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A microseismic approach to unconventional 160

COMING NEXT MONTH The November issue of **E&P** will examine trends in energy independence and their potential impact on global markets. Other features will examine basin modeling, land rig advances, heavy oil, and ROVs and AUVs, and regional reports will focus on unconventional development in Europe and on Southeast Asia. As always, while you're waiting for the next copy of **E&P**, remember to visit **EPmag.com** for news, industry updates and unique industry analysis.



ABOUT THE COVER A complex unconventional fracture system from the Sichuan Basin, China, was imaged by the UniQ point-receiver land seismic system to provide insight for accurate future drilling. Left, Russia is facing sanctions from the U.S. and EU but remains an attractive province for E&P. (Main cover image courtesy of WesternGeco; cover design by Laura J. Williams)

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Tuscany confirms step-out oil find at Macklin

A step-out vertical well drilled for water disposal purposes at Tuscany Energy's 100% working interest property in Macklin, Saskatchewan, Canada, encountered Dina oil pay.

Senex hits oil at Martlet-1 in Australia

The Martlet-1 exploration well on the western flank of the South Australian Cooper-Eromanga Basin in PEL 104 has encountered a Namur oil accumulation, Senex Energy Ltd. said in a press release.

Statoil sells Norwegian Continental Shelf assets to Wintershall

Statoil ASA farmed down in Aasta Hansteen, Asterix and Polarled and exited two assets on the Norwegian Continental Shelf for a consideration of \$1.3 billion, including contingent payment. The buyer is Wintershall.

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Analytics, big data management gain priority in oil patch

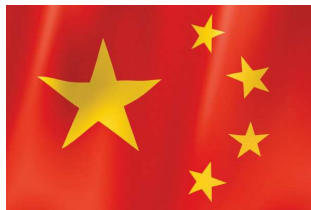
By Velda Addison, Associate Online Editor

Technology and an abundance of data are forcing oil and gas companies to make changes and prepare for new ways of operating.

Fuling Field: China pushes to replicate US shale revolution

By Kome Obonyano, Stratag Advisors

China is widely believed to have the world's largest technically recoverable shale gas resources.



Kosmos gears up for 'second inning' offshore Northwest Africa

By Velda Addison, Associate Online Editor

Plans include drilling offshore Western Sahara, Mauritania and Suriname.

Australia's 'Super Cooper' has more to offer

By Paul Hart, Hart Energy

Two operators describe the basin as 'world class.'

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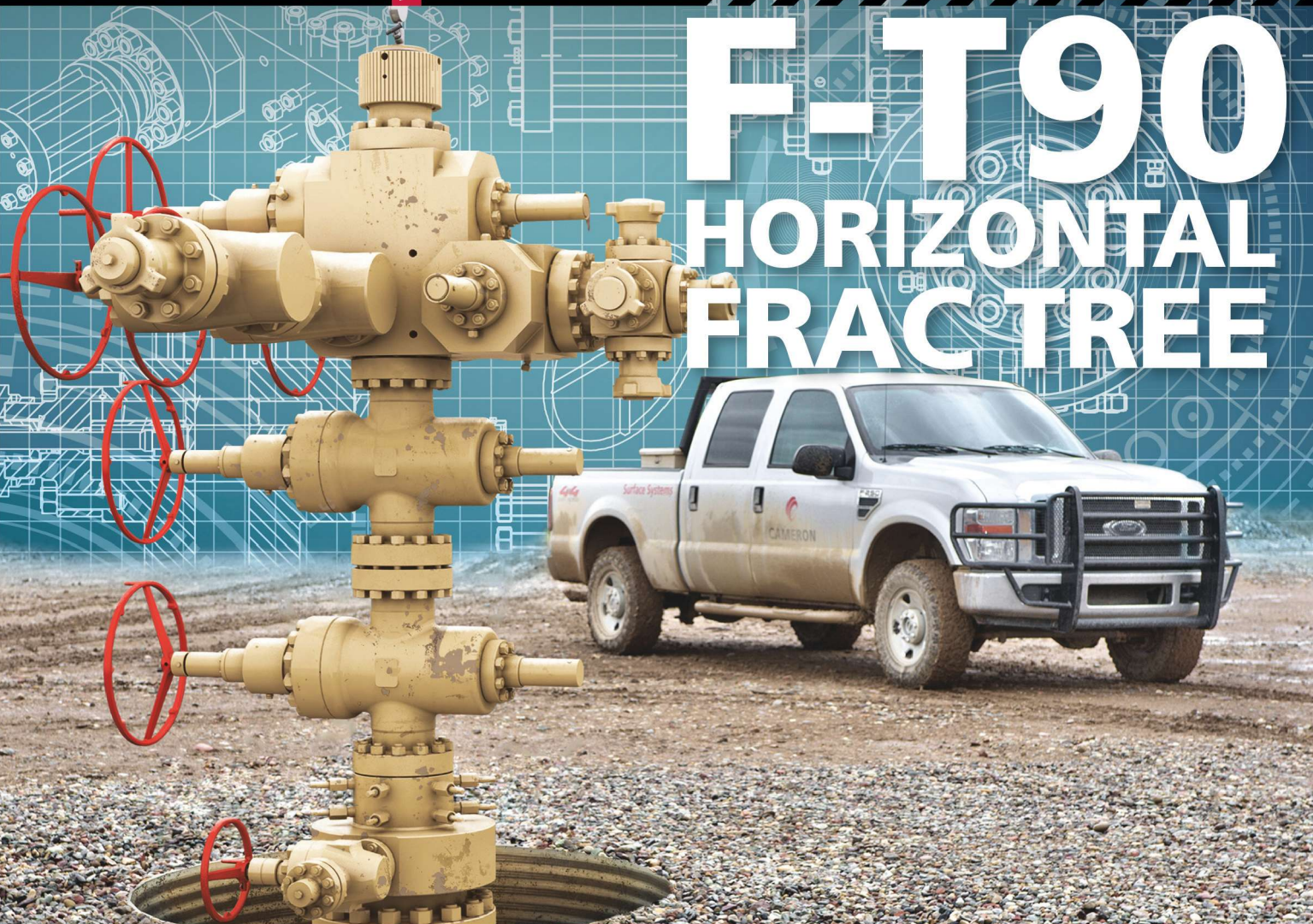
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As I
SEE IT

What goes around comes around

I first came to Houston as a wide-eyed Brit in 1993, visiting like so many others to attend the Offshore Technology Conference (OTC) and to learn more about what was going on in the Gulf of Mexico (GoM).

At that time the oil price was in the doldrums at \$16 per bbl, a level it struggled to break out of until the end of the decade. As a result, the E&P industry in the North Sea and the U.S. threw itself into various cost-reduction initiatives, such as the U.K.'s Cost Reduction in the New Era program.

Sound familiar? Here we are more than two decades later and—although the oil price is at a much higher level—the cyclical nature of the offshore business once again sees it go through various belt-tightening measures. But enough about that; plenty has been said on cost issues in recent months.

Let's go back instead to that first trip to Houston, when I attended many presentations and briefings, including one on Shell's pioneering Auger Field, the tension-leg platform that was in the final stages of preparation to start flowing oil the following year. There was a palpable sense of excitement at OTC about what was being done in the GoM on flagship projects like Auger.

Luminaries at OTC that year like Daniel Yergin of Cambridge Energy Research Associates and Matt Simmons of Simmons & Co. talked of the need for offshore oil and gas activity to grow at a "staggering rate" (according to Simmons) to keep the world's economy running.

Fast-forward to 2014, and the industry has indeed done just that. Offshore activity and production continues to grow globally, but in the GoM it's in a temporary lull. GoM federal offshore oil accounts for 23% of total U.S. crude production, with 1.3 MMbbl/d pumped offshore in 2013. But the lull has seen oil production fall from 584 MMbbl in 2010 to 447 MMbbl last year—a direct result of the Macondo disaster, with the drilling moratorium shelving dozens of projects for several years that would otherwise have come onstream.

The upside is that, as a consequence, crude production in the Gulf is shortly expected to start recovering as operators bring many of those projects to fruition.

At OTC this year I recognized a similar sense of excitement as in 1993, with the next wave of GoM projects coincidentally including another from Shell (Mars B) to help whet the appetite.

For those hungry to know more about the region's resurgence, Hart Energy holds its first Offshore Executive Conference focused on the GoM Oct. 16 in Houston. The lineup of speakers is second to none, with participating companies including Energy XXI, BHP Billiton, Shell, Apache, Statoil, Fieldwood Energy, W&T Offshore, Cobalt International and Venari Resources. Take a look at offshoreexecutiveconference.com.

All are there because they are excited too, playing major roles in the GoM renaissance that's now taking place. They're sure to know a lot more about it than I do, so I guess I'll be the wide-eyed Brit once more... **E&P**

Mad

Attracting and retaining talent in the shale boom

E&P firms face significant people risk when resourcing projects in challenging locations such as the Bakken and Permian Basin.

Melissa Hooper and Doug Thorner, Air Energi

The U.S. shale boom has been touted as the most significant energy development in decades. Although the economic benefits have been much lauded, such rapid economic expansion comes with growing pains, specifically in the form of attracting and retaining talent.

Rising employment in the oil and gas industry has increased competition for an already limited highly skilled workforce and has caused talent shortages, challenges in succession planning and higher turnover rates as companies resort to poaching talent from one another. This has led to increasing levels of risk associated with staffing a growing number of positions, particularly in shales.

Areas that face some of the greatest hiring challenges include Midland and Odessa in West Texas and Williston and nearby Dickinson in North Dakota. These areas are part of booming shale markets where firms are focused on ramping up hiring and growing their footprints. Challenges facing businesses in these areas already include limited local talent pools and a chronic lack of housing and other critical infrastructure.

Capacity crunch

Although construction efforts have ramped up dramatically, the accommodation shortage now runs into thousands of units as job creation in the area continues to outpace construction.

Such is the scale of the problem that some companies are contracting entire hotels to accommodate staff. In areas where companies want professionals to relocate, increasing numbers of workers are living in their RVs or “fifth wheels” on a long-term basis. Often this is not an option in North Dakota, where the extreme cold can prove deadly, further narrowing housing options in Williston and Dickinson and making both locations a challenging sell. Overall, this is a challenge in recruiting new candidates to the area and can be a barrier for those professionals with families.

In both areas, particularly in North Dakota, companies that are open to candidates splitting time between their

work location and their current home have greater options in terms of identifying viable candidates.

Window of risk

This combination of factors has made it extremely difficult for companies operating in West Texas and western North Dakota to staff their plays appropriately. These dynamics present a double-edged sword where attracting talent is on one side and retention of these hard-won assets is on the other. The single greatest expense for any company is its talent, where retention of skilled workers becomes key to the bottom line. Employee churn also causes higher safety risks since up to three times the number of work-related accidents occur within the first month of hire. Retention is vital to reduce the risk of work-related injuries.

Ways to improve retention rates vary by location. For West Texas, big-city amenities with a small-town commute are attractive for those looking to escape the grind of the big city. For North Dakota, companies have managed to address this challenge by placing more focus on recruiting individuals with experience working in areas such as Calgary, Canada, since they are used to withstanding the extreme elements found there.

Selling opportunities

For HR teams, it is crucial to sweeten the reality of working in environments like West Texas and North Dakota. The most important factor in selling opportunities in the Permian and Bakken regions is to really listen to individual candidate needs to enable an outcome that is sensible for the employer and attractive enough for the candidate to sign on the dotted line.

For example, the best option may be to offer individuals a rotation where they are able to return home for a week or so every four to six weeks. Alternatively, if candidates are willing to travel and keen to build on their experience, it is good practice to ensure they are considered for an intercompany transfer when possible.

Certainly, offering professionals the opportunity for career progression is one of the most effective ways to sell them a role in a less attractive location. Shale plays in the Bakken and Permian Basin tend to be operated by firms

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that also have projects and offices in other locations that can be leveraged to attract and retain employees.

While oil and gas professionals with five to 10 years' experience are in highest demand, professionals with less experience that are willing to relocate to North Dakota or West Texas can open doors that would otherwise remain closed. For companies looking to build a pipeline of talent for key disciplines within their business, recruiting to more challenging locations but offering candidates the opportunity to relocate at a later date can entice those looking to build their experience to locations they would not normally consider.

Even some of the majors are adopting a more focused model for tapping into new markets, opening up opportunities for oil and gas professionals with just one to two years' experience. This also applies to those with experience in different industries such as automation, aerospace and construction, where they have engineering skills that are transferrable.

One of the ways companies are increasing hiring activity while maintaining their day-to-day operations is to place greater emphasis on global mobility services. Global mobility services are increasingly pertinent for projects that require workers to relocate or travel with their families. Companies tend not to put down roots unless there is a longer term opportunity. Rather, they follow a project in and out of a country or state since it is not cost-effective for them to install infrastructure locally. However, by working with a resourcing partner and staffing projects on a contingency basis, companies can avoid many of the complications that would otherwise arise if they employed and relocated their own people full-time in a local market.

Counting the cost

The challenge of recruitment and retention in the shale industry is compounded by the ongoing boom, which shows no signs of abating. The opportunities keep coming, but if firms are unable to fill their vacancies, then the risk to their business is significant.

Estimates suggest that the average cost of an unfilled vacancy in the oil and gas sector is as high as \$30,000 per month. If it takes three months to fill a seat, then the cost to the business reaches \$90,000, just for one individual. Consider that cost across multiple plays in multiple regions, and the scale of the issue becomes apparent.

As a result, it is imperative that firms across the industry adopt a new mindset when it comes to attracting and retaining talent. The intense competition for talent is not only on the E&P side but on the supporting services side as well.

For example, demand for engineers skilled in water

excavation or transfer (vital for the development of shale resources) has risen substantially in line with the growth in fracking activity. It is not easy to find professionals with more than five years' experience, even in Oklahoma City, which is considered the birthplace of the water transfer business. An additional challenge is, therefore, creating a path of development and identifying skill sets that are transferrable.

North Dakota's harsh winters can deter some workers from wishing to locate there.



Mitigating rising risk

Ultimately, as firms get busier and employee churn increases, it is often training that is sacrificed. The result is overspend on senior staff to perform tasks below their skill level and the use of less experienced staff, which raises the risk profile of a play.

All of these concerns equate to people-related risk. To counter this issue, Air Energi has partnered with Queensland University of Technology (QUT) in Australia to develop a comprehensive tool called "People Risk Evaluation for Projects" (PREP) for identifying and reducing workforce risks. These risks have been broadly categorized into six core areas: project appeal, recruitment, onboarding and induction, retention, reassignment and demobilization, and compliance.

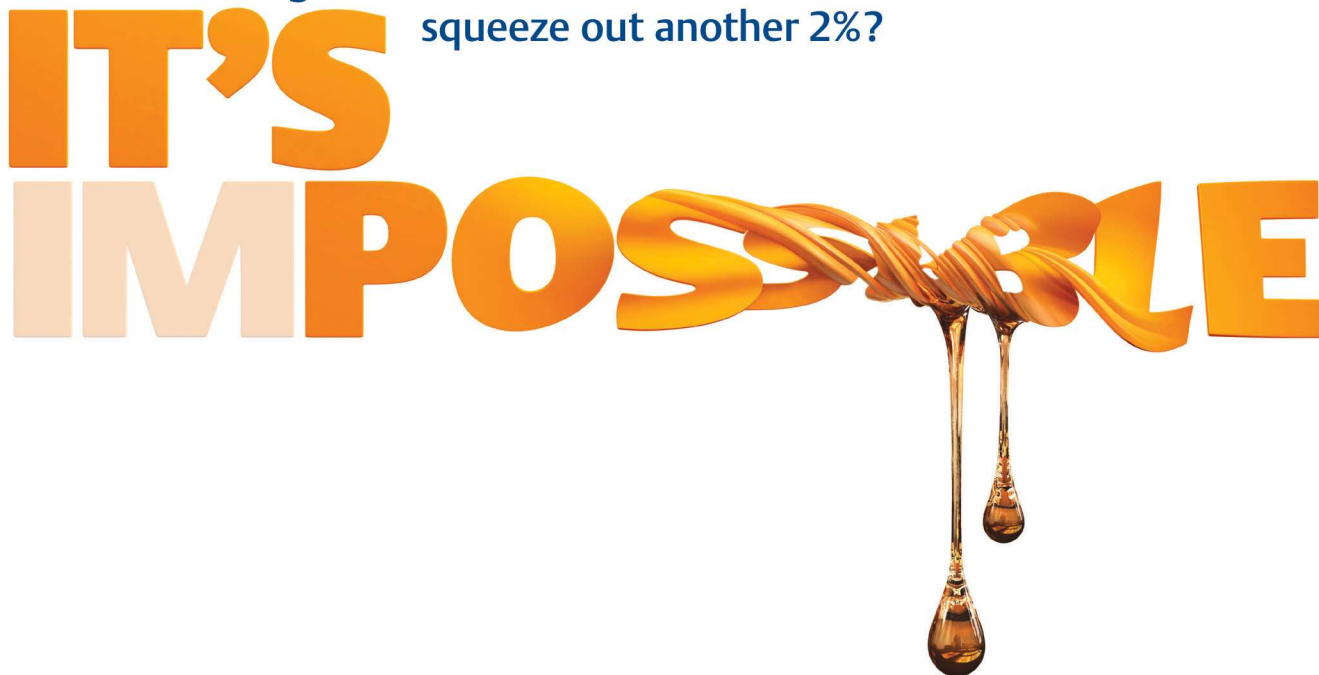
Importance of 'project appeal'

Perhaps one of the most interesting findings of the research is just how much emphasis oil and gas professionals place on the attractiveness of a project itself. However, with locations such as the Bakken and Permian, it is clear more innovative approaches are necessary to enhance project appeal given the prevailing socioeconomic and climatic conditions. Moreover, it is vital that E&P firms and those providing supporting services in these locations look to harness a tool such as PREP to mitigate people-related risk from the outset. **E&P**

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North American lessons in unconventional apply worldwide

Creating a petrophysical model with a fairly limited dataset from exploratory and early appraisal wells leads to success in shale plays.

Scott Weeden, Senior Editor, Drilling

Operators in Argentina, Poland, China and Australia face the same types of challenges that North America has met over the past eight years in developing unconventional plays. No matter where a company operates, the need to understand the rock is paramount in opening oil and gas resources from nanodarcy formations.

“From a geological viewpoint, we’ve got to get as much rock data as we can. We have to get core data and open-hole datasets on these exploratory and early appraisal wells and basically tear those data apart. What we then have to do is calibrate that core data to as much of the basinal data we have to create a petrophysical picture with a fairly limited dataset,” said Dick Stoneburner, managing director, Pine Brook Partners, at the DUG Australia conference in Brisbane, Australia, Aug. 27, 2014.

“What I have done is taken most of the successful American plays and broken them into what I call emerging, evolving and mature plays,” he explained. “I am trying to give you some sense of what we’ve been able to accomplish over the years. Prior to 2006, we really didn’t have a very good plan or technology to complete the rock effectively. When we were able to do isolated multi-stage hydraulic fracturing, we were then able to crack the code.”

Emerging plays

As Stoneburner mentioned, there are geological, drilling and producing aspects associated with each of these maturity levels. “I challenge you early on to establish as much as you can about that core area,” he said. “Make sure you’re in the right rock to spend the capital necessary to test that particular play.”

Although an operator has to start out with a fairly conservative drilling approach in an emerging play, it would need to move away from that conservatism going from the emerging to the evolving play.

“Understanding the fluid types, proppant types and geometry in a new basin is very challenging. It takes a lot of time as well as trial and error, but we have to start

working on that in emerging plays,” he continued.

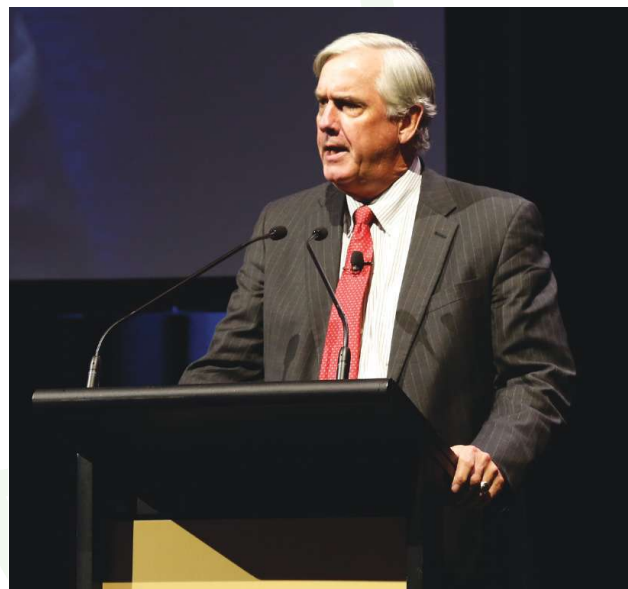
The emerging plays he described were the Utica, Tuscaloosa Marine Shale, East Texas Eagle Ford and stacked plays in the Anadarko Basin.

About two-and-a-half years ago, the Utica was described as the next Eagle Ford. There was a very limited amount of data since there had not been any drilling in the area for decades. The challenge for those who decided to embark on an effort to lease within the Utica was: Where do you go?

“You had a pretty benign area from a data standpoint. You had a very benign area from an infrastructure standpoint. So it was very challenging to identify the areas you needed to go lease,” he added.

“I will tell you a lot of operators wanted to be in that core area. Unfortunately, most didn’t find the right area and [cumulatively] spent about \$1 billion doing that,” he emphasized.

In the Tuscaloosa Marine Shale, operators have known for about 20 years there is oil there. However, the compa-



Dick Stoneburner broke down American shale plays into emerging, evolving and mature plays for the audience at Hart Energy’s DUG Australia conference.



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nies in the play earlier were not what Stoneburner would call experienced shale operators and had very poor results. Since then, three experienced main players have been involved, and results have improved, with 30-day IPs in the 800- to 900-bbl/d range.

“The problem is that about one in four wells has some sort of engineering failure. It is deep. It is hot. It is highly fractured. There are a lot of failures, particularly on the completion side,” he continued. “You have to be doing your engineering homework and some of the nondrilling data assessment prior to getting in there and understanding how you’re going to drill and complete those wells to avoid the pitfalls that a lot of these wells are currently experiencing.”

In the East Texas Eagle Ford, it took operators some time to get a good understanding of the physics involved. It is a matter of doing the petrophysical homework and understanding that what may not look great could be great if one does the right work to uncover it.

“Use different methods. One of these is the Passey method, which is basically using sonic and resistivity tools as opposed to conventional density neutron logs. A lot of these shales will more readily reveal themselves with this,” he said.

The stacked play in the Anadarko Basin was discovered by Newfield in the last 12 to 18 months. “What happened with Newfield is that they were drilling in the known Woodford play and encountered good shows and interest-

ing rock. They did all their homework and defined a new play simply by understanding what the play was,” he continued.

Evolving plays

There is no magical “tollgate” for moving from emerging to evolving plays. The more data a company has, the better geophysical model it can create.

“Early in a play you’re not going to spend money to acquire 300 or 400 sq miles [777 sq km or 1,036 sq km] of data before you have actually proven it is commercial. By this time you have proven it is commercial, and you do need 3-D data to avoid faults and other geologic hazards,” he noted.

“It is really important to understand the fluid types you’re using and that the geometry of that particular completion is appropriate to contact as much rock as you can—what is called stimulated rock volume.”

Operators will increase their capital exposure and move away from drilling a handful of wells to define the extent of the play. They now have to have multirig programs to be able to hold acreage. There is a very earnest effort to develop a play once it’s proven to be commercial.

“One thing I think is especially overlooked in a lot of wells is getting as much production log data as possible. You really don’t know how that

Trends Associated with Maturity Index	
Emerging Plays	
Geologic and petrophysical data gathering	<ul style="list-style-type: none"> - All inclusive openhole log data are critical - Calibration of the log to core is also critical
Variations to the drilling practices	<ul style="list-style-type: none"> - Work toward removing early conservatism - Experiment with variables as early as possible
Variations to the completion practices	<ul style="list-style-type: none"> - Optimal fluid system and proppant type need to be validated - Completion geometry variations need to be tested - Microseismic data should be acquired, but beware of reading too much into it
Evolving Plays	
Geologic and petrophysical modeling	<ul style="list-style-type: none"> - Integrate core-calibrated log data
3-D seismic data acquisition	<ul style="list-style-type: none"> - Acquire 3-D covering prospective acreage position
Regional appraisal drilling	<ul style="list-style-type: none"> - Contract a multirig program to determine how much needs to be held by production
Optimization of wellbore design and construction	<ul style="list-style-type: none"> - Most aspects of the wellbore design are understood - ‘Learning curves’ and continuous improvement need to occur
Variations to the completion design	<ul style="list-style-type: none"> - Fluid system and proppant type have been established - Geometric changes to completion design should be continually tested
Variations to production practices	<ul style="list-style-type: none"> - Production logs and radioactively tagged proppant and fluid are critical - Restricted-rate production testing should be used as pilots
Mature Plays	
Geologic model	<ul style="list-style-type: none"> - Generally known and accepted
Optimal drilling practices are generally known and accepted	<ul style="list-style-type: none"> - Pad drilling efficiencies are recognized
Down-spacing pilots	<ul style="list-style-type: none"> - Understanding the proper spacing is probably the most challenging of all the lessons
More extensive and ‘radical’ variations in completion design and implementation	<ul style="list-style-type: none"> - Geometric vs. geologic completions - Incorporate ‘Silicon Valley’ type technologies to assist in data analysis

Operators use different techniques depending on how mature the shale play is, as shown.

(Source: Dick Stoneburner)

wellbore is performing on a stage-by-stage basis unless you put something in the hole to measure it,” he continued. “You should use any kind of log that will give you an idea where production comes from. I encourage you to gather as much data as you can.”

Restricted-rate production is also important to maximize production. Stoneburner advised the use of it in the Haynesville, for example, where there is a lot of pressure-dependent permeability in the nanodarcy reservoirs.

“You can effect a lot of permeability early in the well life with your fracture stimulation. But if you lose that permeability by overproducing the well and allowing pressures to drop dramatically, you can effectively lose a lot of productivity. I would encourage you to study the effects of pressure-dependent permeability however you monitor that surface pressure,” he explained.

Maturity Index for American Shales		
Emerging	Evolving	Mature
Utica	Niobrara	Barnett
Tuscaloosa Marine Shale	Wolfcamp Delaware Basin	Fayetteville
Eagle Ford East Texas Basin	Wolfcamp Midland Basin	Haynesville
STACK	Woodford Anadarko Basin	Marcellus
		Bakken
		Eagle Ford Gulf Coast Basin

The U.S. shales are grouped into emerging, evolving and mature plays. (Source: Dick Stoneburner)

He listed the Niobrara Shale, Delaware and Permian basins as evolving plays, emphasizing, “Know your rock. Know your play.”

In the Delaware and Permian basins, understanding the burial history is key to finding the best resources. For example, the deepest part of the Delaware Basin is the least mature. “Your product type is a result of that burial history and is incredibly important, particularly



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in today's world of depressed natural gas prices," he said.

As operators move up the basin, they find that the maturity level increases at the western limits where gas is found. "The Davis Mountains tectonic event created the inverted basin. As it is today, even though there is good production in that area, it seems the most commercial area in this basin is in the gas-condensate window," he said.

In the Midland Basin, there was no depositional uplift. "In the central part of that basin, you have the thickest sediment, high pressure and corresponding best productivity. The center of the basin is where you want to be," Stoneburner continued.

There are a large number of stacked reservoirs. The Wolfcamp is more than 305 m (1,000 ft) thick. With the Spraberry above it and the Pennsylvanian below it, as many as eight to 10 stacked reservoirs could be commercial.

The Niobrara extends across many intermountain basins in the central and western U.S. It is mainly in the Denver-Julesburg Basin, with rock also present in other basins like the Powder River and Wind River basins.

"The Niobrara is again a play where you better be in the core area. Know where the rocks are," he emphasized.

Mature plays

Pad drilling in mature plays improves drilling efficiencies. Downspacing begins at this point.

"You are really trying to understand how many wells you need per section or how you are going to space this development. Quite honestly, I don't think we have a very good handle on this in many plays at all. It is going to take quite awhile to really understand how these reservoirs are going to drain," Stoneburner said.

He feels strongly about the concept of geometric vs. geologic completions. "Throughout my upstream career, virtually everywhere we wanted to stimulate every inch of that well bore. In a lot of cases all that wellbore wasn't worth stimulating if you knew more about the rocks. I encourage you to get more openhole data on these laterals with quad combos or anything you can do to learn more about the wellbore itself and design your completions based on that geology as opposed to geometry."

"Understand what you are doing. Do not have the herd mentality and follow someone who says the Mississippi Lime is the way to go."

The Barnett, Haynesville, Fayetteville and Bakken he listed as mature plays. The Barnett was the first shale play in North America. But, he warned, it took George Mitchell and his team 20 years to understand the rock.

"One key lesson to learn from the Barnett is to look for the bottom seal for the shale formation. A lot of companies did not understand that a bottom seal was needed between the Barnett and the Ellenberger, which is a prolific water-producing reservoir in the area. I encourage you to not just focus on the rock, but focus on what is around you and what are frack barriers. How is that well going to frack relative to above and below the shale? It is very important to understand," he added.

In looking at the Fayetteville, Stoneburner said it's important to understand the structure. "Within that section there are an abundance of faults. You can actually see trendings southwest to northeast that are less productive or faulted areas that prove you can't drill horizontally across these faults. When you are going sideways, it is really problematic if you don't have a good idea of what you are going to run into," he explained. In opening the Haynesville, "It was an absolutely insane period in my life within the industry where we were paying upwards of \$25,000 per acre to lease acreage. As it turned out, it was worthwhile. We did understand the sweet spot component of the Haynesville better than most. We felt like pressure, TOC [total organic carbon] and clay were our keys. "When we found that in the north central Louisiana area we had all those components—the highest TOC and geo-pressure and the lowest clay percentage—that really defined the key to the reservoir," he explained.

Avoid herd mentality

Stoneburner emphasized several times, "Understand what you are doing. Do not have the herd mentality and follow someone who says the Mississippi Lime is the way to go. 'Chesapeake did it so I'm going to do it too.' That happened a lot in this play, and a lot of people lost a lot of money." The Niobrara is another example of where the herd mentality kicked in, to the detriment of many operators. "Anywhere the Niobrara existed, people would go. In this case, besides the Wattenberg Field area that produces from the Niobrara, virtually no other areas in the entire central U.S. were commercial for the Niobrara," he said. **E&P**

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TRLs gauge progress on technology, commerciality

This is the second in a two-part series on how the technical readiness level process can be practically used to shorten the time before new technology can be commercialized.

Peter Lovie, James Pappas and Tom Williams, RPSEA

Investors may invest in the development of new ideas, expecting a high return on their investment by rationalizing that since the risks are high, so must be the rewards. In reality, many new ideas do not work commercially for various reasons that are sometimes not readily apparent when starting on a path to develop new technologies. Moreover, it is through fits and starts, trial and error, and much iteration that some new ideas have historically flourished to become worthwhile advances on the status quo. If, for example, a manufacturer believes his widget is ready for commercialization, he had better be certain that his potential purchasers and end users share his thoughts, quite apart from any consideration of technical readiness levels (TRLs). The oil and gas industry is littered with well-intentioned technologies that have been shelved because end users were not convinced of the products' readiness or value.

That said, TRLs may help as a useful marketing tool to show that widget's readiness. A TRL voting exercise can serve as a reality check by removing much of the subjectivity, not to mention personal enthusiasms, from the equation. It may even result in a complete change in business plan.

Although subjected to model tests and field trials, the technology had not yet been fully evaluated for the U.S. Gulf of Mexico's (GoM's) deepwater environment. The project objective was to evaluate the suitability of the technology as a preferable operating and economic alternative for offloading crude in GoM deep waters, determining if it would meet U.S. GoM requirements to enable functioning successfully for both steady-state production situations and in standby roles for emergency situations.

Marine technology development

Determination of TRL figures was part of a RPSEA project on deepwater direct offloading systems by Remora's HiLoad DP equipment. Remora A.S. is the Norwegian originator of the technology, working on it since 2001 and patenting the HiLoad DP device as a system to more safely and efficiently transfer crude oil from storage on an FPSO vessel to a shuttle tanker so that the latter vessel could transport the crude to an onshore processing facility.

Two TRL votes were conducted: one early in the project Jan. 9, 2013, and the second at the end of the study Sept. 5, 2013. The voting panel was comprised of people from operating companies (end users) and nonoperators, all familiar with offloading operations and fully briefed on this project. All individuals were deemed qualified to vote (generally 15 to 35 years industry experience), with a composition as follows:

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No. of Voters	FIRST VOTE	SECOND VOTE
Operators:	9	4
Nonoperators:	5	4
Everyone:	14	8

The same individuals were polled in the second votes, but only eight voted. Each voter was asked for an assessment of TRL based on the RPSEA TRL scale. The development of marine technologies such as offloading is known to be historically slow, so voters also were asked to give their assessment of TRL at some point three

Category of votes	Vote		TRL today	TRL in 3 years	Number of voters in panel
Operators	First	Average	4.3	6.1	9 on Jan. 9, 2013
		Range	3-5	5-7	
	Second	Average	4.8	6.4	4 at Sept. 5, 2013
		Range	3-6	5-7	
Non operators	First	Average	5.6	6.7	5 on Jan. 9, 2013
		Range	5-6	6-7	
	Second	Average	5.0	6.5	4 at Sept. 5, 2013
		Range	4-6	6-7	
Everyone	First	Average	4.8	6.3	14 on Jan. 9, 2013
		Range	3-6	5-7	
	Second	Average	5.0	6.4	8 at Sept. 5, 2013
		Range	3-6	5-7	

FIGURE 1. TRLs were used to gauge progress during a RPSEA technology development project, with a projection for TRL three years later. (Source: RPSEA)

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FIGURE 2. These examples show how TRLs have been used with technologies in the offshore petroleum industry. (Source: RPSEA)

Example	Technology	Typical System CAPEX, \$ million	Study length, months	Study Cost, \$ million	TRL at start	TRL at end	RPSEA Project Number (a)	Applicable Business Sectors	Is it commercial in 2014? (b)
1	Deepwater direct offloading systems	132.0	15	1.073	4.8	5.0	10121-4407-01	FPSO units & shuttle tankers	No
2	Intelligent Production System for Ultra-deepwater Short Hop Wireless Power and Wireless Data Transfer for Lateral Production Control and Optimization	0.5	14	1.424	2.0	5.0	09121-3500-01	Subsea production	Yes
3	Autonomous inspection of subsea facilities	1.4	18	2.718	2.5	5.5	09121-3500-05	Subsea production Offshore pipelines	Probable

(a) RPSEA publishes a final report for work on each of these technologies, which will become public domain and can be tracked using this project number.

(b) While TRL can be a good signal for commerciality, the marketplace still rules and a high TRL is thus no guarantee of commerciality.

(c) Final field trials are in progress. Plans are to commercialize before year-end.

years in the future, assuming all goes well in the operation of a HiLoad DP.

The results of the voting are shown in Figure 1. The operators were more conservative than the nonoperators, giving TRLs that were lower. In the second vote that trend reversed a little:

	FIRST VOTE		SECOND VOTE	
	TRL today	In 3 years	TRL today	In 3 years
Operators:	4.3	6.1	4.8	6.4
Nonoperators:	5.6	6.7	5.0	6.5
Everyone:	4.8	6.3	5.0	6.4

After nine months of thinking about it and reviewing further engineering design, operations, economics and environmental work, the operators had increased their TRL assessment by half a TRL level and the nonoperators by about a fifth of a TRL level. It did seem to be a perceptible increase but, as these studies went at RPSEA, it was not very much considering the expectation had been to increase TRL by one or more levels as a result of the RPSEA process and funding.

Looking into the future for three years, it was interesting to see how the consensus was that even after three years of successful operation, an offloading technology would still be a half level from being fully accepted and proven (i.e., TRL of 6.4 instead of 7), which gave an insight as to how slow-moving and conservative the marine business can be. If that had been a downhole device for drilling operations, one doubts there would be any question at the end of three years of successful operation that the device would be fully proven and a TRL 7.

Example 1 shows: (a) how this particular study effort

was not very effective in advancing TRL and (b) the use of TRLs on a technology that involves large capex, estimated at \$132 million for a typical U.S.-built unit for a GoM application.

Subsea downhole production technology

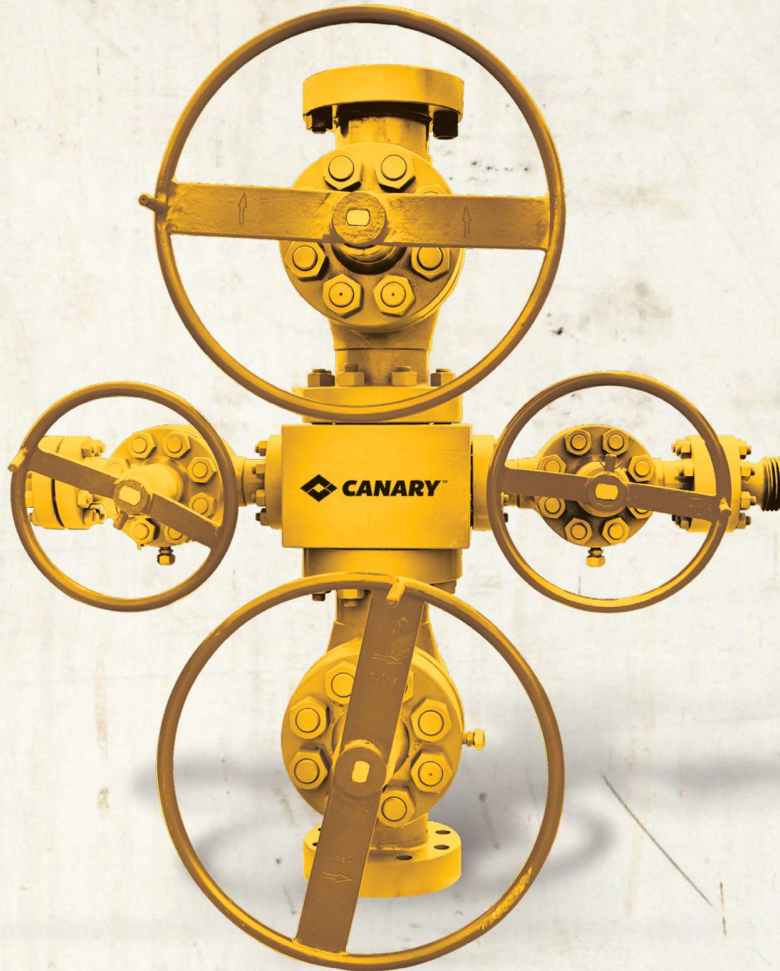
“Intelligent Production System for Ultra-Deepwater Short Hop Wireless Power and Wireless Data Transfer for Lateral Production Control and Optimization” is the name given to a novel system for providing controls and power to downhole subsea production systems in a radically simpler and more economical way than current hardwired systems. While the capex required is much less than in Example 1, the potential payoffs are a high multiple.

This technology is attractive to the offshore production community as it may simplify subsea operations and offer substantial overall economies well beyond the capex of an embodiment of this technology.

TRLs for examples 2 and 3 were established by RPSEA staffers and not an independent voting panel as in Example 1. In Example 2, the technology was shown to work in other oilfield and industry experience but was not proven in subsea or deepwater, which together posed serious new challenges. This RPSEA project succeeded in proving downhole live operations in onshore wells. At this point the TRL was deemed to start at a 2, and afterward the project reached a TRL of 5. Subsequently, the product has been tested by an unnamed operator, commercialized and is now being used in several wells. It also is being developed for higher temperature applications, implying some increase in TRL.

It was developed by Tubel Energy, a small Texas company, with support from the University of Houston.

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Subsea inspection technology

The “Autonomous Inspection of Subsea Facilities” in this example responds to the growing need for subsea inspection of wellheads, subsea flowlines and seabed pipelines. In contrast to Example 2, it was developed by a very large corporation (Lockheed Martin), with the RPSEA study effort providing needed petroleum industry inputs in addition to the objective of advancing the TRL.

The value of using an AUV was first seen in the U.S. Navy and then in oceanographic communities, which encouraged the adaptation for petroleum industry requirements.

Once again the progress with TRL was dramatic, going from the initial stage of between TRL 2 and 3 to a test system operated in a live production situation in 76.2 m (250 ft) of water in the GoM inside 18 months. The final test arrangement was judged to correspond to a TRL between 5 and 6, implying once again that a shift of three TRL levels was achieved, going from 2.5 to 5.5. Within a matter of months the production version of the AUV was routinely operating at depths of up to 305 m (1,000 ft), and newer versions are expected to extend it to 2,438 m (8,000 ft) in the near future.

The capex in a production environment would be about \$0.7 million.

Comments on results

Funding for example 1 did not do much to advance TRLs, but for examples 2 and 3, the funding appears to have had a dramatic effect. That “moving the needle”

may be of value in determining what additional investment should be made before the technology is widely applied in the field as well as represent a signal to operators how far the technology may be from actual trials and use.

That downhole device or survey tool might cost less than \$1 million to buy but may ultimately be supplied and put in service hundreds of times and might become an enabler for many further savings in field developments. For example, the TRL may be a valued signal for commercializing an attractive technology.

Alternatively, with the quantitative indication from TRLs, the payoff may be judged not an attractive enough proposition to make the technology funding investment.

Historically, while TRL ratings may not have been explicitly used in the petroleum industry for making investment decisions, the judgment of seasoned industry experts was first employed and then calibrated by operating company feedback and comments to arrive at as careful an assessment as possible of the technology to fit market needs. That process has often been one of selection with best available judgments in the absence of the new logic of the quantification technique that TRLs can offer. **E&P**

Acknowledgment

The authors are pleased to have the permission of RPSEA to cite the frame of reference of RPSEA in using TRLs and the experience with the specific RPSEA projects referred to.

TRL conclusions

- TRLs are a frame of reference giving a useful quantitative assessment, better than a focus group or market research but not a perfect or absolute number;
- If used consistently, TRLs can be useful in gauging development progress and appear particularly useful when applied in small capex projects that may be of fairly complex technology;
- While employed as a known tool by technology developers, TRLs have broader practical value for business and management decisions;
- TRLs can act as a metric to differentiate among various options, to decide where and how much one should spend on related new technologies and assist technology developers in determining areas of weakness or needed improvements;
- In the world of the big crew change, TRLs may offer a way to codify available judgment to a similar end result, offering a metric that can be understood readily across different types of technologies and across different funding entities; and
- Since TRLs appear to gain importance as a function of larger capex and when safety is imperative, perhaps the onshore oil and gas industry should consider using TRLs since its associated costs and safety issues are on the rise while at the same time new and more complex products are being developed and marketed.

