ft); and like the Eagle Ford, whose reservoir pressure ranges from 4,500 psi to 8,500 psi, Vaca Muerta's reservoir pressure ranges from 4,500 psi to 9,500 psi.

Before YPF's renationalization, its subsidiary AESA participated in projects outside of Argentina, but the company finished its last project abroad in early 2013 to focus on domestic upstream and downstream projects. (Source: AESA)

Despite the technical specifications in Vaca Muerta's favor, among the many challenges stopping Argentina from fomenting its own shale revolution are E&P costs. "The challenge with developing unconventional resources is finding ways of making production more economic," said Santiago Sacerdote of Y-TEC, YPF's R&D branch. "You cannot achieve this with a single technology; rather you need to find the right combination. We need to have a better understanding of the geological characteristics of basins and the hydraulic stimulation process."

A 2014 YPF update on Vaca Muerta laid out the industry's goals:

- To increase productivity, companies in Argentina will need to improve their understanding of the subsurface, identify the sweet spots, optimize completions and master horizontal drilling; and
- To reduce well construction costs, companies will need to improve case drilling techniques, look to local sand, increase operational efficiencies and renegotiate labor contracts.

YPF has made progress in reducing well construction costs. In 2011 it cost about $11 million to drill and complete a well with 3.1 stages in about 43 days; in 2014 it cost about $7.6 million with five stages in about 25 days. About 46% of the total cost now relates to drilling and 35% to completion.

Drawing from the lessons learned in other shale plays will help operators overcome the learning curve associated with developing the Vaca Muerta. Yet López Anadón added, "Regarding operational efficiency, it would be difficult to directly apply the lessons learned in the U.S. to Argentine shale fields. Oil and gas companies in the U.S. have access to 12 million horsepower of fracking equipment, whereas companies in Argentina have access to only about 200,000 horsepower. Oil and gas companies will have to overcome the learning curve associated with understanding Vaca Muerta as a formation. However, lessons related to well completion and the development of drilling and working rigs can be applied in Argentina."

E&P perspective

E&P companies, especially the majors, are known for their willingness to operate in difficult and risky business environments. Yet international players must

The oilfield service market has natural barriers for newcomers, not only because of the needed investments and infrastructure but also due to Argentina's volatile regulatory framework. (Source: Bolland y Cía)

decide whether they are willing to remain in a country after each marginal increase of a country's risk profile. The renationalization of YPF was one such event, which forced international players to decide whether they would remain in Argentina lest they be next. But for several E&P companies, the benefits associated with the successful development of Vaca Muerta outweigh the risks.

Days prior to his departure from Shell Argentina as president, Juan José Aranguren, Argentina's new Minister of Energy and Mining, talked about why the Anglo-Dutch major has remained in Argentina after more than a century, even after YPF's renationalization. "The main objective of an oil company is to convert resources into reserves," he said. "Shell entered into Vaca Muerta in 2012 because it would help the country to develop its resources and the company to produce the oil and natural gas that it needed to remain profitable."

Gustavo Albrecht, managing director of Wintershall Energía, said, "Wintershall has decided to continue investing in Argentina's oil and gas industry for three main reasons. First, Wintershall is convinced about the potential of the oil and gas sector in the country. Secondly, Wintershall has chosen Argentina to develop its center of excellence for unconventional operations, [and] in the future such expertise could be used in other regions in the world where Wintershall is active. The third factor is the massive amount of contingent resources in Vaca Muerta."

But developing Vaca Muerta poses several challenges. Carlos Ormachea, CEO of Tecpetrol, outlines those that stand out to him. "Three stand out at Vaca Muerta. First, Argentina needs a stable financial situation to facilitate the financing of the anticipated projects. The development of these resources will require between $10 billion and $15 billion dollars per year. This is difficult to finance from existing operations without fresh money to supplement it.

"The second challenge is to improve cost efficiency. To attract the investment needed in Argentina, the country needs a minimum critical mass of volume and new services in the country.

"Third, companies need a more precise understanding of the opportunities in Vaca Muerta. Vaca Muerta is undoubtedly a substantial asset, but companies must identify the sweet spots, identify whether these are gas or liquids and determine how best to extract the hydrocarbons. The learning process is costly both in terms of money and time. Overcoming the learning curve will be a great challenge," Ormachea said.

Much relies on YPF's own success, according to Oscar Anibal Vicente, executive vice president of Petrolera Entre Lomas. "Whether the Argentine oil and gas industry manages to take advantage of the country's unconventional resources depends on whether YPF manages to pave the way," he said.

Another challenge will be attracting more small- and medium-sized players, like those that helped foster the U.S. shale revolution. Alberto Saggese, CEO of GyP, said, "Without reform, the second largest reserve of shale gas in the world will be in the hands of a dozen companies instead of the hundreds of companies that are needed. Developing Vaca Muerta will require allowing more players to enter the game."

A significant barrier to entry for independents is financing. Majors willing to take the risk can draw from stockholders and capital markets. Independents often must rely on their own cash flow, especially in Argentina, as Alejandro Joytayan, CEO of Andes Energía, explained. "In the U.S., mid-sized companies financed a significant portion of their unconventional activities with local bank loans. However, Argentina's banks lack sufficient capital and industry knowledge to fully finance necessary investments in unconventional plays, and Argentina's current country risk bars local E&P companies from international capital at a reasonable cost. E&P companies interested in unconventional activities must find alternative financing strategies like financing through not only debt but also equity and their own cash flow. Holding producing conventional assets can provide the cash flow that E&P companies in Argentina need to finance unconventional activities." E&P

Making the connection

Infrared system provides an inside look at tubular connections.

Ray Dishaw, Global Systems Inc., and
Roy Long, National Energy Technology Laboratory

The integrity of downhole tubular connections and the risks associated with failure have been considerations in overall wellbore integrity for decades. These considerations have become much more complex as the types of available connections have multiplied over time. The American Petroleum Institute addressed the multitude of connections available as far back as 1934.

After several decades of advances in connection design, concern emerged regarding overall performance of tubular connections during running casing and installation of completion equipment. This concern led to the development of the torque-turn system that evaluates the torque range achieved during a specific number of turns of the connection. If the desired range was achieved, it was assumed that the connection was made up properly. This empirical approach has become today's primary method for ensuring connection integrity in most operations.

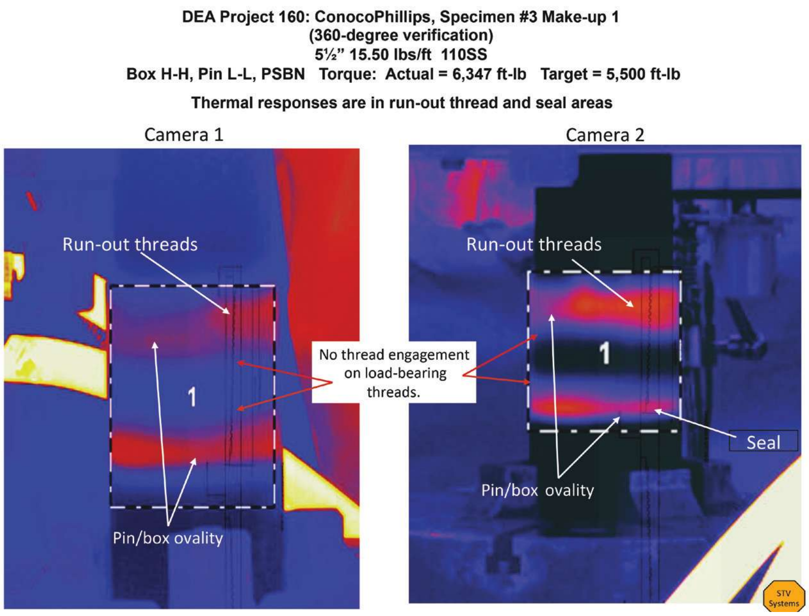


FIGURE 1. An inside view of casing connection demonstrates a potential seal failure. (Source: Global Systems Inc.)

