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Hart Energy's conferences bring top oil and gas executives and experts together for uniquely candid conversations on the most important topics facing the industry.

Since the conference debuted in 2010, the **DUG *Eagle Ford*** audience has come to anticipate its speakers, executives who discuss their companies' strategies in the region. This year, Lance Robertson, VP of Eagle Ford Production Operations for Marathon, returns to the stage, and three CEOs – Glenn Hart (Laredo Energy), Patrick Oenbring (Hawkwood Energy) and Tony Sanchez (Sanchez Energy, a pure-play Eagle Ford producer) have already committed to what's sure to be another strong slate of seasoned industry pros.

Keynote Speaker DUG *Eagle Ford:*

Lance W. Robertson
Vice President – Eagle Ford Production Operations
Marathon Oil Corporation

Keynote Speaker MIDSTREAM *Texas:*

Jim Teague
CEO
Enterprise Products Partners LP

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AUGUST 2016
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COVER STORY: MATURE FIELDS & MMR

SPECIAL SECTION: OFFSHORE NORTHERN SEAS TECHNOLOGY SHOWCASE

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The Eagle Ford: At a Crossroads

South Texas producers navigate the road to recovery.

It has been almost two years since OPEC's decision to increase production sent oil prices crashing below $30. In that time, Eagle Ford rig counts have cratered by 80% or more in most fields, and production growth in non-core areas has screeched to a halt. Even the biggest and best-financed companies have endured deep budget cuts.

Producers have had to completely rethink their business strategies. "The Eagle Ford has become a giant science lab," said Leslie Haines, executive editor at large for Hart Energy. "There's so much more to learn here. At $100 oil, the nuances weren't as important as they are now. That's why we look forward to **DUG *Eagle Ford***, to hear more about how operators are advancing."

As an industry, what have we learned in this downturn? And how do we leverage these lessons to propel us into the coming market recovery? Hart Energy's 2016 **DUG *Eagle Ford*** Conference and Exhibition, scheduled Sept. 12-14 in San Antonio, will explore these questions and more.

The path forward: efficient technologies and strategies

As signs of a market recovery take hold, industry leaders' questions are shifting from "how low will it go, and for how long?" to "how much will it recover, and how quickly?" Many of the world's leading producers consider the Eagle Ford a core asset. And as conditions improve, activity will return to the region. Blessed with 18,000 sq miles of diverse resources (crude oil, NGLs and dry gas), ample takeaway capacity (via pipe and rail), and close proximity to Gulf Coast customers and export terminals, the Eagle Ford has unique advantages over other plays. However, recovery will take time, as companies remain focused on cutting costs and deploying the latest efficiency-focused solutions.

DUG *Eagle Ford's* conference sessions, exhibit floor and all-new Technology Showcase are designed to bring industry professionals together for an in-depth look at what it takes to succeed in this market and how companies should position themselves to prosper.

> "The Eagle Ford has become a giant science lab. There's so much more to learn here. At $100 oil, the nuances weren't as important as they are now. That's why we look forward to **DUG *Eagle Ford***, to hear more about how operators are advancing."
>
> **– Leslie Haines,** Executive Editor at Large, *Hart Energy*

The event features a potent mix of executive-level speakers who will discuss timely topics: balance sheet management, operational strategies, technology development, commodity prices and activity forecasts.

Top industry analysts and leading solutions providers will join the region's most active producers on stage for uniquely candid conference sessions. Topics include:

- Economics in the Eagle Ford: What areas offer an attractive ROI, how are companies financing their activity, and what's happening in the A&D space?
- Technology spotlights: Hear the latest in enhanced oil recovery (EOR) advances, water handling and DUC completion designs.
- Producer highlights: Lower per-well costs and higher productivity make core areas attractive. Find out where top producers are drilling and learn about their results.

On the exhibit floor, hundreds of leading service and supply companies will give attendees hands-on access to products, services and technologies that help producers save valuable time and money. The event's all-new Technology Showcase features case studies and live demonstrations on topics from artificial lift to enhanced completions.

Collaboration is key: co-locating with MIDSTREAM Texas

During these challenging times, it's critical for industry professionals to stay connected. With thousands of attendees converging in San Antonio and 9-plus hours of dedicated networking events, **DUG *Eagle Ford*** is where South Texas' oil and gas community meets. Hart Energy is once again co-locating its second annual **MIDSTREAM *Texas*** Conference and Exhibition with **DUG *Eagle Ford***. Attendees can choose to focus on upstream or midstream content, or they can upgrade to attend sessions at both conferences for greater value. E&P

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__DUG Eagle Ford__ and __MIDSTREAM Texas__ take place Sept. 12-14, 2016, at the Henry B. Gonzalez Convention Center in San Antonio. To register, attend or learn more about exhibiting and sponsorship opportunities, please visit DUGEagleFord.com or MidstreamTexas.com.

DEPARTMENTS AND COMMENTARY

COMING NEXT MONTH The September issue of ***E&P*** will focus on production optimization. Other features will include unconventional exploration technology, multilateral/extended-reach drilling, and proppants as well as floating production, mooring and positioning. The regional report will focus on the Mediterranean and North Africa. 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 Statoil's Heimdal Gas Center on the Norwegian Continental Shelf is an example of how operators are giving new purpose to maturing assets. Left, operator Det norske's Ivar Aasen platform jacket is shown after installation last year offshore Norway. The field is due onstream before year-end 2016. *(Cover photo courtesy of Statoil; left photo courtesy of Det norske; cover design by Felicia Hammons)*

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ACTIVITY HIGHLIGHTS

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Vertical wildcat in Routt County, Colo., produces from Niobrara

A vertically drilled wildcat Niobrara discovery was announced by Southwestern Energy Co. in Colorado's Routt County. Located in Section 26-7n-88w, #1-26 North Hayden produced 11.523 MMcf of gas, 319 bbl of oil/condensate and 6.621 Mbbl of water during its first three months of production (September to November 2015).

Wolfcamp well tests flowing 2.5 Mbbl/d of oil, 7.25 MMcf/d of gas

Anadarko Petroleum Corp. completed a Reeves County (RRC Dist. 8) Wolfcamp well in Texas. The #1H Mesquite Unit 2-2 was tested flowing 2.526 Mbbl/d of 47.1-degree-gravity oil, 205,297 cu. m/d (7.25 MMcf/d) of gas and 9.764 Mbbl/d of water.

New estimate indicates 5 Bbbl of oil in Celtic Sea

Providence Resources has confirmed the Druid and Drombeg Prospects in Ireland's Celtic Sea could hold total cumulative in-place unrisked prospective resources of 5 Bbbl of oil.

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Report: US tight oil wins on lower global cost curve

By Velda Addison, Senior Editor, Digital News Group

Of the 13 MMbbl/d of new supply that could come from tight oil and conventional projects by 2025, 9 MMbbl/d is commercial at $60 oil, according to an energy consulting firm.

India looks to lure oil, gas investors in latest bid round

By Velda Addison, Senior Editor, Digital News Group

The country is offering 67 discovered small fields in 46 contract areas, including 26 onshore, 18 shallow-water and two deepwater areas.

US finalizes drilling regulations in Arctic Outer Continental Shelf

By Velda Addison, Senior Editor, Digital News Group

Industry groups call the rules an "unfortunate turn" and say the regulations include "unnecessary requirements."

Midcon drilling efforts shift to Meramec Shale, STACK play

By Hart Energy Market Intelligence Series

Oklahoma's Kingfisher and surrounding counties saw drilling activity rise in first-half 2016, with Newfield, Continental and Le Norman Operating leading the pack.

E&P

1616 S. VOSS ROAD, STE 1000
HOUSTON, TEXAS 77057
P: +1 713.260.6400 F: +1 713.840.0923
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Editor-in-Chief	MARK THOMAS
Executive Editor	RHONDA DUEY
Group Managing Editor	JO ANN DAVY
Senior Editor, Production	JENNIFER PRESLEY
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Editor-in-Chief
mthomas@hartenergy.com

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Less is more

Recent panic headlines about falling numbers of multibillion dollar megaprojects are missing the point.

Life is full of paradoxes. Making the right decision often takes good judgment based on experience, but that experience might have been gained by having made several bad ones, for example.

Recently I've seen many comments and opinions related to a new study by analyst Wood Mackenzie (WoodMac) that among many insights flagged the falling number of major projects approved annually over the past decade and the undeniable trend that U.S. shale is leading the way in low-cost production.

But what was particularly interesting was how the company's detailed analysis was quickly grasped and pushed out in a more alarming style by the majority of media outlets and industry observers.

One overall message kept recurring—the number of large projects (meaning those with multibillion dollar megaspending) is falling. This, we were told in no uncertain terms by various commentators, was a bad thing. Between 2007 and 2013 there were up to 40 large projects approved annually. But in 2015 there were eight, and this year perhaps 10.

Perhaps this seems too obvious, but probably the biggest reason the industry is going through challenging times is because it overspent on such projects, accepting development costs that were totally nonviable if the oil price fell.

The past year-and-a-half have seen the upstream sector carry out major surgery to survive while—with increasing success—addressing and solving those unacceptable project costs. WoodMac pointed out, for example, that since 2014 costs have fallen 10% to 12% in the global oil industry, led by the super-responsive U.S. shale industry, where costs have dropped on average between 30% and 40%.

The analyst added that 70% of new drilling in U.S. tight oil plays and pre-final investment decision conventional projects are now considered commercial at less than \$60/bbl, but that still means the oil price needs to rise further or, more likely, that costs need to keep falling.

Only a few giant (and very expensive) projects that have lifespans of several decades will go ahead in the meantime, such as Chevron's recent decision to proceed with its \$37 billion 260,000-bbl/d expansion of the producing Tengiz Field in Kazakhstan.

The fact that there are fewer \$10 billion or \$20 billion (or more) projects on the "biggest spend" list of various analysts is a good thing. Such lists for too long contained inappropriate projects whose owners should never have allowed such poor control of spending to take place.

Some of the most successful companies in the coming years are likely to be those whose names we see least on the "most expensive projects" list. Less can be more... E&P

Introducing cost-conscious compliance

The offshore sector can spend less without making compromises.

Richard Nott, Lloyd's Register

The price of a barrel of oil or unit of gas is well known, as are the immediate fees paid to independent third parties, but less so the collateral cost of compliance. Add up all the preparatory activities such as tank preparation for entry and then factor in the production interruptions, and the cost can be vast for duty holders. It also might be unnecessary. Alternatively, cost-conscious compliance offers sweeping financial gains.

Compliance costs should be managed proactively. (Source: Lloyd's Register)

The cost to produce today's barrel of North Sea oil can be greater than the price paid for it. Although particularly challenged, the U.K. offshore sector is not alone in facing unprecedented pressure to cut spending. The dramatic fall in oil prices and decline in gas prices has hit the sector hard globally. The consensus is that this trend will continue, while regulatory demands will only heighten. Bold thinking is needed in all quarters, and compliance should be no exception.

In high-risk sectors, challenging compliance often is regarded as controversial and even underhanded. It should be applauded if done right; taking full advantage of every opportunity to optimize efficiencies is a positive step. Lloyd's Register maintains this as an independent body that has held safety, integrity and high standards as guiding principles for more than 250 years. The argument for cost-conscious compliance does not advocate compromising safety, environmental protection or corporate reputations. It does not dismantle the regulatory framework. Rather, it reconstructs those beams and brackets to build a robustly effective compliance approach for unique offshore assets, be they fixed or floating.

Concentrating on what counts

The supply chain focus on reducing compliance spending is direct but misdirected. Minuscule short-term savings are the result. Take a U.K. North Sea asset, which might incur a £100,000 spend with a classification society and independent


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verification body (IVB). Even a reduction in rates as high as 20% equates to a one-off savings of £20,000. This is insignificant when one considers that a single tank entry will cost roughly tenfold that amount. On top of this, there are the financial losses of interrupting production; the collateral costs for one event can escalate into the millions.

It is this short-term mindset that needs to shift, not the tank's ballast. And it's not just tank entries to consider. Compliance's collateral costs encompasses a spectrum of activities that shut down critical equipment, prevent everyday operations, consume the time of onboard personnel, introduce external inspectors and other professionals, use up helipad slots and more. The majority of these costs can be saved if a company starts from the position that there is little need for compliance-only activities.

Minimizing spend, maximizing benefits

Lloyd's Register sees six main ways to optimize compliance. While goal-setting approaches, notably the U.K. Safety Case regulations, offer greater opportunities for efficiencies, there is more potential than often thought under prescriptive regimes.

1. Fully integrate compliance and integrity assurance activities.
"Double dipping" of activities is commonplace, but with one unified program this costly practice can be avoided. The long-term benefits are considerable for an upfront investment. Working closely with a classification society and experienced IVB, an offshore business can account for all of its asset's collateral compliance costs. With this information, it's possible to comprehensively align regulatory and integrity assurance activities, establishing a proprietary scheme that simply does compliance smarter than previously.

2. Program activities on a true risk-based basis.
A risk-based approach provides particular opportunities for savings, especially for complex assets operating in challenging environments. It allows considerable flexibility in the scheduling of structural inspections, moving away from the traditional five-year survey cycle. Credit can be earned for enhanced design that reduces fatigue and corrosion. Activities can be coordinated with operational or maintenance needs. Schemes can be tuned to operational experience. However, a risk-based approach does not necessarily mean doing less. Determining a risk-based inspection plan is a significant exercise, and it's best to stick to the rules once they have been set. Increasingly, risk-based schemes are available under prescriptive approaches. Lloyd's Register updated its "Rules and Regulations for the Classification of Offshore Units" in 2015 to allow the use of risk-based inspection techniques for a big-ticket item: hull structural inspection.

3. Work with regulators to agree on alternative arrangements.
The opportunities here have largely been untapped, even when it comes to floating installations operating under U.K. goal-setting regulations. The trend is to adhere to international conventions such as MARPOL and SOLAS without contemplating the options. But rules are there to be challenged with sound alternatives that class can agree on. "Equivalent level of safety" clauses appear for a reason. Solutions such as condition-based maintenance are well defined and accepted. Successes can be achieved provided the case is made from an in-depth understanding of what's being challenged.

4. Plan for compliance activities, particularly offshore.
Where compliance-only activities can't be avoided, planning them ahead of time saves money. Aborted surveyor visits are costly. Dealing with an issue offshore that could have been resolved onshore is an unnecessary expense. These all add up. Again, a close relationship with a classification society and IVB will help.

5. Take advantage of credit to be gained from unplanned events, maintenance and testing.
Compliance does not necessarily require an activity to be witnessed by an independent body. An audit of the activity by that body might be perfectly acceptable as long as the details have been suitably recorded. With a little forward thinking, unplanned downtime becomes an opportunity to perform upcoming compliance tasks, not just to investigate the incident. Why run a shutdown test in the near future when equipment already has been forced to power down? There are also efficiencies to be gained when all maintenance and testing is recorded in a way that demonstrates suitability.

6. Be open to using new tools and techniques.
IVBs are able to help the industry assess the pros and cons of employing new ways to demonstrate compliance. Let's return to that cargo tank. Inside an LNG vessel, the membrane will be a big, wide, flat space and, with only a few welded stiffeners, delicate. Such an environment lends itself well to inspection by drones. The increasing use of photogrammetric techniques and supporting software allow operators to see and analyze more than a surveyor can *in situ*. Elsewhere, risk modeling and graphical representations also can support efficiencies.

With a compliance rethink and closer collaboration between the offshore industry and its independent experts, money spent on meeting regulations should never be a waste of money. E&P

Deep water to surface from downturn dip

Deep water will rise from the depths to once again feed the industry's future need for major offshore reserves.

Mark Thomas, Editor-in-Chief

The American novelist Mark Twain—hearing on good authority that he was thought to be dead—once responded cheerfully to a determined reporter, "The reports of my death are greatly exaggerated."

Likewise, for those tolling the death knell for the global deepwater oil and gas sector, its predicted demise is also far too premature. It is human nature perhaps for some folk to write something off too quickly after encountering adversity.

But according to the views of an expert lineup of eminent explorationists from some of the world's most successful E&P operators directly responsible for some of the world's largest discoveries in recent years, any present decline in deep water is—in the bigger picture—just a short-term dip.

35% capex plunge

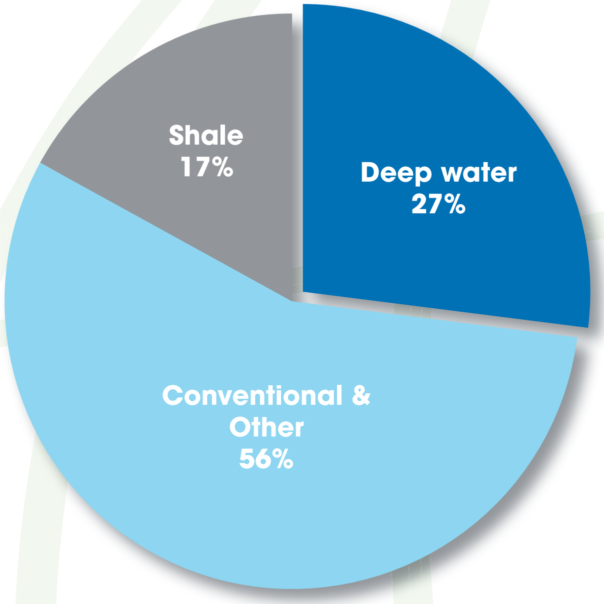
None could—or tried to—deny that deep water has been dramatically impacted by the industry's sustained and brutal downturn. Capex in the sector has unavoidably plummeted during the past 18 months while the upstream industry went into survival mode, with projects delayed, canceled or "reengineered" to take advantage of falling costs.

In May analyst Douglas-Westwood adjusted its forecast for spending on deepwater projects to $137 billion

Transocean's *Deepwater Millennium* drillship is shown flow-testing in the Rovuma Basin offshore Mozambique, where some of the world's largest deepwater gas discoveries of recent years were confirmed by operators Eni and Anadarko. (Source: Anadarko Petroleum)

NEW GLOBAL SUPPLY SOURCES NEEDED TO MEET WORLD DEMAND IN 2025

Estimated 40 MMbbl/d



Deep water remains by far the offshore industry's biggest opportunity to access new and large reserves to feed future demand. (Source: FMC Technologies)

between now and 2020, a dramatic 35% fall compared to its own figures from March 2015. Of that total spend figure, subsea production equipment; subsea umbilicals, risers and flowlines; pipelines; and trunk lines represented 34%, while floating production units were said to account for 28% of spend over the period.

But it added that projects already under construction were unlikely to be affected, with the largest proportion (38%) of the total spend attributed to drilling and completion. Deepwater expenditure will predominantly be driven by Africa and the Americas, set to account for a combined 87% of total deepwater capex. "In the long run, we remain of the view that deep water will be a cost-competitive source of world-class hydrocarbon reserves," it stated.

Biggest offshore opportunity

That "long run" referred to was very much in the minds of speakers from Eni, Shell and Statoil during a discussion panel at the recent European Association of Geoscientists and Engineers (EAGE) annual conference in Vienna, Austria.

According to Eni's head of global exploration, Luca Bertelli, deep water represents and remains by far the offshore industry's biggest opportunity to access new and large reserves.

The industry veteran said that deep water had been the base of large discoveries in past years and that it would continue to be so. "Deep water will remain the main source for significant discoveries for the industry in the future," he said, stressing that the industry would need, however, to do at least two things: drill less but more valuable wells and explore, develop and produce projects more efficiently.

Shell's executive vice president for global exploration, Ceri Powell, agreed, observing that with only 7% of the world's currently produced oil coming from deep water, "It's still an immature play. There's 270 Bbbl recoverable reserves out there in deep water, according to the International Energy Agency."

With the industry reducing the deepwater development breakeven price toward less than $50/bbl, Powell added that further advances in seismic would help achieve better success rates, while a "direct enabler" for further developments would be the increasing amounts of deepwater infrastructure, allowing easier connection of discoveries to existing networks.

New play concepts

New geological concepts such as that proven by Shell in the eastern Gulf of Mexico on its Norphlet Trend would continue to allow access to fresh reserves, she added. The Jurassic period formation already has produced sizeable deepwater discoveries for the operator such as the Appomattox, Vicksburg and Rydberg fields.

"Who would have thought just a few years ago that the eolian and fluvial sands would have produced these?" she said. But it produces tangible results and investment. Shell is of course in the midst of developing its Appomattox Field, which will be produced by a semisubmersible production facility linked to a subsea system with six drill centers, 15 producing wells and five water injection wells.

Bertelli also reminded the EAGE audience that today's lower oil price level was actually the long-term norm. "Before that period of high prices the industry had been working at lower price levels, and everybody was happy," he said. "What changed during the high price period was the cost. Now the price has dropped—it's currently 50% less than it was last year—but the average cost drop is about 25%, no more than that. So there's a big gap between the price of the oil and the cost. We cannot control the price, but we can control our costs, so we need to work together to further lower industry costs and reset the cost structure."

Powell did highlight emerging evidence that the industry is turning the corner on costs. "I have been

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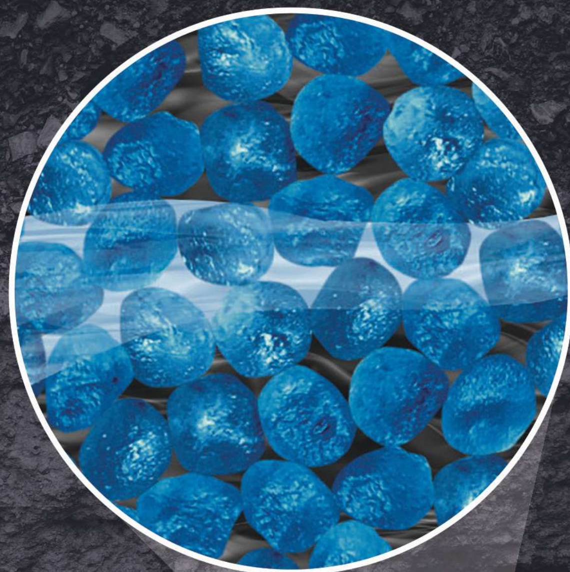

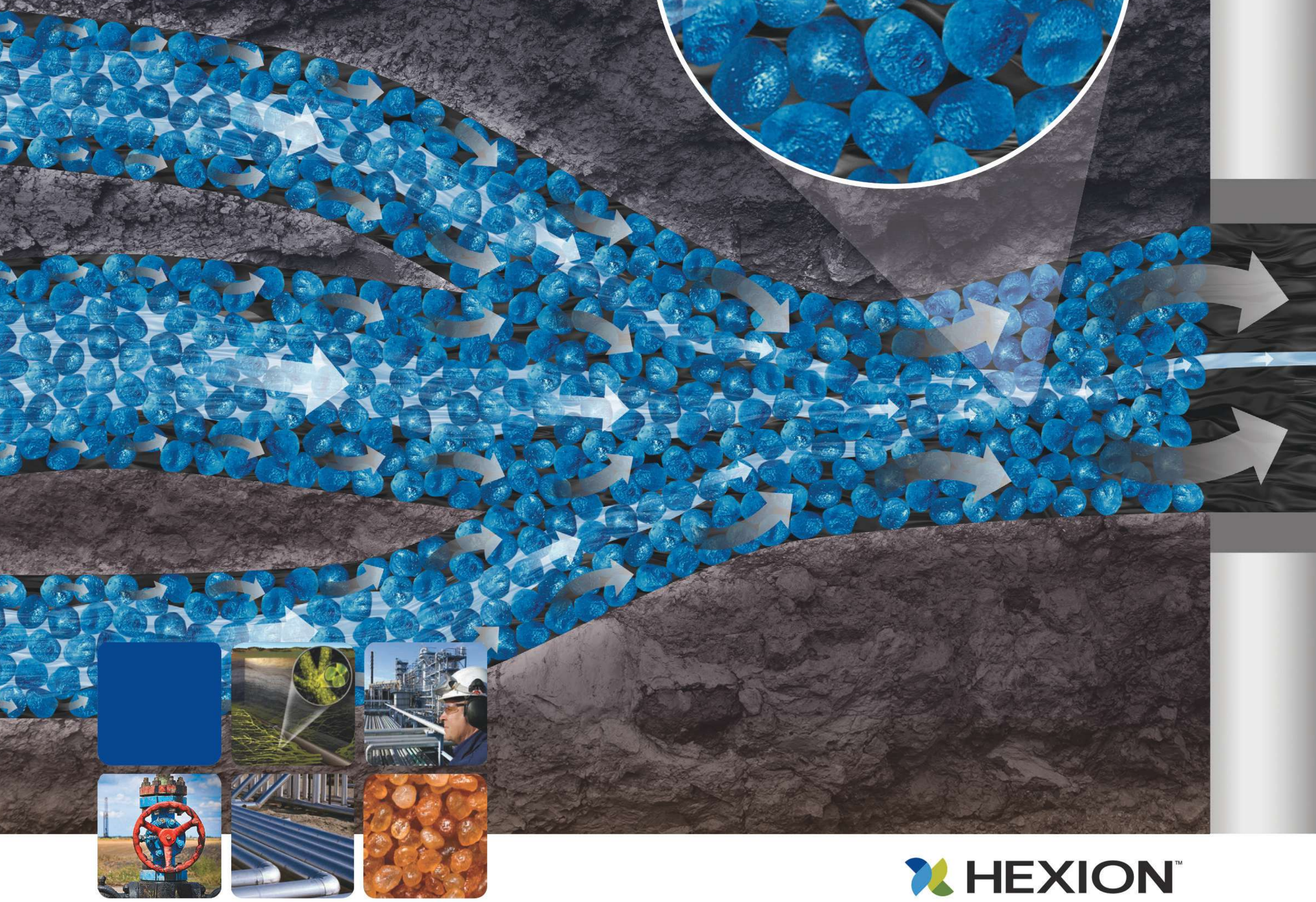

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very encouraged by how we have cut drilling costs, with deepwater wells, for example, now being drilled for much less than $100 million per well in some parts of the world. It's also about efficiency, about how many days it now takes to drill those wells. We are still not drilling enough at present, but we are now doing it very efficiently."

Windfall projects

Tim Dodson, Statoil's executive vice president of exploration, reflected on how the industry had largely used the period of higher oil prices to develop and produce older discoveries as "windfall projects" that previously had not been economic to develop.

There is a need now to acquire assets, he said, as companies cannot replace their produced reserves through exploration alone. But it will be crucial that those companies ensure they acquire the right quality of asset. Although relatively little merger and acquisition activity is happening at present, said Dodson, "I think we will see more in this 'lower for longer' situation."

What the industry is really lacking, he added, was "enough new good ideas. We can easily get swamped by the need for efficiency and controlling costs. But how can we come up with more and better ideas?"

BP backing deep water

Their beliefs were backed up elsewhere by BP's upstream head Bernard Looney, speaking at an investor event in Baku, Azerbaijan.

He highlighted the company's Mad Dog Phase 2 project's dramatic reduction in forecast development costs so far from originally about $20 billion in 2012 to currently less than half that figure. The expected solution for Mad Dog Phase 2 is now a 140,000-bbl/d semisubmersible facility rather than the original giant production spar, with the semisubmersible to be connected to 29 subsea wells and five drill centers.

Working with partners BHP Billiton and Chevron, BP has used new project phasing, simpler optimized design and equipment, and repeat solutions instead of bespoke ones to reduce the cost. The company is still rebidding other key contracts associated with the project ahead of sanction, which could come by year-end 2016. "You can see what it was just two years ago, what similar equipment on Atlantis was built for 10 years ago, and where we are now," he said. "That's a huge saving. And every element of the project is going through this degree of rigorous challenge."

Looney added, "Some people say that deep water is finished. We have a very different view. Based on our current calculations, Mad Dog will break even around the $40 per barrel mark." E&P

Prime time for the Permian?

Permian operators tell contractors they will increase activity, a sign of hope for an oilpatch inflection.

Richard Mason, Chief Technical Director

The Permian Basin is leading the way for those seeking the first green shoots of rising oilfield activity. News of improving conditions in the oil patch has been a long-anticipated event in a sector beset with 18 months of grim headlines.