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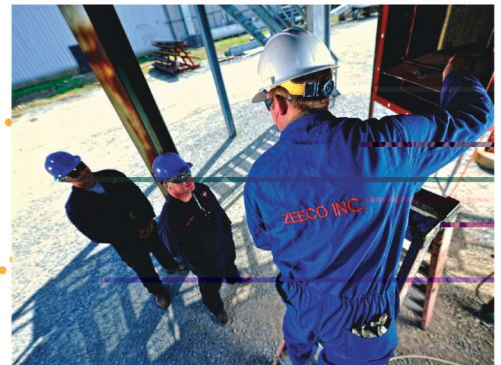
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Microseismic: Shaking all over?

Operators and service providers predict greater use of microseismic as the industry moves to pad drilling and batch completions.

Richard Mason, Chief Technical Director

Is microseismic about to shake loose? The technique is best associated with the early days of the Barnett Shale and the advent of horizontal drilling and multistage fracturing. However, microseismic predates the Barnett and had actually moved toward commercialization in the Piceance Basin a little over a decade ago.

But the technique came of age in the Barnett as operators and service companies scrambled to understand what was happening underground during the fracture stimulation process. That said, market penetration for microseismic, at an estimated 5% of horizontal wells, remains low today.

Hart Energy's Market Intelligence survey program canvassed the industry in August for a status report on microseismic. "We drill five to six wells utilizing microseismic for each 50 to 60 wells drilled," a mid-sized Oklahoma oil and gas operator told Hart Energy surveyors.

Several issues affect market penetration. For one, far-field microseismic events did, in fact, occur during the fracture stimulation process but did not necessarily mean that those events had been reached either by an induced fracture pathway or with proppant. Hence, the productive potential of fracture-stimulated wells was sometimes overstated on the basis of the microseismic readings. The issue led to misperceptions in the market about the effectiveness of the process. Additionally, operators have shied away from widespread use of microseismic because of pricing issues. But that may be about to change.

Hart Energy's survey found both operators and service providers predicting greater use of the technique with the move to multiwell pad drilling and acreage drill-out as the manufacturing phase of the unconventional cycle takes hold. Multiwell pads reduce microseismic costs per well by spreading expenditures across multiple wells while also providing wellbores in close proximity to aid the microseismic process.

"The price of the technology and the proximity of wells for monitoring are the two greatest limiting factors for us," another mid-sized independent oil and gas operator told surveyors. "It will make better sense when we are pad drilling with multiple wells in close proximity."

Service providers and operators said they expect microseismic's share should double to 10% of horizontal wells in the future. Noted a West Texas oil and gas operator, "We use microseismic in 1% to 3% of our wells during our current exploration phase but will monitor 5% to 10% of wells in our manufacturing phase."

Pricing for the service has stabilized after declining over the last decade as new competitors entered the market. Participants in the Market Intelligence survey identified Halliburton subsidiary Pinnacle, who pioneered the process, as the No. 1 provider, followed by Schlumberger, Baker Hughes and Weatherford International. ESG Solutions and Trican Well Services complete the fifth and sixth slots in market share.

Service providers have added advanced interpretive software and 3-D modeling as part of the microseismic package to provide real-time value during the fracture stimulation process. Although the software and data interpretation raise the price of the service, these also increase the value for customers.

"We have seen a great improvement in the usefulness of the data since processing and analysis now happens in-house with the providers and can give real-time displays of the frack as it is happening," said a Texas-based oil and gas operator. Also helping is the fact that the Big Four well stimulation firms now bundle microseismic with other wellsite services. "We brought prices down when we started competing as a package service provider instead of just doing the data processing," one mid-tier microseismic service provider said. "Although competition brought prices down, they have stabilized now." **ESP**

- **Move to pad drilling and batch completions to boost microseismic usage**
- **Microseismic market penetration expected to double to 10% of horizontal wells**
- **Service providers adding better software interpretation and 3-D modeling**
- **Service providers reducing costs by bundling microseismic with other wellsite services**
- **Barriers remain in pricing and misperceptions about effectiveness among customers**

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One of the many issues that set unconventional plays apart from their conventional cousins is their proximity to populated areas. This compounds the entire upstream cycle.

The Wattenberg Field in the Denver-Julesburg Basin in Colorado is directly overlain by the town of Greeley, home to the University of Northern Colorado as well as some 95,000 residents. A paper titled "The Greeley 3-D Seismic Survey: One of the Nation's Largest Urban Surveys Leads to Niobrara and Codell Horizontal Activity" by Jack Wiener of Halliburton, Tagir Galikeev of Unified Geosystems LLC and Collin Richardson of MRI was recently presented at the Unconventional Resources Technology Conference in Denver. The authors describe the Wattenberg Field as one of the largest overpressured basin-centered oil and gas fields in the Rockies in terms of total proved reserves, areal extent and number of wells. While horizontal drilling has been active in the outskirts of Greeley, very little activity has taken place within the city limits. A private company decided to undertake one of the largest urban 3-D programs in the country, 59 sq km (23 sq miles).

The survey required several months to plan due to the densely populated nature of the area. A wireless recording system was chosen both for aesthetic purposes and to avoid safety issues posed by cables. Underground utility locations were surveyed ahead of time to avoid damage during vibroseis acquisition, and traffic control during operational hours was put in place.



A worker controls traffic while vibroseis trucks perform operations.
(Source: Halliburton)



RHONDA DUEY
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During acquisition, particle wave ground motion recorders were used at every vibration point to monitor vibrator sweeps and their effects on nearby structures. Operation hours were restricted to the 12 hours from 7 a.m. to 7 p.m. Residents were alerted well in advance of the survey and were treated to an open house to answer their questions. "Public sensitivity and total transparency were key to successful and smooth operations during the survey," the authors noted.

The layout was irregular because of easement limitations, and sweep frequencies were nonlinear to help avoid ground roll damage. These types of urban limitations can result in a low signal-to-noise (S/N) ratio, but the authors noted that the structural geology is characterized by subhorizontal layering, which lends itself to the common depth point method for increasing S/N. Processing methods also helped maximize the quality and frequency content of the final image.

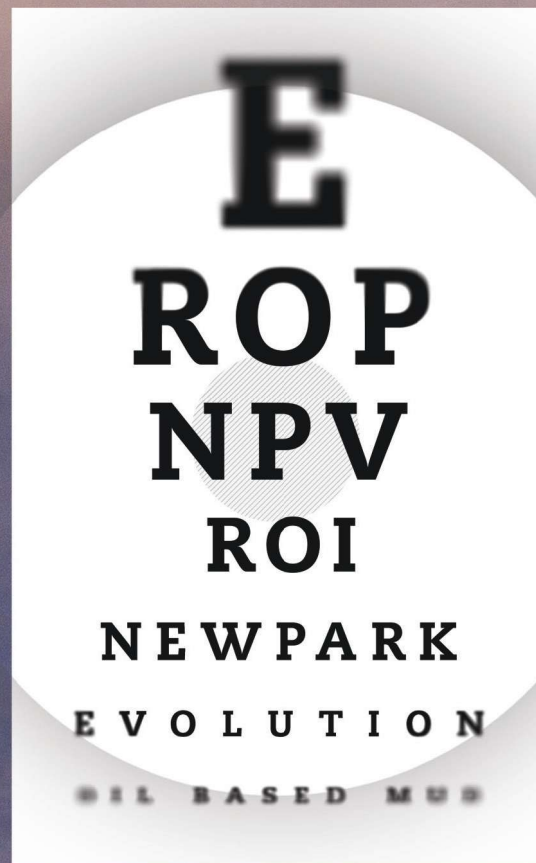
Interpretive products included accurate time-to-depth conversion of the horizons and volumes, detailed structural analysis and framework modeling and neural network inversion for rock properties.

So was it worth the hassle? According to the authors, the final products are providing accurate information for well planning as far as landing the laterals and drilling and completing the horizontal portions of the wells. "Results from the drilling program have been excellent in terms of accurate prediction of the subsurface geology and exceeding production expectations by 25% of published Niobrara EURs," the authors wrote.

It's nice to see the industry combining its ingenuity with its common sense to carry out a survey of this magnitude. This kind of grassroots PR may be just what we need. **ESP**

Rhonda

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What is most important in oil, gas industry? Family

The 3-year-old daughter of an MI-SWACO drilling fluids specialist in Brazil illustrates why oilfield workers do their jobs.

Sometimes it is easy to forget why oilfield hands go to work every day. The push for profits and to make shareholders happy overshadows the real reason the industry remains engaged in providing energy to the world. That reason is family.

Then along comes a story like this to remind us just how important our jobs are for making the world a better place for our children. In MI-SWACO's company magazine *Momentum*, which was published earlier in 2014, there is a photo of Giovanna Ricci in her orange coveralls and hardhat.

Her dad, Paulo Ricci, began working offshore about 10 years ago for MI-SWACO, a Schlumberger company, when he was still single.

Since then he married Renata, and Giovanna was welcomed to the family. The salary he has earned working offshore has allowed him to buy his own home and support his family. However, he has to spend long hours away from home. Communications software allows him to see and talk with his family, providing a fair compensation for his absence.

And that is where his precocious and curious daughter surprised both him and his wife. Giovanna could see in the background that everyone at Paulo's workplace wore orange coveralls. Brazil is a signatory of the International Maritime Authority, which strongly recommends the use of bright orange coveralls for safety. That's when she hatched her plan.

She told her dad that she wanted some orange coveralls. Renata found someone to sew the coveralls for Giovanna a few months later. Then she told her parents that now that she had orange coveralls, she could go to work with her dad.

"My wife was really surprised. We both did not expect that kind of understand-



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As soon as Giovanna Ricci got her orange coveralls, she was ready to go to work offshore with her dad. (Source: MI-SWACO, a Schlumberger company)

ing from our young daughter. My wife and I are both very proud that our daughter is just 3 years old and has a good understanding about what life is and about how her father goes to work for long periods. We're also really glad that she understood this, sees us as a good example and is willing to copy us because she realizes that is the right thing to do," he said.

"We're showing her that work in the oil industry is an honest and good way to make a living. We try to not pressure her too much and let her destiny guide her on whatever is reserved for her," he added. "She is already showing a strong inclination to math and logic, but that's probably because it is what she sees in the home."

The most important thing to come out of this for Paulo is the importance of work/life balance, especially because his job requires long times of absence from home. For Renata and Giovanna, this made them stronger as a family as they all realized that what really matters is not the quantity but the quality of their time together.

You can see the determination in that young girl's face to be with her dad. And that's what makes the work we do so worthwhile. **ESP**

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Surveillance and optimization: critical to CO₂ flooding

Operators must make an ongoing effort to manage CO₂ performance.

Steve Melzer and Ron Wackowski

Knowledge about how to optimize a CO₂ EOR project has grown dramatically in recent years as the number of active CO₂ EOR floods worldwide has more than doubled, from 65 in the mid-'90s to more than 145 today. During this same time period, U.S. projects have increased from 55 to 130.

CO₂ EOR's growing popularity is due in large measure to its efficiency at "cleaning" oil from the rock. But since the properties of CO₂ in the reservoir are such that overall "sweep" through the reservoir will likely be lower than during a waterflood, it is important to know that the CO₂ is doing its job, contacting oil and moving it. And now that supplies of CO₂ are constrained, the cost of CO₂ for EOR projects is higher, and surveillance is even more important. Therefore, active reservoir management and ongoing pattern management is critical. This can only be achieved through an active, ongoing surveillance and optimization effort. Without such an effort, a CO₂ flood's performance can easily and quickly spiral out of control, and its profitability can suffer.

Surveillance

Surveillance operations can be grouped into two categories: routine and nonroutine. Routine surveillance is those basic data that are required to monitor and analyze the flood performance on a daily or monthly basis. It should have a reasonable cost associated with it and is part of the reservoir management team's data gathering plans. It includes production well tests, injection rates and pressures, reservoir pressures, injection profiles, and corrosion.

Nonroutine surveillance is generally

more focused on helping solve a specific problem. It also is likely more expensive. Examples of nonroutine surveillance include transient pressure analysis, production profile logs, borehole image logs, saturation logs, coring and special core analysis, and seismic methods.

Optimization

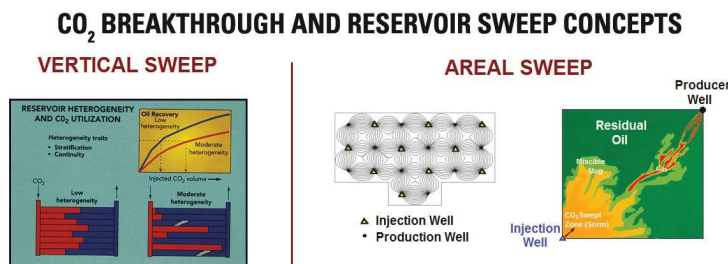
Several techniques can be applied to minimize the adverse sweep water-alternating-gas (WAG) management is the most widely used sweep control technique used for CO₂ EOR projects. WAG management refers to the selection of the optimum WAG ratio and cycle slug sizes for each injector in the project.

The process requires the analysis of the surveillance data obtained, the development of recommendations based on the analysis and the implementation of those recommendations. Important considerations include the incremental oil production and gas production as well as facility constraints such as gas recycling capacity.

Both increasing the WAG ratios (tapering) and reducing the cycle sizes can improve the sweep and, with it, the CO₂ utilization (the amount of CO₂ needed to produce an incremental barrel of oil). They also can both result in more optimal CO₂ retention and therefore help reduce the gas production rate. Reduced half-cycle sizes have the additional benefit of a higher CO₂ processing rate and a reduced fluctuation in produced rates that are inherent with the WAG process.

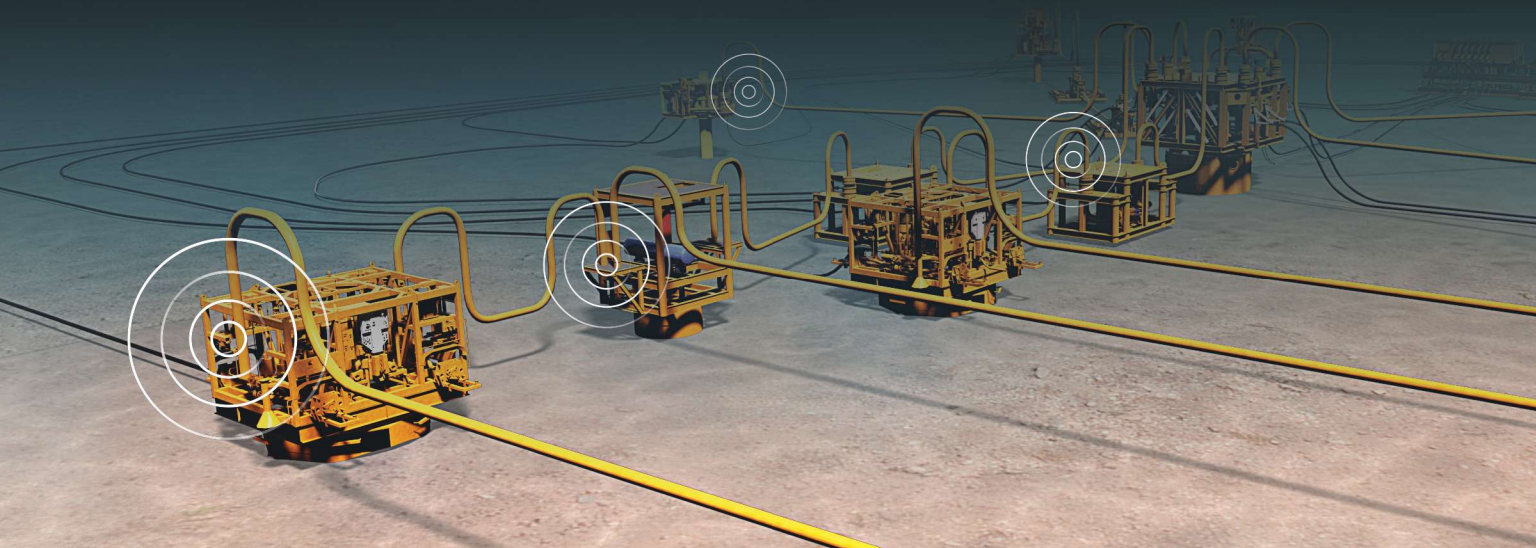
We never know enough about a reservoir to expect a pre-deployment reservoir management plan to be perfect. As a result, CO₂

miscible floods are often complex to manage. It is imperative that operators of such floods dedicate the needed talent and resources to do the proper surveillance and analysis to optimize flood performance and flood profitability. **ESP**

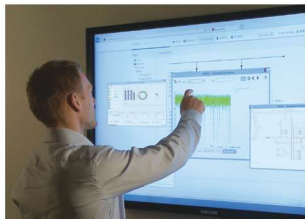


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Seeing success with new eyes

Seismic technology advances over the last 25 years helped one operator score major victories at two of its GoM developments in 2014.

Twenty-five years ago the Berlin Wall fell, more than 1 million demonstrated for democracy in Beijing's Tiananmen Square and two men named Bush and Gorbachev became presidents of their respective superpower countries. Yes, the political landscape changed a bit in 1989. It was a very busy year globally. For those local to the Gulf of Mexico (GoM), it was the news that Royal Dutch Shell had plans to install the world's first deepwater tension-leg platform at its Auger Field that made ample waves. Those waves ripple to this day as 2014 was a very busy year for the national oil company in the GoM.

Last month Shell announced the startup of its Cardamom development. It is the second major deepwater facility the company has brought online this year, following the startup of Mars B in February.

"Cardamom is a high-value addition to Shell's production at the Auger platform and is another example of our excellence in deepwater project delivery," Marvin Odum, Shell Upstream Americas director, said in a Shell-issued press release. "The work to extend the production life of our first deepwater tension-leg platform is impressive and involved advanced exploration and development technology."

Located 362 km (225 miles) southwest of New Orleans, the Cardamom Field is in water more than 820 m (2,700



View of the deepwater wells coming into the Auger platform in the GoM is shown. (Source: Shell)



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ft) deep. Oil from the 100% Shell-owned Cardamom subsea development is piped through the Auger platform, the very same one that was announced in 1989. The Cardamom development includes five subsea wells and—when at full production of 50,000 boe/d—will increase Auger's total production capacity to 130,000 boe/d.

Cardamom is the Auger platform's seventh subsea development since production first started in 1994. Over the years modifications were made to the platform to make the subsea developments possible. The completed subsea system includes five well-expandable manifolds, a dual 18-in. flowline and eight well umbilicals.

The Cardamom reservoir sat undetected by conventional seismic surveys until 2010 when the company used advanced seismic technology to find it. The reservoir sits beneath thick layers of salt in rock more than 6 km (3.7 miles) below the seafloor. An exploratory well was drilled to 9,449 m (31,000 ft) measured depth into the formation and logged 67 m (220 ft) net of oil-bearing Miocene-aged sands, the company's website noted.

The project was green-lighted by the Bureau of Ocean Energy Management, Regulation and Enforcement in February 2011 after the drilling moratorium was lifted in the GoM. It was the first "blue-water well" to receive approval, according to the company.

By using advanced seismic processing on maturing fields to help identify the Cardamom reservoir of Auger and the Boreas and Deimos reservoirs of Mars B, Shell was able to extend the shelf life of its deepwater assets by decades. The ocean is as wide as it is deep, and it houses many secrets, but with industry's ever-growing ability to see with "new eyes," those secrets won't remain buried much longer. **ESP**

Jennifer

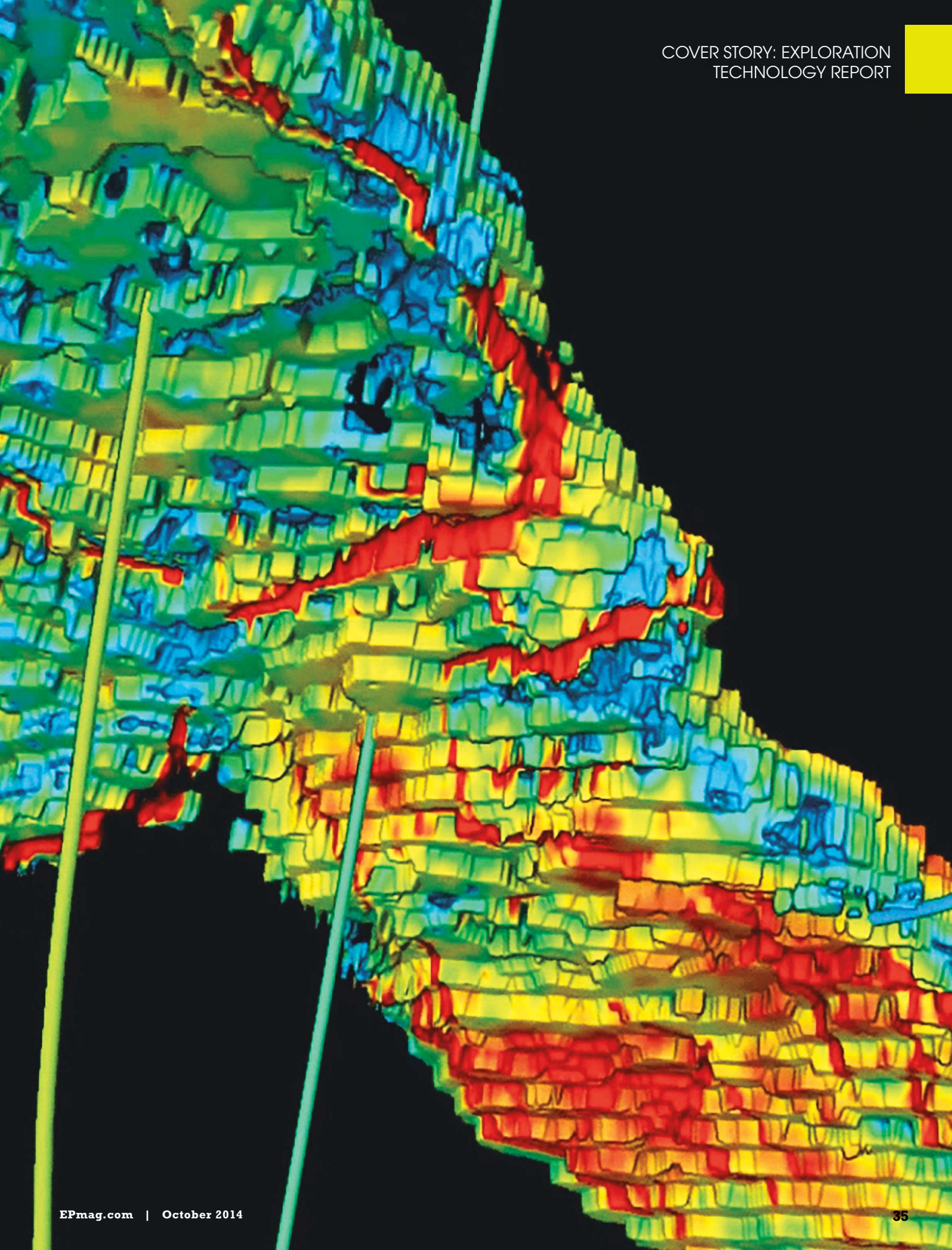
FINDING BURIED TREASURE

Geoscience tools are at the leading edge of one of the world's great detective stories.

Rhonda Duey, Executive Editor

Necessity is the mother of invention, the saying goes, and that adage definitely applies to the upstream oil and gas industry. There was little necessity for exploration technology in the 1800s when some of the first oil wells were drilled. The oil obligingly came to the surface. But by the early 20th century inventive folks began to realize that there were vast reservoirs of oil and gas that weren't nearly so obliging, stubbornly hiding underground.

As a result, new methods of remotely imaging the subsurface were conceived. The first known seismic surveys were conducted by John (Clarence) Karcher and his co-experimenters in Belle Isle, Okla., in 1921, according to Encyclopedia of Earth, and the first electric wireline log was run in 1927 by Conrad and Marcel Schlumberger, according to Schlumberger's website. Fast-forward 90-some years, and the landscape of exploration technology has matured at a phenomenal pace. And it shows no sign of letting up. Whether in data acquisition, processing or interpretation, strides both within and outside of the industry promise to facilitate the necessity of finding oil and gas.



Acquisition

Some of the most impressive strides in recent years have come during the data acquisition phase. And many of these are being driven by other industries.

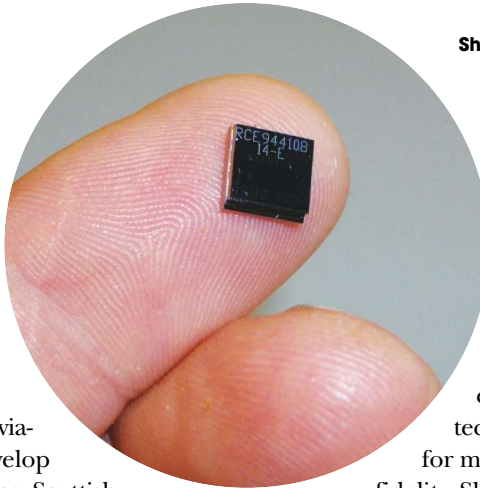
A newcomer on the scene is drone technology. Drones are being examined by the industry today primarily as low-cost and safe inspection alternatives to airplanes and helicopters. But as the Federal Aviation Agency in the U.S. hustles to develop rules governing their use in oil and gas, Scottish researchers already are examining their utility in analyzing remote, inaccessible outcrops of North Sea reservoirs, according to the *Houston Chronicle*.

Drones are not likely to be acquiring “aerial seismic” any time soon, but other airborne measurements such as gravity and magnetics could in theory be acquired this way. Drones also can be useful in characterizing a site prior to beginning operations.

“Before we go out to drill a well, look for a site and shoot seismic in an area, we have to do a fair amount of site inspection,” said Ken Tubman, vice president of Geosciences and Reservoir Engineering for ConocoPhillips. “We can get topography from satellites, but we can also potentially get a much better look with drones.”

Beyond the possibility of providing aerial views and perhaps even subsurface images, the ability for drones to operate in remote environments has HSE implications. Ross Saunders, chief geophysicist for Energy XXI, said that some companies are considering using drones to place and retrieve seismic receivers. “I believe that within 20 years it could easily become something that is an everyday occurrence,” he said.

Already researchers at the Delphi Consortium at Delft University of Technology have introduced the dispersed source array (DSA) concept for simultaneous shooting on land. Rather than using broadband seismic vibrators, which are heavy and expensive, the consortium has experimented with the concept of simulta-



Shell and HP have developed a MEMS sensor that can be used as a geophone. (Source: Shell)

neous shooting with DSAs, producing a larger temporal and spatial bandwidth. The simplicity of these sources could lead to autonomous acquisition, they argue.

According to Dirk Smit, chief scientist, geophysics for Shell, micro-electromechanical systems (MEMS) technology holds considerable promise for miniaturizing geophones without loss in fidelity. Shell has been working on the design of such a system, which has borne interesting results.

“As we all know, it’s not easy to improve on the geophone design,” he said. “It’s a remarkably simple yet very accurate and robust instrument. But we do see that several MEMS solutions have now indeed become superior to what you probably can get with an upgraded analog geophone system, even digital geophone systems. It will start to turn seismic measurements into a commodity.”

While geophysical contractors may wince at these words, Smit argued that additional uses of seismic in the future such as more monitoring of production processes will require more acquisition, both per square kilometer and per unit of time. Hence, the pie will be much larger, but the systems will need to acquire surveys “at a significantly lower cost base,” he said. “And I don’t think any of the technology we have today is able to deliver that except for MEMS technology. It takes a very clean and accurate measurement, in particular at low frequencies, at an ultra-low cost.”

Ultimately, Smit noted, more sophisticated techniques may eventually revolutionize land geophysical acquisition. “I think that subsurface characterization or explo-



A hovering ATMOV prepares to plant a calibration sensor. When flying larger distances, the wing is rotated 90 degrees, allowing high speeds. (Source: Delft University of Technology)

ration will be more driven by more remote-type sensing technologies,” he said. “Perhaps this could be combining more refined measurements of surface expressions affected by climate, biology or geology with probing technologies that can be deployed airborne or on the ground.” These could include techniques like gravity and

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magnetics that probe the surface in addition to surface-based measurements, he added.

“I think that the required sensor technologies will become available because of the use of mobile phones,” he said. “We might be able to monitor subsurface effects by simply (appropriately) using the smartphones of people since they contain all kinds of measurement technologies.”

These developments will be particularly useful in the unconventional arena, he added. He sees the key to global exploitation of unconventional resources as the ability to characterize the subsurface to determine producibility with accurate yet low-cost geosciences technology.

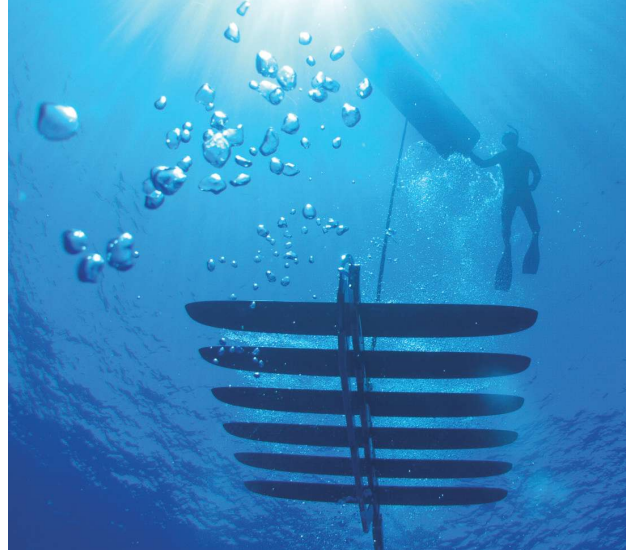
Marine acquisition

Marine seismic also can benefit from the use of different acquisition philosophies. Saudi Aramco has introduced the concept of “RoboNodes” along with CGG and Seabed Geosolutions. These autonomous marine nodes can be programmed to move under water and are controlled by an acoustic system. Their use can solve one of the major issues of underwater nodes—the cost.

The RoboNodes are still under development, but Saunders said that even more traditional forms of seabed acquisition are likely to come down in cost. “There have been some vendor partnerships and alliances recently announced that are going to work together to increase the coverage of nodal data on the [Gulf of Mexico (GoM)] shelf,” he said. “When they get more participants, the price will go down. Just like any new technology, they’re going to achieve greater efficiencies.”

Another relative newcomer on the scene is the Wave Glider developed by Liquid Robotics, which is now a Schlumberger company. These hybrid wave- and solar-powered ocean “robots” are designed to cover vast stretches of ocean without human interference and can be equipped with a variety of sensors to collect weather, currents or even seismic data. In fact, Wave Gliders already have been used in the GoM to collect seismic data, the first time they have been used for that purpose.

Advantages are numerous. These systems can be controlled or pre-programmed to follow a prescribed path and are able to withstand Sea State 8 conditions, which involve waves of up to 14 m (46 ft). They are able to operate in fringe conditions that include low solar or wind environments, and they come with an auxiliary electrical thruster. They can house more than 12 installed payload sensors using up to 24 high-performance payload computers, and they offer plug-and-play payload capability as well as a “data center at sea” that processes large volumes of data and transmits them in



The Wave Glider can be equipped with a variety of sensing equipment, including seismic sensors. (Source: Wave Glider)

real time. Information from Liquid Robotics’ website indicates that Wave Gliders could reduce the cost of a marine seismic survey by as much as 90%.

Tubman said that ConocoPhillips has recently deployed Wave Gliders in experiments to test their utility as data gatherers. “Do we know exactly what we’ll do with them?” he asked. “Maybe not, but for exploration my vision is that we put nodes on them for seismic, and they go off on their own. All of a sudden we have large, randomly distributed quantities of sensors that go in and around facilities in all kinds of ways that we can’t get with our large ships at the moment.”

Other recent advances in marine seismic acquisition are more commercial. For instance, BP tested the concept of wide-azimuth (WAZ) seismic eight years ago, and the concept has caught on quickly since then. WAZ involves shooting a survey from multiple angles to provide better, more geometrical illumination of the subsurface.

Tubman was working for Veritas at the time that BP proposed the survey. “I give BP credit,” he said. “Together we worked it out, and it made a big difference.”

Saunders and his company were involved in the first WAZ survey on the GoM shelf, partnering in the Main Pass area with operator Apache Corp. and Fieldwood. He said that Fairfield Nodal shot an ocean-bottom nodal survey over about 100 blocks.

“We’re in the processing stage now,” he said. “We’ll be able to get a first look at some of that data soon. Early indications are that it will be a step-change in data quality. It’s exciting to not just read about it but to be a participant.”

Original WAZ configurations have been tweaked over the years to include full azimuth, rich azimuth, multi-azimuth and coil-shooting full azimuth, the latter developed by WesternGeco. The coil-shooting technique allows the recording vessel to record continuously by traveling in circles rather than straight lines, according to Schlumberger’s website. The methodology offers advantages over traditional WAZ surveys because it requires only one vessel.



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More recently the concept of broadband acquisition has come on the scene. Useful in both land and marine environments, broadband seismic records the full range of frequencies in a survey, according to CCG's website.

"High-fidelity, low-frequency data provide deeper penetration for the clear imaging of deep targets as well as providing greater stability in inversion," the website notes. "Inversion of broadband data has been shown to provide better well ties, better correlation to geology and better resolution than inversion of conventional data."

Smit said that Shell started looking into broadband (low-frequency) acquisition in 2004 or so, developing a research consortium with PGS to improve processing. It was not the first of its kind—several universities had already started evaluating the possibility of incorporating lower frequencies.

"But as soon as an oil major is involved in the early derisking or development of these technologies, a lot more credibility and robustness is derived from that," Smit said.

Processing

All of the great acquisition technology in the world is of little use if computers can't process these huge amounts of data in a timely and useful fashion. Luckily for explorationists, computers are finally up to the task. "A lot of this theory was done in the '50s," Tubman said. "It's only recently that the compute power has caught up."

One by one these theories have turned into commercially available algorithms, from amplitude vs. offset and prestack depth migration in the '90s to reverse time migration (RTM) and, very recently, full waveform inversion (FWI). According to Schlumberger's website, FWI uses a two-way wave equation to produce high-resolution velocity models. "It performs forward modeling to compute the differences between the acquired seismic and the current model as well as a process similar to [RTM] of the residual dataset to compute a gradient volume and to update the velocity model," the website notes.

Energy XXI is analyzing the benefits of RTM and FWI, Saunders commented, explaining the benefits of the FWI

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process. “All prestack depth migration algorithms are based on mathematical approximations of the solution of the wave equation, which describes seismic wave propagation from the surface down to target horizons and then back up to the surface where they are recorded,” he said. “In the past, due to limitations in computer hardware, we were mainly using approximations of the wave equation called ray tracing.” With recent advancements in both compute power and seismic data quality, Saunders said, the industry has been switching to algorithms that are directly using the wave equation rather than its approximations. “This started by using RTM that is based on subsurface propagation and correlation of full wavefronts,” he added. “We are now progressing to use RTM as the basis for velocity estimation using FWI. The process is based on minimizing the difference between the full recorded wavefield and the simulated wavefield generated for each trial model. By doing that, we construct much more accurate velocity models, necessary for reliable imaging of our exploration objectives.”

Smit added that processing algorithms like FWI have come along just in time for acquisition techniques like broadband and WAZ. “When you see the types of data you can access through wide azimuth or broadband or both, you realize that techniques like waveform inversion may be very beneficial,” he said. “Before that, a lot of the waveform inversion techniques may have been contemplated in academics but never really had an impact on the industry simply because the seismic spectrum wasn’t available to stabilize a lot of the inversion that is hidden in the full-waveform inversion technique.

“You could argue that the uptake of these imaging algorithms is always following advances made in seismic data quality from the acquisition systems.”

Tubman added that many acquisition breakthroughs have resulted in more data to sift through. “Because we have the opportunity to collect so much data, we can’t actually look at them,” he said. “We talk about going from thousands of channels to tens of thousands of channels. How are we going to deal with that? It may be



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that some of these algorithms let us cross things out that we're just not sure about yet."

Interpretation

Seismic processing has increasingly involved the use of

human intuition; seismic interpretation has relied on it all along. But there are techniques afoot that attempt to replace the human brain with computer science to arrive at better results in a more efficient fashion.

Geophysical Insights has recently introduced Paradise, a geoscience analysis platform that uses pattern recognition methods such as self-organizing maps (SOMs) and principal component analysis (PCA). These techniques, according to the company, allow interpreters to scan large volumes to reveal anomalies, discriminate the presence of hydrocarbons and direct hydrocarbon indicators, reveal geologic and stratigraphic features, and identify changes in pore pressure.

"I think this kind of technology has the potential to really make some great gains," said Saunders. "I like the concept because it's a nonbiased application, which means it doesn't have to depend on an interpreter giving it certain parameters to run the neural network routine. So the results aren't biased by well information.

"But it's still in its infancy, so I think maybe once the methods are shown and start to deliver reliable and repeatable results, we might see things being used like that more commonly."

The current scalable, client-server architecture enables independent or collaborative workflows, according to Geophysical Insights. It guides interpreters in the application of SOMs and PCA.

An older but still highly useful technology is visualization. This technology is intended to immerse interpreters in their data, enabling them to view them in a more immersive and collaborative sense. More recent advances in visualization technology include holography, a technique that more accurately captures the three-dimensional aspect of a certain image. Saunders thinks the use of holography in exploration will continue to expand.

"Within 20 years I think holography and holographic imaging could very well be commonplace," he said. "I think



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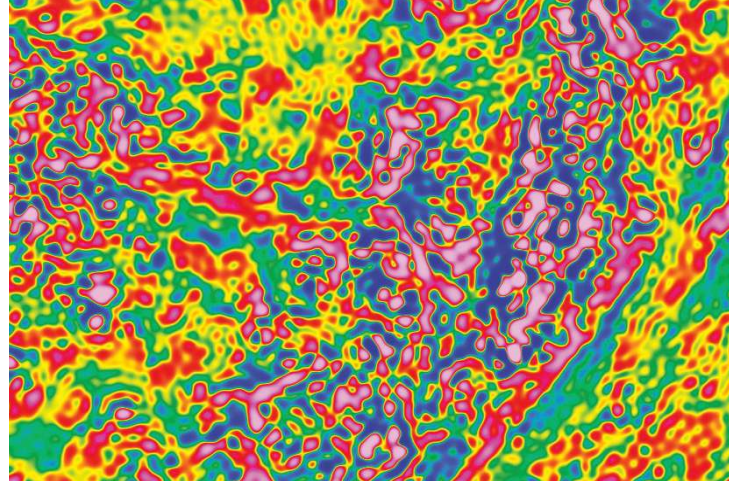
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that's certainly one that could go from science fiction to everyday use."

Another newcomer on the scene is quantitative interpretation (QI). According to DownUnder Geosolutions' website, QI uses amplitude analysis to predict lithology and fluid content in between wellbores. "This process should make use of all available data, assist in risk assessment, account for uncertainty and ultimately foster confidence in the predictions," the site notes. The process relies on seismic inversion and rock physics analysis to quantify reservoir conditions.

While quantification is good, there is still something to be said for good old-fashioned human interaction. But even this might be more automated than is currently practicable. "I think the real breakthrough is continued pushes on integration," Tubman said. "Integration is a holy grail. We're getting better at it, but we're not there yet.

"Part of the way we've made big advances in imaging in the past is by combining the geologic model and driving the imaging with that. But there are other opportunities



This image shows the filtered first derivative of Appalachian Basin magnetic data. (Source: NEOS GeoSolutions)

for integration—for instance, to have a model that will cycle back as we monitor the reservoirs."

Added Smit, "I think that the expert effort is not necessary at every step of the process. But it can be done with other people and only at a few points really needs expert knowledge and insight.

"On the other hand, this could be accelerated so that the decision-making can be sped up rather than slowed down and so that we can make decisions that we can only dream of today." **ESP**

BEDB
BRUNEI DARUSSALAM

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THE BRUNEI ECONOMIC DEVELOPMENT BOARD

Open Invitation for Proposals to Invest, Build and Operate an Integrated Marine Supply Base in Brunei Darussalam

REF NO: RFP 14 02 00

The Brunei Economic Development Board (BEDB), in collaboration with the Energy Department, Prime Minister's Office (EDPMO) intends to develop an Integrated Marine Supply Base (IMSB) in Brunei Darussalam to support the local and regional needs of the oil and gas industry.

In this context, the BEDB invites interested parties to submit their Expression of Interest (EOI) to design, build, finance and operate an IMSB that will be the dedicated onshore logistics base for all oil and gas activities in the Muara and Serasa areas.

Who should register?

Interested parties may be an individual company or consortium with experience and proven track record in the design, build, finance and operations of an IMSB. *At the minimum, the company must have at least 3 years of management and operating experience of a supply base or marine terminal facility in support of the oil and gas industry.*

To register an expression of interest (EOI), interested parties should send an email to RFP@bedb.com.bn

with subject heading, "**Expression of Interest to Design, Build, Finance and Operate an IMSB**" upon which they will be provided with EOI forms for completion and submission.

Upon conclusion of the EOI period, interested parties will be short-listed and successful candidates will be invited to conduct due diligence and submit detailed proposals under the subsequent Request For Proposals (RFP) stage. Once shortlisted candidates have submitted a signed Non-Disclosure Agreement (NDA), a RFP document containing more information on the investment opportunity will be provided.

Completed EOI forms should be submitted no later than **3pm on 27 October 2014**. Late submissions will not be entertained.

For all correspondence, please contact:

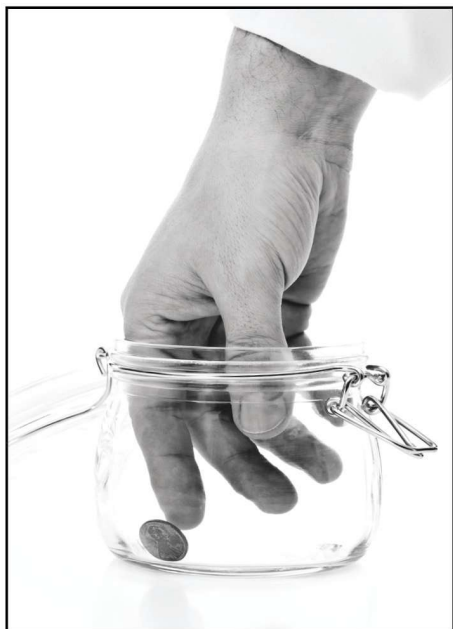
RFP Secretariat

The Brunei Economic Development Board
Block 2D, Jalan Kumbang Pasang
Bandar Seri Begawan, BA 1311
Negara Brunei Darussalam
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Facsimile: +673 223 0074
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NOTE: This advertisement does not constitute an offer from the BEDB and shall be subject to terms and conditions contained in the RFP Documents. The BEDB is under no obligation to respond to any enquires it receives and reserved the right not to follow up on any submission at its sole discretion without explanation.