'See' the threads

There is a new technology that, while still performance-based, can "see" in significant detail whether or not there are irregularities in the connection thread form and seal areas that might impact performance. This system is based upon a high-resolution infrared imaging of the connection during makeup.

This new makeup verification system was introduced as a joint-industry project (JIP) topic at the June 2005 meeting of the Drilling Engineering Association (DEA), now the International Association of Drilling Contractors' Drilling Engineering Committee. It subsequently became JIP DEA-160 and was called the Shoulder/Thread Verifier (STV) System. The system offers a new level of detailed thread examination in any connection during makeup without interfering with or slowing the makeup process in any way.

It achieves this capability by passively recording the infrared signature created by the pin and box threads engaging during makeup. The recording is made possible using multiple infrared cameras recording at differing angles. A number of interesting capabilities of the system were noted during the DEA-160 JIP testing. The first was accurate imaging of irregularities during makeup of various types of connections that would not be observed using conventional makeup verification systems.

Figure 1 shows—in real time—a casing connection being made up. With the imaging system it is easy to note the following key items likely to lead to connection seal failure and, potentially, axial strength failure:

- The thread ovality is obvious from the differential heating around the circumference of the threads;
- Essentially no heat is being generated at the center of the thread body on the load-bearing threads; and
- Ovality is observed in the seal area, indicating sealing was limited.

Figure 2 shows a specially altered drillpipe connection that has had ³⁄₃₂ in.

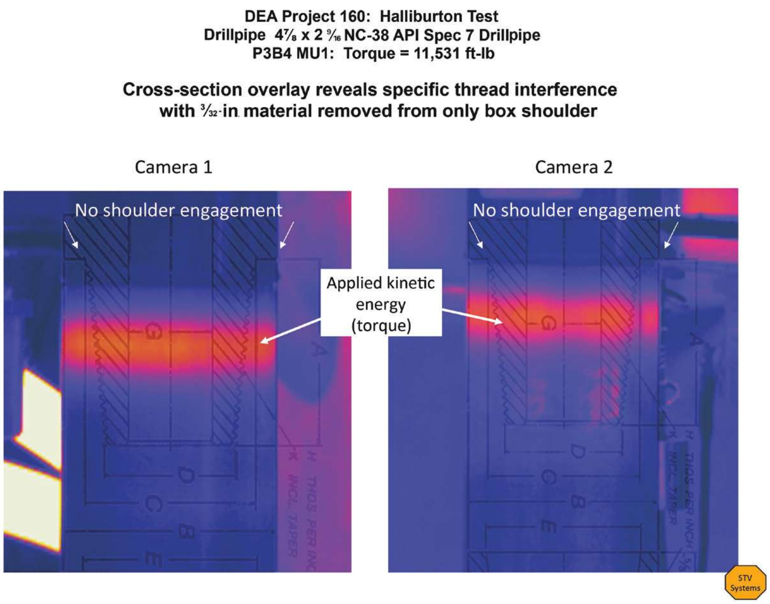


FIGURE 2. A view of a specially altered drillpipe connection with abnormal heat signatures is shown. (Source: Global Systems Inc.)

removed from the box shoulder, as might be found on reconditioned or overly worn pipe. The STV system clearly showed abnormal heat in the thread body with no heat signature in the pin/box shoulder where it should be. This is made more apparent by the addition of the specific thread form outline for the connection. The simultaneous heat imaging on the thread form outline was a significant improvement to the initial software setup.

From the DEA-160 JIP, it became obvious that the STV technology has a series of unique capabilities for assuring connection integrity in an operating environment, including:

- Verification that torque is being applied to the complete length of the mating threads, seal and shoulder;
- Provision of high-resolution images with a change detection limit as low as 0.012 C (32 F) throughout the connection; and
- Provision of real-time makeup displays on the user monitors.

Field-testing

Field tests of the STV established that not all connections coming from the mill were the same. Slight variations between connections from one manufacturing run can be out of tolerance enough from cutting inaccuracies in another run that sealing and thread loading issues become obvious under the detailed scan of the STV cameras.

While the nonuniform mating in the pin and box threads was apparent, it might not always result in failure of the connection to perform. In cases where the connection is well within design limits, it is possible that pipe dope or other thread lubricant/lock materials could provide adequate sealing and even some degree of improved sealing performance. What would not be known in this case, however, is at what unexpected running or operational loads within expected designed limits might the string fail.

Recently the STV technology was used to evaluate a completion string deployed in severe conditions that started leaking early in the string's life. The system was set up to evaluate connections once the string had been returned to the shop and a bucking machine was used to break the connections.

Figure 3 shows monitoring applied to the breakout operation. This level of detail shows that there was a problem with the bucking machine once torque was applied; it rotated very slightly (note misalignment in the graphic). This rotation or bending caused inaccurate torque readings during breakout. This was a very important finding since it potentially affected all other versions of this particular machine.

In summary, the STV technology has demonstrated a significant technology gap across the industry from when the connections are made up at the mill to connection integrity to verification when running tubulars into extreme environments and horizontal wells. E&P

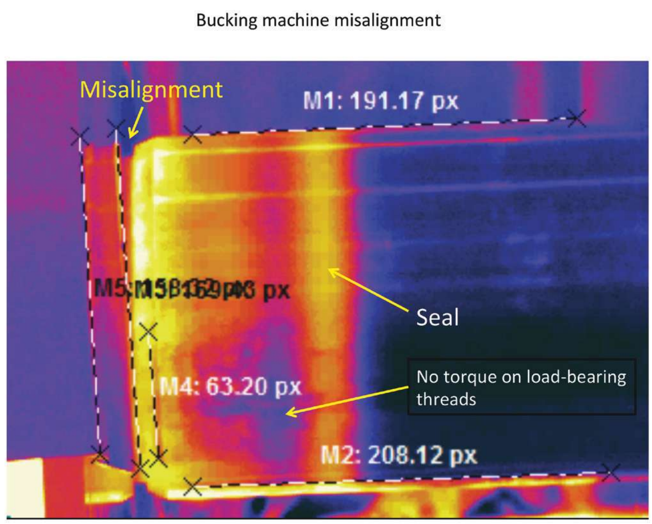


FIGURE 3. Monitoring of a breakout operation shows a misalignment in the bucking machine once torque was applied to the connection. (Source: Global Systems Inc.)

Trout fishing and automation

They actually have a lot in common.

Alex Gelsick, Gray Matter Systems

The first thing one notices about trout fishing in western Pennsylvania on a clear April morning is the stunning, unnerving calm. The quiet that blankets the shores of the state's waterways right around 5 a.m. is so still and peaceful it's nearly sacred.