But recent coffee shop talk—and a host of E&P acreage transactions—suggest the Permian Basin has become the San Juan Capistrano swallow that signals a new season for energy producers.

Roughly half of *Heard in the Field* survey respondents identified an uptick in both inquiries and work volume at the end of second-quarter 2016. Furthermore, pricing appears to have bottomed across all service lines, ending a long, painful journey for beleaguered contractors. True, service pricing remains abysmal and has yet to improve, but contractors see a positive in the fact that pricing is no longer deflating.

- **Permian operators will expand activity in second-half 2016.**
- **Wolfcamp gains marketshare as a primary target.**
- **High-density completions and longer laterals are becoming standard procedure.**

Well stimulation firms appear to be first on the call list as operators tackle the drilled but uncompleted (DUC) well backlog. The price of oil has reached a threshold where it makes sense to bring production online from an estimated 470 wells comprising the Permian DUC backlog.

Commodity prices need to move higher for drilling to accelerate significantly. Still, other stimuli are at work besides attrition of the amorphously defined DUC portfolio. In the Delaware Basin, operators are moving from delineation in one of the most sparsely settled areas of the U.S.—and the attendant lack of infrastructure—to optimization, which is evident in steadily increasing lateral lengths and higher proppant loading.

Basically, Delaware Basin operators have defined where the hydrocarbon goody is. Now they are deploying best practices from mature unconventional basins to increase the size of the harvest and reduce well costs on a "per unit" basis.

Responses to Hart Energy's *Heard in the Field* survey program identified instances of proppant loading approaching 2,000 lb of sand per linear foot on extended laterals in second-quarter 2016 (vs. 1,200 lb or less previously). Furthermore, Permian oil service providers are witnessing a recent increase in batch completions as zipper fracks rose from 35% of completions in the commodity price challenged first-quarter 2016 to 41% at the end of the second quarter.

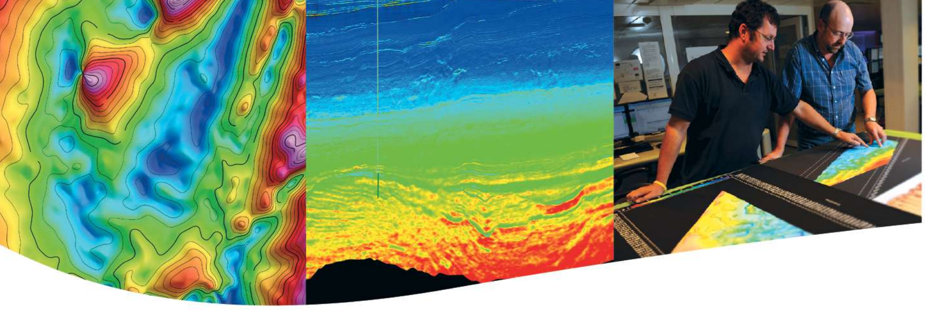
As one top tier operator told Hart surveyors, "The use of the zipper frack will go way up. It saves about 15% on multiwell fracks."

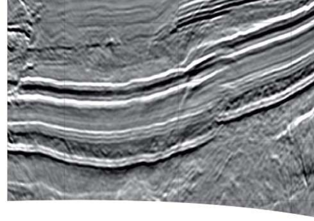
Indeed, the completion recipe has not changed materially in technique, though it is evolving rapidly in lateral length extension in the Delaware and in greater proppant loading in both the Midland and Delaware basins.

Overall, operators are reducing Bone Spring targeting in Lea and Eddy counties in New Mexico in exchange for multiple extended-length laterals in one or more benches of the Wolfcamp Shale in Culberson, Reeves and Loving counties in Texas along, or close to, the New Mexico border. Wolfcamp targets now account for 31% of Permian wells, and the nominal level of Wolfcamp drilling—and its marketshare—rose, even as all other geological targets declined. The Spraberry remains the No. 1 target at 35% of Permian well starts.

Also of note, several privately held operators are adapting unconventional drilling and completion methodologies to legacy conventional reservoirs in the Central Basin Platform.

For oil services, the sum of all parts is rising crew count and hydraulic horsepower capacity in the Permian, though this trend represents consolidation of services from other regions with contractors providing people and equipment out of the Permian as needed. Define it any way you want. At the end of the day, it finally feels like spring in the oil patch. E&P





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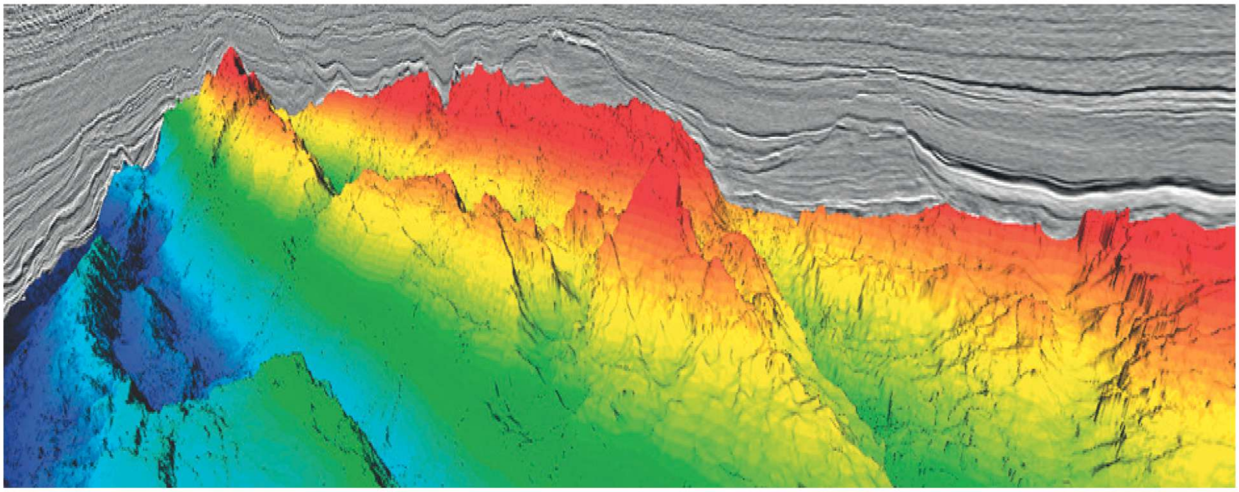

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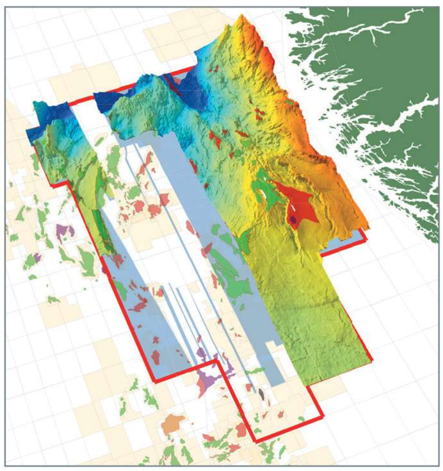

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Getting to the core of the matter

A research project aims to study the effects of one of the world's largest extraterrestrial encounters.

RHONDA DUEY
Executive Editor
rduey@hartenergy.com

Read more commentary at
EPmag.com

Compared to the pockmarked appearance of Earth's lone satellite, our planet has had it relatively easy when it comes to giant space objects smashing into it. But once in a while our luck runs out.

Such is the case with the Chicxulub crater in the Yucatan Peninsula. The meteor that caused the crater is widely believed to have led to the extinction of non-avian dinosaurs as well as most of the rest of life on earth. And a new study is expected to shed even more light on this devastating event.

Earlier this year an expedition obtained 830 m (2,725 ft) of core from the "peak ring" of the crater. The core was sent to Weatherford Laboratories in June for computed tomography (CT) scanning. The cores also were logged while still on the drillship. Later they will be shipped to Bremen, Germany, where they'll be slabbed and analyzed by a team of more than 30 scientists.

Why? According to Sean Gulick, a professor at the University of Texas and one of the chief scientists on the project, there are three primary goals. One is understanding how large impact craters work. These craters are rare on Earth, and the Chicxulub crater is the best preserved. "By drilling a very diagnostic landform called a peak ring that lies buried in the center of the crater, we hope to be able to figure out the processes that take place during an enormous impact," Gulick said.

Scientists hope that core samples from the Chicxulub crater will help them better understand the nature of impact events. (Source: Weatherford)

Secondly, of course, is the extinction event. Theories abound as to whether it was dust in the air that halted photosynthesis, acid rain from the sulfur kicked up by the impact, changes to the oceans' chemistry or the fact that impacting a carbonate formation led to CO_2 emissions and a greenhouse effect.

Thirdly, there is interest in learning about life in the subsurface. Impacts create porosity, and there is anticipation that microorganisms might dwell in these spaces. "There might be very specific types of organisms that give us some clues about evolution in general," he said.

For Weatherford this project is a bit of a departure from its usual work with cores. "It's a lot of continuous core," said Mike Dixon, manager of geologic services. "And some of the rock types and features that we may encounter could be relatively different than what we see in a normal oil and gas core."

He added that the CT information is a good complement to the other testing being done because it provides an early look at the core before it undergoes more destructive processes. "It gives you complete documentation of 100% of the core, and the resolution is on the order of a half millimeter," he said. "Every cubic millimeter of that rock is permanently documented so that at any time, whether it's tomorrow or 20 years from now, you can go back to this digital rendering and see what the core looked like."

CT data also can be helpful in determining which portions of the core should be slabbed, and in fact it enables the core to be slabbed in a virtual environment.

It's still early days for this project, but already interesting discoveries are taking place. "The sheer volume of rock we have in conjunction with the mechanical changes that occurred to these rocks after the impact appears to be pretty significant based on our preliminary passes," said Angela Schwartz, petrology group manager for Weatherford. "It's going to be very interesting to see what effect this impact had on these rocks." E&P

Rhonda

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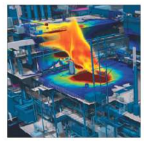

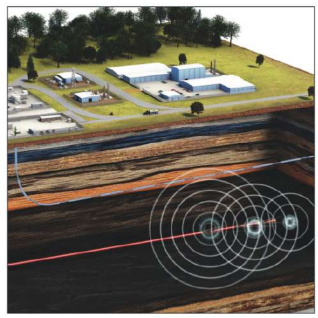

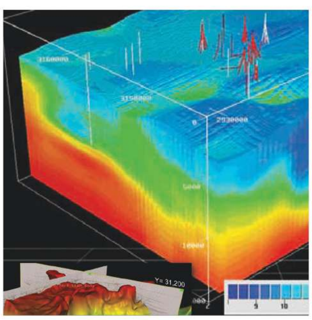

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Rig count continues slow climb, highlights regional increases

The variations in the rig count give indications about the areas that can increase operations with oil prices hovering around $45.

SCOTT WEEDEN
Contributing Editor
slweeden@hartenergy.com

Read more commentary at
EPmag.com

The Baker Hughes rig count continues to inch slowly upward as operators get used to $45 crude oil. The international rig count is headed in the opposite direction, led by fewer rigs operating in Latin America. What do these rig counts tell us about which plays or regions can make money at $45?

The July 8 rig count was up by nine rigs to 440 units, following the July 1 rig count that was up by 10 rigs. The rig count has been rising since May 20, when it bottomed at 404 rigs. That's a very slow rise over the last seven weeks as operators test their confidence in whether or not the price of oil will remain in the mid to upper $40s.

In a July 8 blog Gaffney, Cline & Associates said, "Perhaps operators are providing an early signal that they see the need to increase, or at least maintain, future U.S. crude production. The recent string of week-over-week increases in the onshore oil rig count could be a positive event but also should have been expected at this stage in the cycle.

"Rig count tends to lag increases in oil price by as much as a quarter. Oil has enjoyed a strong quarter; it's possible that will boost rig count in second-half 2016," the report continued.

"Oil has traded between $45 and $51 per barrel in the last month after almost doubling from a 12-year low in February during supply disruptions and falling U.S. crude production. The recovery has prompted operators to begin returning drilling rigs to service, leading to an expectation that the decline in production will slow," the report added.

Putting drillbits back to work will occur in the lower cost plays like the Permian Basin. (Source: Baker Hughes)

At 201 rigs Texas has 45% of the rigs that are running in the U.S. Of those rigs in Texas the Permian Basin has 158 rigs (78.6%) turning to the right. The Texas count bottomed out at 173 rigs May 20 and May 27. The Eagle Ford with 33 rigs operating is the second highest count, followed by the Cana Woodford and Williston, each at 28 rigs.

The Permian Basin shows the strongest inclination to make money at $45. Most of the oil/condensate plays have shown slow increases, while the rig counts for the gas plays like the Marcellus, Utica and Haynesville have been static. There are no rigs running in the Ardmore Woodford or the Fayetteville. That shows that operators will be pushing the oil plays first at the current prices.

The international rig count for May 2016 was 955 units, up nine from the 946 rigs counted in April 2016. The June count dropped 28 rigs to 927 units. The biggest drop has been in Latin America, which is off 25 rigs since April. The international offshore rig count for May 2016 was 229 rigs, up 9 from the 220 units counted in April 2016. The June count was down by six units to 223 rigs.

Years ago the seismic industry was looking for bright spots for places to drill. Now the drilling industry is looking for bright spots of a different kind. E&P

Scott

Revved-up well decom

Optimized well decommissioning approach reduces time and costs through concurrent rather than sequential steps in operations.

JENNIFER PRESLEY
Senior Editor,
Production Technologies
jpresley@hartenergy.com
Read more commentary at
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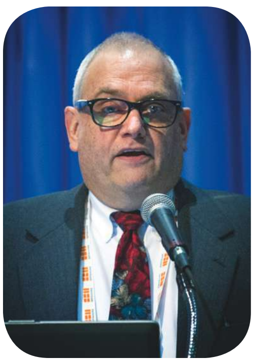
One can watch the history of the offshore oil and gas industry unfold on a helicopter flight out of Houma, La., to most any platform in the Gulf of Mexico. From the short-legged shallow platforms to the floating giants tethered to the seafloor, the industry's march into the Gulf's deeper waters over the past century is clearly visible. However, time is no friend to these structures, and like the wells they support, the day always come when history's signposts must fade away. A new approach presented at the 2016 Offshore Technology Conference (OTC) offers a different way to help operators decommission their aging wells and structures.

At the beginning of 2011 there were more than 4,500 idle wells and 783 idle structures in the U.S. federal waters of the Outer Continental Shelf. These aging assets pose an environmental risk, prompting operators to feel a renewed pressure to decommission idle infrastructure sooner rather than later, according Gary Siems of Montco Oilfield Contractors in his OTC presentation.

"In a four-year period, there were 183 structures and 1,082 wells toppled by hurricanes," he said.

The increased number of toppled assets led the U.S. Department of the Interior's Bureau of Ocean Energy Management Regulation and Enforcement to issue guidelines that specified that lease operators had to permanently decommission and remove wells and structures no longer useful for oil and gas production as soon as possible, but no later than five years after cessation of production, he said.



Gary Siems shares an optimized method for well decommissioning that cuts time and costs. (Photo courtesy of *CorporateEventImages.com*)

In his presentation, Siems compared the old, multistep way of decommissioning a structure and well with a new and better optimized process that employs the newest technologies to get more work done safely and at a lower cost.

He noted that the eleven steps typical to the traditional process are performed sequentially, with most requiring separate and specialized workers and equipment.

"The traditional method is what I like to call the 'minivan' model," he said. "It's very slow but gets the job done."

He highlighted in his talk a forecast conducted in January 2011 by an independent operator needing to decommission its idle iron inventory of 245 wells and 93 structures over a five-year period to be $409 million using the traditional methods.

"That's very expensive for a mid-size operator," he said. "We had to look for something different. We needed a new idea."

That idea came in the form of a new optimized decommissioning methodology that employed the size and capabilities of a newly designed and constructed 335-ft self-elevating, self-propelled liftboat. The new boat provided the space and lifting capacity necessary to perform the majority of the work steps concurrently—rather than sequentially—and in just one spread mobilization.

"This change from the traditional minivan approach is what I call the Ferrari method," he said. "It is sleeker, faster and allows us to get more done in less time."

According to Siems, over a 30-month period the new concurrent model resulted in 140% more wells and structures being removed over the number expected to have been removed using traditional methods. Using the optimized method, decommissioning costs were reduced to $278 million, he said. E&P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EXTREME MAKEOVER

New technologies are pushing mature fields farther into the future as operators look to do more with existing infrastructure.

Jennifer Presley,
Senior Editor, Production Technologies

While not as glamorous as new discoveries, the attractiveness of mature fields is growing as they can provide operators with quick access to low-risk resources. With 70% of the hydrocarbon liquids produced in the world today coming from fields that have been in operation more than 20 years, focus has shifted onto developing these fields with the goal of producing more of the remaining resources.

Take, for example, the decision to expand the supergiant Tengiz oil field in Kazakhstan. Production of the sixth largest field in the world started in 1993. In July Chevron Corp. affiliate Tengizchevroil, in a joint venture with Exxon Mobil Corp., KazMunayGas and LukArco, announced its decision to proceed with a $36.8 billion future growth and wellhead pressure management project. The plan calls for, upon completion, production at the field to increase by 260,000 bbl/d to 850,000 bbl/d through the use of sour gas injection technology developed and proven during the field's previous expansion in 2008.

In some cases, the best use of a maturing asset is to give it a new purpose. Statoil's Heimdal Field, celebrating its 30th anniversary this year, is one example of this. The first well in the field was drilled between July and December 1972 and proved to have both gas and condensate reserves. At the time of first production in December 1985, the Heimdal platform was the largest steel jacket platform on the Norwegian Continental Shelf.

Declining production after a decade of steady production led to a transition from production to processing. In January 1999 approval was given for the Heimdal Gas Center. The center serves as a hub for the processing and distribution of gas. According to Statoil, gas from Heimdal is processed together with gas from the Huldra and Vale fields. Heimdal receives gas from the Oseberg Field Center through the Oseberg Gas Transport system. Gas is exported via the Vesterled and Statpipe pipeline after processing.

In this report, *E&P* delves into a new casing exit service that uses real-time information to increase efficiency. The report also looks into how Maersk Oil has breathed new life into Denmark's oldest producing field at its multiplatform Dan Field complex in the Danish North Sea sector, how exploration in mature basins has led to new discoveries and how an internal liner system can be used as an alternative for subsea pipeline replacement. E&P

Casing exit service delivers significant reduction in rig time

New service combines integrated well planning with real-time data and lessons learned from thousands of casing exits to optimize drilling of a development well in a mature San Juan Basin Field.

Tom Emelander, Weatherford International

The line-by-line budget cuts have been exhausted industrywide. Pressured to reduce costs everywhere possible, operators seek the rare technologies and techniques that improve both efficiency and effectiveness without the corresponding creep in opex.

Capturing bypassed reserves

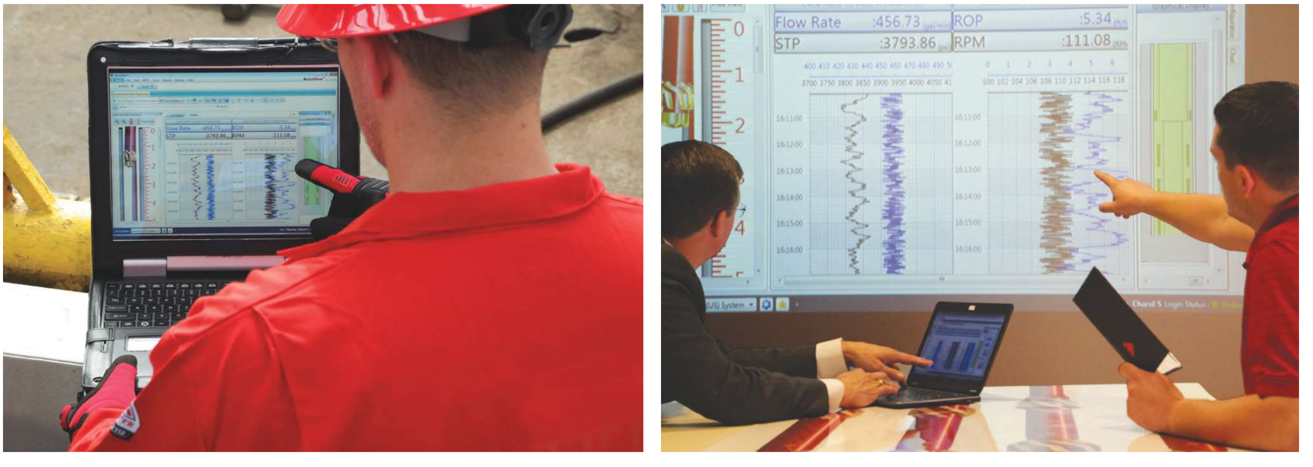
An operator working in the San Juan Basin in New Mexico sought one of those technological gems for a 5 ½-in. casing exit in a gas-producing development well. In hopes of accessing bypassed reserves and reviving production in this mature asset, the operator planned a 4.75-in. 10-degree sidetrack from the 5 ½-in. 17-lb/ft (25.2-kg/m) parent casing into the mixed sand and shale reservoir. This new dual-lateral drilling project—including the described sidetrack plus a second lateral out of the shoe—would produce from the same formation.

Working with a previous service provider, the client had executed three similar jobs with an average casing-exit and milling time of 14 hours per job. For this well the operator set a goal of a single-trip job with a total operational time of 12 hours or less. It requested use of a retrievable hydraulic-set system to avoid the additional time and costs associated with mechanically setting the whipstock anchor with a bridge plug.

Choosing the right solution

After an extensive review of the job specifications, Weatherford recommended the newly released QuickCut Pro service, which consists of the field-proven QuickCut casing-exit system, the AccuView collaboration system, a highly trained onsite specialist and a remote team of experts.

This real-time technology integrates well planning with real-time data and lessons learned from thousands of casing exits. This database is used to optimize key performance indicators such as ROP, pressure and flow rate in the planning phase, which are then displayed on the rig floor in an easy-to-interpret graphic user interface on a portable computer display. The simple-to-use plug-and-play technology requires no technician for installation and is ready to operate in 15 minutes or less on virtually any rig.



The QuickCut Pro service, powered by AccuView software, contributed significantly to the efficiency of the casing-exit operation by enabling real-time data display and enhancing communication between onsite rig personnel and the offsite Weatherford team of experts. (Source: Weatherford International)

During operations the system securely delivers useful job-specific real-time information to the onsite and remote casing-exit experts. These data not only help to ensure that the casing exit is milled according to plan foot-by-foot but also that the operation is completed quickly, safely and economically.

Efficient problem-solving was the key to the drastic reduction in rig time.

Remote collaboration

The Weatherford specialist on site began by inputting the pre-job plan into the AccuView system, which created an asset manager-controlled template that includes preloaded documents such as a job-hazard analysis, lifting plans, technical manuals and checklists. Once connected to the secure onsite network, the system began secure data transmission to offsite personnel, which included a top-tier casing-exit expert based in Houston.

The rig crew tripped the system into the well to the planned kickoff depth of 793 m (2,603 ft) and oriented the hydraulic MultiCatch whipstock for setting. Using the flow rate and nozzle calculations from the planning phase, the crew brought the pumps online and then increased flow rate to initiate the setting sequence. After holding for two minutes, they lowered the weight with the expectation that the anchor had been set. However, the system indicated no weight loss, meaning that no solid anchor setting was achieved.

The crew then pulled the string back up to depth and increased the flow slightly; still no anchor was set. Another attempt at a slightly higher flow rate yielded the same result. Unable to achieve the expected result based on pre-job plans, the onsite crew and operator turned to the experts in Houston for troubleshooting.

The expert, with real-time access to all operational details of the job and to thousands of "what-if" scenarios modeled on data from similar operations, immediately suggested an actionable solution to mix 20 bbl of high-viscosity 11.4-lb potassium chloride mud, pump it downhole at the maximum possible rate and then proceed as planned.

The onsite crew pumped the mud mixture downhole as recommended and held for three minutes. After the crew pulled up on the string, the anchor took weight and sheared off at 14,000 lb. Weight was then set to 20,000 lb per procedure. The crew marked the pipe, set down to 20,000 lb again and the system landed on the mark.

After picking up the pipe to neutral weight, the team set milling parameters and milled from 791 m to 793 m (2,595.5 ft to 2,603 ft). Sweeps at every 0.6 m (2 ft) of the borehole produced the expected amount of metal returns. As the QuickCut system milled the window and rathole, the software displayed all operational parameters in real time to onsite Weatherford experts and in Houston. Parameters were adjusted on the fly to minimize the load applied to the milling assembly, which helped to maintain a better-than-average ROP of 1.83 m/hr (6 ft/hr) throughout the process.

Once milling was complete, the crew marked the pipe in the system and milled the rathole from 793 m to 795 m (2,609 ft). Next, it reamed the window from 791 m to 795 m multiple times using a low torque and weight. The assembly slid through with the pump with no rotation, and then with no pump or rotation, which indicated a clean window. Finally, the crew pumped 10 bbl of sweep fluid and pulled the assembly out of the hole.

Time and cost savings

The operator originally sought to reduce milling time from the offset average of 14 hours to 12 hours, which equates to an about 15% decrease in rig time. The Weatherford system milled the window and rathole in a single trip in just over 3 hours. The total milling time was 9 hours faster than the client had required, a 78.5% reduction compared to the nearby well average, representing a record for the field.

Efficient problem-solving was the key to the drastic reduction in rig time. The issue encountered when setting the whipstock anchor would typically have required tripping out of the hole or would have resulted in significant downtime associated with phone calls between the job site and the Houston-based subject matter expert to discuss the problem. Because the system enabled real-time collaboration between the onsite crew and a remote team of experts, the team identified an efficient solution that incurred no nonproductive time. In addition to providing a flawless one-trip casing exit, the operation had zero recorded safety incidents.

Already among the most efficient means of mature field revitalization, sidetracking with the QuickCut Pro service helped the operator to boost well and reservoir profitability with minimal investment. Further, the service established a repeatable benchmark for casing exits in the field, which will enable the operator to reduce rig time and associated costs even more in future jobs. And because the problem-solving and predictive capabilities of the service are enhanced with each operation, the data and lessons learned from this job can be applied to improve casing-exit efficiency across the industry. E&P

Maersk enjoys bravura performance on Bravo

Innovative thinking helped to virtually triple the original life expectancy planned for a pioneering Danish North Sea platform to an impressive 70 years.

Mark Thomas, Editor-in-Chief

Maersk Oil's original multiplatform Dan Field complex in the Danish sector is one of the grand old dames of Europe—it was the first permanent production facility anywhere in the North Sea region.

Containing an estimated 2 Bbbl of oil in place, it is the country's oldest producing field after coming onstream in July 1972 following its ground-breaking discovery early the previous year. The Dan A wellhead and Dan B production platforms were installed 200 km (120 miles) offshore and have performed admirably since first oil, and so far Maersk estimates that close to 28% of the country's total oil production has come from the Dan Field alone.

The operator also has added several other satellite installations in and around Dan in the southwestern part of the Danish North Sea sector over the decades to maintain production levels from the field's main central area and flanks as well as employing innovative drilling and subsurface EOR techniques throughout the field's life to improve the reservoir's initially low recovery factor (originally under 10% but well into the 30% range by the mid-1990s, thanks largely to horizontal wells, fracturing and water injection solutions).

Makeover

However, after four decades of sterling service—already well beyond the initially envisaged 25-year operational lifespan—the operator decided it was not yet time to retire the facility and instead opted to give platforms A (the wellhead platform) and platform B (the production center) a comprehensive makeover.

This led to a lifetime extension program called the Dan Bravo Rationalization project, which saw Maersk select Boskalis Subsea Services carry out work on the two platforms between 2013 and 2015 and achieve a number of offshore industry firsts along the way.

According to Bert van der Velden, commercial director at Boskalis Subsea Services, the major subsea structural reinforcement campaign on the wellhead platform (Dan A) "has extended the platform's life by another 40 years at least."

Largest 3-D photogrammetry

Speaking at the Subsea Expo event in Aberdeen, Scotland, earlier this year, van der Velden highlighted in particular the project team's undertaking of the world's largest-ever 3-D subsea photogrammetry on the structure.