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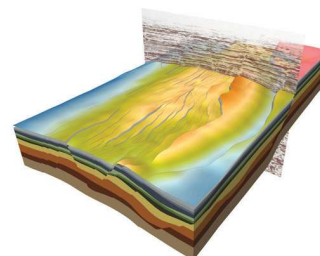


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Bringing seismic ideas to acoustic logging

A new methodology creates a new processing technique for acoustic logging.

Partha Biswas and Shreya Ley, GeoBiz Technology Inc.

As the oil and gas industry transitions to a dependence on the more costly unconventional reservoirs, operators strive to find new and more efficient ways to produce from those reservoirs. There has been much focus on drilling and hydraulic fracturing technologies, but what about identifying natural fractures? Natural fractures exist in the producing zones, and only about 20% of the fracked area actually produces. If the industry was better able to identify the naturally fractured zones, it would be able to focus on that 20%.

Currently, the industry uses acoustic logging or imaging to infer or find fractured zones. Unfortunately, however, the move to unconventional reservoirs has brought shortcomings in those techniques to the forefront. For images, widespread use of oil-based mud and the common practice of drilling high-angle wells render image data mostly unusable. For shear wave anisotropy, fractures are simply inferred and, for many reasons, that inference cannot be relied on, particularly in unconventional reservoirs. Perhaps imaging and shear wave anisotropy need to make way for different processing techniques.

Furthermore, present-day tools are only able to detect anisotropy when logged sections are more than 5% anisotropic, leaving the subtle fracture systems undetected. For this last issue, the industry needs to look no farther than seismic and microseismic techniques for guidance. Due to issues with signal attenuation and a high signal-to-noise (S/N) ratio, seismic has long used techniques such as stacking to improve results and amplify anomalies.

A new methodology adopts techniques from seismic and microseismic to provide useful and informative results on fractures, creating a new processing technique for acoustic logging.

Current limitations

Current techniques such as shear wave anisotropy and imaging still have applications in certain situations. However, they each have limitations. Fractures are

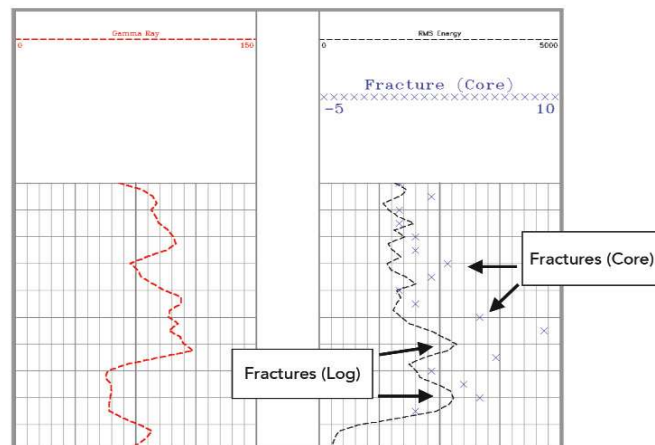
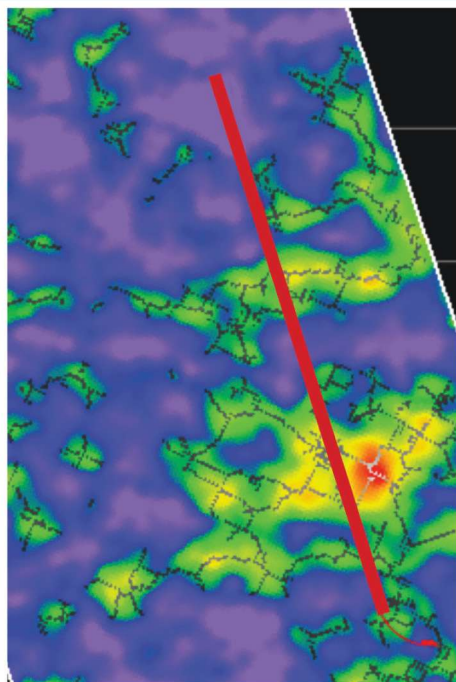


FIGURE 1. RMS energy distribution (right) across a fractured interval indicates where fractures coincide with a sharp drop in energy. (Source: GeoBiz Technology Inc.)

anisotropic, so shear wave splitting can be an indication of fractures in subterranean formations; however, not all anisotropic formations are fractures. Therefore, use of shear wave anisotropy is not so much a definitive indicator of fractures but a definitive indicator of anisotropic formations. Those formations may be fractures but may alternatively be other anisotropic or seemingly anisotropic formations. Furthermore, fractures, though anisotropic, can also exist in mildly anisotropic formations that cannot be detected by the present-day tools using current methods since it is difficult to distinguish the subtle fracture patterns from the surrounding anisotropic media using shear waves. Since fracture detection is the ultimate goal, given that fracture patterns indicate producing areas, a move toward a technique that actually identifies fractures as opposed to simply inferring fractures is logical.

The processing technique created by GeoBiz Technology Inc. allows the industry to move toward a more direct method of characterizing fractures since shear wave anisotropy does not allow direct fracture detection. Although several industry tools, including LWD tools, collect sectorized compressional (P) waves, there has been little to no use for them in acoustic logging. However, looking at seismic research, work has been done to

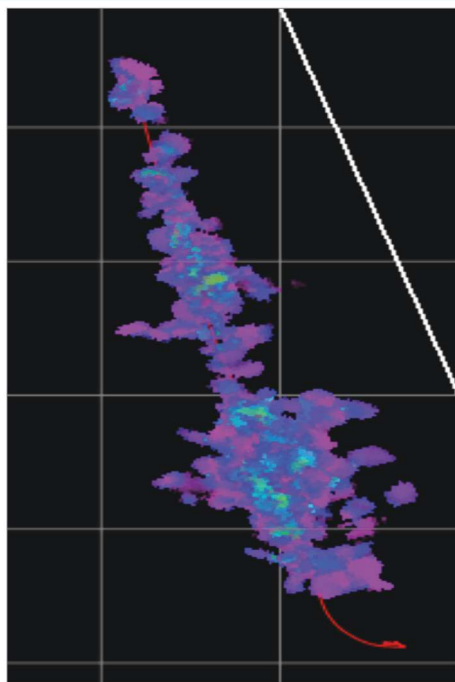
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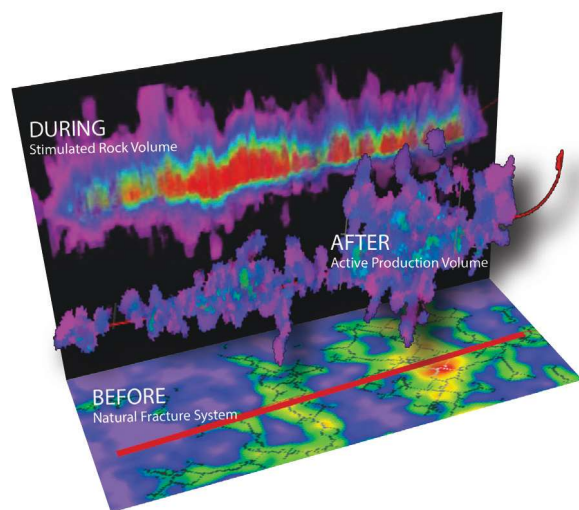
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find fractures using P waves. Adapting the research that has been done to acoustic logging allows the industry to characterize fractures using P waves. Since tools already exist that collect necessary data, only the processing technique needed to be developed. The theory used to

develop the GeoBiz processing technique is based on the theory that, across an open fracture, P waves show a significant drop in energy. By mapping this drop in energy, fracture location and azimuth can be calculated. This technique has been tested in a number of wells and compared against core results. Test results show a match of approximately 90% between core data and log data in both fractured and unfractured intervals (Figures 1 and 2).

Elements of characterization

As noted, some tools already exist that collect sectorized P waves. The use of these sectorized waves is key in fracture characterization. The use of sectorized waves allows mapping the waveforms in a manner similar to what is currently done with shear waves but with modified algorithms. The use of raw, sectorized P waves is one of three key elements in the characterization method.

Although not mentioned in most publications, root mean square (RMS) normalization is essential not only in processing sectorized P waveforms but also in shear wave anisotropy. In both anisotropy and the new fracture detection method, four quadrants must be combined to compute RMS energies from 0 to 90 degrees. To combine these four quadrants without normalization, it must be assumed that the raw RMS energy output from all four quadrants is matched, which is unlikely and unrealistic. Therefore, the RMS energy must be normalized prior to combining.

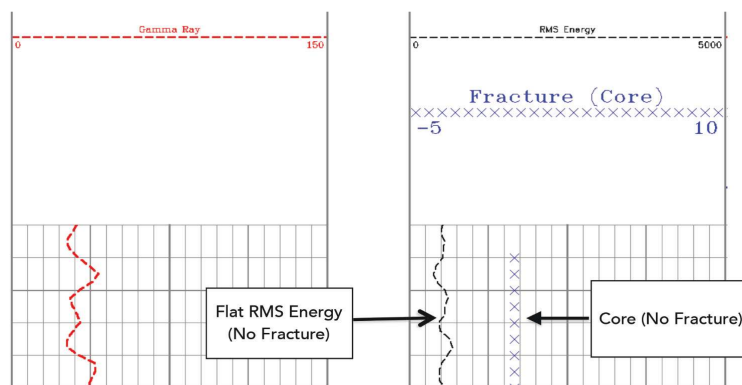


FIGURE 2. Across an unfractured section RMS energies show little variation (right). (Source: GeoBiz Technology Inc.)

acoustic logging tools. Improving this ratio again requires the adaptation of seismic techniques. In seismic data acquisition, stacking of data gathers is routine. Until now, acoustic logging has found stacking techniques unnecessary. However, to find natural fractures, which are the defining characteristic in a productive unconventional reservoir, the S/N ratio must be improved using a modified stacking technique. GeoBiz has developed software to efficiently stack data gathers, allowing the delivery of results within the time restric-

tions of operators in the field. For a tool with 13 receivers, a 52-fold stack can be achieved. Stacking has led to a significant improvement in the S/N ratio, enabling more confidence in identifying subtle variations in amplitude. This is the third key element to the characterization method.

Fracture pattern characterization

In addition, the method allows not only the identification of fractures but also the full characterization of the fracture patterns. Tests show the azimuth of fractures seen by both the imaging tool and the sectorized P tool match well (Figure 3).

In summary, the use of sectorized P waves to map energy in the formations, RMS normalization to achieve amplitude independence and stacking of data gathers to increase the S/N ratio show remarkable accuracy when compared to core results in a shale play for both fracture identification and finding the azimuth of fractures. **ESP**

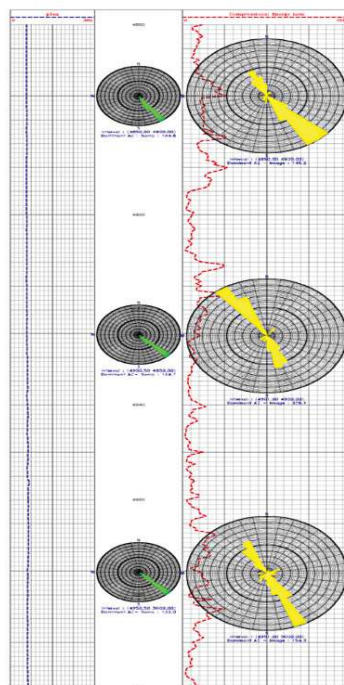


FIGURE 3. The azimuth of fractures seen by the imaging tool match well with the azimuths seen in the sectorized P tool. (Source: GeoBiz Technology Inc.)

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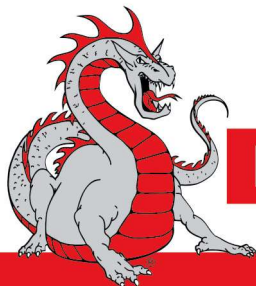
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Resolving subsurface velocities with FWI

Full-waveform inversion is becoming a practical and important technology for determining seismic velocities.

Sverre Brandsberg-Dahl, PGS

Full-waveform inversion (FWI) was introduced to the field of exploration seismology in the early '80s by Albert Tarantola. However, it is only recently that FWI has entered the mainstream of seismic imaging and become the preferred tool for estimating complex velocity distributions. In his groundbreaking work, Tarantola laid out the theoretical foundation for FWI, and now, almost 30 years later, little of this has changed except for what one could call a revolution around the practical implementation aspects of the technology.

The key idea behind FWI is a data-space matching, where the objective is to match synthetic/ modeled data to the data recorded in the field. As FWI inherently is a nonlinear problem, the solution is pursued in an iterative manner, where the data misfit or data residual is added (in a smart way) to the starting velocity model that was used to create the synthetics, creating an updated velocity model that yields synthetic data that more closely match the field recordings. This data-driven

approach holds the promise of being a highly automated way of estimating velocities where, given the right data, one could directly recover an estimate of the velocity distribution in the subsurface. This velocity model could then be used to create accurate images of the subsurface, even in regions with very complex geology and velocity distributions that have normally challenged seismic imaging technology.

So why has it taken this long for the technology to mature? The key factors have been access to sufficient compute power and appropriate seismic data that support the assumptions behind FWI. Access to faster central processing units and larger compute clusters have enabled 3-D implementation of FWI that was needed to make it relevant for oil and gas exploration. Further, for 3-D marine seismic, the introduction of longer offsets (in excess of 8,000 m [26,247 ft]) and more recently the introduction of broadband seismic have enabled the recording of data with long offsets and low frequencies—data that are much better suited for FWI than the typical legacy marine dataset.

With access to modern marine seismic data and large, fast computers, FWI is now finally starting to live up to its promise as introduced in the '80s. Today it does indeed offer a highly automated path to derive accurate velocity models for seismic imaging. The velocity models provided by FWI are improving the resolution and accuracy of seismic imaging and are often even serving as a useful attribute on their own.

FWI methodology

FWI is applied in an iterative manner to simplify the treatment of what is inherently a problem of wave propagation as a nonlinear function of earth parameters. The details for application of FWI by reverse time migration are well known throughout the industry; they basically involve shot records that are modeled by the two-way wave equation and data residuals (the difference between the modeled and recorded data, as shown in Figure 1) that are back-propagated to form a subsurface image. The cumulative image from all shots is then mapped into a spatial distribution for the velocity perturbation that is used to

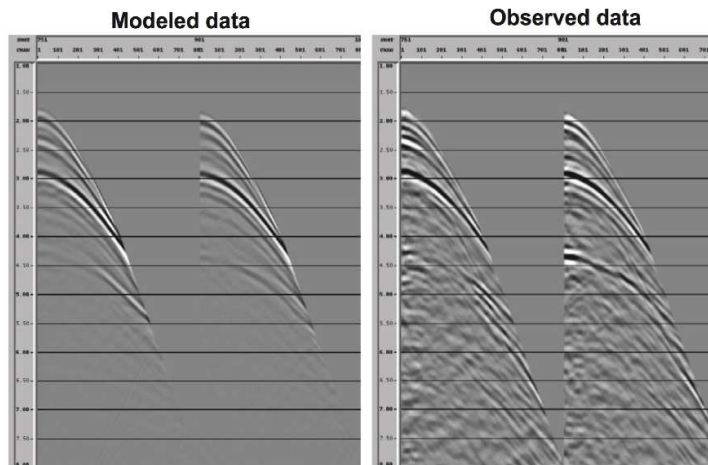


FIGURE 1. This figure illustrates the data misfit used in FWI. The modeled data on the left can be compared to the actual field data on the right, something that in practice is done inside the FWI objective function. (Source: PGS)



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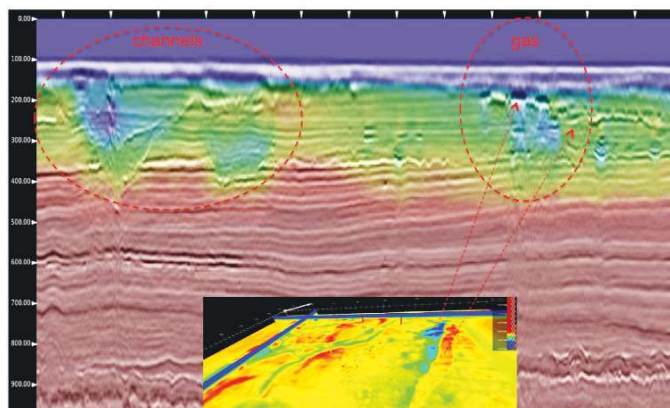


FIGURE 2. This illustration shows the high-fidelity velocity models that can be derived by FWI in a shallow-water setting when sufficient offsets and low-frequency data are available. This example from the Johan Sverdrup Field in the southern North Sea shows how both shallow channels and shallow gas accumulations are recovered using a GeoStreamer dataset acquired in 2009. The maximum offset in the data was 6,000 m (19,685 ft). (Source: PGS)

update the starting model. The above process is repeated until the data residual for all the shots (objective function) satisfies a convergence criterion.

The objective function for nonlinear problems typically has many minima, although only one minimum corresponds to the desired (global) solution. Practical inversion strategies thus incorporate procedures for inverting successive subsets of the data to guide the solution as closely as possible to the global minimum. Because a given starting model represents a smoothed representation of the desired solution, these procedures attempt to inject the longest possible wavelengths (smallest wavenumbers) in the early stages of an inversion and successively larger wavenumbers in the later stages.

Diving waves, refractions and reflections each possess different capabilities for improving the resolution of a model. Diving waves and refractions can update the velocity model anywhere between the water bottom and their turning point in the subsurface. In a given velocity regime, the depth sampled by the refractions is typically increasing as a function of longer offsets, hence the need for long offsets in the data. As a natural consequence, shallow water provides the best environment for exploiting such data for FWI. In deepwater, where diving waves and refractions may not be present, there is no alternative but to use reflections. Under these circumstances, it can be fruitful to treat the image of the residuals as a perturbation in reflectivity.

In summary, band-limited data are inverted with the lowest frequencies first because the lowest frequencies

provide the most linear behavior. The lower the frequencies present in the data, the better the inversion result will be. This is where broadband seismic is making key contributions to the field of FWI. The lowest wavenumbers are selectively inverted first by picking a mute above the first breaks and then applying a time taper to window just the leading edge of the first arrivals. The length of the taper is extended for later inversion stages, which has the effect of accommodating higher wavenumbers.

Examples

An application of FWI following the strategy outlined above is shown in Figure 2. In this North Sea example, shallow velocity anomalies are beautifully recovered and help improve the overall quality of the seismic image. Here, the presence of long offsets and low frequencies in the data help provide an FWI velocity model that solved an outstanding issue of accurately determining the near-surface velocities. The area just beneath the seafloor is complicated due to the presence of channels, shale bodies and gas accumulations, all of which are resolved spatially and in magnitude by FWI.

To assess the accuracy of lateral resolution exhibited in the FWI model, a depth slice from the PSDM image volume is displayed with the inverted velocity model overlain in Figure 3. The high-resolution velocity updates introduced by FWI correlate very well with the channels and other features shown in the PSDM image. From this depth slice the fast and slow channels in the sediments can be identified.

For inversion depths below the deepest turning point of any available diving waves and refractions, the avail-

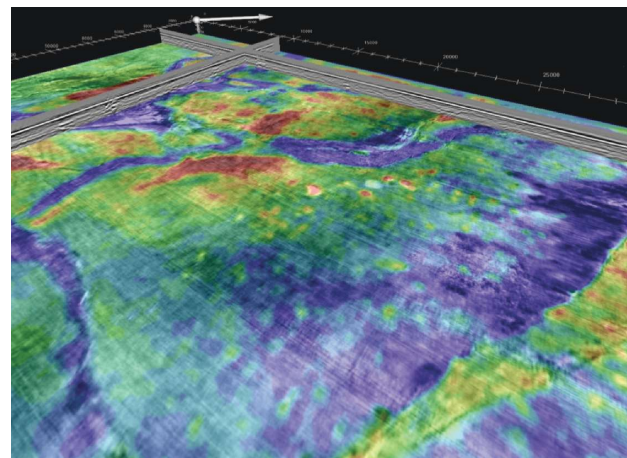


FIGURE 3. FWI velocities with seismic overlay show how the FWI velocity recovers the velocity variations associated with shallow channels. (Source: PGS)

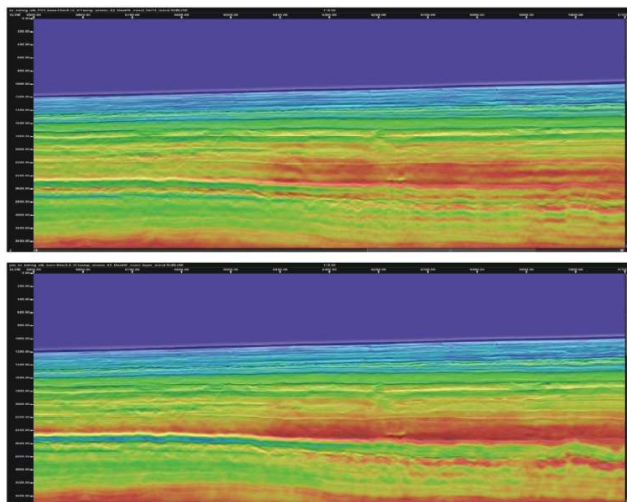
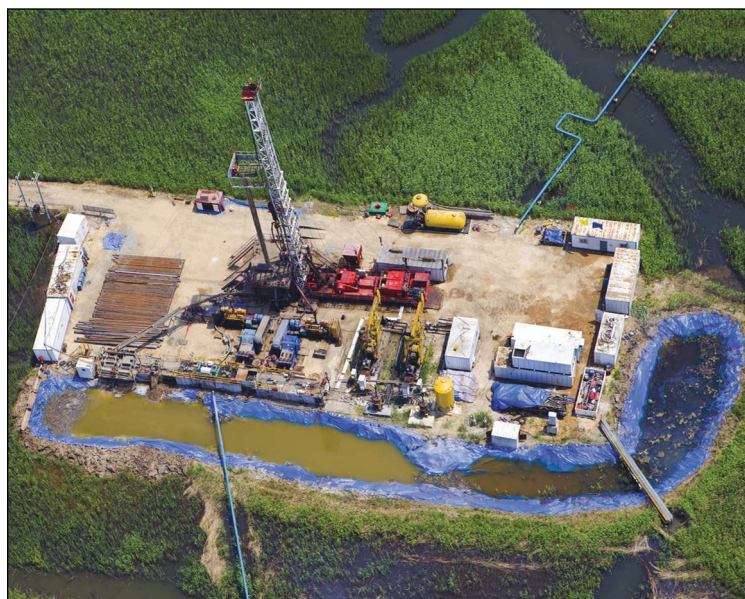


FIGURE 4. The importance of low frequencies in the seismic data used for FWI is illustrated in this deepwater example. When the low frequencies are not present in the field data, as shown in the top image, the resulting FWI update gets degraded and 'ringy.' With proper broadband data the velocity variations can be recovered with depth as shown in the bottom part of the figure. (Source: PGS)

ability of low frequencies becomes the key to successful use of FWI. Without the presence of low frequencies, low wavenumbers will be missed, resulting in an inversion result with a "ringy" appearance. In Figure 4, broadband data provide a rich low-end data spectrum that is well suited for FWI. The velocity model resulting from applying FWI to these data is geologically consistent and lacks the "ringy" and erroneous features shown in the model when FWI was applied to data lacking in low frequency.

The power of FWI

Powered by recent advances in compute power and seismic data acquisition, FWI is now emerging as a practical and important technology for determining seismic velocities. Through advanced 3-D modeling and aided by modern broadband data such as those recorded with PGS GeoStreamer technology, the power of FWI is finally available for application to the most challenging exploration problems being faced today. **E&P**



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Fire suppression systems protect valuable assets

Automated system guards vehicles from catastrophe.

Ken Daniels, AFEX

Fire is the worst thing that can happen to an oil and natural gas operations site. All of the time, effort and resources dedicated to a well pad can literally go up in smoke in minutes, as was the case recently in Monroe County, Ohio. In this instance there were thankfully no injuries, but there was a total loss of surface equipment (which estimates put at tens of millions of dollars), a temporary evacuation of local residents and a fish kill in a nearby river that is being investigated for ties to the fire. Thus far the Environmental Protection Agency, the Ohio Environmental Protection Agency and the Ohio Department of Natural Resources have been involved in the investigation process.

The fire at the Eisenbarth property was so hot that first responders had to fall back and allow the flames to die down before they could mount a successful firefighting effort. Clearly, site personnel were not able to fight the fire themselves. Even if they could have maneuvered into position quickly enough, which is questionable, they would not have had enough firefighting agent on hand with only handheld portable extinguishers at their disposal. (Once the fire became established, tankers filled with water from a nearby river had to be brought to the site in support.) But even if they had the resources, the dangerous nature of a congested fracking spread makes it inadvisable for anyone other than a trained professional firefighter to make the attempt. Fortunately, the wells themselves were not involved in this instance. Had they been, the entire situation likely would have been far worse, as other thermal events over the years have shown. Even so, with just the surface equipment involved, eight regional fire departments were needed to fight the conflagration.

Fire suppression systems

The well's operating company has stated on its website that the fire was caused by a "mechanical problem with hydraulic tubing." This explanation strongly suggests that it was the result of a compromised hydraulic fluid line spraying atomized liquid onto a hot machine surface. This is known to be the single most common cause

of fires on mobile heavy equipment within the mining industry, which uses engines of similar type and size as those used on hydraulic fracturing equipment. This sort of fire is not at all unusual in mining, which is a major reason why the industry embraced the use of vehicle fire suppression systems more than 20 years ago.

A vehicle fire suppression system is a pre-engineered safety accessory that is permanently mounted to a piece of mobile equipment. Its sensors automatically actuate the system whenever temperatures are reached indicating fire; its nozzles are positioned to attack fires at the most common starting points. This means that the vehicle is protected at all times whether supervised or not, which is important when considering the long hours that industrial equipment is typically run. Advanced systems are designed for remote-controlled firing. This is a desirable feature due to the tight quarters typical of a site being hydraulically fractured as it keeps personnel from having to move toward a burning vehicle to actuate the manual override on the system.

Once a system is activated, the machine's engine can be set to automatically shut down. This keeps additional fluids from being pumped onto the fire as well as stops any cooling fans, which otherwise might encourage a blaze. This is a critical step in suppressing a vehicle fire.

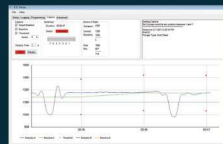
Generally, vehicle fire suppression is designed to combat a fire as quickly as possible. Accordingly, the material most commonly used in systems is an A:B:C dry chemical powder that features a very fast knockdown, which essentially chokes the fire before it can become fully engaged. In addition, a liquid firefighting agent can be used that will cool hot surfaces as well as suppress flame, which significantly reduces the risk of a fire reflash. A dual-agent system that uses both dry and liquid agents would be appropriate for a hydraulic fracturing application since these vehicles have very large engines with many hot surfaces and large volumes of highly flammable liquids and materials.

Other considerations would include that the system used be robust and purpose-built for heavy equipment and that its manufacturer be experienced with demanding work environments. Take public transportation buses as an example. They use fire suppression systems,

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but the light-duty products appropriate for them are not rugged enough to withstand the rigors of long hours of operation at high temperatures, constant vibration, and significant flexing and twisting of the platform. These factors all impact a fire suppression system's components over time, which is why they need to be as sturdy as possible.

Other industries besides mining have fully embraced rugged vehicle systems as well, going back 50 years to when the technology got its start. The forestry and solid waste industries are traditional users, as are the military, paper mills and steel mills. Also protected are chippers and grinders in the wood processing arena, which are the closest match to fracking trucks since they have similar chassis and use very large, powerful engines that run hot.

Use in onshore environments

Within the oil and gas industry, fire suppression on offshore rigs is known to be serious business. But this attitude toward land-based mobile equipment, despite all the known risks, has yet to be widely adopted. However, there is a growing sense across the industry that this is about to change as original equipment manufacturers and end users alike are engaging in conversations about the value of vehicle fire suppression systems. Incidents like the one referenced above are understandably accelerating the process.

The downside of fracking equipment fires is so severe that all stakeholders surely must agree that doing everything possible to mitigate them is desirable. Besides the exceedingly high cost of replacing burned equipment, there is the loss of profits from the lost fleet to consider. And a service provider must take into account the potential impact any fires will have on its ability to secure future business.

Whether it be in actual dollars spent or in the form of damage done to a company's reputation, crisis management has significant costs also. This past February, when a company provided free pizza vouchers to those impacted by its four-day-long well fire near Bobtown, Pa., the overall reaction was largely one of derision. This obviously was not the intention of the outreach program, but there are bound to be negative responses to any public relations campaigns, no matter how well-



Fire suppression systems make particularly good sense in fracking operations. (Source: AFEX)

meaning, in a climate that has such a vocal anti-fracking contingent. Prevention is therefore the best proactive strategy when managing such a volatile topic in the court of public opinion.

Safeguarding personnel and the environment, protecting investments made in expensive machines, and keeping profits flowing are all valid reasons for investing in fire suppression systems. On top of these, mitigating bad publicity is another factor to consider. And finally, as an industry under the microscope of constant scrutiny where the slightest slip-up is amplified, no company wants to be in the position of being accused of having been able to do more to avert a tragedy. **E&P**



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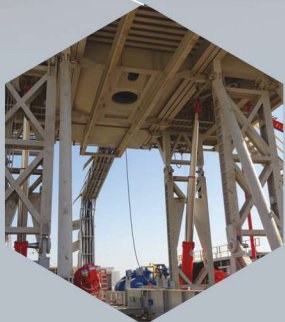
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Driving greater efficiencies in produced water clarification

New technologies increase operational efficiency while ensuring sustainability.

Chuck Martin and Steve Hoyles, Dow Oil, Gas & Mining

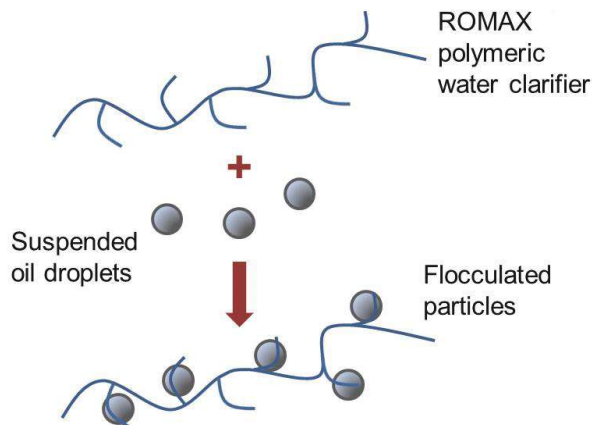
As “easy oil” from traditional wells becomes depleted over time, the oil and gas industry has looked toward other more aggressive methods of meeting the world’s energy requirements. Production and extraction from unconventional oil sources provides new recovery opportunities—for example, 10% of estimated oil resources are in shale or tight formations, according to the U.S. Energy Information Administration—but this also results in unique field challenges. The continued development of advanced technologies and chemistries is necessary to enhance operational efficiency and capture valuable hydrocarbons while at the same time meeting economic incentives and environmental obligations.

The oil and gas production process is water-intensive. In fact, by volume water production represents approximately 98% of the nonenergy-related waste produced by the oil and gas industry, yielding about 77 Bbbl of water per year worldwide, according to Argonne National Laboratory. However, with the United Nations anticipating that world population will grow from 7 billion in 2011 to more than 9.5 billion by 2050, profound stress has been placed on the world’s limited water supply, not only by its burgeoning population but by other issues such as rapid urbanization, industrialization, pollution and climate change.

Limited freshwater supplies are driving the industry to seek improved solutions for reducing oil in water prior to discharge and to employ reuse schemes in water-intensive activities such as boilers and direct injection for EOR processes.

Convergence between oil and water

As oil and gas exploration continues to expand, so have water management challenges associated with onshore and offshore operations. Water management decisions within oil production fall into three primary categories: water acquisition, water utilization within operations and the disposal of wastewater from drilling and production. A typical petroleum reservoir or well is able to extract about 10% to 15% of oil during primary recovery in



Water clarifiers are used after demulsifiers to further separate oil from water. (Source: Dow Oil, Gas & Mining)

which hydrocarbons rise to the surface without employing extensive pumping. During secondary recovery, operators are able to extract additional hydrocarbons through the process of water injection, in which water is injected into the reservoir at high pressures to effectively stimulate additional oil recovery to the surface. This industry practice typically allows an additional 20% to 30% of oil to be recovered throughout the life of the well, but not without challenges.

During crude oil production, a mixture of formation water and oil is recovered. Once oil has been separated from this water mixture, produced water remains. Produced water can contain high amounts of salts, solids and organics such as benzene, toluene, ethylbenzene and xylene along with residual oil. In some cases, produced water undergoes chemical and mechanical treatment to separate contaminants and oil from the water so that crude oil can be sent for refining and treated water can be reinjected, disposed or reused. However, the removal of solids from produced water is challenging due to its widely varying characteristics, which depend on location and formation geochemistry, among other considerations.

Technology advancements promote water reuse

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gies to reduce costs, increase uptime and protect downstream assets. Consequently, advanced water systems and chemistries can provide an economic advantage while addressing strict environmental regulations to meet oil and grease specifications on discharged water. Releasing even a small quantity of oil back into the environment through produced water can quickly add up, negatively impacting an operator's bottom line and raising a red flag to environmental regulators. Water reuse is widely seen as a potential means of reducing the impact on local water resources, particularly in areas where water is relatively scarce.

Despite the quantities of water needed in oil recovery, there is no reason that the water used in oil and gas production needs to be dependent on freshwater assets. Water to support oil and gas production can come from a variety of sources, including fresh or brackish water from surface or groundwater withdrawal, treated industrial or municipal wastewaters, and recycled produced water.

While operators must take vigilant steps to ensure that specific water chemistry is compatible with any given reser-

voir, the trend of water reuse underscores the importance of using effective filtration technology and clarifying chemistry as a means to promote sustainable industry practices and reduce operating costs. Recycling not only supplies oil and gas operators with large amounts of water for reuse in secondary oil recovery and well drilling, among other uses, but also reduces the need for long-range trucking of makeup water to the well pad and subsequent wastewaters to remote disposal facilities. Advancements in technology allow the reduction of wastewater requiring disposal and increased recycling of water recovered from producing oil and gas wells.

Aqueous-based chemistry

Environmental concerns are clear: We must value and respect the scarcity of water as one of our most precious natural resources. Numerous technologies are available today to enable complete or tailored removal of ionic, organic and particulate contaminants from source waters for injection or produced waters for discharge.

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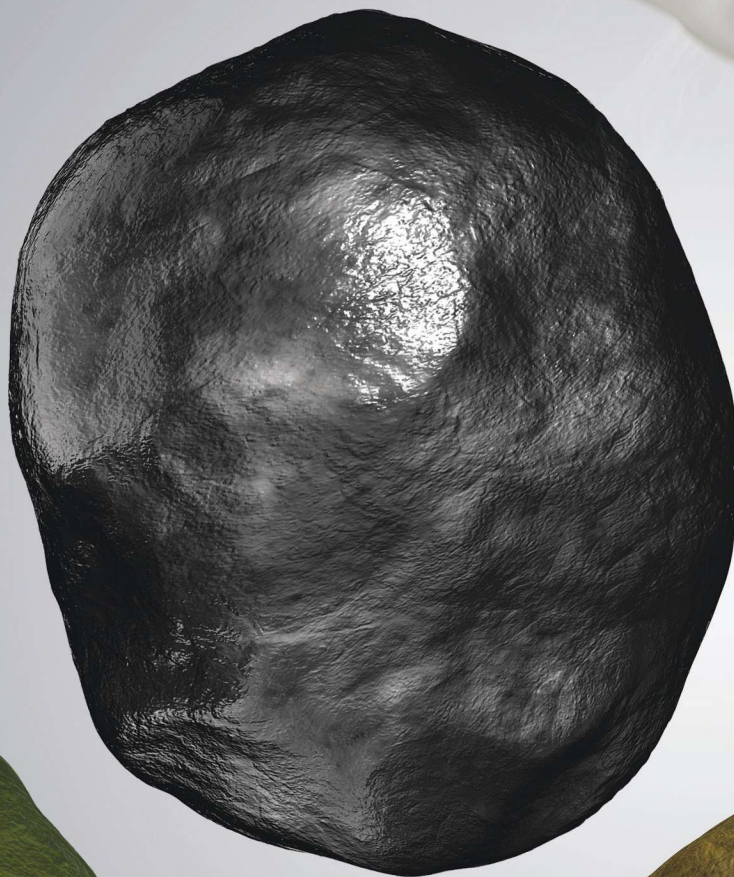
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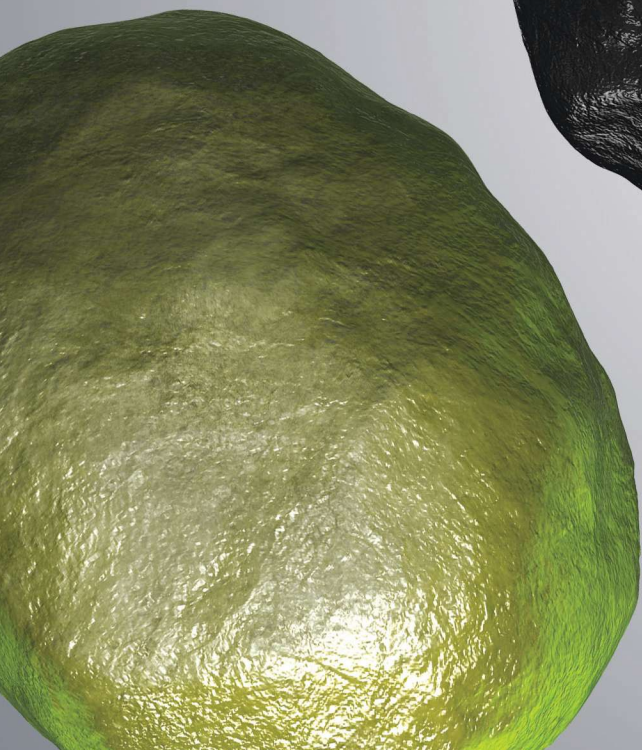
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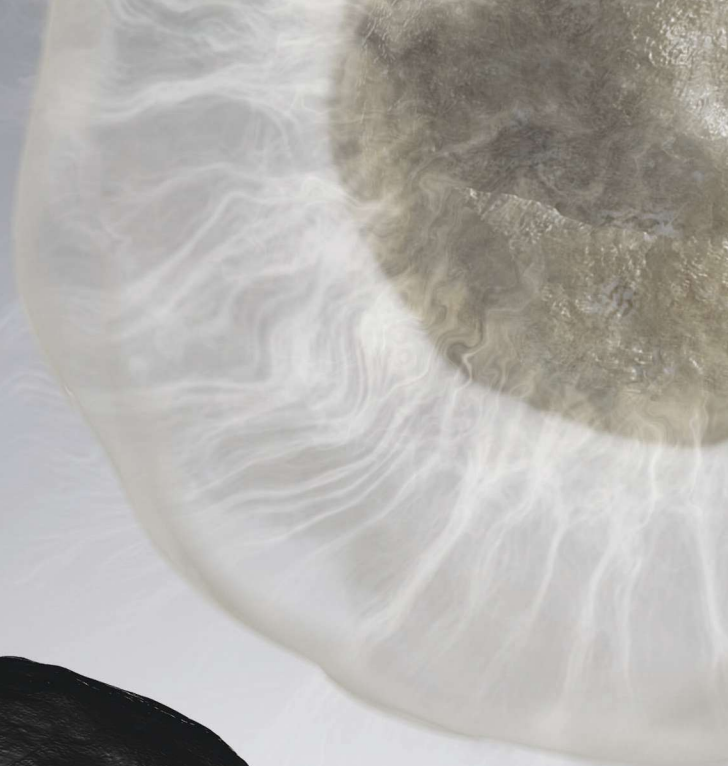
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During the primary separation step, produced water is treated with demulsifiers that aid in removing water from water-in-oil emulsions; however, a variety of solids and organics are still present. Water clarifiers are then used to further separate oil from water streams to meet regulatory discharge limits required for reinjection, disposal and reuse.

ROMAX Water Clarifiers from Dow provide a solution for separating oil from produced water and reverse (oil-in-water) emulsions, helping to protect both the environment and production equipment. These products are effective and environmentally responsible and can help treat produced water for reinjection, discharge or recycling in areas such as chemical EOR.

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Pumpable
(recycle for 18 hrs)



The ROMAX 9000 series of water clarifiers can operate at temperatures as low as -40 C. (Source: Dow Oil, Gas & Mining)

One of the biggest factors hindering long-term uninterrupted system operations blockage is caused by fouling generated during oil and produced water processing. For example, conventional clarifying technologies have, in some cases, been found to cause downstream issues including water-handling system fouling and the extraction of gel-like oil during the clarification step.

Consequently, it is of the utmost importance that produced water is treated with precise, reliable chemistry that not only reduces solids and contaminants but prevents pump and system fouling. By minimizing fouling, ROMAX 6000 and 9000 water clarifiers protect the chemical injection pumps used to dose the chemicals into the produced water stream. Similarly, Dow's clarifier chemistry effectively streamlines treatment and helps increase operational efficiency, which can ultimately reduce capital costs, maintenance and handling so that produced water meets regulatory oil and grease specifications and can be reinjected, reused or discharged back into the environment.

Conventional clarifier technologies can take the form of hydrocarbon-based dispersions that require a main-

nance-intensive mixer to support the inversion process prior to dosing. Dow's aqueous-based products require no such inversion, which means they can be dosed directly. In addition, these water clarifiers eliminate the need for dilution or activation, which ultimately reduces operating expense. In fact, the series of anionic, cationic and non-ionic water clarifiers are fully formulated and ready to use as soon as they arrive at the field.

For colder climates, the ROMAX 9000 series of water clarifiers are freeze-stabilized formulations for use at temperatures as low as -40 C (-40 F). This capability allows the operator to practice without issue, even in the harshest climates.