It's a serenity that commands respect. It forces grown men to creep along its pathways like children sneaking downstairs on Christmas morning. If they talk, they only do so in a whisper. If they break the silence by snapping a twig, they twist up their faces in embarrassment and apologize profusely but quietly.

There's a lot of art in fishing—especially fly-fishing—but there's a fair amount of science involved too. Knowing the best time of day and what bait to use can mean the difference between winning and losing.

While it might sound simplistic, that's pretty much the way applying automation and technology to oil and gas operations works. The more data an operator collects on its surroundings and the better it knows the environment, the better chance it has of being successful.

Streaming data

In the early morning, just after a light rain, as the sky clears and the sun comes out, drops of water collect on leaves and begin to pool. The weight of the water pulls the leaf down and a trickle of water spills out into the river. A small amount of water joins the flow and becomes part of one large stream.

The same goes for the information that unknowingly streams into our networks on a daily basis. Piece by piece, information is collected from offshore platforms and onshore oil wells and transmitted via microprocessor-controlled electronic devices called remote telemetry units. One stream means one thing and came from a specific place, making it usable when operators collect it and learn from it.

HMI/SCADA

Watching a river pass by is not unlike how operators learn about their processes through a SCADA system. Operators interact with the SCADA system by using a human machine interface (HMI), which can be something as simple as a computer screen that displays the SCADA interface.

The data coming into the SCADA system can be as simple as a picture of a tank filling with an animation that represents a certain capacity. When the tank in the field is half full, an animation of the tank onscreen rises to 50%.

In addition to visual cues, the SCADA system also provides alarms that indicate if there's a problem. There also is the "control" aspect, which refers to the operator's ability to remotely operate the equipment.

Historical data

What if every piece of information needed to catch every fish on the first cast could be captured?

Today's powerful historian software does just that. It logs data continuously without fail, collecting thousands of pieces of data and locking them away. For oil and gas companies, this means being able to take years of data from their operations and capturing them into a robust, never-fail locker.

Once those data are captured, they can be analyzed for trends to make better decisions. These practices, while grossly oversimplified, are how companies use Big Data to make things better. Companies analyze years and years of operational data and search for commonalities and trends that will provide insight into how they can improve in some areas or discover deficiencies in others.

A cybersecurity strategy

What if fishing wasn't just a hobby for you? What if your favorite fishing hole was actually the sole source of food for your family, and you needed to protect it at all costs? What if you could segment your part of the river from the rest of the world and cloak it in such a way that no one else could see it?

In the wake of high-profile attacks on big businesses, oil and gas companies across the country are getting serious about implementing a cybersecurity strategy. The Industrial Control System Cyber Emergency Response Team, or ICS-CERT, recommends a defense-in-depth approach involving specific countermeasures to create an aggregated security posture. It can help defend against cybersecurity threats and vulnerabilities that affect an industrial control system.

That technology exists now, and oil and gas com-

SCADA systems can alert operators to situations like when a tank is nearing capacity. (Source: rCarner/Shutterstock.com)

panies are using it to hide critical parts of their network. These cybersecurity solutions can sit on a network and cloak high-value assets, servers and endpoints to safeguard against cyberbreaches.

Standard operating procedures

Standard operating procedures are beginning to change in a very real way. The practice of locking down standard operating procedures makes a lot of sense for a number of reasons. First, it ensures all operators respond to specific situations in a certain predetermined way. Next, it captures the best practices of the best operators before they are lost to retirement. Finally, it ensures that the critical steps required to complete certain activities, some of which may be regulated by government agencies, are followed strictly and documented diligently.

While the variables involved with fishing are part of the game, for the oil and gas industry, technology has become quite adept at weeding out variability in such a way that it becomes a nonfactor. The technology exists today to predict outcomes with great certainty, forecast asset failure accurately and connect people with real-time data so they make informed decisions. E&P

Asphaltene inhibitor improves production flow, delays remediation needs

Baker Hughes has released its high-performance, low-dosage FATHOM XT SUBSEA525 inhibitor that helps control asphaltene deposition in deepwater wells, providing better flow assurance and reducing remediation costs by minimizing the risk of blockages in production lines and equipment, the company said in a news release. The inhibitor was designed and certified for offshore applications using a proprietary qualification protocol and a stringent laboratory evaluation method to enable full compatibility with subsea equipment and effective performance at low treatment levels. During production, crude oils can deposit asphaltenes inside pumps and pipes, creating serious production issues such as plugged flowlines and fouled equipment and resulting in the need to stop operations and perform a costly remediation procedure to get production back online at acceptable levels. Many times these procedures only offer temporary relief. To lessen the risk of asphaltene deposition and enhance flow, the FATHOM XT inhibitor can be applied at low treatment levels during IP and throughout the life of the well. The low-dosage rate simplifies supply logistics, reduces onsite storage and lowers handling risk, the company said. *bakerhughes.com*

GE's Equipment Insight will help GDS International improve its data collection, analytics and management capabilities in equipment such as the pictured GDM500 top drive system in an Orion Drilling mast. (Source: GE)

Platform brings benefits of industrial Internet to power industries

Automation & Controls was born from the Alstom Power acquisition and announced in November 2015. The solutions enable users to connect their machines, data and people for better, faster, safer and more reliable performance, the company said in a release. The comprehensive portfolio of automation and control solutions provides the foundation to enable the collection of data from assets and processes and helps customers leverage those data to derive actionable insights. The products included in GE's Automation & Controls solution platform—industrial software, distributed control systems and process safety systems—control, automate and optimize the processes that power the world. GE's Automation & Controls technology controls and monitors thousands of assets worldwide every day. In addition, Automation & Controls provides customers with support services, including a global network of professionals with application and industry-specific expertise, 24/7 emergency support, online case management and more. *geautomation.com*

Environmental monitoring, oil spill detection made easier

International oil spill player Aptomar has developed a new method for environmental monitoring, making it simpler, more reliable and cost-efficient for oil companies to have around-the-clock monitoring, detection and reporting on unintended oil spills, a press release stated. The newly developed environmental monitoring service, Blue Deal, is tailor-made for monitoring fields in both E&P phases. The service is based on a new technical concept for surveillance and monitoring. Through the BlueDeal service, Aptomarin, the Aptomar 24/7 maritime control center, will on behalf of the customer monitor the sea surrounding the installation or vessel and operationally and technically take responsibility for documenting and reporting that the oil company is operating within the given requirements. It also will detect unintended oil spills within 1 to 3 hours. Aptomarin will be responsible for gathering, analyzing and trending the data from the operation in addition to creating detection reports where the spill, probable polluter and events leading up to the accident are documented. The conducted environmental monitoring will be summarized in a yearly or end-of-well Blue Environment report, which can be used internally or offered to the government or the public. *aptomar.com*

Aptomarin will gather, analyze and trend operations data as well as create detection reports. (Source: Aptomar)