First the platform jacket's members and nodes had to be completely cleaned back to bare metal using grit blasting and flush grinding by air and saturation divers. It was then marked out with about 2,900 magnetic coded markers, with about 20,000 overlapping high-definition images subsequently being taken by a work class ROV between July and September 2013.

These photographs were converted into an exact geometric 3-D model using the information from the

The Dan Bravo Rationalization project, completed late last year, has extended Dan's original planned 25-year lifespan to potentially up to 70 years. (Source: Maersk Oil)

markers, which was used for the onshore fabrication of subsea reinforcement structures (K-node clamps). High accuracy was required for these steel-to-steel clamps, van der Velden said, which reinforce the jacket structure where a horizontal member is intersected by cross members. These clamps were fixed to the jacket with the help of two diving support vessels (DSVs), the *Constructor* and *Protea* DSVs.

Complex installations

A new conductor guide level also was installed on the Dan A platform by Boskalis as well as two old conductor guide levels removed from it.

These installations required the careful maneuvering of various pieces of fabricated steel weighing up to 5 tonnes through slots in the facility's structure guided by divers and rope access teams. Two temporary knuckle boom cranes also were installed on vertical platform members 12 m (39 ft) above sea level to help with the maneuvering of the new steel sections as the platform's single existing crane had only a 2.3-ton capacity.

Van der Velden said 136 metric tonnes of new steel was installed, involving 88 connections, with 220,000 man hours spent on the job, a project personnel total of 320 people and more than 200 vessel days required. Operations were performed in water depths varying from 10 m to 41 m (33 ft to 135 ft). The last part of the offshore campaign was to remove the temporary cranes before the winter season began.

Industry first

The reinforcing of the Dan A platform in this way and to this scale had never been done before elsewhere, van de Velden added, who said the majority of its work on Dan was focused on the wellhead facility to preserve its structural integrity until at least 2042.

He also pointed out that this complex and challenging work program was all carried out subsea on a mature platform, sometimes in unfavorable and challenging weather and visibility conditions, while it continued to produce hydrocarbons.

A further key aim was to carry out as much of the work as possible onshore to help avoid more costly work offshore, with a close working relationship established between the operator and the contractor. The latter was contracted for the installation, fabrication, procurement, equipment testing and structural examinations.

There were no lost time incidents reported over the course of the 200-day offshore work program, he added, which also included fitting a new boat landing to Dan B. E&P

Diamonds in the rough

Mature basins continue to represent a vital source of fresh reserves in a cautious climate.

Mark Thomas, Editor-in-Chief

The oil industry's history demonstrates clearly that new plays and prospects have long been found in mature basins that were thought to be well on the way to being squeezed dry. Through the acquisition of new data, developing new concepts and coming up with fresh interpretations, long-producing basins around the world from the North Sea to Malaysia have continued to reveal new riches.

With the E&P sector having cut back drastically on its exploration activity in new and emerging areas during the present downturn, operators have openly acknowledged the importance of focusing and refocusing attention on the world's established producing areas to extend the lives of existing fields and infrastructure. New ideas, techniques and technologies can directly result in high-value new plays.

Royal Dutch Shell's executive vice president for global exploration, Ceri Powell, is in no doubt. Shell has found 10 Bboe of reserves in its mature basins around the world since 2005 in places such as Oman, Brunei, Malaysia and the North Sea, she pointed out during a panel session at the recent European Association of Geoscientists and Engineers (EAGE) annual conference in Vienna, Austria.

Hydrocarbons breed hydrocarbons

Powell commented, "Hydrocarbons breed hydrocarbons. There's a deep understanding of the basins within our companies and within other companies because of this experience. And with a good position in such basins, we can still look for new plays."

Innovation very much exists within these mature heartlands, she added, using as an example the company's own RON (Rejuvenate Opportunity Now) internal initiative. Shell regularly brings together lots of brainpower from its generations of explorers, all with direct and mixed levels of geological experience of working in a particular area and with strong understanding of the subsurface.

Put together into a room with lots of paper, charts and no computers, these gatherings of old and young geoscientists have produced quantifiable results. "At Shell in Oman they came up with six new plays—four of which have now been drilled," Powell pointed out.

She also stressed the importance of increased and coordinated industry collaboration on a basinwide scale, giving as an example a major basinwide 3-D seismic survey that was carried out offshore Malaysia. It took the national oil company PETRONAS to help facilitate that coordinated effort, she said.

"And it's very important when doing this kind of exploration that the explorers do not work alone but within the asset teams, the production and operations teams."
—Luca Bertelli, *Eni*

Incremental discoveries

Eni's Global Head of Exploration, Luca Bertelli, stressed at the same EAGE event the importance of carrying out "deep reviews" of the potential of all parts of a mature province.

"And it's very important when doing this kind of exploration that the explorers do not work alone but within the asset teams, the production and operations teams," he said. "This often enables companies to make small incremental discoveries around mature fields developed via such relatively low-cost methods as tiebacks within just a few months. It provides very good value for operators."

However, there is always the danger of leaving things too late and not sufficiently examining the remaining potential of mature fields and basins before the existing production infrastructure is decommissioned. Heiko Meyer, Wintershall's vice president for strategy, said time in some areas already is close to running out. "Some need to be explored now, or these chances may be gone," he warned. E&P

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CASE SUMMARY 6 OF 9 | STARR COUNTY, TX

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OVER RESIN-COATED SAND COMPLETIONS

92% INCREASE
1185-Day Cumulative BOE

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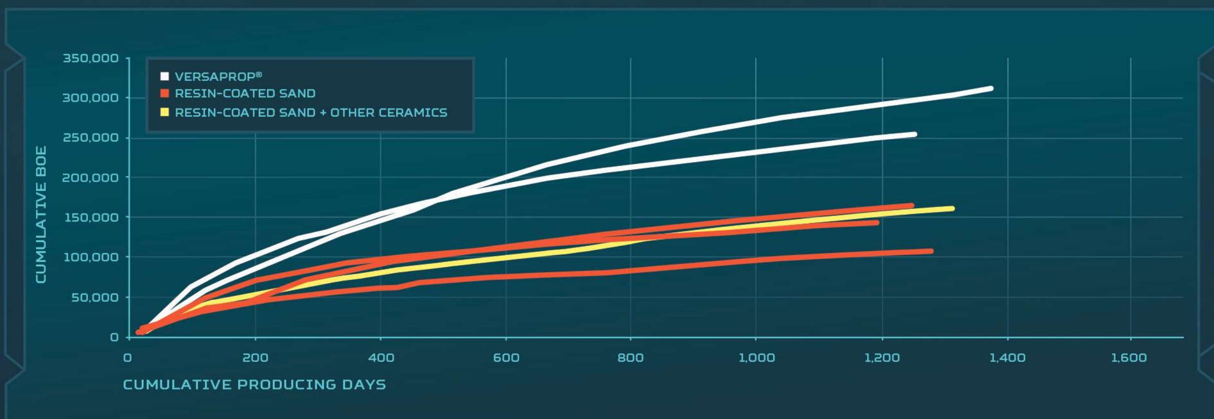
3-Year Cash Flow

PARAMETERS USED IN ECONOMIC ANALYSIS:
WTI@$55/BBL, GAS @ $4.00, 20% ROYALTY



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Liner offers alternative to replacement of subsea pipelines

Rehabilitation rather than replacement of existing subsea pipelines is now possible with Kevlar-reinforced liner system.

Dennis Snijders, Anticorrosion Protective Systems LLC

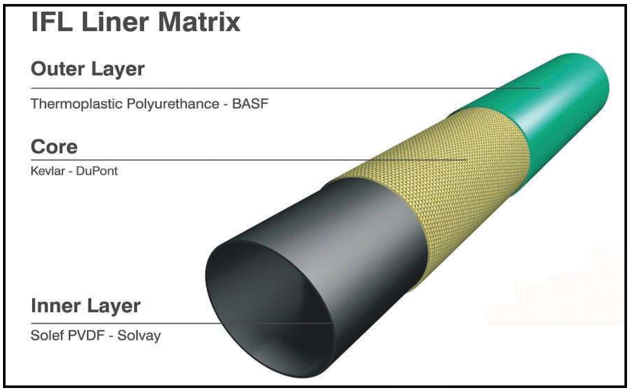
During this period of declining oil prices, PETRONAS recognizes the extremely effective cost optimization represented by the ability to rehabilitate near-end-of-life pipelines as opposed to mounting large-scale replacement campaigns.

The InField Liner (IFL) system, developed under the joint management of PETRONAS and Anticorrosion Protective Systems (APS), when installed in existing subsea pipelines acts as a corrosion barrier, providing protection against aggressive service conditions and extending the use of the pipeline far beyond its original design life.

The IFL system was successfully piloted at PETRONAS Carigali Sdn Bhd's (PCSB) Samarang Field in September, and a commercial trial was deployed at West Lutong Field in November 2014.

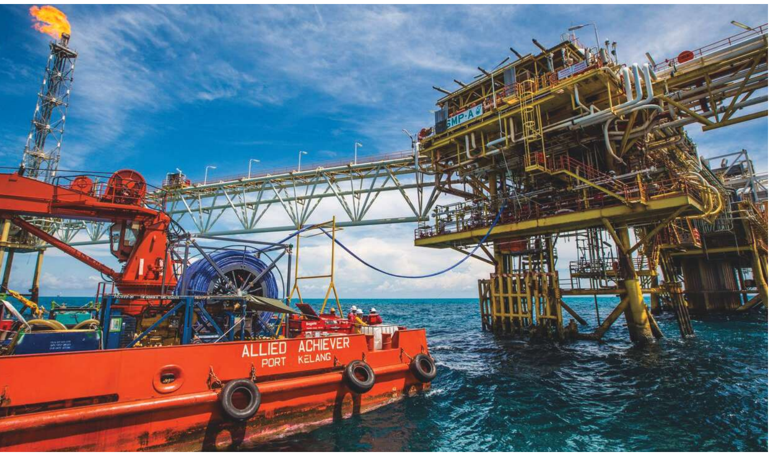
Liner specs

The IFL comprises a polyvinylidene fluoride (PVDF) inner liner from Solvay and a tightly woven Aramid core using Dupont Kevlar fabric with an outer layer of abrasive-resistant thermoplastic polyurethane (TPU) from BASF.



The flexible Kevlar-reinforced IFL has a high tensile strength. (Source: Anticorrosion Protective Systems LLC)

The inner PVDF layer provides a high chemical resistance against the most aggressive hydrocarbon exposure conditions, including hot sour crude oil up to 110 C (418 F). The Kevlar core provides the liner with an extremely high tensile strength, thus enabling the insertion of single lengths of multiple kilometers of liner through multiple 90-degree bends down to 5-D radii. The outer TPU covering provides a maximum protection and abrasion resistance as might be required during the pulling and insertion process of the IFL system into the host pipeline.



IFL can be used as a corrosion barrier for new pipelines in extremely corrosive environments. (Source: Anticorrosion Protective Systems LLC)

Liner applications

The IFL system is ideal for rehabilitating infield subsea pipelines running from platform to platform or from platform to shore. The IFL also can be used as a corrosion barrier for new pipelines that will be exposed to extremely corrosive environments incurred due to the aggressive environmental influences or in combination with high water cuts or other conditions where the predicted lifespan of the pipeline is reduced without the application of a fully effective corrosion-resistant layer.

The IFL system was originally developed as a viable and cost-effective method for subsea pipeline rehabilitation; however and in addition to this, the IFL system also might have specific applications for the onshore hydrocarbon pipeline industry as well. An example of this would be where a pipeline passes under an area where, for one

A shipboard crew deploys the IFL system at the PCSB Field. (Source: Anticorrosion Protective Systems LLC)

reason or another, site access is extremely limited, and thus the pipeline has to be rehabilitated over much longer lengths with single pulls of up to 5 km (3 miles).

Liner development

During the IFL development project, a detailed research program was conducted into the potential rehabilitation market for this technology. At present there are about 175,000 km (108,740 miles) of subsea pipelines in operation around the globe, of which about 15,000 km (9,320 miles) will become due for replacement in the next 10 years as these pipelines have reached the end of their planned service life. These pipelines, ranging in diameter from 4 in. to 20 in., form the main target market for the IFL technology.

Regionally, the largest market potential for IFL worldwide is in North America and specifically the Gulf of Mexico, a large and aging pipeline network where close to 3,000 km (1,864 miles) of pipelines are in need of replacement during the next 10 years. Also, the Middle East and Southeast Asia have large potential markets for the IFL, each having about 2,000 km (1,243 miles) of pipelines that will need to be replaced during the next 10 years.

Prior to APS being granted the exclusive license to produce and market the IFL technology at the end of November this year, a soft launch of the IFL technology was instigated with the major offshore oil and gas operators, mainly in Southeast Asia, the Middle East, North America and West Africa. The main benefit is to provide a viable alternative to pipeline replacement.

PETRONAS granted APS a global 20-year exclusive license to apply the technology for other oil and gas operators.

"The exclusive license will enable the globalization of the IFL technology so that it becomes available for usage in PETRONAS facilities in and outside Malaysia. This also opens the market toward a new and cost-effective way in recommissioning damaged or corroded pipelines for other oil and gas operators," said Tn Hj Zakaria Kasah, chairman of PETRONAS Technology Ventures.

Planned projects

APS was awarded multiple production and installation contracts worth more than $150 million in late 2015 by PETRONAS for the rehabilitation of various 6-in., 8-in. and 10-in. subsea crude oil gathering and high-pressure gas and condensate lines varying in lengths from 700 m (2,296 ft) up to 3.5 km (2.1 miles). These pipeline rehabilitation projects are expected to be executed during the course of 2016 and the start of 2017, and more contract awards are expected at the start of 2017 for execution in 2018 and 2019. E&P

Small-volume seismic licensing

How to access seismic data when you think you can't afford it.

Nancy House, Integrated Geophysical Interpretation Inc., and **Kelly Limbaugh**, Geokinetics

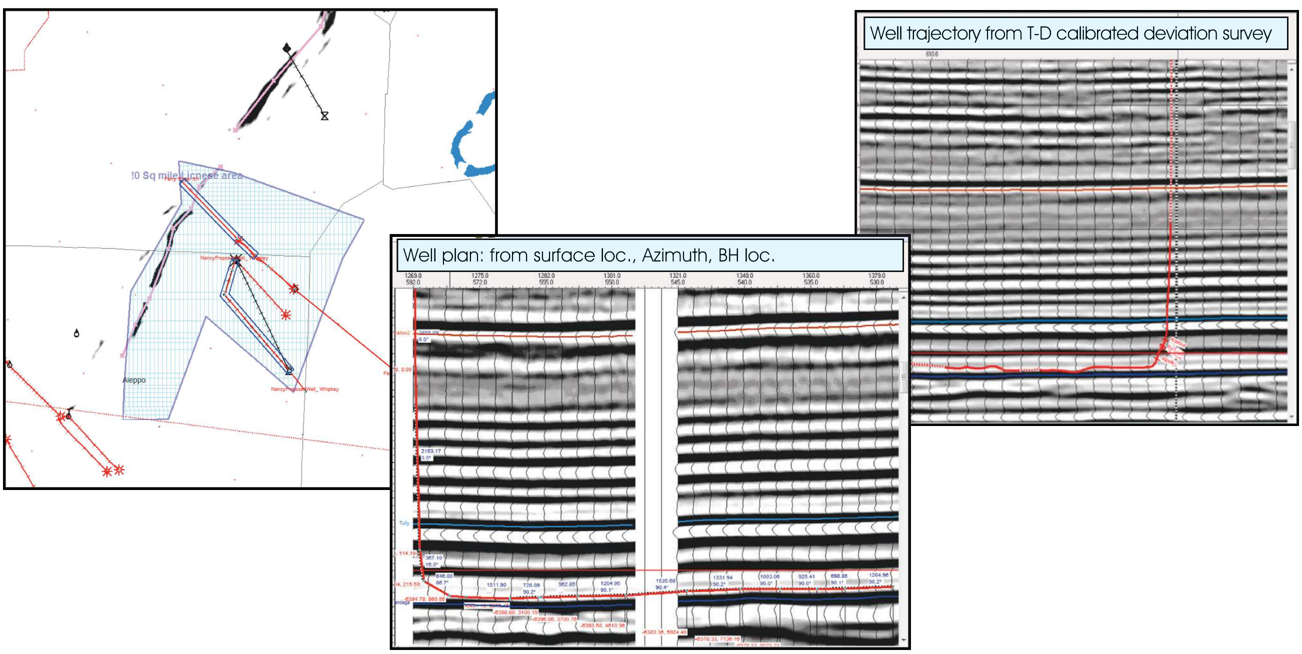
It is well documented that 3-D seismic improves the chance of success in conventional exploration plays. For unconventional resources some companies have a misconception that seismic is not needed because the geologic risk is very low. Other companies do not want the added expense of acquiring new data, or their position is too small to warrant seismic acquisition. But there is a new way to have access to seismic data that makes economic and logistical sense: Companies can license data for only the area they need, and it would be delivered fully interpreted and ready to use.

How multiclient works

To have a more comprehensive picture of the subsurface geology in an acquisition or drilling area, especially if a company's acreage is "postage stamp" size and discontinuous in nature, E&P companies work together, on occasion, to acquire data over a larger area. They might participate in the underwriting of a multiclient program to increase coverage over their acreage. Multiclient companies work with multiple E&P companies to design and acquire a seismic program with optimum parameters, allowing the full suite of emerging shale technologies to be used to high-grade acreage and identify sweet spots to be developed with more success. The multiclient company owns the data, which reduces the exposure and financial risk to the E&P companies, and the E&P companies obtain a license to use the data. This allows them to create drilling programs and develop their acreage. E&P companies save money, and the multiclient company is able to license the data to other leaseholders as a way to recoup its costs.

A new model

The new model is to license 3-D seismic data in smaller increments and deliver fully interpreted data that have been incorporated with the required ties from outside the licensed area. This allows the buyer to use the data immediately. The deliverables could include depth maps to the zone of interest and other key formations as well as proposed well-



This figure shows a sample 26-sq-km license area. On the left is a proposed horizontal well with planned deviation. (Source: Integrated Geophysical Interpretation Inc.)

bore plans and displays for presentation to partners and investors. The interpreter could have follow-up meetings to review and discuss the interpretation. The cost per square mile would be increased to cover the additional value added by the interpretation, but required mileage could be significantly reduced along with the time and hassle involved with independently interpreting the data. This saves time by eliminating these factors: determining the amount of data required for the interpretation, finding a consultant, communicating the requirements and understanding the products delivered by said consultant. The need for obtaining hardware and software for the interpretation and communicating those results to the operations, leasing, management, partner and investors will be reduced.

In this case, the interpretation is delivered at the time of the purchase and development drilling, and partner presentations and investor presentations will be supported for a period after the initial data delivery.

Economics

The economics of licensing the perfect amount of seismic data needed to image the acreage with critical well ties and regional geology incorporated is compelling. For example, for a 13-sq-km (5-sq-mile) contiguous lease tract, it is generally recommended that a company license at least 26 sq km to 39 sq km (10 sq miles to 15 sq miles) or more depending on the wells it wants to compare and the wells to tie into the surrounding geology. The cost can quickly climb to more than $500,000 or more, just for the data. This is without interpretation and ready-to-drill recommendations.

The company would typically hire a consultant, communicate the critical well ties and wait for the interpretation to be completed. This could take months. It might decide to forego the purchase and drill based on depths the geologist interpolates from surrounding wells. While this will generally work in a structurally noncomplex reservoir, there are instances where there is hidden complexity that might require numerous sidetracks, as in some portions of the Marcellus. Additionally, in many of the shale development plays the reservoir target zone is very thin, less than 15 m (50 ft). This makes it important to identify a fault that could put the wellbore out of zone. It is critical to be able to see ahead of the bit and instruct the drillers that there may be a 15-m downdrop or upthrown fault at a general "vertical section" position in the wellbore. Encountering a fault without any preconceived knowledge formulated from seismic data creates a challenge for geosteerers and drillers to get the wellbore back in zone without sacrificing time and, more importantly, the economic portion of the wellbore that can effectively contribute to the reserves.

Understanding how the economic success of a specific well can be impacted by 3-D seismic application and how that translates to all of the wells being planned for a given acreage position is imperative. Assuming average spacing of 40 acres or horizontals 201 m (660 ft) apart with required 100.5-m (330-ft) setbacks from lease lines results in about six wells/sq km (about 16 wells/sq mile). A typical small-volume seismic purchase from a multiclient company costs about $17,370/sq km ($45,000/sq mile). If the fully integrated drill-ready interpreted volumes with support cost $21,230/sq km ($55,000/sq mile) and the license was restricted to only 13 sq km (5 sq miles), the total cost would be $275,000. That's about $3,500 per well, or $86 per acre. This cost is equal to that of a well log, and it is much less than the cost to lease the acreage. The cost of seismic becomes an economic viability when the cost per acre or cost per development well is evaluated. Being able to avoid sidetracks or missed landing zones also is a cost benefit that can be hard to calculate on the front end, but avoiding these issues results in significant cost savings.

The example shown illustrates tying in a well and planning a subsequent well based on a high-quality 3-D seismic survey. Once a horizontal is tied into the seismic accurately, subsequent well plans can be produced that will predict the landing depth and landing inclination. Significant dip changes and/or faults might be encountered along the proposed well path.

A proposed deviation survey can be delivered directly from the seismic interpreter to the drilling team to efficiently drill a "no surprise" well. This might be more important in the development stage of an area and later if complex areas become an issue. It generally allows infill wells to be drilled without need to sidetrack on landing and stay in zone for longer. All of these add to creating a more economic development in an economically stressed economic climate.

Three-dimensional seismic interpretation has been shown to improve horizontal well placement, reduce the requirement for sidetracks and decrease re-drills due to unforeseen structural complications. When 3-D seismic is used in well planning and geosteering, it increases effective lateral length and can show subtle faulting not recognized in geosteering correlations, which affects completion effectiveness. E&P

Hydromechanical perforating tool halves P&A project

Unconventional design eliminates explosives to increase safety and efficiency.

Joe P. DeGeare, Energy Fishing and Rental Inc., and **Joe Hrupp**, Lee Energy Systems

The basic technologies associated with the plugging and abandoning (P&A) of wells has not changed significantly since the 1970s, as the National Petroleum Council pointed out in its North American Resource Development Study. Water-based slurries of cement and drilling mud are still the basic materials used to plug most wells, although progress has been made in use of additives to customize the cements and muds for specific types of wells.

Recent shale gas developments have rediscovered some P&A issues in the forms of older oil or gas wells that never were adequately plugged but which now pose possible cross-contamination or leakage risks. Furthermore, eventual retirement of uneconomical shale gas wells must address P&A practices that are specific to issues affecting gas wells and especially horizontal gas wells.

The lack of progress in P&A practices is attributable to absence of a long-term vision and inattention to corresponding research that recognizes the benefits of P&A to oil and gas development projects. Specific findings are that:

- Benefits from reduced operational costs and/or increased production, especially in redeveloped older fields, generally have been underappreciated;
- By plugging wells correctly, future environmental issues related to fluid or gas leakage can be avoided, thereby preserving savings otherwise eroded by remediation or litigation costs; and
- Research has lagged on materials and methods for plugging wells, although advances in technologies for drilling and completion should be applicable to practices in P&A.

Conventional tools used for P&A operations have certainly seen advances; for example, service companies

HYDROMECHANICAL PERFORATING TOOL:

Day 1:

1. Run in-hole with Gator and packer assembly.
2. Alternately perforate and set packer on each zone to confirm feed rate or circulation.
3. Re-perforate as required if no feed rate is obtained.
4. Pull out of hole (POOH) and lay down tools.

Day 2:

1. Run in-hole and sequentially cement squeeze zones via packer assembly.
2. POOH and lay down pipe.

In this project, a single well required two rig days, two round trips and one perforator/packer run, with zero spent perf guns. The entire project required 32 rig days, 32 round trips and 16 perforator/packer runs, again with zero spent perf guns.

E-LINE AND PERF GUNS:

Day 1:

1. Run in-hole with perf gun and perf first zone. Lay down gun.
2. Confirm feed rate on first zone.
3. Run in-hole with perf gun and perf second zone. Lay down gun.
4. Round trip packer in-hole to confirm second perf zone.

Day 2:

1. Run in-hole with perf gun and perf third zone. Lay down gun.
2. Round trip packer in-hole to confirm third perf zone.
3. Run in-hole with perf gun and perf fourth zone. Lay down gun.
4. Trip packer in-hole to confirm fourth perf zone.

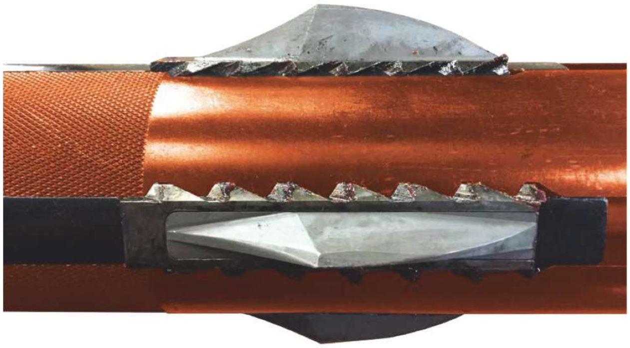
Day 3:

1. POOH with packer.
2. Run in-hole with perf gun and perf fifth zone. Lay down gun.
3. Round trip packer in-hole to confirm fifth perf zone.
4. Run in-hole with perf gun and perf sixth zone. Lay down gun.

Day 4:

1. Trip packer in-hole to confirm sixth perf zone.
2. Run in-hole and sequentially cement squeeze zones via packer assembly.
3. POOH and lay down pipe.

For a single well, using E-line and perf guns would have required four rig days, five round trips and six wireline runs, with six spent perf guns. The entire project would have required 64 rig days, 80 round trips and 96 wireline runs, with 96 spent perf guns.



Gator hydromechanical perforating tool blades are shown extended. (Source: Energy Fishing and Rental Inc.)

have made numerous improvements in shaped-charge technology for perforating (perf) guns. However, such tools still have limitations and drawbacks that can only be overcome by a step change in P&A methods.

Hydromechanical perforating

A new approach to perforating has the potential to eliminate the explosive perf gun, a major risk in most types of completion and well abandonment operations. For P&A operations in particular, the Gator hydromechanical perforating tool also has demonstrated efficiency improvements over conventional perforating-gun methods.

The tool itself is simple. In essence, stackable pistons responding to hydraulic pressure force cutter blades out of the tool housing and into the casing. As this happens, the inner mandrel in the tool's "dump sub" moves up, exposing vent holes to the annulus, which produces a visible pressure drop that indicates a successful cut. Because it's not a gun that has to be reloaded, the tool is reusable without retrieval.

Because of the mechanical nature of the perforating process, there is no damage associated with the perforations, unlike the large damage area associated with explosive perforations. Cuts can be indexed in-hole for a spiral effect, which improves fluid sweep.

Sixteen-well P&A program results

A six-zone 16-well P&A project was recently performed for a large North American operator using the hydromechanical perforating tool and a packer. This successful project provides a contrast to how the same project would have been conducted with a conventional e-line and perf guns (see shadeboxes).

In both cases, the well was prepped, with the producing zone being plugged.

For the 16-well project the hydromechanical perforating tool saved the operator about $380,000 in direct costs. Even more important were the potential savings associated with the substantial risk reduction from the elimination of explosive perf-gun handling and use.

In another application, the tool was used by an operator for remediation of low cement tops at time of abandonment. Using the tool combined with a packer system, the operator completed cuts at the required geological intervals while isolating previous cuts. The operator also could conduct independent feed rates or attempt to establish circulation to surface. Over a six-well abandonment project, this operator gained operational efficiency over traditional perforating systems from the elimination of the need to trip tubing for each cut while maintaining a sufficient flow area to cement through. In this project the operator cemented through a single cut without increases in pumping pressures as a result of pressure losses across the entry point.

Perf efficiency

Flow area measurements show greater perf efficiency over conventional perf guns. A conventional perf gun provides a total flow area per charge of 0.74 sq. in. and a total flow area with 16 shots per meter (five shots per foot) of 3.7 sq. in.