ROMAX water clarifier technologies can help lower the oil and contaminant content of injection water so that it can be safely and responsibly reused or discharged back into the environment. This is especially necessary for offshore operations, which focus on controlling the quality and subsequent impact of seawater that is either injected into the formation during secondary recovery or sent to overboard discharge. Clarifiers can help with water cleanup and have even helped reduce sheening issues in discharge water.

Residual oil in reinjection water also can adversely affect injectivity if reused in the reservoir, resulting in lost revenue and remediation costs. Clean water is necessary for peak performance as well as long-term production of a well. These products help facilitate oil levels that are low enough that water can be confidently reused and integrated back into the system. With dosage rates of 1 ppm to 100 ppm of ROMAX technologies, it is possible to reduce residual oil-in-water from more than 1,000 ppm to below 20 ppm.

In a recent case study, an oil and gas service company was able to significantly reduce pump fouling by switching to a ROMAX 9000 product. Making the switch allowed it to meet its oil and grease specification while reducing the manpower needed to maintain the chemical addition pumps in the field. Next-generation technology will continue to be researched and developed to help improve quality and the environmental integrity of a well's performance without increasing the cost of servicing the well.

As the global population continues to grow, balancing the need for clean water and energy will remain a clear focus for operators and regulators alike. By employing effective water clarifiers that reduce pump and system fouling and streamline the oil recovery process, operators can increase operational efficiency in a cost-efficient way and play an integral role in the trend toward more sustainable, environmentally conscious EOR operations. **E&P**

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Opening Keynote Speaker: Tuesday, November 11



Aubrey McClendon
President and CEO
American Energy Partners LP

**American Energy Partners –
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Aubrey McClendon has already raised some \$10 billion for his new start-up, and landed more than \$4 billion of acquisitions in the Permian, Utica and Marcellus. Hear his plans for American Energy Partners.

Veterans Day Tribute

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Conference Agenda

Monday, November 10

5:00 pm Opening Reception

Tuesday, November 11

7:30 am Registration Opens – Breakfast in Exhibit Hall

8:00 am Welcome & Opening Remarks

- **Leslie Haines**, Editor-in-Chief,
Oil and Gas Investor, **Hart Energy**

8:05 am **Awards Presentation:**
20 Years Of The Executive Oil Conference
*A special presentation honoring the 20-year history of the **Executive Oil Conference**, including award winners for 2014 and a unique award for a renowned industry veteran.*

8:30 am **Opening Keynote: American Energy Partners — Building In The Permian & More**
For his new start-up, Aubrey McClendon has

already raised some \$10 billion—and landed more than \$4 billion of acquisitions in the Permian, Utica and Marcellus. Here are his plans for American Energy Partners.

- **Aubrey McClendon**, President and CEO,
American Energy Partners LP

9:00 am **Industry Observers Panel: Hot Spot Still Sizzles**
Analysts and capital providers deliver their insights on why the Permian Basin remains a hot spot for further investment dollars, whether for start-up E&Ps, buyouts, or drilling.

- **Jordan Marye**, Partner, **Denham Capital**
- **Chris Carter**, Managing Director,
Natural Gas Partners
- **Andy Taurins**, Managing Director,
Lantana Energy Advisors

10:00 am **Networking Break**

10:30 am **Operator Spotlight**
Glean insight into the plans, the budget and the play that's attracting the drill bit from one of the region's most successful operators.

- **C. William Giraud**, Executive Vice President,
Chief Commercial Officer and Corporate
Secretary, **Concho Resources**

10:55 am **Roundtable Discussion: The Oil And Water Mix**
The oil and gas industry continues to examine ways to reduce its use of fresh water and increase water recycling, reuse and conservation. Here's a look at some of the more innovative and



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determined ways that is being accomplished in the Permian.

- **Clane LaCrosse**, Founder, President and CEO, **Bosque Systems, LLC**

11:40 am Operator Spotlight

As rising rig count helped producers report a high number of completions, this longtime Permian Basin leader will reveal some of the hard work that makes the success look so compellingly easy.

- **James T. McManus**, CEO, **Energen**

12:05 pm Networking Lunch

1:15 pm Afternoon Keynote: The Big Picture On Crude Oil Exports

Exports of crude oil from the US are restricted at present, but with US production at more than 8.2 million barrels a day and rising, pressure to allow higher levels of imports is growing. What are the prospects for large volumes of US crude flowing to different countries, and how might this affect the world's geopolitical landscape?

- **Tom Petrie**, Chairman, **Petrie Partners LLC**

1:45 pm Panel: Bumps In The Boom?

Will the booming Permian and Midland basins experience a bit of turbulence for operators after flying high for so long? As land prices have soared, some analysts forecast that the money and time spent evaluating and drilling in the area will be tested, and price weakness may set in.

- **Bob Brackett**, Senior Vice President & Senior Analyst, North American E&P, **Sanford C. Bernstein & Co.**
- **Travis Nichols**, Director, Investment Banking, **Tudor, Pickering, Holt & Co.**

2:20 pm Operator Spotlight

- **Travis Stice**, CEO, **Diamondback Energy, Inc.**

2:45 pm Networking Break

3:15 pm Panel: IPO Fever In The Permian

Investors are enthusiastically honing in on the Permian arbitrage as privates go public with lucrative results. These A&D advisors and recent Permian buyers analyze the deal landscape and offer their opinions on future prospects.

- **Mike Kelly**, Vice President, **Global Hunter Securities LLC**
- **Steven D. Gray**, CEO and Director, **RSP Permian, Inc.**

4:15 pm Midstream Panel: Newest Twists In Pipelines

After deep spending on infrastructure to solve the bottleneck and move crude to the best-priced markets, here's an overview of more notable pipeline projects in the Permian.

- **Ken Snyder**, Vice President, Business Development, **Frontier Energy Services LLC**
- **Brett Wiggs**, CEO, **Oryx Midstream Services**

4:45 pm Conference Adjourns

*Agenda content and timeline subject to change

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- An **overview of notable pipeline projects** in the works after deep spending on infrastructure to solve the bottleneck and move crude to the best-priced markets.
- **Insights into the plans, the budget and the play** that's attracting the drill bit from some of the region's most successful operators, including a new start-up that's raised some \$10 billion in little more than a year.
- About the innovative methods being employed to **reduce fresh water consumption and increase water recycling, reuse and conservation**.

Featured Speakers:



Aubrey McClendon
President and CEO
American Energy Partners LP



Tom Petrie
Chairman
Petrie Partners LLC



C. William Giraud
Executive Vice President,
CCO and Corporate Secretary
Concho Resources



Travis Stice
CEO
Diamondback Energy, Inc.



James T. McManus
CEO
Energren



Jordan Marye
Partner
Denham Capital



Chris Carter
Managing Director
Natural Gas Partners



Bob Brackett
Senior Vice President
& Senior Analyst,
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10:00 am Shotgun Start
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VIV suppression: changing the current in subsea operations

Suppression devices like helical strakes and fairings can help prevent substantial fatigue damage of risers and tendons.

Don Allen, VIV Solutions

The upsurge of deepwater E&P activities during the last 20 years has caused operators to think smarter and prioritize complex matters to minimize financial, health, environmental and safety risks while simultaneously improving project economics and insuring asset integrity.

One important issue that impacts the outcome of all of these goals is vortex-induced vibration (VIV). While VIV was a well-known occurrence before this time, its importance has grown due to an increased probability of encountering large ocean currents and the difficulty associated with predicting and suppressing VIV in deepwater.

When a current flows past a cylindrical object such as a riser, tendon, jumper or horizontal pipeline span, it creates VIV. The friction against the cylinder's surface causes boundary layers to form on each side of the cylinder. The retardation of the flow due to the friction ultimately causes the boundary layers to separate from the tubular and form vortices. The vortices shed from the cylinder in an alternating pattern, thereby imposing alternating (oscillating) forces on the cylinder. For a long deepwater

tubular, the frequency of this vortex shedding will be sufficiently close to one or more of the natural frequencies associated with bending, thereby causing VIV.

Tubulars experiencing VIV can eventually fail due to fatigue. To prevent substantial fatigue damage, it is usually beneficial to install VIV suppression devices over at least part of the tubular span to reduce the vibration amplitude and/or frequency. VIV suppression devices such as helical strakes and fairings can often minimize VIV if care is taken to select, design and install these devices during the project execution phase.

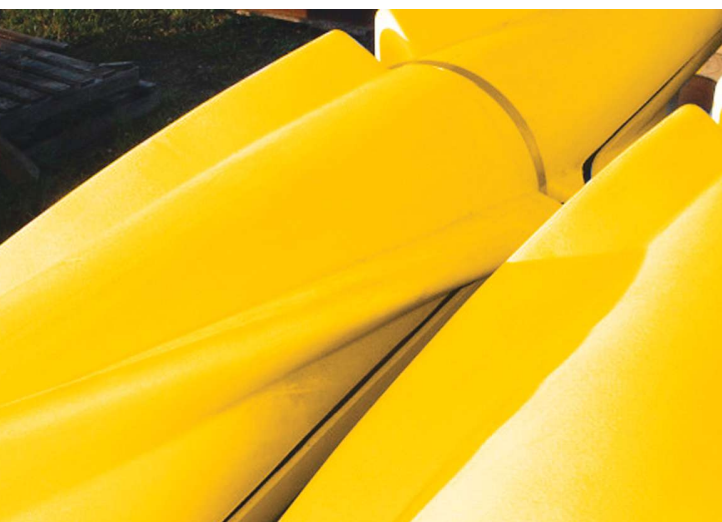
Strakes or fairings?

One popular solution for suppressing VIV of subsea tubulars is helical strakes. Protruding fins disrupt the correlation of vortex shedding along a tubular's span, resulting in lower and randomly phased lift and drag forces. Strakes are a common candidate to solve VIV issues with regard to risers, tendons, jumpers and horizontal pipeline spans.

Strakes consist of one or more fins that are wound helically around a tubular. Traditionally, strakes were designed for wind applications and consisted of three starts (three fins, each 120 degrees apart around the tubular), a pitch per start of about five times the tubular diameter and a fin height of 10% of the diameter. Upon early testing of strakes for deepwater tubular applications, results found traditional wind parameters were inadequate and that the strakes performed best with a fin height closer to 25% and a pitch per start in the range of 12 to 20 times the tubular diameter. The configuration using three starts for deepwater operations was generally maintained.

Because helical strakes directly encounter the oncoming flow and often produce early separation of it, they are associated with higher drag. Depending upon various parameters such as the Reynolds number (a dimensionless quantity that relates the inertial forces to the diffusion forces of the flow), the surface roughness or the presence of marine growth, the drag coefficient for strakes typically varies from about 1.3 to 2.0 for most deepwater tubulars.

In comparison, fairings provide unrivaled protection against VIV forces by streamlining the flow of currents around a tubular, effectively dispersing the vortices that



A strake's protruding fins disrupt the correlation of vortex shedding along a tubular's span. (Source: VIV Solutions)

cause oscillating forces on its surface and causing them to shed farther downstream. Fairings are designed to rotate freely around the tubular and self-orient with the tail pointing downstream.

One key advantage of fairings is that they significantly reduce drag. Fairings are especially beneficial in high-current regions or near the top of the water column where surface currents dominate. Tail geometry also can be customized to achieve maximum performance. Fairings also are less susceptible to marine growth performance degradation than other types of suppression devices such as strakes.

Assisting the performance of fairings are thrust collars, which are installed between fairing bodies to serve as a bearing surface for fairing rotation. These collars also help the fairings maintain their axial position along the riser string, and specialized collars can be used on tubulars with insulation to accommodate diameter changes caused by hydrostatic shrinkage.

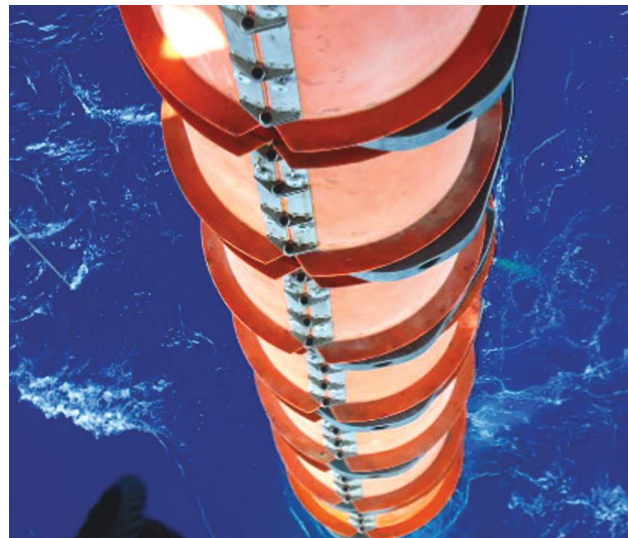
However, not all fairings are equal. As with strakes, fairing performance is dependent upon a number of factors including the fairing chord (the distance from the fairing nose to the fairing tail), the fairing thickness, Reynolds number, surface roughness, the shape of the fairing side walls, fairing tail thickness and shape, the annulus between the fairing and the tubular, etc. It is prudent to obtain proper consultation on fairing design to insure that performance of the fairing system is optimized.

Because fairings streamline the flow similar to an airplane wing, effective fairings produce substantially lower drag than helical strakes. Fairings are also a little less sensitive to soft marine growth on their surface than strakes and usually produce lower motions on downstream tubulars than other VIV suppression devices. While fairing drag coefficients depend on various factors too, it is possible to design fairings with drag coefficients less than about 1.0 for a production riser and in the range of 0.6 or less for a drilling riser.

Fairings, like helical strakes, can experience substantially reduced effectiveness due to the presence of hard, barnacle-type marine growth. However, tests have shown that soft marine growth can be well tolerated by fairings with a sometimes negligible reduction in the fairing's VIV suppression performance. While it is possible to apply antifouling coatings, it is most important that the bearing surface between a fairing and adjacent fairings or thrust collars is kept relatively free of marine growth so that the fairing can properly weathervane with the flow.

Suppressing for success

Sailing in the seas off the Kii Peninsula and engaged in



Fairings provide a significant reduction in drag and a lower susceptibility to marine growth performance degradation. (Source: VIV Solutions)

research, the R/V *Chikyu*, a Japanese scientific drilling ship built for the Integrated Ocean Drilling Program, faced a major problem requiring resolution before riser drilling could succeed: how to handle the effects of VIV resulting from the Kuroshio Current, which can flow at 3 knots (1.5 m/sec or 5 ft/sec) or more, as noted in the March 2010 issue of *Chikyu Hakken—Earth Discovery*. When 1.2-m (4-ft) diameter riser pipes were lowered from the *Chikyu* and deployed to the seafloor drilling site, the riser would shake due to VIV. The solution was to use VIV Solutions Tail Fairings, a modular type of suppression device consisting of a pointed tail and two straps, to help channel the flow of water around the riser and reduce vortex shedding.

Lowered about 305 m (1,000 ft) below the surface, the riser pipe, equipped with 132 fairings, showed almost no vibration despite currents reaching anticipated speeds well in excess of 3 knots. Results were confirmed by sensors placed on the fairings as well as by data collected from an analysis system that recorded the movements of the riser pipe.

This application is just one of many examples showcasing the power of VIV suppression devices to mitigate devastating downtime during drilling operations and prevent fatigue damage of critical operating equipment. Both strakes and fairings can effectively reduce VIV; however, various considerations such as the presence of marine growth, the need for low drag to prevent contact of adjacent tubulars and the potential of vortex shedding affecting downstream risers are all important to evaluate when designing and procuring VIV suppression devices. **E&P**

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The front left side displays the mighty derrick towers standing like sentinels in tribute to oilmen past and present. On the rear panel two roughnecks tripping pipe complement the banner THE AMERICAN OILMAN.

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The 19th century oilfield was a dangerous place. It took a special blend of courage and curiosity to become an oilman. The hazards of unexplored fields, threats of well fires and lost fortunes were only a few of the many obstacles an oilman encountered. Each step into the oilfield, into the unknown, created the American Oilman of today who continues a tradition of exploration and technological development that lessens our dependence on foreign oil and reduces our footprint in the field.

Though larger-than-life oil barons like J.D. Rockefeller and J. Paul Getty are gone, we salute the American Oilman who's still exploring, innovating and propelling the American oil industry into the future.



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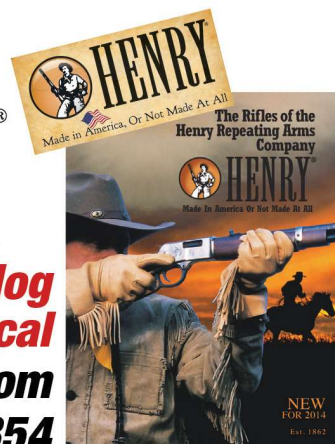


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Satellite imagery helps companies face challenges

Geospatial solutions aid in sound decision-making throughout the entire oil and gas life cycle.

Bud Pope, Spatial Energy, a DigitalGlobe company

Satellite imagery and the information derived from it are playing a greater role in the management of exploration and production operations as oil and gas companies increase activities in remote regions of the world.

DigitalGlobe, a commercial high-resolution earth observation and geospatial solutions company, acquired Spatial Energy earlier this year, and the company is seeing an increase in energy companies using satellite imagery to not only monitor exploration and access facilities but for emergency response and environmental monitoring as well as seismic and new well planning. A high-resolution image acquired prior to exploration and drilling activity serves as a baseline for other activities, including site modeling, facilities monitoring, environmental assessments and vegetation reclamation. Commercial satellites also have the ability to monitor for the illegal tapping of pipelines and pipeline oil spills.

In fact, satellite imagery significantly helps oil and gas companies reduce operating costs, facilitate sound decision-making and contribute to responsible development of this important resource through all of the phases of finding, producing and distributing it.

The oil and gas industry has used imagery and remote sensing to coarsely map areas for decades, but advances in digital technology and remote sensing applications since then have multiplied the value and applications for imagery throughout the oilfield lifespan.

Remote oil fields

One customer was in the process of developing a production facility in a very remote oil field in the Middle East where it was difficult to put people on the ground due to security and road infrastructure issues. Its biggest challenge was understanding the condition of the field, but it also needed information about the natural environment, existing infrastructure and potential hazards. A number of factors prohibited the acquisition of on-the-ground mapping and elevation data: limited access to the project area; health, safety, security and environment (HSSE) issues; and military and environmental legacies in the project area. A baseline dataset was needed, and with no recent mapping available, high-resolution satellite imagery was used to close the gaps.

The customer worked with DigitalGlobe to produce detailed maps and highly accurate digital elevation models using the satellite imagery. The imagery revealed that the oil field had a very low elevation, and its proximity to major rivers provided a risk of flooding. There also were many dykes in the area that needed to be studied and monitored since the integrity of dykes was key for flooding protection. Using 50-cm resolution satellite imagery and the key information pulled from it, including digital elevation models, the customer was able to identify 13 critical locations on the dykes that included breaches and weak points where water may flow through or beneath the dyke. This analysis enabled the customer to determine which dykes needed to be repaired.

Ultimately, the high-resolution satellite imagery and elevation models supported the site selection of a production facility at an elevation high enough to prevent

Satellite imagery provides information that is sometimes difficult to obtain at ground level. (Source: DigitalGlobe)



flooding, supported the development of a new access route to the field and helped reduce field staff exposure on the ground. The customer continues to use satellite imagery to confirm the dykes are still in good repair and map routine flooding that occurs in the area to ensure the facility is not at risk.

Near-shore planning

Satellite imagery also can assist oil and gas companies with offshore planning. Analyzing high-resolution imagery and oil and gas maps helps companies build accurate surface models and avoid poorly suited areas. Spectral bandwidth allows surface characterization and identification of surface obstacles.

For example, one customer was planning to develop an offshore pipeline and port facility in the Middle East and needed bathymetry surveys conducted close to shore. Using sonar technology is often very expensive for creating a bathymetry map, particularly when it's unknown where the port facility and pipeline should be developed. However, satellite imagery can look at a broader area of interest at a fraction of the cost to determine the most optimal area for development.

The customer decided to use imagery from DigitalGlobe's WorldView-2 satellite, a high-resolution imaging satellite with eight-band technology, to see further into the water and support bathymetric studies around the globe. The bands also enable the satellite's camera sensor to map the depth of the water.

Remote sensing of the shallow ocean floor has become much clearer as a result of the additional spectral bands, which include coastal blue. Researchers have shown that the combination of coastal blue with yellow and the more tightly focused green band can discriminate underwater features more efficiently with remarkable accuracy, agility and collection capacity.

The customer was able to map the terrain underwater and determine the most favorable area for producing its landing pipelines and building piers. It was able to rule out unreliable deep areas of the water and select an ideal area of terrain that didn't drop off or have abrupt channels running through it. The customer continues to use satellite imagery and the information derived from it to monitor the construction of the offshore facility.

Seeing a better world

Petroleum companies also are using multispectral satellite imagery to monitor their environmental impact more rigorously. Multispectral imagery is essential for mapping land use and environmental impact. Periodic resurveying of oil fields, pipeline corridors and refiner-



Combining coastal blue with yellow and green bands can discriminate underwater features more efficiently. (Source: DigitalGlobe)

ies is an efficient and accurate method for ensuring that environmental impact is limited to an absolute minimum. By measuring the length and width of the right of way through which seismic lines have been acquired, oil companies can document their impact on the local forests and vegetation.

Multidate imagery also is critical for oil and gas companies because the information is a time-stamped documentation of land status on a fixed date. Strategic use of periodically acquired imagery from orbiting satellites enhances technical analysis and the bottom line for all professionals involved in oilfield and regulatory operations. DigitalGlobe's archive of more than 4 billion sq km (1.5 billion sq miles) of imagery helps companies look back in time for more than 13 years.

DigitalGlobe's sixth satellite, WorldView-3, was recently launched in August and will soon offer an even sharper view of exploration and production operations and assets. Its 31-cm resolution makes it the highest resolution commercial satellite in the world, and it is the first commercial satellite with 16 high-resolution spectral bands that capture information in the visible, near-infrared and short-wave infrared regions of the electromagnetic spectrum.

Oil and gas companies are facing new challenges: how to explore cost-effectively in remote regions, especially those in developing nations with limited mapping data and infrastructure, and how to optimize existing production in already discovered oil and gas fields. These types of geospatial solutions continue to serve as a strong foundation for sound decision-making throughout the entire oil and gas life cycle. **E&P**

Multiphase flow gets closer to reality

A transient multiphase simulator improves accuracy for temperature calculations and prediction of slug behavior.

Shane McArdle, Kongsberg Oil & Gas

With the need to produce from deeper, colder and less accessible fields, production systems are becoming more complex, and the risk of flow assurance problems is becoming proportionally higher. Through game-changing technology and extensive testing, a new breed of simulator brings multiphase flow calculations even closer to reality.

Emergence of multiphase flow research

Multiphase flow research in the oil and gas industry has been driven over the past 30 years by two Norwegian institutes, SINTEF and IFE. These institutes developed a technology that made it possible to transport oil and gas in a single pipeline over long distances, which became known as multiphase transport. Transportation of the multiphase fluid stream over long distances is extremely complicated, and before operators could invest in long subsea pipelines they needed to understand these challenges and reasonably predict any flow assurance problems such as slugging and hydrate formation.

New discoveries in the Norwegian Continental Shelf at greater water depths (50 m to 70 m or 164 ft to 230 ft) and sharply increasing costs in the 1980s were the drivers to develop a multiphase flow simulation tool that could facilitate these types of projects. The first transient engineering tool for design, operational support and simulation of multiphase pipelines was developed, enabling the application in smaller fields and subsea-to-beach transfer.

Since then, long-distance multiphase transport has been firmly on the agenda for oil and gas companies as field developments have moved into deeper water (850 m to 1,500 m or 2,789 ft to 4,921 ft) and with longer step-offs (up to 550 km or 342 miles).

Aware of these subsea challenges and the need for improved accuracy predicting flow conditions, ConocoPhillips and SINTEF teamed up to develop a new multiphase flow tool. Total E&P soon came on board along with Kongsberg Oil & Gas, and the integrated tool known as LedaFlow was born. For more than a decade LedaFlow has continued to keep pace with the maturing of the digital oil field.

Dynamics of multiphase behavior

The LedaFlow multiphase transient simulator is a tool that models the dynamics of multiple fluid phases within well and pipe networks. Understanding the dynamics of multiphase behavior assures safe and reliable operation of complex production systems while uncertainties in predictions can result in serious operational problems. Improved prediction accuracy of transient multiphase flow allows the design of longer multiphase pipelines, therefore reducing the amount of processing required offshore and increasing the operational safety margins.

Adding value across the life cycle

LedaFlow is used throughout field development in feasibility studies, conceptual studies, FEED and detailed designs, and operation of the field.

Transient simulation is needed to address more detailed design and operability considerations. The fundamental driver to model the dynamics of multiphase flow in wells and pipelines is to understand and thereby manage the liquids, both within the system and as they leave the pipelines and enter the first stages of processing.

A transient multiphase simulator must accurately determine the locations for liquid accumulation due to local differences in phase velocity (slip). Some typical flow assurance applications for LedaFlow include determining system/component warm-up and cooldown times, blow-down fluid rates and temperatures, slugging behavior (rate change, hydrodynamic and more severe terrain-induced slugging), liquid inventory during pigging and rate changes, prediction of liquid holdup in low-rate gas/condensate systems, gas lift impact on flow conditions, inhibitor tracking and hydrate risk assessment, and thermal design of flowlines.

Two key features that provide increased operability stability are:

- The LedaFlow Buried Pipe Model that provides increased accuracy and resolution for temperature calculations, reducing uncertainty and leading toward optimal design. Relevant applications include blow down, top-of-line corrosion, material selection, pipe thermal stress, wax deposition and hydrate risk; and
- The LedaFlow Slug Capturing module, the first commercial implementation of technology that predicts

hydrodynamic slugs. Previously, it was possible to approximately replicate field observations by imposing user-controlled slug seeds and tuning them to match the observed results as closely as possible. However, this approach did not capture the interaction of hydrodynamic and terrain slugging, and that meant that the limits of stable operation were not properly understood. This could lead to significant operational difficulties avoided with the LedaFlow Slug Capturing module.

Validated against lab, field data

LedaFlow has been extensively validated against laboratory and field data to confirm the primary objectives of accurately estimating liquid holdup that causes pressure to drop within pipelines.

Testing included comparison with experimental data (more than 12,000 experimental points) and field data (pipelines and wells, from wet gas to oil) as well as comparisons to other commercially available software. Another part of the testing was focused on typical flow assurance user cases; transient simulations such as turn-down, shut-down, startup and depressurization were run for a number of realistic field geometries.

Development of the tool has been based on both existing and new large-scale experimental data from the Tiller loop. Data were acquired for holdup, pressure gradient and flow regime. These data are exclusively available for the development of LedaFlow and fill in data gaps in the existing SINTEF database.

The LedaFlow partners provide field data from various types of fields in operation around the world. A joint industry project called LedaFlow Improvements to Flow Technology or LIFT is a three-year project to compare LedaFlow against field data provided by the operator partners and identify areas of improvement in the models used. There is a focus on areas where LedaFlow provides particular strength such as the solution of three energy equations to resolve temperatures with greater accuracy, the prediction of slug behavior and the flexibility of the solution to allow users to impose their own physical models. All of the operators involved share relevant field data from various fields around the world.

The LedaFlow partners have installed more than 90 solutions across the globe, and it is now a proven alternative to legacy solutions.

The transient three-phase 1-D simulator offers new modeling capabilities as it is based on a model concept conserving mass for nine fields (bubbles, droplets and continuous fluids), using three momentum equations and solving for the enthalpy and temperature of the three

individual fluid zones. The multifluid, multiphase approach is unique to LedaFlow in that no other multiphase flow tool on the market today solves as many equations. The additional number of mass and energy equations provides increased results and insight into fluid changes on a first-principle level.



LedaFlow was developed to improve the overall design and operation of multiphase pipelines. (Source: Kongsberg Oil and Gas Technologies)

Future of multiphase operations

Improving accuracy and reliability on the existing multiphase flow tools that are out there is important as challenges in multiphase flow increase and evolve. Improved accuracy will result in confidence in designing pipelines with reduced safety margins.

There have been many attempts at developing an alternative multiphase flow tool, but they have not achieved the level of success or market share desired. What makes LedaFlow different includes the industry involvement from the start, early market input from a commercialization partner with a strong background in this domain, an agile and experienced development team, and access to one of the world's largest experimental databases.

With strong support from key major oil companies, LedaFlow has proven itself a viable alternative to the existing commercial tools and will continue to improve the overall design and the operation of multiphase pipelines. **E&P**

Meeting tough process sealing challenges

Perfluoroelastomers improve reliability, increase mean time between repairs and reduce operating costs.

Jean-Luc Matoux, DuPont

The oil and gas industry is on a quest for new oil resources, and companies are being forced to drill deeper in new, more difficult formations, leading to upstream operating temperatures in excess of 200 C (392 F) and pressures above 29,000 psi.

EOR methods such as injection of steam or CO₂ under high pressure, presence of higher concentrations of hydrogen sulfide (H₂S) in the wells and amine-based corrosion inhibitors can seriously challenge the polymers used downhole to seal drilling equipment, particularly in cases where a sudden drop in pressure can cause seal damage from rapid gas decompression (RGD).

These more aggressive chemical environments are beyond the mechanical, chemical and thermal resistance of most commonly used sealing elastomers, including hydrogenated nitrile rubber (HNBR) and fluoroelastomer (FKM).

Damaging RGD

RGD can lead to seal damage when a sudden pressure drop causes gas dissolved within the elastomer to expand, building up internal stresses that can form blisters or internal cracks.

NORSOK standard M-710, Rev. 2, October 2001, and TOTAL general specification GS EP PVV 142, Rev. 8, the internationally accepted industry test standards for non-metallic sealing materials, are used as benchmarks of performance of elastomer seals in critical oil and gas service and are considered essential to qualifying an elastomer seal for RGD environments.

Consequences of inadequate seal selection

Premature damage and unexpected failure are the most obvious consequences of selecting a seal material lacking the three key parameters of mechanical, chemical and thermal resistance.

The outcome is likely to be unscheduled maintenance. Take the case of a sudden seal leak in drilling equipment



The picture on the left shows an example of extrusion damage to a seal caused mainly by selection of an elastomer incompatible with the medium, causing the polymer to swell, damaging its matrix, lowering its modulus and prompting rapid extrusion. The picture on the right shows an example of mechanical damage caused by overcompression of the seal in an incorrectly designed groove. (Source: DuPont)

The Gulf of Mexico Renaissance: Short-Term Recovery to Long-Term Trend

The roughly \$110 million in high bids at the BOEM's western Gulf of Mexico lease sale in August represent "down payments" on years of E&P activity. Infield Systems estimates GoM projects will attract 10% of global offshore CAPEX over the next 5 years – and could yield **7 billion barrels** of new oil and gas reserves.

Today's GoM leaders will detail their plans in a uniquely candid setting – the inaugural **Offshore Executive Conference: Gulf of Mexico**. This information-packed, one-day conference from Hart Energy, the businessleader in oil and gas events,

has secured an unparalleled line-up of offshore executive speakers.

Hear major players like **Shell E&P, BHP Billiton, Apache, Energy XXI, Fieldwood Energy, W&T Offshore, Statoil** and **Cobalt International**, as well as top-level oil and gas investment analysts and one of Mexico's foremost financial leaders, explain what lies ahead.

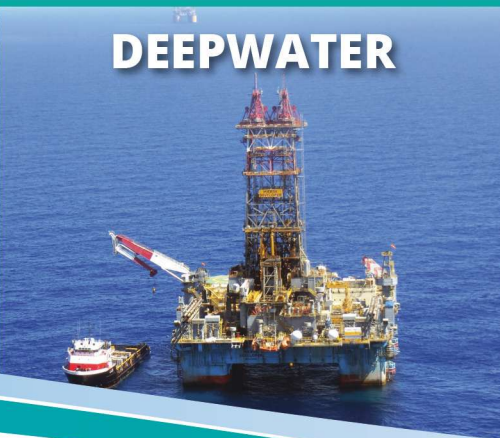
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AGENDA

Thursday, October 16, 2014



7:30 am Registration Open and Networking Breakfast

8:30 am Welcome & Opening Remarks

■ **Mark Thomas**, *Editor-in-Chief, E&P, Hart Energy*

8:35 am Opening Keynote: A New Era of Opportunity In The Gulf Of Mexico

With its \$2.6-billion acquisition of EPL, Energy XXI now operates 10 of the largest oilfields on the Gulf of Mexico shelf. Learn how this expanded portfolio increases Energy XXI's scale, and the new opportunities it provides.

Moderator: Mark Thomas, Editor-in-Chief, E&P, Hart Energy

■ **John Schiller**, *Chairman and CEO, Energy XXI*

9:00 am Roundtable: Gulf of Mexico Renaissance – Differing Perspectives

The resurgence of activity in the U.S. sector of the Gulf of Mexico in both its deep and shallow waters has been astonishing, but each requires a different approach. Hear from operators on how they approach each province and what the future may hold.

Moderator: Eldon Ball, Executive Editor, Hart Energy

■ **Tracy Krohn**, *CEO, W&T Offshore*

■ **Martijn Dekker**, *Vice President Appraisal and HCM, Upstream Americas Exploration, Shell Exploration & Production Co.*

■ **Thomas E. Voytovich**, *Executive Vice President and Chief Operating Officer, Apache Corp.*

10:00 am Networking Break

10:30 am Operator Spotlight: The Leading Shelf Producer

From a standing start through acquisitions in 2013, privately held Fieldwood manages 630 platforms on more than 500 blocks from Mustang Island to Mobile Bay – it is the largest producer and acreage holder on the Shelf. How will Fieldwood pursue the multiple opportunities it sees ahead on this asset base?

Moderator: Jennifer Presley, Senior Offshore Editor, E&P, Hart Energy

■ **Matt McCarroll**, *Chairman, CEO and President, Fieldwood Energy LLC*

11:00 am Panel: Finance, Investments & Market Outlook

Capital requirements for Gulf of Mexico development are enormous, and investments are long-term. This panel of experts delivers perspectives on capital markets, economics, A&D transactions and future investment outlooks.

Moderator: Mark Thomas, Editor-in-Chief, E&P, Hart Energy

■ **Mike Haney**, *Director, Douglas-Westwood Inc.*

12:00 pm Networking Luncheon

1:00 pm Operator Spotlight: A Deepwater Focus

BHP Billiton holds an exceptional position in a number of major Gulf of Mexico fields, including Shenzi, Mad Dog and Atlantis. Learn what this international player plans for its choice deepwater assets.

Moderator: Eldon Ball, Executive Editor, Hart Energy

■ **Stephen Pastor**, *Asset President, Conventional, BHP Billiton*

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**1:30 pm Roundtable Discussion:
Striking The Right Balance
In The Deepwater**

Set to overtake the shallows in terms of total expenditure, drilling activity, and production, the deepwater Gulf of Mexico is pushing the technological boundaries to achieve staggering growth numbers.

Moderator: Mark Thomas, Editor-in-Chief, E&P, Hart Energy

- **Jason Nye**, *Senior Vice President, U.S. Offshore, Statoil*
- **James H. Painter**, *Executive Vice President, Execution and Appraisal, Cobalt International Energy, Inc.*
- **Stephen Pastor**, *Asset President, Conventional, BHP Billiton*
- **Brian Reinsborough**, *President and CEO, Venari Resources*

2:30 pm Networking Break

3:00 pm Trade Spotlight: What's New From NOIA

The National Ocean Industries Association has set its focus on expanded access to undeveloped offshore acreage and developing the next five-year offshore leasing plan with the U.S. Department of Interior. The association's new chairman gives an update on these and other vital NOIA projects.

Moderator: Jennifer Presley, Senior Offshore Editor, E&P, Hart Energy

- **John Rynd**, *President and CEO, Hercules Offshore and Chairman, NOIA*

3:25 pm Panel: Emerging Plays

Where's the next big thing in the Gulf of Mexico? As exploration heats up in the ultra-deepwater, hear from leaders on lessons learned, what's been found, and what's to come.

Moderator: Eldon Ball, Executive Editor, Hart Energy

- **David Reid**, *Appraisal Manager for the GoM, Shell Exploration & Production Company*
- **Jez Averty**, *Senior Vice President, Exploration, North America, Statoil*

4:25 pm Closing Keynote: Mexico's Path Forward

Mexico is keenly interested in developing its deepwater Gulf of Mexico sector. What will successful development mean to the Mexican economy? How will these huge projects be financed, and how is the government promoting this development to international companies? Hear the unique perspective of one of Mexico's foremost economists and financial leaders.

Moderator: Mark Thomas, Editor-in-Chief, E&P, Hart Energy

- **Dr. Guillermo Ortiz Martinez**, *Governor, Central Bank of Mexico, former Public Finance Minister of Mexico, former Secretary of Communications and Transportation of Mexico, and formerly Mexico's ambassador to the International Monetary Fund*

**4:45 pm Conference Adjourns and
Networking Reception**

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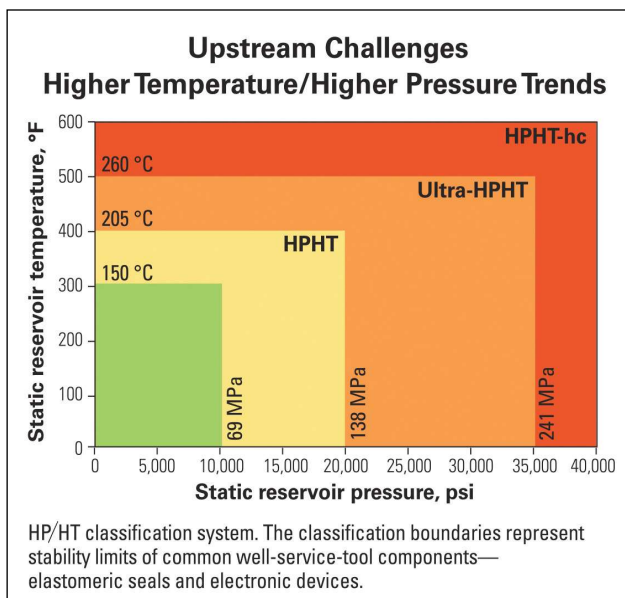


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This chart illustrates the trend from conventional oil wells (shown in green) to high HP/HT and ultra-HP/HT wells and above. (Source: DuPont)

due to RGD. The operator must factor in the time and cost of tool removal, repair, reinstallation and, certainly, a day lost.

High-performance elastomers

Elastomer seals are widely used in petroleum exploration, refining, distribution and transportation equipment. The chart above ranks the principal elastomers in terms of heat and oil resistance, with the highest performing elastomers grouped within the green area.

Seals of properly compounded HNBR provide good chemical, thermal and RGD resistance for standard wells operating at around 150 C (302 F), but higher temperatures often necessitate fluoroelastomers formulated for RGD resistance. However, HP/HT and ultra-HP/HT conditions go beyond the thermal capabilities of most HNBR and FKM elastomers and require perfluoroelastomers (FFKMs).

FFKM seals such as DuPont's Kalrez offer the highest resistance to elevated service temperatures, aggressive amine-based corrosion inhibitors and high levels of H₂S.

FFKM sealing parts

Kalrez FFKM parts combine the resilience and sealing force of a traditional elastomer with the chemical inertness and thermal stability of polytetrafluoroethylene (Teflon), help reduce unscheduled downtime, extend seal life and save cost in harsh industry environments.

The benefits of these parts include temperature stability from -42 C (-43 F) to 327 C (620 F), resistance to more than 1,800 chemicals and aggressive fluids, excellent sealing force retention, low compression set, and elastic recovery. Kalrez 0090 K312 "A" O-rings, specifically developed for oil and gas applications, have attained the best possible NORSOK M710 rating of "0000" for RGD resistance.

Typical uses

O-rings: The high-hardness O-rings are used in upstream applications where elevated temperature, chemical and extrusion resistance is necessary. They are often installed with backup rings where pressures and seal designs require.

Packers: The parts can be made in sizes up to 10 in. in diameter and 5.9 in. long for long-term service in retrievable packers.

Valves: Large valves in H₂S service between upstream and downstream processes require the chemical resistance of FFKM sealing parts. The O-ring seals can be supplied in nonstandard sizes up to 1.5 m (5 ft) in diameter for such applications.

Boots: Kalrez boots as small as 1.6 in. in length and 0.4 in. in diameter are specified for downhole submersible pump connections.

Seal selection and total system cost

When considering the economics of elastomer seals, it is vital to look beyond the cost of the seal itself and compare total system cost, i.e., the costs of the seal plus installation plus downtime plus loss of production plus cleanup.

A case study illustrates the point. Elastomeric seals used in a mixed ethylene oxide and amines process pump operated by an oil and gas processor failed every 15 days. The user decided to switch to FFKM O-rings, enabling a realistic cost comparison to be made over one year of operation.

The comparison looked at the cost of shutdowns caused by the failure of each O-ring. Each FFKM O-ring provided 3.5 months of service—seven times longer than the previous elastomeric O-rings. Factoring in a conservative downtime cost of \$1,300 per shutdown, covering maintenance costs and production losses, the new O-ring delivered savings of about \$28,800 per year for one pump alone. **E&P**

Acknowledgment

This article is based on the June 26, 2014, webinar "Solving sealing challenges in upstream and downstream environments" hosted by Smithers Rapra and presented by Jean-Luc Matoux of DuPont. The webinar and the whitepaper of the same name are downloadable at downloads.intertechpira.com/solving-sealing-challenges-upstream-downstream-environments-webinar/

Benefits of best practice maximize production and profits

Applying best practices for measurement control means better production management decisions can be made based on more accurate and timely data coming from separators and heater treaters.

Michael Machuca, Emerson

Production management decisions are based on field measurement data and are intended to drive well optimization, sustain reservoir life and result in long-term profitability.

In most oil and gas operations, the production measurement data used to make decisions come from the separator and/or heater treater. By applying proven measurement control best practices, operators can prevent data anomalies, diagnose and avoid production issues, drive uncertainty out of the operation, and maximize production and yield.

The importance of well testing

It's important to know how a well and field are producing to maximize the efficiency of hydrocarbon recovery operations. Most wells start out free-flowing and, over time, decline in production. As the well ages, steps need to be taken to improve oil and gas recovery such as implementing artificial lift, secondary recovery or EOR—all of which add cost.

No matter which technique is used, it is important to understand how much oil, gas and water is being produced from each well to maximize output while minimizing recovery costs. In addition to suboptimal recovery operations, unexpected flow assurance issues like paraffin buildup, water breakout or scaling can cause production decline or result in wells being unavailable for production.