Web-based mobile technology captures, shares operations data

Flogistix LP has released its new Flux technology that provides visibility into long-term performance of oilfield compressors by digitally capturing and sharing operations data in real time, according to a product announcement. Flux is a user-friendly, web-accessible interface that provides real-time insight into unit performance. This visibility provides Flogistix field personnel and customers with immediate answers and capabilities of seeing long-term trends. It is built on top of clustering technology that gives it the ability to run multiple parallel computations on data as it streams in. Sensor data are automatically optimized for viewing over large timespans, giving the user the ability to quickly identify performance trends and possible scenarios. Flux allows users to quickly assess how their rental fleet is running by maintaining a rolling 30-day run-time calculation for each unit. Built on HTML5 mobile-friendly web technologies, Flux is accessible via any mobile device. Flux data are stored securely in the cloud using government-level encryption. *flogistix.com*

Mobile units help reduce emissions, keep oil wells operating at full capacity

How do you meet ever-stricter flare gas capture requirements in an area with limited oil and gas infrastructure? For Enerplus, the answer includes mobile gas capture and natural gas extraction units from GTUIT, a manufacturer in which Caterpillar is a minority shareholder, a press release stated. The units, which are about the size of a semitrailer and easily connect to an engine or generator set, significantly decrease the volume of flared gas at the wellhead, reducing the volume of volatile organic compounds released into the atmosphere. Instead, those compounds are captured as NGL, which can be conserved and sold on the market for later use. *cat.com*

Tool provides high-quality imaging in horizontal, deviated wellbores

Weatherford International Plc has released its Compact oil-based mud (OBM) microimager (COI), a slim-profile tool that delivers fullbore high-definition images in wells drilled with oil-, diesel- or synthetic-based muds. The tool's 4.1-in. diameter enables deployment in a wide range of geometries including narrow, horizontal and highly deviated wells. The COI, which joins the company's established Compact suite of formation evaluation measurement tools, features eight pads with 72 total measurement electrodes that provide optimum coverage. The images can be further enhanced through Weatherford Reveal 360 image processing. Reveal 360 technology uses structural and textural information in the measured parts of the image to reconstruct any gaps between pads. "The COI tool enables us to offer a more comprehensive logging program in OBM wells," said Olivier Muller, global vice president of Wireline and Testing Services at Weatherford. "By analyzing COI images, we can detail the structural, stratigraphic and depositional geology around the wellbore—even in wells previously deemed too complex for imaging services." *weatherford.com*

This slim-profile tool delivers fullbore high-definition images in wells drilled with oil-, diesel- or synthetic-based muds. (Source: Weatherford)

Software makes driver-based compliance the new regulatory standard

A better way for oil and gas companies to technologically manage their complex regulatory requirements is available from Houston-based ACS Engineering through its Continuous Compliance Monitoring System (CCMS) software, according to the company. Eliminating the inefficient, awkward but widely used task-based approach, the CCMS is regulation/driver-based and unique in design, delivery and maintenance, making it exceed other automated concepts. For all the regulatory complexities, ACS system's operation is simple; now companies do not have to painstakingly figure out how to comply with applicable regulations. With the CCMS, companies only receive relevant regulations, which are auto-applied to compliance manuals and tasks. As a compliance-centric bonus, using only site-specific applicability rules (not more or less) loaded into the system saves time and increases economic efficiency, the company said. No glitzy software "extras." Driver-based software is the key. This system deals exclusively with permits, regulations, plans and manuals, for example, that drive the compliance tasks. After the system is populated with a company's applicable regulations—e.g., formatted by task and frequency—it continually expands its knowledge base with each new operation. By automatically tracking and continuously updating the drivers, the system stays current 24/7 without the traditional manual rigors. The CCMS has become a compliance game changer for companies not because of technological complexities but because it simplifies compliance. *acsengineering.com* E&P

Battle ahead for UK North Sea

Oil & Gas UK warns of tough times ahead for the North Sea, but projects due to come onstream offer a glimmer of hope.

John Sheehan, International Editor

Oil and gas producers in the U.K. North Sea increased output by more than 7% in 2015, the first rise in 15 years.

But the industry will be hard-pressed to sustain this into 2016 in a lower-for-longer oil price world, Oil & Gas UK's CEO Deirdre Michie has warned.

She said, "While the U.K. offshore oil and gas industry is having to adapt to the low oil price and drive greater efficiencies throughout its operations, the fact is that the value of our product has more than halved. Times are really tough for this industry and for the people working in it. We will continue to see job losses as we move into 2016.

"As we go through these times, we have to be resilient and focus on what we need to do to get us through the coming months to ensure an enduring industry for the future."

Despite the gloom, however, there are a number of projects due to come onstream that will help keep oil and gas flowing in the region.

The Cladhan Field has been tied back to the Tern platform. (Source: TAQA)

Cladhan Field begins production

There already has been some good news for the U.K. sector at the start of 2016, with Abu Dhabi National Energy Co. (TAQA) bringing the Cladhan oil field northeast of Shetland onstream.

The field, which has been developed as a subsea tieback to the TAQA-operated Tern Alpha platform, is expected to produce 10 Mbbl/d.

The Cladhan Field is located in the northern North Sea in a water depth of about 150 m (492 ft) and straddles U.K. Continental Shelf (UKCS) blocks 210/29a and 210/30a. The development consists of two producer wells and one injection well.

Premier Oil's Solan Field also is expected onstream imminently, although timing of startup is weather-dependent.

Solan is located in UKCS Block 205/26a in 135 m (443 ft) of water and is expected to produce about 40 MMbbl of oil at an initial rate of 24 Mbbl/d.

Two production wells and two water injectors have been tied back to a normally unmanned processing deck supported by a jacket.

Oil will be stored in a 45-m by 45-m by 25-m (148-ft by 148-ft by 82-ft) subsea tank prior to being offloaded to shuttle tankers. Premier said recent tanker trials have been successful, and commissioning work has continued.

Schiehallion, Loyal redevelopment

BP also will be busy in 2016 on its Quad 204 project, a redevelopment of the Schiehallion and Loyal fields, which will extend production out to 2035 and possibly beyond.

The *Glen Lyon* FPSO vessel is currently undergoing sea trials at the start of its journey from the Hyundai Heavy Industries yard in Korea to the west of Shetland, where it will serve as the hub for the 450-MMbbl Quad 204 development.

The project involves connecting and commissioning the new FPSO; the drilling of several new production and injection wells; and upgrading the subsea pipeline, manifold and wellhead infrastructure that will enable the full development of the reserves.

New subsea infrastructure includes five new production flowlines, one new dynamic umbilical, two new static umbilicals, six new risers and two new manifolds.

The new *Glen Lyon* FPSO vessel will be able to process and export up to 130 Mbbl/d of oil and store up to 800 Mbbl of oil.

The vessel will head to Norway in March or April for commissioning prior to startup toward year-end 2016.

Shell, meanwhile, has a swathe of projects on the horizon including Brent decommissioning, redevelopment of the Penguins Field and Brent Charlie and a subsea tieback project on Fram.

EnQuest has multiple projects

EnQuest has revealed plans to build a new pipeline from its northern North Sea Thistle Field to Cormorant Alpha because of the decommissioning of the Dunlin Field infrastructure.

The current 16-in. Thistle oil export pipeline route runs 30 km (18.64 miles) to Dunlin before heading on to Cormorant Alpha and the Sullom Voe terminal, but Fairfield Energy's decision to shut down Dunlin has left EnQuest in the lurch.

The planned pipeline highlights EnQuest's desire to continue to invest in its North Sea assets.

