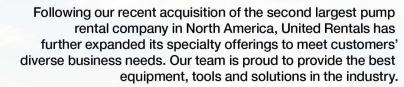




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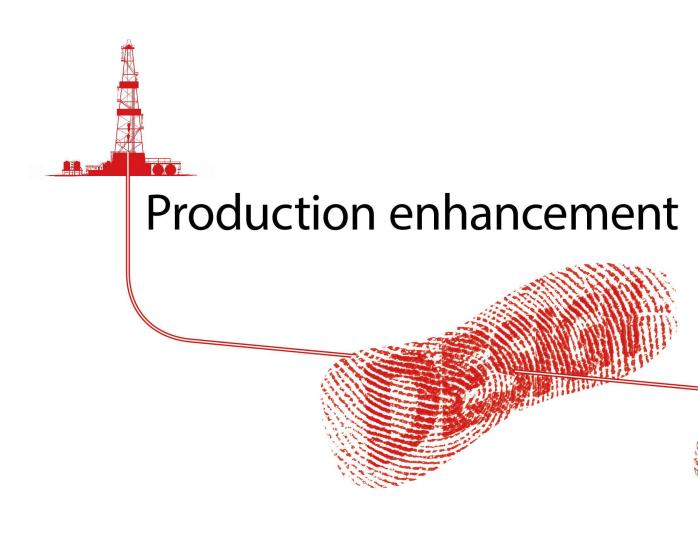
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OFFSHORE SOLUTIONS

High-definition exploration requires complementary systems

Submersion and directed flow cooling solution for oil, gas

COMING NEXT MONTH The August issue of **E&P** will examine new advances in powering the oil field. Other features will focus on rock physics, unconventional completion optimization, CO₂ management, and subsea trees and workover advances, and featured regions will be the Permian Basin and the North Sea. 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 International shales are picking up momentum, while in the U.S. new plays are being delineated. And despite the risks, the Middle East's proven hydrocarbon reserves continue to attract new and ongoing developments. (Main photo courtesy of Halcón Resources, side photo courtesy of Saudi Aramco; cover design by Laura J. Williams)

E&P (ISSN 1527-4063) (PM40036185) is published monthly by Hart Energy Publishing, LP, 1616 S. Vass Road, Suite 1000, Houston, Texas 77057. Periodicals postage paid at Houston, TX, and additional mailing offices. Subscription rates: 1 year (12 issues), US \$149; 2 years (24 issues), US \$279. Single copies are US \$18 (prepayment required). Advertising rates furnished upon request. POSTMASTER: Send address changes to E&P, PO Box 5020. Brentwood, TN 37024. Address all non-subscriber correspondence to E&P, 1616 S. Voss Road, Suite 1000, Houston, Texas 77057; Telephone: 713-260-6442. All subscriber inquiries should be addressed to E&P, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442. All subscriber inquiries should be addressed to E&P, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442. All subscriber inquiries should be addressed to E&P, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442. All subscriber inquiries should be addressed to E&P, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442. All subscriber inquiries should be addressed to E&P, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442. All subscriber inquiries should be addressed to E&P, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442. All subscriber inquiries should be addressed to E&P, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442. All subscriber inquiries should be addressed to E&P, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442. All subscriber inquiries should be addressed to E&P, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442. All subscriber inquiries should be addressed to E&P, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442. All subscriber inquiries should be addressed to E&P, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442. All subscriber inquiries should be addressed to E&P, 1



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UK launches subsea research initiative

A major subsea research initiative has been launched. The National Subsea Research Initiative will be the focal point for the coordination of R&D activities for the U.K.'s subsea oil and gas sector.

Arctic subsurface separation study underway

Kvaerner has been backed by Canadian-based research organizations for a new technology study on using subsea separation and storage in Arctic conditions as an alternative to surface facilities.

AziPac gains stake in Bone Bay area

Newly launched explorer AziPac Energy has taken a 40% stake in a shallow to deepwater block offshore Indonesia joining Mitra Energy in the Bone production-sharing contract in the Bone Bay region.

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Hurricane forecast could bode well for GoM output

By Velda Addison, Associate Online Editor

NOAA predicts a below- to near-normal season, but only one storm could cause major damage.

Seismic work, drilling picks up in New Zealand By Steve Hamlen, Special to E&P

Recent activity has included survey and well completions as well as a licensing round launch.





Future could hold rise in global frack capacity By Velda Addison, Associate Online Editor

A drilling and completion activity forecast shows global frack capacity increasing by 16.2 MMhhp this year.

ONGC Videsh ramps up overseas portfolio By Ravi Prasad, Special to E&P

The company is targeting areas worldwide including in Latin America and Russia.



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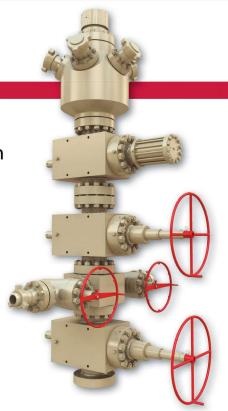
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The Goldilocks strategy

When it comes to the pace of technology development, it has to be just right.

s far as fairy tales go, the one about Goldilocks and her fussiness over the temperature of her porridge in the bears' house is well known.

She demonstrates her fussy nature after taking a mouthful of breakfast by declaring the first two options on the table as simply "too hot" and "too cold" (with little thought for modern hygiene, it must be said), and she then of course decides that the baby bear's porridge is "just right."

It's a tenuous analogy, but it was interesting to hear the CTO of a major U.S. and international operator use the same phrase to describe his company's approach to the pace of the development and application of new technology.

Ram Shenoy, CTO at ConocoPhillips since early 2012, was talking at a recent event put on by Schlumberger Information Solutions about how the operator had been expanding its capabilities in deepwater and oil sands and today how it also has a strategy to become a leader in unconventionals.

The use of technology to give it its position in the U.S. unconventionals business has and is playing a key role. With strong positions in the liquids-rich Eagle Ford and Bakken, the company is looking to expand its production from a 2013 figure of about 170,000 bbl/d to 370,000 bbl/d in 2017.

"We have a pipeline of unconventional assets at varying stages of maturity." But the pace of development cannot be too fast or too slow. It has to be just right," Shenoy said. Other operators in the past felt the need to perhaps run faster, but in the case of ConocoPhillips, he said, "We find if we take the time, we can maximize the returns."

The company is this year investing about \$3 billion in the Eagle Ford Shale alone (\$1 billion more than last year), no doubt helped by the fact that Shenoy admitted the company originally thought it would produce about 160,000 bbl/d in 2014. "It's going to be nearer to 250,000 bbl/d," he confided. That's quite a ramp-up in production.

Maximizing returns largely means better drilling efficiency in basins like the Eagle Ford and Bakken, and Shenoy outlined how the company has reduced its drilling days by an impressive average of 40% while also reducing its completion costs per unit of proppant by the same amount.

It also has installed an integrated operation center that gathers key operating data in real time using a fieldwide wireless Internet system. This, said Shenoy, has enabled it to reduce the number of shut-ins "dramatically" despite the number of actual wells rising.

Being able to pace yourself well has always been a good discipline. When the benefits of doing so, as in this case, are so clearly beneficial to a company both operationally and commercially, it demonstrates that likely similar improvements by the industry as a whole will be no fairy tale.



Connecting key elements

A new approach to integrating people, processes and technology can change the safety-productivity dynamic and drive risk-based operational excellence.

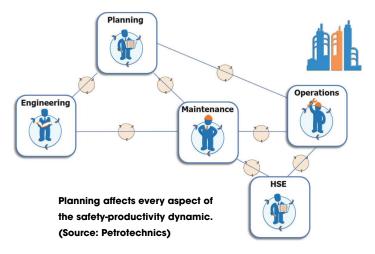
Scott Lehmann, Petrotechnics

A sset integrity, safety performance and production efficiency are inextricably linked in hazardous industries. While it may seem simple in theory to ensure that the work needed to maintain safe, efficient and sustainable production gets executed safely and efficiently, the reality is often very different.

Competing work conflicts, stretched resources, differing priorities across business functions and changing workforce demographics are just a few of today's realities across the global oil and gas industry. Add to this the challenges that go with increased global demand, aging assets, maintenance backlogs and compliance requirements against the ever-present production requirements, and companies have the complex reality that faces frontline managers and operations staff each day as they make the difficult calls regarding safety and productivity.

People dimension

With a less experienced and more culturally diverse workforce recruited from across the globe coupled with the increasing complexity of operating environments, many companies find themselves in a race just to stay even, let alone improve. Employees jump from company to company in search of improved conditions, contractors have become the principal suppliers of frontline staff in



some regions, and subject matter experts have become hot commodities.

Process and systems dimension

One of the key systems used across all hazardous industries is a work management system that typically encompasses at a broad level engineering, planning, maintenance, operations and HSE. Across these functions is the day-to-day management of the safety-productivity dynamic and the identification, prioritization, planning, scheduling and safe execution of the work activity required to ensure long-term safe and efficient production.

In each of these business functions (that are often managed separately) there has been a lot of focus at improving or optimizing processes. So, for example, in planning some organizations have spent significant time, effort and money to improve planning processes. They have been improved, in some cases quite markedly. However, often there is little improvement in terms of maintenance effectiveness, safety performance or improved production efficiency. The key may be in looking at how the end-to-end system can be optimized.

Technology dimension

Technology can play a vital role in underpinning and optimizing the end-to-end work management process in two critical ways. It can intelligently systematize best practices and policy into operational practice, and it optimizes the process to improve operational decision-making with improved collaboration and coordination across functions based on a common currency of operational risk.

By capitalizing on new technology such as operational performance and predictive risk software platforms, companies can embed policies, rules and regulations into operational workflows and automatically generate consistent and reliable operational and risk-related data. They can ensure that all of the risk assessments take into account process hazards relevant to the location and equipment being worked on and that they are communicated to work crews. Frontline workers can be prompted by the system to be aware of process and hazard safety considerations and control mechanisms relevant to the area of work.



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Through their scalable and enterprise nature, these systems can be deployed across a single plant, multiple assets or even the enterprise. The standardized and harmonized implementation cultivates a realistic and pragmatic approach to working across the plant and yet retains the flexibility to support regional, local and cultural contexts. The frontline workforce can flourish under the guidance of a tool that provides operational decision support and raises risk management capability and competencies.

Over time, this can manage out variances and different ways of working. It can nullify practices that can foster subconscious bias toward inappropriate behaviors leading to unpredictable work execution, compliance failure notices and inaccurate planning. It can reduce high levels of shutdown and incidents while generating and sustaining improved culture, discipline and behavior for operational excellence and enhanced safety.

From frontline to boardroom

Managers tend to identify and prioritize work. They plan the work and then refine their plans and schedule. They need to account for resources, contractors, equipment and other supply chain constraints.

They then typically hand the project over to operations to execute, but they don't always see the levels of plan attainment, reduction in the maintenance backlog and increases in time or in production efficiency. Often planners note that their plans seem to break down at the seven-day time frame.

With operational performance and predictive risk software platforms in place, risk and execution can be built into the plan. The impact of planned and live work can be visualized alongside the current barrier impairments related to process safety and asset integrity risk.

With this common currency of a practical view of risk across the organization, operators can improve decision-making and make dynamic adjustments to the schedule to optimize workload against risk.

Better information drives better decisions, which drive better outcomes. The ability to automatically visualize the often complex picture of workload and risk can be invaluable for frontline managers and staff, especially in light of the impact of the big crew change. With policies embedded to guide people to the right decisions around workload and risk, the ways in which things are done across organizations can be systematized.



Barrier impairments related to process safety and asset integrity risk can be visualized. (Source: Petrotechnics)

The larger implications of a common currency of risk across the functions involved in the work management process are significant. Given that these systems are collecting both real-time and actual data on work activity and risk, this data-driven information can be fed back to other work management systems to improve future plan accuracy and prioritization. More importantly, real improvements in operational excellence can be driven by further optimizing the business processes across functions:

- Operations and HSE can ensure company baseline best practices are followed consistently across the organization with risk built into the plan up front, leading to better decisions and better outcomes to ensure long-term safe production;
- Maintenance and operations can improve coordination and collaboration to drive increased maintenance effectiveness since maintenance can better prioritize to operations' capacity to prepare the work site and manage controls; and
- Planning and engineering with better visibility of barrier impairments help to prioritize safety-critical maintenance earlier in the planning process.

Changing the safety-productivity dynamic requires a new approach to people, processes and technology. Better connecting key elements of the work management process such as integrated activity planning, workload prioritization, operational risk management, and work control and execution with operational performance and predictive risk software can provide a common and practical view of operational risk across the organization. Frontline workers and senior leaders are empowered to make better decisions around workload and operational risk, and operators can move in a direction of risk-based operational excellence to improve the asset integrity of their facilities, keep their people safe and ensure long-term production.

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Finding more, spending less

A global exploration strategy focused on drilling high-impact wells is transforming Statoil's reserves portfolio.

Mark Thomas, Editor-in-Chief

A s finding fresh reserves offshore Norway becomes tougher by the day, a long-term strategy to establish new core areas around the world has proven to be an outstanding success for the country's state-owned player.

That strategy has been spearheaded by Tim Dodson, executive vice president for global exploration at Statoil. Recalling the situation in 2010, he paints a grim picture that year in which the company replaced only a third (250 MMbbl) of what it was producing, with the upstream industry as a whole also struggling to replace its resources.

Speaking at the recent SIS Global Forum in Barcelona, Dodson outlined Statoil's global push over the past four years to continue investing through the drillbit to find new reserves and establish core areas where it could then apply the technologies and decades of experience it has gained on the Norwegian Continental Shelf to maximize the long-term returns from those areas.

Think big

"Statoil had to find new reserves and achieve early access at scale. It was very obvious to me why we were not finding enough—we were not drilling enough deep wells," he said. The answer was to think big. "Drilling enough high-impact



wells has been the key. We have drilled 20 such wells over the past three years, and they have produced 70% to 80% of the volumes we have discovered. We are reaping the rewards now from these core areas around the world."

The period between 2011 and 2013 saw Statoil discover 3.9 Bboe of new reserves, making 11 high-impact (recoverable reserves of 250 MMboe-plus) discoveries and opening up the new plays. This, he said, was done at an impressively competitive finding cost of around \$3 per barrel.

The company's strategy has seen it increase its net international acreage, and it now possesses what Dodson describes as a robust, balanced and "oily" portfolio with significant follow-up potential.

That portfolio features core areas in the Barents Sea, Tanzania, the Gulf of Mexico (GoM), Canada and Angola, with close to 90% of its activity focused in these areas.

New plays

In the Barents Sea the operator continues to pursue new oil plays in the Skrugard and Wisping discovery areas, with a total of three operated wells to be drilled in the frontier Loop area this year. The chances are good, with Statoil having achieved a 70% success rate with wells drilled in the Barents Sea during 2013.