Well testing can determine decline rates and provide the critical data needed to maximize net revenue over time from the well, field and reservoir. In many regions the well measurements taken are used to determine royalty payments to the mineral rights owner and, if these measurements are not correct, it can lead to over- or underpayment, disputes, legal actions and potential fines.

Growing complexity

Traditionally, onshore production measurements were not taken at the heater treater or separator but at the tank.

Today operations have become more complex due to the focus on unconventional plays.

Operators are moving toward larger well pads with longer laterals that may have multiple lease holders per pad and tank. Larger facilities are now requiring commingling of production into a single tank or pipeline. As a result, it is necessary to measure production at the separator or heater treater to ensure proper allocation of royalties to the land owner and to fully understand how each well is producing.

It is also common practice to use a test separator that only provides production data on a periodic basis. Production rates must be assumed to be constant until the next test. It is therefore important to get measurements correct during each well test since it may not be checked again for an extended period of time.

Because of these increasingly complex requirements, ensuring proper separator and heater treater production measurements has become increasingly important. Traditional mechanical control and measurement devices are now being displaced with more accurate and reliable technology as well as remote monitoring to provide diagnostic insight.

Separator and heater treater selection challenges

It is challenging to implement best practices for separator and heater treater production measurement. Rapid deployment of facilities, limited information on expected production rates, accelerated production decline and constrained resources can lead to equipment selection that may not be best suited to provide accurate and reliable production measurement.

The separator and heater treater act as a complex flowmetering system where accurate accounting of oil, water and gas is measured. When measurements don't meet expectations, the root causes can most often be traced to:

- Poor level control;
- Inaccurate pressure control;
- Inadequate retention time;

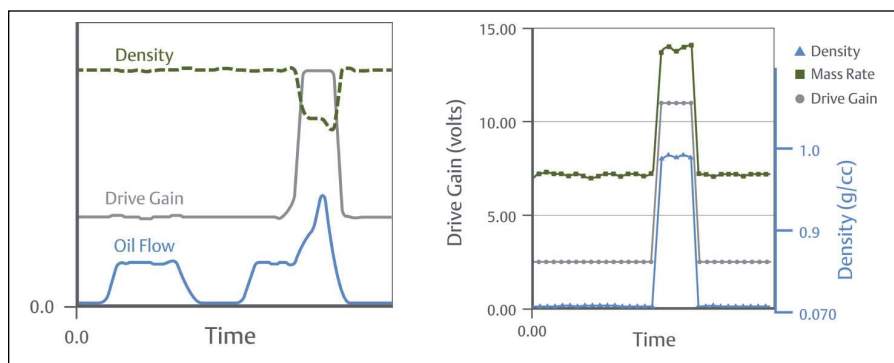


FIGURE 1. Flowmeter diagnostics using density can detect gas carry-under into the oil leg (left) and liquid carry-over into the gas leg (right) of the separator or heater treater. (Source: Emerson)

- Poor temperature control;
- Flow control (valve sizing, stuck dump valves, etc.);
- Flow measurement errors;
- Operating error; and
- Poor well test management practices.

It can often be a daunting task to select the best technology to most effectively manage separator and heater treater operations with so many technologies available to choose from. The unique characteristics of each production field and the constraints that come with operating remote facilities only make this task more challenging.

Best practices

The following are some best practices to instrument and control the separator and heater treater.

Use sophisticated flowmeter diagnostics to detect gas carry-under, liquid carry-over, oil/water contamination and device health: Gas carry-under and entrained gas in the oil that flashes in the flowmeter presents one of the most significant challenges to separator operations. Entrained gas can result in flow measurement errors, can damage the meter and will lead to royalty disputes. In addition, high levels of entrained gas going into the stock tanks will increase costly emissions and flaring and loss of associated natural gas that potentially could have been sold to increase profit.

Some Coriolis flowmeters have diagnostic capability that uses the density and a measure of the energy consumed to keep the meter tubes vibrating called “drive gain” to detect entrained gas in the oil or water leg of the separator or heater treater. A drop in density associated with an increase in drive gain indicates free gas passing through the meter (Figure 1, left).

Similar diagnostic capability also can be used to detect liquid carry-over into the gas leg (Figure 1, right). In this case, it is an increase in density coupled with an increase in drive gain that indicates liquid carry-over.

A third diagnostic capability is realized when a density measurement that is higher or lower than expected on the oil or water leg, respectively, is used to identify oil/water contamination (Figure 2).

For line sizes 2-in. in diameter and larger, ultrasonic meters can use speed of sound and flow profile diagnostics to detect both gas carry-under and liquid carry-over.

Vortex meters have the ability to detect the change on the water outlet from a liquid flow measurement

to gas flow measurement. This can be an indication of a stuck dump valve that is allowing high volumes of gas to pass into the water tanks. By taking advantage of flow measurement diagnostic tools, separation inefficiencies can be detected and corrective action can be taken such as adjusting the level controller, separator pressure, temperature or dump cycle flow control to reduce the risk of HSE incidents and production measurement errors.

In addition to using these diagnostic tools to detect separator problems, it is important to take advantage of diagnostics that ensure the health of the flowmeter itself. Diagnostic tools are available to verify the health of the flow sensor and transmitter *in situ* without the need to remove the flowmeter from the line. This is a powerful tool that can help eliminate the meter as the source of the measurement error while troubleshooting the process.

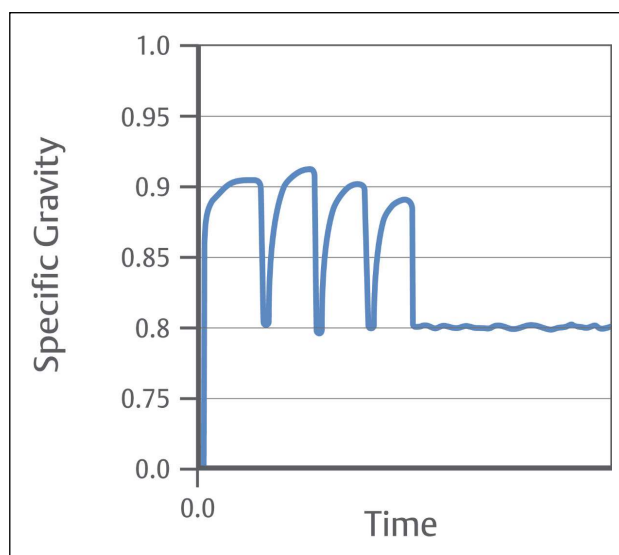


FIGURE 2. Flowmeter diagnostics also can measure density to help detect oil/water contamination in the oil or water leg. (Source: Emerson)

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Exploration workflow enables timely decision-making

A detailed workflow allows operators to de-risk international shale plays.

Richard Salter, Schlumberger

The unconventional boom that has transformed North America's hydrocarbon landscape is expanding its horizons into international markets as operators consider launching ambitious campaigns in plays with potentially rich source rock. A detailed understanding of the economic viability of the reservoir, however, is critically important in providing companies with the data and confidence they need to make quick, informed decisions to drill exploratory pilot wells in new unconventional frontiers.

Early unconventional exploration wells tend to be considerably more expensive than equivalent production wells in North America, where extensive data, conventional well production and established efficiencies enable timely decision-making with considerably less economic risk.

A new exploration workflow, tailored for the burgeoning international unconventional market, is giving operating companies in several regions the necessary decision-making packages to move forward with appraisal drilling programs. The multidisciplinary workflow integrates existing reservoir information including core, log and seismic data in a 3-D depth model to calibrate a petroleum systems evaluation to map the fairway or sweet spot and estimate recoverable resources.

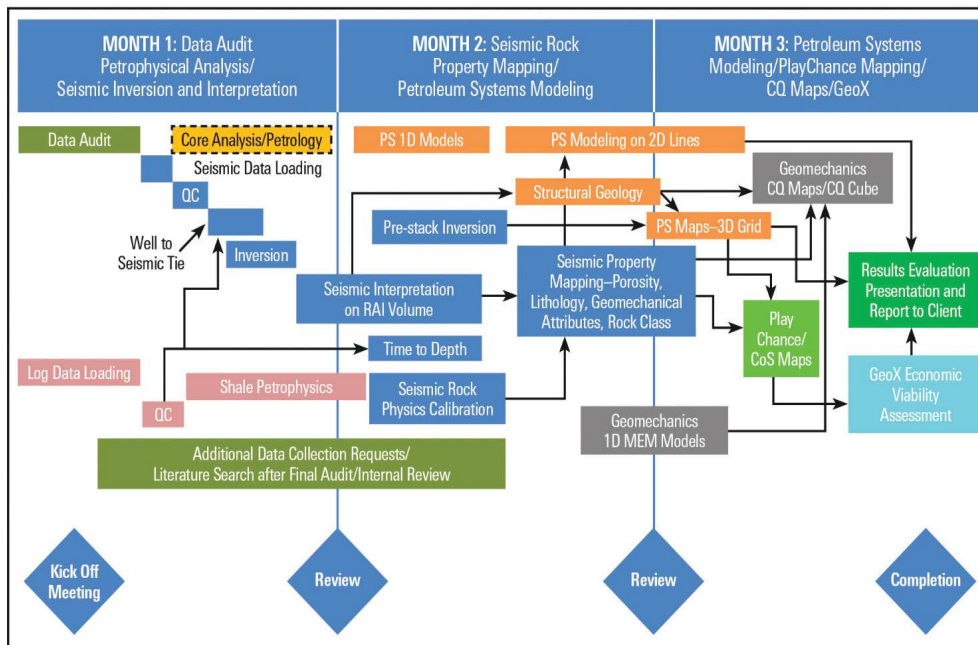
Several rapid resource assessment workflow case studies have been performed globally, including the Middle East, North Africa and Western Europe. The primary objective has been to evaluate the potential of unconventional source rocks by integrating all available reservoir data in a seven-phase process over a period of just three months. The methodology provides valuable information in determining the economic viability of an initial exploration program.

The initial concept for each resource assessment study

focuses on key reservoir quality (RQ) elements. Combined with completion quality (CQ) maps, a multidisciplinary team determines if there are viable locations for testing reservoir potential in a given basin. Once a location with a high chance of success has been identified, the team provides detailed data, planning and recommendations for a pilot program to appraise the formation.

Baseline of understanding

An important aspect of the early exploration resource assessment workflow is to establish a baseline of key production drivers defined by lessons learned in North America that can be applied to emerging unconventional developments considering that every shale is unique. Production drivers

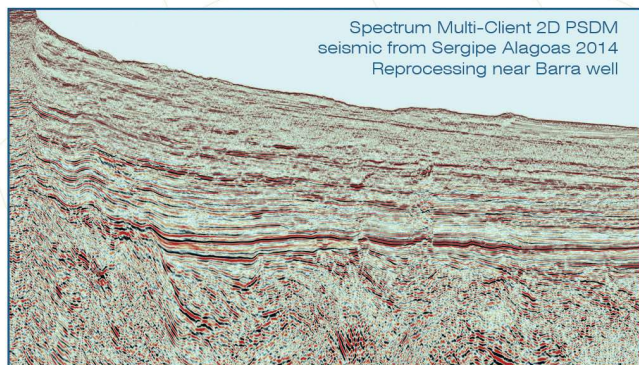
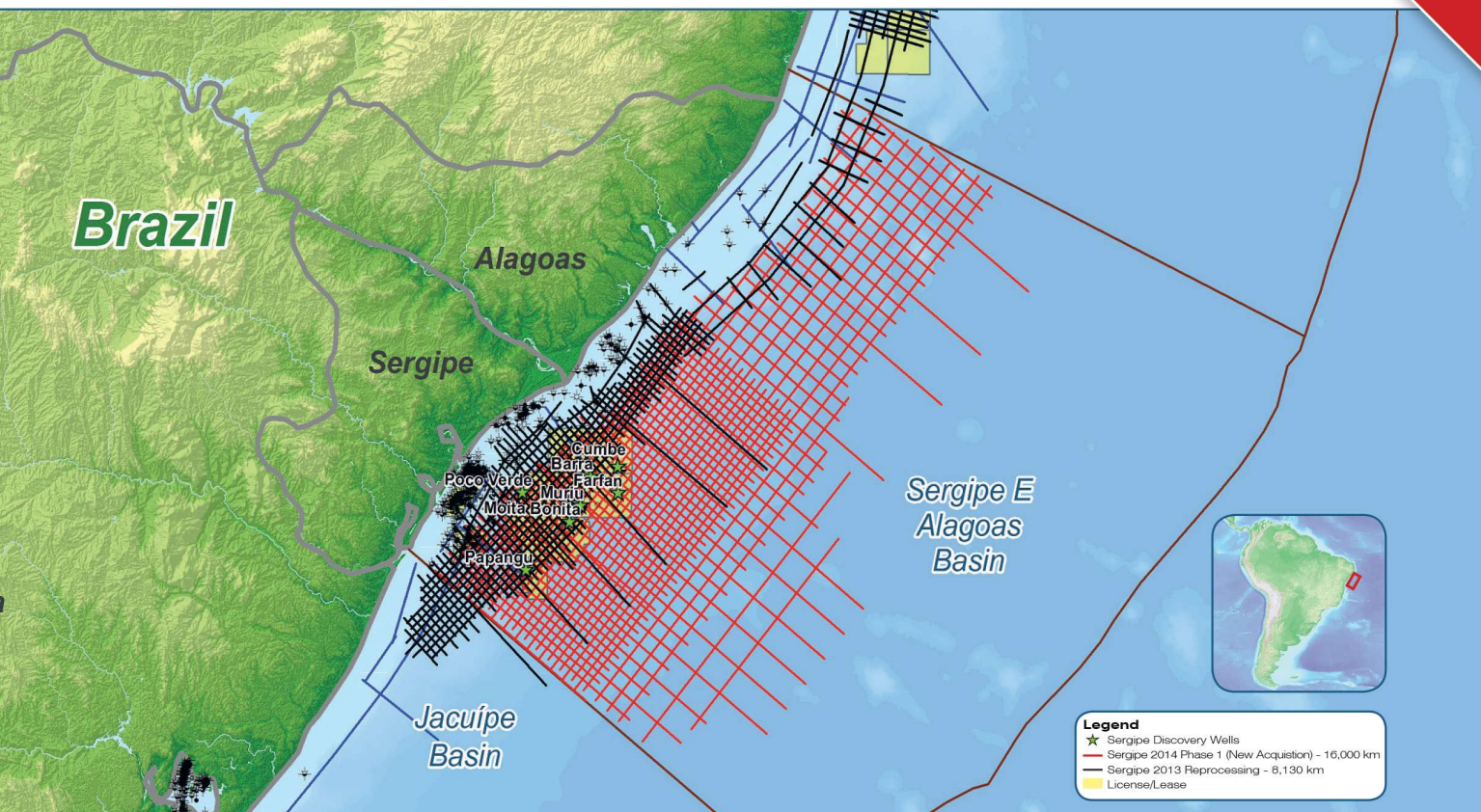


A generalized workflow allows for exploration of unconventional source rocks.
(Source: Schlumberger)

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Spectrum has commenced a 16,000 km Multi-Client 2D seismic survey offshore Brazil in the Sergipe and Alagoas Basins along the Eastern Margin of Brazil. The new acquisition program will tie key wells in the Basins including the recent Barra, Muriu, and Farfan discoveries. PreSTM and PreSDM data will be available in Q4 2014.

To supplement the new acquisition in this active exploration area, Spectrum has completed the reprocessing of 8,130 km of data through both PreSTM and PreSDM and is offering this data to industry in order to gain a head start on the expected upcoming round in 2015.

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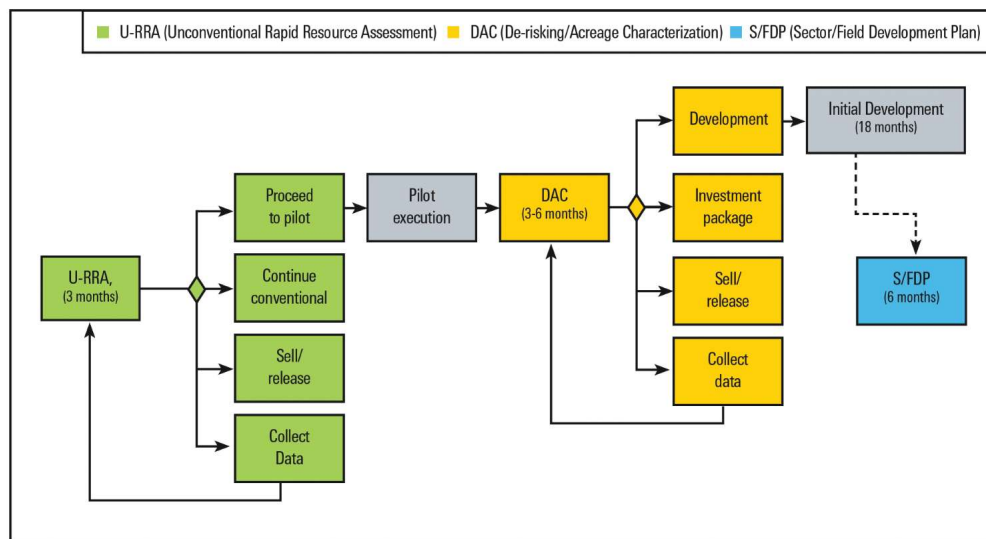


include charge or hydrocarbon-generation factors as well as migration and maturation risks and volume related to the organic material in the source rock; RQ features such as porosity, hydrocarbon saturation, thickness, lithology, total organic carbon/kerogen type and maturity of the petroleum system; structural components, including natural fractures and complexity; CQ factors, including fracture geometry, fracture conductivity, geomechanics and lateral CQ variability; and fluid-related deliverability components, including pressure, viscosity and fluid phase envelope.

For each study performed with the workflow so far, limited logging data across the source rock interval and some previous geochemical analysis of the source rock has been used. We place initial emphasis on log analysis. Petrophysical shale evaluation on selected log suites from existing wells that have penetrated the source rock interval provide an understanding of the formation. Typically, three to five key wells are selected for shale gas analysis. However, all available existing well data in the area of interest are incorporated into the model and for constraining data inputs into other phases of the study.

The goals are to assess the potential of the source rock and make recommendations for core and log measurements needed in future boreholes targeting further assessment of the source rock. Shale evaluation data also integrate into the other phases of the study.

The next phase of the workflow, seismic reservoir characterization, integrates available 2-D and 3-D seismic data to construct a 3-D depth model over the entire area of interest. As large basin areas of 2,000 sq km to 5,000 sq km (772.2 sq miles to 1,931 sq miles) are commonly assessed, the seismic plays a critical role in building and representing the structural framework that feeds into the petroleum systems modeling workflow. By converting inverted seismic attributes such as acoustic impedance and Poisson's ratio into lithology and porosity measurements, spatial maps of reservoir characteristics can be created to better understand the depositional environment and locate spatial variations, which are key indicators of reservoir quality.



The decision-making process is outlined from the exploration workflow through to sector/field development planning. (Source: Schlumberger)

Determining play viability

The centerpiece of the workflow is petroleum systems modeling to quantify and understand the subsurface and provide insight into the viability of shale plays. Accumulated hydrocarbons generated and retained within the source rock interval are modeled by reconstructing the burial history of the rock to understand when the rock reached the depth of burial and temperature where the organic material began converting to hydrocarbons. Organic material matures and converts in different phases of hydrocarbon—bitumen, oil and gas—at different temperatures and is dependent on the time exposed to sufficient heat flow for the maturation process.

Results from the petrophysical evaluation, seismic reservoir characterization and petroleum systems modeling are integrated to generate play fairway maps, which determine viability and identify the target areas where an operator would have the best chance of drilling a successful pilot exploration well.

Based on the RQ and CQ production drivers, the maps determine how much of the organic material has converted to hydrocarbons based on being buried at the right temperatures. If the conversion ratio is too low, the play typically won't generate enough mobile hydrocarbons to be producible; if the transformation ratio exceeds a certain threshold, there is a reasonable chance enough mobile hydrocarbons will accumulate in the pore spaces to be producible.

Other variables often used in the play chance mapping include porosity, vitrinite reflectance and hydrocarbon saturation. It also is important to understand the potential variability of CQ. The expectation is that any uncon-



ventional source rock would require multistage hydraulic fracturing to produce desirable economic rates. Based on tectonics or stress predictions, a CQ mapping layer can provide early indications of where the operator might best place locations with a high chance of being able to initiate fractures in the source rock.

The final step is to perform an economic viability assessment by dividing the study areas into assessment units characterized by similar RQ. A probabilistic assessment of the range of resource volumes in place is then calculated using a specialized toolkit to perform simulations as part of the unconventional resource assessment. By assigning screening economic assumptions on well density together with drilling and completion costs, EURs, and initial production in each assessment unit, it is possible to further account for variable CQ.

Information from the play fairway mapping combined with these petroleum engineering estimates can provide probabilistic estimates of economically recoverable resource volumes in each assessment unit, establish

whether there is opportunity for economically viable production and select the most favorable areas for further evaluation and/or exploration drilling.

Using this information delivered in a rapid time frame and encompassing a broad range of parameters, including economics, the unconventional exploration workflow enables operators to make informed decisions, fast-tracking pilot programs into high chance-of-success locations in new formations and avoiding drilling expensive exploration pilots in areas with no or low potential.

This is only the first step in providing a systematic and efficient decision-making package for the unconventional life cycle. Once a successful pilot program has been undertaken, the model can be rapidly updated during a further de-risking/accreage characterization phase. This becomes the catalyst for an initial ramp-up phase by providing a ranked well inventory. With continued success in the ramp-up phase, the way is then clear for the development of more detailed sector or field development plans. **E&P**



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Vertical success in Poland

Testing leads one company to conclude that a successful horizontal well is the likely next step.

John Harkrider and Tyler Micheli, SIGMA³

While some operators may have given up on the potential of shale gas in Poland, San Leon Energy (SLE) is invested and blazing a trail in the Baltic Basin, determined to find the sweet spots, optimize production and prove commercial viability. As is typical in unconventional reservoirs around the world, the Gdansk W Concession has thick, laterally extensive source rock 3,000 m to 4,000 m (9,843 ft to 13,123 ft) deep.

SLE has been performing a methodical vertical frack testing program in the upper and lower Ordovician target zones to determine the frack design that will allow commercially viable gas flow when effective stimulation is applied to future horizontal wells.

After testing two frack strategies in the lower Ordovician, both of which showed suboptimal proppant concentration, SLE's objective for the stimulation in the upper shale interval, an area not previously stimulated, was to prove the ability to fracture and enable sustained production. A key objective was to achieve a high proppant concentration and, if successful, the same strategies would then be applied to a multistage stimulated horizontal well in the lower Ordovician, which has superior gas saturation and porosity, with the intent to open the upper and lower intervals and deliver consistent commercial flow rates.

Stimulating the upper target zone

In November 2013 the SIGMA³ engineering team performed the stimulation design and onsite real-time fracture monitoring on the two-stage hydraulic fracture treatment conducted by United Oilfield Services (UOS) that targeted and stimulated the lower and upper Ordovician Shale.

Stage 1 was a refrack of the lower zone, and its treatment design served as a starting point for refinement based on the response of the formation. Although proppant concentration improved, the results were still not viable for sustained production.

The objective of Stage 2 was to incorporate lessons learned from the frack/refrack of the Lower Ordovician interval as well as efficiency improvements in drilling and fracturing operations that are being applied to shale wells in the U.S. to:

SLE has been conducting a vertical frack testing program in the Baltic Basin in Poland. (Source: UOS)



- Effectively stimulate the upper Ordovician;
- Evaluate the formation response during the hydraulic fracture treatment; and
- Identify opportunities for improving stimulation.

Integrated approach

By analyzing the geology, reviewing lessons learned during the frack and refrack of the lower zone and drawing from experience in other shale reservoirs, the onsite team designed a plan (Stage 2) that would best match the formation's response to treatment.

Stage 2 was pumped through a new set of perforations, with a plug above the lower zone to isolate the upper Ordovician from the previously fractured lower zone. When the perforating guns were fired, frack pressure from the earlier frack stages was communicated into the wellbore through the new perforations, indicating that previous fracks grew to at least the level of the new perforations (27 m [89 ft]).

SIGMA³ had a plan that enabled the onsite engineering team to adapt the treatment design quickly to match the formation's response, and SLE considers Stage 2 as proceeding exactly as planned.

By taking into account excessive fracture complexity and proppant type and reducing the treatment rate, Stage 2 placed far higher proppant concentrations into the for-



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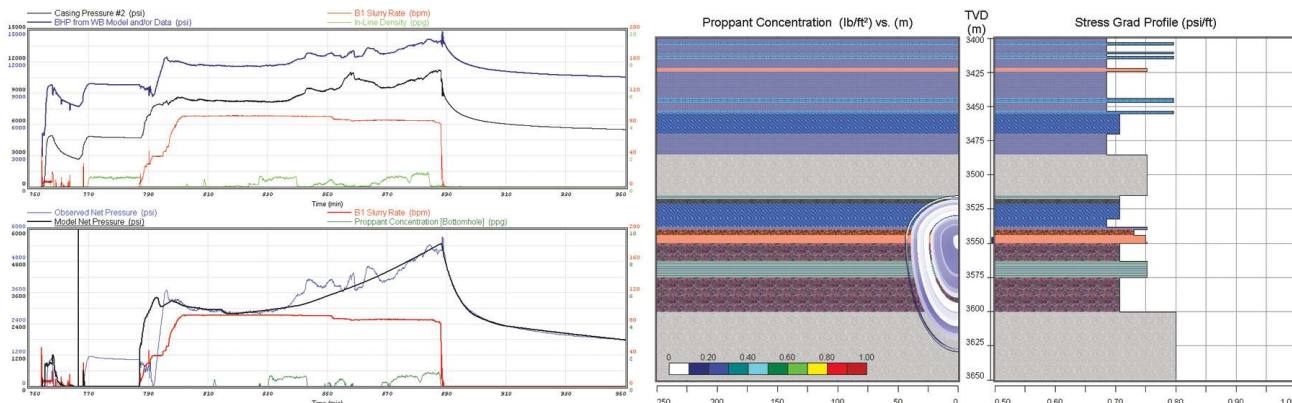
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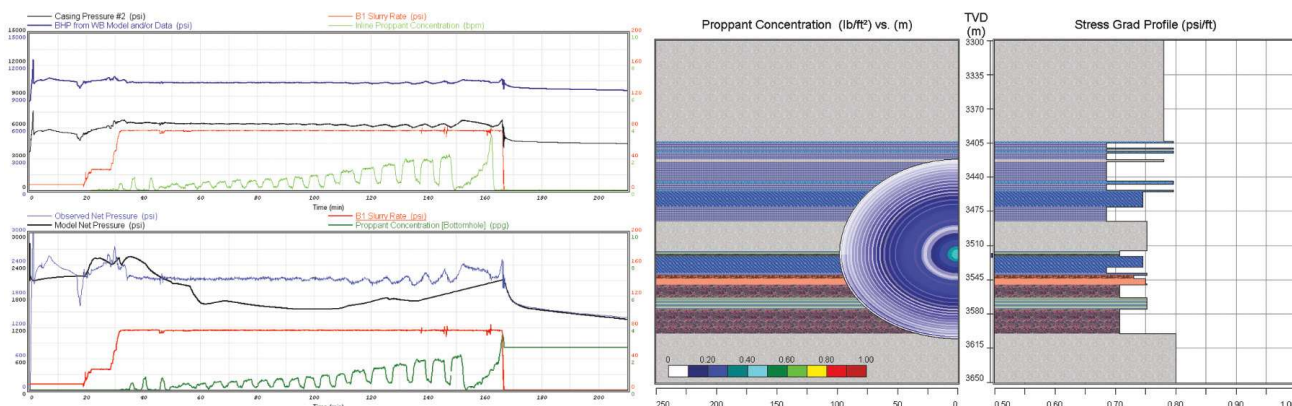
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Stage 1 shows the failed treatment and resulting small and under-propped fracture geometry. (Source: SIGMA³)



Stage 2 shows a successful treatment and the resultant track geometry. (Source: SIGMA³)

mation with little pressure increase. Frack modeling indicates this stage grew down well through Stage 1's target and into the lower target zone.

"SIGMA³ provided engineering expertise for the final frack campaign of the vertical well, and it went exactly as planned," said Joel Price, COO for SLE. "This breakthrough frack design is critical to the successful shale development in Poland's Baltic Basin as well as Europe by association. We are excited about applying these learnings to the upcoming horizontal well with the aim of achieving commercial flow rates."

Penetrating lower target zone

SIGMA³ advised, and SLE/UOS agreed, that all sustained production is coming from the upper Ordovician zone, although simulation suggested the frack may have penetrated the lower Ordovician. The frack did not stay open, most likely due to the higher clay content layer between the upper and lower target zones. To maximize the potential to connect the lower and upper targets of the horizontal well, future completion strategies will place higher

conductivity and relatively wider fractures, with particular attention given to proppant type. This type of design should help avoid proppant embedment in the higher clay content layer.

Commercially viable horizontal well

"The vertical well was the testing ground, enabling us to learn more about the well properties and change the stimulation program to achieve maximum production. We are confident that fracks can be designed in the horizontal well that will cover the entire Ordovician target zone," Price said. "SIGMA³ and the team concluded that the production from the third frack campaign is coming from the upper half of the formation. The lower interval has even better reservoir characteristics and is our primary target. There is significant upside once the horizontal well is executed."

SIGMA³ will be participating in frack design and analysis of the upcoming horizontal well, set to drill and frack later this year. The frack program will be 10 to 30 stages, similar to completions in the U.S., and will build on the successful aspects of the vertical well's stimulation. **ESP**

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Photo credit: Ron Rulhoff, VISIT DENVER

Top-drive sensors, monitors provide real-time preventive maintenance

Drilling contractors can plan routine equipment maintenance and prevent downtime, providing near-instantaneous information to monitoring personnel.

Ryan Graham, Tesco Corp.

Strides within the industry to keep drilling equipment fully operational often result in pushing equipment beyond its design limits and impacting the ability to ensure it is running at optimal condition. Typical maintenance programs rarely coincide with fast-paced drilling cycles and accelerated rig moves. Furthermore, with the industry use of pad drilling, few hours are left between the end of drilling one well and starting the next one, the time that traditionally allows maintenance to take place.

To address the industry's concern, Tesco Corp. (TESCO) developed the Equipment Health Monitoring (EHM) system, a sophisticated system of sensors, communication infrastructure and real-time monitoring support. Using the array of features within the EHM, drilling contractors can plan routine equipment maintenance and prevent downtime. This preventive maintenance allows

drilling contractors to more realistically meet scheduled operational deadlines and reduce nonproductive time (NPT), ensuring the quality of its equipment over the product's lifetime.

Considering the significant contribution the top drive provides to the drilling operation, early development of the system chartered that both hydraulic and electric TESCO top-drive models were to be fully commercialized at product launch. During field-testing of the EHM, both top-drive variants were exposed to real-world drilling conditions, providing full system product assurance. Test sites included multiple locations throughout varying regions of North America as well as international locations, where part failures without the EHM system could result in excessive NPT.

Efficient maintenance

The EHM adds value to the rig operation by ensuring that maintenance is conducted efficiently, discovering potentially defective parts that need to be replaced before failure, and positively impacting the bottom line by reducing the spare parts inventory required on the drillsite.

The system provides field technicians with step-by-step guidelines to easily perform maintenance and gives supervising service managers insight into the work being performed. Operations managers have detailed diagnostics into how the top drive is being used, allowing for optimal operational planning.

These benefits stem from the main features of the system, which fall into three categories: asset management, maintenance tracking and predictive health monitoring. The EHM technology allows drilling contractors to view the current operating status and GPS location of their equipment, review and manage maintenance records, and proactively plan for service events remotely from anywhere in the world using the TESCO MATION web portal.



EHM cabling is installed and cleanly tucked to prevent snagging with the derrick. (Source: Tesco Corp.)

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Sensors monitor parameters

A network of sensors connected through a wired and wireless infrastructure provides near-instantaneous information available to monitoring personnel. The current EHM system includes pressures, fluid flows and temperatures monitoring critical path components. If these parameters went out of range, it could quickly impact the performance of the top drive.

An example would be a fast pressure drop in the lube pressure hose on an electric top drive that would quickly be identified and signal that action must be taken, reducing the impact to the equipment before a catastrophic event could occur.

In addition, shock and vibration sensors are used to provide a holistic understanding of the overall use of the equipment. The EHM is able to predict critical system failures by analyzing both real-time and historical data. These predictive abilities combined with an experienced operational support team can greatly reduce unforeseen damage to the top drive.

By analyzing an increasing vibration in the gear train, this trend could potentially indicate a failing part, or by looking at extreme shock events, monitoring personnel may be able to determine equipment abuse. By allowing users the ability to review historical equipment utilization trends, comparisons can be made between current and past driller performance.

Trending data also provide insight into parts fatigue and can identify when to service parts, avoiding NPT caused by a failure and ultimately lowering operating costs and reducing parts inventory.

Service personnel are able to plan, record and report maintenance events for the top drive by using TESCO's Wellsite Interface Panel on the rig. If a service event is performed, this same interface is used to update the system without the need for paper copies that are hard to track and require additional documentation control.

Maintenance and service data become available for review by anyone from anywhere with an Internet connection. Through the TESCOMATION web portal, it is also

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possible to set up maintenance scheduling and alerting based on TESCO's Global Preventative Maintenance Program guidelines. If maintenance has been missed, email notifications can be set up to remind field technicians or supervising personnel, automating the call to response.

An additional advantage of the web interface is a direct link to the aftermarket sales and service teams for help with parts identification and ordering, further reducing NPT by ensuring accuracy and reducing potential miscommunication.

Installation kits

Specific installation kits are available for all of TESCO's hydraulic and electric top drive models between 150 tons and 750 tons.

EHM installation kits feature a robust, field-tested programmable logic controller (PLC), a wireless access point and electronics contained within stainless steel enclosures located on the top drive. The remainder of the kit contains Class 1/Div 2 wireless antennas, sensors, cables and interconnections with other rig components such as the Top Drive PLC to ensure critical data are fed into the EHM system.

Satellite or cellular services are available to connect the rig to the web portal, or the system can plug directly into the rig's communication system. Installation of an EHM system can easily be performed between spud dates or during the recertification of the top drive.

The EHM system is scheduled to be commercial by Dec. 31, 2014. Several drilling contractors have already used the system on their rigs as part of the external field trial stage.

Continuous monitoring of the top drives on these rigs has assured proper maintenance to the equipment. Furthermore, TESCO's rental fleet has 11 units installed as part of the internal field trial test phase. These rental units are already seeing the benefit to increased drilling uptime.

Currently developed for TESCO Top Drives, the EHM system will be expanded to include TESCO catwalks, third-party top drive models and other rigsite equipment, providing rig contractors cross-product commonality. **E&P**



A TESCO field technician checks a sensor on the top drive after installation.

(Source: Tesco Corp.)

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Engineering solutions teams drive drilling efficiency

To expand the performance envelope, a strong engineering capability for both planning and delivery is needed.

Jeremy Greenwood, Halliburton

The continual delivery of consistently improving performance and efficient operations in the many diverse global petroleum plays can provide significant challenges to both operators and service companies. Although it is relatively easy to establish a status quo for performance and be satisfied when nothing goes wrong with an operation, it is a very different proposition to drive a process of continual improvement that may briefly increase the risk profile as new approaches are tried.

As each performance enhancement is delivered, the next set of challenges to overcome continues to increase in complexity, and potential solutions become fewer. Options also are restricted by the economic constraints associated with the exploitation of hydrocarbons across the spectrum of well and reservoir types, limiting the solutions that can be developed and deployed.

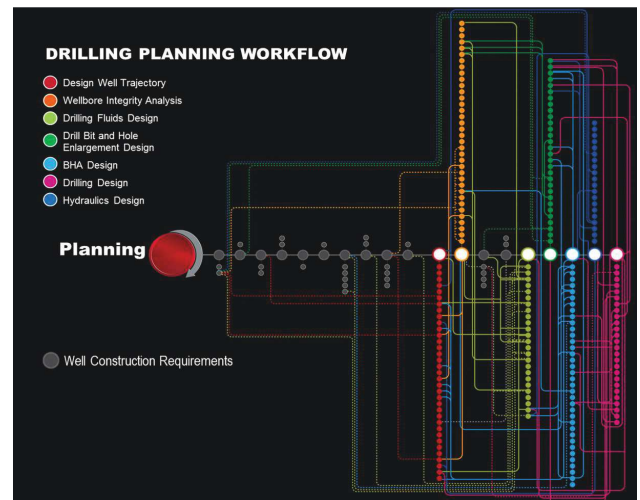
The capability to identify the specific requirements of each unique situation is only effectively achieved through the creation of experienced multidisciplinary teams. An engineering solutions team with the right blend of abilities can identify the factors limiting performance and develop the most effective answers.

Halliburton's response to this market need is the creation of Drilling Engineering Solutions (DES) teams to develop this ability in key geographical locations globally.

Performance improvement opportunities

Opportunities for increasing the performance of an operation can be classified in three ways, including risk mitigation that prevents failures and cost overruns, drilling efficiency that decreases the required expenditure and improves the capital efficiency and improvements in the productivity of the well or field.

The development of a strong engineering capability for planning and delivery is needed, with teams of domain experts who can analyze the drilling behavior and develop new designs as well as field engineers with specialist training in interpreting surface and downhole measurements.



A comprehensive planning workflow enables design optimization and increased drilling efficiency. (Source: Halliburton)

Risks created by unplanned events or conditions, rather than those that are expected, are mitigated through delivering the required wellbore trajectory and reducing positional uncertainty. This type of risk mitigation includes survey management and controlling drilling dynamics, vibration and stress overload to prevent premature failure of equipment and reduced drilling performance. It also includes determining the wellbore integrity and *in situ* wellbore pressure boundaries and managing the hydraulics system to remain within the wellbore pressure boundaries and deliver effective hole cleaning. All of these requirements need to be managed effectively to maximize the average ROP.

Drilling efficiency opportunities occur most often during the planning of the well, in which the single best well design and equipment are selected from many options. At this stage, the previous performance is analyzed, the factors limiting efficiency are identified and solutions are developed; both technical and economic feasibility is assessed. Fluids, drilling systems and drillbits can be custom-designed for the expected conditions. Managed pressure drilling and underbalanced drilling feasibility studies can be performed and procedures and best practices created for the operation.

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Productivity improvements can be delivered through improved planning and during execution. Planning the most efficient field drainage pattern with the minimum number of pads or wells will decrease the overall cost.

Understanding the reservoir geomechanics to orient the reservoir sections to maximize fracture potential or minimize the sanding potential will increase the total production from the field. Geosteering the wellbore to maximize the reservoir contact and drilling wells underbalanced to reduce skin damage will improve the production per well.

The Halliburton software platform DecisionSpace Well Engineering contains commercial engineering modules and has been devised by Landmark to enable the development of plug-in modules. This capability enables individuals to develop their own software applications containing proprietary capabilities and have them work in the same software framework and access the same database.

For the DES teams, an application called DrillingXpert has been developed on the DecisionSpace Well Engineering framework providing full access to all of the commercially available and Halliburton-proprietary analytical software tools and planning databases used by solutions teams.

Performance improvement in action

A steam-assisted gravity drainage well pair placement had the potential for future infill drilling and needed to maintain the wellbore quality within softer unconsolidated formations.

The planning phase required a detailed analysis for the trajectory designs and the application of survey management to perform quality control to reduce the uncertainty of the wellbore positions. This need also extended to the geosteering modeling required. It also was necessary to ensure that correct LWD tools were selected to determine the proximity to the reservoir boundaries while maintain-

ing bottomhole assembly (BHA) directional performance.

The wellbore integrity analysis required the development of methods to maintain the stability of the oil sands while drilling. The bit design must resist abrasion from drilling the sands, maintain ROP and be matched to the BHA for directional performance. The BHA design required that it could deliver a wellbore with minimum tortuosity while steering effectively in the unconsolidated formations.

The project required that a minimum of a 3-m (10-ft) standoff was to be maintained from the reservoir base and that a smooth wellbore was delivered with less than 3 deg/30 m (3 deg/98 ft). Tortuosity would be minimized through no overcorrections while maintaining extremely tight injector/producer steering windows; a 5-m (16.4-ft) offset would be maintained between the injector and producer wells.

In addition to the geometric constraints, the geology also played a significant role. The reservoir sands are part of a fluvial-dominated estuarine complex, and the base reservoir is rarely flat for any large extent, with 1-m (3.3-ft) to 3-m localized variations being common. Consequently, the modeling of tool responses in this environment was required. To improve detection of bed boundaries, an azimuthal resistivity tool was selected as the best measurement.

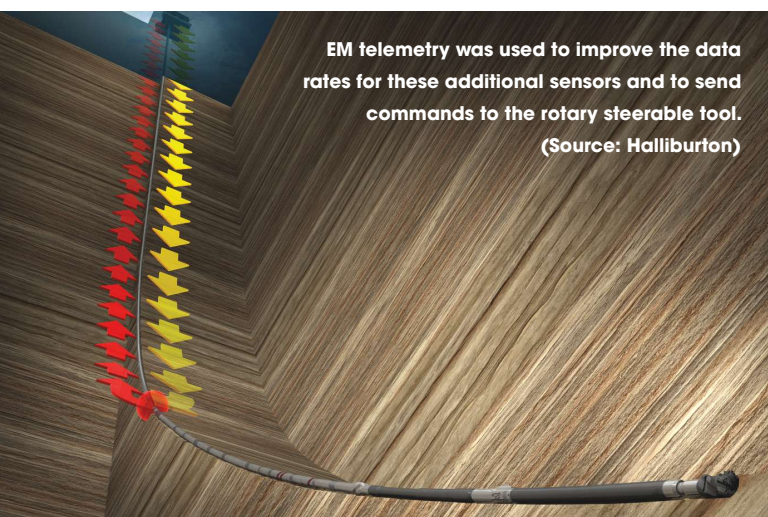
The reservoirs in question consisted primarily of bitumen that will flow when heated. Mud coolers were used to maintain the drilling fluid temperatures to be as close to the virgin reservoir temperature as possible. Temperatures of about 20 C (32 F) were maintained, which then controlled the choice of the elastomer used in the motor power sections and the choice of oil used in the rotary steerable system (RSS).

Additional limitations were imposed by the rig, with surface revolutions per minute (rpm) limited to 60. The use of long-gauge bits with a point-the-bit RSS was proven to deliver a considerably higher hole quality than the use of a motor or of push-the-bit systems. In this case, a RSS powered by a downhole motor was selected to meet the trajectory challenges and to provide greater bit speeds without exceeding the 60-rpm surface limit.