The company, which is the largest independent oil producer in the North Sea, last year started up production on the Alma/Galia Field.

Plans are now being finalized for the next step in the Kittiwake project, with tiebacks planned from the nearby Scolty and Crathes fields. The company's *Quad 9 Kraken* FPSO project also is on track, on budget and on schedule for first oil in 2017.

John Cowie, in charge of the northern North Sea area for EnQuest, said, "In the northern North Sea we're the only people drilling. People are decommissioning and abandoning, but we're the only ones making investments in the northern North Sea, and we're doing that very successfully.

"We're a lot more streamlined and agile than a supermajor. Everybody wants to know how we do it."

Apache continues Forties, Beryl work

Cory Loegering, managing director of another nimble North Sea producer, Apache, said his firm has two of the most prolific North Sea hydrocarbon accumulations at Forties and Beryl.

Forties was acquired in April 2003 from BP for $630 million, and Apache has since invested $2.3 billion in infrastructure and $2.3 billion on drilling and workovers.

The Beryl area was bought in January 2012 from Exxon Mobil for $1.44 billion, and $300 million has since been spent on infrastructure.

The *Glen Lyon* FPSO vessel will operate on BP's Quad 204 project. (Source: Halvorsen)

Apache describes itself as an industry leader for operating costs in the North Sea. Its operating costs per barrel were $13.62 in 2015.

Loegering said Apache will be spending more of its capital on drilling in the future. In 2012 to 2015 the company allocated 51% of capital on drilling and completion, but this is due to jump to 78% during 2016 to 2020.

Inevitably, there have been some delays to projects in the wake of the oil price crunch, and Statoil has pushed production startup on its Mariner Field out to 2017. The average production is estimated at about 55 Mbbl/d of oil over the plateau period from 2017 to 2020.

Expected recoverable oil volumes are estimated at more than 250 MMbbl.

The field will be developed with a production, drilling and quarters platform based on a steel jacket with 50 active well slots and a floating storage unit of 850 Mbbl capacity.

There is plenty of activity planned in the U.K. North Sea in 2016 and beyond, but the industry will have to continue to raise its game to ensure it has a globally competitive and efficient base that continues to attract investment.

Michie added, "Even in these challenging times, we continue to have a supply chain that is the envy of the rest of the world as a center of excellence for offshore technologies. [It] generates tens of billions of pounds in domestic and export sales. It has a workforce with expertise that is unsurpassed globally and whose skills will be critical in helping us unlock the remaining barrels on the U.K. Continental Shelf. With up to 20 billion barrels of oil and gas estimated still to recover, there is good opportunity ahead." E&P

Piney Woods gusher

The East Texas oil boom first bloomed near Mrs. Bradford's garden in 1930.

Jennifer Presley, Senior Editor, Production Technology

The year was 1930, and discoveries at Santa Rita No.1 in the scrubby West Texas desert and elsewhere had helped to boost the state to the top spot as the nation's leading producer of oil. Residents of the Piney Woods of East Texas had yet to experience the thrill of seeing gusher wells fling oil high into the sky.

They'd heard tales of the chaos that wells like the one drilled at Spindletop in 1901 could deliver. It is why when the Daisy Bradford No. 3 rattled its way into memories on Oct. 5, 1930, it did so before a crowd of thousands. That well would go on to become the first of more than 30,000 wells drilled within the 140,000-acre spread that would become known as the East Texas Oil Field.

The field is sourced by oil from a stratigraphic trap in the Eagle Ford-Woodbine group of the Cretaceous, according to a Texas State Historical Association (TSHA) article. Due to the large size of the field geographically, the first wells were located several kilometers apart. However, over time the determination was made that all the wells produced oil from the same Woodbine sands.

The boom that followed the discovery of oil at the Daisy Bradford No. 3 brought thousands of wildcatters and drillers into East Texas, turning once quiet little communities like Kilgore, Texas, into bustling cities. With more than 1,000 wooden oil derricks lining its streets, the city became home to 'The World's Richest Acre,' where more than 1 MMbbl of oil was produced. Steel replicas of the old derricks stand in memory of those raucous days. (Source: Lori Martin, Shutterstock.com)

The discovery

In 1927, a 67-year-old wildcatter named Columbus Marion Joiner and crew spudded the Bradford No. 1 well on an 80-acre tract belonging to a Mrs. Daisy Bradford, according to the TSHA article.

After six months of drilling and no sign of oil, the hole was lost to a stuck pipe and the well abandoned. In 1928, after securing funding through the sale of certificates of interest though a mail promotion, a second well was spudded at a site 30 m (100 ft) northwest of the original well, the TSHA article noted. The Bradford No. 2 reached a depth of 767 m (2,518 ft) before drillpipe twisted off and blocked the hole. As with the first well, there was no show of production, leading the well to be abandoned.

To drill Bradford No. 3, Joiner again sold certificates of interest to secure funding. According to the TSHA, on May 8, 1929, the well was at a new location 114 m (375 ft) from the second site. Drilling proceeded off and on over the months. Progress was slow as funds to pay the crew and keep the rig running were low. Tires were burned to keep the boilers going, and the team worked on Sundays so visitors and possible investors could see a well in operation, Thomas Smith noted in his GeoExPro article, "The Great Black Giant." On Sept. 5, 1930, after the well reached a depth of 1,094 m (3,592 ft) in the Woodbine sand, it flowed live oil and gas on a drillstem test, leading to the decision to upgrade the rig and run casing.

According to Smith, once word was out about the cement plug being drilled out, an estimated 8,000 to 10,000 people made the trip to the well site to "see something happen." It took several days, but finally, on Oct. 3, "oil spirited from the casing and over the crown block, and those gathered there gave vent to their emotions with a loud cheer," Smith said.

IP from the Daisy Bradford No. 3 was 300 bbl/d, according to the TSHA. In the 86 years since discovery, more than 5 Bbbl of oil have been produced from the thousands of wells that comprise the East Texas Oil Field. E&P

Latest in a venerable line

The drillship has been and remains a versatile vessel design that has proved itself an integral part of the E&P industry's adventure into deeper waters since Global Marine's converted *CUSS 1* first entered the scene in the late 1950s.

Since then, the technologies and sheer scale of these vessels have evolved dramatically to the point where one of the latest sixth-generation ultradeepwater units, to have entered the market—Maersk Drilling's *Maersk Voyager*—is a very different creature to its distant forebear.

Although still recognizable as two of a kind, Maersk's Samsung 96K design vessel is a much more potent beast, and its dimensions and capabilities illustrate the concept's development over the course of almost six decades. The *CUSS I*—a surplus navy barge named after the Continental, Union, Shell and Superior oil consortium that originally developed it with Glomar in 1956 as a technological test bed for nascent oil drilling in the Gulf of Mexico—came in at a length of 79 m (260 ft), with a width of 14 m (48 ft) and the initial ability to drill in up to 122 m (400 ft) of water. It was a truly remarkable vessel for its time, which would, of course, go on to drill the famous Project Mohole in the 1960s.

As in all areas of the offshore business, however, more than 50 years of evolution means technologies have advanced the boundaries far beyond what was originally thought possible. The *Maersk Voyager*, delivered to Maersk Drilling early in 2015, is nearly three times as long at 228 m (748 ft) and also nearly three times as wide at 42 m (138 ft). Able to drill in up to 3,600 m (12,000 ft) of water, it can drill wells to a total depth of 12,000 m (40,000 ft).