Tanzania was highlighted as another outstanding exploration success for the company, having achieved a 100% drilling success rate since 2012. With between 481 Bcm and 566 Bcm (17 Tcf and 20 Tcf) of recoverable gas reserves discovered, Statoil is pushing on quickly with its exploration and appraisal program this year.

Off Africa's west coast, Angola remains an area of continued strong focus for the company, especially now that work by the independent Cobalt Energy has "de-risked the play," Dodson said. Statoil has a five-block portfolio there, including Block 39, which it operates in the presalt Kwanza Basin and where Statoil discovered a major prospect called Dilola, due to be drilled imminently. "This is a megastructure. It's one of the biggest closures offshore I have seen this year—but it is high-risk," he said. Angola remains Statoil's largest contributor to its oil production outside Norway, yielding around 200,000 boe/d in 2013.

Across the Atlantic in the deepwater GoM, Statoil is currently drilling a high-impact well on the Martin prospect in Mississippi Canyon Block 718, with Dodson saying the



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RIGHT: A core sample is taken from an appraisal well on the Aldous discovery offshore Norway, one of Statoil's successful high-impact wells. (Source: Statoil) BELOW: Seadrill's West Aquarius semisubmersible rig drilled Statoil's high-impact Bay Du Nord discovery well in the Flemish Pass offshore Canada last year on a prospect previously offered out twice unsuccessfully for a farm-out by the Norwegian operator. (Source: Seadrill)



company will follow this Miocene probe with another on its operated Perseus prospect. Both are close to Shell's Vito discovery, in which Statoil is also a partner.

High-grading of prospects

One of the reasons Statoil is enjoying such strong and sustained success with its exploration strategy has been its focus on "high-grading" prospects, its speed of response and a willingness to be flexible when needed. This global calibration and prioritization of basins, prospects, rigs and seismic has paid off in a number of ways, and Dodson highlighted the benefits in one core area in particular—Canada.

Previously something of an underachieving province, Canada has benefited from Statoil's ability to accelerate good opportunities. Last year its exploration team high-



lighted a much better prospect to target than had originally been envisioned. "They had a much better prospect to drill and told us about it, so in two weeks we totally changed our plans and drilled Bay Du Nord instead. We acted swiftly, and now we're looking at accelerating the development of that prospect. The thing was, we actually tried to farm it out twice previously and failed. So with hindsight I'm glad we did not do it."

Cracking the code

Dodson went on to describe persistence as a key factor. "We'd found Mizzen previously, things had been rather disappointing, we'd struggled, and then finally we cracked the code with Bay Du Nord," he said. The discovery, located in the Flemish Pass approximately 500 km (310 miles) northeast of St. John's, Newfoundland and Labrador, is currently estimated to contain recoverable reserves of between 300 MMbbl and 600 MMbbl of light oil.

He also pointed out the importance of maintaining "portfolio churn," as evidenced by Statoil's recent decision to farm-down its interest in the high-potential Block 39 offshore Angola, keeping a strong equity level but reducing its exploration risk.

With the company due to spend an estimated \$2 billion on exploration wells this year and \$3.5 billion in total exploration expenditure, capital discipline is vital as the company pushes toward its stated goal of achieving total daily production of more than 2.5 MMbbl.

"We must mitigate cost exposure, improve efficiency and increase focus," he said. "We have to find more and spend less. I do not have 'P&L' [profit and loss] in my department; I just have 'L.' So I need to find more oil and gas."



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Bridging the skills gap

As more people retire from the oil and gas industry, companies are getting creative to find their replacements.

Rhonda Duey, Executive Editor

No need to worry about when the Big Crew Change is going to happen—it's already here. Staffing issues are among the key challenges facing operators and contractors. Many companies are relying on recruitment firms to help them find talented and qualified employees.

One such company is NES Global Talent, a U.K. company with offices worldwide. NES has been operating an office in Houston for 15 years and has medium-term plans to open offices in other U.S. hotspots such as Pittsburgh, Pa., and Midland, Texas. Andrew Carr, lead search consultant for NES, attended the recent American Association of Petroleum Geologists (AAPG) annual meeting in Houston and talked about his company's approach to finding the best person for the job.

Increasing market presence

Carr said that NES tries to differentiate itself by getting its name out there. It had a presence at AAPG to find what he calls "passive candidates," people who aren't actively looking for a job but are interested in learning what opportunities are available.

It also has a very discipline-specific group of consultants. Carr's team, for instance, only covers subsurface jobs. Other disciplines include drilling, completions and petroleum engineering. "We like to think our consultants are real specialists in their given markets and are increasing their knowledge of what candidates are in the market and what specific projects are happening that we can make them aware of," he said. "I think a lot of companies are having to get a little bit creative in what they're offering and what opportunities they are creating."

For instance, he added, many companies are becoming a bit more diverse by including more women in the workplace. A recent NES report titled "Attracting and retaining women in oil and gas engineering" noted that the engineering sector is facing "a crippling skills shortage."

"The industry needs to find creative ways to attract women, not just at primary and secondary school level but at an undergraduate and graduate level," wrote Neil Tregarthen, CEO of NES. "It must also continue to work to attract women working in other industries to oil and

gas engineering, shining a spotlight on what a welcoming and rewarding career it can be and highlighting the opportunities."

Beyond that, Carr said, it boils down to demographics. "I think one of the biggest changes we're seeing is that companies are realizing that they just aren't bringing in employees with eight to 20 years of experience," he said. "Essentially they will be the next generation of leaders in the business. They're really going all out to get those individuals on board, whether it be changes in position, going from purely technical roles into leadership opportunities, or almost creating roles for specific individuals to at least get them into the business."

Another differentiator is the fact that the company is trying to get away from being perceived as just a staffing



A quarter of women employed in oil and gas do not find the industry welcoming. With a shrinking workforce facing them, companies are trying to bring more women into the industry. (Source: NES Global Talent)

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SAFE AND ENVIRONMENTALLY FRIENDLY APPLICATIONS!

REPORT

firm. Carr said that NES wants to provide more of a consultancy service to its clients.

"We now offer what we call our five permanent solutions," he said. "We have your standard contingent recruitment, but we can offer a full retained service as well. We cover multinational deployment, and we can deploy NES staff on site with clients."

He added that several NES employees work onsite with a major engineering company and have helped it recruit 150 new hires in just a few months. "We take the recruitment process off their hands and outsource it to ourselves, running it as an entire project," he said. "When you're going through that kind of growth, it really takes the strain off of the internal recruitment teams, especially in these kinds of niche disciplines."

Going back for seconds

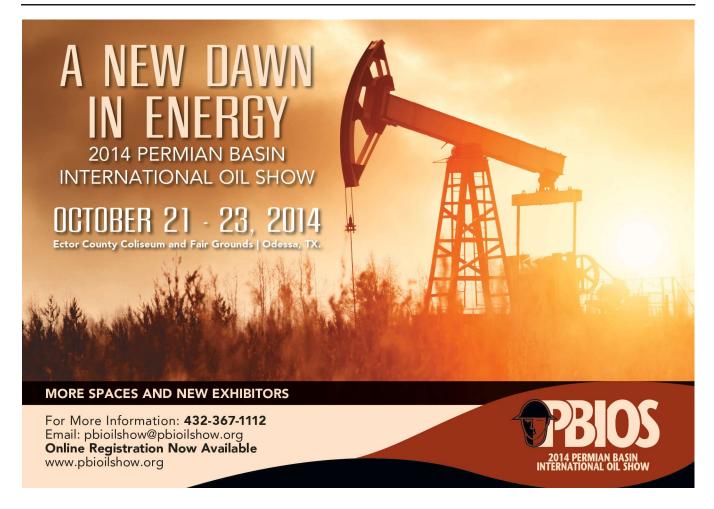
Carr's subsurface area covers geoscience, reservoir engineering and petrophysics, and within those disciplines retirements are already having a profound effect. But

not all of them stay retired. "A lot of people who did retire are coming back to the industry because of the salaries they can now command," he said. "The day rates on a consultancy basis for candidates with 30 to 35 years of experience have really gone through the roof in the last few years, so they can come back to the industry for one to three years on a contract basis and set themselves up for retirement again."

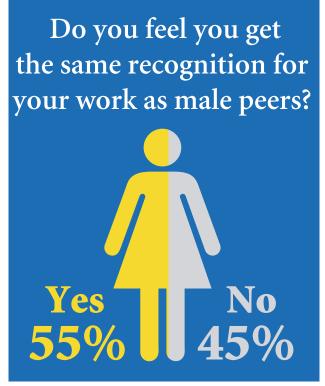
Looking for work?

Companies are not the only ones benefiting from these types of services. Carr said that NES offers "the full lifecycle service" to employees looking for work. Candidates are advised on curriculum vitae preparation and interview preparation as well as knowledge about the industry in general.

"A lot of people who have been working within a company for their entire career have absolutely no experience at going to an interview and really showing their skills," he said. "From a permanent perspective, we man-







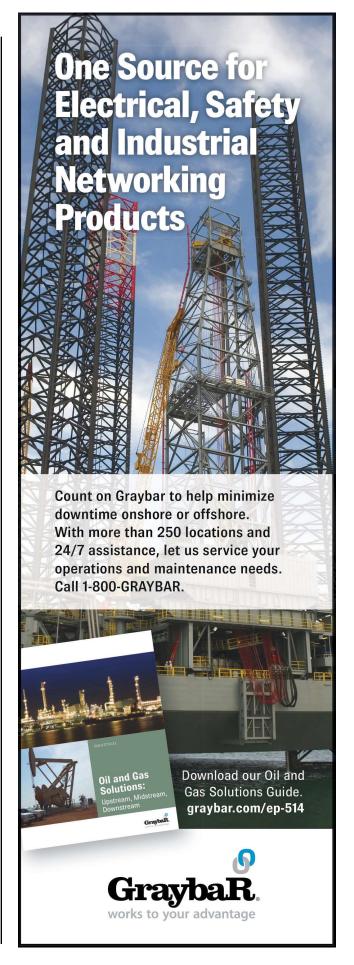
Almost half of the women in the industry feel that their accomplishments are not appreciated. (Source: NES Global Talent)

age the entire process, from presentation to the client through to salary negotiation to ensure the smoothest process and transition we can."

Mindful of the fact that not all oil and gas jobs are permanent, the company also works with contractors from contract generation to onsite support for staff during their tenure with a company.

Global perspective

Countries such as the U.S. are actively seeking employees from around the world, and NES helps these companies in that search. Carr said that U.S. companies are embracing the concept of bringing in people from other countries, and the main issue is the difficulty in procuring work visas. "A lot of companies are increasing their reliance on intercompany transfers," he said. "Businesses like BP, Anadarko, ExxonMobil and Hess that have international offices are transferring staff from there to the U.S. to pick up the workload in their Houston hubs. A lot of these people are staying here and going down the green card route and looking to remain here longer term, which hopefully should address some of the issues with the skills shortage and the demographic change as well."



EPmag.com | July 2014



The demand for sand

The growing role of slickwater fracks and the addition of more stages per lateral drive increased usage.

Richard Mason, Chief Technical Director

Demand for proppant used in hydraulic fracturing increased sharply in first-half 2014, prompting price increases that are expected to continue into 2015 even as the cost of transportation to get proppant to the well site is increasing.

Pricing for sand has risen roughly 20% since 2012 and is likely to rise another 20% during the course of 2014, according to participants in a Hart Energy survey of proppant suppliers.

Rising demand—and the attendant price increases—stem from multiple factors including the growing role of slickwater fracks, which are gaining marketshare even in markets like the Bakken that were previously dominated by crosslink gels. Slickwater represents the sledgehammer approach to hydraulic fracturing and employs greater volumes of proppant than other well stimulation methods.

Secondly, operators are adding more stages per lateral and placing them closer together with a larger number of perforation clusters between each stage. Operators also are pushing lateral length beyond 1,525 m (5,000 ft) in many cases, further boosting stage count. In a few atypical cases, operators have fracture-stimulated as many as 80 stages in a single lateral, though it is more common to see 35 to 40 stages per lateral vs. 17 to 19 one year ago.

Other factors include the move to pad drilling, which has increased the number of completions relative to rig count, coupled with increases in drilling levels in regional markets such as the Permian Basin. More than 300 rigs are drilling horizontally in the Permian, creating organic growth in regional proppant demand even as incremental sand use per stage grows.

"Sand usage is up 40% at each well," one wellsite delivery service provider told Hart Energy telephone surveyors.

This increase in downhole intensity is the main story in 2014, just as the transition to pad drilling and batch completions constituted the main industry narrative in 2013 or drilling efficiency gains dominated the discussion in 2012.

Demand is higher for all grades of sand, including 20/40, 30/50, 40/70 and 100 mesh grades. Sand represents 87.2% of proppant demand among industry representatives participating in the Hart Energy survey, with

- Greater downhole intensity is increasing proppant demand
- Price for sand is up 20% since 2012 and expected to rise 20% through 2015
- Operators are using more sand per stage and packing more stages closer together in each lateral
- Slickwater fracks are gaining marketshare and increasing proppant demand

ceramics accounting for 7.5% and resin-coated sand representing the remaining 5.3%.

Ceramic suppliers told Hart Energy that use of high-end ceramic proppants is growing, particularly in the Bakken as operators attempt to reduce the decline rate and increase first-year production.

"The volumes for ceramic will grow with the new interest in decreasing the decline rate here," said a Bakken area ceramic supplier. "Wells completed with ceramics show 30% increased production."

Demand for sand is coinciding with bottlenecks in transportation, exacerbating tight supply conditions. Those shortages were particularly acute in the Bakken during the extended winter of 2014. Hart Energy survey respondents cited shortages of locomotives and the rail cars used to transport sand as the bulk commodity competes for rail space with crude oil or other cargoes. One respondent said there is a shortage of 20,000 rail cars across the country.

"We are bringing our imported proppant in through Baltimore because the rail coming from the east is less congested," one top-tier ceramics supplier said. "We quit shipping through Texas."

A Midcontinent mining and sand supplier reports looking for alternatives to rail.

"Rail is such a challenge at present," the supplier said. "We put a big focus on shipping as much as possible by river barge. Every barge gives us 1,500 tons of storage while in transit."

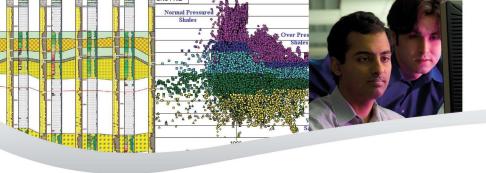
A top-tier Texas supplier is adapting to transportation bottlenecks by expanding regional storage facilities.