BHA design modifications

Further modifications of the BHA design were required. The RSS was customized for the softer formations with extended-reach rollers added to the reference housing. The second modification was the addition of a lower housing stabilizer to help compensate for hole enlargement. If the formation compressive strength is less than the fulcrum force, the hole will enlarge until the forces balance, reducing the build/drop capability of the tool.

This design moves the fulcrum point back from the bit



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to the stabilizer, which is nonrotating, reducing the hole enlargement because there is no side cutting. The final modification is the upper stabilization optimization, which resulted in significantly lower cumulative doglegs and greater consistency in reducing the doglegs compared to conventional mud motors.

To maintain the distance above the base reservoir, an azimuthal resistivity tool was used. The tool assigns the resistivity measurements into 32 bins to provide an up-and-down resistivity measurement that has significantly more character than an averaged measurement in determining distance to bed boundaries.

The tool has three frequencies, enabling it to identify bed boundaries up to 5.5 m (18 ft) away, and under ideal conditions it has greater vertical resolution and accuracy in high-resistivity formations. Using this type of measurement will map out the base reservoir surface for the entire lateral section as compared to shallower reading measurements in which intermittent identification of the reservoir surface is obtained.

To improve the data rates for these additional sensors and to send commands to the rotary steerable tool, electromagnetic (EM) telemetry was used. EM telemetry also has the benefit of not requiring a differential pressure to function. Active ranging, where an EM signal is emitted from the target wellbore, was used both to twin injector and producer wells and to range wellbore positions to the observation wells, which are important when modeling the life of the reservoir and the effectiveness of the steam injection.

To manage and successfully deliver all of the elements of this engineered solution, an established and documented diagnostic approach is necessary, which includes a formalized engineering process that crosses multiple disciplines and determines the interaction of different experts.

Establishing a dedicated organizational capability ensures a rigorous adherence to procedures while providing the level of integration to design fit-for-purpose drilling systems and establish consistent connections between planning and execution. **ESP**

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Pumping paradox solved

High reservoir temperatures, wellbore deviations and abrasives are a way of life in Canada's oil sands. So how does a company increase the reliability of downhole pumping equipment while also meeting the challenge of these extreme conditions?

Colin Drever and José Caridad Urena, Schlumberger

Canada has the third-largest oil reserves in the world, with 168 Bbbl situated in the oil sands of Alberta and Saskatchewan. However, more than 80% of this resource is too deep to be mined and requires an *in situ* recovery technique. The oil sands consist of a mixture of sand, water, clay and highly viscous bitumen. This mix requires a complex combination of thermal and artificial lift techniques to mobilize the fluid to surface. But despite the tough environment, the valuable prize contained in the oil sands inspired an industry accustomed to technical challenges to hone its methods for extracting heavy oil.

SAGD and ESPs to the rescue

Steam-assisted gravity drainage (SAGD) emerged as the preferred *in situ* recovery method for these oil sands. SAGD involves the horizontal drilling of two wells, one (an injector well) above the other (a producer well), typically with 5 m (16 ft) of vertical separation. Steam is pumped into the upper injector well to heat the bitumen and reduce its viscosity. Through gravity drainage, the resultant emulsion of oil and water can be produced to surface via the lower producer well.

On paper, this process sounds simple; however, its effectiveness depends on many factors, including reservoir depth, quality and thief zones, where the required reservoir pressures and temperatures needed to mobilize and lift the bitumen to surface can be difficult to achieve. Additionally, the steam/oil ratio (SOR) has a significant impact on the efficiency and economics of the SAGD process, and optimizing the SOR is key to a successful project.

Initially, most SAGD wells were completed with gas lift systems, which provided a simple completion solution and had no temperature limitations. The downside was that gas lift required a minimum reservoir pressure, and with the drive to optimize the SOR through lower steam and reservoir pressures, the limitations of gas lift completion were soon recognized. The industry was forced to look for alternative artificial lift solutions.

One such alternative was electrical submersible pumps (ESPs). ESPs do not have the reservoir pressure limita-



The Schlumberger REDA Hotline SA3 third-generation high-temperature ESP system integrates components to boost reliability and efficiency. (Source: Schlumberger)



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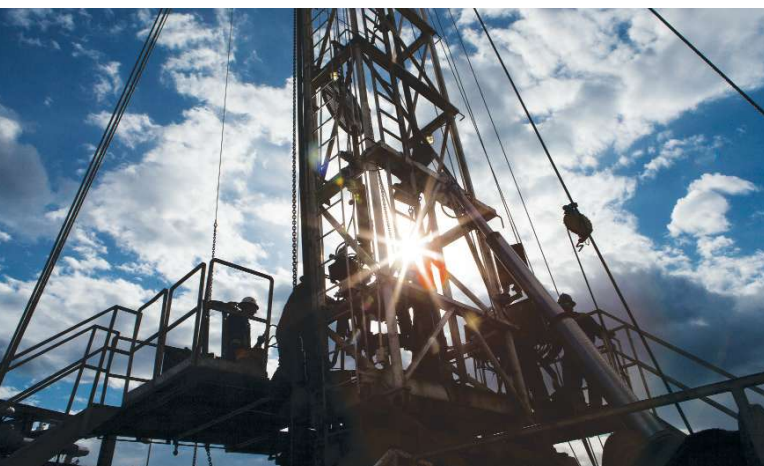
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tions of gas lift and can operate over a wide range of flow rates typical of SAGD wells. The challenge was that the maximum operating temperature of the electric motor was 150 C (302 F), too low for SAGD wells.

The introduction in early 2003 of the Schlumberger REDA Hotline 550 ESP system changed the landscape because this system was the first high-temperature ESP—rated to 218 C (424 F). This increased temperature rating provided SAGD operators with the ability to install ESPs in their wells, enabling them to lower reservoir pressures, lower SOR and ultimately lower production costs. The enhanced capabilities marked the start of an ESP revolution, and today more than 700 ESPs are operating in SAGD wells in Canada.



A Hotline SA3 ESP is deployed in a Canadian SAGD well.
(Source: Schlumberger)

Challenge and success

The success of the Schlumberger Hotline ESP encouraged SAGD operators to push the pump's operating envelope, challenging ESP suppliers to develop systems that could operate at even higher operating temperatures—up to 250 C (482 F)—and with the improved reliability needed to prolong ESP run life. Starting in 2007, engineering teams in Singapore and the U.S. began working on a new high-temperature ESP system. The result was the REDA HotlineSA3 third-generation high-temperature ESP system, which features the first step-change in ESP design. A new integrated configuration of the internal motor is a complete rearrangement of the traditional ESP design. Unlike conventional ESP systems, the seal section of the integrated motor, often referred to as the protector, is split in two. The shaft sealing functions are maintained on top of the motor section within the shaft seal module (SSM), while the motor oil compensation and pressure equalization functions are moved below the motor. The SSM,

motor and compensator, and sensor portal make up the integrated motor component.

The short shaft sealing sections are stacked on top of the motor to add redundancy and layers of protection, thereby enhancing motor reliability. The shorter SSM increases the tolerance to dogleg severity (DLS), which can be substantial in SAGD wells. When operating in high-DLS wellbores, the ESP components—shafts, flanges, bolts and bearings—are subjected to mechanical stresses that can be detrimental to the ESP and can ultimately reduce run life. The SSM also includes filters to prevent damage to sealing components and ceramic bearings with a high load capacity to handle abrasives. With the compensator located at the bottom of the motor configuration, the pressure equalization and abrasives are isolated from the critical components of the SSM.

To further improve the reliability of the system, all non-metallic components were reassessed and upgraded to withstand the new well temperature rating of 250 C and internal motor temperature rating of 300 C (572 F). O-rings, motor insulation, motor oil, and radial and thrust bearings also were upgraded.


The integrated motor incorporates a prefilled plug-in concept, which reduces the potential for human error during system installation. Motor oil is prefilled at the factory or service center, eliminating the need for filling at the well site. The prefilling process uses ultrapurified motor oil that increases insulation and reliability. The plug-in pothead design has a positive pressure system and dual elastomeric seal to prevent fluids from escaping and entering the motor while the connection to the power cable is being completed.

Finally, to improve ESP performance and provide the opportunity for well optimization, a sensor portal was added to the system. The sensors measure internal motor temperature and annulus pressure and temperature.

Paradox solved

At first glance, the challenge of successfully operating an ESP in a SAGD well seemed impossible. The presence of very high temperatures, high well deviations and abrasives were all components that typically led to early ESP failure. However, by tackling the problem head on, engineers eliminated each of these problems. Moving away from conventional ESP architecture to the integrated motor configuration along with the availability of high-temperature materials proved to be the turning point in improving ESP reliability and operating range.

The result was that ESPs—which lower lift costs and improve production uptime—continue to be the preferred artificial lift method in SAGD. **ESP**

The background of the advertisement is a photograph of an oilfield at sunset. A tall derrick is silhouetted against a bright orange and yellow sky. Several workers in hard hats are visible on the derrick and on the ground. The overall tone is industrial and professional.

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Sucker rod helps overcome challenges in unconventional wells

Rod connection design improves field performance and rod's fatigue life.

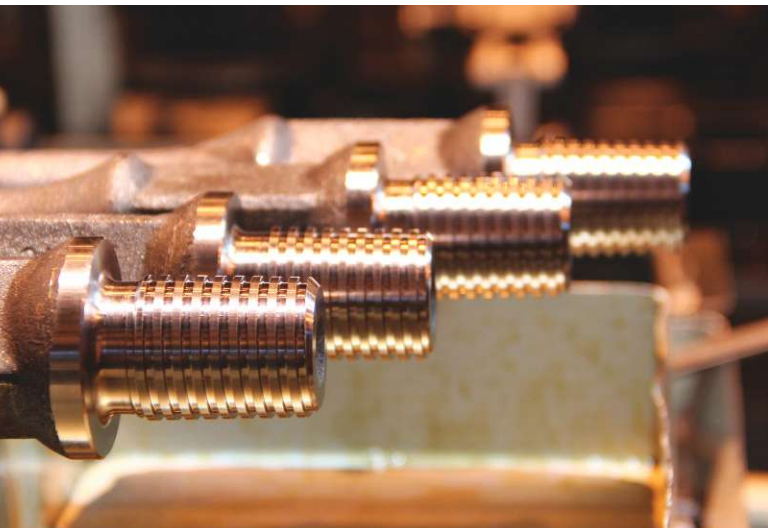
Rodrigo Ruiz Saavedra and Gustavo Alvarez, Tenaris

Shale plays usually require artificial lift systems, mostly because of rapid depletion rates during the first year. Sucker rods with more resistant connections that overcome the limitations of conventional designs provide numerous advantages in unconventional wells that use beam pumping.

In the first stages of oil production, oil and gas flow easily from the reservoir to the surface. The well's high reservoir energy ensures high production rates. However, pressure soon and rapidly begins to fall, making it necessary to resort to artificial lift systems. For a period of time, transitional methods are enough to keep production going at acceptable levels, but beam pumping soon becomes the best option.

Beam pumping applications for shale wells

Shale operations have been consistently growing in number in recent years, posing increasing challenges such as deeper wells, deviated wellbore geometries, corrosive environments and higher production rates.



Tenaris's BlueRod connection was designed especially for high loads. (Source: Tenaris)

In this scenario, beam pumping applications can offer many advantages. They are a flexible form of artificial lift as well as a cost-effective method able to handle different well conditions since they can be used in a wide variety of production rates and depths.

To design a beam pumping application, operators must take into consideration the costs as well as the expected run life of the system as a whole. A beam pumping installation for shale wells is typically characterized by:

- Tubing size: 2½ in. or 2 in.;
- Pump plunger diameter: up to 1¾ in.;
- Rodstrings: 86 (1-in. SH-7/8-3/4) or 76 (7/8 SH-3/4);
- Rod steel grades: D or D Special (due to H₂S presence);
- Pump depth: 2,134 m to 3,048 m (7,000 ft to 10,000 ft); and
- Additional loads due to well deviation and use of guided rods.

Sucker rod challenges

Beam pumping applications pose several challenges for sucker rods, strongly increasing the risk of pumping failures. Due to their characteristics, some shale installations require 2½-in. diameter tubing strings. This impacts the size of the sucker rods that can be installed in the column since 1-in. rods do not fit inside this size of tubing. Diameters no larger than ¾ in. with slimhole couplings can be used.

To maintain the pumping and production capabilities of the system, rods must be able to provide maximum tolerance to cycle loads. API rods are limited in this capacity, so high-strength rods are usually required. However, corrosive environments make it difficult to use high steel grades as their mechanical properties increase the risk of facing body failures due to H₂S or CO₂ corrosion.

Shale wells present deviated wellbore geometries and severe doglegs. Pumps must be set beyond the kickoff point (KOP), and this increases tubing-rod contact force. To ensure the required rod and tubing life, molded guides must be included in certain sections of the string with a very severe dogleg or with a constant inclination.

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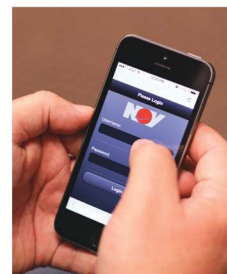
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Conventional rods do not have the increased fatigue resistance required to withstand the extra axial load generated in the pumping cycle by the contact of the guides with the tubing.

Rods with standard connections frequently back off, are easily over- or under-torqued, and present high stress concentration areas because they distribute stress unevenly along the thread profile.

In addition, API connections make it necessary to oversize beam pumping installations in every level because of the deeper depths and common well conditions of shale wells. This situation causes several difficulties, including a heavier rodstring.



The premium rods allow operators to design lighter rodstrings made up of sucker rods with smaller diameters. (Source: Tenaris)

New design for high loads

Tenaris's BlueRod premium sucker rods are especially suitable for shale operations that require beam pumping. The rod connection was particularly designed for high loads, improving field performance as well as the rod's fatigue life. Therefore, they maximize the results of rod pumping systems applications.

Main features include the cut-tapered trapezium profile thread with diametrical interference, which reduces the pre-tension in the pin makeup. The flank-to-flank contact eliminates the gap that is present in the conventional thread profile and increases the interference level, reducing the tendency to loosen. The lower displacement during makeup and uniform contact between the flanks ensures a better stress distribution and a reduction in the

permanent deformations created in threads during both makeup and operation. As they were developed for high loads, they provide improved performance in wells facing this challenge.

Tenaris BlueRod premium sucker rods offer the following benefits:

- Higher working capacity of the rod pumping system to operations that are normally restricted to electric submersible pumps;
- Improved performance in high-load operations;
- Reduced stress level and energy consumption in the pumpjack, as small diameter sucker rods reduce the rodstring's weight;
- Improved performance in mild corrosive conditions with extreme mechanical demands, given that the BlueRod premium sucker rods can be manufactured with 4320 KD steel grade, a softer steel with better toughness and improved fatigue corrosion behavior; and
- Reduced number of sucker rod failures and therefore lower need of workover operations.

Premium rod connections allow operators to design lighter rodstrings composed of sucker rods with smaller diameters. This ensures additional benefits. For example, there is still a chance to use regular pumping units if the design is appropriate, performance improves in high-load operations, and lighter rodstrings reduce the stress level and energy consumption in the pumpjack.

Special tools are not required for handling and makeup operations with Tenaris BlueRod premium sucker rods since conventional power sucker rod tongs can be used. In addition, Tenaris produces all the accessories required for using this product, including reductions and crossovers.

Proven technology

Tenaris BlueRod premium sucker rods already have a history of success. A major U.S. operator chose this technology for a 200-well project in the Eagle Ford Shale. Depletion rates in the Eagle Ford Shale are high. After the first year liquid production tends to drop below 350 bbl/d, so beam pumping is commonly installed.

Tenaris analyzed a representative group of wells from this field to extract conclusions that might help oil and gas companies better choose products for their shale operations. As an example, a representative shale oil well with production requirements of 245 bbl/d and a pump depth of 1,646 m (5,400 ft) was analyzed. The tubing diameter was 2% in., and the pumping unit available was a 640 Mark II with a stroke length of 168 in. This 76 guided design was 90% loaded with premium



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connection Modified Goodman rating with a service factor of 1, what is analogous to a load of 170% Modified Goodman rating of an API D string, SF1. This installation has been running for more than a year without rod failures.

Among the sample of wells analyzed, H₂S concentration found in gaseous face was from 800 ppm up to 2,100 ppm. More than 90% of the premium connection sucker rodstrings installed were 4320 KD grade, and they showed an improved fatigue corrosion behavior.

About 96% of the strings analyzed were guided, a condition that increases the drag force and thus the maximum axial load in the pumping cycle, placing API rodstrings above their fatigue resistance. BlueRod premium sucker rods are designed to overcome this challenge.

The maximum depth for a 1½-in. pump was 3,353 m (11,000 ft) pumping 170 bbl/d. Due to the higher depths and the common shale well conditions, the API connection design sets limits to the beam pumping sys-

tem, forcing engineers to oversize their installations in every level of the system. Using those limits, Tenaris compared an 86 type API D rodstring with a 76 premium rodstring for the same production requirements.

This experience showed some of the benefits of working with premium connection rods. API D rodstrings would be working at 100% of Goodman ratio when a 76 premium connections rodstring would be working at 80% of its total capacity. A 76 premium connection rod design allows the use of a 2½-in. tubing by running ¾-in. with slimhole couplings. In addition, premium rod designs provide a rodstring that is 16% to 20% lighter. Tenaris observed that more than 50% of the pumping units installed with premium connection rodstrings were 640s.

Finally, in those cases where the depth or rate forced the operator to choose an 86 design, premium connection sucker rods offered extra strength using 4320 KD steel with the advantage of providing mild corrosion protection. **ESP**



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As activity booms, the industry is investing time and money in innovating solutions for unconventional production.

Luis Moncada, GE Oil & Gas Well Performance Services

Even as the energy industry continues to report explosive growth of new unconventional oil and gas production activities throughout the U.S., the industry is still experiencing a learning curve as companies seek to better understand the technical challenges involved with operating in such fields. How fast will total production decline over the life of the well? Which artificial lift system is needed at a given time? What is the optimal combination of artificial lift systems to maximize production while lowering lifting cost?

As a result, a tremendous amount of effort and money is being pumped into unconventional wells R&D, which includes improving existing techniques for drilling, setting up equipment in the field and pursuing new technology advancements—including artificial lift systems and remote monitoring applications that help operators maximize the performance of new and existing wells.

Artificial lift, used in 94% of the roughly 1 million oil-producing wells around the world, helps lift hydrocarbons to the surface in reservoirs with low pressure and improves the efficiency of naturally flowing wells. A vast majority of the new unconventional oil and gas sites are horizontal wells, with most of them requiring some form of artificial lift technology. With operators investing \$8 million to \$12 million per well, artificial lift and other well optimization applications have become key targets for R&D.

Research centers

A number of artificial lift research initiatives are underway within the industry, including one spearheaded by the Artificial Lift R&D Council, which established the Horizontal Well Artificial Lift Consortium at the University of Tulsa in Oklahoma. Officially known as the Tulsa University Horizontal Well Artificial Lift Projects, the consortium (which began with 15 companies) is studying how to improve the design and operability of artificial lift, including for shale fields where wells are often deep with long horizontal lateral sections.

Companies also are actively researching artificial lift in other ways. GE Oil & Gas has ramped up its unconventional R&D investments by partnering with customers to find solutions at the company's flagship Global Research Center in Niskayuna, N.Y., and at its Oil & Gas Technology Center in Oklahoma City. The Oil & Gas Technology Center is GE's first industry-specific global research facility and will feature labs, test wells and collaboration spaces. Scientists and engineers at the tech center will be working to develop and apply new oil and gas technologies, products and solutions, and field-testing to determine commercial viability. Scheduled to open in 2015, the center will focus on accelerating mid- to later-stage oil and gas technologies related to production systems, well construction, water use optimization, CO₂ solutions and energy systems. The facility will capitalize on its close proximity to unconventional oil and gas companies in an important producing region.

At the May 2014 groundbreaking for the new research center, Oklahoma City-based Devon Energy signed an agreement with GE to collaborate on innovations in several specific technology areas, including artificial lift systems used to increase the flow of liquids from production wells.

Even as such research efforts continue, the unconventional sector is already moving full steam ahead and now accounts for more than half of all new wells that are being drilled in the U.S., primarily in three basins: the Eagle Ford, the Permian and the Williston. These three basins account for nearly half of the wells drilled in the U.S.

The industry is expected to invest more than \$140 billion to \$160 billion annually in overall oil and gas activities between 2013 and 2019 in the U.S. alone, with much of that driven by unconventional. By 2035, unconventional gas production is expected to account for 35% of the world's increased supply of energy. In turn, the unconventional boom is driving rapid growth in the artificial lift segment: In 2014, the global artificial lift market was valued at \$14.8 billion and is growing at an annual rate of 10% to 12%.

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GE Oil & Gas has invested more than \$6 billion in acquisi-

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tions within the last three years alone to quickly move from being a relatively small player to become one of the largest artificial lift equipment suppliers in the world. In 2011, the company acquired the John Wood Group PLC Well Support division, including its electric submersible pump (ESP) business platform. The \$2.8 billion transaction enabled GE to begin capitalizing on the fast-growing demand for EOR technologies including for unconventional fields. ESPs are a popular artificial lift option at the beginning of production, when flow rates are generally expected to be at their highest.

In 2013, GE completed its acquisition of Lufkin Industries Inc., a leading provider of artificial lift technologies and a manufacturer of industrial gears, for about \$3.3 billion. The Lufkin acquisition broadened GE's artificial lift capabilities beyond ESPs to include rod lift—the industry's most common type of artificial lift system—as well as gas lift, plunger lift, hydraulic lift, progressive cavity pumps and a sophisticated array of well automation and production optimization controls and software. The company now offers the industry a complete artificial lift product portfolio.

GE's Well Performances Services business—the home of GE's artificial lift operations—has seen a majority of its ESPs deployed in the Midcontinent and Permian regions, while Lufkin has been a prominent player in the fast-growing Bakken Shale Field of North Dakota. However, with both the former Wood Group ESP and Lufkin product platforms now part of GE Oil & Gas, the company has a full menu of artificial lift solutions located across North America and can provide support based on the operator's well lifecycle requirements.

This is crucial because during the production life of an unconventional well, as it shifts from higher to lower flow rates, operators are expected to require at least two different artificial lift technologies to maximize production rates and ensure the best performing and most efficient system is used at each stage of the life of the well.

Monitoring tools

Because of the extreme fluctuating nature of unconventional well performance, remote monitoring and diagnostic tools also are increasingly critical for helping operators better understand and predict how a given well will behave in a given period. Given the learning curve that the industry faces with unconventional wells, remote monitoring tools—such as GE's suite of Predictivity products that leverage the power of big data and the Industrial Internet—help operators address the critical question of when is the right time to move from one artificial lift technology to another at a given well.



GE now has a full menu of artificial lift solutions to meet the lifecycle requirements of each well. (Source: GE Oil & Gas)

Situational awareness is crucial for unconventional oil and gas operations in remote locations. With conventional monitoring systems for ESPs, when a ground fault occurs on the ESP power cable, the gauge's power supply is cut off. Although the pump continues to run, its performance is no longer monitored, thus reducing the operator's ability to effectively monitor activities and optimize production. To address this decades-old problem, GE Oil & Gas introduced its Zenith GFI Ground Fault Immune ESP monitoring system, the first ground fault-immune gauge that is designed to not be disturbed by cable ground faults, allowing operators to manage against production losses and equipment failure through continued reliable data delivery despite ground fault conditions. The technology is expected to have a significant impact on the artificial lift market, with an average of 15% of existing ESP gauges losing production data due to ground faults within the first year of operation, resulting in up to a 25% reduction in fluid output compared to pumps optimized with a live downhole gauge. A 25% loss from a well producing 800 bbl/d at \$100/bbl equates to \$7.3 million per year in lost revenue from a single well. The GE Zenith GFI system helps operators avoid such losses.

The growth potential for artificial lift applications for unconventional oil and gas well performance is not just limited to North America. The U.S.—where the unconventional revolution began—is expected to be merely the launching point for what is expected to become a global segment as other countries—chiefly China and Argentina—seek to rapidly develop their respective unconventional resources. A bit further along will be Mexico, which is in the process of implementing a sweeping national energy reform program. As a result of these reforms, Mexico is expected to open up production in the country's portion of the Eagle Ford shale play, which is already being rapidly developed on the U.S. side of the border.

Buckle up; the energy industry's unconventional learning and opportunities curve is about to go international. **ESP**



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Low-flow lift solution developed for extended-reach laterals

A novel artificial lift solution promises reliable production for marginal wells while preventing potential gas-locking problems.

Marissa Shults and Jeffrey Bridges, Baker Hughes

To counter dwindling reservoir pressures and maintain production at economic levels, many wells will eventually have to go on some form of artificial lift. And while downhole pumps such as sucker rod pumps and electrical submersible pumps (ESPs) have been widely used to successfully bring oil to surface from low-pressure wells, they share a common challenge in the form of produced gas. High gas volumes entrained in the fluid prevent the use of conventional pumping equipment and require a solution to handle or avoid free gas entrained in the fluid from being produced.

As liquid rates fall and gas production rises in a well (a process that may take only a few months to a few years), these pumps reach a limit on reliable operation. In horizontal wells, for example, the accumulation of gas and water in the low spots of the lateral predispose the well to slug-like production cycles characterized by an alternating flow of gas and liquid. Gas slugs can cause erratic liquid loading, which may cause the pump to cycle on and off. Under such conditions, gas separators and tapered pumps, which are typically used to prevent gas locking, are rendered ineffective.

The industry has deployed several pumping methods to avoid gas ingress, including positioning the pump below the perforations (in the rathole) to take advantage of the natural separation there. Tangent sumps also have proven effective at avoiding gas, particularly in extended-reach drilling applications. However, these solutions are often expensive to build and

complex to construct and may prove ineffective in marginal wells with flow rates below 100 bbl/d of fluid.

Artificial sump solution

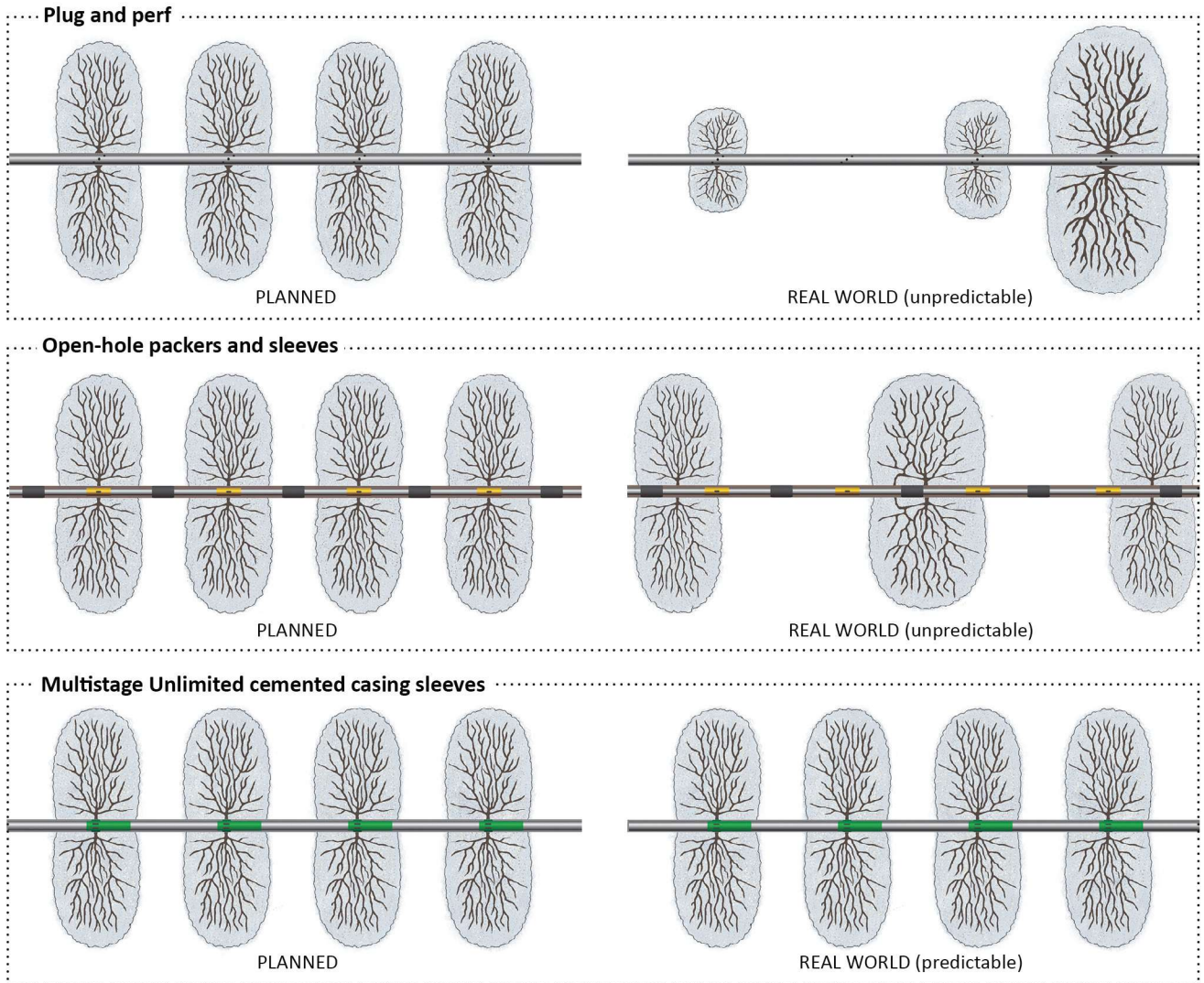
A new pumping solution has recently been developed that provides simple and low-cost gas management for marginal production wells. Known as an artificial sump configuration, the system features a high-performance, low-flow stage ESP (which can reliably produce wells at rates as low as 50 bbl/d of fluid) in tandem with a system designed to avoid gas without the requirement of drilling a fixed sump. The artificial sump provides the gas-managing benefits of a wellbore sump without the added drilling/completion cost.

The artificial sump pumping system is a self-contained pumping unit designed to ensure reliable operation in high gas conditions consistent with uncon-



Field service technicians prepare to connect ESP units during installation. (Source: Baker Hughes)

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Marginal wells can benefit from the new lift solution. (Source: Baker Hughes)

ventional low-flow applications. The system components are configured to provide adequate flow to cool the motor while achieving the desired production levels. Systems set below the perforations do not have enough fluid flow past the motor to prevent excessive heat



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buildup during operation and require forced fluid flow to prevent overheating. The recirculation system is designed to provide forced cooling liquid to the motor. It uses a tapered pump system, in which a portion of the output from the lowest pump is redirected into a conduit that transports the cooling liquid and then exits below the motor.

Because it is required to move more liquid volume, the recirculation pump must have a higher flow rate than the lift pump. Ample stages must be included in the recirculation pump to produce sufficient pressure at its discharge so as to overcome the frictional drag that occurs inside the recirculation conduit.

The artificial sump system also enhances capillary deployment of chemical treatments into the ESP system, keeping the system protected from negative effects of scale, paraffin or asphaltenes. Regardless of whether the capillary tube is terminated above the pump or below the motor, a portion of the injected chemicals is carried below the motor along with the recirculation fluid to provide continuous chemical treatment for the motor.

Bringing oil wells back online

An operator in Oklahoma faced gas-ingress challenges with a conventional ESP system installed in several low-flow oil wells. These wells used ESPs from the outset of production, but within nine to 12 months rising gas levels in the produced fluid stream began to cause frequent gas locking in the pumps, leading to overheating and shutdowns. The pumps eventually failed, requiring them to be pulled out of hole and leading to a complete loss of production from the wells.

Since the existing operations were not successful, the operator asked Baker Hughes to test its artificial sump

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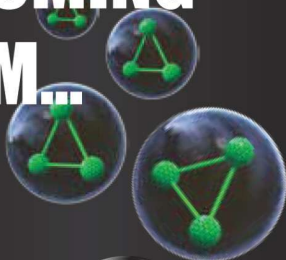
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configuration in three wells based in part on their own past work history with the service company and the new system's successful deployments for other operators in the region. The two companies met several times to discuss the wellbore geometry and reservoir fluid properties, the specifics of the system, how it was performing in similar applications, and how it should be designed and deployed for the operator's wells.

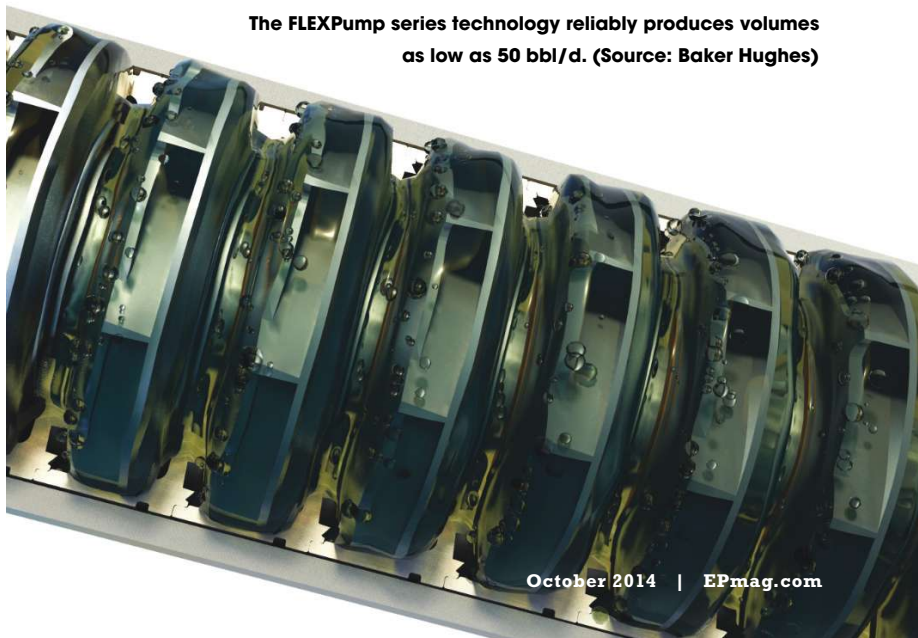
Three wells were selected for the first field trial with the system, each of which required pumping systems at a depth of about 1,700 m (5,600 ft) and with 36- to 45-hp motors. The installation process was quite straightforward and varied only slightly from normal ESP installations. Each ESP was designed to produce between 200 bbl/d and 300 bbl/d of fluid. Because sand production was a concern (and would compromise the operation of the pumping system), sand-control screen systems were installed on each well.

Installation of the first artificial sump went according to plan. The wells have been back in production for two to three months, and the operator is recording production rates in line with expectations for these marginal wells. The artificial sump is operating much more reliably compared to the previous ESP systems, and nonproductive time due to gas locking and pump overheating has been eliminated.

The operator is confident that this new pumping solution will run longer than conventional pumping systems and has requested that ESPs with artificial sumps be installed in an additional five to six wells as of this article's publication date. This is in addition to the 15 wells that already have this pumping solution installed, bringing the total number of systems in the field to more than 20.

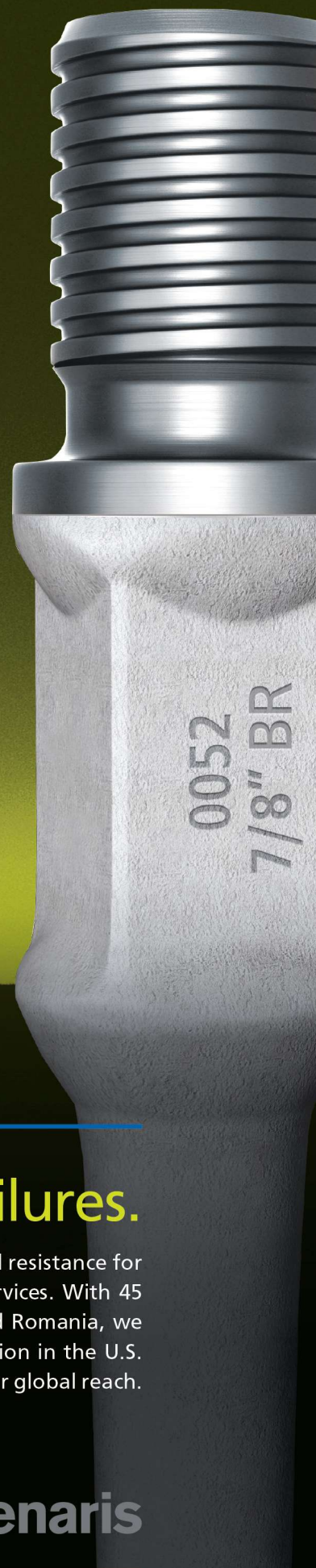
As more of these ESP configurations are installed in place of gas lift and conventionally deployed ESPs, they continue to demonstrate an ability to dramatically improve the economic viability of so-called "end-of-life" wells that might otherwise be abandoned. **ESP**

The FLEXPump series technology reliably produces volumes as low as 50 bbl/d. (Source: Baker Hughes)



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Paradox point for subsea processing

Subsea processing solutions have reached something of a ‘paradox point.’ The industry is standardizing equipment and cutting costs while also having to advance into harsher environments with increasingly complex new technologies.

Mark Thomas, Editor-in-Chief

Much has been written in recent years about subsea production technology and its application not only for deepwater and harsh environment projects but also for shallow-water and brownfield developments.

Several scenarios are currently playing out, with oil companies having to balance the advantages of applying seabed processing solutions—driven by the need to enhance reservoir recovery rates from their relatively low present levels—while also being fully immersed in a major cost-reduction cycle.

This is no easy balancing act. Every offshore operator today is fully focused on lowering costs, but anyone who works in the upstream business knows that it must at all times retain a long-term view for each and every field it develops. If developing a new or advanced subsea processing solution means it can be applied to a greenfield or brownfield development to increase the overall recovery rate—while also potentially removing the need for surface facilities—then according to those criteria there are cost advantages that can only be achieved by near-term and greater investment.

The basic elements of subsea processing are well known—booster pumps, compression and separation equipment. According to a report by DNV GL earlier this year for Norway’s Petroleum Safety Authority, “The motivation for subsea processing has changed, from reducing topside weight to being an enabler for late-life production till today, where subsea process facilities have been installed on greenfield developments. Increasing the oil recovery is a key driver.”

Producing fields with heavy oils and/or low reservoir pressures might also become feasible if installing subsea processing equipment, it continued.

Seabed experience growing

There is a growing record of industry experience in this sector, according to DNV GL’s report. It highlighted the Kvernboer Booster Station (KBS) in the 1990s that was built and tested although never actually used as well as the subsea separation projects Troll Pilot and (a decade later in

2007) Tordis, both installed on the Norwegian Continental Shelf.

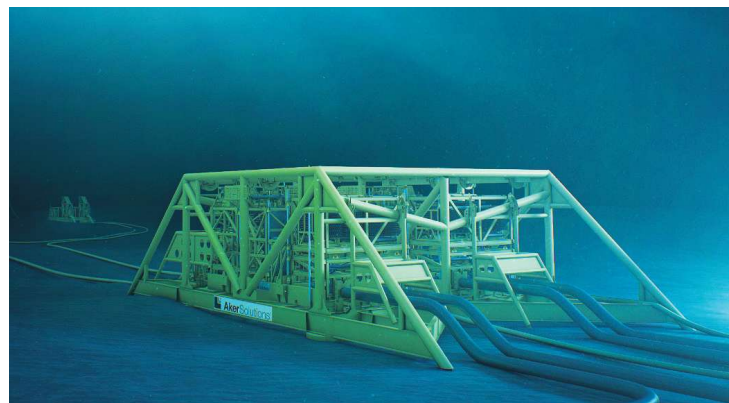
Tordis was the world’s first full-scale commercial subsea separation, boosting and injection system, removing water and sand from the wellstream and reinjecting it into a nearby formation. A multiphase pump was installed to assist in transporting the oil and gas to the topside facility.

More recent flagships have included Shell’s Perdido and Total’s Pazflor projects in the Gulf of Mexico (GoM) and Angola, respectively, which were the first full-field subsea separation and pumping systems in their regions. Both use vertical gas/liquid separation units, whereby the gas free-flows to the topside host and the liquid mixture is boosted by means of subsea pumping.

Petrobras’ Marlim Field (2011)—the world’s first system for deepwater subsea separation of heavy oil and water—installed a horizontal pipe separator to separate oil from water, with the latter reinjected for reservoir pressure support. The oil and gas, meanwhile, are commingled downstream of the separator station and free-flow to the topside facility.

Compression complexities

This year there are three major projects in progress involving the addition of subsea compressor stations—or at least,



The Åsgard subsea compression station will boost production to the Åsgard B facility from the Mikkel and Midgard fields by about 280 MMboe in total. The 1,800-mt template—as large as a soccer field—was installed on the seabed last year, with production to start by mid-2015. (Source: Aker Solutions)

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'Lego brick' approach to subsea

"Lego brick" standardization of interfaces for subsea processing systems has been flagged as a key element in realizing the reality of a subsea factory system.

Norway's Statoil said subsea processing systems have so far been tailor-made to meet field-specific requirements and components, but it wants to take the initiative to standardize internationally the interfaces for such plants on the seabed. The operator has engaged DNV GL as an independent party to initiate a joint industry project (JIP) to develop the standard. The JIP is open to operators to collaborate to help ensure major benefits throughout the subsea supply chain.

Statoil's first subsea compression systems are being installed before the end of this year and are due to start operations in 2015. Substantial cost and time goes into developing these systems, Statoil stated, in part thanks to fields frequently having tailor-made solutions with extensive qualification programs. Adding to the cost are the special installation tools required, often on specialized vessels.

Adaptability for project needs

By standardizing tie-in technology and module sizes, the operator said it will be easier to combine different types of technology and modules to adapt developments to project needs.

Margareth Øvrum, executive vice president of technology, projects and drilling at Statoil, said in a press statement, "Think of the modules as Lego bricks. By having standardized module dimensions, which may be assembled using standard tie-ins, we may combine technology from different suppliers and also cover several needs through subsea solutions. This will reduce costs and increase volume."

DNV GL has been commissioned to run the JIP to ultimately define standard interfaces for the typical modules in a subsea processing system, she added.

Statoil believes the standardization initiative will help increase the number of business cases for subsea processing and reduce the cost of new projects.