Maersk probably wishes the costs had not also risen accordingly, however—Glomar's *CUSS II*, for example, despite being nearly twice the size of *CUSS I*, "only" cost about $4.5 million to build in 1962. The building of the *Maersk Voyager* and its three sister vessels, *Maersk Viking*, *Maersk Venturer* and *Maersk Valiant* (all delivered in 2014), represents the slightly higher total investment of $2.6 billion.

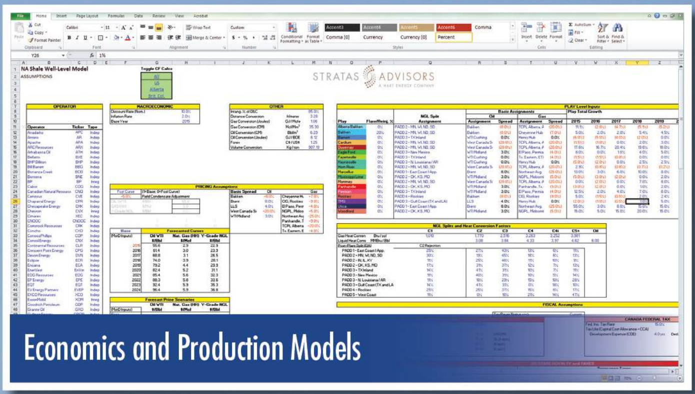
The *Maersk Voyager* is the last in the series of four ultradeep drillships in Maersk's rig fleet and was delivered in February 2015 from the Samsung Heavy Industries shipyard in Geoje-Si, South Korea. It has been working for Italy's Eni offshore Ghana, West Africa, since July 2015, and is planned to stay on contract until December 2018, with an option for a further year, representing expected revenue from the firm contract of $545 million.

The drillship has all the technical specifications expected of a sixth-generation dynamically positioned drillship, including dual derricks and large subsea work and storage areas. Able to stay in a fixed position in severe weather conditions with wave heights of up to 11 m (36 ft) and wind speeds of up to 26 m/sec (85 ft/sec), the drillship also is equipped with multimachine control on the automated drill floor to ensure the latest standards in modern safety levels. E&P

Vessel Facts	
Sector:	Drilling
Owner:	Maersk Drilling
Built:	Samsung Heavy Industries, South Korea
Gross Tonnage:	60,683 tonnes
Hull Length/Breadth:	228 m by 42 m
Variable load:	20,000 tonnes
Well control equipment:	15,000 psi, 18 ¾-in. BOP; six-cavity BOP stack
Top drive:	2 hp by 1,340 hp
Drilling depth:	Up to 12,000 m (40,000 ft)
Water depth:	Up to 3,600 m (12,000 ft)
Accommodation:	230 people
Location:	Ghana, West Africa
Class:	American Bureau of Shipping

Maersk Voyager **is the last of Maersk Drilling's present series of four ultradeepwater sixth-generation drillships and is now drilling for Eni on the Offshore Cape Three Points block offshore Ghana. (Source: Maersk Drilling)**

EXPLORE



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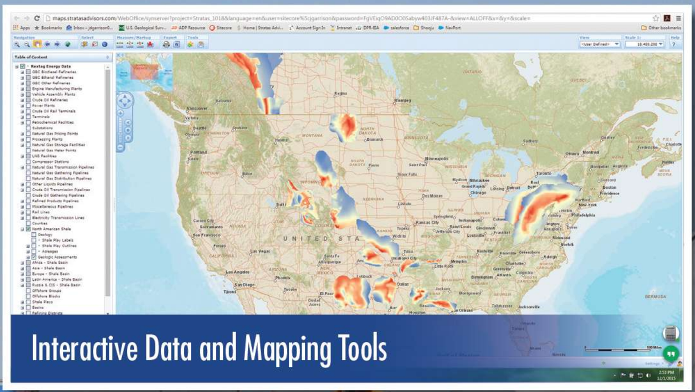
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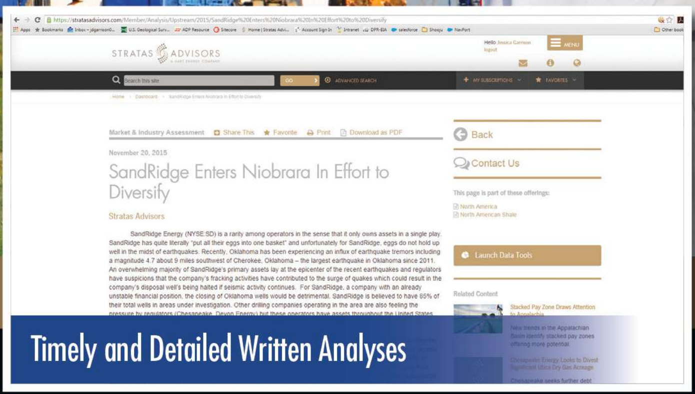

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AFRICA

Etom-2 well hits oil in Kenya

The Etom-2 well in Block 13T in northern Kenya has encountered 102 m (335 ft) of net oil pay in two columns, Tullow Oil said in a December 2015 news release. The objective of the well was to explore the Etom structure in an untested fault block identified by recent 3-D seismic. Oil samples, sidewall cores and wireline logging all indicate the presence of high API-degree oil in the best-quality reservoir encountered in the South Lokichar Basin to date. Additional prospectivity identified on the 3-D seismic in the north of the basin, including the Erut and Elim prospects, will now be considered as part of the future exploration drilling program.

The PR Marriott Rig-46 drilled the Etom-2 well to a final depth of 1,655 m (5,430 ft) and will now move to Block 12A, where it was scheduled to spud the Cheptuket-1 well around year-end 2015. It is the first well to be drilled in the Kerio Valley Basin. (Source: Tullow Oil)

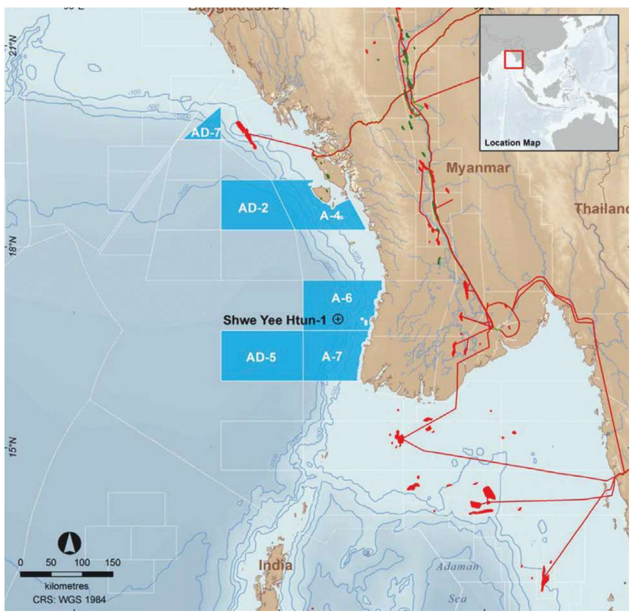
Israel approves natural gas exports to Egypt

Israel's government has given the go-ahead to begin exporting natural gas to Egypt, signaling a potential improvement in relations between two countries that have been at loggerheads over energy supplies, Reuters reported in December 2015. Israel will be able to sell 5 Bcm (176 Bcf) of gas to Egypt in the coming seven years from the Tamar Field off its Mediterranean coast, Energy Minister Yuval Steinitz said in a statement Dec. 24. "After years of delay and debate, we are starting to move forward and to position Israel as a regional natural gas power," he said.