"We are building new, bigger terminals to handle 24,000 tons of storage in both the Eagle Ford and Permian," the supplier said. **EP**

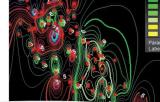


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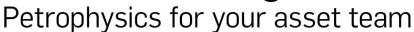






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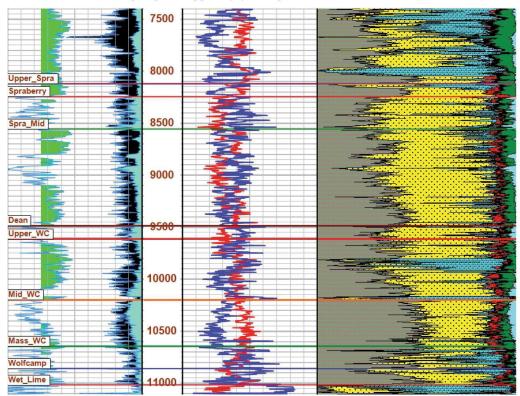
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The next evolution of data storage

A new hybrid approach takes advantage of the best that network and cloud storage have to offer.

Those of us of the "older persuasion" can remember the advent of computing technology in our lives and jobs. When I started at Hart Energy in 1995, for instance, we didn't even have email, let alone Internet access.

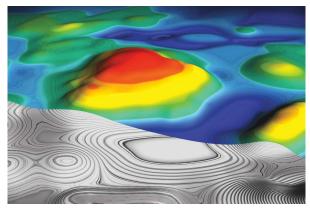
In the seismic world, the size of the datasets has almost always outpaced the ability of computer technology to store and manage the data. Nonetheless, contractors, processing shops and operators made due with whatever was available.

"In the early days, the digitized oil and gas data were stored on and accessed from direct-attached storage," said Vaughn Miller, vice president of vertical business development at Avere Systems. "This meant that all of the storage was directly attached to individual computers or workstations. That created quite a few issues."

In the 1990s there was an evolution toward networkattached storage, which Miller said was of some concern due to debate as to whether or not large amounts of data could be delivered over networks to workstations at a fast enough rate. However, in reality this type of storage actually accelerated data access in many applications because of file system technologies and low latency of networks.

As the industry moves through the second decade of the 21st century, little debate remains about the efficacy of these systems. However, according to Miller, the next evolutionary step is on the horizon—cloud storage.

Avere provides a hybrid solution that combines network-attached storage on premises as well as in the



The seismic processing environment can be optimized by scaling storage performance even higher using a hybrid system. (Source: Avere Systems)



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cloud. "In the first generation of this, hybrid offpremises or cloud storage might be used primarily for archival data," Miller noted. "But we see the trend over the next few years going to where an increasing amount of geocomputing data will be both on premises and in the cloud."

Companies like Avere are enabling this hybrid storage by allowing secure, high-performance data storage in the cloud. Miller noted that Avere also enables traditional applications to access the data without making any changes to those applications.

"Data security has been a barrier to cloud adoption in the past, but Avere is able to do the encryption and keep the keys for the encrypted data in the cloud, on premises and inside the firewall," said Miller.

"In the case of seismic data, the cloud offers the opportunity to store archival data off-premises in a cost-effective manner," added Tom Ledoux, senior systems engineer at Avere Systems. "It also offers a high-performance computing [HPC] environment in which Avere can provide very high throughput to both on-premises storage and cloud-based storage in the hybrid environment. For companies that are looking to the cloud for temporary HPC, they can now do both on-premises processing and even rent resources in the cloud to expand their compute infrastructure without having to buy new hardware.

"These types of hybrid systems won't interfere with current data management policies and procedures," he continued. "If you have policies and procedures on how to manage seismic data, which is a massive problem in and of itself, Avere won't interrupt or change any of that—we just accelerate access to the data that are being used on a daily basis."

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GWDC's Heavy Oil Technology - the dark secret of success!



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- Steam Assisted Gravity Drainage (SAGD)
- Thermal production FDP design
- Steam drive

- Water flooding energy
- Natural cold production
- Immiscible flooding

CSB applies new term to explain Macondo drillpipe buckling

The U.S. Chemical Safety Board used a term—effective compression—to explain its findings in the failure of the BOP in the *Deepwater Horizon* disaster.

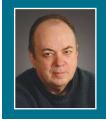
A two-volume draft investigation report on what the U.S. Chemical Safety Board (CSB) claimed caused the drillpipe to buckle and jam the *Deepwater Horizon*'s BOP was released June 5. The CSB, which is an independent federal agency investigating chemical accidents, has been very proactive in pursuing its own investigation of the incident.

Now the agency has come out with its own explanation of how and when the pipe buckled. The report concluded that the buckling occurred in the first few minutes of the blowout. According to a press release, the identification of the new buckling mechanism for the drillpipe, called effective compression, was a central technical finding of the report.

CSB stated effective compression occurs when there is a large pressure differential between the inside and the outside of the pipe. The release continued, saying that condition likely occurred when the pipe rams were closed, temporarily sealing the well. This unfortunately established a large pressure differential that buckled the steel drillpipe inside the BOP.



CSB's first recommendation is for the American Petroleum Institute to revise Standard 53 for BOP equipment systems.



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The agency even created an 11-minute animated video to illustrate its theory. You can see it on its website at *csb.gov*. The CSB claimed its model differs from industry buckling theories due to "insufficient supporting evidence" for earlier explanations. How is it that CSB evaluates one well blowout, and it is a model, while all the other explanations are theories?

Although I am not an engineer, I could see another cause for pipe bending—the pressure of the uncontrolled flow forcing the drillpipe upward into the BOP.

In an earlier report in 2011 by the National Academy of Engineering—Macondo Well-*Deepwater Horizon* Blowout: Lessons for Improving Offshore Drilling Safety—there was a different conclusion about why the shear rams didn't cut the pipe. The study was sponsored by the U.S. Department of the Interior.

The report provided a detailed forensic analysis of the BOP. One finding was that when the blind-shear ram was activated, it was unable to center the drillpipe in its blades, which were a combination of straight and "V" blades. This combination has been shown to be inferior to the double-V blade geometry. Because the blind-shear rams did not fully span the BOP annulus, a mashed segment of pipe was caught between the rams and prevented the rams from closing.

I have only read the CSB press release. The blade geometry wasn't mentioned, although it is shown in the animation.

It is probably good to have an outside agency provide another perspective. If it makes sense, include it. **EP**

List

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America the innovative

Booming shale business encourages industry growth, investment in new technology.

t has been exciting to experience the U.S. energy renaissance during the last decade. The jobs created by the country's shale boom have helped hoist the economy out of the depths of its Great Recession, and the call for industry talent continues to be broadcast far and wide.

This progress stems from discoveries of massive oil and gas reserves in large shale plays across the U.S. and from the development of new techniques and technology to thoroughly explore and exploit them. Through these ever-improving horizontal drilling techniques and advances in hydraulic fracturing, operators are amassing enormous wealth.

This success has enticed operators from all over the world to invest in North America onshore activity—even Norwegian giant Statoil, which is known for its

significant offshore and subsea presence.

"In the 10 years we've been in North America we've invested \$16 billion, with \$10 billion invested in the onshore space alone," said Veronica Roa, vice president of early stage projects and land for Statoil. Roa presented "Statoil's North America Growth Strategy, Learning and Promises" on May 7 at the 2014 Offshore Technology Conference in Houston.

But as fast as Statoil and other operators are drilling

and completing these shale wells, they are finding it challenging to keep the good times rolling after production begins to decline. While they might be tempted to close down a mature well and drill a new one, advances in artificial lift are extending their investments, said Cleon Dunham, director of the Artificial Lift R&D Council (ALRDC).

"There's a lot of focus on development of the technology, testing, training and support for the [unconventional oil and gas] industry," Dunham said. "In



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[the ALRDC's] conferences we have lots of presentations and exhibits that cover the technology and techniques being used to assist in producing deep horizontal wells. How you install the equipment, land it, operate it and maintain it are all big issues for any well, but particularly in deviated and horizontal wells."

Service companies also are planning ahead by mak-

ing the wells they drill today "refrack-ready" for tomorrow, said Juan Carlos Flores, product line manager for restimulation services and multistage completion and production systems at Baker Hughes.

"The focus right now is to complete the wells knowing the [production] decline will likely occur in three to five years," he said. "We need to get more than five or 10 years out of the investment, so we will need to make them refrack-ready



The U.S. shale boom has enticed operators from all over the world, including Norwegian giant Statoil, to lease land in American shale plays such as the Eagle Ford, shown here.

(Photo by Mieko Mahi; Source: Statoil ASA)

before we complete the well the first time."

This is all to America's benefit, of course. It ensures the country can look forward to achieving energy security and maintaining it, especially as crude exporting laws are scrutinized and hopefully reconsidered by Congress. While the industry continues to evolve, the whole world will benefit. It's what keeps us all moving forward and innovating for our future.

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Hart Energy Acquires Zeus Intelligence

Strengthens LNG Information Services

Hart Energy has taken another step forward in its evolution as the preferred information provider to the world's energy industry by acquiring the assets of Zeus Intelligence (zeusintel.com) from Houston-based Zeus Development Corp. The deal includes all Zeus Intelligence databases, biweekly reports, consulting services, and events, including the annual World LNG Fuels conference. All Zeus Intelligence employees will join the Hart Energy team in Houston.

■ Since 1991, Zeus has focused on LNG, upstream natural gas, gas-to-liquids (GTL), and gasification technologies.

zeus Intelligence

- This move significantly expands Hart Energy's capabilities in providing news, data and analysis about rapidly expanding global LNG markets.
- This unique information portfolio strengthens Hart Energy's capabilities in Australia, where it recently launched Oil and Gas Investor Australia magazine and is preparing to stage its second annual DUG Australia conference.

Hart Energy believes synergies between its upstream, midstream and downstream information services and these newly acquired Zeus Intelligence assets are evident, and the transaction was entered to bring more comprehensive capabilities to customers in North America and around the world. Please contact your Hart Energy representative with any questions or suggestions about using its newly expanded capabilities to help you reach your business goals.

For 40 years, Hart Energy editors and experts have delivered market-leading insights to investors and energy professionals.

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Subsea alliance forged

Two industry leaders come together to bring solutions to the challenge of subsea production.

Improving

the rate of hydrocarbon

recovery from deepwater

of the alliance.

etting a new product out into the market is—as we all know—a time- and labor-intensive task that can bring great reward if successful. In a way, it is like watching a toddler take those first few steps, where they go from crawling on all fours to tottering on two before sprinting off toward teen-dom. The same could be said for the subsea market.

Since taking its initial steps in 1961 with Shell's installation of the first subsea production tree in the Gulf of Mexico's West Cameron Field, subsea technology has evolved to where phrases like "subsea factory" show real promise of becoming reality. It is an evolution driven by technology advances, attractive oil prices and declines in production seen in maturing fields that have pushed operations farther offshore into deeper, more remote waters.

The need for subsea solutions will only continue to grow. Studies indicate that the number of subsea oil wells is expected to double by 2020, with a majority of these wells being in the deepwater, according to the Subsea Production Alliance.

delivered single-digit rates — The alliance was formally introduced at this year's Offshore Techis one of the many goals nology Conference. It joins the expertise in the design and installation of subsea production and processing systems of Aker Solutions with the well completions and artificial lift technology knowledge of Baker Hughes.

The structure of the alliance provides flexibility for each company to offer any products and services to design the best solution for the customer's production challenges, according to a release. Improving the rate of hydrocarbon recovery from deepwater wells—which have historically delivered single-digit rates—is one of many goals of the alliance.

To accomplish this, the alliance will bring to market fully integrated in-well and subsea production systems like horizontal electric submersible pump (ESP) systems and ESP-ready subsea trees—that are engineered to work in unison to improve recovery in deepwater developments



JENNIFER PRESLEY Senior Editor, Offshore jpresley@hartenergy.com

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while reducing installation and production costs.

In a Hart Energy Offshore Connect exclusive, Alliance General Managers Svenn Ivar Fure of Aker Solutions and Brage Johannessen of Baker Hughes shared with viewers their insights into the future of the subsea market and the

> direction the Alliance is taking to tackle the challenges of subsea production.

> > tric submersible pump in any subsea well out there in the entire world," to unlock the subsea market for ESPs and thereby increase the subsea market itself. It is a really powerare just a handful [of ESPs] functioning subsea."

Other areas of development include improving the interfaces of subsurface trees to make them friendlier to control lines, according to Johannessen. These interfaces provide access points for control lines to be inserted to control completions components downhole.

"We've discussed many times the interfaces on a subsurface tree, where traditionally our two company segments of the industry work in isolation," he said. "It's a clear area of optimization for us and gives us the ability to improve the architecture surrounding that interface."

From a water depth of 17 m (55 ft) in West Cameron more than 50 years ago to today's depths of thousands, the fleet-footed evolution of subsea technology is set to carry the industry for decades to come.

"The alliance has many goals. One of our primary objectives is to put an elec-Fure said. "Our ultimate objective is wells—which have historically ful objective because right now, there

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Is the next Bakken or Eagle Ford just now being delineated?

Rhonda Duey, Executive Editor

North America has been the beneficiary of an enormous revolution in the oil and gas industry—unconventionals. Some of the more established plays have practically become household names—the Bakken, the Eagle Ford, the Marcellus. And as these plays mature, there aren't a lot of contenders, at least in the U.S., to take their place.

John Dunn, Lower 48 manager for Wood Mackenzie, recently told a group of reporters that of the new plays that are being examined, "we don't have a play that's as exciting as the Eagle Ford or the Bakken."

Still, there are some interesting stories unfolding not only in shale but in other unconventional reservoirs as well. And there are hopeful players who are poised to be early movers in these plays.

TMS

Not to be confused with "TMI" (too much information), "TMS" stands for the Tuscaloosa Marine Shale, and the information about this play is very encouraging indeed. Players such as Goodrich Petroleum, Comstock Resources, Sanchez Energy, Encana and Halcón Resources are quite bullish on the region.

According to information on Goodrich's website, the play covers about 2.5 million acres in eastern Louisiana and southwestern Mississippi. A number of vintage wells dating back to 1962 have helped define oil saturation and rock quality. Wells produce high-quality crude and high-Btu gas.

In a slide comparing cumulative TMS production to a Bakken and Eagle Ford base case, Goodrich and Encana both have wells with better cumulative production than these more established plays, with Goodrich's Crosby 12H-1 cumulatively producing 180,000 boe by its 15th month of production.

Halcon recently announced the results of its first well in Wilkinson County, Miss., which achieved a 24-hour IP rate of 1,208 bbl/d of oil and 31 Mcm/d (1.1 MMcf/d) of 1,551-Btu gas on a ¹%-in. choke. Based on gas composition analysis and assuming full ethane recovery, the company estimates that the well will produce an additional 212 bbl of NGL per day for a total 24-hour average IP rate of 1,548 boe/d.

Floyd Wilson, chairman and CEO of Halcón, was at Petrohawk when that company discovered the Eagle Ford Shale in South Texas. Later, at Halcón, Wilson and his colleagues pushed the Eagle Ford east into Brazos and Burleson counties and named the discovery "El Halcón." The play is mostly oil, and Wilson said the geology basically extends from the Mexican border all the way to Florida.

"It's the same age rock; in fact, we would say it's the Eagle Ford," Wilson said. "But it's become convention to call it the TMS."