The equivalent hydromechanical perforating tool provides a total flow area per hole of 1.71 sq. in. and a total flow area per cut (four holes) of 6.84 sq. in.—nearly double the flow area.

Hydromechanical perforating technology offers considerable efficiency improvements over conventional explosive perf guns. This technology can be applied beneficially in completions, production, P&A and water injection well integrity. But of even greater value is the incalculable improvement hydromechanical perforating makes to personnel safety on the rig floor. E&P

Perforations made by the hydromechanical tool can be indexed in-hole in a spiral effect for improved fluid sweep. (Source: Energy Fishing and Rental Inc.)

Continuous data acquisition saves time, expense in logging

Combining microseismic measurements with VSP recording aids in determining the benefits of a permanent system.

Nicholas Randall, Baker Hughes

Monitoring microseismic events provides valuable information about the oil and gas production process. It can help operators maximize production and ultimate recovery and, in a growing number of applications, warns of potential environmental and safety issues. The value of monitoring these microseismic events can be as much about observing how the events change over time as it is about knowing they are happening in the first place, making permanent monitoring the ideal method. However, the expense, planning and design work required for permanent microseismic monitoring systems make it a major commitment.

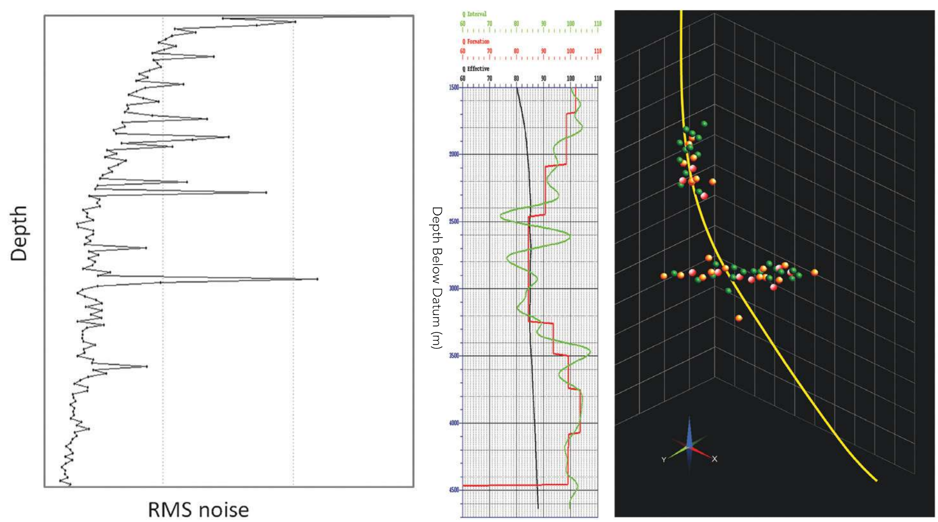
A new continuous seismic data acquisition service provides a simple, cost-effective method of previewing the microseismic environment to help operators determine if they should install permanent microseismic monitoring systems and the best way to go about it. The CONDAQ continuous seismic data acquisition service from Baker Hughes seamlessly acquires both high-quality vertical seismic profile (VSP) and microseismic data during VSP surveys without an additional wireline logging run, eliminating the costs that this would require.

The service obtains VSP and microseismic data using exclusive infield software to deliver two datasets for VSP and microseismic analysis with no need for extra rig time or operational planning. High-speed wireline telemetry allows data to be recorded continuously without interruption. An automatic process extracts VSP data from the continuous stream. The VSP data, which are equivalent to the data acquired from a series of conventional individual shot records, are immediately available at the well site without compromising data quality or complicating processing.

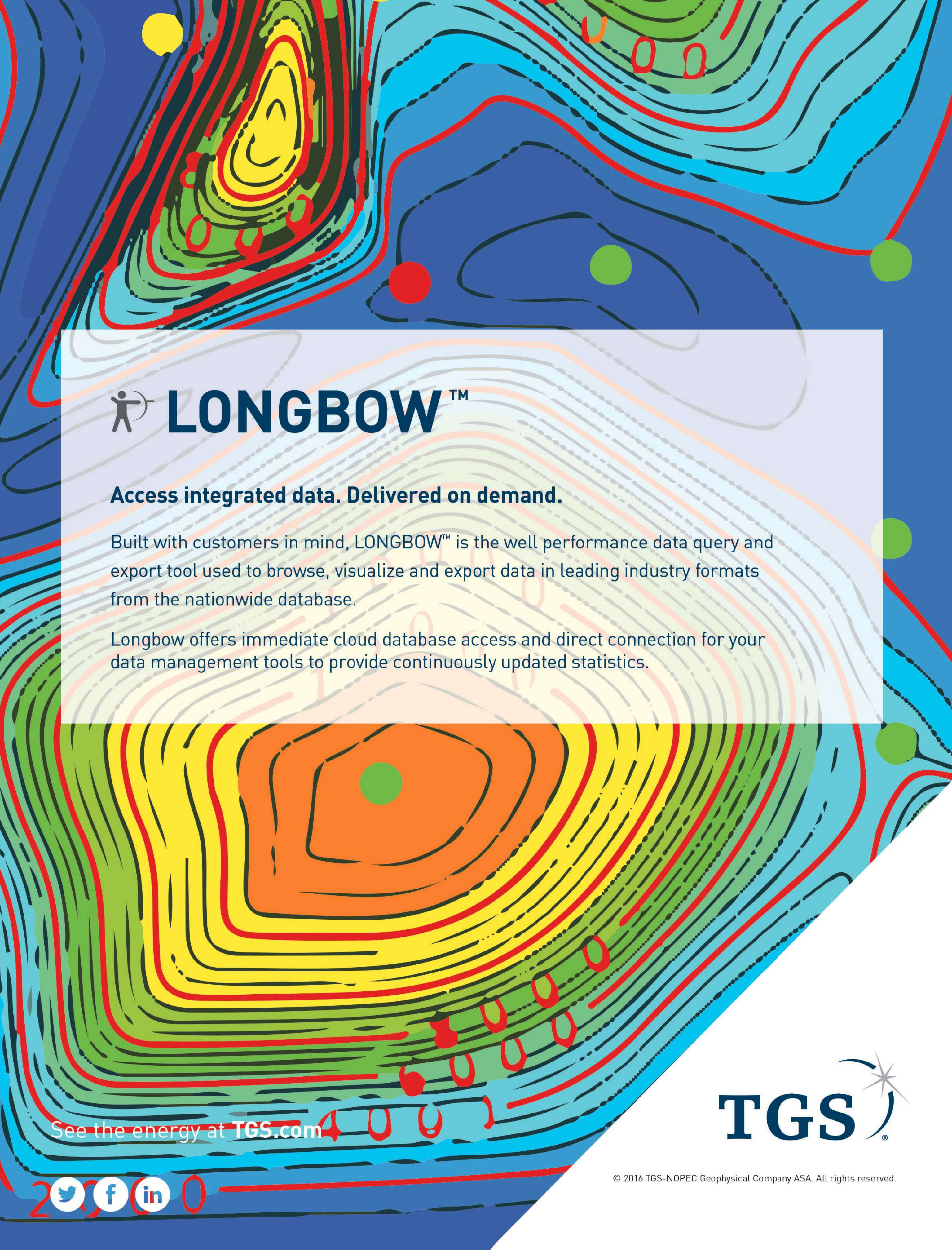
The value of microseismic monitoring

Operators of U.S. shale plays are familiar with the value that short-term microseismic monitoring offers in hydraulic fracturing operations. Monitoring during the stimulation process is carried out using an array of temporarily deployed receivers. The measurements identify fracture properties such as azimuth, length and height and also indicate stimulated reservoir volume and complexity. These data can be used to monitor the performance of the ongoing stimulation operation as well as optimize future well spacing and design.

In addition to hydraulic fracturing applications, microseismic monitoring can be used to track induced microseismicity that occurs over time, providing valuable information about the nature of what's occurring in the rock formation. A better understanding of reservoir production can be obtained or the progress of an injection plan observed. It also can be used to monitor well integrity by identifying and analyzing compaction and potential well sta-



This example of microseismic analysis available from CONDAQ data shows (left to right) distribution of background noise, variation in seismic attenuation with depth and processed microseismic event locations. (Source: Baker Hughes)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bility problems. The ability to see substantial microseismic activity in or near a region where it is not expected can raise an alarm and lead to an investigation of what is taking place, the possible consequences and how they might be mitigated. Other applications include monitoring injection and drawdown of underground gas storage to understand cyclic pressure and stress changes on local formations and the possible ramifications for the nearby environment.

Daunting commitment

Because induced microseismic events usually evolve over time, understanding the way they change can be as important to oilfield operations as the events themselves. Consequently, maximizing the benefit of induced microseismic data requires a permanent—or semi-permanent—downhole monitoring system. Yet because of the significant expense, planning and design work required to install a permanent system (and the difficulties involving well access), many operators are hesitant or unwilling to make the commitment without being certain that meaningful microseismic activity is occurring. This means that it's advisable to conduct a trial and feasibility study to understand if there are potential benefits from using a permanent sensor system. This typically requires a dedicated wireline logging run with associated costs from service charges and rig time plus operational inconvenience.

The new continuous seismic data acquisition service eliminates the need for a dedicated logging run by providing a seamless, cost-effective alternative that allows operators to confidently assess whether using permanent microseismic monitoring is the right way to go. The keys to the service are its advanced high-speed-telemetry seismic receiver systems that allow continuous recording and exclusive infield software.

Doubling up on VSPs

As part of this new method, established VSP techniques are used for geophysical appraisal of the region around a well. The resulting high-resolution 2-D and 3-D images yield important structural and stratigraphic information that assists in understanding the reservoir, including identification of faults and salt flanks. Amplitude-variation-with-offset calibration and anisotropy measurement also can be obtained. Integrated with surface seismic and well-logging data, VSP data can be used to define formation rock properties and pore pressure indicators and identify other reservoir details with high resolution. The results give operators a clearer understanding of the best ways to capitalize on the reservoir.

During the traditional approach to VSP acquisition, seismic data are recorded in bursts while a source is putting seismic energy into the ground. In the interval between these, the receivers are often stationary and acquiring no data, an unproductive use of rig time. By continuously acquiring data through this new service, this time is spent more efficiently recording microseismic data in addition to the VSP data being recorded. The continuously acquired data corresponding to the VSP shots are automatically extracted infield to provide records equivalent to a conventional VSP. These can be displayed, quality-controlled and processed to generate a normal VSP dataset.

A second microseismic dataset consisting of the continuous recordings also is available to be analyzed and used to help determine the viability of permanent monitoring in a well. A number of microseismic indicators can be pulled to characterize the nature of the microseismic environment. For example, the distribution and characteristics of the noise levels in and around the well can be established. Any spontaneously occurring recordable microseismic events also will be captured, providing information about their nature and frequency of occurrence. Combining this with other information gained from the VSP dataset from the same well is highly beneficial. Used with VSP-derived attenuation and velocity data, sensitivity maps can be generated. These show what events can be detected and from how far away. These sensitivity maps can be produced for different permanent monitoring configurations, allowing for optimization of planned designs.

Recently, the continuous seismic data acquisition service saved 24 hours of offshore rig time in an application to determine the viability of and best techniques for employing a permanent microseismic monitoring system to help ensure well integrity. While shooting a VSP in a well in the same area where proposals for a permanent monitoring system had been submitted, the service obtained both a VSP and a microseismic dataset. Information from the microseismic dataset enabled the level of microseismicity to be assessed and the measurements to be gathered for a variety of parameters useful in refining the plans for a permanent monitoring system. The ability to simultaneously gather VSP and microseismic data eliminated the need for dedicated microseismic monitoring rig time, with savings estimated at $600,000.

Ongoing applications of the new service later this year are expected to further confirm its value in assessing the viability and optimizing the design and placement of permanent microseismic monitoring systems. E&P

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Fiber-optic borehole seismic vector sensor technology

System provides sensitive recording for high-resolution reservoir characterization and monitoring.

Björn N.P. Paulsson, **Jon A. Thornburg**, **Ruiqing He** and **Michael T.V. Wylie**, Paulsson Inc.

A new generation of borehole seismic vector sensor systems has been developed based on all-fiber-optic data transmission and fiber-optic sensor technologies. The new vector sensors are much more sensitive and are able to record much larger bandwidth data with better vector fidelity than is possible with current seismic sensor technologies. The new sensors also can operate in most hostile environments found in boreholes such as HP/HT conditions. This improvement in data quality and density will generate better images and more precise monitoring results, which will allow a much improved high-resolution interpretation and ultimately better oil and gas production.

Since the borehole seismic system does not require electric power for either the optical sensors or the hydraulically operated deployment system, the entire system is intrinsically safe. The new system is capable of deploying up to 1,000 three-component (3-C) sensor pods suitable for deployment into HP/HT boreholes. Tests of the fiber-optic seismic vector sensors have shown that the new sensor technology is capable of generating high vector fidelity data with a very large bandwidth of 0.01 Hz to 6,000 Hz. Field tests have shown that the system can record events at magnitudes smaller than M-3.0 at frequencies up to 2,000 Hz. The sensors also have proven to be about 100 times more sensitive than the regular coil geophones that are used in borehole seismic systems today. The optical vector sensors come in ½-in. and 1-in. sizes. The 1-in. model is used for a redeployable borehole system, while the ½-in. model is used for a permanent borehole system. The ½-in. optical sensor, despite the small size, still outperforms state-of-the-art accelerometers and geophones.

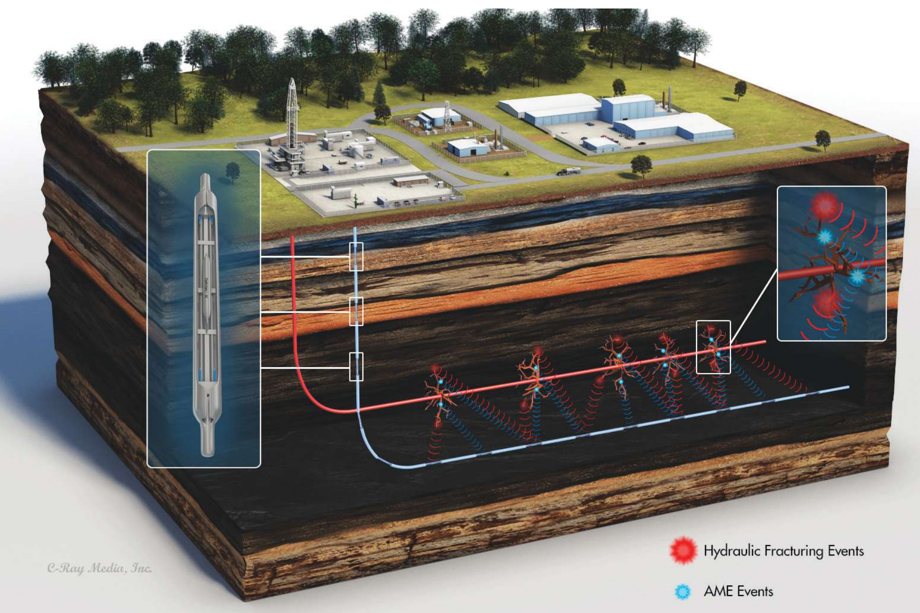

FIGURE 1. The fiber-optic seismic sensor system was deployed in a horizontal well near a well that was being hydraulically fractured. (Source: Paulsson Inc.)

Fiber-optic borehole technology

A large-aperture ultrasensitive borehole seismic array with a close interpod spacing capable of operating at high-temperatures will for the first time enable the recording of large amounts of data with the high quality and high frequency needed for high-resolution borehole seismic 3-D imaging and 4-D monitoring of conventional and shale oil and gas reservoirs.

The fiber-optic borehole seismic array will be able to monitor and map the injection of fluids into the reservoirs using 3-D mapping of microseismic events. This system will allow acquisition of broad bandwidth microseismic data with frequencies of more than 1,000 Hz with a moment magnitude less than M-3.0 during monitoring of microseismic events from induced fracturing.

The drillpipe deployment design allows the receiver array to be deployed in both vertical and horizontal wells, which is an operational requirement in shale oil and gas wells since many of the wells drilled for shale oil and gas are highly deviated or horizontal. The deployment of the drillpipe-deployed borehole seismic system is shown in Figure 1. The application depicted in this illustration is the combined monitoring of the microseismic events from the primary fracturing process as well as monitoring the injection of acoustic micro-emitters (AMEs) into the fracture. The AMEs generate small microseismic events at a predetermined time after being injected into the fractures together with the proppant in small concentrations. The all-metal clamping system for the 3-C sensor pods uses drillpipe hydraulics as a power source. The fiber-optic sensors are operated using only pulsed laser light from surface electronics and manufactured using high-temperature fibers.

Fiber-optic sensor

The key to the performance of the fiber-optic seismic array is the fiber-optic seismic vector sensors. The fiber-optic vector sensors are designed using a mass-spring system that is configured so the directionally vibrating mass strains along the fiber proportionally to the directional seismic strain sensed by the 3-C sensor pod. One advantage with this approach is that the sensor can be made very small. The sensor has a modeled cross-axis isolation of 80 dB, allowing a high-fidelity separation of the different wave modes.

The fiber-optic seismic-sensor system dynamically measures the strain of the fiber between two Fiber Bragg gratings surrounding the mandrel using an interferometric measurement technique comparing the phase angle between two spaced reflections from the same light pulse traveling in the fiber. It is using a time division multiplexing technique to transmit the dynamic fiber strain information to the interrogation instruments at the surface. This allows the measurement of extremely small strains in the fiber. The fiber-optic seismic sensor is immune to electric and electromagnetic interference in the borehole since the system does not require any electronics at the fiber-optic sensor end. This design also makes the fiber-optic seismic sensor extremely robust and able to operate in extreme environments such as temperatures up to and more than 300 C (572 F.). Even higher temperatures are possible using specialty metal-coated fibers.

Field data sample

The prototype system was tested in a survey to evaluate the response of the fiber-optic seismic sensors using both surface and downhole seismic sources. The data shown in Figure 2 are from string shots. The downhole sources comprised very small TNT charges that were shot in a well 335 m (1,100 ft) from the receiver well where the fiber-optic seismic sensor array was deployed.

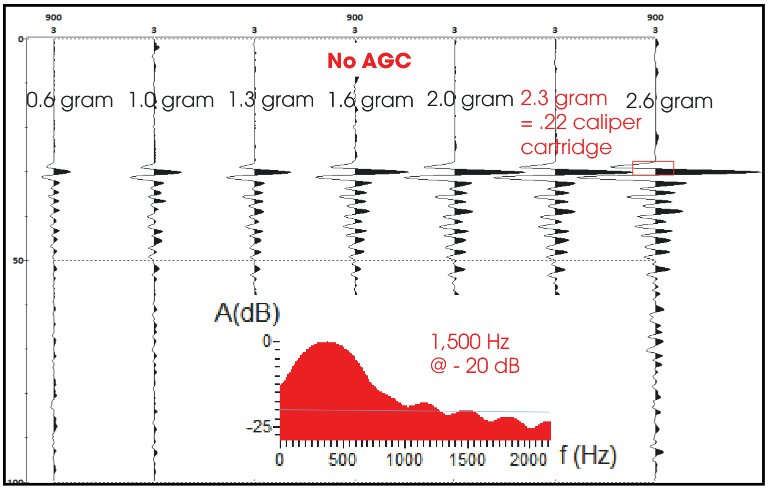

FIGURE 2. Principal component data were rotated to point to the TNT source. Seven small shots of TNT a source/receiver distance of 366 m are shown. The data show how the true amplitude changes with the size of the explosive charge. The inset figure shows the frequency spectrum of the first arrival wavelet. Filter slice analysis shows useful seismic energy to more than 1,500 Hz. (Source: Paulsson Inc.)

The source was set off at a depth of 91 m (300 ft), while the receivers were placed at a depth of about 274 m (900 ft). The straight line distance between the source and the receiver is thus about 366 m (1,200 ft).

The data displayed in Figure 2 are from shots ranging from 0.6 gram to 2.6 gram of TNT (string shots).

They are post 3-C rotation displayed using true relative amplitude. Figure 2's inset image also shows the frequency spectrum of the data from a charge of 0.65 gram of TNT. Filter slice analysis of the data shows energy more than 1,500 Hz.

All the sensors are calibrated so the optical output amplitude into absolute acceleration can be mapped. The data recorded from the small TNT charge were analyzed and compared to micro-earthquakes. It was calculated that the 0.6 gram of uncoupled TNT in a fluid-filled well is equivalent to an earthquake with magnitude M-2.9. Small earthquakes do not only have low energy, they also generate mostly high-frequency seismic data, so any sensor that is deployed to monitor small microseismic events must not only be sensitive but also be able to record high frequencies. E&P

Acknowledgments

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Combined approach facilitates drilling

Using WBS in tandem with MPD enabled the drilling of a well with unstable shales and depleted sands.

Maurizio Arnone, **Said Boutalbi**, **Hunter Craig**, **Julian Hernandez** and **Alex Ngan**, Weatherford

Tapping the full potential of long-producing reservoirs often requires drilling through unstable shale formations and depleted sands, conditions that present stiff challenges for conventional drilling programs. Issues related to lost circulation and wellbore stability significantly drive up nonproductive time (NPT), impacting operators' ability to drill and complete wells economically.

As the industry confronts increasingly complex formations, sophisticated drilling methods such as managed pressure drilling (MPD) are being implemented with greater frequency to overcome technical and financial obstacles. MPD, which maintains constant bottomhole pressure (CBHP) by applying surface backpressure (SBP) in a closed-loop system, has a strong track record for maintaining wellbore integrity while improving drilling efficiency. The approach is especially effective when used in concert with wellbore strengthening (WBS) techniques, further mitigating risk and cost.

A major operator worked with Weatherford to implement a combination of MPD and WBS techniques to successfully drill challenging hole sections in five offshore development wells in a region of the Caribbean Sea that had been producing since 1961.

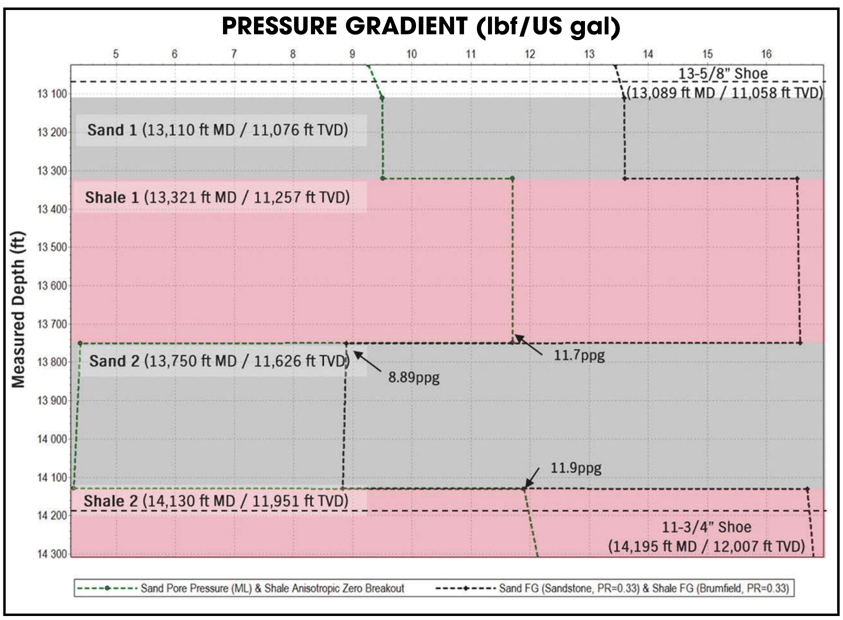
Previous attempts by the operator to conventionally drill the sections had resulted in costly remediation, including sidetracks, due to bottomhole pressure (BHP) fluctuations and poor wellbore stability. The repetitive fluctuations that occurred as a result of lost frictional pressure when pumps were turned on and off between drilling and makeup led to wellbore fatigue, especially when crossing through the unstable shale sections.

Creating a drilling window

The centerpiece of the project was the Weatherford Microflux MPD Control System, an automated closed-loop system that, unlike conventional drilling methods, detects and controls even the most minor fluid influxes or losses to minimize well control incidents and enhance drilling efficiency. This enables operators to make decisions based on actual surface and wellbore data rather than predictive models. The system's ability to optimize mud weight is especially beneficial when the window between pore pressure and fracture gradient is very narrow or, in this case, nonexistent.

A key component of the automated MPD control system is the rotating control device used in the closed-loop system to contain annular fluids while drilling. The device makes underbalanced, near-balanced and overbalanced drilling possible when the risk of gas kicks is elevated. It diverts fluids through a control manifold engineered with advanced sensory technology that extracts critical data from the fluids.

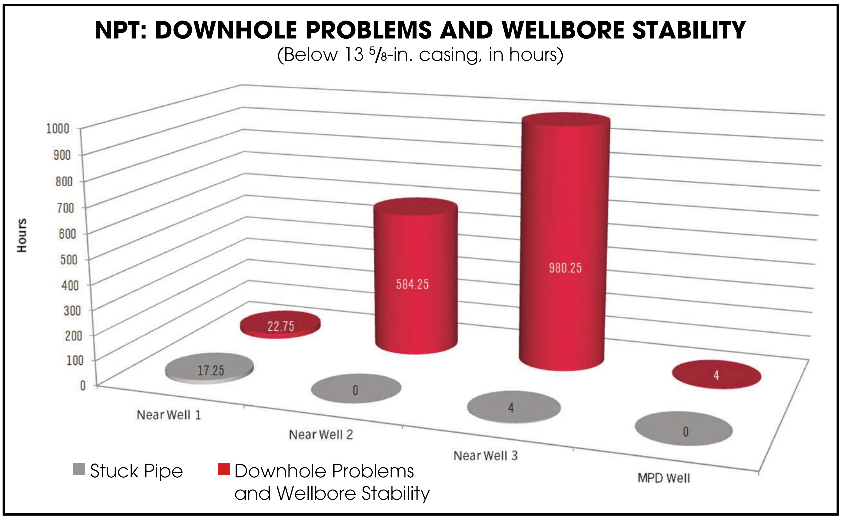
Extensive planning and engineering determined the optimum mud weight,



Without the utilization of MPD and WBS techniques, the drilling window in the 12 ¼-in. by 14 ¾-in. section was nonexistent. (Source: Weatherford)

rheology of the WBS material, and drilling fluid and drilling parameters for the MPD operation for all phases of the project, including drilling, tripping, well balancing, WBS pill placement, liner running, cementing and contingency MPD operations.

The 12 ¼-in. by 14 ¾-in. section had a drilling window defined by two unstable shales, indicating there was no operating window to drill through the depleted sand without incurring losses. This necessitated the use of the lowest possible mud weight that fulfills the wellbore stability gradient requirement and the fracture gradient of the depleted sand. The objective was to drill through the depleted sand and isolate it with an 11 ¾-in. liner.



The well drilled using MPD techniques had zero NPT from stuck pipe and significantly lower NPT from downhole problems and wellbore stability issues compared to near wells that were drilled using conventional methods. (Source: Weatherford)

Weatherford used the automated MPD control system to drill the section from the 13 ⅝-in. casing shoe at 4,037 m (13,245 ft) measured depth (MD) to the top of the first shale at 4,359 m (14,302 ft) MD. In this section the team used an 11.7 ppg equivalent mud weight (EMW) fluid while dynamically strengthening the wellbore, incorporating lost circulation material into the drilling fluid to increase the anticipated sand fracture gradient from 8.9 ppg to 11.9 ppg EMW. Before reaching the first shale, it applied SBP to create 11.9 ppg equivalent circulating density (ECD) while drilling and 11.9 ppg EMW when making connections. A 10.8-ppg mud pumped at 1,100 gal/m was used for drilling to ensure good hole cleaning, and 625 psi SBP was applied during connections to minimize pressure fluctuations.

Significant time, cost savings

For the 10 ⅝-in. by 12 ¼-in. hole section, the 11 ¾-in. liner was set at 4,359 m MD with the liner top at 3,885 m (12,745 ft) MD. After drilling the hole to the next planned casing depth setting at 4,684 m (15,366 ft), a dedicated 12 ¼-in. hole-opener bottomhole assembly was run to total depth (TD). A 9 ⅝-in. liner was then run and tied back to the 11 ¾-in. liner at 4,207 m (13,802 ft) MD.