ASIA

Woodside discovers gas offshore Myanmar

The Shwe Yee Htun-1 exploration well in Block A-6 in the Rakhine Basin offshore area of Myanmar has hit a gross gas column of about 129 m (423 ft), Woodside said in a news release. About 15 m (49 ft) of net gas pay was interpreted within the primary target interval. The well reached the planned original total depth (TD) of 4,810 m (15,781 ft). Following drilling, wireline logging was conducted and confirmed the presence of a gas column through pressure measurements and gas sampling. The well was subsequently deepened to a final TD of 5,306 m (17,408 ft). Spudded Nov. 27, 2015, the well reached its original target Dec. 23, and wireline logging concluded Dec. 29. Woodside said Shwe Yee Htun-1 targeted one of many identified channel complexes that run over a large anticlinal feature, the Saung Anticline. "Further analysis will be undertaken to understand the full potential of the play, but this de-risks a number of leads, which will now be matured," Woodside CEO Peter Coleman said.



The Shwe Yee Htun-1 exploration well in Block A-6 in the Rakhine Basin offshore area of Myanmar has hit a gross gas column of about 129 m. (Source: Woodside)

Sinopec strikes oil at Beibu Bay test well

Sinopec Corp. said it struck high-yielding oil and gas in a test well offshore Beibu Bay near China's southwestern coast, marking a rare offshore oil and gas find by the state firm that is largely focused onshore, Reuters reported. The Wei-4 well, some 110 km (68 miles) southwest of the coastal city of Beihai, tested a daily output of 1,264 tonnes of crude oil and 71,800 cu. m (2.5 MMcf) of natural gas at a first layer after identifying oil-bearing layers nearly 100 m (328 ft) thick. On the second layer, Sinopec struck 1,184 tonnes of daily oil flow and 76,000 cu. m (2.6 MMcf) of natural gas, the company said in a statement Jan. 6. The well, drilled in the shallow part of the sea, is 3,783 m (12,411 ft) deep. It took 29 days to drill. "It's a high-flowing offshore test well rarely seen over the last decade," Sinopec stated.

EUROPE

Oil price may prompt exploration in Norway's Lofoten area

The low price of crude could make it more likely that oil firms will be allowed to explore in Norway's Lofoten region after 2017, which is currently off-limits due to environmental concerns, the country's energy minister said Jan. 7, according to a Reuters report. "The resources offshore Lofoten and Vesteraalen must at some point come into play, and it is clear that this will be more relevant because of the low oil prices and the situation we now see in the industry," Petroleum and Energy Minister Tord Lien told Reuters. The shallow waters off Lofoten are expected to hold large reserves that can be produced at a lower cost than the more expensive areas currently being explored farther north on Norway's continental shelf. When the right-wing minority government of the Conservatives and the populist Progress Party came into power in 2013, however, it agreed with two smaller support parties not to open several sensitive areas to oil and gas exploration, including Lofoten. The next general election is due in September 2017.

NORTH AMERICA

Talisman Energy changes name to Repsol Oil & Gas Canada

Talisman Energy Inc.'s legal name is now Repsol Oil & Gas Canada Inc., effective Jan. 1, according to a news release. Repsol Oil & Gas Canada Inc. is a wholly owned subsidiary of Spain's Repsol SA. The legal name change will not create new entities or affect the rights or obligations under current agreements, licenses or permits. Addresses did not change, and until further notice, the names of all other Talisman subsidiaries will remain unchanged.

RUSSIA CIS

Russian's 2015 oil production hit post-Soviet record high

Oil output in Russia, one of the world's largest producers, hit a post-Soviet high in December and in 2015 as small- and medium-sized energy companies cranked up the pumps despite falling crude prices, Energy Ministry data showed on Jan. 2, according to a Reuters report. The rise shows producers are taking advantage of lower costs due to rouble devaluation and signals Moscow's resolve not to give in to producer group OPEC's request to curb oil output to support prices. But the rise will contribute to a global oil supply glut and exert continued downward pressure on oil prices, which hit an 11-year low below $34 per barrel in January 2016, having fallen almost 70% in the past 18 months.

SOUTH AMERICA

Rio de Janeiro state implements new oil, gas production tax

Brazil's Rio de Janeiro state, facing a budget shortfall caused in part by plunging oil prices, imposed new taxes on petroleum and natural gas Dec. 31, 2015, a move critics said will slash investment in an already battered industry, Reuters reported. Brazil's economy is suffering its worst recession in decades, while a corruption scandal at Petrobras has choked off investment and delayed new output. Rio de Janeiro state's financial crisis has reached a point where universities and health services have suffered cuts, many public servants have not been paid in more than a month and the sick have been turned away from hospitals. Rio de Janeiro, responsible for 67% of Brazil's crude output and 40% of its natural gas, will charge a flat tax of 2.71 reais ($0.69) on every barrel of oil equivalent produced in the state. The government hopes the tax will raise about 1.84 billion reais ($476 million). The state also imposed an 18% goods-and-services tax on each barrel of oil or barrel of oil equivalent produced. The tax will be applied on the reference price for each well's oil set by Brazil's oil regulator, ANP. According to the text of a law published Dec. 30, the flat tax was imposed to better regulate and supervise petroleum operations. Among the state's main producers are Petroleo Brasileiro SA, BG Group Plc, Royal Dutch Shell Plc and Galp Energia SGPS SA. IBP said the taxes are illegal and that it will challenge them in court. E&P

on the MOVE

PEOPLE

Kevin Gallagher has been selected as Santos' managing director and CEO effective Feb. 1.

The International Association of Drilling Contractors announced the resignation of **Stephen A. Colville** as president and CEO and the appointment of **Jason E. McFarland** as interim president effective Nov. 30, 2015.


Lorenzo Donadeo (left), co-founder and CEO at Vermilion Energy Inc., will retire as CEO March 1, at which time he will transition to his new role as chair of the board of directors. **Larry Macdonald**, the company's current chair, will transition to lead director. **Anthony Marino** (right), the current president and COO, will assume the role of president and CEO upon Donadeo's retirement.

Hannon Westwood appointed **Richard McGrath** as CEO Nov. 24, 2015.

Warren Resources named **Frank T. Smith, Jr.** senior vice president and CFO and appointed **James A. Watt**, president and CEO, to the board of directors.

Andy Hill, Oniqua Intelligent MRO's co-founder and CEO, retired Dec. 4, 2015, after 25 years of service. **Steve Herrmann**, executive vice president of marketing and alliances, will serve as interim CEO.

Occidental Petroleum Corp.'s board of directors has promoted **Vicki A. Hollub** to president and COO and appointed her to the board. Hollub will succeed **Stephen I. Chazen** as CEO, effective at the company's 2016 annual shareholder meeting.

WellDog hired **Trenton Thornock** as WellDog's Group CFO.