While Wilson balks at being credited with any kind of TMS discovery, "We have jumped in with both feet," he said. In 2013 Halcón built its acreage position to more than 300,000 acres. It already has announced its first well results, is completing its second well and is spudding its third.

The older well data are helpful, he said. "We did a huge amount of research. We probably had 20 people working on it for more than a year before we started drilling.

"And we're really excited about it. It may not be the last, but it's going to be one of the last really large-scale oil shale plays in the U.S. in my opinion."

A large areal extent helps. Wilson said the fairway is 161 km to 240 km (100 miles to 150 miles) east to west and 48 km to 77 km (30 miles to 40 miles) north to south. "It has room for thousands and thousands of wells."

Cleveland Sandstone

The Anadarko Basin has been home to oil and gas activity for decades, and most recently operators have been chasing the Woodford Shale and the new South Central Oklahoma Oil Province play. To the west of these new plays, the historically productive Cleveland formation has been seeing increased attention as well.

While not a shale by geologic standards, the Cleveland formation is characterized by a tight, shaly sand with low permeability that lends itself to enhanced drilling and completion technologies. According to Jonny Jones, founder and CEO of Jones Energy, the formation is very similar to other Pennsylvanian reservoirs in the mid-continent, with porosities ranging from 8% to 10% and permeabilities ranging from the nanodarcy scale up to microdarcies. There is very little natural fracturing.

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Jones Energy and its predecessor, Jones Energy Holdings LLC, have been active in the Anadarko Basin since the late 1980s. The Cleveland was not the original target, Jones said, but it started to look promising around 2004 due to the success other operators were having. Jones Energy drilled two wells in 2004 and ramped up rapidly to drilling 45 in 2008. After prices began to recover in late 2009, the company resumed drilling in 2010 and averaged roughly 30 wells per year through the end of 2012. That figure rose to 70 wells in 2013, and Jones is budgeting for more than 100 wells to be drilled in 2014 in the Cleveland alone.

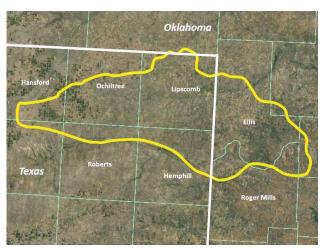
"The appeal of the Cleveland formation stems from the overall industry shift to horizontal drilling," he said. "The Cleveland was always a potential target in a vertical well case, but the real value proposition became apparent once early movers in the play started to see positive returns from drilling horizontally."

Jones Energy currently has drilled about 350 horizontal wells in the play, he added. "Our continued reapplication of lessons learned within this play has allowed us to become the low-cost leader," he said.

Jones Energy has eight rigs running in the Anadarko Basin—seven in the Cleveland and one drilling Tonkawa wells. Jones said there are currently no plans to increase the rig count, but the company might increase capex to accommodate an enhanced completion technique. A recent frack trial involved 20 wells and used a cased-hole completion with 20 three-cluster frack stages per well. Proppant and water rates were increased. While full results of the test have not been released, 18 of the 20 wells are performing at or above Jones' historical Cleveland horizontal type curve.



Halcón Resources found success with its El Halcón Field in East Texas. It is now chasing the play into Louisiana and Mississippi. (Source: Halcón Resources)



The Cleveland play covers more than 1 million acres, making the size of the prize significant. (Source: Jones Energy)

So what makes this play a keeper for Jones Energy? "The Cleveland play covers more than 1 million acres, making the size of the prize significant, with thousands of wells remaining to be drilled," Jones said. "This play will continue to be a paramount asset for us ... [because] we know how to make money in the Cleveland."

Frontier Formation

Located in the east Powder River Basin at depths of more than 2,590 m (8,500 ft), the Frontier Formation is comprised of the Belle Fourche member, the Emigrant Gap member and the Wall Creek Sandstone member. Each member has its own lithology characteristics. The formation is part of the larger Mowry Composite Total Petroleum System.

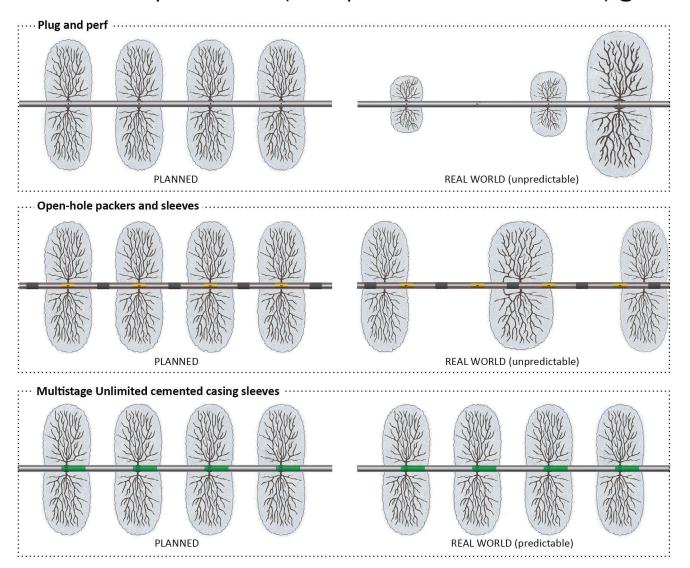
The play is so new that several operators declined to comment until they obtained more information. "The majority of operators are still in the appraisal mode of development, even after five years of drilling in some cases," said Ryan Duman at Wood Mackenzie's Lower 48 Upstream Team. "The transition to full-scale development has been slow, but operators have recently allocated greater capital and rigs to the play, indicating improved optimism."

Duman added that positive traits include the presence of multiple stacked productive formations, oil-rich production and growing rail takeaway capacity. Negative traits include variable well costs, geologic heterogeneity across the basin and permitting delays.

"Watch for drilling to home in on particular zones, and also watch for portfolio high-grading by smaller players with Powder River deep-sand asset packages coming to market," he said.

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Mexico's energy reform opens door to shale resources

With six basins believed to hold unconventional resources, development could be within reach if fiscal terms are favorable for developers.

Velda Addison, Associate Online Editor

The shale boom that continues to sweep across the U.S. could spill into Mexico, providing a much-needed boost to stagnant production. However, it is too early to tell which oil and gas companies will jump at the opportunity to develop Mexico's shale resources as legislators are still considering laws governing the recently opened energy sector.

Bills that will make way for production-sharing and profit-sharing contracts as well as regulation establishing local content requirements, which could increase to at least 25% by 2025, among others were expected to be debated by Mexican legislators in June.

Finalized fiscal terms on which companies' decisions hinge are forthcoming and could arrive sometime this summer. Mexico's energy ministry has until Sept. 17 to make a decision on state-run Pemex's entitlement request as part of Round Zero, the round in which areas are set aside for Pemex with the rest being made available to private investors, making it unlikely that the first bid round would come anytime soon. But some companies, including Chevron, have already signaled interest in forming partnerships in Mexico.

The potential appears great, considering the U.S. Energy Information Administration (EIA) estimates the country has the world's sixth-largest amount of technically recoverable shale gas resources at 16 Tcm (545 Tcf).

"While the southern region of the country contains the largest share of proved reserves, the northern region has the potential to be the center of growth in future reserves as it contains almost 10 times as much probable and possible natural gas reserves," the EIA said in its most recent report on Mexico. "The figure of technically recoverable shale gas resources is far smaller than the total resource base because of the geologic complexity and discontinuity of Mexico's onshore shale zone and other issues, including the availability of required technology and water resources."

Speaking during the Mayer Brown Global Energy Conference in May, EIA administrator Adam Sieminski said there is more opportunity for gas development in Mexico, which has currently been importing much of its gas from the U.S. due to higher gas demand from its industrial and electric power sectors. Mexico's energy ministry predicts U.S. pipeline exports to Mexico will more than double the 54 MMcm/d (1.8 Bcf/d) average in 2013, rising to 114 MMcm/d (3.8 Bcf/d) in 2018.

Successfully developing shale prospects could upend the estimates, prompting the EIA to alter its forecast. Geologically, the potential is there, Sieminski said, but it is impossible to know until more development occurs.

"I think the reform down there could lead to opportunities for Mexico to develop its own gas resources, maybe even joining the U.S. in becoming an exporter, which would be another remarkable event," Sieminski said.

Basins believed to hold shale resources line the country's northeastern and eastern parts. Basins include the Chihuahua, Sabinas, Burro-Picachos, Tampico-Misantla, Veracruz and the Burgos, which could be the most promising because of its proven resources and continuation of the prolific Eagle Ford Shale play across the border in Texas.

In an investor presentation, Pemex said the Woodford also has continuity across the border, and the Bakken and Haynesville shale plays are analogues of plays in Mexico. The Tampico-Misantla Basin possibly holds 34.8 Bboe in prospective unconventional resources, with Burgos holding about 15 Bboe, Sabinas with 9.8 Bboe and the Veracruz with 0.6 Bboe in prospective unconventional resources.

"In a short time we can start developing the Eagle Ford just like in Texas," said Jordy Herrera, former energy secretary for Mexico, before pointing out other shale prospects. "We have plenty of resources. Mexico realized this new industry for unconventionals only three years ago."

In 2011, Pemex first saw shale gas from an exploratory well in northern Mexico and announced earlier this year plans to drill 10 shale test wells. That would bring Mexico's total to 175, which pales in comparison to the more than 13,000 wells drilled in Texas, based on EIA data.



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Pemex, however, lacks the technology and finances needed to successfully develop these resources, Herrera said. That could change because the reform allows Pemex to form joint ventures. The company's 2013 annual report calls for getting specialized technology and additional investment for shale oil and gas prospect-

ing as part of its plan to maintain reserve replacement of greater than 100%.

Unconventional resources such as shale and heavy oil have been categorized as high technical and low to medium geological risk, said Pemex's acting E&P director Gustavo Hernández during a March conference call about Round Zero. During the call he explained the strategy behind Pemex's request.

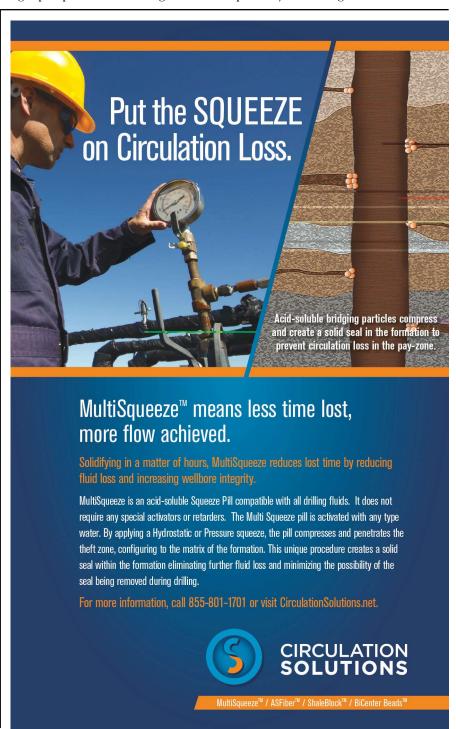
"We are requesting 31% [of prospective resources]. That accounts for 34.5 billion barrels," said Hernández, who was recently named CEO of Pemex E&P. "There are still lots of opportunities for other players to come to explore and to convert these prospective resources—both conventional and unconventional—accounting for 78 billion barrels to be discovered."

While operators and service providers have been relatively quiet about any plans, or lack thereof, to pursue shale prospects so early in the process, several seismic companies are already laying the groundwork for potential onshore developments.

Among these are ION Geophysical Corp. subsidiary GX Technology, which landed a multiyear contract with Pemex. As part of the contract, GXT will provide seismic data processing for onshore and offshore surveys during the next three years.

In addition, U.K.-based ffA signed a multiyear technical assistance agreement with the Instituto Mexicano del Petróleo for the use of its GeoTeric software and geological expression consulting services for the Sener-Conacyt Shale Gas/Oil project, which the company said will involve acquir-

ing and processing 2,700 sq km (1,043 sq miles) of 3-D seismic data from the Limonaria and Galaxia areas. The data—which will include full-azimuth, high-density and multicomponent seismic data—will aid in studying the Eagle Ford and Pimienta shales in the Tampico-Misantla and Burgos basins, respectively, according to ffA.



Australia pushes boundaries on shale development

The Cooper Basin continues to lead in shale exploration and development, but other basins are picking up exploration momentum.

Scott Weeden, Senior Editor, Drilling

ommercialization is beginning to creep into the vocabulary being used to describe shale gas plays in New South Wales, Queensland, Northern Territory and Western Australia as operators increase unconventional activity in these states.

In its first-quarter 2014 financial report, Santos stated, "The unconventional gas exploration and commercialization program continued as planned with several milestones and project objectives achieved during the first quarter."

This Schramm T500XD drilling rig was recently delivered to Energy Drilling

Australia, which is upgrading its fleet with the next generation of automated Telemast rigs that can walk in any direction.

The rig is under a one-year rolling contract with Senex.

(Photo by Jennifer Presley)

The company noted in a recent presentation that clear progress was being made along the commercialization pathway. Two shale wells are now producing, including the Moomba-194 vertical well, which recorded a peak flow of 87,820 cm/d (3.1 MMcf/d). A horizontal well in a shale target was drilled and stimulated, and it achieved flow. The company expected to stimulate the Moomba-193H in June with 10 stages.

Its Cooper Basin Center Gas exploration program confirmed a prospective resource through coring, logs and other analyses. The program proved gas accumulation in the Nappamerri Trough with more than 1,000 m (3,280 ft) of gas-saturated rock. Santos noted it is "building knowledge and technological capacity to 'crack the code.'"

Senex Energy Ltd. also is focused on commercialization. In a Feb. 24 press release, the company reported two farm-out agreements with Origin Energy Ltd., where the latter got interests in three petroleum exploration licenses in the Cooper-Eromanga Basin in South Australia. In the first stage of a work program, the companies will evaluate tight gas sands, shales and deep coal seams. The second stage will evaluate the commerciality of the gas resource.

More companies are now focusing on commercializing the resource given the success of earlier exploration efforts.

Targeting three key basins

Beach Energy Ltd. has strategically targeted three key basins for unconventional acreage—Cooper, Otway and Bonaparte. Its Cooper Basin activity includes Nappamerri Trough natural gas with Chevron and Icon Energy and its South Australian Cooper Basin Joint Venture (SACB JV) targeting the unconventional Roseneath-Epsilon-Murteree (REM) formations and basincentered gas plays.

The company is targeting unconventional gas and gas liquids in the Otway and Bonaparte basins. It is out to uncover sweet spots, with focused activity around them. Well profiles are a key focus, and Beach expects process

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improvements and technology to drive efficiencies, which would drive down costs. EUR per well is the key for commerciality.

The company recently awarded a four-well fracture stimulation program to Condor Energy Services Ltd. The stimulation program is scheduled to begin in July 2014. Six vertical wells will be drilled, and four will be fracture-stimulated.