Liv Hovem, director of Division Europe and Africa at DNV GL, said that the first step for the JIP will be to collect ideas and input from the supplier industry regarding the areas they believe will benefit from standardization. "Our goal is to define standards for the interfaces, support structures and installation tools for the modules in a subsea processing facility," she said. "The Subsea Factory Interfaces standard will as far as possible build on open industry standards. The key issue is to leave ample room for innovation by standardizing how the technology is packaged, connected and installed." ■

there were. Two are progressing as planned and are in the implementation phase: Gullfaks South, scheduled for the second quarter of 2015, and Åsgard just before it in the first quarter. The third, Ormen Lange, however, was delayed in a high-profile decision in April by operator Shell and supported by its partners (with the exception of the Norwegian state company Petoro).

Acting as a reminder that subsea processing is, despite its growing track record, very much still a work in progress, the Ormen Lange Management Committee decided the project was simply not viable at this time.

Ormen Lange faces greater challenges than the compression projects on Åsgard and Gullfaks, not only because of the deeper waters—Ormen Lange sits in approximately 900 m (2,953 ft) of water, while Åsgard is in 340 m (1,115 ft) and Gullfaks 135 m (443 ft)—but also because of the step-out distance. The gas field has been producing subsea-to-beach since 2007 over a distance of 120 km (75 miles). The subsea compression solution on Ormen Lange needs more electrical components and systems to be installed on the seabed than Åsgard or Gullfaks due to that larger step-out distance for the electrical power transmission.

Ormen Lange alternatives

Committee Chairman Odin Estensen said in a public statement at the time of the decision: "The oil and gas industry has a cost challenge. This, in combination with the maturity and complexity of the concepts and the production volume uncertainty, makes the project no longer economically feasible. The Ormen Lange license remains committed to the ambition of maximizing the ultimate recovery from Ormen Lange in a sustainable manner. Significant new information both on reservoir behavior and technology developments will become available in the next few years and provide basis to [evaluate] new options."

The partners clearly are not giving up on the solution, however, with the chairman continuing, "The Ormen Lange License group believes in the subsea compression technology and still regards the qualification of this technology to be an important stepping stone for the Ormen Lange future development alternatives. Subsea compression technology is a key contributor for ongoing and future field developments on the Norwegian Continental Shelf."

Essentially this is a project that now will sit on the shelf for a number of years while the operator and its partners wait for both the technology and economics to add up.

Instances such as this are likely to happen whenever the limits are pushed in terms of the complexity of equipment and systems.

Pump it

When the term "subsea processing" first came on the scene as a concept, the focus was expected to be on seabed separation, with the other elements such as gas compression, boosting and raw water injection somewhat trailing behind.

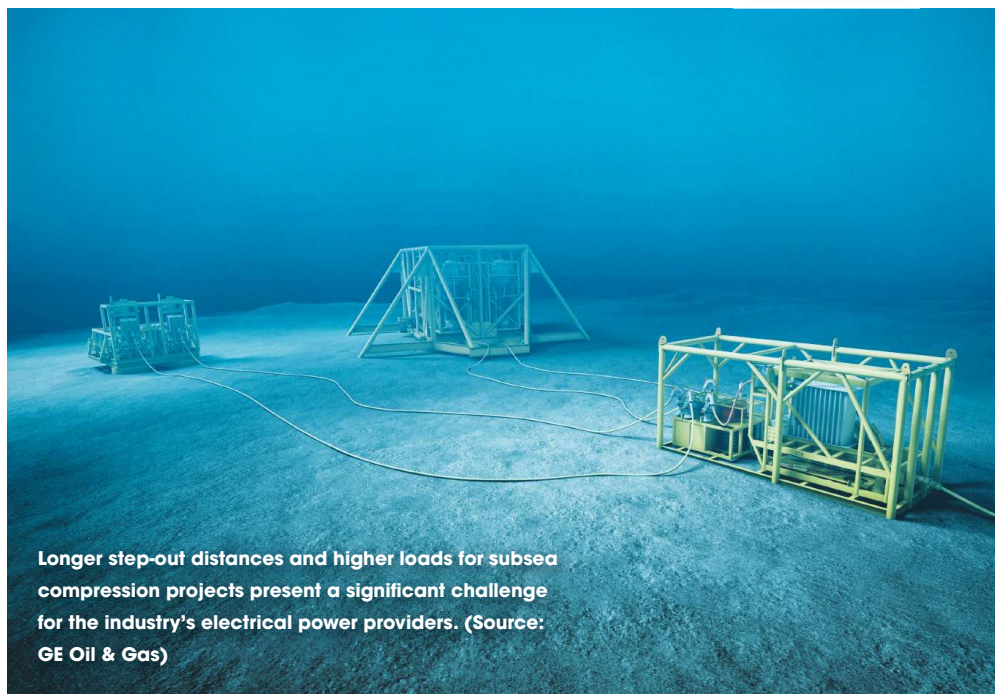
However, the emphasis has firmly shifted in recent years toward rotating machinery, not only on the seabed but also in the well.

The Subsea Production Alliance (SPA), formed earlier this year between Baker Hughes and Aker Solutions, has talked about offering “reservoir development services”—like their rival OneSubsea established in 2012—to get the most oil out of the ground. The focus is very much on improved and new boosting systems, including what is now known as “dual boosting,” i.e. seabed and down-hole pumping working in parallel. Baker Hughes told *E&P*’s sister publication *Subsea Engineering News (SEN)* at the 2014 Offshore Technology Conference in Houston that it has been working for some time on improving the reliability of its Centrilift brand electric submersible pumps (ESPs). Its through-tubing design is aiming at a run-life of 10 years—a major advance from the 90 days of old. Another big element will be a rigless intervention system, an aspect that will be of significant interest to a growing number of operators.

Rigless intervention

Related to this, earlier this year Baker Hughes confirmed that its seabed-installed ESP, supplied to Petrobras for the deepwater Cascade Field in the GoM, came into operation. This is just one example of how an ESP can be deployed in such a way that intervention would be rigless. Petrobras has also used this configuration in its domestic waters.

The other half of the SPA “dual” system will be a seabed multiphase pump that Aker Solutions has been working on for several years. The design is called a “semi-axial” hybrid pump. SPA is not the only one working on pumps. OneSubsea is already a market leader for seabed pumping based on its Framo Engineering legacy designs. According to *SEN*, there are plans to increase the power of both the Hi-Boost pump and its wet gas compressor, one of which is being supplied for Statoil’s Gullfaks South enhancement. The latter unit is 5MW, and the aim is to slowly increase the power to 6MW, then 8MW and eventually 10MW. **E&P**



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Dealing with produced water subsea

When it comes to seabed processing solutions, the ability to accurately measure the quality of produced water subsea would be a significant step forward, and the offshore industry is working hard to close this technology gap.

Dr. Ming Yang, NEL

Subsea processing is an effective technology that contributes toward maximizing recovery of a field's oil and gas reserves. Two important parts of the subsea processing strategy are subsea separation and produced water reinjection or discharges, and subsea seawater treatment and injection.

Separating water at the seabed offers many additional benefits in terms of minimizing flow assurance issues, easy separation, reduced use of production chemicals and energy savings. However, for these to be realized, the measurement of water quality needs to be addressed since without it operations of subsea separation and produced water reinjection and subsea seawater treatment and injection systems could not be effectively controlled and run.

Subsea water quality measurement is required to support subsea reinjection for pressure maintenance or for disposal or direct discharge into the marine environment. Presently there are no instruments available on the market that can be used for continuously monitoring the quality of produced water separated subsea.

This absence is an important reason why there has been no wider uptake of subsea separation systems—without a reliable and accurate water quality measurement device, regulators cannot permit produced water discharge subsea.

More challenges subsea

The development of a continuous online water quality measurement device for subsea applications will have many more challenges compared to surface applications because:

- Subsea is a much tougher environment;
- Water quality measurements will often need to include both oil and solids in water;
- There are a limited number of potential technologies;
- There is a lack of qualification testing facilities and standards;
- There is a lack of regulator involvement for developing procedures and standards; and
- There is little previous experience to build upon.

If the produced water is reinjected for disposal or for pressure maintenance, water quality in terms of oil concentration and solid concentration, as well as particle size, will be important. This is because both oil droplets and solid particles can damage the formation and impair the injectivity of produced water. In the case of reinjection for pressure maintenance, injectivity impairment can affect the oil production and net oil recovery.

Technology development

In the quest to develop a suitable water quality measurement mechanism for subsea separation and produced water reinjection or discharge applications, a number of technologies have been considered. The measurement techniques previously explored and used include photoacoustic, erosion, microscopy imaging analysis, laser-induced fluorescence (LIF) and ultrasonic as well as a combination of these.

For oil-in-water concentration measurement, LIF is well established and thought to be a good option for subsea applications. This allows manufacturers to construct an analyzer with a probe that can be inserted directly into a pipeline.

For sand detection and monitoring, both erosion-based (intrusive) and acoustic-based (non-invasive) technologies have been developed to protect equipment and for effective sand production management. However, these are not proving to be sensitive enough to support produced water applications.

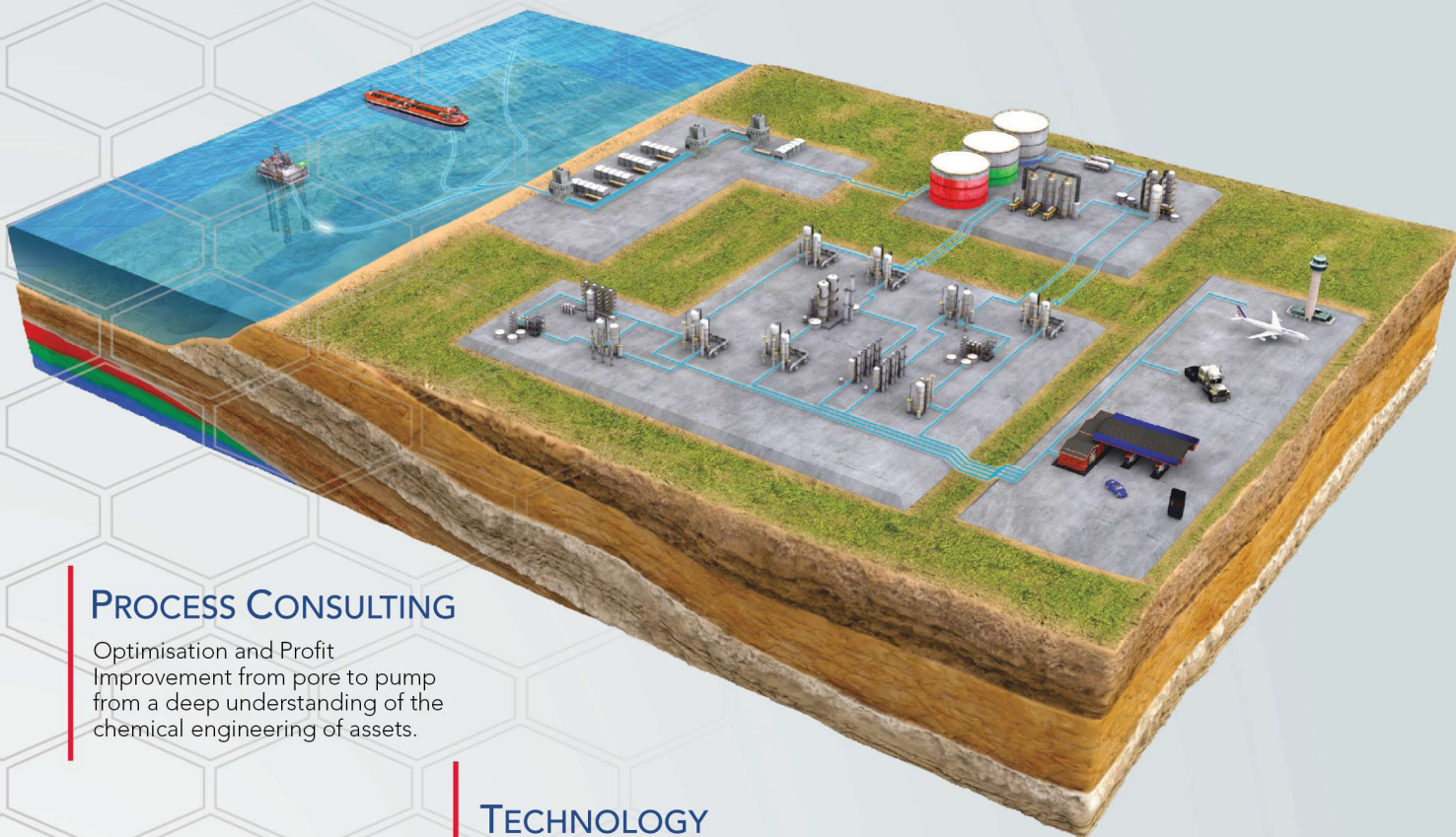
For produced water reinjection, measurements of solids and oil content as well as particle size and size distribution are important. There are many different types of particle size analyzers available on the market. For the purpose of produced water quality measurement, image analysis, ultrasonic and a combination of LIF and image analysis-based systems are considered to have potential.

Reduce risk

All subsea equipment will be expensive and time-consuming to repair, retrieve or replace once installed. To reduce the risk of failure and ensure equipment reliability, testing and qualification is critical. However, there is no protocol



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specifically established for produced water quality measurement devices.

A few existing industry-recommended practices and standards provide some good guidance in terms of what is required. These include ISO 13628:2006: "Petroleum and natural gas industries—design and operation of subsea production systems—Part 6 Subsea production control systems," which provides the most detailed requirements regarding the types of tests that may be needed for a subsea water quality measurement device. Other useful documents include DNV RP 203 "Qualification procedures for new technology" and API 17 Q "Subsea Equipment Qualification, Rev. 1 January 2010."

There is, however, not a completely unified approach on achieving increased reliability, reducing risk and ensuring the safe operations of subsea equipment and systems. Also, different companies will have a different perception of risk, so acceptable test criteria may differ from organization to organization.

Qualification tests

Generally there are two main types of qualification test—environment and duty. They serve three main purposes:

1. To demonstrate functional requirement;
2. To screen out faults and manufacturing/assembly defects; and
3. To improve robustness and reliability.

Environment tests may include shock, vibration, temperature variations, thermal cycling and electromagnetic compatibility.

Duty tests may include those related to function and performance. This includes responses to a change in process conditions such as temperature, pressure, salinity and

chemicals. It also includes instrument stability, accuracy, repeatability, uptime and availability. These tests help to ensure that the equipment is fit for the specific application.

For all types of tests it is important that instrument developers communicate with testing organizations and discuss testing requirements in detail. This is because some of these organizations, in particular those associated with environmental tests, may not be as familiar with the standards and recommended practices.

Furthermore, subsea water quality measurement devices will ultimately be part of a subsea process control system and will need to be integrated into the overall process control system. It is therefore advised that integration tests also are carried out to ensure that they can work alongside other subsea instruments and equipment.

This means that close collaboration between instrument suppliers, subsea separation equipment providers and offshore operators is vital. Subsea separator providers and operators have the experience in successfully qualifying subsea separation equipment in the past and therefore know not only the qualification process but also the acceptance criteria.

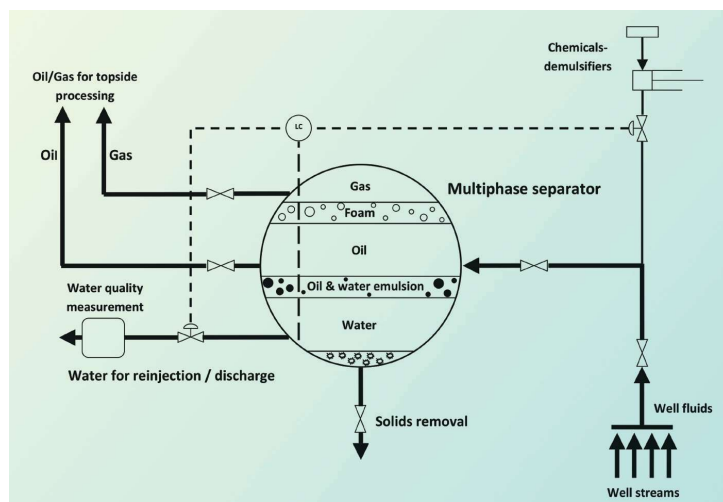
More needs to be done within the oil and gas industry to foster a close collaboration to help accelerate the development and deployment of subsea water quality measurement technologies.

Technology stumbling blocks

Water quality measurement remains a technology stumbling block, which affects the wider uptake of subsea separation systems. It is thought that with the risk and costs involved in developing these technologies, joint industry projects (JIPs) that bring together operators, subsea separation system providers, independent testing organizations and technology suppliers offer the best route to successfully developing industry-accepted subsea water quality measurement technologies.

Following two earlier JIPs carried out between 2009 and 2013 in which potential technologies were reviewed, tested and a gap analysis performed, NEL has started a third JIP supported by major operators and subsea separation system providers. The two-and-a-half-year project is aimed at helping vendors develop their technologies up to Technology Readiness Level 5.

Clearly there is a strong need to develop subsea water quality measurement devices as produced water reinjection or discharge forms an integral part of seabed processing. However, while water quality measurement remains an issue, with the R&D work currently being undertaken, there is now a high expectation that this technology gap will be substantially closed in the next few years. **E&P**



This illustration shows a generic subsea separation and produced water handling system. (Source: NEL)

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Momentum builds for Australia's unconventional plays

Whether it is in shales, tight sands or CSG, the number of international oil companies jumping into the Australian plays to 'crack the code' is increasing along with spending.

Scott Weeden, Senior Editor, Drilling

The Cooper Basin in South Australia and Queensland and the Surat/Bowen Basin in Queensland are seeing unprecedented levels of spending to develop conventional and unconventional oil and gas resources and coal seam gas (CSG), respectively. Export markets for LNG from three plants under construction on Curtis Island near Gladstone, Queensland, are driving domestic gas prices higher, which boosts the drilling and completion of more wells in these basins.

In turn, areas of great gas potential such as the Canning, McArthur, Meerenie/Amadeus and Perth basins benefit from both the higher prices and greater interest from major oil companies such as Statoil, ConocoPhillips, Hess and Chevron.

"Cooper Basin unconventional gas is no doubt a massive opportunity, whether it is value, production or resource size," said Ian Davies, Senex managing director and CEO, at the DUG Australia conference in Brisbane Aug. 27. "But it is high-risk. What do we do with that being a smaller company? The oil business is absolutely fantastic for marginal cash flow. It will be a mainstay of the business going forward. Gas, however, is the key to a long-term, stable business, albeit low-margin, high cash flow and with much more longevity."

The goal for every operator in eastern Australia is to be commercial. Many companies focus on areas where there is already infrastructure to get natural gas to markets. Strike Energy, for example, concentrates on areas in the Cooper Basin under the Moomba-to-Adelaide pipeline.

"For any molecule we can get to the surface and produce, we've got a market for it and the infrastructure to get it to market," David Wrench, Strike CEO, explained during the conference.

Barry Goldstein, executive director, Energy Resources Division, Department of State Development, South Australia, also speaking at the conference, emphasized that there are four hydraulic stimulation crews in the Cooper



Ian Davies, Senex managing director and CEO, told attendees at DUG Australia about the company's plans for the Cooper Basin.

Basin in South Australia. An estimated \$3.5 billion is expected to be spent over the next five years in South Australia.

Infrastructure in other areas of the country such as the Northern Territory and Western Australia remains the biggest challenge, driving up especially the logistics cost for drilling and completing wells. Even if a well is commercial, there are not always nearby markets where natural gas can be easily delivered.

That hasn't dampened the enthusiasm for shale plays, CSG and tight sands in Australia. The momentum to develop unconventional gas reserves is building.

Senex targets conventional, unconventional plays

The Cooper Basin is a major asset portfolio for Senex. The company is spending a lot of time, money and effort to understand every part of the basin from conventional oil and gas to unconventional oil and gas.

In fiscal year (FY) 2015, the company's 2P reserves were at 41.6 MMboe. Its target for FY2018 is 100 MMboe

to 150 MMboe. Oil and gas production in FY2015 was 1.4 MMboe, with a target of 3 MMboe to 5 MMboe in FY2018.

Its growth assets include Cooper Basin unconventional gas, Cooper Basin conventional oil and gas, Cooper Basin tight gas, Surat Basin CSG, the Hornet Tight Gas project and Cooper Basin conventional oil E&P.

For its gas acreage, the company has four principal play types—conventional structural and stratigraphic traps, unconventional gas in shale or coal seams, and tight gas. The Cooper Basin features conventional and unconventional gas and tight gas, while the Surat Basin has CSG.

The Cooper Basin was considered a “dead” basin only five years ago. “We have been successful at finding new conventional oil discoveries. Tens and tens of millions of barrels of oil have been discovered in the last five years. In our conventional oil portfolio, we have a long way to go. It is our core business. We are drilling 16 wells this financial year based on new 3-D seismic. With some success, that grows exponentially,” he continued.

Davies said the company also needs to be successful in finding conventional gas. That consists of shooting new 3-D seismic, using new ways of interpreting that seismic and drilling both structural and stratigraphic natural gas discoveries.

In the Surat Basin, Senex is “working with our partners to try to do appraisals, get pilots up and running and create value from those assets,” he added. “We’re focused on monetizing that position. Surat Basin has 157 Bcf [4.4 Bcm] of 2P reserves.”

Hornet is a tight gas discovery in the South Australia Cooper Basin. The company is currently involved in appraisal drilling on the field. “We’re flow-testing in about a month’s time [late September]. We’ve hooked up to the [South Australia Cooper Basin joint venture], which is a Santos-operated system. We’ve got a gas sales agreement with them for early production,” Davies said.

The company will be doing appraisal of the Hornet discovery and is considering an exploration program in the area to find more gas. The field is being hooked up to the pipeline system and will begin production this year.

For its gas projects, Senex is targeting true unconventional gas—basin-centered shales and deep coals that have not been produced in commercial quantities in the Cooper Basin. “It is all there. It is a massive opportunity for us and all the players in the basin. Unconventional gas is a whole new adventure. We’re conducting 3-D seismic in the next six months and will be drilling on that 3-D seismic in other areas of the basin-centered gas for stratigraphic conventional gas plays in the Patchawarra Trough

and the Allunga Trough in the southern Cooper six months after that. It is all rather imminent,” he said.

The company also is focused on one conventional gas field in the northern part of the Cooper Basin. The Vanessa Field was discovered in 2007. “It is an existing discovery very near a whole heap of other discoveries,” he added. “It produced about 4 MMscf/d to 5 MMscf/d [113 Mscm/d to 142 Mscm/d], and it is wet gas. It produced around 120 bbl/d to 140 bbl/d of condensate. There are many more of these things around that we are going after through 3-D seismic and drilling.”

With about 40% of the acreage in the Cooper Basin, Senex is in position to develop all of its assets. How does the company do that? “You’ve got to put in the effort, put aside the capex, and incentivize the staff and hold them accountable for it in each and every play type. Otherwise it never gets done. What you don’t incentivize your staff to do, you’re not generally going to get a fantastic result,” he continued.

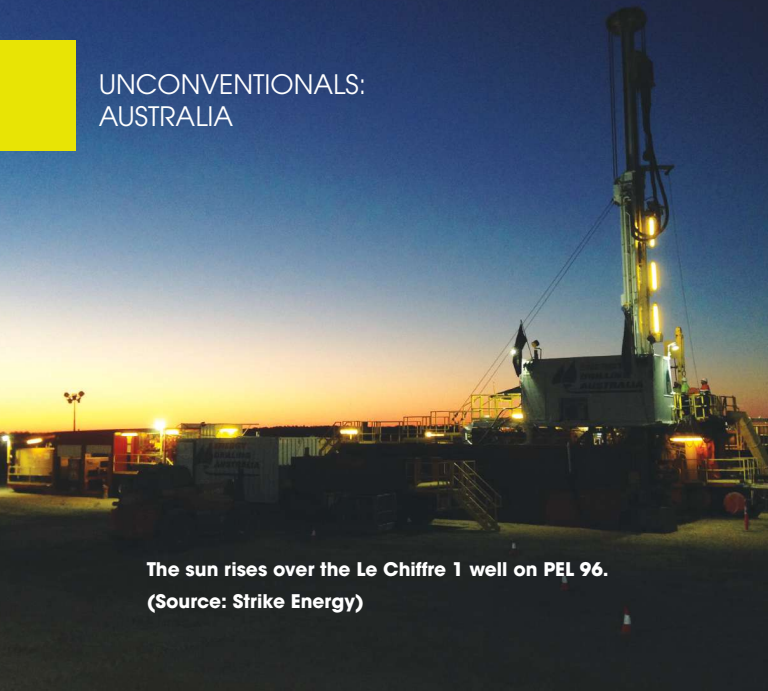
Tapping deep coal measures

Strike Energy has been active in the Eagle Ford and Permian Basin in the U.S. “While what we’re doing in the Cooper Basin geologically is completely different from the U.S., the approach is very similar. We’ve been able to benefit from seeing firsthand how the U.S. industry is doing it,” Wrench said at DUG Australia.

In the Cooper Basin, the company has a number of permits—PEL 94, PEL 95, PEL 96 and CO2013-B—predominantly around the southern flank of the basin. Strike has a project focused on a large gas resource with about 127.4



Production testing for the Hornet-1 well is expected to begin in the second quarter FY2015. (Photo by nadineshaw.com; Source: Senex Energy)



The sun rises over the Le Chiffre 1 well on PEL 96.
(Source: Strike Energy)

Bcm (4.5 Tcf) of gas resource net to the company.

“We’re focused in particular on a series of very big coal measures that were discovered over the last few years. We’ve just completed a completion and testing program on these coals. Contrary to our beliefs going into this that we would have a very low permeability system, we actually have a high permeability system. We are planning to continue testing these coals commencing in the next four or five weeks,” he explained.

The company is moving toward reserve certification as quickly as possible on the path to commercialization. Strike is targeting commercial production in 2017.

The blocks cover about 1.7 million acres. Currently the company is focused around three wells—Klebb 1, Le Chiffre 1 and Davenport 1—that are located about 40 km (25 miles) apart. In each of these wells is a series of coal seams that are consistent over the distances between the wells with 65 m (223 ft) of net coal at depths of 1,900 m to 2,000 m (6,232 ft to 6,560 ft).

“We’ve mapped these coals over incredible distances, and they are very, very thick. The seams are Patchawarra coals. There are two main seams—Vm3 and Vu. The Vu seam splits into upper and lower plays,” Wrench said.

Over the past few months Strike has conducted hydraulic stimulation and short-term flow testing. The results were surprising. “We had been expecting permeabilities in the 0.1 mD range for the coals at these depths. We’re seeing permeabilities at the Le Chiffre well at 20 mD to 25 mD. We started getting fluid back at a rate of 5,000 bbl/d as we turned the well back. We got quite an entirely different system than we were expecting,” he explained.

In the Klebb well, the company downsized the scale of the stimulation that was pumped into the upper coal. “We pumped a frack about 10% of the size of the frack that was pumped in the same zone in the Le Chiffre well. This well produced at high rates as well even

though we pumped a much, much smaller frack stimulation job,” he said.

The same result occurred in the Davenport well. “What we saw across all these coals were very, very similar reservoir properties. The foundations of this play are pretty clear. We have a very large resource with very low-cost completion potential,” he continued.

Saturation in the coal seams is close to 40% to 50%. EURs are in the 113 MMcm to 170 MMcm (4 Bcf to 6 Bcf) range. “We’re about to go back into the field and start pumping. We did not have the capacity at the surface to deal with the volumes of fluid that we were recovering,” Wrench said.

“Our objective is to achieve sustained gas flows to the surface. We also want to understand water management. We have formation water in the system, and we have to understand what the volumes and rates over time will be,” he added.

The company will go back to the Le Chiffre well and drill offsets, which will be about economics and optimization of the field at that point.

“We are moving to reserve delineation and certification through 2015. We are at the proof-of-concept stage. The next step on that track is understanding the production mechanism of this play. The next step after that is reserve delineation. We are starting to work on the design of surface facilities, capital and opex estimates, and regulatory and environmental approvals,” Wrench continued.

“In 2017 we see a shortfall of gas as all of the LNG trains reach capacity. We see a key time in the marketplace for gas supply. We have signed offtake agreements with a number of industrial customers. As we reach certain milestones, those customers will start making prepayments. Access to capital is key for small companies,” he emphasized.

Small-cap company remains player

Ray James, managing director of Icon Energy Ltd., said the company holds a 35.1% interest in ATP 855 in southwestern Queensland, which covers 414,000 gross acres. Beach Energy Ltd. is the operator and Chevron is the other owner. Chevron can farm in as operator following completion of a second exploration and development phase.

Six unconventional wells have been drilled to date, targeting a Permian-age play. All of the wells had “significant” gas shows, which are a long way from commercial production. The Permian in the Cooper is an HP/HT formation that will require more work to crack the code for commerciality.



Having Chevron, with its extensive research and development capabilities, as a partner is proving to be a valuable asset, he added.

While most operators in eastern Australia are counting on the LNG export market, Icon is focused on rapid growth in the domestic market. The region's gas demand is expected to triple between 2012 and 2016, he explained.

Santos touts collaboration

To attain commercial development of unconventional resources in Australia, the industry needs to collaborate to avoid repeating mistakes, said Colin Cruickshank, general manager, unconventional resources and exploration for Santos, at the conference.

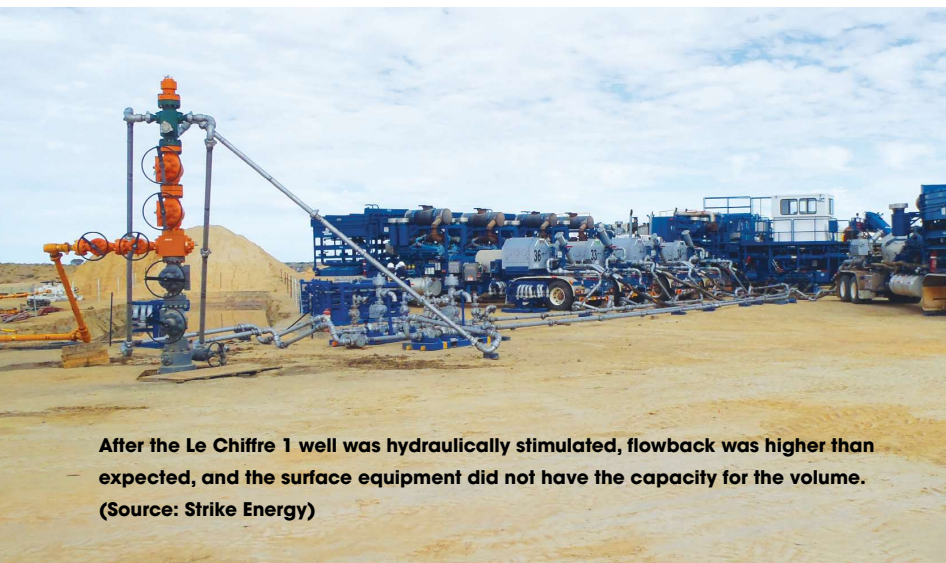
"We don't collaborate as well as our North American counterparts," he explained. With drilling costs in Australia higher than those in North America, operators need to make maximum use of predrilling data, including seismic, drilling cores and other sources and share what they know without delving into proprietary data.

Useful collaboration will help the industry "crack the code" to make that vast potential commercially successful. That will require getting drilling and completion costs down. Support from drilling contractors and other service firms is improving, which is increasing competition and lowering costs, he said.

Santos has three unconventional targets in Australia—the Cooper Basin, McArthur Basin and Mereenie/Amadeus Basin. Santos has been working in the Cooper Basin since the 1960s. Its unconventional plays include tight shales and deep coal seams below 2,500 m (8,200 ft).

The McArthur Basin in the Northern Territory has liquids-rich gas prospects. The Mereenie/Amadeus Basin is in the southern Northern Territory and offers attractive gas-bearing shales, he continued.

He pointed out that the McArthur Basin has some of the oldest hydrocarbon-bearing rock in the world, more than 1 billion years old, rarely found elsewhere but productive in some locations. The Cooper Basin in South Australia and Queensland holds unusual Lacustrine shales that differ from the more typical marine-based shale formations found in North America. **ESP**



After the Le Chiffre 1 well was hydraulically stimulated, flowback was higher than expected, and the surface equipment did not have the capacity for the volume.
(Source: Strike Energy)



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Improving performance in SAGD wells

CENTigrade ESP production system works at elevated temperatures to reduce equipment downtime and reliability issues.

Mary Hogan, Associate Managing Editor

When Baker Hughes introduced its CENTigrade electrical submersible pumping (ESP) production system, the technology was designed to reduce equipment downtime and improve reliability issues. Left unaddressed, these issues can reduce the amount of oil recovered by operators and can increase operating expenses.

The system has proven very effective in steam-assisted gravity drainage (SAGD) wells in extreme conditions that require an ESP system. “We have seen a considerable adoption of the system globally, but the main region that has adopted our technology has been Canada for SAGD applications,” said Carlos Alberto Montilla, Artificial Lift Systems Heavy Oil and Geothermal Segment Manager at Baker Hughes.

Baker Hughes’ Centrilift CENTigrade Ultra Temperature (UT) ESP system won the production technology category of Hart Energy’s 2012 Meritorious Awards for Engineering Innovation.

As the first UT ESP system for SAGD wells, the technology can reliably operate at higher temperatures compared to conventional ESP systems and features an enhanced electrical insulation system. “One of the things that we’ve seen across a lot of the thermal recovery operations is that downhole temperatures tend to increase over time,” Montilla said. “Obviously, that has an impact on the overall reliability of the equipment.”

Additionally, the system can operate in applications with fluid temperatures up to 250 C (482 F), according to a Baker Hughes product release. Applications include thermal recovery producing wells; low flow wells where fluid velocity is insufficient to cool the motor; harsh wells with gas, sand or scale; and SAGD.

The technology remains viable and has not been eclipsed by newer applications. “What I have perceived is that operators are getting more comfortable with the technology as it and the industry have evolved,” he added. “We definitely see a lot more use than we used to see a few years back.”

The company constantly works on improving the system. “Due to the harsh conditions that are typical for



The CENTigrade ESP production system can reduce equipment downtime and improve reliability issues while working in SAGD wells in extreme conditions. (Source: Baker Hughes)

this type of application, the internal components of the system have to be upgraded electrically, mechanically and chemically,” Montilla said. “That way it is a more robust system that is fit for purpose in this type of harsh application.”

In recent years, operators have introduced the concept of infill wells to the SAGD process. In SAGD pairs, a steam injection well is typically positioned above the producing well. On well pads with several SAGD pairs, a smaller-diameter infill well is positioned between the SAGD pairs. “The overall objective of this is to drill a less costly, smaller-diameter well while still getting the advantage of the nearby steam injection at a lower cost. Then the operator will try to recover as much as possible from that reservoir,” Montilla said.

To meet the needs of operators, Baker Hughes is in the process of releasing its system-compatible technology for infill wells. “The benefit of the system for infill wells is that it will allow operators to artificially lift oil from the infill wells that they drill,” he said.

In July, the company also introduced a newer version of its CENTigrade ESP motor, which is rated to a bottomhole temperature of 275 C (527 F). “Basically, what that means is it can potentially improve the reliability of SAGD operations,” Montilla said.

The company foresees the continued growth of the system to meet the needs of operators. “Considering that a high percentage of the recoverable reserves in the world are heavy oil, we expect to see an increased uptake in the market on thermal recovery processes and technology improvement for this particular area,” Montilla said. **ESP**

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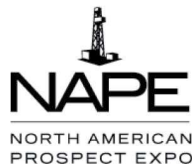


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Cryogenic fracking could boost recovery, save water

Researchers are studying a new well completion technique using liquid nitrogen and CO₂.

Velda Addison, Associate Online Editor

Horizontal drilling and hydraulic fracturing have boosted oil and gas production to new heights in the U.S., but cryogenic fracturing could lift sagging recovery rates, prolong the life of fields and reduce use of what is becoming a more precious commodity.

By replacing water with cryogenic fluids such as liquid nitrogen or liquid CO₂, researchers hope to provide operators of gas fields with a new well stimulation technique with multiple benefits. Researchers at the Colorado School of Mines working with CARBO Ceramics, Pioneer Natural Resources and the Lawrence Berkeley National Laboratory are testing various approaches as part of a \$2.7 million project with the Research Partnership to Secure Energy for America (RPSEA).

With a goal of significantly increasing permeability in a large reservoir volume surrounding vertical and horizontal wells, RPSEA said the benefit of the project will be twofold if successful. "First, it would reduce or eliminate the water usage during hydraulic fracturing, which has clear environmental benefits including reduced ground-water pumping and eliminating flowback disposal that sometimes leads to induced seismicity," said Kent Perry, vice president of onshore programs for RPSEA. "Second, from production's point of view, it should reduce or eliminate formation damage caused by capillary trapping of fracturing fluid and/or interaction between fracturing fluid and clay."

Now is a good time for such an effort because there is much need to improve the productivity of shale gas wells while also reducing the resources consumed and lessening the environmental impact posed by fracturing operations, he added.

The project

As part of the three-year project led by Yu-Shu Wu, professor and foundation CMG reservoir modeling chair at the Colorado School of Mines' Petroleum Engineering Department, two sets of lab experiments are being conducted. The first investigates the cryogenic fracturing process at room temperature using isotropic media; the

second uses natural rock and core samples under reservoir temperature, stress and pressure conditions. Both sets will test the potential of liquid nitrogen and CO₂. A triaxial loading frame is being used to simulate down-hole stress conditions.

As of mid-July researchers had conducted fracture initiation tests in transparent acrylic and glass samples, concrete blocks and sandstone blocks. They also designed and built cryogenic fluid delivery systems, a loading frame and acoustic sensors for monitoring and detection in addition to the capability of injecting pressurized liquid nitrogen and nitrogen gas, according to an emailed response jointly from Perry and Wu.

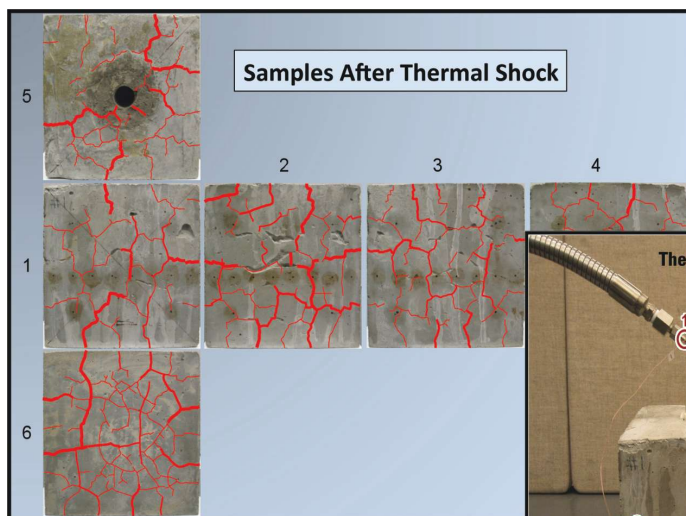
"We are about to start cryogenic fracturing fluid injection testing," the researchers said. "So far we only tested liquid nitrogen. This fluid is easily obtainable, boils rapidly, cools rock quickly and is nontoxic."

The most significant finding so far, according to researchers, is that "cold temperature can initiate complex fracture patterns on the surface of a sample."

But the team also has encountered some challenges. These have involved the availability of pressure equipment and seals rated for liquid nitrogen temperature and use of stainless steel and proper designs to direct the cold temperature to where it is needed, such as the rock's surface rather than to seals where it could be harmful.

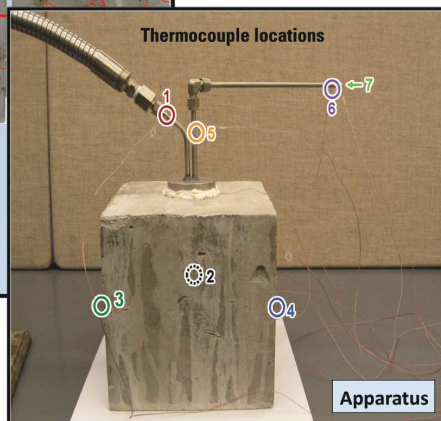
"In the field, there will be challenges in delivering liquid nitrogen to the depth needed, but there is industry experience in that field," the researchers said. Transporting proppants could pose additional challenges. "The proppant-carrying ability of liquid nitrogen is not as strong as other fluids, and it will vary because of changes in gas state and velocity. We think some kind of proppant will be needed to keep the fractures open, and this will be explored by the experiments."

In a previously conducted and unrelated study, the higher viscosity of gelled liquid CO₂ used to stimulate fractures in tight gas sand formations enabled proppant to be carried more easily than cryogenic CO₂ and nitrogen, which lack high viscosity. A lightweight proppant would be favorable for use when the viscosity of the cryogenic fluid of choice is low, or a self-propping mechanism may suffice.



Cryogenic fracking could become a new well stimulation technique with multiple benefits.

(Source: RPSEA)



10,000 Mcf/d [283 Mcm/d] to 1,000 Mcf/d [28 Mcm/d] in three years, etc.”

But if cryogenic fracturing is successful, environmental benefits and reduced water usage could follow with minimal environmental impact.

“If cryogenic fracturing grows into a large-scale service, there should be impacts associated with building new gas separation plants to meet the supply,” according to the researchers. “But other than that, we think the impact should be minimal compared to conventional hydraulic fracturing. In addition, cryogenic fracturing has the benefit that there will not be flowback

fluid that needs to be disposed of.”

Other hurdles also would need to be overcome to make the technique a viable option for industry: economics and more field trials. Previous field trials have been conducted using liquid nitrogen, but it is not commonly used in the field. However, fracturing with nitrogen gas foam is being used by some companies in combination with some water use in water-sensitive, low-pressure formations, the researchers said.

“As it is not being carried in the field today, it is difficult to put a price tag on how much such service would cost. When compared to hydraulic fracturing, one must realize that conventional hydraulic fracturing is a matured system, whereas liquid nitrogen technology would probably bear the cost of initial investments in R&D and special equipment,” they continued. “SPE 38623 (1997) reported the costs of five field trials, and they ranged from \$37,000 to \$86,000. The average was \$54,000. The refracturing operation in the same area cost about \$47,000 on average.”

Moreover, use of cryogenic fracturing would require modifying pumping systems, delivery lines and the blender for proppants to withstand cold temperatures.

It is still too early to say which types of formations cryogenic fracturing would best suit, “but intuitively those with low thermal conductivity and high thermal expansion coefficient would be more amenable to cold temperature-induced failures. Also, brittleness will help just like the case for regular hydraulic fracturing.”

For more information about the project, visit RPSEA’s website at rpsea.org/projects/10122-20/. **E&P**

If the technology yields favorable laboratory tests, a field trial will be conducted and could provide more insight—such as depth of fractures—into what operators may find in the field.