The drilling window was defined by unstable shale and the fracture gradient of the depleted sand, leaving no drilling window. MPD was used to drill from 4,359 m to 4,684 m MD with a 12.5-ppg mud at 900 gpm and 600-psi SBP applied during connections. While drilling, the depleted sand was dynamically strengthened to 13.4 ppg EMW until TD, when the sand was further strengthened to 14.34 ppg EMW.

In both sections MPD tripping, circulating and cementing strategies ensured the downhole ECD was within the new operating window during the liner run and cementing operations. Once the depleted sands were fully exposed, a static WBS technique was applied to create a window for tripping and running the liner. In this case, with the bit at bottom, the operator used a limited-volume WBS pill, spotting the corresponding mud volume with the required concentration in front of the sand and suspending circulation. MPD applied SBP until the target EMW was reached. The string was rotated and reciprocated up and down slowly to prevent differential sticking. Using MPD technology enabled the driller to keep the bit on bottom and effectively eliminated the need for a wiper trip.

The combined MPD/WBS operation reduced rig time and NPT significantly, saving the operator an estimated three days of rig time. The MPD technique mitigated BHP cycles by maintaining CBHP, enabled drilling with the lowest possible static mud weight and maintained a delicate wellbore pressure profile to avoid wellbore collapse. WBS increased near-wellbore stress across the depleted sands to create a drilling window and avoid losses and stuck pipe.

The MPD well required 533 hours to drill both sections compared to 2,410 hours to drill the same sections conventionally in the previous offset well. The MPD well recorded only 4 hours of NPT related to downhole issues and wellbore stability compared to 980 hours of NPT in the offset well. Whereas the offset well required extensive back-reaming, the MPD well required no back-reaming to achieve a good-quality wellbore. E&P

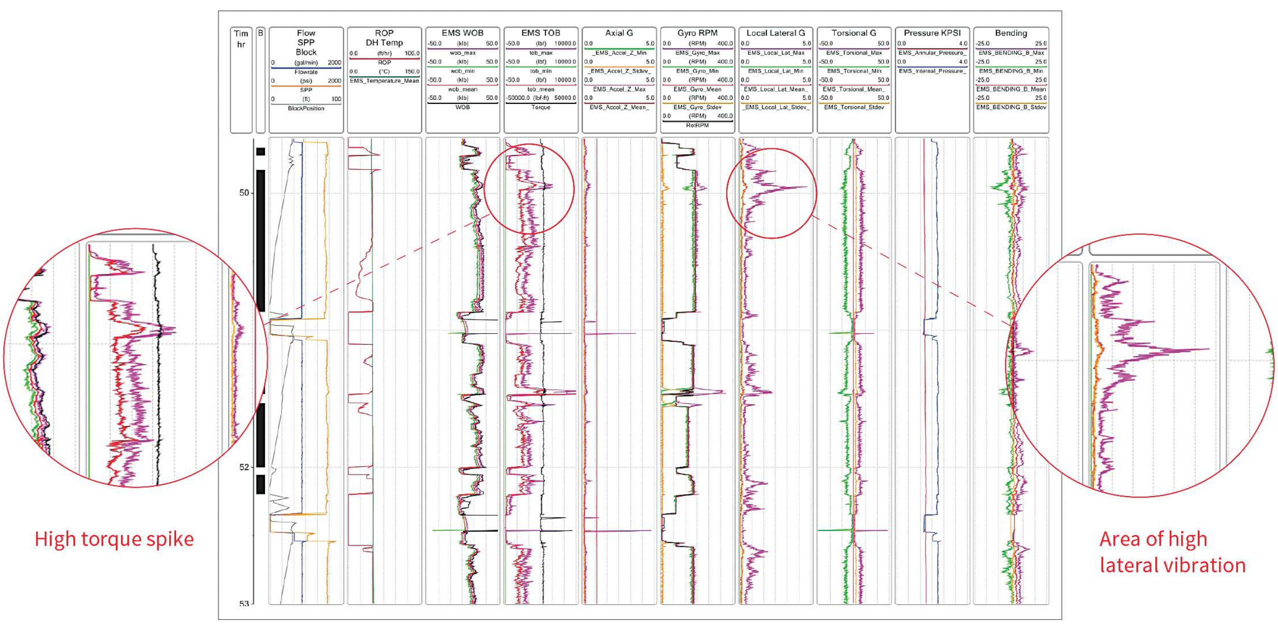
Integrated system improves drilling operations

Surface, downhole data collection aids in understanding operational problems.

Stephen Forrester, NOV

The current state of the oil and gas industry, which is experiencing its worst downturn since the energy crisis of the 1970s, is necessitating powerful innovation in how it produces and develops oil and gas reserves. No longer will the maxim "We've always done it this way, so it must be right" suffice when breakeven prices often are significantly higher than the cost of a barrel of oil. With the need to increase drilling efficiency mounting, operators are seeking out new solutions to an old problem, looking to service companies to assist them in making their operation economically feasible. Among the innovations in optimization that are currently driving positive change in the industry is a new offering from NOV, the eVolve Optimization Service. The service's four-tiered approach ranges from surface data-based optimization to full closed-loop downhole drilling automation. Through these tiers, the service equips existing rigs and rig crews with an advanced toolkit to improve performance, enable real-time decision-making and enhance analytics capabilities.

The eVolve service's second tier, ADVISE, is a data-driven optimization service that incorporates NOV's BlackBox memory-mode logging tools to enable improvements in drilling efficiency that drive substantial savings. The BlackBox tools capture data with a variety of sensors and can be placed in the drillbit, bottomhole assembly (BHA) and/or drillstring. The tools enable a better understanding of true downhole events such as pressure, vibration, weight transfer and torque reactions while drilling. When combined with data acquired at surface, the tools provide a comprehensive overview of the downhole environment and how drilling practices affect performance and reliability.



In this example, a high-density surface and downhole dataset from BlackBox tools reveals the correlation between a spike in downhole torque and an area of high lateral vibration. Access to this level of granular detail enables creation of a driller's roadmap for application in future wells, ultimately allowing operators to avoid issues such as reduced ROP and significant equipment damage. (Source: NOV)

BlackBox tools are an important part of the eVolve optimization process. This memory-mode logging tool, which records parameters such as RPM, weight, torque and vibration, is available in various sizes and configurations to allow flexible placement in the BHA or drillstring. The tools facilitate the identification of drilling inefficiencies such as lateral downhole vibration, weight transfer issues and stick/slip. (Source: NOV)

The integrated approach of the ADVISE tier builds on this optimization foundation by combining surface data with downhole data obtained from the BlackBox tools to analyze dynamic behavior of drilling activities, enabling better design and component selection for the BHA. Software identifies harmful vibration and evaluates rock properties and formation characteristics, alerting the driller to potential risks and dysfunctions. Torque and drag, mechanical-specific energy, buckling and other dynamic behaviors are assessed to provide a clearer overall picture of the drilling environment. In addition, real-time remote monitoring ensures that the rig crew is always well informed with respect to current conditions on the rig and that it has around-the-clock access to technical expertise.

NOV was tasked with increasing performance on several global shale projects to maintain their viability in this difficult economic environment. Drilling dysfunctions such as stick/slip and torsional and lateral vibration were resulting in nonproductive time, equipment damage and overall below-average performance across the clients' operations. Increases in ROP, decreases in destructive vibration modes and reductions in drilling time were the major successes from using downhole drilling dynamics to drive enhancements in performance in these projects. The first three, referenced below, took place in the Haynesville Shale, while the final project took place in the Permian Basin.

Vibrations causing bit damage

The eVolve team used a combination of BlackBox tools on two offset wells to record and study vibrations that were inducing severe bit damage and causing low ROP and discovered that severe torsional vibration was the most problematic aspect, leading to reduced performance for the client. An analysis and evaluation of the downhole data from the tools enabled the creation of new parameter guidelines to increase drilling efficiency and reduce that damaging vibration. In addition, the introduction of the more durable Helios thermostable cutters extended bit life and enhanced overall performance. The implemented changes led to a reduction in the average number of bits used, an increase in average ROP of about 32% and a reduction in average drilling time of about 37%.

Dysfunctions causing below-average performance

The eVolve team analyzed downhole drilling dynamics using BlackBox tools, which determined that the primary causes of reduced performance were stick/slip and lateral vibration. The tools experienced about 13 hours of extreme vibration in the 2,195-m (7,200-ft) interval of the well, which included the Massive Anhydrite, Travis Peak and Cotton Valley formations. This high-frequency vibration was causing the problematic decreases in overall performance. After accurately monitoring drilling dynamics, specific formation-based surface parameter changes were suggested to mitigate the damaging vibration; implementation of these changes allowed the client to increase ROP by about 33% and decrease vibration by about 85%, which reduced its total drilling time from eight to six days.

Revising BHA parameters

NOV deployed BlackBox tools in the 9 ⅞-in. section of the client's first well to observe surface and downhole drilling dynamics parameters and establish a benchmark, with the eVolve team noting that the primary drilling dysfunction was severe torsional vibration in the BHA. After making specific BHA and drilling parameter recommendations to address loss of energy at the bit and bit damage, the client was able to drill the section it had previously drilled in 112 hours in 90 hours, a reduction in drilling time of 20%. The client was able to successfully drill the section, which had previously taken up to three bits, in a single bit run, which translated to further increases in operational cost-effectiveness through the reduction or elimination of the equipment damage caused by drilling dysfunctions.

Avoiding cutter damage

The eVolve team observed drilling practices and used BlackBox tools located in multiple positions in the BHA to analyze the operation, revealing that poor connection and slide-to-rotate procedures were causing harmful vibrations, in turn leading to cutter damage. This analysis also identified problematic BHA components that were causing poor weight transfer and reducing overall performance. After the benchmark well was drilled at 14.8 m/hr (48 ft/hr), the client used NOV's recommendations to correct drilling practices, reduce cutter damage and optimize BHA design. This led to increased ROP in the next two wells of 60% and 164%, respectively—and a consequent reduction in time to total depth of 1.5 days and 2.5 days in the same two wells. Assuming a spread rate per day of $100,000, this saved the client $400,000.

The oil and gas industry is currently in a position to drive enormous advancements in wellbore technologies, with increases in drilling efficiency becoming more and more critical moving forward. This need will allow the type of optimization service that NOV has developed to see broader application in the types of shale environments detailed in these projects and beyond. The value that these projects provided clients is just one example of how services like this can be utilized to create more efficient and cost-effective solutions to the global drilling industry's challenges. The ADVISE tier is an integral piece of the optimization puzzle, and through a commitment to continuous improvement, the eVolve service and the software and processes that support it will ensure that the industry at large is poised to confidently move forward. E&P

Keeping the flow flowing

Nontoxic paraffin removal agent helps return flow to a GoM pipeline slated for abandonment.

Jennifer Presley, Senior Editor, Production Technologies

There's little debate on how the oil and gas industry has benefitted greatly through the transfer of technologies from other industries like aviation and medicine to solve its big challenges. Beer brewing can now join the industry's list of tech transfer success stories.

That transfer is a natural fit as the two industries struggle with similar challenges in keeping their production lines free from blockages. However, removing any blockages that might form is not always as easy as pouring a liquid cleaner down the drain, especially when that blockage is in a subsea pipeline hundreds of feet below water.

There's now an environmentally friendly alternative to the traditional chemical and mechanical methods of well remediation. The roots can be traced back to the trial-and-error experimentation with solvents and oxidizing agents to develop solutions for the food and beer brewing industries to keep equipment like brass filtering plates and tanks clean.

That cleaning solution, with some additional tweaking in the laboratory, became WellRenew. In late 2015 a blocked Gulf of Mexico (GoM) pipeline was treated with WellRenew and is flowing crude once again. The nontoxic paraffin removal solution, developed by Lafayette, La.-based Ideal Energy Solutions, is not limited by the challenges that traditional paraffin and asphaltene management systems face, like low temperatures and long pipeline lengths.

Blocking flow

The deposition of paraffin in flowlines and production equipment is one of the more difficult challenges an operator can encounter over the life of its wells. Buildup occurs inside the lines naturally during the flow of crude, with the paraffin forming into solid wax particles when the crude temperature falls below the cloud point.

"As paraffin, asphaltene, oil and formation deposits lay down in the line, it does so like rings in a tree trunk," said Charlie Talley, chief developmental chemist for Ideal Energy Solutions. "The biggest challenge that we had was in coming up with something that could actually lower the surface tension enough so that the material could go around the pipe's surface and we could push the plugs out of the pipe."

Typical remediation methods like line heating, warm solvent or hot oil treatments, and chemical wax inhibitors are limited in their effectiveness by low temperatures and pipeline length, making them unsuccessful in most cases. Where coiled tubing can be effective, its use can be limited by pipeline length and bends. Also, the mobilization and utilization of these tools is costly, and there are many risks associated with the process.

"Coiled tubing involves taking an entire coil unit on location, and depending on the length of the pipeline, the crew might actually have to go in from both sides," said Kevin Ayers, COO for Ideal Energy Solutions. "There's a lot of equipment involved, and it's very expensive. It also can be dangerous, which is another

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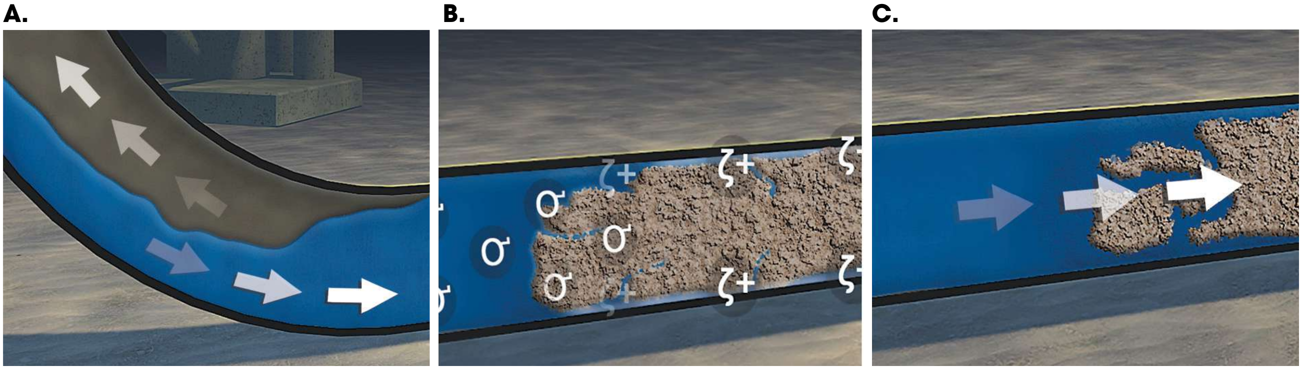


A) The low surface tension of the cleaning solution (blue) allows it to penetrate the area between the deposit and pipe walls. B) Oxygen from the solution is released and neutralizes the zeta charge responsible for the stickiness associated with paraffin and asphaltenes. C) The cleaning solution reacts with a portion of the oil to create a simple soap lubricant. (Source: Ideal Energy Solutions) advantage that WellRenew has because it's nonhazardous and has a minimal equipment spread."

Unblocking flow

The solution is based on three principles: surface tension, hydrophilic-lipophilic balance and controlled oxygen. The extremely low surface tension of the solution allows it to penetrate the area between the deposit and pipe walls and into any cracks or crevices present in the deposited material, Talley said.

"WellRenew works through a controlled oxygen release mechanism. We found that oxygen will neutralize the zeta charge that causes the stickiness of the paraffin plug," Talley said. "To get it around the pipe, you have to be able to lower the surface tension. We've come up with some very unique surface-active agents that can reduce the surface activity down to about 20 dynes."

This approach does not dissolve paraffin or asphaltenes but rather floats them and allows them to be pumped. When hot solvents are used and appear to dissolve these materials, the solutions will gel again when cooled and become hard to remove.

"Many people in the industry think you can dissolve paraffin, but you can't. It's virtually nonreactive," Talley said. "The only thing that you can do is get it to the point where you can move and pump it. That's what WellRenew does."

Field results

A major operator in the GoM had performed multiple chemical and mechanical remediation treatments to reestablish flow in a 7.9-km (26,000-ft) 4-in. pipeline that connected two of its platforms with limited success. Before abandoning the line, the operator treated it with WellRenew. Limited flow returned to the line after 5 hours of treatment, with full flow returning to the line 75 hours into the treatment with the solution.

Realizing flow assurance through clamp-on production surveillance

A proactive flow assurance strategy using clamp-on surveillance meters can help minimize potential production interruptions.

Arran Davidson and **Carolina Uribe Stopkoski**, Expro

Operators are increasingly focused on implementing a proactive flow assurance strategy to minimize any potential interruption to hydrocarbon production. Failure to implement an adequate strategy can lead to unplanned production outages as well as further compounding issues including formation blockages that will require costly intervention and/or remediation activity.

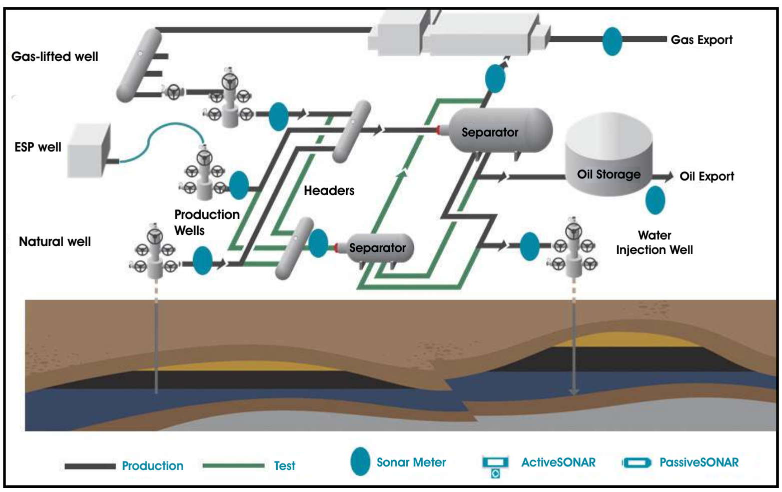
In the production phase of the life cycle, having a stronger understanding of flow behaviors can lead to proactive decision-making, resulting in improved overall flow assurance. This approach includes a range of portable metering technology that can be deployed quickly and cost-effectively to a range of brownfield, mature infrastructure and newbuild facilities.

Delivering improved flow assurance

Monitoring of individual well production and flow performance through the associated piping network provides critical data to validate flow assurance models and implement associated improvements. Where infrastructure is already in place, the use of traditional in-line flow measurement technologies is challenged by a number of factors, including obsolescence, turn down, change in fluid properties and operability. The repair and/or replacement of existing in-line flowmetering can be cost-prohibitive.

In an effort to provide operators and asset managers with a means to manage flow assurance, Expro developed a range of nonintrusive clamp-on flowmeters: ActiveSONAR and PassiveSONAR. The company successfully deploys these meters globally for the surveillance of naturally and artificially lifted production wells, water and gas injection wells, and midstream process applications.

The clamp-on design and measurement principle offers flexibility in meter placement and application suitability since the meters can be installed on existing pipework on a temporary or permanent basis with no process shutdown. The technology's flexibility means that the flowmeter can be applied in a variety of monitoring applications, including both single and multiphase flows, which allows the technology to be applied to both upstream and midstream applications—from wellhead to separator.



The use of clamp-on flowmeters offers flexibility in placement and can be installed on existing line or on a temporary or permanent basis. (Source: Expro)

Providing multiphase measurement

Sonar meters measure the velocity of the mixture flowing through the pipe. Production optimization of the well typically requires the knowledge of individual phase rates—produced gas, oil/condensate and water. Expro has developed the Total Production Surveillance (TPS) system, incorporating PassiveSONAR and/or ActiveSONAR meters, for multiphase reporting of black oil (naturally flowing, electrical submersible pump, gas-lifted) and gas condensate production wells. The TPS system leverages a combination of pressure-volume-temperature models and multiphase flow correlations for production surveillance, where flow assurance is critical.

Individual well production surveillance

Identifying and understanding the performance of each production well and how hydrocarbons flow through the surface piping and process plant is critical in assessing and managing

Clamp-on flowmeters enable monitoring of production in real time. (Source: Expro)

potential flow assurance issues. Production trends and flow-rate management have become a leading focus in the flow assurance cycle, where identification of underperforming wells enables operators to address potential decreases in production early on.

The clamp-on sonar flowmeter was successfully deployed for fieldwide surveillance on Centrica Energy's North and South Morecambe fields, which are among the largest on the U.K. Continental Shelf (UKCS) in terms of original reserves. The fields consist of a central production facility alongside several normally unmanned installations with no individual well surveillance or export metering. The operator was experiencing measurement issues that were leading to errors in back allocation calculations. Retrofitting ActiveSONAR meters onto the existing pipe network provided a cost-effective solution that facilitated the delivery of real-time flow assurance data at the central production platform and onshore.

The wells were liquid-loaded, compounded by halite buildup across the perforations which, if left untreated, would often kill the well. Remedial action involved calling out a coiled tubing unit and nitrogen lift to unload excessive liquid from the wellbore.

The ability to monitor production rates in real time allowed the operator to proactively manage the well unloading and, where possible, avoid the requirement for costly well intervention activity. The real-time production data also allowed the operator to optimize the duty cycle between flowing and shut in, a technique used to promote liquid unloading from the wells, which resulted in a net gain of doubling peak production from those individual wells.

Fourty-four ActiveSONAR meters have now been installed in Centrica Energy's platforms in the UKCS to date and have been in operation since 2010.

Optimizing gas lift

Operators must balance the benefits of maximizing liquid production from a gas-lifted field vs. recycling the lift gas and constraining the pipeline network capacity. Expro's meters were recently used in an onshore brownfield in North Africa where the operator was trying to maximize liquid hydrocarbon recovery from individual wells.

Comprising a large, comprehensive and distributed pipeline network, the field has been in production for more than 30 years, and the wells are now flowing below bubble point. A temporary sonar meter is being used to monitor gas-lift injection rates during production testing operations to establish a set point for gas lift and achieve maximum hydrocarbon liquid production rates.

This gas-lift optimization can in some instances result in a net increase of +/-10% of liquids on a well-by-well basis, which could equal about $500,000 per well per year. A further benefit also includes a reduction in lift gas, which increases capacity within the production piping for additional produced liquids and associated gas. The meters also are being used in this field to optimize gas injection distribution and for water injection for pressure support.

Flexible approach

In a lower-for-longer price environment, nonintrusive metering technology will have a growing and essential role to play in providing flow assurance surveillance solutions that capture critical data and enable companies to make the most informed production optimization decisions.

In brownfield applications, where production rates and fluid properties have changed, it allows operators to collect real-time measurements, update their flow assurance models and validate new strategies.

Sonar meters operate in both single and multiphase flow regimes, offering a single technology platform in which to implement fieldwide surveillance in support of flow assurance. Simultaneous measurements from wellheads, flowlines and process equipment allow a visualization of the interdependency of various "nodes" within the well and production network. Any consequence of change can be observed simultaneously at a system level rather than just a discrete point within the network. A change to a production choke at the wellhead might take hours or days to ripple through the network and validate that change.

The clamp-on nature of the meters offers either a permanent retrofit to an existing or newbuild facility for long-term monitoring of flow assurance strategies or as a temporary portable tool to provide real-time diagnostics where flow assurance issues are suspected.

Offering this flexible approach to metering is increasingly important as operators continue to develop and refine their plans for a cost-effective flow assurance strategy. E&P

References available.

Disposable downhole fiber-optics solution

The world is increasingly becoming a throw-away society, so it's no surprise that disposable fiber-optic technology is being looked at for well intervention applications.

Mark Thomas, Editor-in-Chief

While some find the idea of consumerism and a throw-away approach a wasteful and therefore distasteful one, others will equally argue that spending more money than is needed to do a job is equally as poor a philosophy.

A disposable solution for well intervention applications is being developed, inspired by technologies taken originally from the military and aerospace industries. If it comes to fruition it will be a radical advance, but industry support so far shows the technology is more than just a throw-away idea.

Well-SENSE Technologies, a downhole-focused company started up in June 2015 based in Aberdeen, has developed its FibreLine Intervention (FLI) solution to the point where it has already picked up support from Scotland's Oil & Gas Innovation Centre (OGIC), which both partly funds emerging technologies and also acts as a matchmaker to link innovative small and medium-sized enterprises with relevant academic expertise via the country's 14 universities.

Temporary fiber optics

In a nutshell, FLI is a disposable method of intervention, which essentially means the temporary installation of fiber-optic lines into wells. These would perform distributed acoustic sensing, distributed temperature sensing or distributed pressure sensing duties.

By vastly increasing the number of fiber-optic lines installed into wells, the collection of data would dramatically increase and result in a greater understanding of downhole performance and integrity. This would logically lead to the more efficient and safe recovery of oil and gas while lowering cost and risk profiles.

According to Well-SENSE, FLI would allow current well interventions to be performed in a much more simplified way and permit tools to be deployed to depths and deviations previously unheard of.

Back to the '80s

Disposable fiber optics is not a new idea, of course, with the idea dating back to the 1980s and the days of similar solutions being developed for missile guidance systems. Since then, the oil and gas industry also has increasingly embraced the use of today's more durable downhole fiber-optic systems—thanks largely to glass chemistry advances in materials science—for real-time downhole temperature and pressure monitoring in harsh well environments both on and offshore.

But Dan Purkis, the company's technology director and co-founder, sees significant further potential. "The scope for FLI applications is so vast that for FLI to make the biggest impact and rapidly progress, many companies will need to develop technology to complement it. Ultimately, FLI is a platform from which multiple new generations of increasingly sophisticated intervention tools can be launched, and the opportunities are endless," Purkis said.

The rapid-shot concept has firm believers behind it, all of whom recognize that such advances can help the U.K. North Sea achieve its ongoing ambition to maximize economic recovery from the continental shelf.

Reviewed and approved by a specialist OGIC peer review panel, Well-SENSE is now working with Robert Gordon University to develop the technology further.

OGIC's CEO Ian Phillips described the project as being a "prime example" of the industry's emphasis over the past year or so on the need for collaboration, communication and innovation to secure the North Sea's future.

Outside-industry concepts

Purkis, who holds more than 50 industry patents, spoke about FLI earlier this year when he was presented with the Significant Contribution Award at the 2016 SPE Aberdeen Offshore Achievement Awards.

He told award ceremony attendees, "As a massively simplified intervention method, which has applications in virtually any well, it offers many benefits to operators—including a huge reduction in costs. Collaboration is at the heart of this development, and we aim to continue our work with other technology partners, complementing our expertise with theirs as the fastest route to the development of a complementary suite of tools to work with FLI." E&P

Innovative technology lessens P&A costs and regulatory burden

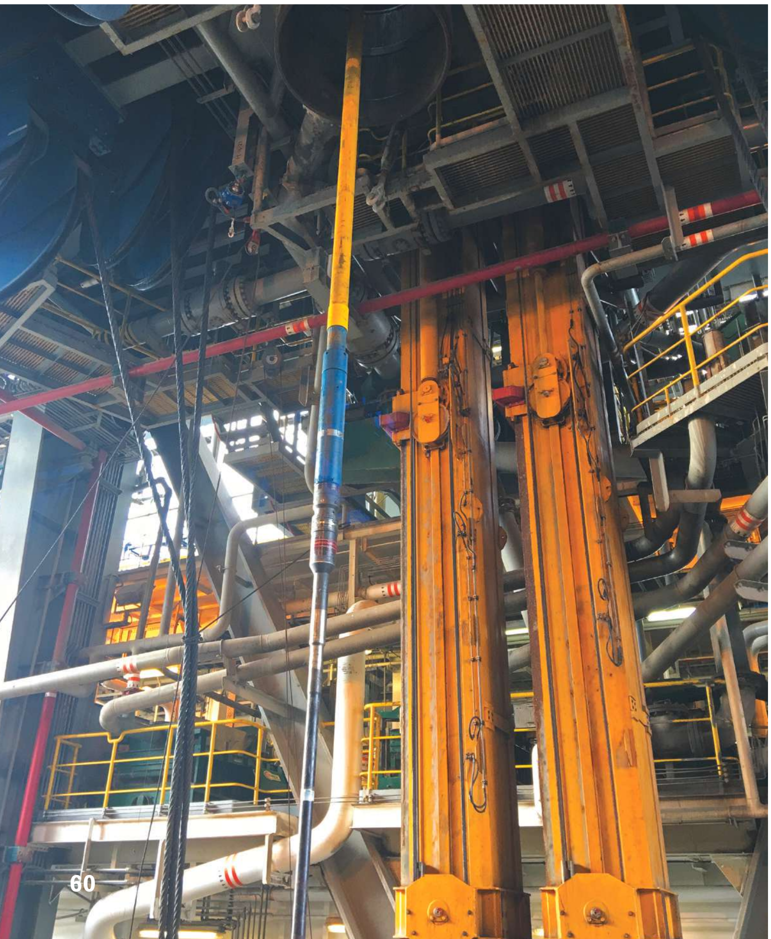
With regulatory P&A requirements increasingly stringent and costs rising exponentially, a faster and cheaper solution is delivering the goods.