Beach recently completed the sixth and final exploration well drilled in its current campaign. The Etty-1 is a vertical exploration well in ATP 855, owned by Beach, 46.9%; Icon Energy, operator with 35.1%; and Chevron Exploration Australia 1 Pty. Ltd., 18%. Preliminary interpretation of wireline logs indicated the target interval to be gas-saturated. The well will be cased and suspended for fracture stimulation and production testing to assess the deliverability potential of the basin-centered play.

Acquisition expands unconventional resource

Drillsearch Energy Ltd. acquired Ambassador Oil and

Gas Ltd., according to a May 30 press release. Drillsearch will provide full carry on a \$42.5 million work program in PEL 570 targeting unconventional resource potential. The program is to be operated by New Standard Energy with technical support from Magnum Hunter Resources.

The acquisition offers regional diversification for Drillsearch's unconventional business, which is currently focused on ATP 940P in the Central Unconventional Fairway in the Nappamerri Trough.

On April 21, the Charal-1 vertical exploration well in the fairway reached a total depth of 3,866 m (12,680 ft) with indications of elevated gas in the primary target intervals. The well has been cased and suspended for hydraulic stimulation and production testing, which are planned for the September quarter.

Cooper Basin unconventional gas

Within the Nappamerri Trough basin-centered gas play, initial flow-testing was completed on the Langmuir-1





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vertical well located within PPL-102, according to Santos. Ten fracture stimulation stages were placed across sand, shale and coal intervals within the Toolachee, Patchawarra and Tirrawarra formations.

In Santos' Roswell project in the REM shale play, the Roswell-2 horizontal shale well was successfully stimulated and flow-tested during the quarter. Roswell-2, located in PPL-9, is a horizontal well drilled to a measured depth (MD) of 3,481 m (11,418 ft), which includes a 550-m (1,804-ft) horizontal lateral within the lower Roseneath Shale. Five fracture stimulation treatments were placed along the lateral section. Additional diagnostics including surface microseismic monitoring and stimulation stage fluid tracers also were obtained to provide critical information for optimization of future wells.

In the Aurora project, the Moomba-193H horizontal well was drilled to an MD of 3,996 m (13,110 ft) with a 900-m (2,952-ft) horizontal lateral within the Murteree Shale. The well is Santos' second horizontal shale gas well. Fracture stimulation activities are scheduled for mid-2014 using 10 frack stages planned with further optimized stimulation treatments based on Roswell-2 experience to scale up flow rates.

In the SACB JV unconventional gas program, further drilling to appraise the basin-centered gas accumulation focused on reservoir characterization and stimulation optimization.

In the Southwest Queensland Joint Venture (Beach, 23.2%, Santos, 60.06%, Origin, operator, 16.5%, and Australia Pacific LNG Ltd., 0.24%) a two-well gas development campaign began with the Vega-4 well.

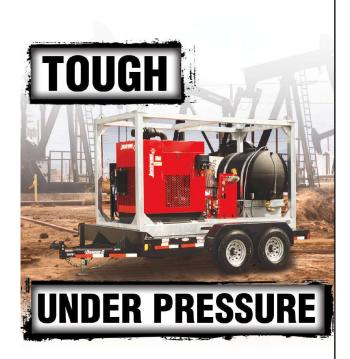
In the Bonaparte Basin in the Northern Territory, the Cullen-1 exploration well in EP 126 (Beach, 75%, and Territory Oil & Gas Pty. Ltd., operator, 25%) spudded on May 23. The well is targeting the conventional and unconventional hydrocarbon potential of the largely unexplored Keep Inlet sub-basin.

Western Australia activity

AWE Ltd. is on track to drill three additional gas wells in calendar year 2014. The company tested the Arrowsmith-2 appraisal well on EP413, high-grading the Carynginia and Irwin River Coal measures.

The Drover-1 exploration well on EP455 is scheduled to spud in the June quarter. An appraisal well—Senecio-3—will spud on L1/L2 in September.

Gross unconventional prospective resources for EP413, EP455, L4 and L5 were independently estimated at 314 Bcm (11.1 Tcf) and 31 MMbbl of NGL.



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'Potential' the key word as Europe eyes unconventionals

Estimated reserves are promising, but progress is slow.

Mark Thomas, Editor-in-Chief

events dramatically affecting the dynamics of the upstream industry can occur rapidly—the Arab Spring in the Middle East, North America's unconventional revolution or the Crimean crisis in the Ukraine, for example. At other times progress can appear to be little faster than continental drift as legislation, investor caution and environmental concerns run their course.

Britain and the wider Europe are currently caught somewhere between the two. The concerns over energy security create waves of urgency among political leaders and industry supporters who know that fossil fuels remain a vital part of the future energy mix.

But that initial surge is almost immediately dampened by a hard dose of reality, as most people acknowledge that what is taking place in the U.S. was enabled by a unique set of circumstances related to the size of reserves, the availability of infrastructure and a readymade world-class supply and logistics network.

'No silver bullet'

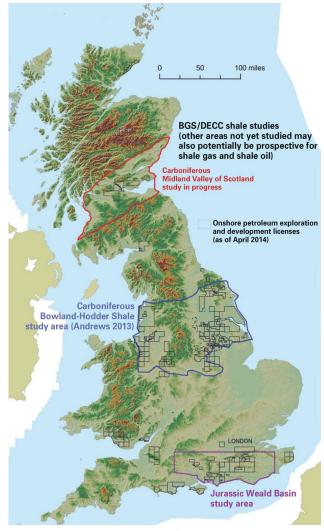
For the U.K. and Europe, the reality is that "there is no silver bullet," according to U.K.-based consultant petrophysicist Andrew Foulds of Petrafiz Ltd.

Speaking at the Unconventional Gas event in Aberdeen, Scotland, earlier this year, he pointed out that "shale does not equal shale oil or shale gas" and urged caution regarding the estimated reserves figures put out within the past year by the British Geological Society (BGS). He flagged up the progress, or relative lack of it, in Poland as a relevant reference.

Foulds estimated that up to 300,000 wells may be required in Europe to "get the reserves out" and added that between 500 and 1,000 wells would need to be drilled to fully understand the shales there.

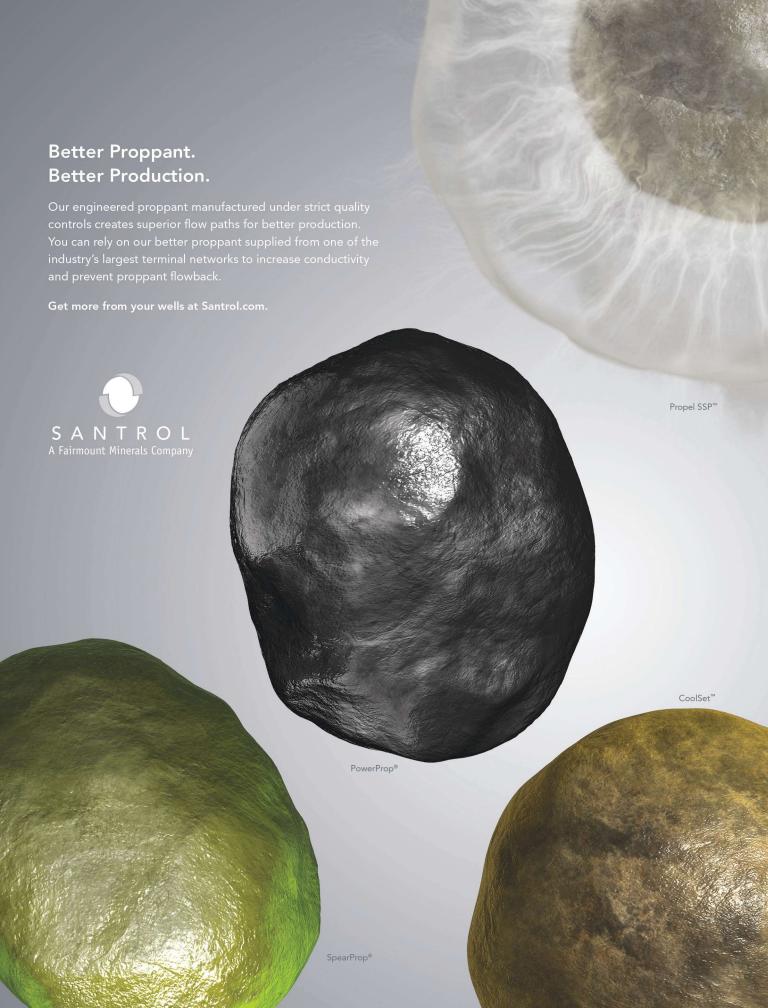
"Poland has 40 to 50 wells drilled so far. We need a lot more to fully understand it," he commented, while adding that logistics for both the U.K. and Europe remain another separate major challenge.

His cautionary tone was echoed at the same event by



The map represents the location of the latest study area in southern Britain, along with prospective areas for shale gas in northern Britain and currently licensed acreage. Other shale gas and shale oil plays may exist, according to the BGS. (Source: BGS)

Schlumberger Fellow Dr. Robert Kleinberg. "These shales are not like rocks we have done so far," he commented. "They are as different as rocks on Mars. Historically we've



been fracturing a long time, as it was first done in the late 1940s. But appropriate to shales there's still a lot to learn. We are in the equivalent of the early 1900s in terms of understanding shale."

However, being something of a technology guy (Kleinberg holds more than 30 U.S. patents with several commercialized geophysical instruments), he is optimistic: "Speaking as a technologist, we are never done."

Optimism remains

That optimistic tone is one that remains prevalent for all those looking at the potential of European unconventionals. Connie Jump, senior technical director for Chevron Onshore Europe, is someone who stepped across from the energy revolution in the U.S. to work the Silurian Shale in Europe.

"We are still in the very early stages of exploration, and there is much more to learn about the geology in Europe," she told delegates.

Just for comparison, the 40 or so wells drilled in Poland in total can be held up next to the figure of around 400,000 drilled in the U.S., she pointed out.

Again, the word used is "potential." Poland possesses an estimated 1.8 Bbbl of shale oil and 4 Tcm (146 Tcf) of shale gas resources, according to the latest estimates. "The potential is still there for an increased domestic resource," she said.

The U.S. major has drilled just four wells and has shot some new recent 3-D seismic. For Chevron and for the industry generally Europe is likely to remain in this nascent stage for some years to come despite geopolitical drivers such as events in the Ukraine adding pressure to move faster. However, with most players looking at the region within at least a 40-year time frame, no one is being rash with their investment dollars when so many rival opportunities to access new reserves around the world are still emerging.

It also will take time to formalize the regulatory framework within each European country, as well as European Union directives, along with a gradual buildup of the logistical and supply chains. "The permitting pace at present is not fast, with lengthy procedures," Jump commented. "In the U.S., of course, rig movements are no big deal. But from Romania to Lithuania? It's very different."

Long-term picture

The likely long-term future for European shale gas was backed up by Statoil's chief executive, Helge Lund, at the recent Platts Energy Week event in Washington, D.C. Unconventional gas from shale will not be developed in Europe anytime soon because of the region's population

density and a current lack of enough fiscal and popular support for its development. "You need efficient rocks. You need fiscal arrangements around these resources that make it investable," he said, according to Platts. "You need public support."

Statoil was of course an early investor in U.S. shale plays, so the company knows the benefits as well as the challenges. "It is more challenging to develop these resources in areas that are more densely populated," he said. "We do not think that shale will play a part in the short- and medium-term in Europe."

Trying to make it a nearer term solution is the U.K. government, which has strongly backed industry efforts to study shale formations from north to south.

Development enabler

The Office of Unconventional Gas & Oil (OUGO) sits within the U.K. Department of Energy and Climate Change's Energy Development Unit, which oversees the country's energy development. Duarte Figueira, who heads up OUGO, stressed the need to "make the most of our natural resources and enable development."

"Future gas demand projections we have are of 80 Bcm [2.8 Tcf] a year. In 2003 it was different; we were a net gas exporter. Now we are a gas importer with falling offshore gas production," he said at the Unconventional Gas event in Aberdeen.

He mapped out the government's desire for there to be between 20 and 40 wells drilled in the next few years in an initial exploration phase he believes stands a strong chance of proving sufficient reserves for a commercial phase. "We recognize that there are legitimate concerns about shale gas and that we must explain ourselves," he said. "But gas is a bridge to a low-carbon future. The carbon footprint for shale gas is lower than for LNG projects and comparable to conventional resources. We're hoping to take our next licensing round—the 14th—forward later this year, and we have been [putting] and continue to put in place tax and other incentives to support U.K. shale growth potential."

House of Lords support

Figueira's message has been more than backed by the U.K.'s influential House of Lords Economic Affairs Committee. It expressed disappointment that exploratory drilling with hydraulic fracturing needed for shale gas development has hardly begun, commenting that "since the lifting of a moratorium on hydraulic fracturing in 2012, the Environment Agency has not received or approved a single application for the permits necessary for exploratory drilling."



Lord MacGregor, Chairman of the House of Lords Economic Affairs Committee, said in a prepared statement, "The committee strongly supports the government's decision to go 'all out for shale.' But here in the U.K. we have not yet left the starting gate. Developing a successful shale gas and oil industry in the U.K. must be an urgent national priority.

"Only exploratory drilling with hydraulic fracturing, then appraisal, can show how much of the U.K.'s shale resource can be developed economically. But there seems to be a regulatory logjam."

Companies in the vanguard

In the U.K. it is relatively small companies such as Cuadrilla Resources, IGas, Dart Energy, Alkane and Egdon that are at the vanguard of early activity.

Most of the current onshore licenses are concentrated in areas such as the Bowland Basin in northern England and the Weald Basin in the south, which already produce conventional oil, gas and coal.

Cuadrilla is the largest and most prominent of these potential shale developers, with access to external finance from institutional investors via the private investment firm and main shareholder Riverstone.

However, others such as IGas Energy are stepping up their game. IGas reached a farm-out agreement earlier this year with Total, selling a 40% interest in two licenses to the French major. In exchange, Total committed to contribute at least \$20 million and possibly nearly \$50 million to help pay for the acquisition of 3-D seismic data; drill and test a vertical exploration well; and, conditional on the results from the first well, to drill and test a second horizontal appraisal well.

In May, IGas confirmed the takeover of Dart, which owns more than a dozen licenses in the Bowland Basin—including many adjacent to ones held by IGas. This makes it the company with the largest area in the U.K. under license of more than 1 million net acres, including major U.K. shale basins.

Fact or fiction?

The bottom line remains that no shale gas or oil has actually yet been produced in the U.K. Although last year's BGS estimate put the Bowland-Hodder Shale Formation in northern England at more than 37 Tcm (1,300 Tcf) of natural gas in place, it is not known yet if it can be commercial.

The same is true in southern England, where the Jurassic shale of the Weald Basin has just been estimated by the BGS in a new report to have little chance of gas because the shale is thought not to have reached the geological maturity required. However, it has issued a range for shale oil in place of between 2.2 Bbbl and 8.6 Bbbl, with a central estimate of 4.4 Bbbl but also a "high degree of uncertainty."