However, “note that microseismic does not really tell us whether the fractures have actually reached there. They only tell us something happened there because of injection. But it is perhaps the only method that we currently have in the field to gauge the size of the so-called ‘stimulated rock volume,’” the researchers said. “Also, cryogenic fractures can occur at locations that may not be activated solely by pressure and in different directions as well because of the different process. These new fractures can then be stimulated by other means [pressurized liquid nitrogen, gas] that will reach deep into the formation.”

Field tests would be conducted at a well owned by Pioneer, possibly in the Pierre Shale.

The benefits

Just as no shale well is the same, the rate of production varies from field to field, from well to well and from the initial stage of production to the late life of the well, the researchers said.

“For example, the Barnett Shale typically has an initial rate of about 2,000 Mcf/d [57 Mcm/day] and declines to about 400 Mcf/d to 500 Mcf/d [11 Mcm/d to 14 Mcm/d] after three years,” they said. “The Marcellus Shale has an initial rate of about 4,000 Mcf/d [113 Mcm/d] and declines to about 500 Mcf/d [14 Mcm/d] after three years as well; the Eagle Ford from about

Big takeaways from big data

Big data empowers oil and gas companies to deliver profitable results.

Egbert Schröer, Microsoft

Today's digital oil field encompasses a comprehensive list of transformative technologies that deliver increased productivity in upstream, midstream and downstream operations. Of all these technologies, big data remains one of the most disruptive and elusive competitive advantages that an oil and gas company can achieve.

Big data capabilities are becoming a key differentiating factor in the hunt for reserves of oil and natural gas. The U.S. Energy Information Administration projects that world energy consumption will increase 56% by 2040. To meet this demand, oil and gas companies must produce more from the conventional fields via EOR methods as well as developing techniques to maximize production from unconventional reserves. Competition is fierce, and the companies that are best able to adapt and begin a digital transformation of their businesses are the ones who will succeed.

The need to make strategic and tangible decisions from massive sets of raw data is becoming more important for tapping into both of these production efforts, particularly as the conventional and easy-to-produce hydrocarbon sources become more depleted.

Increasing recovery rates require improving operational excellence and using digital oilfield approaches that integrate practices such as seismic processing, reservoir modeling, drilling optimization and real-time production monitoring. Exploration and extraction of unconventional reserves further introduces advanced physical technologies as well as new information management and decision-making challenges.

What is big data?

Big data is a difficult term to grasp, in large part because everyone seems to have their own definition. A significant part of the complexity with big data is attributed to the fact that this term has become an expression for all advanced data analytics.

At Microsoft the term big data refers to several IT concepts and tools, spanning from strategic planning and

advanced mathematical analysis to collaborative human interaction and reporting. Working together, these technologies provide tangible takeaways from massive amounts of data. The process of collecting operational insights from massive amounts of data is a difficult feat and the key ingredient to what makes big data a transformative technology.

When properly implemented and used, big data gives companies the power to find value in data that otherwise would yield few results. In oil and gas this could mean anything from finding new reserves of gas to improving operational integrity.

Big data has a lot of moving parts. In order for the technology to provide a positive effect on an organization, it needs to be able to provide real-time, actionable insights that add to what the organization already knows. The real struggle behind a successful big data solution is the need to manage several technologies using a variety of both structured and unstructured data. Microsoft's approach toward big data is to bring together all these moving components and extrapolate business value by leveraging underlying data. In executing this mission, Microsoft's approach is simple: Democratize big data with commonly used tools that let organizations interpret the results to better understand and drive their company direction.

Democratizing big data

Oil and gas organizations need a consolidated approach toward big data that includes not only the high-tech and mathematically cutting-edge tools associated with the technology but an easy-to-learn and -use human interface that allows decision-makers to view, assess and take action anytime from anywhere.

Microsoft's approach toward big data involves a whole platform of devices and services designed to bring data to everyone. This includes a front-end interface using PowerBI and Power Pivot for Office 365 and Excel. As a self-service business intelligence (BI) product, Power Pivot is intended to allow users with no specialized BI or analytics training to develop data models and calculations. This universal platform enables the end user to not only visualize and analyze the information but also search, manipulate, analyze and develop new models



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that could be adopted by the enterprise without the need for already limited IT specialists and developers.

This “democratization of big data” starts at the back-end with the analytics platform system. This appliance, comprised of the SQL-server parallel-data warehouse Azure HDInsight and PolyBase, is how structured data are combined with semistructured data that reside on Hadoop, an open-source storage software for large-scale processing of datasets on clusters of computers.

Azure HDInsight is Microsoft’s Hadoop-based solution for the cloud. It was architected to handle any amount of data and can scale from terabytes to petabytes on demand. Companies can deploy Hadoop in the cloud without buying new hardware or incurring other upfront costs. There’s also no time-consuming installation or set up since Azure HDInsight is part of Azure, an open and flexible cloud platform that enables users to quickly build, deploy and manage applications across a global network of managed datacenters. Being a part of Azure allows organizations the ability to launch new clusters in minutes. For customers wanting a lot of the same cloud benefits in an on-premises solution, Microsoft also offers HDInsight as part of the APS appliance so Hadoop can still be deployed on-premise.

Azure HDInsight’s ability to process data from web clickstreams, server logs, devices and sensors makes it vital in oil and gas, where operational technology is a significant portion of an enterprise’s infrastructure. Its

compatibility with Hadoop also allows organizations to unleash new and more profitable business possibilities.

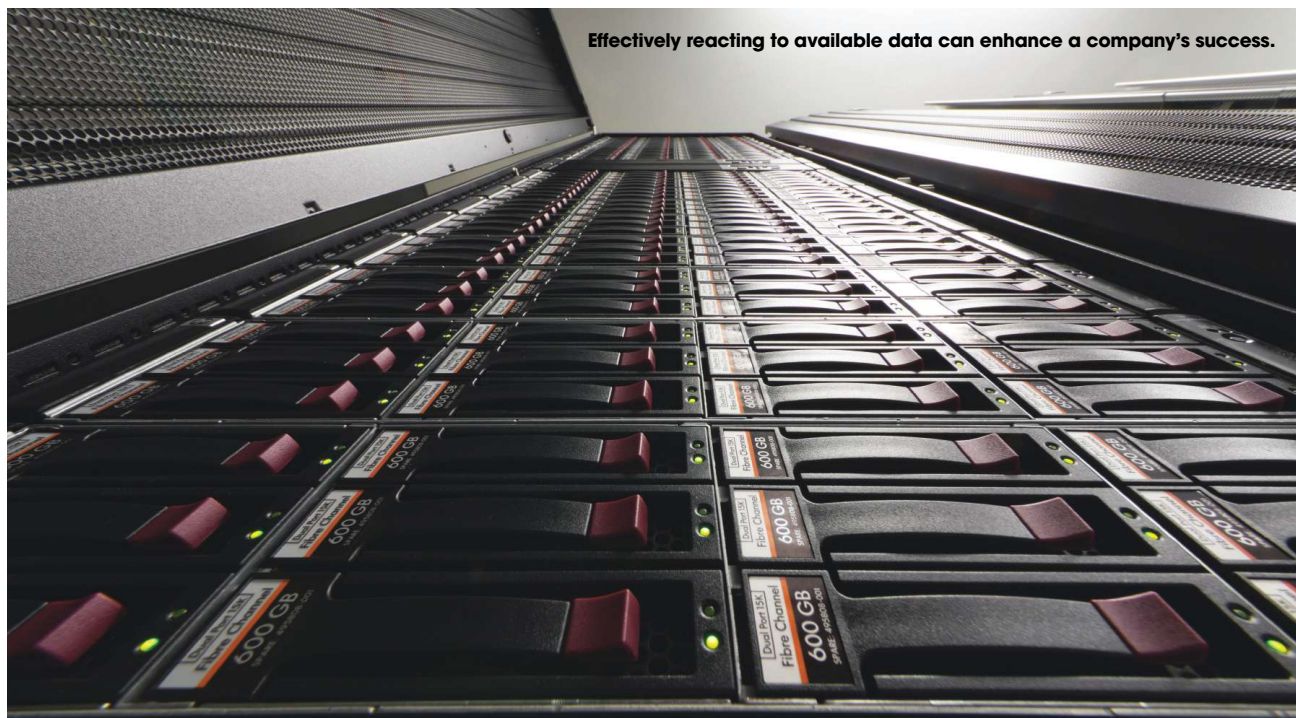
Getting tactical

Big data can be defined as high volume, velocity and variety. This is particularly important in oil and gas, where effectively reacting to available data can differentiate successful organizations from the others. In enhanced E&P, for example, big data can reduce the nonproductive time of assets by predictive maintenance of critical components such as electric submersible pumps. Big data also can help reduce HSE incidents within drilling and production and provide end-to-end views of hydrocarbon reservoirs through advanced pattern recognition.

Big data also can improve overall asset performance by managing real-time metrics across different subsystems. The machine learning capabilities of Microsoft’s big data solutions provide predictive analytics in areas like condition-based and predictive maintenance, which is a predominant theme for every successful oil and gas company.

Big data encompasses many technologies and systems that, working in concert, truly enable today’s digital oil field. Big data empowers oil and gas companies to deliver profitable results, critical in an era when costly EOR and ever-changing unconventional extraction techniques are needed to meet rising production demands. **E&P**

Effectively reacting to available data can enhance a company's success.



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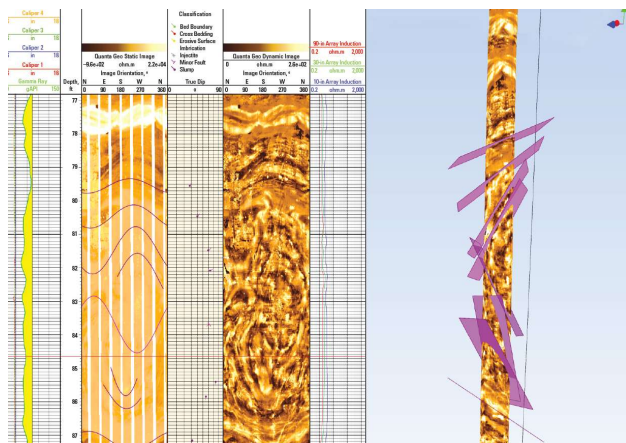
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Photorealistic reservoir geology service helps model reservoir distribution

Schlumberger launched the Quanta Geo photorealistic reservoir geology service, which includes the industry's first microresistivity imager that produces oriented photorealistic core-like images of the formation in wells drilled with oil-base mud (OBM). Interpretation of the images identifies geological features and predicts reservoir trends in 3-D with a high degree of certainty, a company product announcement said. Geological imaging in wells drilled with OBM has been recognized as a major technical challenge, particularly in deepwater, according to Hinda Gharbi, president of wireline at Schlumberger. The physics of the Quanta Geo service's high-resolution array of 192 microelectrodes overcomes the electrically resistive barrier imposed by OBM. The articulated caliper and independently applied pads enable downlogging at up to 1,098 m/hr (3,600 ft/hr), which significantly reduces rig time while mitigating operational risk and delivering data assurance. The service is combinable with most other Schlumberger wireline openhole tools. Using the Schlumberger Techlog wellbore software platform, data acquired by the Quanta Geo service are easily rendered, creating an image of 0.24 in. resolution that resembles a whole core. This enables extraction of key reservoir parameters such as the structural dip or the identification of sand body type, extent and orientation. slb.com/qgeo

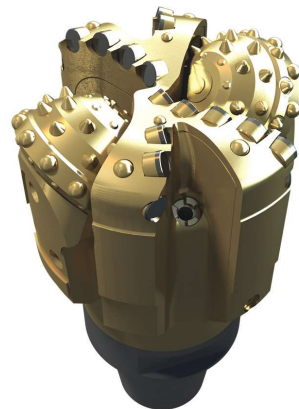


The Quanta Geo service produces photorealistic core-like images of the formation in wells drilled with OBM. (Source: Schlumberger)

Modified bit provides better curve drilling performance, rig economics

Kymera FSR directional hybrid drillbit from Baker Hughes delivers fast, smooth and reliable performance while drilling curve sections in challenging carbonate forma-

tions, according to a company press release. The bit was designed to capture more pay zone at high penetration rates and with improved directional precision. Kymera FSR's modified design allows it to go up to twice as fast in conglomerates as the Kymera drillbit, and it typically completes a curve with one bit. The hybrid design of the Kymera FSR bit combines the attributes of both polycrystalline diamond compact (PDC) and tricone bit technologies and, as a result, outperforms those bit types in carbonates.



The Kymera FSR bit combines attributes of PDC and tricone bit technologies for optimized performance. (Source: Baker Hughes)

The sharper, more aggressive teeth on the bit's roller cones crush these formations with ease, while the PDC cutters of the bit sweep away debris and efficiently clean the borehole. While tricone bits tend to run at a slower pace with less torque and PDC bits drill fast with higher reactive torque, the Kymera FSR bit design allows it to drill much faster while reducing reactive torque fluctuations. This performance decreases damage to the bit and drillstring and provides added toolface control. The result is faster, more precise and smoother drilling for longer distances, often to total depth at a higher buildup rate, the release said. bakerhughes.com

Service integrates data to optimize stage-by-stage completions

FracRx from MicroSeismic Inc. is a proprietary service that allows operators to increase asset values by optimizing the treatment of each well, a product announcement said. The service integrates microseismic data with an operator's pump and geological data to track the growth of the fracture network in all directions and determine how the cumulative fracture area grows with injected fluid volume. This near real-time analysis allows improved stage coverage, treatment efficiency and ultimate recovery to increase production, the company said. In addition, information gleaned from FracRx during a treatment helps operators optimize stage length and treatment design on subsequent wells. Operators can easily identify and react to fault reactivation, determine optimal stage length based on drainage area near the wellbore, effectively evaluate whether the treatment is creating new fractures or opening existing fractures, and ensure the treatment is staying

in zone. This information can be used to make cost-saving decisions and maximize production. microseismic.com

V3-rated plugs create reliable, high-performance downhole seal

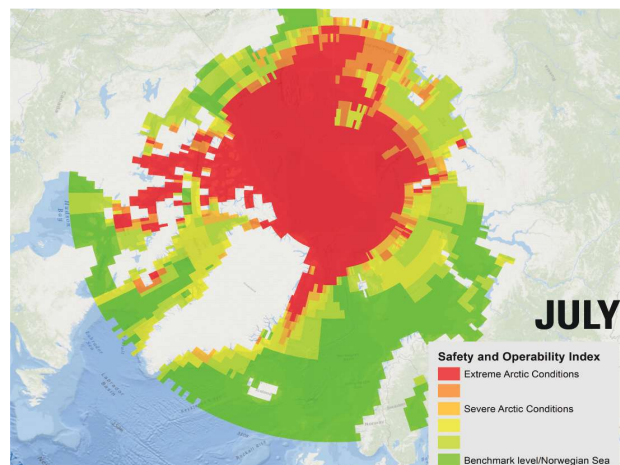
Peak Well Systems has introduced the new SIM PLUS range of V3-grade plugs certified to ISO-14310, including the SIM PLUS Retrievable Bridge Plug. The retrievable bridge plug is for well barrier applications in monobore wells and creates a reliable, high-performance downhole seal, according to a product announcement. This bridge plug can be deployed by all conventional means—drillpipe, coiled tubing, wireline or slickline—and is mechanically set, providing a simple setting solution. The SIM PLUS range of products is modular and employs interchangeable components that facilitate a variety of downhole applications such as zonal isolation, wellhead isolation, contingent plugging, straddles and chokes. The large internal diameter of the retrievable bridge plug makes it useful for modular straddle systems that can improve well performance. The bridge plugs are available in sizes from 2½ in. up to 7 in. peakwellsystems.com

New christmas tree addresses deepwater challenges

GE Oil & Gas has announced its Deepwater Vertical Xmas Tree (DVXT) rated for depths of up to 3,000 m (9,843 ft). It is pre-engineered, prequalified and modular to enable it to be brought to market faster. The DVXT is deployed with the company's next-generation remote electronics canister, the SemStar5-R, and incorporates the latest in communication technology. It is designed with the objectives of higher subsea reliability, extended service life and improved environmental monitoring. With communications out to 220 km (137 miles) at depths up to 3,000 m, the ModPod subsea control module is designed to complement the DVXT's modular layout and enables a more flexible communications network, which is important for field expansion and access to remote wells. ge-energy.com

Interactive Arctic risk map communicates region's complex risk picture

DNV GL has developed an interactive Arctic Risk Map to present the risks associated with offshore and maritime activities in the Arctic. The map aims to provide stakeholders with a comprehensive tool for decision-making and transparent communications. The map presents multiple dimensions such as the seasonal distribution of ice, meteorological conditions, sea-ice concentrations, biological assets, shipping traffic, and oil and gas resources in a single lay-



The Arctic Risk Map has a location- and season-specific index to help identify regions that require special attention for planning purposes. (Source: DNV GL)

out. It also includes a safety and operability index showing the variation in different factors that impact the risk level depending on the season and location in the Arctic. A location- and season-specific index has been developed showing the environmental vulnerability of marine resources with respect to oil spill as an external stressor. The map is a useful tool to identify regions that require special attention when it comes to planning activities and for imposing mitigation measures throughout the year. The map also can provide input to decisions-makers about restricting certain types of activities in specific areas at different times of the year. dnvgl.com

System provides accurate volume measurements in unconventional resource plays

Halliburton's CoreVault system provides a more accurate volumetric picture of the amount of oil and gas trapped in unconventional reservoir rocks. The system makes it possible for operators to contain and bring the reservoir fluids within rock samples to the surface, allowing measurement of the volume of hydrocarbons in place, a product announcement said. Traditional coring tools allow 50% to 70% of the hydrocarbons to escape from the rock as the samples depressurize when brought to surface, said David Topping, vice president of Wireline and Perforating at Halliburton. Building a model of the volume of oil and gas in a reservoir required operators to estimate this fluid loss rather than measure the fluids in place, which often made estimates inaccurate. By preserving 100% of the fluids within the core sample, the CoreVault system allows an improved understanding of potential production within the reservoir. halliburton.com **E&P**



Geopolitical angst, sanctions threaten, but Russia's basins beckon

The push to develop hydrocarbons in the Arctic and tight oil onshore continues, but political tension and other risks create future uncertainty.

Velda Addison, Associate Online Editor

For oil and gas companies hoping to strike and successfully develop massive hydrocarbon finds in Russia, adjusting plans for the political wildcard has become a requirement.

The outlook can appear sunny one day, and then actions of the powers that be can strike, bringing rainy days and clouding the future. Russia was dealt a blow when the U.S. and EU imposed sanctions that shut off the flow of energy technology and financial backing in response to Russia's actions threatening Ukraine's sovereignty and territorial integrity.

Despite a cease-fire and a peace deal struck between Ukraine and Russia, the EU—followed by the U.S. whose president said “we have yet to see conclusive evidence that Russia has ceased its efforts to destabilize Ukraine”—deepened the sanctions in September. The restrictions include prohibiting the export of goods, services and technology in support of E&P for Russian deepwater, Arctic offshore, or shale projects to Gazprom, Gazprom Neft, Lukoil, Surgutneftegas and Rosneft. The mandate gave U.S. persons until Sept. 26 to “wind down applicable transactions.”

ExxonMobil, which said in a press release that it is complying with all U.S. sanctions, was later given more time by the U.S. government to safely and responsibly wind down drilling operations at the well site. Bloomberg reported that the company “sought the exemption from the deadline after engineers involved in the project warned they needed more time to properly plug the well with cement and conduct tests to ensure there are no leaks, cracks or faults that could damage the reservoir or allow environmental contamination.”

The situation is fluid with the potential for more fallout from what has been called Russia's invasion into the post-Soviet state—or not if Russia complies with certain terms. But what remains unchanged is Russia's enormous amount of hydrocarbon resources and the possibilities for more oil and gas discoveries onshore and offshore, from the Arctic to Siberia.



After being prepared for arctic conditions, the West Alpha semisubmersible rig traveled more than 1,900 nautical miles, according to Rosneft, to begin drilling operations in the East Prinovozemelskiy-1 License Area in the Kara Sea. (Source: North Atlantic Drilling)

By 2020, Russia's oil production is predicted to rise to about 565 million tons per year, up from about 491 million tons in 2007, most likely bound for the Far East and Western Europe, according to Energy Bloc Research. Likewise, gas production is expected to jump, climbing more than 100 Bcm (3.5 Tcf) to reach 760 Bcm (26 Tcf) per year by 2020. Data from the U.S. Energy Information Administration (EIA) showed Russia had 80 Bbbl of proven oil reserves and 51 Tcm (1,688 Tcf) of gas reserves as of Jan. 1, 2013.

However, in September Russia's energy ministry said oil production will stabilize at about 525 million tons in 2015, up slightly from the anticipated year-end 2014 production of 525.3 million tons. Production could inch up to 526 million tons in 2017, according to the Russian government.

If E&P programs already underway progress as planned and prove successful, the outlook could change.

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Areas capturing oil and gas companies' attention include the Arctic, where Rosneft and partner Exxon-Mobil kicked off exploration drilling in the Kara Sea in August; Sakhalin Island, site of the Exxon Neftegas-operated three-field oil and gas project; and Eastern Siberia, including the Irkutsk region where Rosneft discovered three new hydrocarbon deposits in 2013. These areas could play a large role in the long run in addition to possible large reserves in the Russian sector of the Caspian Sea and undeveloped parts of Timan-Pechora; however, West Siberia—namely the Priobskoye and Samotlor fields—continue to provide the bulk of Russia's oil production, the EIA said.

"We are seeing a dual push to lower permeability reservoirs—but not true unconventional reservoirs—such as the Tyumen and Achimov formations and more frontier regions onshore such as East Siberia," Duncan Milligan, Russia upstream analyst for consultancy Wood Mackenzie, told *E&P*. "These will maintain a broadly flat rate of liquid production until 2020. The expected decline post-2020 is unlikely to be countered by conventional onshore regions, and this has led to the renewed push into the offshore Arctic and into tight oil production over the past two to three years."

The Arctic

Covering 1,200 km (746 miles) with a 500-m (1,640-ft) hydrocarbon trap, Rosneft believes the Universitetskaya structure in the Arctic could contain more than 1.3 billion tons of oil equivalent. Already, a "total of some

30 structures were found in three East Prinovozemskiy areas of the Kara Sea, and the entire resource base of the three areas is estimated at 87 billion barrels," according to Rosneft, which also noted the Kara Sea oil province resources will be comparable to the resource base of Saudi Arabia.

Using North Atlantic Drilling's *West Alpha* semisubmersible rig, Rosneft and ExxonMobil began work at the Universitetskaya-1 well in the Kara Sea. Rosneft said the well marks the farthest north rig for the Russian Federation. In preparation for the project, the rig was prepped for harsh arctic conditions. In addition to being equipped with a system that monitors ice condition, detects icebergs and tracks sea ice, Rosneft said an eight-anchor positioning system holds the rig in place and that most of the platform is outside the reach of waves.

"*West Alpha* was upgraded to improve the overall reliability of its main and supplementary equipment and for all systems to be ready for low temperatures, including, most importantly, life support and evacuation systems," the Russian oil giant said. "To make sure *West Alpha* can operate safely in severe ice conditions, Rosneft and ExxonMobil developed a unique iceberg collision prevention plan. It even includes applying physical action to the ice.

"Should experts suspect a hummock or floe can damage the rig, special support vessels will tow it away to a safe distance. If physical action is impossible, the system will isolate the well in a way that is harmless for the environment, and the rig will transfer to a safer location," Rosneft



The entire resource base for Universitetskaya, East Prinovozemskiy and the Kara Sea as a whole is estimated at 87 Bboe.



said. “The rig is equipped with two groups of blowout preventers and an enhanced subsea shut-in device.”

The project’s future, however, is uncertain given the latest round of sanctions. Moreover, having the right equipment in place checks one box, but the Russian Arctic presents additional challenges.

“Without the ice and remoteness, the Kara Sea would be a ‘simple’ geological development. However, the ice and 1,000-kilometer [621-mile] distance to port means that exploration well costs are extremely high,” Milligan said. “The Arctic is a very complicated logistical and environmental challenge, and successful ice management will be key for both exploration and development.

“Offshore developments with seasonal ice-cover exist already—in Sakhalin and Canada as well as the Arctic Pirazlomnoye platform, but all of these are much closer to existing infrastructure,” he continued. “Should several discoveries occur in the Arctic and operators decide to proceed with investment, it is likely that a large infrastructure building campaign would be needed. The

Russian state acknowledges as much and is investing in things such as nuclear icebreakers, which will be key for safe Arctic development.”

Siberia

Another set of challenges and opportunities waits in Siberia, site of the Bazhenov Formation, which has been compared to the Bakken in the U.S. The Russian formation in the West Siberian Basin is believed to be one of the world’s largest shale oil and gas deposits, with the EIA estimating risked shale oil and gas in-place at 1,243 Bbbl and 58 Tcm (1,920 Tcf), respectively. The technically recoverable resource estimates are far lower at 74.6 Bbbl for oil and 9 Tcm (285 Tcf) for gas. However how much oil and gas can be recovered and at what cost remains to be seen.

Salym Petroleum Development, the joint venture company formed by Shell and Gazprom Neft, started drilling the first horizontal appraisal well earlier this year. The work comes as part of a pilot program that calls for

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drilling five multifracked horizontal appraisal wells from 2014 to 2015.

While exploration efforts are in the early stages for the Bazhenov, Milligan pointed out that the push for tight oil is already underway with the Tyumen Formation, a mid-way point between the traditional conventional reservoirs and the Bazhenov, and production here has doubled between 2010 and 2014. He noted similar growth seen in the Achimov and Ryabchik formations, which has countered the decline of Russia's mature fields.

"For the Bazhenov, the challenge is to find a way to spot and drill sweet spots. The arrival of players like ExxonMobil (with experience from XTO), Statoil (Brigham) and Liberty Resources (large volume fractures in the Bakken) into West Siberia should help with the methodology in how to drill in unconventional reservoirs, but the tax environment and lack of high-end equipment at scale is challenging," Milligan said. "The Russian government has the ability to reduce export duty, which accounts for around \$55/bbl, but will probably only do so once more information about costs and returns is available."

Research and consulting firm GlobalData said Russia's finance ministry has begun to implement a shift of tax burden from export duty on oil to a revamped mineral extraction tax (MET). Export duty could drop from 59% to 55% by 2016.

"The base rate of the oil MET is set to increase from RUB495 (\$13)/tonne to RUB559 (\$15)/tonne. This base rate is multiplied by a number of other coefficients, including a price factor of around 10," GlobalData said. "However, there have been reports of a more substantial change from 2015, which would reduce the oil export duty to 42% in 2015, 36% in 2016 and 30% in 2017 while at the same time increasing the base rate of the oil MET

to RUB775 (\$21)/tonne, RUB873 (\$24)/tonne and RUB918 (\$25)/tonne in each of these years, respectively."

Considering most of the oil produced is exported, the change could improve the profitability of oilfield developments, according to Anna Belova, GlobalData's lead upstream analyst for Russia. "The shift in tax burden would also increase the effectiveness of some incentives, such as regional MET holidays and reduced MET for depleted fields, heavy viscous crude, and unconventional oil," she said.

But the firm noted that amendments could be made.

"The requirement for tax breaks to render certain projects profitable might be even more pronounced if the proposed MET increases are put in place," said Will Scargill, fiscal analyst for GlobalData. "However, any new targeted incentives are only likely to be available for projects that have strategic importance for the government either from an economic or political perspective. In particular, special incentives for projects supplying China and other Asian markets may become more common."

Then there are sanctions, which could impact some projects. "The sanctions are focusing on the post-2020 pillars of Russia's oil strategy, but the naming of companies and specific technologies has created a much higher degree of uncertainty," Milligan explained. "For the technology sanctions, it will be the application of the sanctions that will dictate the ultimate impact they will have, and this hasn't been tested yet."

Belova told Bloomberg that the sanctions "impose pain on Russia on a five- to 10-year horizon," and that the exploration projects disrupted or delayed by the sanctions wouldn't turn into productive oil fields for years. However, oilfield service companies, including Schlumberger, have already warned that the sanctions could impact their earnings.

Risky business

The biggest impact of the sanctions against Russia is to the investor climate, Victoria Brudenell, senior manager of business intelligence and investigations for the Salamanca Group, said during a phone interview. The sanctions tightened debt financing restrictions by lowering the maturity period for new debt issued by six Russian banks from 90 days to 30 days. To get needed funding, the sanctioned companies will look within Russia or go east and ask China.

After the U.S. imposed sanctions in July, which aim to end the conflict with Ukraine, Rosneft asked the state for up to \$41 billion of aid. Since then, the country's largest oil producer and Lukoil have received loans from OAO Promsvyazbank, Bloomberg reported.



The U.S. EIA estimates that the technically recoverable resources for the Bazhenov Formation are about 74.6 Bbbl for oil and 9 Tcm for gas. (Source: Salym Petroleum Development)



"I think people are going to be pretty wary about investing in Russia, particularly in the oil and gas sector, but actually across Russia widely," Brudenell said. "The foreign direct investments have fallen through the floor. I think it is expected to contract by 50% this year on last year, although last year was obviously a peak year because of the Rosneft-BP deal. But even still, I think that is the biggest issue."

Speaking on other perceived political and operational risks for companies involved in Russia's oil and gas sector, Brudenell said the issues of tenders can be nontransparent, corruption remains an issue and it's often assumed that political connections are required; therefore, local partners are needed. "There is a lack of technical knowledge among the workforce in Russia," she added. "Oil and gas contributes an enormous percentage of the GDP of the country, and therefore the state plays a heavy role in it, and that comes with its challenges."

Her advice for companies considering operating in Russia is to "know who you are dealing with and not just who you are dealing with on paper," trust and understand why partners are involved in projects, consider the requirements for technical expertise, have a good legal contract and framework within which to work and be aware of the level of risk. International oil companies make a lot of money in Russia, but investors "have to be willing to accept a certain level of risk. The most important thing is to be well informed and to read beyond the headlines," she continued.

Interest remains

Despite the operational risks, Russia stays on companies' radars, and more than likely, international oil companies (IOCs) remain on Russia's radars because it needs outside expertise to develop some of its hydrocarbon assets, whether it is EOR for mature fields or technology for frontier areas.

Russia is a place where companies, including supermajors, can chase conventional resource opportunities, Milligan said, noting others include Saudi Arabia, Iraq and Iran. "For this reason alone all major IOCs keep a watching brief on Russia even if they don't currently hold any investments.

"Due to abundant onshore resources Russia hasn't to date needed to develop offshore projects, and when it has it has often turned to IOCs," Milligan said, using Sakhalin 1 and 2 as an example.

But as Russia turns focus to more costly developments such as in the Arctic and unconventional shale plays, outside funding and expertise will be crucial.

"The Arctic is a long-term play, and Rosneft will be keen to learn from the 50 years of offshore experience that the IOCs hold. This can be seen in the U.S. and Norwegian partnerships between Rosneft, ExxonMobil and Statoil, for example. The likely cost of developing any offshore Arctic discovery is also likely to be so great that having an IOC to help fund the development will be very advantageous."

Several high-impact frontier areas remain onshore, Milligan added, noting each has challenges. For the Astrakhan region, the challenge is deep HP/HT reservoirs with sour gas. For the Gydan Peninsula, it's remoteness and likely gas. For the southern part of East Siberia, it's again remoteness along with limited infrastructure and long lead times to first production.

"Against this backdrop, exploration in the offshore Arctic and exploring tight reservoirs looks more attractive," he continued. "Offshore the key areas are offshore Sakhalin and appraisal of the possibly super giant South Kirinskoye Field and in the Kara Sea—an extension of the prolific West Siberian Basin." **E&P**



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SOUTH AMERICA

YPF discovers gas, oil in Santa Cruz

YPF made a discovery of gas and conventional oil in Los Perales–Las Mesetas Field in Santa Cruz located in Patagonia, Argentina, according to a press release. The discovery has a potential of 200 Mcm/d (7.1 MMcf/d) of gas and 370 bbl/d of oil. The discovery was made in well YPF.SC.LM.xp-778, which reached a final depth of 2,770 m (9,088 ft).

Jupiter well proves extension of Santos presalt find

Petrobras has confirmed the extension of the Jupiter discovery in Santos Basin presalt block BM-S-24 off the coast of Rio de Janeiro following drilling operations at well 3-BRSA-1246-RJS (3-RJS-732), informally known as Apollonia, the company said in a news release. This well is the fourth well drilled in the Jupiter Field. Drilling activities have confirmed a hydrocarbon column of about 313 m (1,027 ft), starting at a depth of 5,166 m (16,949 ft), with rocks showing good porosity and permeability conditions, the release said. Besides the gas cap and condensate, the well verified an oil column of some 87 m (285 ft) thick.

GULF OF MEXICO

Noble confirms drilling results in GoM

Final well results at the Katmai exploration well and the Dantzer appraisal well in the deepwater Gulf of Mexico (GoM) showed additional pay at Katmai and increased resources at Dantzer, Noble Energy Inc. said in a press release. At Katmai, wireline logging data indicate a total of 47 m (154 ft) net of crude oil pay was discovered in multiple reservoirs. Total gross resources at Katmai are now estimated at between 40 MMboe and 100 MMboe. The Dantzer-2 appraisal well, located in Mississippi Canyon 782 in the GoM, encountered 37 m (122 ft) net of crude oil pay in two high-quality Miocene reservoirs. Gross resources at Dantzer have increased to between 65 MMboe and 100 MMboe.

EUROPE

Lundin confirms oil column in Luno II

Lundin Petroleum AB, through its wholly owned subsidiary Lundin Norway AS, has successfully completed

drilling of appraisal well 16/48 S in the Luno II discovery. The discovery is located about 15 km (9.3 miles) south of the Edvard Grieg Field in the North Sea sector of the Norwegian Continental Shelf. The well was drilled 4 km (2.5 miles) southeast of the Luno II discovery well. The well encountered about 500 m (1,640 ft) of gross sandstone section of Jurassic/Triassic age. A gross oil column of 30 m (98 ft) has been proven, underlying a thin gas cap. The pressure data indicate a barrier toward the discovery well 16/46 S.

Statoil shuts down Huldra production

Statoil is terminating production from Huldra, making it the first gravity-based Statoil-operated installation in the North Sea to be shut down permanently, the company said in a press release. The platform has produced gas and condensate for six extra years compared to the original plan. The Huldra Field (PL051/052) came onstream Nov. 21, 2001, and has a recovery rate of 80%. The Huldra cessation project has considered the possibility of reusing the platform instead of scrapping it, and the platform was therefore put up for sale in 2011. The project is still actively seeking a solution of reuse.



Statoil is terminating production from Huldra six years after it was originally planned to be terminated. (Photo by Harald Petersen; Source: Statoil)

RUSSIA CIS

Rosneft, Seadrill, NADL sign agreement

Rosneft, Seadrill Ltd. and North Atlantic Drilling Ltd. (NADL) signed a framework agreement that envisages long-term cooperation in the area of oilfield development projects, a press release said. The document foresees the acquisition by Rosneft of NADL shares through an exchange of assets and investments in NADL charter capital. The deal will allow Rosneft to acquire a fleet of platforms and drilling rigs to conduct onshore and offshore drilling operations. **E&P**

PEOPLE

Sigma Cubed Inc. appointed **Mauricio Arbodela** as executive vice president of operations.



Pinnergy promoted **Lance Cauthen** (left) to vice president of operations

for drilling services and **Andy Snow** (right) to vice president of drilling.



Dan Oakley (left) became sales director at BMT Reliability Consultants, a subsidiary of BMT Group Ltd.

Rose Petroleum tapped **John Blair** as director of oil and gas and CEO of the firm's U.S. business. The company also added to its U.S. technical team with the appointment of **Wade Pollard** as vice president of land and **Ty Watson** as vice president of operations.

Circulation Solutions LLC promoted **Zach Grigor** to vice president of business development and **Mark Laurent** to vice president of operations.



BP named **David Lawler** (left) CEO of its U.S. Lower 48 Onshore business.

Baker Hughes Inc. made **Kimberly A. Ross** senior vice president and CFO.



Vikoma International Ltd. appointed **Karen Lucas** (left) as its new general manager and director.

Stochastic Simulation has chosen **Leo Mullins** as its new managing director.

Geir Egil Olsen has been appointed by Competentia as CEO of the group.

AziPac selected **Frank Inouye** to be managing director.

James Adam Thadchanamoorthy has been appointed to the board of Leni Gas & Oil Plc as finance director.

Chet Akiri has taken on the roles of senior vice president and chief corporate development, new ventures and strategy officer for Bristow Group.

Paul Hopkins has become principal engineer for 2H Offshore, an Acteon company.

Chesapeake Energy named **Brad Sylvester** vice president of investor relations and communications.

Integrated Environmental Technologies Ltd. hired **Bradley W. Rockman** as president and general manager of the company's newly established oil and gas division.



Decom North Sea tapped **Karen Seath** (left) as general manager.



Wild Well Control Inc. named **Wayne Stennes** (left) managing director and



Christian Haustead (right) area manager for the Asia-Pacific region.

Rocky L. Duckworth joined Glori Energy's board of directors.

Gary T. Clark has taken on the role of vice president of investor relations for Apache Corp.



Wood Group Intotech has appointed **Colin Smith** (left) to lead the expansion of its operations across the Americas.



Christopher Salinas (left) joined Alloy Metals and Tubes International as senior outside sales representative.

Aminex Plc named **Tom Mackay** as a nonexecutive director of the company.

The Aberdeen branch of the Society of Petroleum Engineers selected **Ross Lowdon** as its new chairman.



Michael Oxman (left) was named partner in the Houston office of Acorn International.

David Styles became a lead consultant in Brisbane, Australia, for NES Global Talent to grow its subsurface business.

Headwave Inc. named **Dan Piette** to the board of directors as a strategic adviser.

Great Western Oil & Gas Co. LLC selected **Bob Heinemann** as chairman of its board of directors.

Nautronix chose **Thomas McCudden** (right) to be global sales manager for NASNet.



COMPANIES

InterMoor, an Acteon company, has opened a major storage, maintenance and inspection facility in Aberdeen, U.K. The new base is on a 3-acre site with a warehouse, 20 permanent onsite staff and a large mooring inventory and will support InterMoor's global mooring



Pulse Structural Monitoring Inc. opened a new facility in Katy, Texas. (Source: Pulse Structural Monitoring Inc.)



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operations with a focus on Europe, Africa and Asia. The new facility will enable storage and maintenance of InterMoor and client equipment and is designed for onsite inspection and testing of wire and anchors. **Pulse Structural Monitoring Inc.**, another Acteon company, has opened a new, purpose-built facility in Katy, Texas, that will provide office, production and testing facilities. Staff at the new facility will be responsible for Pulse's engineering, project management and testing operations in the U.S. and Canada.

Robert Gordon University in Aberdeen, U.K., has launched a new center for smart data technologies, which aims to bring the benefits of analyzing and min-

ing vast quantities of data to industry. The center will focus on big data analytics, particularly for the oil and gas sector. It is intended that the industry will secure huge efficiencies from the use of analytics to extract added value for processes such as increasing speed to first oil, enhancing production, improved asset maintenance and reliability, reducing risks in health and safety, and reducing costs.

Applus RTD will open a base in Straume, Bergen, Norway, to provide nondestructive testing (NDT) services in the region. The new office and test facility will provide in-house and onsite NDT; metallurgic field work; and a range of inspection services including rig, paint, derrick and hull inspection. **E&P**

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A microseismic approach to unconventional

Advances in data processing calibrate hydraulic fracture design models to improve field economics.

Kari Anne Hoier Kjolaas-Holland, Schlumberger

As operators shift from appraisal to full-scale field development of their core assets in unconventional plays, they are increasingly confronting challenges surrounding the placement of wells—spacing between wells, vertical position in the reservoir, lengths and orientation of the laterals—parameters that are critical to maximizing field economics.

Modeling the subsurface and simulation of production results based on different field development scenarios is a common method used to optimize recovery; however, variability in well performance leaves remaining uncertainties and requires that both the reservoir and the completion be addressed thoroughly and properly in the production simulation. Reservoir quality can be addressed with log measurements taken along the lateral, which provides a good understanding of where the wellbore is located in the reservoir, as well as with seismic surveys, which measure deeper formation characteristics using active sources.

A more comprehensive way of assessing completion quality and the effectiveness of hydraulic fracture stimulation is with microseismic measurements, a passive methodology that uses sound to detect the energy created by rock as it cracks and assess the hydraulic fracture geometry as the wells are stimulated with fracturing techniques. Microseismic measurements are currently the best way operators can understand the geometry that is being created during the hydraulic fracturing process—where and in which direction the complex hydraulic fracture network is going, the length of the fracture network into the reservoir, and whether it is growing up or down into unwanted intervals. The information can be used to create a feedback loop, enabling operators to improve fracturing techniques based on what they have learned.

As field development progresses there is a growing number of infield wells drilled adjacent to and hence potentially interfering with existing producers. The capabilities of microseismic analysis are being expanded with new techniques in data acquisition and processing.

The oil and gas industry has long known that the seis-

mic energy produced from hydraulic fracturing contains information about the geomechanical deformation that occurs during stimulation. Moment tensor inversion (MTI) is a seismic data-processing technique that extracts that information from microseismic measurements and uses it in the modeling and simulation of the complex hydraulic fracture network that is created. Advances in signal processing, presentation and interpretation of MTI data now make it possible to calibrate the fracture design model and reduce uncertainty in the simulation.

Understanding the fracturing process

The technique analyzes the radiation pattern of the seismic amplitudes at different locations to determine the fracture plane and slip and define the mode of fracturing as shear or tensile opening. MTI data also enhance microseismic interpretation of fracture geometry by including the additional source parameters for each microseismic event.

By processing microseismic data with more detail and certainty, the advanced MTI processing service can be used to model discrete fracture networks, validate stimulation design and analysis, and evaluate multiple production scenarios, resulting in better decision-making in the field. Schlumberger has developed a comprehensive workflow in an exploration and production platform that now incorporates MTI results in designing hydraulic fracturing to enhance understanding of the reservoir.

Introduced in 2013, the Schlumberger MTI analysis has been deployed in several oil and gas shale well projects throughout North America. Recent projects in Canada and in the U.S. have illustrated that MTI data can help reduce uncertainty when assessing the completion quality and forecasting production results. The applications for this approach are numerous but also include the important questions operators face when deciding on well spacing patterns in unconventional.

Advances in microseismic technology mark a breakthrough in enabling operators to obtain precise, actionable information about the hydraulic fracture geometries as wells are stimulated and use that information to improve decision-making going forward. **ESP**

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