Martial Burguieres, Wild Well Control

The number of new deepwater wells has decreased as part of the general decline in the offshore market, but the number of wells requiring plugging and abandonment (P&A) still rises as assets age.

At the same time, the regulatory requirements to P&A those wells continue to get more stringent. As a result, the cost to P&A a well has risen exponentially and looks set to continue increasing.

Wild Well Control, a Superior Energy Services company, has developed a subsea P&A approach that is changing the way the industry performs deepwater P&A operations by offering a rigless, riserless intervention system to meet the demands of increasingly stringent regulatory bodies.



The DeepRange tool, used in conjunction with the 7Series intervention system, is certified to operate in water depths of up to 3,048 m (10,000 ft) and a maximum working pressure of 10,000 psi for P&A operations. It also has gained full approval from the Bureau of Safety and Environmental Enforcement (BSEE) in the U.S. Gulf of Mexico (GoM).

Subsea P&A in the GoM

Moreover, all that is required for system deployment is the use of a multiservice vessel, although current operations are being conducted from a mobile offshore drilling unit due to current market pricing.

The new tools and techniques have been used on a subsea P&A operation underway in the GoM and already have exceeded the expectations of Wild Well Control as well as those of the operator.

When compared to more traditional P&A methods such as "cut and pull" of casings, the DeepRange system leaves casings intact, which is less invasive and therefore much less costly. Other methods such as "perf and squeeze"—while less expensive than "cut and pull"—can provide cement plugs of dubious quality and permanence.

The circulated plugs rendered by the DeepRange methodology provide the same quantitative qualities of "cut and pull," while still being price competitive with "perf and squeeze."

How does it work?

To simplify a complex process, the DeepRange/7Series subsea P&A system can best be explained in this 10-step process:

- *Step 1:* Pre-operational engineering and planning involves creating and resolving interfaces with the well and vessel of choice, developing detailed operating procedures and creating a project execution plan.

The DeepRange tool works in conjunction with the 7Series system in the GoM. Each well in the program used the tool to successfully isolate the outer annulus by circulating a minimum of 61 m of cement in place and pressure-testing the plug per BSEE regulations. (Source: Wild Well Control)

- *Step 2:* Crews perform the temporary abandonment of the well, cutting and pulling the tubing before installing a cast-iron bridge plug and packer.
- *Step 3:* The upper assembly—consisting of an isolation bushing, tubing-conveyed perforating guns and a telescoping joint—are landed and latched into the packer.
- *Step 4:* The upper tubing is conveyed and the lower standard perforating guns are fired into the B annulus.
- *Step 5:* Circulation is established through the tubing, into the lower perforations, up the B annulus, out through the upper perforations and back up the production annulus. The isolation bushing diverts flow to the return lines.
- *Step 6:* The binary plug is circulated into the B annulus. After waiting on the cement to harden, a mandatory pressure test is performed.
- *Step 7*: The upper tubing is conveyed, and the lower standard perforating guns are fired into the C annulus.
- *Step 8:* Circulation is established through the C annulus as with the B annulus previously.
- *Step 9:* The binary plug is circulated into the C annulus. The plug is left in a "balanced" condition with the production annulus. After waiting on the cement, testing is performed.
- *Step 10:* The upper assembly is unlatched from the packer and pulled from the well. A cast-iron bridge plug is set above the highest perforations and cement is bailed as per regulations.

Complementing the operation is the wholly in-house Wild Well Advanced Engineering group that provides any necessary computational fluid dynamic, structural and thermal analyses. The DeepRange/7Series subsea P&A system delivers an extremely cost-effective operation using a binary plug comprising resin and cement for a long-lasting, effective alternative to traditional P&A operations.

Annular isolation requirement

Wild Well had worked on 11 wells previously where the temporary abandonment (TA) of a subsea well was accomplished with the 7Series riserless intervention system.

While TA of a subsea well with a riserless system from a vessel of opportunity was a significant accomplishment, the subsea team set out to develop tooling to fulfill the regulatory requirement to provide isolation of the outer annuli of the well. This requirement is what prompted the development of the DeepRange methodology.

The current DeepRange/7Series riserless intervention suite has so far successfully performed full P&A operations on seven subsea wells (with wells eight and nine in progress simultaneously) in the ultradeepwater GoM months ahead of schedule. Specifically, crews have used the DeepRange tool in each of the wells to isolate outer annuli by circulating more than 61 m (200 ft) of cement in place and pressure-testing the plug, which exceeded BSEE requirements.

Wells requiring temporary abandonment, pulling of production tubing and isolation of a single outer annulus have taken an average of 15 days to fully complete. One of the wells that required three annuli to be isolated was completed in only 20 days. This well in particular would have required the cutting and pulling of three successive strings of casing if done with the traditional "cut and pull" method at far greater cost and time.

Advantages

The differences between the 7Series and DeepRange tool and other P&A techniques are many. The first is water depth—the 7Series system is a 10,000-psi, 3,048-m graded system—with the deepest well P&A to date using the system located in 2,244 m (7,362 ft) of water. This water depth is beyond alternative annular isolation tools on the market. Other potential competitors are operators of subsea intervention systems similar to the 7Series, but none have a system that can perform annular isolation, only the "perf and squeeze" method.

The system also is deployed underneath a full pressure control assembly so any pressure control issues on a particular well can be mitigated. With subsea wells it might also not be known if an annulus has pressure, if that pressure is going to be sustained or if it is going to bleed off. There are still many unknowns. Such wells also can be sub-hydrostatic, or on vacuum. The Wild Well system gives the flexibility to address unplanned circumstances while performing the annular isolation.

The 7Series was originally designed for live well intervention and, as such, Wild Well can accomplish a multitude of intervention tasks. Bullheading chemicals, perforating, sliding sleeves and logging can all be accomplished and present an added bonus for an operator who not only has P&A liability but also wells that require intervention to optimize production.

On a larger campaign, wells could be restimulated and worked over with wireline to increase production. If certain wells do not "come back," they can then immediately be fully and competently P&A, all with a single mobilization.

Deepwater operations have become synonymous with high complexity and risk, and subsea wells were therefore traditionally expensive to work over and ultimately P&A. By taking an outside-the-box approach to intervening on subsea wells, a suite of tooling and methods is now available that can significantly decrease the costs of managing brownfield subsea assets. E&P

The Mancos Shale: time for another look

A new resource assessment gives this unconventional play world-class status.

Jessica Pair, Stratas Advisors

The Mancos Shale of the Rocky Mountain Region has long been known as a major source rock for the various producing formations of the Rocky Mountain sub-basins. In June 2016 the U.S. Geological Survey conducted a new resource assessment of the Mancos within the Piceance Basin of Colorado and Utah. The revised assessment has placed the Mancos in the same playing field as the Marcellus in terms of its technically recoverable shale gas resource potential. The Mancos is now estimated to contain 1.9 Tcm (66.3 Tcf) of technically recoverable shale gas and 74 MMbbl of shale oil resources within the Piceance Basin, specifically. These numbers are much improved over an earlier estimate of 595 Bcm (21 Tcf) of technically recoverable resources estimated by the Energy Information Administration in 2009.

The Mancos Shale unit is found within the larger Mancos/Mowry Total Petroleum System and spans each sub-basin within the Rockies region. Multiple shale units are found within this system, including several well-known units such as the Mancos, Mowry and Niobrara shales. The Mancos Shale unit contains an upper and lower member providing Type II and Type II/III kerogen and yielding both gas and oil resources. Historically, the Niobrara Shale is the most explored unit within this total system; however, the Mancos Shale is beginning to show a slight uptick in well completions targeting the specifc Mancos unit. Currently, there are about 450 total wells targeting the Mancos (Figure 1). The majority of these completions have

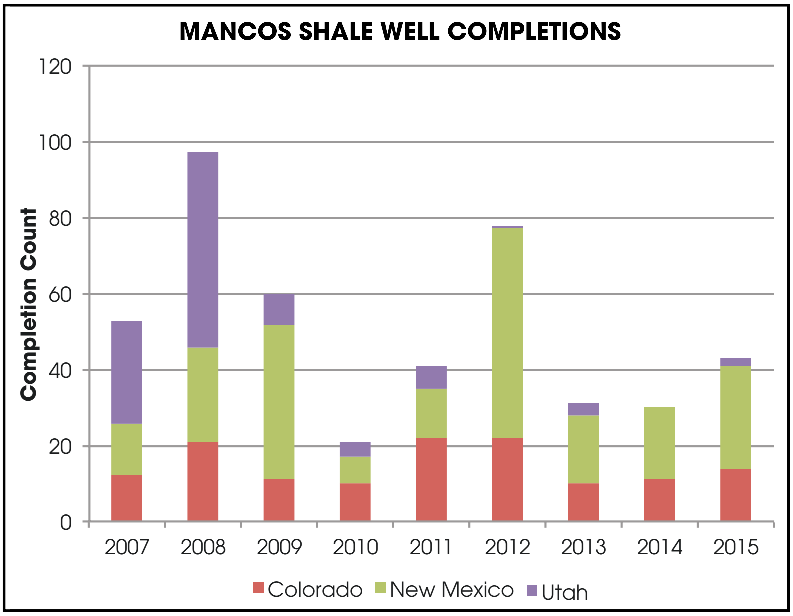


FIGURE 1. Total amount of well completions within the Mancos Shale unit are shown. (Source: Stratas Advisors)

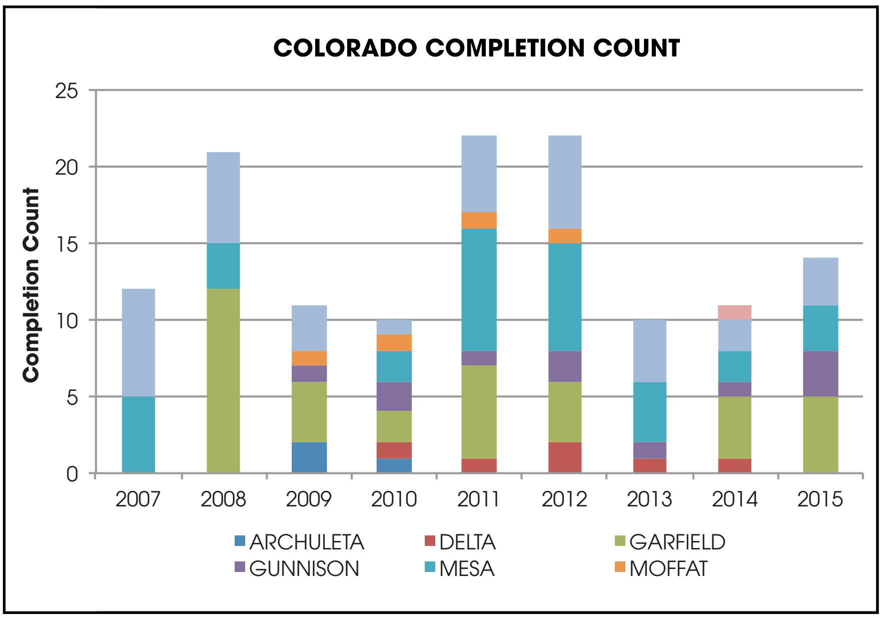


FIGURE 2. Colorado completions are on the rise after dipping in recent years. (Source: Stratas Advisors)

taken place in New Mexico, at 63%, and Colorado, at 33%, respectively (Figures 2 and 3).

The Mancos Shale provides key resources within each sub-basin of the Rockies region.

About 80% of the wells being completed within the shale unit have used raw sand as the dominant proppant type since 2012. Over the last two years the industry has demonstrated a clear shift in utilizing raw sand as the main source of proppant in new and refracked wells as a potential way to reduce service costs in the downed markets. Fracturing fluids used within these wells have remained steady since 2012 with 60% of wells using linear gel and 20% using slick water. As the amount of completions has increased over the last several years, the average lateral lengths also have increased by about 64% since 2014, which had an average lateral length of about 1,402 m (4,600 ft). These laterals then increased to about 2,316 m (7,600 ft) in 2015. The majority of reported lateral length increases have been attributed to Black Hills Exploration & Production (averaging 3,048 m [10,000 ft] in horizontals), Encana Corp. (averaging 2,713 m [8,900 ft] in horizontals) and Gunnison Energy Corp. (averaging 1,676 m [5,500 ft] in horizontals). Operators also have shown varying EURs for wells targeting this formation, ranging anywhere from 269 Mboe to 739 Mboe (Figure 4). Private operator Piceance Energy LLC shows the largest average EUR followed by Encana, Gunnison Energy and Black Hills Exploration & Production. As completions continue to increase in Colorado and operators further delineate and optimize this technique, it is likely that overall costs will be driven further and more operators will enter into this particular shale play. The Mancos Shale provides key resources within each sub-basin of the Rockies region, and with this new assessment of resources present, it is likely that the shale unit will gain more attention as operators cash in on the shale's potential. E&P

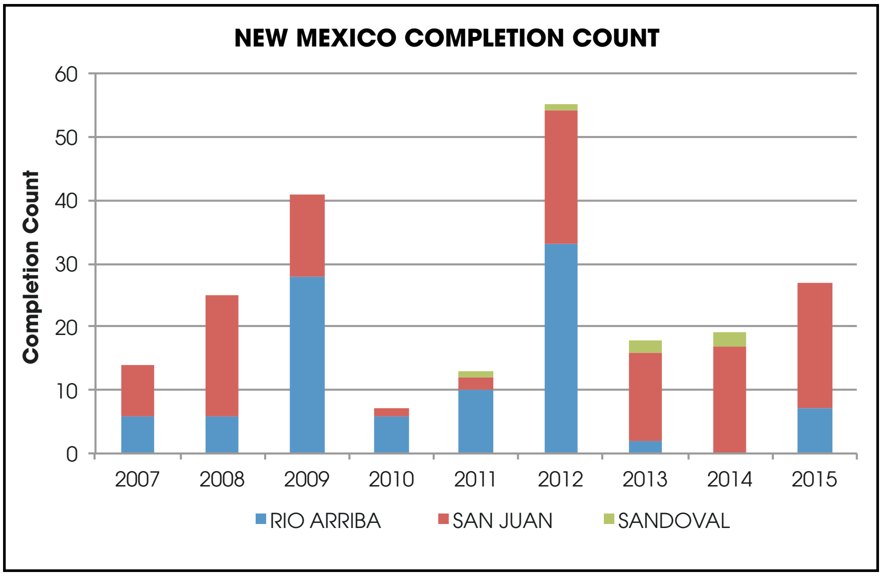


FIGURE 3. The majority of wells completed targeting the Mancos Shale are in New Mexico. (Source: Stratas Advisors)

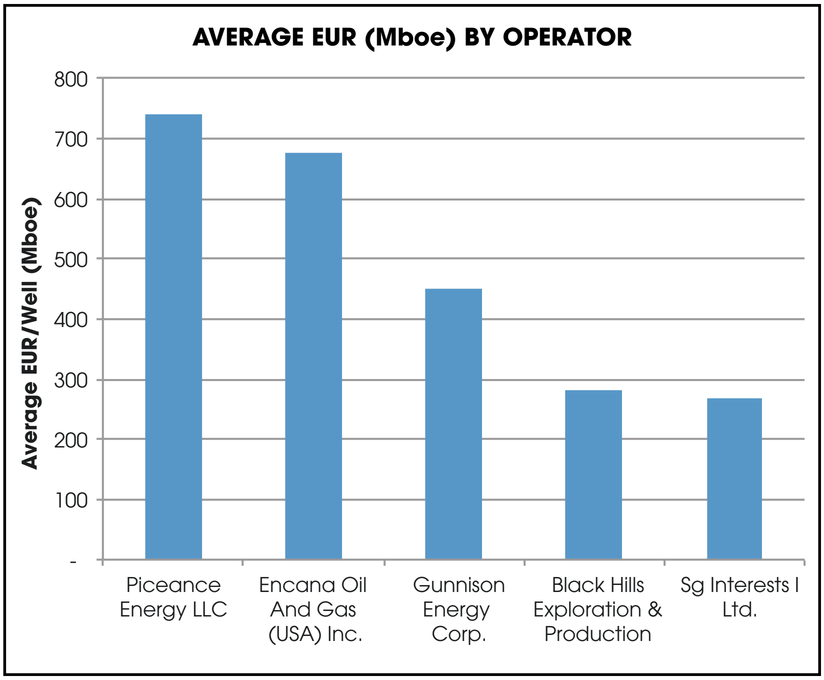


FIGURE 4. This graph shows the calculated average EUR (Mboe) by operator targeting the Mancos Shale unit. (Source: Stratas Advisors)

A nonhydraulic means to complete wells

Shaped charges can replace hydraulics in new system.

Nick Collier, Innovative Defense LLC

While hydraulic fracturing is recovering profitable quantities of oil and gas out of large volumes of formation, it is not without controversy and problems. The transportation, use and disposal of fracking water and the cost of machines, manpower and fuel are just a few of those issues.

Additionally, hydraulic fracturing is plagued by high cost and limited performance and is coming under greater scrutiny due to concerns about minor earthquakes and water contamination; already 16 states do not allow hydraulic fracturing.

Innovative Defense (ID) LLC has developed a new nonhydraulic means to complete wells that eliminates the issues mentioned above. This new method could reduce or eliminate the need for hydraulic fracturing and at about 20% of the cost. This patent-pending process is called concussive or shock fracturing.

Shock fracturing

In the early days of oil production large quantities of explosive were lowered into the well to the level of the oil-bearing formation and detonated. The shock from these large explosive quantities fractured the formation around the borehole, but of course it ruined the casing and the wellbore in the process. ID's Shock Frack system employs a more surgical application of much smaller quantities of explosive, strategically delivered and directionally controlled, into the gas- or oil-bearing formation.

A patent-pending select-fire multichambered downhole gun and delivery system is the innovation that allows discreet quantities of high-explosive or other energetic materials to be delivered deep into a formation from the main borehole. Traditional perforating guns simultaneously fire a volley of conventional shaped charges from a common chamber. The small-diameter jets penetrate through the casing and into the formation in preparation for hydraulic fracturing. The ID select-fire gun system consists of one or more segments, each consisting of multiple blast chambers containing one or more super-caliber hole-producing shaped charges. Since the shaped charge produces a super-caliber hole, follow-on charges can be aligned and propelled deep into the formation through the primary super-caliber hole made by the number one charge from each segment. The hollow cylindrical jet formed from the charge makes the hole

Hydraulic fracturing is a successful technology but faces many challenges. (Source: Yarygin, *shutterstock.com*)

deeper, and the shock from the explosive couples to and fractures the formation in the vicinity.

Gun system, shaped charge delivery

The recent development and testing of the Super-Caliber Hole Producing shaped charge (SuperCal charge) has made it possible to deliver controlled quantities of explosive in the form of self-contained shaped-charge grenades deep into a formation. A super-caliber hole means a hole larger than the charge diameter (CD) making the hole. This allows repeated insertions of same-size charges into the existing hole, increasing its depth and shock-fracturing across all layers and in all directions. This is only possible using the super-caliber charge.

As a strong concussive shock travels through a formation at the sonic velocity of the rock structure, it fractures the microstructures separating oil- or gas-bearing voids, increasing porosity and thus the flow to the wellbore. Standard perforating charges produce only about a 15% CD hole in the casing and taper to a decreasing size in the formation. Repeated firings of SuperCal or standard charges could be accomplished with the select fire gun system described above.

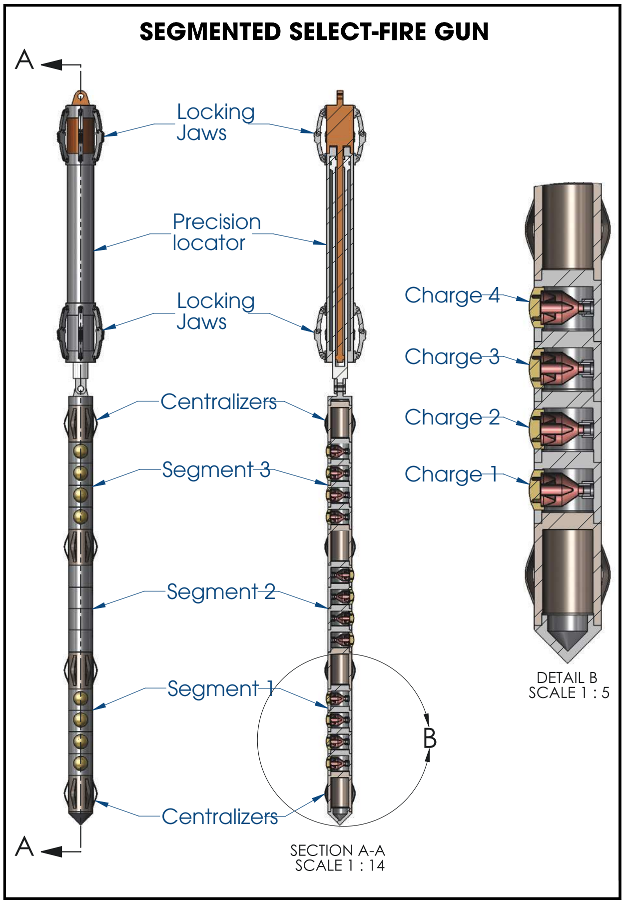
About shaped charges

Shaped charges use high explosive to collapse a hollow cone-shaped liner made of powdered metal, in the case of oil well use. The concentration of the explosive energy collapsing the liner on the longitudinal axis of the cone (the Munroe Effect) produces a rod-like stretching projectile (commonly called a jet) that has a velocity in the 5 km/sec to 10 km/sec (3 miles/sec to 6 miles/sec) range. Using this principle, the SuperCal charge design spreads the energy into a stretching hollow cylindrical jet that produces a super-caliber hole.

The process by which a shaped charge jet penetrates is by extremely rapid erosion of the target material. The pressure applied to the target by the jet is in the 6 million psi range, and no known materials can resist penetration under such forces.

How the system works

The segmented loaded select fire gun system is sent downhole to the location of interest by wireline or tubing-conveyed means; in the future it could be autonomous. The gun system is then centralized, and the precision locator is locked in the wellbore. The No. 1 charge from each gun segmented is fired from the gun, and an initial super-caliber hole is made in the casing and into the formation. The gun is then precisely lowered by the precision locator so that the second charge or set of charges are aligned with the initial super-caliber hole. At this point the No. 2 charge from each segment can be fired from the gun to increase the initial hole depth and get greater distance from the casing, or it can be propelled into the initial hole where it will increase the hole depth and also fracture-shock the formation in the vicinity. This process is repeated until all charges from each segment are expended.



Each segment of the select-fire gun system has multiple blast chambers containing one or more super-caliber hole-producing shaped charges. (Source: Innovative Defense LLC)

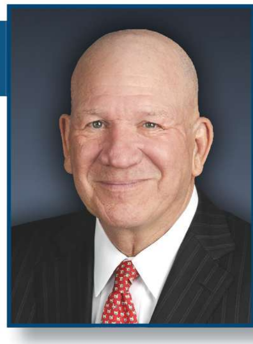
Other benefits

There are thousands of abandoned wells across the country in which as much as 80% of what was originally there is remaining and is not recoverable using hydraulic fracturing. The SuperCal fracturing system might be able to access these reserves. Since oil prices are low and seem to be slow to increase, it makes sense to find a less expensive means of producing the product. The shock fracturing method offers a large reduction in the cost of stimulating new wells and rejuvenating older ones. E&P

OPENING KEYNOTE, DAY 1

Texas' Role in Midstream's Future

The Lone Star State is the axis of midstream action in North America. This leading operator discusses the present and future of midstream infrastructure in Texas, including the highlights of some significant projects.



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Protecting onshore assets with surveillance that connects

Camera solution allows operators to benefit from heightened levels of situational awareness spanning all process, security and safety aspects.

Amedeo Simonetto, Synectics

With oil and gas providing the world's 7 billion people with 60% of their daily energy needs, there is absolutely no doubt that protecting these critical assets is a demanding responsibility, particularly when faced with ever-increasing physical threats and cyberthreats.

Reports by intelligence agencies in a number of countries have clearly identified the oil and gas industry as a target for terrorist attacks. In recent years the average number of attacks on oil and gas targets (facilities and personnel) has totaled the 300 mark.

But threats do not simply come in the form of malicious incursion or deliberate damage intent. Operational failures, theft, extreme weather conditions and process inefficiencies can all have a detrimental impact on oil and gas assets and the economies they serve.

Such a varied range of security, safety and efficiency challenges demands a multifaceted approach to protection, and that is a brief seamlessly delivered by intelligently integrated surveillance solutions.

Protection is paramount

Before exploring this solution in-depth, it is first useful to examine why it is that the oil and gas industry is susceptible to risk.

Extreme weather is just one of many threats that can have a detrimental impact on oil and gas assets and the economies they serve. (Source: Piotr Krzeslak; *Shutterstock.com*)

Sites are attractive targets for external attack: The physical and chemical properties of the materials handled and stored by the oil and gas industry have the potential to cause damage to populations and ecosystems and have significant media impact. The strategic and global nature of the oil and gas industry also means any disruption has serious consequences to the world economy.

Sites are vast and complex: The scale and complexity of oil and gas facilities is hugely challenging. With constant logistical activities and multiple sophisticated and often hazardous processes taking place at any one time, they are challenging environments to monitor.

Locations can be remote: Pipelines, sub-sites and outlying process areas are all common to the sector. Though remote, such facilities are crucial to the oil and gas ecosystem. Yet due to scale, accessibility and economic efficiency, these areas often are unmanned or are bases for skeleton crews only.

Oil and gas is hazardous: It seems an obvious thing to say, but the industry is dangerous. Potential risk to health and safety is high, yet the sector is dependent on an efficient, healthy and motivated workforce. Any threat to them is a threat to overall operations.

Complex needs, overarching solution

The complex mesh of security, safety and operational threats facing oil and gas assets on a daily basis has traditionally been addressed by implementing multiple protection measures and technologies.

Perimeter security, intruder detection systems, process monitoring, workforce communications, access control, emergency incident alarms and site surveillance (spanning hazardous and nonhazardous areas) are all common and necessary. They should be considered and treated as a complete solution, but unfortunately that is not always the case.

Treating them as separate entities to maintain and manage leads to inefficiency (taking more time and manpower) and fragmentation—those operating such systems only see a small part of the puzzle. In such conditions achieving full-site situational awareness becomes an almost impossible task because isolated incidents can never be presented and understood in the broader context of other events.

Intelligently integrated surveillance has the power to address these issues. Open protocol surveillance command and control platforms enable video (analog, digital and thermal cameras), intruder alarms, fire and gas detection, access control, critical asset tracking, and site management systems to be integrated, monitored and managed within a single unified environment.

Automated alerts notify users of any event or combination of events that requires investigation. Such alerts also can trigger prioritized live video footage to aid users in visual verification of threat level.

It is a development that means operators located in a central security center on- or offsite can achieve a 360-degree view of data and events. For example, an integrated solution of this nature can not only detect "obvious" isolated incidents such as a forced perimeter fence breach but also can be programmed to look for specific circumstances, which individually might not mean anything but together signify threat.