The Weald Basin already has 13 producing conventional oil and gas sites, so it is a proven province.

Later in 2014 the Carboniferous shales of the Midland Valley of Scotland will also be the subject of a further BGS report. But all involved acknowledge that what is needed is drilling and testing activity, and with up to 40 wells targeted by more than 10 companies within the next two years, it will soon be clear whether companies are witnessing the birth of a U.K. shale industry or a false dawn.



Argentina's Vaca Muerta Shale

How have recent events affected its development?

Laura Atkins, Hart Energy Research & Consulting

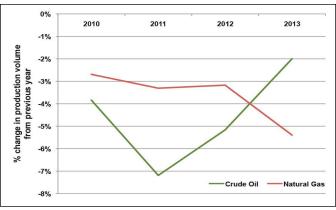
rgentina possesses some of the richest source rocks in the world, consisting of formations with highly favorable characteristics for shale oil and gas production. These source rocks are located in seven sedimentary basins containing multiple formations covering a total area of 308,210 sq km (119,000 sq miles). Of these, the Vaca Muerta Shale in the Neuquén Basin is the largest and represents the best potential to increase Argentina's oil and gas production in the medium term. Also within this basin are two additional source rocks—the Los Molles and Agrio formations—that have considerable potential for natural gas production.

By early 2012, several foreign companies as well as Repsol-Yacimientos Petrolíferos Fiscales (YPF) were beginning to drill exploratory wells in the Vaca Muerta Shale.

Then, in April 2012, the government of Argentina sent shock waves through the industry when it announced it would take over Repsol's share of the former state-owned oil company YPF. The government's action was driven by the ever-increasing energy imports, which Argentina can little afford. Natural gas from Bolivia and spot market LNG make up the bulk of energy imports. The current account deficit is increasing every year and will be about \$14 billion this year, mainly because of natural gas imports.

Showing promise

Before the expropriation, Hart Energy Research & Consulting viewed the Vaca Muerta Shale as the most promis-



While oil production is in decline, gas production is ramping up in Argentina. (Source: Hart Energy Research & Consulting)

ing of all shale developments outside the U.S. and Canada. Investment by foreign companies in exploratory and pilot wells was proceeding at a rapid pace. These companies, which include large U.S. independents, international majors and small independents from Canada and Argentina that also have concessions in the Neuquén Basin, were exploring the shale resources. What has happened to development since the expropriation?

Reactions by foreign companies to the nationalization were mixed using data on wells drilled by operator by year from the Argentina office of the Secretary of Energy. Chevron, though it had been active in Argentina for years, didn't drill any wells in 2012. ExxonMobil, which had recently reentered the upstream, postponed drilling on its concession until 2013. Total reduced its well count in 2012 to half that of 2011. Other companies such as Petrobras and Apache maintained a steady drilling pace.

By 2013 most companies were drilling again at about the same pace or higher than in 2011. This was driven by several factors, beginning with Chevron's agreement with YPF in July 2013 to jointly invest \$1.24 billion to drill 161 wells in the Vaca Muerta Shale. Chevron and YPF recently announced that they would spend another \$1.6 billion on unconventional development in the Neuquén Basin, including drilling another 170 wells. Chevron operates the joint venture (JV) and will drill 140 gross wells in 2014.

Shale concessions

Also in 2013, recognizing that the country needs investment by companies with expertise and financial strength, the federal government made certain significant changes to the fiscal regime through Federal Decree 929. Key provisions of the decree include a change to the oil import tax that raises the internal oil price to \$83/bbl, the lifting of some of the restrictions on repatriating profits earned in Argentina and price supports for natural gas production. The situation also improved in December 2013 after the government agreed to pay Repsol \$5 billion for its assets that were expropriated in Argentina.

The government added specific provisions for shale concessions that allow concession extensions over the Vaca Muerta to be extended by 35 years rather than the standard 25-year extensions. On natural gas prices, the government replaced the Gas Plus plan, which was an agreement between a producer and an industrial user that rarely



yielded more than \$4/MMBtu, with a guaranteed price of \$7.50/MMBtu. The hitch with the gas price support is that companies must maintain a high production rate determined by the government over a fixed time frame to get the higher price. This may be difficult for companies that are primarily drilling shale gas wells because of the need to continuously drill wells to maintain a production rate. A second potential pitfall is that the difference between the fixed gas price and the \$7.50 price is to be paid directly to the operating companies by the government.

YPF has continued to drill wells in the Vaca Muerta, closely following the plan laid out by Repsol-YPF. With 169 wells as of mid-2014, YPF has drilled the majority of Vaca Muerta wells to date, mostly on its Loma La Lata Block. Production from these wells at the end of April 2014 was reported to be 19,000 boe/d. Most of the wells are vertical or directional and are producing from the Quintuca Formation, which YPF considers part of the Vaca Muerta.

There are two potential advantages to drilling vertical wells, at least early in the development phase. First, they cost less to drill. Second, the Vaca Muerta is very thick, up to 305 m (1,000 ft) or more, and the geological properties of the shale can vary dramatically over the vertical section making it difficult to determine where to land the lateral portion of a horizontal well. Vertical wells can be logged over the entire formation providing useful data over the vertical interval. YPF also reported results from one horizontal well that produced an initial rate of 450 bbl/d of oil.

The JV between Chevron and YPF is focused on the Loma Campana Block, which is adjacent to the Loma La Lata Block and within the oil window. Production from this concession started in February 2014, and by March it was producing nearly 10,000 bbl/d of oil. Out of the planned 141 wells in the first JV agreement, 82 were completed in 2013, and the companies plan to drill 170 wells this year. Additionally, Chevron will spend \$140 million to explore in the Chihuido de la Sierra Negra concession 100 km (62 miles) north of the Loma Campana concession.

Other companies are drilling again in the Vaca Muerta Shale. ExxonMobil drilled five wells in 2013. Its latest horizontal well in the Bajo del Choique Block in May 2014 tested at an average rate of 770 bbl/d of oil. The well was drilled to a total measured depth of 4,572 m (15,000 ft) with a 1,000-m (3,280-ft) lateral.

Shell has four producing oil wells in the Vaca Muerta on its Sierras Blancas Block. Production began in March 2013 at 465 bbl/d of oil. Shell will increase its unconventional drilling capital to about \$500 million in 2014 from \$170 million in 2013. Total is planning to drill 12 horizontal wells and will conduct pad drilling on the Agua Pinchana Block in the wet-gas window.

A world-class play

The Vaca Muerta certainly has the potential to become a world-class shale play. Much will depend on the economics of the play, which are driven primarily by oil and gas prices and well costs. The new gas pricing will create a good incentive if it holds up. Though exploratory wells have cost upward of \$15 million, drilling and completion costs should come down in the development mode. YPF's current well drilling and completion costs average \$11 million, but the company reported that it expects to reduce them to \$7.5 million on the Loma Campana Block by deploying pad drilling and walking rigs.

Still, the industry must use caution when comparing well costs in Argentina with costs in the U.S. The typical Vaca Muerta horizontal well has a lateral length of about 1,000 m, which is considerably less than the 1,524-m to 3,048-m (5,000-ft to 10,000-ft) laterals that are common in most U.S. shale plays.

Despite the recent activity, oil and gas investment in Argentina is risky. The macroeconomic picture has continued to deteriorate. Inflation remains at 25% per year or higher, the currency was recently devalued, and labor unions continue to strike for higher wages to keep up with inflation. Though the decline in overall oil production has been arrested, having reached 7% per year in 2011, natural gas decline rates have increased and are approaching 6% per year. Since most of the current account deficit stems from natural gas imports, the current Vaca Muerta oil window development plans will not likely improve the situation. There is considerable shale gas potential in the Neuquén Basin, in the Vaca Muerta and other formations. If it wants to reduce gas imports, the government may need to increase the gas price support to bring it closer to the cost of LNG imports and eliminate the production requirement as a condition for obtaining higher price.

Meanwhile, companies will continue to focus on shale oil. According to Juan Jose Aranguren of Shell, if total spending in Argentina over a six-year period were to reach \$300 billion to develop Vaca Muerta, the country would be oil self-sufficient starting in 2020 and would keep producing for as many as 40 years.

In early 2012 before the nationalization of YPF, Hart Energy developed a scenario indicating that Vaca Muerta shale oil production could average 82,000 bbl/d in 2020 with the drilling of 1,825 wells at a cost of about \$18 billion to \$25 billion. After the nationalization this seemed to be unrealistic, but now it again appears achievable. YPF and Chevron are on track to drill significant numbers of wells, and other companies may follow as long as the proper incentives remain in place.

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From correlation to production

A Horn River completions evaluation case study shows that larger SRVs result in higher well production regardless of the percentage of proppant-filled fractures.

Asal Rahimi-Zeynal, Mike Mueller and Sudhendu Kashikar, MicroSeismic Inc.

icroseismic is now an accepted technology used to monitor hydraulic fracturing that measures the geometry, location and complexity of the fractures. Although microseismic monitoring has added value in understanding hydraulic fractures, there is still significant information and value that can be extracted from many microseismic monitoring programs. Most of the microseismic analysis performed to date is qualitative and has provided limited value in optimizing completions.

To fully optimize the completion and fracture treatment, it is important to understand various aspects of fracturing treatment such as differentiating propped and unpropped fractures, fracture growth and geometry, fracture overlap between stages and wells, stress shadowing effects and treatment efficiency. Currently this is achieved by a qualitative comparison of microseismic points with simulation models.

Figure 1 shows an idealized process for completions and fracture optimization. Today, fracture evaluation is performed using various simulations that may use as input microseismic pointsets to qualitatively calibrate the model. New developments enable valuable information to be extracted by combining contextual information such as geology, well logs, treatment data, etc., with deterministic

Fracture

Completion and

Fracture Design

Monitoring

analysis of the microseismic measurements. The result of this deterministic analysis provides quantification of the hydraulic fracturing. Some of the key aspects of this analysis are:

FIGURE 1. This figure outlines completion and fracture optimization. (Source: MicroSeismic Inc.)

Fracture

- Fracture geometry—height, length and azimuth;
- Fracture complexity and tortuosity;
- Fracture coverage (overlap between stages and
- Characterization of fracture mechanisms (dip-slip, strike-slip, etc.); and
- Identification and avoidance of geohazards.

The completions evaluation analysis provides a mechanism to better calibrate and build underlying geomechanical and reservoir models, improving forecasting of fracture placement and production and helping to accelerate optimization of future wells and treatment designs.

This distinct process of completions evaluation consists of a workflow and tools to perform diagnostic analysis of microseismic pointsets, enabling accurate evaluation of the fracture treatment. It is designed to precisely characterize the fracture network growth and complexity while providing a methodology to evaluate the wellbore spacing, stage lengths, cluster spacing and treatment parameters.

Case study

In a field located in northeast British Columbia in the Horn River Basin, the target is the Muskwa and Evie members of the Horn River Formation. Gas is produced from both members, but commercial production requires horizontal drilling and fracturing since it is lowpermeability. Original gas-in-place estimates in the Horn River are in excess of 14.2 Tcm (500 Tcf), making this the third-largest undeveloped gas resource in North America.

The microseismic acquisition method used a permanently installed near-surface buried array consisting of 98 stations (Figure 2). The wide-azimuth, large-aperture and high-fold geometry allows for a consistent microseismic event resolution under the entire footprint of the array, in this case covering an area of more than 40 sq km (15.4 sq miles). This acquisition geometry provides rich wavefield sampling and enables high-quality passive seismic emission tomography imaging, resulting in a high-confidence estimate of event magnitude and determination of the failure mechanism for every event.

The location of this case study was at a seven-well pad in the Horn River Basin in which 201 fracture stages over a

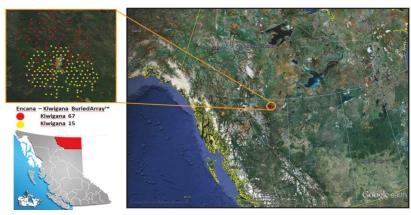


FIGURE 2. Almost 100 near-surface arrays were used in the Encana survey. (Source: MicroSeismic Inc.)

70-day period were monitored. Figure 3 shows the wells displayed with green color. Pink dots represent microseismic events resulting from the stimulation job. During the monitoring period, more than 11,200 events were detected and located. The events are mostly confined to the target zones. Hypocenter event location uncertainty is on the order of 10 m (30 ft) laterally and 20 m (60 ft) vertically as determined from velocity calibration using perforations and the event signal-to-noise ratio.

Modeling the microseismic events as 3-D fractures allows the computation of fracture flow properties by assigning various attributes to the modeled fracture planes. This is based on the assumption that the microseismic events indicate rock failure. This modeling based on a microseismic pointset creates a discrete fracture network (DFN, Figure 4).

The DFN was generated using event attributes from the microseismic pointset. In the modeling approach every fracture plane is centered on a microseismic event. For each event the source mechanism was identified and the failure orientation for each fracture plane was assigned according to the source mechanism. Fracture lengths are calculated from the seismic moment of each event.

The positioning and overall geometry of the modeled DFN and individual fracture set strikes and dips provides insights into the stimulation effectiveness, drainage patterns, unstimulated zones and influence of geologic features such as geohazards.

There is consistent fracturing to the west of the pad, more intense formation response to the stimulation in the east and a possibly unstimulated area along and immediately west of a larger swarm of strike-slip events. These features may be interpreted more confidently due to the laterally large acquisition footprint, which allows equal and consistent microseismic imaging across and beyond the entire pad.

When the DFN model is placed in a geocellular framework, the total fracture volume, average fracture aperture and total stimulated reservoir volume (SRV) may be calculated. The SRV is defined as the sum of the volume of all of the cells in the geocellular model for which nonzero values are calculated. The cell size in the model is 30 m (90 ft) on each side. Relative fracture permeability is calculated for every cell in the model that contains a fracture, including partial fractures.

The SRV characterizes the volume of reservoir rock with increased permeability due to stimulated fractures (Figure 5).

Microseismic-based well productivity estimates are based on the assumption that in ultralow-permeability shale reservoirs, pore pressure changes due to hydraulic fracturing cannot move far away from the activated fractures. Therefore, the microseismic event cloud or pointset corresponds to the effective fracture network size. The 3-D volume of the microseismic pointset can be estimated as the maximum extent of the stimulated fracture network. While the effectively producing fracture network could be smaller by a certain percentage, it is expected that the effective network and the stimulated network have a direct correlation. However, SRV is not the only driver of well production. In a given SRV, fracture conductivity and fracture spacing can affect hydrocarbon production and can have a major impact in recovery calculations.

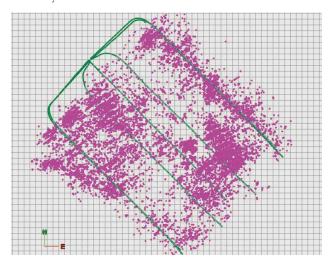


FIGURE 3. Wells are displayed in green. Pink dots represent microseismic events resulting from the stimulation job. (Source: MicroSeismic Inc.)