Karl Chalabala joins SunTrust Robinson Humphrey as a director to cover the E&P space out of Houston.




Danos added to its leadership team by promoting **James Callahan** (far left) to vice president of finance, **Mark Danos** (second from left) to vice president of project services, **Stacey Gisclair** (far right) to vice president of human resources and **Reed Peré** (second from right) to vice president of production services.

Wood Group appointed three senior engineering specialists who will lead a new team of up to 20 people in the U.K. **Mark Hutchinson** will become operations manager of Wood Group's U.K. vibration team, **Jonathon Baker** joins as sales and business development manager, and **Rob Swindell** will take on the role of R&D and technical authority.

Dr. Alan J. Cohen joins Headwave as strategic adviser.

Marathon Oil Corp.'s **Michael J. Stover**, currently vice president of operations services, retired Nov. 30, 2015, following nearly 30 years of service.

Emco Wheaton appointed **Lee Webb** production manager at its Margate plant in Kent, U.K.

The executive board of MAN Diesel & Turbo appointed **Per Rud** head of PrimeServ Diesel.

Fernando Hernandez has been selected as U.S. sales manager at SECC Oil & Gas.

Energy Software Intelligence Analytics Group named **Malcolm Ricketts** research director.




TAM International announced strategic changes in its U.S., Latin American and global leadership roles. **Tim Davis** (far left) has been appointed global technical director for TAM. **Marty Coronado** (second from left) joined TAM in November 2015 as engineering director. TAM appointed **Art Loginov** (second from right) as director of Latin America for Western Hemisphere operations. **Mike Beleau** (far right) has accepted the role of business development director for TAM U.S.

Fike Corp. selected **David Kemp** as executive director of sales for the Americas.

Henrik Brünniche Lund has been appointed investor relations director at DONG Energy.

The board of the Australian Petroleum Production & Exploration Association announced the reelection of **Bruce Lake** as chairman and **Richard Owen** as vice chairman.

Decom North Sea appointed **Alistair Hope**, **Alan Edwards**, **Sebastiaan Pauwels**, **Robert McCaig** and **Gerard Lubbinge** new board directors, while **Pamela Ogilvie**, **Tom Leeson**, **Murdo MacIver**, **Roy Aspden** and **David Dent** have been reelected as directors to the board.

Junex Inc.'s board of directors endorsed the appointment of **André Gaumond** as a director of the company.

The Severneftegazprom board of directors named **Vladimir Dmitruk** the company's director general Nov. 23, 2015.

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Cabot Oil & Gas Corp. elected **Dorothy M. Ables** and **Robert S. Boswell** to its board of directors Dec. 2, 2015.

Drillinginfo appointed **Dr. Phiroz (Daru) Darukhanavala** to its board of directors.

COMPANIES

Unique Group will expand its operations into the Kingdom of Saudi Arabia with the opening of two new facilities in Riyadh and Dammam.

Well Control School (WCS) relocated its training center in Lafayette, La., to 425 Settlers Trace Blvd. WCS was scheduled to hold its first classes in the new larger center Nov. 30, 2015. The training center also includes state-of-the-art simulators and computer stations for its System 21 e-Learning programs.

Wood Group has expanded into Slovakia, opening an office in Bratislava that the Automated Technology Group, a Wood Group Mustang company, will use to support automation projects in Slovakia and the surrounding region.

BHR Group launched a commercially available open-access downhole test facility in December 2015, based in Cranfield, U.K. The onshore facility is the first of its kind in the U.K., providing an easily accessible secure flexible onshore environment that accurately reproduces downhole conditions. E&P

ADVERTISER INDEX

Leveraging a down market to improve company fundamentals

Industry slowdown provides the time needed to identify and capitalize on opportunities.

Don Gawick, C&J Energy Services

When a severe industry downturn occurs, most service companies institute a well-worn series of steps to counter the effects. The companies immediately halt nonrevenue producing programs to stem cash flow, slashing the overall budget (both current and long-term) and instituting massive layoffs. While some cuts are necessary, many are made without any overarching vision or strategy. In fact, many of these cuts are short-sighted remedies that ultimately sacrifice the future growth of a company.

Although no one wants to see a continuation of today's depressed oil and gas market, the current state of the industry presents an opportunity to review and improve critical components of a company's business and operational programs. These components are not only limited to traditional processes around safety, maintenance and supply chain but can be applied to enterprisewide initiatives that address data and operational efficiency, research and technology development, and even mergers and acquisitions.

During periods when it is not feasible to deploy new equipment, companies are well served to review and focus maintenance programs that extend the life of existing equipment and reduce overall operating costs. For example, C&J continues to work on extending the life of its fluid ends and also is upgrading the control systems in its fracturing units. These programs will result in better performance, lower costs and enhanced service quality and will eventually achieve a standardized platform across all its fracturing operations.

Enterprise technology implementations such as an enterprise resource planning system require companywide participation. While projects of this scale are challenging in any market, a downturn offers the opportunity to step back and assess the current state of data and processes. From those observations, a solution can be designed that is responsive to the needs of the organization and its customers. C&J is prioritizing solutions that will enable more informed business and operational decisions and faster response to field and market conditions by delivering the right information to the right people at the right time.

Slower periods are an ideal time to reinforce HSEQ standards and help ensure that all employees are engaged and aware of safety protocols.

In a downturn, all aspects of supply-chain management must be examined. Now is a good time to renegotiate contracts; review procurement practices and supplier lists; and standardize price books, systems and processes. With the right fundamentals in place, companies will be positioned to achieve increased economies of scale both in today's market and as conditions improve.

A continued commitment to research and technology development can yield a competitive advantage, especially those technologies that create additional customer value and improve the bottom line. For example, C&J recently introduced the LateralScience engineered completion process. This technique helps optimize completions placement to increase well productivity. The company's new Ultra Short Bearing Section drilling motor contains the industry's shortest bit-to-bend length and is designed to drill the vertical, curve and lateral in a single run, resulting in fewer trips downhole and reduced nonproductive time.

Acquisition in a low-cost environment does not have to be on a massive scale to be strategically important. C&J recently completed the acquisition of ESPCT, a small Houston-based company that specializes in artificial lift accessories and hardware for installation of electric submersible pumps. Their capabilities fit well with the C&J strategy of expanding its presence in the production phase of the well.

The industry as a whole has a wealth of experience managing downturns—C&J has seen them before and will see them again. But while it is standard practice to adjust budgets and headcounts during market contractions, it is just as essential to preserve the core abilities and long-term vision of a company so it can take full advantage of the market return. Strategic commitments to human capital, technology, processes, safety and maintenance help companies navigate short-term challenges and lay the foundation for future success. E&P

THE POWER SECTION

Reliability and torque—a valuable combination.

An operator in the Eagle Ford Shale recently drilled a record run using Dyna-Drill's 7-in power section, which is engineered with a proprietary hard rubber elastomer. The customer drilled one of its fastest curve/lateral hole sections, averaging 3,078 ft/d with ROP up to 400 ft/h while maintaining 1,400-psi differential pressure.

Since our founding in 1958, Dyna-Drill has been committed to providing robust, high-performance technologies that consistently deliver unprecedented value to our customers.

Find out more at

dyna-drill.com/products/power_sections

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