In summary, it is an approach that ensures that all sections of an estate—whether isolated, dangerous or cost-inefficient to man—can always be monitored with ease.

Camera choice remains critical

A holistic view of operations that incorporates visual, audio, statistical and numerical data from multiple systems has clear benefits. It is important to give specific mention to camera choice. Visual verification of any event alert (triggered for any number of reasons) can make a vital difference to the reactive protocols that follow.

Cameras for this market should always be certified to international standards and be capable of operating in extreme temperatures and weather conditions. Salt, sand, wind and chemical corrosion are all risks that need to be considered.

It also is essential to consider application and image objective. For example, is a specific camera in a specific location required for process or presence, or is it detail-driven? If detecting machinery malfunctions or equipment efficiencies is the aim, the primary image objective is process-driven. This might mean thermal camera technology is the most appropriate choice, perhaps for monitoring overheating, spillages or high-stress areas.

With a virtual tripwire application, however, where detecting any movement within a specified perimeter is key—perhaps as a safety precaution around a hazardous zone—the image objective is most likely presence-driven. In this setting a multispectral camera that can detect movement in any light conditions might be the most suitable to the task in hand.

When using a fully integrated solution for threat detection and incident management, anomalies that require investigation may well initiate from a nonvisual source (e.g., a gas reading or unauthorized access card swipe). But taking steps to safeguard image quality and suitability will ensure that actions taken and evidence gathered are as "visually informed" as possible.

Integrated surveillance in action—Tempa Rossa project

The $1.9 billion Tempa Rossa project, located in southern Italy, is a joint initiative between Total and Shell. Tempa Rossa will comprise eight production wells, a new oil processing center, an LPG storage center (with associated loading points) and updated utilities/distribution infrastructure. It is anticipated that once fully operational, the site will produce 50,000 bbl of oil, 230,000 cu. m (8 MMcf) of gas, 240 tons of LPG and 80 tons of sulfur daily.

The site has adopted an integrated surveillance solution developed and delivered as a partnership between Synectics and Thales in Italy incorporating Synectics' Synergy command and control platform and more than 80 COEX camera stations (fixed and pan-tilt-zoom) with access control, intruder detections systems, and integrated control and safety systems.

This solution allows the operators to benefit from heightened levels of situational awareness spanning all process, security and safety aspects. The surveillance brief also required fully integrated factory acceptance testing (FAT) prior to deployment.

"In addition to testing the solution in its own dedicated FAT facility, Synectics also created the Synergy macros we needed to allow us to analyze 'operation-ready' integration at our Italian site. It's a partnership that has enabled us to deliver the best result for the client," said Marco Ficozzi from the R&D department at Thales in Italy.

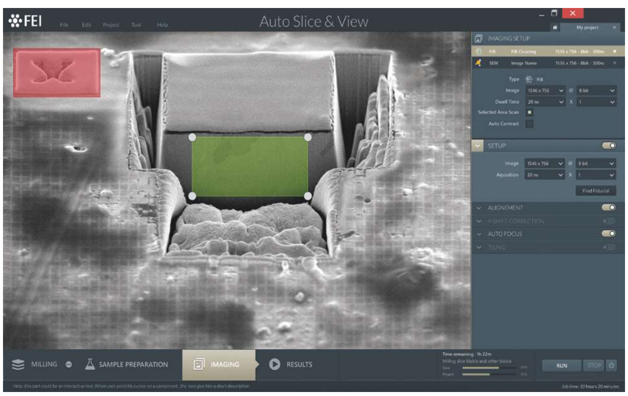
Synectics' support for the Tempa Rossa project ensured that high-quality visual data (live or recorded) can always be paired with incident detection alarms to investigate and initiate response procedures. Alerts triggered by people or processes will immediately prioritize image feed from the nearest available cameras. The Synergy command and control platform also will generate scenario-specific workflows to guide operators through appropriate protocols. E&P

Technology brings safety, cost boost to North Sea E&P

A new technology that delivers vital nitrogen supplies to platforms, vessels and onshore worksites by refining the gas from the atmosphere has been developed, tested and deployed in the North Sea by E Innovation in conjunction with a major operator, a press release stated. Certified for safe use in ATEX Zone 1 hazardous areas, the Nitrogas unit already has been deployed in the U.K. Continental Shelf, removing a long-standing reliance on expensive sea conditions-dependent bottled gas deliveries. The technology has achieved savings of more than 65% compared to traditional nitrogen delivery methods—in financial terms that would equate to a figure of $170,532 saved within a 30-day project. The Nitrogas unit's onboard software and filtering systems manufacture nitrogen by removing oxygen from the air before pumping it directly into platform infrastructure or for storage at the worksite for future use. The mobile unit, which is the same size as a domestic refrigerator, replaces cumbersome traditional quads. It also significantly reduces the risk of slips, trips and falls by removing trailing lines and cabling used in traditional methods since it can be placed directly at the workface. *einnovation.no/home*

Slice-and-view tool for 3-D reconstruction

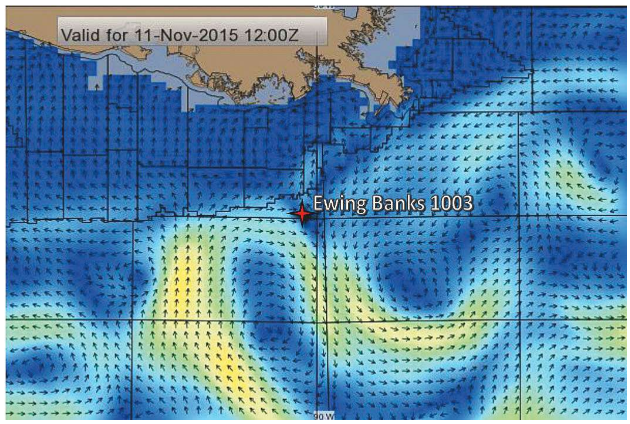
FEI has released the latest version of its Auto Slice & View 3-D reconstruction software, which makes 3-D imaging faster, easier, more accurate and more cost-effective, according to a product announcement. The software works with all of FEI's current DualBeam-focused ion beam/scanning electron microscope platforms to enable 3-D structure and composition of samples at the nanometer scale. *fei.com/software/auto-slice-and-view/*



FEI's Auto Slice & View 4 Imaging setup screen enables 3-D structure and composition of samples at the nanometer scale. (Source: FEI)

Ocean current forecast service provides site-specific awareness

Offshore oil, gas and marine companies that experience project-related disruptions from fluctuating ocean currents now have a new tool to better manage those challenges. The Wilkens Weather Technologies (WWT) Ocean Current Guidance Forecast service provides site-specific awareness of currents to give operators a clear understanding of oceanic conditions, a press release stated. "We designed this service for anyone engaged in smaller scale budget-sensitive projects where ocean current awareness is necessary but where current solutions are often cost-prohibitive," said Ryan Fulton, program manager at WWT. The Ocean Current Guidance Forecast service uses global current modeling to provide insight into ocean current conditions and their expected changes over the next 120 hours. The service provides users with high-resolution customized zoom-level charts as well as a five-day site-specific forecast of current speed and direction. *wilkensweather.com*



A localized WWT ocean current chart is shown for a location in the Northern Gulf of Mexico. (Source: Wilkens Weather Technologies)

Artificial lift protection and control system

Franklin Electric Co. Inc. has released the FluidWise Drive and Control System that protects and controls artificial lift motors, electric submersible centrifugal pumping systems and electric submersible progressive cavity pumping systems for gas well dewatering, mine dewatering and oil stripper applications, a press release stated. The FluidWise system incorporates increased functionality and data acquisition capabilities, allowing the pumps to operate at depths up to 1,500 m (4,921 ft). The FluidWise Drive and Control System for artificial lift applications includes three running modes: a set speed, regulated speed to reach a set target water level or a regulated speed to reach a desired flow rate (must have a flowmeter). The system provides underload/overload protection including dry run protection, one-second datalogging with Microsoft Excel file downloading capability, real-time data monitoring, alarms and alerts sent directly to any cellphone or email, web page interface via direct or Wi-Fi connection, and a Franklin Electric controller designed specifically for dewatering applications. *franklin-energy.com/products.aspx*

New ultrasound camera for straight and angled beam NDT inspections

Imperium Inc. has released its latest ultrasound camera and rugged controller system, the AcoustoCam i700, a press release stated. The AcoustoCam i700 improves inspections on straight beam applications such as composites and pipeline corrosion mapping as well as angled beam inspections for weld and time of flight diffraction. The AcoustoCam i700 offers higher resolution C-scan images than automated ultrasonic testing (UT) or phased array systems. It creates images in flat or curved materials up to 6 in. thick and is fully compliant with most industry UT codes. The camera produces sub-millimeter images of an entire field rather than a single pinpoint for better detection of pitting, cracking and other defects while reducing false positives. Large area maps are created in real time and reviewed offline via analysis reporting tools. *imperiuminc.com*

Instant C-scan images of weld defects, corrosion and various other defects are available with the AcoustoCam i700. (Source: PRNewsFoto/Imperium Inc.)

Drill floor safety system monitors traveling block parameters

Rig Control Products (RCP) has released the latest version of its Travelling Block Monitor (TBM) following a six-month period of design and product development, a press release stated. The TBM is an advanced electronic floor and crown saver system designed to continually monitor traveling block parameters to calculate a safe working envelope for the blocks. The system has been proven to avert serious equipment collisions on the drill floor, making it a safer environment for personnel to work as well as providing time and cost savings associated with equipment incidents, downtime and HSE investigations. The new system is designed with extended operational longevity in mind, a capacity for displaying and recalling historical system data and inbuilt diagnostics with condition-based monitoring to reduce the need for offshore technical assistance. *rcpat.com*

Subsea connector enhances reliability of high-voltage operations

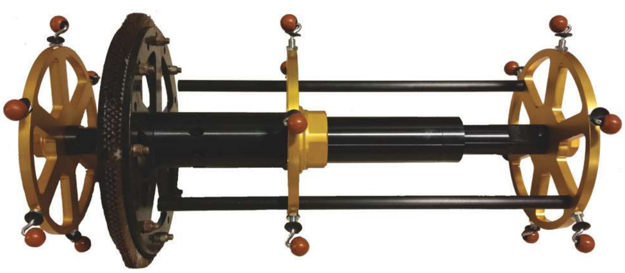
GE Oil & Gas has completed the qualification of its upgraded 36-kV high-voltage wet mate connector, according to a press release. MECON WM 36/500 offers far more reliability and predictability in subsea power system connections and can be used with equipment such as transformers, switchgears, variable speed drives and motor loads. “Our MECON Wet Mate 36/500 connector is designed to provide highly reliable connections of subsea high-voltage equipment. Unlike conventional stab-type connectors, we deploy a unique connection process that ensures that we are in full control of the electrical environment inside the connector before completing the electrical connection,” said Alisdair McDonald, subsea power and processing leader at GE Oil & Gas. In addition to offering greater control and predictability compared to conventional stab-type connectors, MECON WM 36/500 can act as an isolation switch at rated system voltage and can be used to verify system health prior to commissioning or to find faults after failure. MECON 36/500 has undergone more than a year of extensive testing to comply with the latest industry-wide standards. The connector has been certified for operation up to 36 kV and

500 amperes in water depths down to 3,000 m (10,000 ft). *geoilandgas.com*

GE uses the same patented technology for all its MECON Wet Mate connectors. (Source: GE Oil & Gas)

Waterless riser cleaning tool is air-actuated, self-propelled

Chet Morrison Contractors has released a new tool for cleaning drilling and production risers that is safer, faster and more cost-effective than current methods, a product announcement stated. MUDBUG is an air-actuated self-propelled device that uses oscillating brushes to clean debris buildup inside risers, moving through the length of the riser and back out again. Unlike other methods, MUDBUG does not require high-pressure water to remove the rust, scale and drilling mud that builds up in drilling and production risers. MUDBUG uses only 120-psi air to operate, thus eliminating the problem of water disposal and risk associated with high-pressure washing. MUDBUG can be operated by a two- or three-man crew instead of the usual five-man team required to clean a riser. Because the device is portable, it can easily be transported via plane or helicopter to any remote location either onshore or offshore. Its small job box (.6 m by .6 m [2 ft by 2 ft]) takes up very little space, making it ideal for rigs or other offshore operations. When operational, MUDBUG is about .9 m (3 ft) long and 19 in. in diameter. *mudbugrisercleaner.com*



MUDBUG uses only 120-psi air to operate. (Source: Chet Morrison Contractors)

Production tubing paraffin treatment provides uninterrupted oil production

YESSS OIL has released its thermal electric downhole paraffin treatment system, which is designed to eliminate the need for costly chemical or hot oil treatments to ensure consistent crude production free from wellbore fouling, a press release stated. YESSS OIL's paraffin systems provide uninterrupted oil production by combining MCAAA's proven downhole heater cable technology with intelligent controls to regulate and monitor the tubing heating system. Production tubing is maintained above wax appearance temperatures to eliminate paraffin plate-out and subsequent well clogging. Surface equipment is safe, quiet and nearly maintenance-free. YESSS Oil's systems require minimal capex and are simple to deploy. The robust stainless steel-sheathed cables have no external splices and band directly to production tubing. Wellhead feedthrough is simple and effective. The technology has been proven to provide consistent and predictable production with an expected life of more than 10 years. *yesssoil.com*

Oxygen sensor operates in low temperatures

Tyco Gas & Flame Detection's CTX 300 is available with a new oxygen sensor with a five-year life. It carries a full four-year warranty and is compatible with any existing CXT 300 O_2 detector in the field. Designed for industrial applications in unclassified areas, the new sensor ranges from 0% to 30% vol O_2 and operates from -40 C to 50 C (-40 F to 122 F) continuously for use in a wide range of low-temperature applications. The detector is a 4-20 mA analog gas transmitter and offers a wide range of sensor options in addition to oxygen, including monitoring for CO_2, toxic gases and refrigerant gases. The CTX 300 transmits data in record time and has the flexibility to protect many potentially hazardous environments. The device is easy to maintain with precalibrated sensors and an optional LCD display. *TycoGFD.com* E&P

Please submit your company's updates related to new technology products and services to Ariana Benavidez at abenavidez@hartenergy.com.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Focused players positioned to fuel NCS' future

Norway's oil and gas era kicked off more than 50 years ago, but recent corporate activity demonstrates that plenty of life and potential remain in this mature province.

Mark Thomas, Editor-in-Chief

Norway's North Sea sector remains the region's most vibrant and well-invested market, and faith in its long-term potential received major affirmation in June when a deal was unveiled by BP and Det norske oljeselskap to create the new independent offshore player Aker BP.

Following on from a smaller but also significant deal the previous year, when former BP boss Lord Browne's L1 Energy company first acquired DEA and then just months later snapped up E.ON's Norwegian E&P business to more than double its production in Norway to about 75,000 boe/d, the latest transaction is expected to formally close during third-quarter 2016.

Any deal led by Lord Browne, who steered BP between 1995 and 2007 through what many see as a golden period in its history, is bound to have been watched closely by his former company. It may even have partly prompted the global major to follow suit, as it was only six months later that it revealed its own Norway-centric deal with Det norske, whose main shareholder is Aker (in turn controlled by Norwegian billionaire Kjell-Inge Roekke). Aker will hold 40% in Aker BP, with BP owning 30% and the rest held by other Det norske investors.

Appealing proposition

What is it that makes Norway such an appealing proposition as an oil and gas province in tough times, when breakeven costs are today's apparent dominant factor?

Firstly it is its dependability, not only in its fiscal and economic policies but also in terms of its production. The latest monthly preliminary figures available as *E&P*

The Ivar Aasen jacket is shown being transported to its installation site offshore Norway for operator Det norske. The field is due onstream before year-end 2016 and will be one of the assets of the newly formed Aker BP company. (Source: Det norske) went to press, for May, showed Norway's average daily output at about 1.94 MMboe. This consisted of 1.55 MMbbl of oil, 360,000 bbl of NGL and 35,000 bbl of condensate. Oil production is about 2% above the equivalent figure from May 2015. This is a solid production record that can be relied upon, backed up by a government that is almost always fully prepared to invest long term in the sector's future in areas such as technology R&D as well as licensing and exploration in new areas.

> "We will look predominantly for oil assets and will put value over volume."
> —Karl Johnny Hersvik, *Det norske*

A relatively expensive offshore province it still remains, but that is a perception that is slowly changing as Statoil and the other operators on the Norwegian Continental Shelf (NCS) continue their focus on squeezing down development and operations costs and increasing standardization. A growing number of the sector's producing projects and those under development now fall well within today's requirement for sub-$50/bbl breakeven costs.

Need to cut costs

BP and Det norske's deal to merge their Norwegian businesses in their $1.3 billion all-share deal was largely driven by that stated need to cut costs. The venture also offers BP a solid opportunity to access new oil production and reserves within the next decade, something that has extra appeal after the stringent cuts in exploration activity it has imposed in recent years.

One of the jewels in the crown for BP is undoubtedly the gaining of a minority stake in the Norwegian flagship field Johan Sverdrup, the country's largest oil find for 30 years, which is under development and in which Det norske holds an 11.57% stake. Due onstream by late 2019, operator Statoil said the field would be economic even at sub-$30/bbl oil.

But the creation of Aker BP also allows BP to continue its ongoing policy of slimming itself down globally, shedding some older assets off its books while also putting them, with little risk, under the management of a smaller and potentially more efficient operator. At the same time it also will manage to maintain its long-term presence in Norway and access potential new reserves.

The new entity is expected to start with a production level of about 122,000 boe/d once it is approved,

NCS decommissioning market

Norway's decommissioning market could be worth up to NOK 160 billion in the period to 2024, according to a recent report.

The NCS could see up to 23 decommissioning projects ranging from small subsea tiebacks to full-scale integrated platform removals in that time. According to data from the U.K. industry group Oil & Gas UK, supported by the Norwegian Petroleum Directorate, the decommissioning report highlights 12 concrete facilities, 19 floating steel facilities, 88 steel facilities and nearly 350 subsea systems currently in place. An estimated 3,000 wells also will need to be plugged and abandoned (P&A).

Oil & Gas UK worked with five key operators on the NCS to produce the data as part of its efforts to help the industry prepare for forthcoming decommissioning projects. The survey required operators to provide data on their decommissioning activity forecasts on the NCS from 2015 to 2024 and was carried out in second-half 2015.

Plan submittal

The Norwegian Petroleum Act regulates the shutdown and disposal of NCS facilities, with operators required to submit a decommissioning plan two to five years prior to an installation ceasing production. About 800 wells already have been P&A on the NCS, with close to 300 more forecast to be P&A by 2024. Up to 26 pipelines with a total length of 360 km (224 miles) are forecast to be made safe in preparation for decommissioning over the same period.
Up to 14 platforms are forecast to be made safe and their topsides prepared for decommissioning up to 2024, with full or partial removal planned at this stage. The platform weights range from 3,000 tonnes to more than 30,000 tonnes. ■

Heerema's *Thialf* deepwater construction vessel installed Det norske's Ivar Aasen jacket earlier this year. The first phase of the field is planned to flow 16,000 boe/d, rising to 23,000 boe/d in later phases. (Source: Det norske)

instantly making it one of Europe's biggest E&P players. Once Johan Sverdrup is onstream, Aker BP's production could hit 250,000 boe/d by 2023. Its estimated P50 reserves are put at 723 MMboe.

Production ramp-up

For Det norske the deal also was logical in that it gave the company ownership in three producing BP fields—Skarv, Ula and Valhall—with net 2015 production of about 62,000 boe/d and a means of generating instant cash flow to help it fully fund its share in the development of Johan Sverdrup.

Production levels will be further ramped up later this year when the first phase of Det norske's Ivar Aasen Field offshore Norway comes onstream in the fourth quarter. With several other fields also under development, Aker BP is expected to achieve production of more than 152,000 boe/d in 2020 before the Johan Sverdrup Field's expected ramp-up in output further boosts this figure.

Aker BP also will hold a portfolio of 97 licenses on the NCS, of which 46 will be operated.

BP CEO Bob Dudley said he wants his company to do business in Norway since it has impressive capacity for production growth there and "significant opportunities." Speaking during a conference call related to the deal, he stated, "The need for choosing how to spend money and capital very carefully is right at the forefront of everyone in oil and gas." Bernard Looney, BP's chief executive, upstream, added that Det norske's "lean approach" also would benefit his company.

Competition on NCS

Heading the new entity will be Det norske's CEO Karl Johnny Hersvik, who has previously called for the need for bigger competitors to go up against the Norwegian giant Statoil on the NCS. The new and stronger Aker BP, with its extra financial capability, will undoubtedly be looking for other targeted acquisitions. "We will look predominantly for oil assets and will put value over volume," Hersvik said in the call.

This challenge to the dominance of Statoil (responsible for 60% of the country's oil and gas production) is seen by many as a trend that can only be a good thing, encouraging further countercyclical merger and acquisition investments and competition in Norway's offshore. E&P

Editor's Note: L1 Energy's executive chairman, Lord Browne, will lead a panel discussion on long-term perspectives and future projects for the NCS at the Offshore Northern Seas conference in Stavanger, Norway, (Aug. 29 to Sept. 1) alongside speakers from Statoil, Lundin and Aker Solutions.

Technology key to unlocking offshore challenges

Advances in technologies and techniques are at the forefront of the offshore sector's efforts to drive down costs, enhance efficiencies and grow sustainable production levels.

Staff Report

Innovation—whether through developing new products or standardizing and simplifying existing equipment and methods—exists at all levels of the E&P business. The need, therefore, to stay up to speed with the latest trends is vital if companies and individuals are to remain capable of moving swiftly when the time is right.

In this special section *E&P* highlights some of the products and technologies being shown at the Offshore Northern Seas (ONS) conference and exhibition in Stavanger, Norway, that can benefit companies in their ongoing drive to efficiently find, develop and produce offshore reserves.

The forward-looking main conference sessions have panel sessions discussing "big ticket" items such as global energy projects and transitioning markets, finance, security challenges, and energy game changers. In a further 20 dedicated technical sessions a North Sea-focused agenda has been put together under the challenging theme of "Demand and Supply 101," with participants highlighting proposed technology solutions to specific industry problems and issues.

Focus areas

Designated 101 subject areas include what the petroleum industry can learn from other industries such as car manufacturing and space, new drilling and well-related concepts to mitigate cost, more cost-efficient greenfield developments and brownfield modifications, production optimization solutions, extending mature field life, downhole advances, Barents Sea drilling and development technologies, subsea and boosting advances, reducing plugging and abandonment costs, and decommissioning solutions.

Solutions also are being specifically highlighted through the ONS Innovation Awards, which this year have attracted a record 130 candidates. A prime example of how advances large and small can make a difference, the oil price downturn has if anything increased the industry's efforts to find, explore and create new opportunities.

Innovation

The Innovation Award first arose in 1982, with companies today competing in two categories, one for large organizations and one for small and medium-sized enterprises. A Special Innovation Award also is presented to an individual or organization that has played a significant role in the wider energy sector.

Entries cover a huge range of technologies and disciplines including CO_2 capture, well integrity, FPSO repairs, riserless coiled tubing drilling, flow measurement, robotics, formation testing, multiphase compression, BOP monitoring, BOP stacks, wind-powered water injection, digital oilfield solutions, electric submersible pumps, explosion-proof cameras, drones, downhole diagnostics and light well intervention. A full list of entries is available on the ONS website at *ons.no*.

With more than 1,300 exhibitors expected to participate at ONS—with the event now into its fifth decade—there are plenty of innovative products and solutions to be found on the show floor as well as being discussed in the technical sessions.

The following entries are just a taste of what will be exhibited. They have been contributed by the companies concerned and do not reflect the opinions of Hart Energy.

Improved availability of continental gas export

The ABB Predictive Drive Torque Control (DTC) ensures that the drive for electrical motors remains in operation during power grid disturbances such as voltage dips. Power grid disturbances affect the variable speed drive system. Until now all load commutated inverters (LCIs) have seized, delivering zero torque during supply voltage dips. This results in compressor system and plant shutdowns. In addition to production losses amounting to millions of U.S. dollars, plant upsets and shutdowns also result in increased CO_2 emissions and wasted energy. The present innovation is a new control algorithm. The ABB Predictive DTC ensures that the ABB variable speed drive MEGADRIVE-LCI keeps mission-critical pumps and compressors in operation. Based on operational experience, Gassco plant management supports the statement that the solution with the Predictive DTC has contributed to more reliable energy supply to Europe. *new.abb.com*

ABB's variable speed drive MEGADRIVE-LCI keeps mission-critical pumps and compressors in operation. (Source: ABB)

Tool joints can be sheared with pipe centered, off-center

Operators must have confidence that the shear rams inside the BOP will shear the pipe and allow the rig to disconnect and move offsite. This confidence must also apply to previously "nonshearable" tool joints and hardbanding whether the pipe is centered or off-center. To provide this necessary performance, Cameron, a Schlumberger company, has designed and qualified BroadShear enhanced shearing technology. This shearing ram is an innovative approach to solving recent industry concerns regarding nonshearables across the BOP, reducing the amount of nonshearables across the BOP from about 10% to less than 2%. This major advancement in casing shear enables tool joints (both through the pin/box and through hardbanding) to be sheared with the pipe centered or to one side of the BOP. BroadShear rams enable shearing of casing diameters up to 16 in. The tool joints and hardbanding can even be sheared off-center. To learn more, visit booth 415 in ONS Hall D. *cameron.slb.com*

Tool joint hardbanding is sheared off-center by the Cameron BroadShear technology ram. (Source: Schlumberger)

Increase efficiencies, success in solving complex well challenges

Frank's International is recognized for ingenuity and innovation across its well completion, intervention and recovery equipment and services. Attendees visiting Frank's International booth 5670 at this year's ONS can explore technology advances that include Frank's new Xtreme3 Premium Connectors, which are designed to handle extreme requirements. Frank's also is showcasing 1,000-ton tools designed to dramatically reduce the possibility of slip crushing when compared to standard casing elevators or spiders available in the industry. Frank's specializes in running corrosion-resistant alloys with a specialty product line designed to handle these critical materials. Frank's patented Fluid Grip technology and Collar Load Support system eliminate die penetration marks and iron transfer, mitigating corrosion and allowing well life to be maximized. These tools offer the industry's only completely non-marking tubular running solution. Frank's International will be showcasing Xtreme3 premium connectors, Remote Tong Systems, casing running tools, Fluid Grip, Collar Load Support system, Rotary Mounted Completion Spiders, control line management system, Drill String Torque Reducer subs and 1,000/1,250-ton tools at ONS 2016. *franksinternational.com*

Frank's new Xtreme3 Premium Connectors are designed to handle extreme requirements. (Source: Frank's International)

Helping reshape the industry through digitalization

GE Oil & Gas will showcase technologies (introductions and enhancements) that are designed to help the wider industry adjust to a new market reality as GE seeks to provide the foundations for better decision-making and increased productivity, from automating its pressure-testing process to providing operators with remote monitoring capabilities. As highlighted by the "transition" theme of this year's ONS, the industry is at a turning point. All players in this space have a shared responsibility to drive a more viable way of working. At the event GE Oil & Gas' focus will be on how it can—and is—transforming its operations, driving greater productivity and helping to reshape the industry landscape through digital, predictive analytics and automation across the entire value chain. For example, GE's advanced manufacturing solutions are designed to improve cost-effective fabrication, while digitalization has the potential to dramatically improve efficiency in production and service of oil and gas facilities through boosting flow and recovery rates as well as implementing predictive maintenance. Through high-tech sensors, Big Data, software analytics and robotics, GE is helping lead the digital industrial revolution. *geoilandgas.com*

Drill tower will develop, test robotic advancements

Huisman has expanded its testing and commissioning facilities in Schiedam for new drilling equipment. A new 90-m (295-ft) high drill tower capable of handling 55-m (180-ft) stands and 46-m (150-ft) risers and with the ability to simulate dynamical vessel movements is completed. The Huisman Innovation Tower (HIT) will be used to demonstrate Huisman drilling equipment, to develop and test future equipment and systems, and for the training of operators and Huisman staff. The tower will validate existing robotic drilling technologies and be used to investigate future automation opportunities. Engineered with 3 million pound to 3.6 million pound hookload capacity, the HIT is designed and built to prove up the robotic advancements. The HIT has been designed as another acknowledgment of the continually evolving nature of drill floor robotics and their undeniable contribution to safer, more efficient and more economical offshore drilling operations. *huismanequipment.com/en*