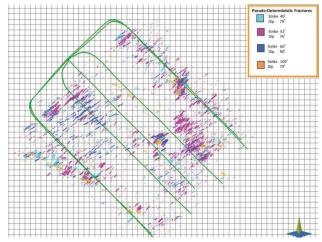


FIGURE 4. This map view shows the DFN. (Source: MicroSeismic Inc.)

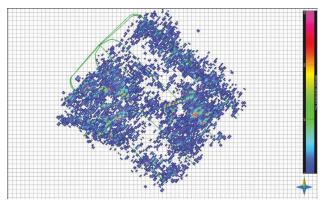


FIGURE 5. In this map view of the modeled SRV calculated from DFN, the color bar shows relative fracture permeability. (Source: MicroSeismic Inc.)

Results

The individual well SRVs obtained from the microseismic pointset are compared with actual field 30-day production data. This demonstrates the correlation

of the microseismic results with production from the seven-well pad. Testing is underway to determine whether this concept may be used to predict well performance. The plot shows that larger SRVs result in higher well production for the Horn River Basin study wells (Figure 6). Deviations from the linear relationship might be related to variations in geology (i.e., reservoir quality) as well as fracture spacing and conductivity. This plot does not provide a deterministic quantification of what percentage of the network is contributing to production.

The quantification of the effective size of the fracture network may be performed by numerical reservoir simulators and proppant placement analysis. For this study, the 90% correlation of the well-by-well total SRV vs. 30-day production data demonstrates that this concept may be used to predict microseismic-based well productivity.

The 90% correlation between production and SRV for each well shows that larger SRVs result in higher well production regardless of the percentage of the SRV that contains proppant-filled fractures for the first 30 days. The direct relationship of the SRV and production can be used to predict a new well's potential productivity immediately upon completion of the stimulation job. This suggests that a key completion effectiveness tool is to provide production prediction by monitoring stimulation microseismically. This may allow operators to optimize their overall completions planning and, in turn, maximize recovery.

Extensive microseismic results across the top shale oil and gas plays in the U.S. and Canada have been gathered and used to understand the correlation of microseismicity to production at the local scale. From this analysis the relationship between microseismic pointsets and hydrocarbon production was determined. This can be used to predict a new well's potential productivity immediately upon completion of the stimulation job.

Operators may test varying completion techniques to determine which treatment design gives the largest and most effective SRV and use this information to obtain maximum recovery and well performance.

Acknowledgments

The authors acknowledge MicroSeismic Inc., Encana Corp. and Kogas Canada for contributing data and for supporting this research. Special thanks to Michael de Groot for his assistance. Some of this information appeared in SPE paper 169541 and has been reprinted with permission.

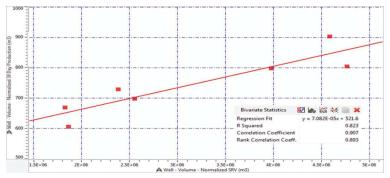


FIGURE 6. The correlation of SRV to production is shown in the Horn River Field. (Source: MicroSeismic Inc.)



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Fracking in the Golden State

Hydraulic fracturing hasn't been banned in California—yet. Groundwater monitoring might save it from extinction.

Charles C. Correll Jr., King & Spalding

Until recently, the U.S. Energy Information Administration (EIA) estimated that California's Monterey Shale contained more than 13.7 Bbbl of unproved technically recoverable oil reserves. Even factoring in the EIA's recent revision of its estimate of recoverable oil down to 600 MMbbl, the Monterey Shale is still the sixth largest oil play for hydraulic fracturing techniques in the U.S.

The Monterey Shale is about 4,532 sq km (1,750 sq miles), and it covers a substantial portion of the San Joaquin Valley. Tapping this resource could have tremendous economic benefits to the state. By one estimate, successful E&P activities targeting these reserves could create nearly \$30 billion in additional tax revenue for the state, create nearly 3 million jobs and significantly reduce California's dependency on oil imports.

Why is this play controversial? California is the nation's third largest oil producer. And unlike some other states, fracking techniques are not new to California—producers here have been using such methods for more than 50 years without protest. And despite its reputation for litigiousness, California has not seen anywhere near the same level of oil and gas royalty litigation as other states. In some respects, exploiting the Monterey Shale reserves can be seen as a natural progression of this state's historic E&P activity.

Yet times have changed. The increased attention fracking has drawn nationally certainly has played a role in increasing its profile in California. For example, while producers have long used fracking fluids offshore on federal leases in Southern California, the U.S. Environmental Protection Agency only recently issued reporting and discharged permit regulations for such fluids due to publicity around fracking. And environmental groups' opposition to hydraulic fracturing is more vocal now, alleging not only that the practice will be detrimental to the local environment but also contesting any increase in oil production as exacerbating global warming.

Gov. Jerry Brown and the California legislature stepped into the breach last year, passing a comprehensive law covering "well stimulation" known as Senate Bill (S.B.) 4. This bill and the regulations that ultimately will accompany it do not ban hydraulic fracturing in California but establish

a detailed regulatory scheme for reporting and monitoring potential groundwater impacts.

No ban—yet

One of the most significant aspects of S.B. 4 is that it does not ban hydraulic fracturing. The bill requires California's Department of Conservation-Division of Oil, Gas and Geothermal Resources (DOGGR) to conduct a scientific environmental assessment of the hazards and risks to natural resources and to public, occupational and environmental health and safety and to report its findings by Jan. 1, 2015. However, S.B. 4 does not ban hydraulic fracturing in the interim. In fact, the bill explicitly requires DOGGR to continue to issue permits for hydraulic fracturing in the interim. This provision is significant as experience teaches that interim bans can be quite lengthy. New York, for example, issued a moratorium on hydraulic fracturing in 2008 while its Department of Environmental Quality conducted a supplemental environmental review. That report still has not been issued, and many wonder if it ever will be.

S.B. 4's provisions about interim permits were critical in the dismissal of a lawsuit early this year that sought an injunction preventing DOGGR from issuing any fracturing permits until the agency fully assessed (and mitigated) the alleged environmental and health impacts from such activities. The lawsuit was filed in 2012. Industry groups intervened after passage, arguing that S.B. 4 set forth DOGGR's responsibilities for an environmental assessment and that it commands DOGGR to allow the practice in the interim. The trial court dismissed the lawsuit, holding that the environmental groups' claims about past practices were moot and that the current regulations deserve deference. Thus, interim permits are still allowed, although the environmental groups are appealing that ruling.

But the fight over a ban is not over. Just last month the California State Senate Natural Resources and Water Committee voted S.B. 1132 out of committee, which would place a moratorium on hydraulic fracturing and other forms of well stimulation until the state examines the potential economic, environmental and public health impacts. Five Democratic senators voted for it, with only the two Republican members voting against (while two other Democrats abstained). It now goes to the Senate Environmental Quality Committee. If enacted into law in



its current form, it would prohibit various forms of well stimulation until: (a) DOGGR completes a broad environmental assessment (with a new deadline of June 2016); (b) a multistate agency panel reviews the report and makes recommendations to the governor; and (c) the

Oil producers should welcome these provisions. Although they undoubtedly increase costs, the data should prove very helpful to producers and industry in the future. The unknown is often worse for oil companies in the mind of the public or jurors. By collecting baseline



Even with downward revisions, the Monterey Shale still holds tremendous promise if fracking is allowed to continue in California. (Source: Christopher Halloran)

governor concludes that state regulations and other measures protect public health and welfare and the environmental and economic sustainability of the state and such well stimulation will not impede progress for greenhouse gas reduction under California Global Warming Solutions Act of 2006. If the governor concludes that any of the preceding conditions are not satisfied, the ban on well stimulation will remain in place.

It is not clear if the Senate will pass S.B. 1132 despite a large and coordinated lobbying effort by environmental groups. The two Democratic senators on the committee who abstained cited economic reasons for doing so, and Gov. Brown has shown no support for the bill. So for now at least, hydraulic fracturing continues in California.

Notice and groundwater monitoring

Under S.B. 4, 30 days before commencing well stimulation a well owner/operator must notify surface property owners within a 457-m (1,500-ft) radius of the wellhead and surface owners within 152 m (500 ft) of the horizontal projection of the subsurface portions of the well. The surface owners can request that operators test their wells, which will establish a baseline condition. Owners also can request that operators test their wells going forward on the same schedule as pressure tests in the oil well. The well operator pays for this testing and must report the results of any such testing to the State Water Board.

data and then conducting periodic testing, oil companies can establish that their operations have not impacted local wells. Over time, this should help alleviate concerns over fracking. And if an impact is discovered, producers will be in a position to react quickly before the problem escalates.

S.B. 4 also requires a groundwater monitoring model plan. The State Water Board is currently working with DOGGR to develop such regulations, which are due by July 1, 2015. This may take the form of individual well monitoring plans or regional plans. Depending on the regulations ultimately proposed, this may prove beneficial to the industry in the long run. Groundwater modeling in contamination cases is often ripe for abuse by experts seeking to develop large damage claims against oil companies. Obtaining data in real time will guard against any unfounded claims and, in the event issues are uncovered, operators can address them quickly before the problem worsens.

Hydraulic fracturing may allow the production of vast, technically unproven reserves in the Monterey Shale. S.B. 4 allows such operations but will require increased groundwater monitoring. Both are good for industry; however, there are still efforts in the state to ban fracking, at least in an interim period while the state studies the potential environmental and economic impacts of well stimulation.

References available on request.



Solutions in the spotlight

Life can be a paradox at times. Like when someone asks for submissions of award-winning technologies that must be both 'new' and 'proven' at the same time.

Mark Thomas, Editor-in-Chief

N ot only that, but the technology must be "original, groundbreaking and capable of revolutionizing the offshore E&P industry."

That's a tough call. But showing once again that the upstream industry's engineers like nothing better than a challenge, the lineup of the Offshore Technology Conference (OTC) Spotlight on New Technology award winners demonstrates it is very possible to at least tick most of the above boxes and plenty of others as well.

In addition to the above criteria, other notable demands by the OTC awards committee (made up of representatives from the OTC's board and program committee) include:

- The technology must be less than two years old from the time it was first introduced to the marketplace or announced;
- It must be proven, either through full-scale application or successful prototype testing;
- It must have broad interest and appeal for the industry; and
- It must have significant impact, with the technology providing significant benefits beyond existing technologies and with environmental impact also an important criterion.

Impressively, since these awards for both hardware and software solutions were launched in 2004, the industry has produced more than 100 winning technologies.

Cast your mind back 10 years, and worthy inaugural winners included Baker Hughes' TesTrak formation pressure testing solution, Epcon Offshore's Compact Flotation Unit produced water system (now owned by Schlumberger) and FMC Kongsberg's Subsea Riserless Light Well Intervention solution.

This year the winners included novel FPSO, LNG transfer, seismic, drilling, downhole, intervention, monitoring and other solutions from companies including Baker Hughes, FMC Technologies, GE Oil & Gas, Schlumberger, Halliburton, SBM Offshore, Weatherford, WesternGeco and West Production Technology AS.

Very high pressure fluid swivel

One offshore solution of particular relevance as the global

floating production sector continues to thrive is SBM Offshore's winning Very High Pressure Fluid Swivel (VHP Fluid Swivel) technology.

This patented solution allows operators to use FPSO vessels for the development of ultrahigh pressure reservoirs. The company said in its awards release that to date this has not been possible where a weathervaning system was needed in conjunction with fluid reinjection into the reservoir.

Currently, fluid swivels are proven up to 7,542 psi. SBM stated that its fully qualified VHP Fluid Swivel has raised this limit by almost 60% to attain operating pressures of up to 12,000 psi.

An OTC statement added that the technology increases the operating range of high-pressure swivels by using "a patented technique to cascade the pressure drop over multiple seals. The 12-in. prototype toroidal swivel has been fully qualified to 12,000 psi including long-term



SBM Offshore's VHP Fluid Swivel was one of the Spotlight Award winners at OTC, with the technology enabling the use of FPSO vessels for the development of ultrahigh pressure reservoirs and being qualified to handle pressures of up to 12,000 psi. (Source: SBM Offshore)



endurance test runs and has the potential to operate at over 14,500 psi."

With more qualification testing planned to take place during the course of this year to further increase its capability to that desired 14,500-psi level, SBM is focused on applying its swivel technology for operators exploring the potential reserves of the Lower Tertiary fields in the Gulf of Mexico (GoM). The company said the swivel technology is applicable to the ultra-HP/HT challenges inherent in this region.

Essentially the toroidal steel swivel will enable gas or water reinjection into ultrahigh pressure reservoirs such as those found in Lower Tertiary fields from a turret-moored FPSO unit, helping operators boost recovery factors and opening up the possibility of using FPSO vessels for Lower Tertiary applications beyond current early production systems (enabling their use for full field developments where reinjection will be needed).

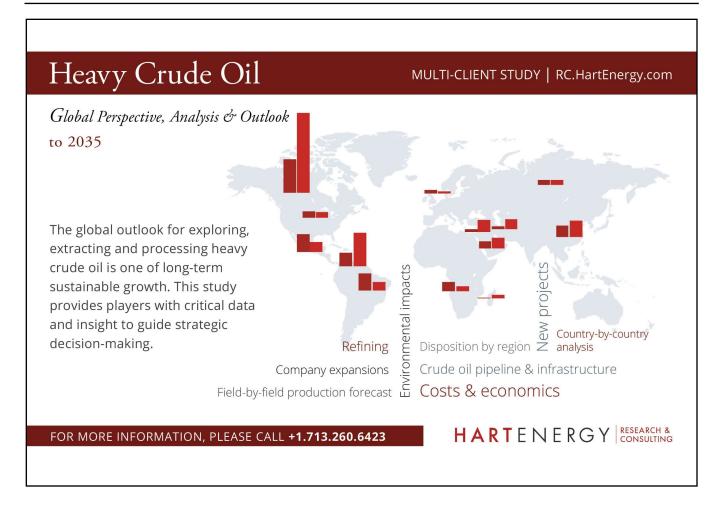
Monaco-based SBM is already heavily involved in the industry's push into the Lower Tertiary, with the contrac-

tor supplying disconnectable FPSO units suitable for steel risers such as the FPSO *Turritella*, destined for Shell's Stones project in the GoM.

FMC's helping arm for FLNG

FMC Technologies, meanwhile, received its OTC accolade with a Spotlight award for its Offshore Loading Arm Footless (OLAF). The new loading arm was developed for LNG transfer between side-by-side moored floating LNG (FLNG) vessels and conventional LNG carriers, such as Shell's giant Prelude field facility destined for the western coast of Australia.

OTC stated the design is able to deal with the large elevation difference between an FLNG facility's deck and the LNG carrier's piping connection at a lower level without overloads. "OLAF covers 100% of side-by-side operability in harsh environmental conditions thanks to its concept, its targeting system for connection assistance and Constant Position Monitoring System, SIL3, to manage the emergency disconnection," it continued.