Huisman's latest development is the Huisman Innovation Tower. (Source: Huisman)

A single resource to identify critical assets

Almost 63% of those polled in the 2015-16 Technology Radar survey said pressure to reduce asset downtime has increased in the last year. Asset costs also are a major concern for oil and gas industry decision-makers, with almost half reporting that asset integrity savings are more important than they were 12 months ago. Axxim has been developed in response to these operational challenges. The product provides the industry with a single resource to identify critical assets, increase equipment reliability and uptime by at least 20%, reduce failure risk by 80%, and determine an optimum approach to inspection and maintenance that can achieve costs savings of up to 50%. Axxim embeds decision-making techniques, including risk-based inspection, reliability-centered maintenance, root cause analysis, and failure mode and effects analysis, directly into an organization's enterprise asset management application through MaxGrip's strEAM+ technology. *lr.org/axxim*

Axxim embedded software assists in asset management cost reduction. (Source: Lloyd's Register)

Fiber-rope retrofit extends subsea crane capabilities

MacGregor has released a fiber-rope retrofit option for any existing subsea crane, enabling operators to increase their fleet's lifting capabilities without having to invest in new vessels. The modular upgrade can be rapidly installed and replaces the crane's original steel wire rope with high-performance fiber rope. It uses the same advanced technology as MacGregor's fiber-rope offshore crane, FibreTrac, launched earlier this year, including traction technology delivered in partnership with Parkburn Precision Handling Systems and a low-tension storage drum. Fiber rope enables a crane to use its full lifting capacity at practically any depth because, unlike wire rope, it weighs virtually nothing in water. Owners can therefore bid on a wider range of contracts as a smaller crane can be used for more assignments. For example, a 100-tonne fiber-rope crane has the same lifting capacity as a 250-tonne wire-rope crane lifting loads at 3,500 m (11,483 ft). *macgregor.com*

ROV enhances user interface, reliability to perform complex subsea tasks

Oceaneering will showcase its newly advanced and environmentally friendly ROV, the eNovus. The eNovus serves as the basis for a future hybrid between AUVs and ROVs. With remote piloting and automated control technology (RPACT), the eNovus enhances user interface and reliability to perform common and complex subsea tasks. RPACT, which revolutionizes operational efficiency, will be demonstrated at ONS. Subject matter experts or ROV pilots can establish ROV control through a satellite or wireless network link to support operations at a remote work site. RPACT diminishes operational and environmental risk while reducing potential damage to tooling, manipulators and subsea assets. Oceaneering also will be exhibiting a compact and cost-effective second-generation M5 monobore connector for subsea intervention such as gas lift, chemical injection, well stimulation, hydrate remediation, flooding and venting operations, acid injection, and scale squeeze. This ROV flyable connector features the Grayloc metal-to-metal seal and provides reliable sealing after more than 25 make-and-break cycles. *oceaneering.com*

The eNovus serves as the basis for a future hybrid between AUVs and ROVs. (Source: Oceaneering)

Sensor provides significant risk reduction, reduced costs

Cameron, a Schlumberger company, will feature the OneSubsea AquaWatcher water analysis sensor in ONS Hall D at booth 415. Live demonstrations and technical presentations will illustrate the AquaWatcher sensor's capability to detect minuscule quantities of water in multiphase and wet gas flows, determine the salinity of that water and the ratio of injected chemicals to water plus measure the conductivity of produced water at any gas volume fraction and most water cuts. With the AquaWatcher sensor, breakthrough of injected water in waterflood applications can be detected at very low concentrations, and crucial information about the origin of produced water can be provided. This sensor provides significant risk reduction and reduced costs for chemical injection and reclamation as well as allowing additional production to be brought online due to improved utilization of the available injection and reclamation capacity. *cameron.slb.com/onesubsea*

The OneSubsea AquaWatcher water analysis sensor can be installed anywhere in a subsea production system, including at the wellhead or in a subsea tree. (Source: Schlumberger)

Rubber-based fire deluge system is corrosion-free

Trelleborg will present a selection of offshore solutions at ONS, including its range of Vikotherm thermal insulation materials, Firestop passive fire protection, Elastopipe flexible piping system and subsea buoyancy solutions. Vikotherm thermal insulation is a range of materials that ensure superior joint strength, increased thermal conductivity and heat capacity as well as flexibility and resistance to the hydrostatic collapse of flowlines. Firestop is a customizable rubber-based passive fire protection solution that provides corrosion, thermal, fire and mechanical protection. Elastopipe is the first corrosion-free explosion-, impact- and jet fire-resistant flexible piping system. Trelleborg's subsea distributed buoyancy modules provide uplift to reduce the weight of the pipeline. *trelleborg.com/offshore* E&P

Trelleborg's rubber-based fire deluge system Elastopipe is shown. (Source: Trelleborg)

ONS 2016 INNOVATION AWARD CANDIDATES

COMPANY	PRODUCT NAME
ABB	ABB Predictive Drive Torque Control (DTC)—compressor operates through disturbances
AGR Software	iQx—well data management and analysis software
Air Products AS	CO_2 capture by membrane technology
Aker Solutions and Baker Hughes	POWERJump
Aker Solutions	MMO Simulation Centre
Aker Solutions	FieldKeeper
Aker Solutions	KBeDesign
The Barents Sea Exploration Collaboration (BaSEC)	The Barents Sea Exploration Collaboration (BaSEC)
Bentley Systems Inc.	Bentley AssetWise—combining predictive analytics with asset integrity management
Cameron, a Schlumberger company/Longford, Ireland	PULSE LF low-flow ultrasonic chemical injection metering valve
The Crosby Group	Easy Loc V2
DNV GL	WIN WIN wind-powered water injection
Draka Norsk Kabel (part of Prysmian Group)	BFOU Jet Fire
Dresser-Rand business, part of Siemens Power & Gas Division	LNGo natural gas distributed LNG system
FMC Technologies	InLine ElectroCoalescer
FMC Technologies/FMC Kongsberg Subsea AS	Well access management system
Glamox AS	Glamox Plug-in PRO for PDMS
Huisman	Robotic drill floor
Intergraph Prosess, Power & Marine	Intergraph Smart Yard
Intergraph Prosess, Power & Marine	Intergraph Smart Mobile Scan
Intergraph Prosess, Power & Marine	Intergraph SmartPlant Fusion
Interwell	Barrier Verification System
IHS	IHS Vantage
Island Offshore/Centrica	Riser-less coil tubing drilling
KROHNE	M-PHASE 5000; the magnetic resonance solution for upstream oil, water and gas flow measurement
Lloyd's Register	Axxim
Lloyd's Register	New industry guidance for the industrial use and deployment of unmanned aircraft systems and drones
LUKOIL	Through-tubing sequential hydraulic fracturing
MacGregor	MacGregor fiber rope retrofit system
Marine Aluminium AS	Aluminium railing system with integrated LED gangway light
National Oilwell Varco	PowerBlade
National Oilwell Varco	RCX BOP stack
National Oilwell Varco	RIGSENTRY BOP for predicting operational failures in subsea BOP
National Oilwell Varco and Bullard	AboveView Hard Hat, expanding awareness of surroundings
National Oilwell Varco, Subsea Production Systems	Actively heated flexible pipe
NOV Fiber Glass Systems	FAST
NOV Drilling and Intervention	Safety Lock Module for drilling jars
NOV Wellbore Technologies, Drilling & Intervention	VectorEDGE rotary steerable system
Oceaneering International Inc.	Remote Piloting and Automated Control Technology (RPACT)
Oceaneering International Inc.	3-in. M5—large bore ROV flyable connector with subsea replaceable seal
OneSubsea, a Schlumberger company	AquaWatcher
OneSubsea, a Schlumberger company	Multiphase compressor
Rolls-Royce Marine AS	Fiber rope crane
Schlumberger	Formation testing while tripping
Schlumberger	MaxFORTE high-reliability electric submersible pump system
Schlumberger Oilfield Services	New generation cables reduces pre-plug and abandonment by 18 days
Siemens AS	"Fault Ride Through" Testing of LV DC Power solution, BlueDrive PlusC
Siemens AS Process Solutions	Digitalization of the oil and gas industry
Siemens Industry Software	COMOS Walkinside
Siemens Subsea Connectors	SpecTRON 45 Wet Mate Connector
Siemens Subsea AS	Advanced converter and switch
Trelleborg Offshore	Mobile Production Unit
Trelleborg Offshore	Tri-Strake Combi
Trelleborg Sealing Solutions	FPSO *in situ* SealWelding
Welltec	Welltec Annular Barrier (WAB) for well integrity
Welltec	Well cleaner power jetting tool
Welltec	WAB liner top barrier
WITTENSTEIN motion control GmbH	SSEAC—electrical subsea actuator and condition monitoring

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1 Canada

Ressources et Energie (Squatex) has received the results of a major reassessment of resources for the eastern part of the Masse structure in Quebec, Canada's Lower St. Lawrence permits. The assessment by Sproule Associates includes an authentication of in-depth analyses performed by the company's technical team on the well logs at #2-Masse. Sproule's analysis indicates that the resources simulations could extend over a probable average area of 5.2 sq km (2 sq miles). Well log evaluation included St. Leon and Sayabec formations in the eastern part of the Masse structure. The study indicates a potential of 1.5 Bcm (53.6 Bcf) of gas and 52.2 MMbbl of oil over the probable average area. The gross pay of Silurian Basin rock of the Lower St. Lawrence extends to about 540 m (1,772 ft), and the net pay zone varies between 66 m and 210 m (216.5 ft and 689 ft) with an average thickness of 130 m (426.5 ft). According to an internal study by Squatex, the Masse structure could extend over more than 80 sq km (30.8 sq miles). Squatex and partner Petrolympic are planning a new drilling program to further validate the potential of the Masse structure.

2 Falkland Islands

An independent study for Rockhopper Exploration Plc of its North Falkland Basin contingent resources confirms that the basin has 1 Bbbl of recoverable oil. Rockhopper's acquisition of Falkland Oil & Gas Ltd. also doubled its net contingent resource, including reservoirs that make up the Sea Lion Complex and the reservoirs discovered in the Zebedee well. Field development will be conducted in two phases, the first of which will develop the Sea Lion resources in the northeast and northwest of the SL10 and SL20 fans. Sea Lion alone has almost 270 MMbbl of low-risk near-field upside, including the SL20 west flank in an oil-bearing case. The Isobel Elaine discovery has the potential to be a third regional development potentially containing more than 500 MMbbl. Premier Oil is the operator of the North Falkland Basin licenses with 60% interest. Rockhopper Exploration holds the remaining 40%.

3 Egypt

Eni announced another gas discovery in the Baltim South Development Lease in the East Nile Delta. Exploration well #1-SW Baltim was drilled to 3,750 m (12,303 ft) in 25 m (82 ft) of water. It hit 120 m (394 ft) of gross gas column and an approximate 62-m (203-ft) gas pay zone in Messinian sandstones. The discovery, which is 12 km (7 miles) from shoreline, is a new accumulation along the same trend of Nooros Field, which is now estimated to hold 70 Bcm to 80 Bcm (2.4 Tcf to 2.8 Tcf) of gas. Additional appraisal drilling is planned. Eni is a 50% partner with BP.

4 Israel

Noble Energy Inc. has received approval of its development plan for the Leviathan Field in the 349/Rachel and 350/Amit petroleum licenses offshore Israel. The plan calls for a subsea system that connects production wells to a fixed platform with a tie-in to shore. The initial capacity of the platform is anticipated to be 33.9 MMcm/d (1.2 Bcf/d) of gas that can be expanded to 59 MMcm/d (2.1 Bcf/d). The field is believed to contain as much as 538 Bcm (19 Tcf) in gas resources. Noble is the operator of the Leviathan Field with 39.66% interest in partnership with Delek Drilling (22.67%), Avner Oil Exploration (22.67%) and Ratio Oil Exploration (1992) (15%).

5 Saudi Arabia

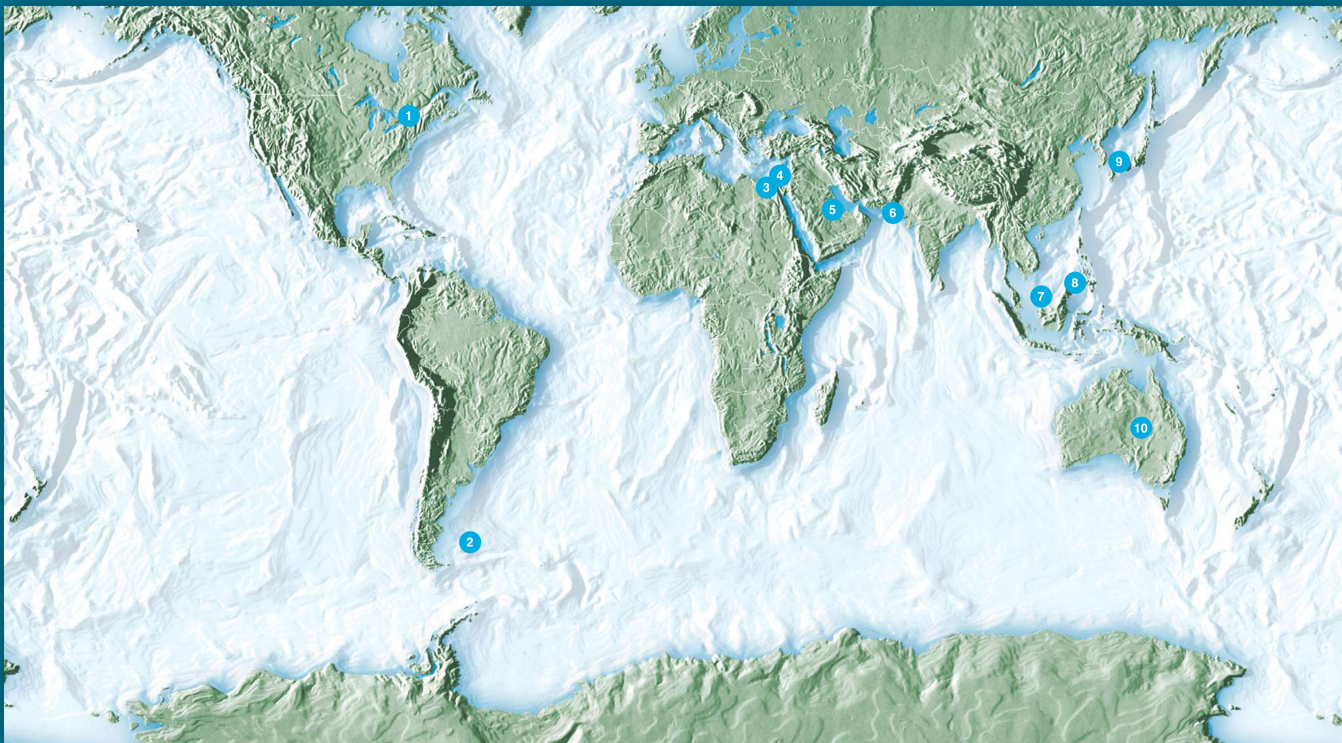
Saudi Aramco has announced new onshore field discoveries—one in the eastern portion of Rub al Khali (Maqam) Field and one east of Ghawar Field. According to a ministry spokesman, the company also has made two nonassociated gas field discoveries: Edme west of Haradh and Murooj in the Rub al Khali. An offshore discovery, Faskar, also was announced in the Saudi sector of the Persian Gulf near Berri Field. Saudi Arabian crude reserves were put at 261.1 Bbbl in 2015, with gas reserves up from 8.3 Tcm (294 Tcf) in 2014 to 8.4 Tcm (297.6 Tcf) in 2015.

6 Pakistan

In the Hyderabad District in Pakistan's Sindh Province, operator Pakistan Petroleum Ltd. has reported a gas discovery at exploration well #1X-Kotril. It is the first discovery in the concession and was drilled to 3,892 m (12,769 ft). Based on the gas shows during drilling and wireline log evaluation, a cased-hole drillstem test was conducted in Lower Goru Massive sands. The well flowed an average of 96,277 cu. m/d (3.4 MMcf/d) with a flowing wellhead pressure of 608 psi. Preliminary test data analysis suggests that it might be a tight gas discovery, and further evaluation is required to determine if it is commercial. Pakistan Petroleum is the operator of the Kotri Block (Block 2468-12) and #1-X Kotril with 100% interest.

7 Malaysia

Results from an offshore Sarawak gas discovery were announced by Sapura-Kencana Energy from its three-well



2015 drilling campaign within the Block SK408 production sharing contract area in Malaysia. The wells in the program targeted nonassociated gas within the primary Late Miocene carbonate reservoirs. The #1-Jerun had an interpreted gross gas column of about 800 m (2,625 ft) based on analysis of electric log, pressure and sample data. The #1-Jeremin, about 15 km (9 miles) west of the F9 gas field, hit a 104-m (341-ft) gross gas column. Sapura-Kencana is the exploration operator with a 40% working interest. Its partners are Petronas (30%) and Shell (30%).

8 Philippines

Two deepwater South Sulu Sea exploration wells are planned on the Dabakan and Palendag prospects in Block SC56 in the Philippines by Mitra Energy Inc. An independent assessment by Lloyd's Register Senergy indicates that there are about 30 MMbbl of oil and about 70.7 Bcm (2.5 Tcf) of gas on a high estimate. The best estimate is 10.3 Bcm (367 Bcf) for Dabakan and 5.8 Bcm (207 Bcf) for Palendag, with a low estimate of 3.5 MMcm (125 MMcf) for Dabakan and 2.7 Bcm (96 Bcf) for Palendag. Dabakan's best estimate for oil is 4.1 MMbbl, while Palendag's is 2 MMbbl. Mitra is the operator of the block with 25% interest. Total holds the remaining 75%.

9 Japan

INPEX is drilling an exploratory well in the Sea of Japan to assess the presence of hydrocarbons in the area. The project was commissioned by the Agency of Natural Resources and Energy of the Ministry of Economy, Trade and Industry. A semisubmersible rig will drill the venture in 210 m (689 ft) of water. The operations are about 130 km (81 miles) northwest of Shimane Prefecture and about 140 km (87 miles) north of Yamaguchi Prefecture.

10 Australia

Real Energy Ltd. has announced results from fracture stimulation of its #1-Tamarama in the Queensland portion of the Cooper Basin. The venture was fractured in five stages in Toolachee and Patchawarra at about 2,300 m (7,546 ft). The well hit 21 m (69 ft) of net sandstone gas pay (44 m [144 ft] gross) in Toolachee and 66 m (216.5 ft) of net sandstone gas pay (121 m [397 ft] gross) in Patchawarra. The venture is in Cooper Basin Block ATP927P. Additional testing is underway. E&P

PEOPLE

C&J Energy Services Ltd. appointed current COO **Don Gawick** to the position of president and CEO.

AIRIS Wellsite Services named **Brendan Ryan** CEO.

Ahmed Saeed Al Calily has been appointed CEO of the energy platform of Mubadala, Abu Dhabi's state-owned investment company.

Ricardo Darre will take the role of CEO of Argentina's 51% state-owned YPF SA.

Alan Snider has been appointed president and COO at Laney Directional Drilling.

Henrik Lundin has been named COO of TAG Oil Ltd.

Beach Energy Ltd appointed **Morné Engelbrecht** CFO, effective Aug. 29.



Hoover Container Solutions appointed **Joseph Levy** (top) senior vice president and CFO. **Johan Wramsby** (middle) has been appointed senior vice president and COO, and **Arash Hassanian** (bottom) has been appointed senior vice president, global sales and marketing.

Tap Oil Ltd. appointed **Chris Bath** CFO and company secretary.

OleumTech Corp. named **Brent McAdams** vice president, OEM & Strategic Initiatives.

CNOOC Ltd. announced changes in directors and senior management. **Yang Hua** has been appointed CEO and redesignated executive director. He remains chairman of the company. **Wu Guangqi** has been redesignated nonexecutive director and has resigned as compliance officer. **Yuan Guangyu** has been appointed as president and executive director. **Li Fanrong** has resigned from his position as CEO, president and executive director. **Chen Wei** has been appointed as compliance officer and general counsel.

Stokes & Spiehler has promoted **Blair LeBlanc, P.E.** (far left), to vice president, offshore operations; **Russ Bellard, P.E.** (second from the left), to vice president, onshore operations; **Tony Shell** (second from the right)to vice president, sales and marketing; and **Donnie Busscher** (far right) to engineering manager.

InterMoor, an Acteon company, has named **Cleiver Moulin** managing director in Brazil.

AccessESP selected **Ed Sheridan** as its Asia-Pacific region manager.

Emco Wheaton Houston promoted **Hector Ornelas** to engineering supervisor.

Steve Adcock and **Jeremy Wilkerson** have joined Burns & McDonnell as senior project managers in the Houston region, and **Kirsten Glesne** and **Chris McFarland** were named senior project managers based in Denver.

ACE Winches appointed **Chris Dixon** hire and services director.

Four leading figures in the energy industry have been appointed as Energy Institute (EI) vice presidents. **Malcolm Brinded** CBE FREng FEI also took on the role of president elect. Brinded will succeed **Jim Skea** CBE FEI as EI president in 2017 for a two-year term. **Dr. Bernie Bulkin** FEI is joined by **Vivienne Cox** CBE, **Steve Holliday** FREng FEI and **Ceri Powell** FEI to take positions on the council.

Mike Hinson has been tasked with leading Parsley Energy Inc.'s newly established corporate development department, taking the role of vice president, corporate development.

Tom Williams, a former official of the U.S. Department of Energy, has been retained by HBW Resources LLC to help manage a new partnership with the Research Partnership to Secure Energy for America.

COMPANIES

The Oilfield Technology Group of Hexion Inc. announced the expansion of its resin-coated proppant manufacturing facility in Canada to provide a more efficient supply of proppants to fracturing service companies and operators in the oil and gas industry.

HTL, a provider of controlled bolting, flange working and portable machine solutions, has joined the Energy Industries Council.

Array Petroleum LLC, a privately held oil and gas producer based in New Orleans, has been formed by former executives of Whitney Oil & Gas LLC.

MARKETING | SALES | CIRCULATION

Vice President of Publishing
RUSSELL LAAS
Tel: 713-260-6447
rlaas@hartenergy.com

United States/Canada/ Latin America
1616 S. Voss Road, Suite 1000
Houston, Texas 77057 USA
Tel: 713-260-6400
Toll Free: 800-874-2544
Fax: 713-627-2546

Senior Director of Business Development
HENRY TINNE
Tel: 713-260-6478
htinne@hartenergy.com

Director of Business Development
DANNY FOSTER
Tel: 713-260-6437
dfoster@hartenergy.com

Sales Manager, Eastern Hemisphere
DAVID HOGGARTH
Tel: 44 (0) 7930 380782
Fax: 44 (0) 1276 482806
dhoggarth@hartenergy.com

Advertising Coordinator
CAROL NUNEZ
Tel: 713-260-6408
cnunez@hartenergy.com

Subscription Services
E&P
1616 S. Voss Road, Suite 1000
Houston, Texas 77057
Tel: 713-260-6442
Fax: 713-840-1449
custserv@hartenergy.com

List Sales
MICHAEL AURIEMMA
Venture Direct
212.655.5130 phone
212.655.5280 fax
mauriemma@ven.com

AEREON has acquired select assets of Abutec, including the Abutec brand, burner technology and Quad O Certified Enclosed Combustors used extensively across the U.S. shale basins.

Nelson Fastener Systems has been formed, creating a rebranded business unit that consists of six manufacturing entities: Nelson Stud Welding Inc., Ferry Cap & Set Screw, Specialty Bar Products, EBC Industries, Automatic SMP and Spiegelberg Manufacturing. They were formerly part of Doncasters Fastener Systems.

Solenis introduced a new Equipment Service Team. The group is made up of professionals specially trained to service Solenis-owned chemical feed equipment. The program was launched in North America in early 2016 and will begin rolling out in Europe, the Middle East and Africa in mid-summer 2016. Full global implementation is expected by the end of the year.

Abrado Wellbore Services has acquired the specialty tool product lines of Deltide Energy Services LLC for an undisclosed amount. As part of the deal, Abrado takes full ownership of Deltide's proprietary Medusa section milling technology, Rattler suite of downhole magnets, Mud Viper surface ditch magnets and suite of fishing tool services.

The Underwater Centre has linked up with Bibby Offshore to provide ROV apprentices with the opportunity to gain practical hands-on experience unavailable anywhere else in the world. The apprentices, who are employed by Bibby Offshore but are too young to go offshore, will benefit from operational experience in the field with live ROVs and will undertake a wide variety of tasks including the mobilization/demobilization of the work class ROV.

W Energy Partners has been formed as an E&P company seeking to acquire nonoperating working interest in acreage and production in the Williston Basin.

ADVERTISER INDEX

Integrity management in a downturn

The industry's quest to save money includes looking at routine integrity management activities, but any impact on an asset's risk profile must be fully understood—and accepted.

Dr. Andrew Pople, Penspen

With the market price for Brent crude sitting below $50 per barrel at time of writing, in many basins this is well below the production cost. The industry is working in an environment where significant amounts of capex on exploration and development activities have been postponed or canceled.

Operators are looking for ways to further reduce outgoings, and among other cost-saving measures, the industry has experienced headcount reductions both within the operator community and throughout the supply chain.

Given the desire (read: "need") to reduce costs to ensure long-term economic survival, operators are looking to see where opex can be reduced, and routine integrity management activities are coming under increasing scrutiny.

Can we save money?

The question is: Can we save money on integrity management in this industry?

The majority of my career has been spent working with oil and gas pipelines, which are expensive to install and are low-redundancy items (i.e., there is unlikely to be a "spare"). Catastrophic failure means our export route to market is lost.

Therefore, high focus is placed on ensuring that these assets remain viable, and we (generally) do not tolerate failure of pipelines for both societal and economic reasons.

In an oil price downturn, an operator's corporate priorities and therefore its integrity management organization's priorities remain unchanged, namely the protection of human life, the environment and the organization's business aims.

To reduce opex spend on integrity management, we need to understand the impact on the risk profile for our assets. Ideally we will be able to maintain an equivalent (i.e., acceptable) level of risk. If we cannot, then we need to make a conscious decision to accept the new risks for our operations.

Effect on assets

We need to interrogate our operations to understand how the downturn has affected the functioning of assets. To use a pipeline example, has anything changed that would affect the threats (and hence risk given that the consequence of failure will remain unchanged) that infrastructure is exposed to? For instance:

- Are our pipelines experiencing more start-stops (accelerated fatigue accrual)?
- Are there periods where pipelines are standing or experiencing reduced flow with the potential for water drop-out (enhanced corrosion)?
- Are the pipelines operating at reduced pressure (potential extension of fatigue life)?
- Has a strategic decision been made to reduce the required remaining operating life (i.e., can we tolerate greater pipeline deterioration)?

These (and similar) questions help us to review our risk-based inspection strategies. We might find that a reduced short-term spend on integrity management is justified and identify where the potential for cost savings can be made.

We also must recognize that this activity could indicate that a continued or increased spend on integrity management is justified during the current economic epoch.

Nobody likes bad surprises

In summary, I believe there are three points regarding integrity management during a downturn worthy of consideration.

First, understand the risks the infrastructure is exposed to. Changing operating conditions and future life expectations brings the opportunity to reevaluate risk-based inspection strategies with the potential for cost savings. Conversely, if required cost savings result in an increase in risk or a lesser understanding of risk, then this needs to be understood and accepted at corporate level.

Secondly, plan for recovery. We need to avoid putting our infrastructure into a position where degradation cannot be economically recovered from. Early catastrophic failure could well spell the end for otherwise viable (or marginally viable) fields.

Finally, nobody likes bad surprises. Integrity management has a lot to offer, so make sure you do enough to avoid the unexpected. E&P