The system is likely to help further minimize the transfer times between vessels, a key advantage for facilities such as Prelude, located in the harsh environment of the Browse Basin where weather conditions can change rapidly. The Prelude facility will have seven OLAF systems, also helping to reduce the likelihood of partial vaporization.

FMC clinched another Spotlight Award for its ISOL-8 Pump developed by its Schilling Robotics subsidiary. The pump enables secondary intervention for BOPs in compliance with API Standard 53. The pump is tightly integrated with FMC's own UHD III ROV, with the company saying it meets the 45-second requirement for closing BOP shear rams. It consists of independent pistons synchronized with software control. Flexible configuration allows optimization for a variety of demands and can simultaneously provide up to 190 l/min (50 gal/min) at 5,000 psi, according to FMC.

Crucially, OTC said in its award statement that "compared to existing industry solutions, this system is depthinsensitive and can save operators up to \$4 million per rig."

Winners Circle

Other Spotlight Award winners this year were:

- Baker Hughes LaunchPRO Wireless Top Drive Cement Head, a remote-activation system for deepwater applications, launching balls, plugs or darts during cementing of extremely heavy subsea long strings and long, heavy liners;
- GE Oil & Gas SeaLytics, which enables drilling contractors to monitor performance and plan maintenance of BOPs using predictive analytics based on actual component performance data. This can improve BOP system uptime, reduce unnecessary maintenance and lead to better cost forecasting;
- GE Oil & Gas Zenith GFI (ground-fault immune) ESP monitoring system. On average, 15% of ESP well monitoring systems fail to provide data following earth leakage in the ESP cable, according to GE. This system cannot be disturbed by ground faults, enabling continued well surveillance for production optimization and pump protection despite fault conditions;
- Schlumberger's Geoservices FLAG (fluid loss and gain) detection service, aimed at meeting the challenges of increasingly complex drilling programs in deeper waters with an early warning system highly sensitive to fluctuations but intelligent enough to help prevent false alarms. The service provides accurate fluids monitoring and precise coriolis flow metering with any drilling fluid on any rig, the company stated;
- Halliburton Drill Bits and Services TDReam tool, a
 downhole innovation designed to significantly reduce
 rathole length and reach total depth in one run.



FMC Technologies' OLAF system, another Spotlight Award winner, will be used on Shell's giant *Prelude* FLNG vessel to offload LNG to carriers. (Source: Shell)

Halliburton designed a more efficient tool with optimized steerability and fluid flow and reduced tool length based on the proven reliability of the near-bit reamer technology;

- Schlumberger Seismic-guided drilling pore-pressure prediction ahead of the bit, which can predict formation pressures hundreds of meters ahead while drilling, Schlumberger said, using both surface seismic and LWD data to provide a 3-D look-ahead velocity model with more accurate results. It enables proactive drilling decisions, particularly in deepwater exploration. Velocities ahead of the bit are recalculated from seismic reflections by using LWD velocities behind the bit as a constraint;
- Weatherford CasingLink EM antenna system, developed to address the signal attenuation encountered while drilling in deeper depths with an electromagnetic telemetry system. It employs an insulated wire that is externally attached to a standard casing string, a borehole receiver typically located downhole and connected to the casing and a surface transceiver.
- West Production Technology AS SwarfPak technology, for plug and abandonment and slot recovery with significantly reduced rig time and environmental footprint. All the swarf particles will be deposited and left downhole, avoiding the use of surface swarf-handling equipment. Another benefit is that milling speed is greatly increased: and
- WesternGeco IsoMetrix marine isometric seismic technology, which delivers high-fidelity point-receiver seismic data while overcoming spatial bandwidth compromises that the company said limited all previous towed-streamer methods. The new streamer design results in fine isometric sampling in both crossline and inline directions.



Australian reservoir laboratory provides integrated shale services

Recently opened reservoir characterization laboratory in Brisbane has advanced rock mechanics testing capabilities.

Arnis Judzis, Matthew Loth and Ben Leggo, Schlumberger

The Australian oil and gas industry is positioning itself as a significant global LNG supplier with massive investments occurring on both the eastern and western coasts of the continent. The developments in western parts are propelled by production from a small number of highly complex deepwater wells.

In contrast, the developments in eastern Australia rely on thousands of wells to exploit relatively shallow coal seam gas (CSG). By creating a new lucrative market, the developments in the east also have energized the exploration and appraisal activity, spurring

operators to redevelop existing plays and explore new ones, especially the unconventionals.

Although the offshore and unconventional projects on these two coasts vary dramatically in their physical characteristics, all of them require improved reservoir understanding to efficiently and safely extract the valuable contents.

The rugged environment, complex geology and limited amount of reservoir knowledge make shale oil and gas recovery both a challenge and an opportunity. Unconventional resources display extreme variability in rock composition and post-deposition diagenetic processes.

Operators must quickly and efficiently locate reservoir sweet spots and identify well landing locations to recover hydrocarbons at economically viable levels. Core and fluid analysis services play an important role in improving knowledge of shale reservoirs and, ultimately, unlocking reserves in areas such as the Cooper Basin, where the understanding of complex and heterogeneous reservoirs is critical.

Reservoir characterization lab opened

Schlumberger recently opened a reservoir characterization laboratory in Brisbane to address the needs of Australian oil and gas operators through comprehensive rock analytical services for offshore and onshore operations, including the rapidly growing shale and CSG activities.

The facility combines field and laboratory analytical capabilities starting with sample acquisition, laboratory measurements on reservoir core and fluids, interpretation and modeling services, and providing recommendations to operators. This approach saves operators valuable time and costs by capturing core at the well site, preparing samples, managing the project, and analyz-

ing and interpreting the data.

The timely delivery of accurate reservoir characterization information is essential in reducing projects' risk, simplifying operations and improving field productivity.

A key component of the service capabilities rests with the company's petrotechnical experts, who are available to provide actual simulations and results based on the core analyses. Whether the challenge is calibration of a mechanical earth model for hydraulic stimulation or a validation of

gas-in-place estimations from the core analysis, they can develop a complete solution including logging program design, core analysis test pro-

gram, model development and log calibration.

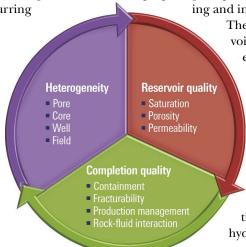


FIGURE 1. The laboratory relies on a three-pronged approach to help operators better understand unconventional reservoirs. (Source: Schlumberger)

Laboratory overview

The new laboratory is one of the few facilities in Australia that has advanced rock mechanics testing capabilities. Previously, the local industry relied on universities, research laboratories and overseas facilities to fulfill their testing and analysis needs. Depending on the size





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and complexity of the project, rock mechanics testing could take up to 12 months to complete. Now operators have a local and timely alternative.

To better understand unconventional reservoirs, a three-prong workflow is used for the quantification of heterogeneity, measurements of reservoir quality and completions quality (Figure 1). All of these rock measurements complement fluid characterization measurements obtained in the Brisbane laboratory and the global network of Schlumberger Reservoir Laboratories (SRLs). The network has the capacity to conduct analyses of fluid properties and integrate rock and fluid data for full reservoir characterization.

In a recent example, the laboratory delivered test results to a customer in Australia within five weeks of wellsite operations. This rapid turnaround enabled the operator to be better informed as work progressed.

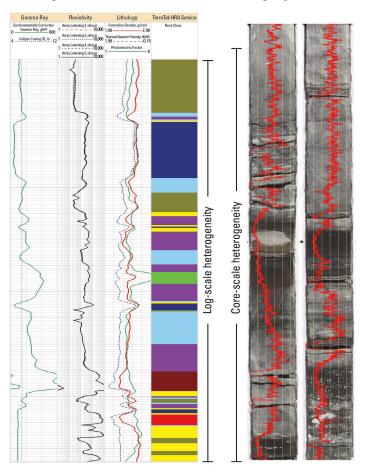


FIGURE 2. An N-dimensional HRA of logs and high-resolution, continuous strength profiles along the core length are used to select the samples for laboratory testing to ensure that all of the different rock units of the core are adequately represented. (Source: Schlumberger)

The facility has its own geomechanics testing equipment. The laboratory houses tri-axial rock mechanics machines. Computer-controlled and designed to simulate *in situ* stress and strain, these machines help determine physical properties of geotechnical core samples.

The test systems simulate actual *in situ* conditions and characterize a test sample's behavior under these conditions. Axial load, pore pressure and a confining pressure to create horizontal stress can all be precisely controlled. In-vessel instrumentation, directly in contact with the rock sample, accurately measures the sample's response to testing variables.

In addition, specialized core analysis equipment available through SRLs accurately measures reservoir rock petrophysical properties such as porosity, permeability and saturations. For unconventional reservoirs, this equipment uses both pressure and pulse decay methodologies to measure properties of tight rocks.

Geoscientists and petroleum engineers from across the organization serve as global subject matter experts. Specialists in nanodarcy to microdarcy permeabilities contribute specific unconventional core expertise.

Also, the laboratory collaborates with Queensland University of Technology to broaden regional capabilities and research efforts, particularly in enhancing CSG production. Together, the organizations investigate challenges such as thin coal seams and stimulation methods as well as development opportunities of unconventional Australian resources.

While the laboratory addresses regional operators' needs, it also leverages the specialized capabilities of other SRLs. Through these network facilities, the Brisbane laboratory provides special core analysis, including relative permeability, nuclear magnetic resonance and electrical properties in addition to reservoir fluids analysis such as composition and phase behavior.

Geomechanics, core analysis

The laboratory provides extensive rock mechanics testing capabilities for land and offshore operations and also core analysis for unconventional reservoirs. Operators evaluate geomechanical properties to understand wellbore stability during well construction and reservoir depletion during the production phase.

Pore volume compressibility and depletion measurements help operators anticipate signs of subsidence in maturing fields. For unconventional onshore operators, shale core analysis, for example, assists in hydraulic fracturing stimulation and well placement decisions required to optimize reservoir production.



Sample selection is critical to ensure reliable and representative results. Even small differences between predicted and actual texture, mineralogy or fluid saturations can affect tight shale gas producibility. For this reason, the laboratory offers the heterogeneous rock analysis (HRA) service, a log interpretation technology that identifies different rock classes as part of the sampling strategy.

Operators also can use the HRA service in conjunction with rotary sidewall plug sampling in tight gas shales and other wildcat wells. A well-designed rotary sidewall plug plan identifies a sufficient number of representative samples to evaluate reservoir sections and their heterogeneity adequately.

Laboratory experts work closely with the other specialized teams to conduct petrophysical and geomechanical studies in a timely manner. A geomechanics study to reduce wellbore problems during drilling and enhance the completion design for a major Australian operator was completed in less than half the time a previous supplier had required.

Integrating fluid, core analysis services

The technology skills and experience to integrate the measurements performed in the laboratory include the propagation of results and solutions to a wellbore scale. This is known as core-to-log integration. The HRA plays a key role in the core-to-log integration serving as a robust platform that identifies different lithologies and provides a sampling strategy to optimize the characterization of reservoirs in the laboratory setting (Figure 2). The HRA is used for all formation types, though it is most often used for unconventional reservoirs where the material properties change the most.

Finally, integration of fluid and core data is vital for the enhancement of hydrocarbons production in shale plays. Not only are the fluids analyzed but also the rock properties that enable the reservoir producibility. The integration of results from both fluid and rock properties strengthens the services of other experts who provide wireline logging, drilling, completion and well stimulation treatments.



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Addressing challenges in petrophysical modeling

Analysis should be based on all available data to gain a geological interpretation of the reservoir.

Samir Walia and Garrett Leahy, Emerson Process Management

Petrophysical reservoir modeling and the ability to generate a spatially accurate description of properties such as porosity and permeability are crucial to the understanding of fluid distribution and flow properties within the reservoir and act as vital input to reservoir management decisions.

Yet petrophysical modeling today comes with a number of challenges. Fundamentally, there is the challenge of scale. Well logs and analogue outcrop studies indicate that heterogeneity in petrophysical properties occurs over a variety of scales. From fine-scale diagenetic processes that affect flow properties to larger scale compaction and deformation trends, the quality of reservoir rock is known to vary in ways impossible to detect before drilling.

Another challenge is the increasing complexity of reservoirs. This includes fluid flow characteristics that are difficult to predict, large variations in permeability, and complex geologies and geometries that lead to highly heterogeneous reservoir descriptions. Petrophysical models that simplify these complexities fail to deliver the vital information operators require and can ultimately lead to misplaced wells and lower recovery.

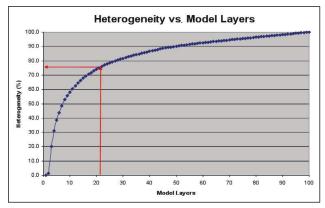


FIGURE 1. In this workflow, the heterogeneity is plotted vs. model layers. (Source: Emerson Process Management)

A third challenge is the growth in giant reservoirs and reservoir models—models that can sometimes contain millions of cells and thousands of wells. In such cases, there is a need to upscale the model for reservoir simulation without losing the original structure and petrophysical characteristics of the model. All geological data affecting fluid flow and rock properties such as porosity and absolute and relative permeability need to be upscaled accurately.

There also is the importance of incorporating seismic constraints into the petrophysical model. With seismic imaging and interpretation being the standard workflow for mapping and developing subsurface reservoirs, it's essential that all features and anomalies in the seismic data are incorporated into the petrophysical model. The goal here is to translate features and anomalies in the seismic data into heterogeneities in reservoir rock properties.

Finally, there is the importance of a seamless workflow in petrophysical modeling with links to volumetric calculations, connectivity analysis, full well planning functionality and reservoir simulation.

In summary, petrophysical modeling today can only be truly effective if interpreters have the necessary tools to integrate all available data—especially well and seismic data—and from all reservoirs, including the largest and most complex. It is only then that multiple scenarios can be assessed and reservoir uncertainty better quantified.

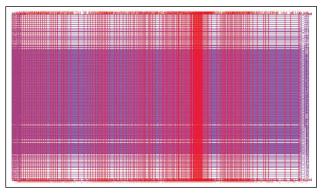


FIGURE 2. The distribution of controls lines indicates that bigger cell sizes are on the flanks and smaller cell sizes are on the crest. (Source: Emerson Process Management)









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Richard Stoneburner Senior Advisor, Pine Brook Partners, (ret.) President, North American Shale Production Division, BHP Billiton Ltd.



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Tuesday, 26 August



New for 2014: Hydraulic Fracturing Workshop

1200-1645

Take a deep-dive into hydraulic fracturing technologies in this targeted half-day workshop. Industry experts will cover topics such as: designing effective completions, proppant solutions, microseismic technologies, water use and green technologies.

Visit Australia DUG. com to view the workshop agenda.

1700 Opening Reception

Use this opportunity to participate in the Opening Reception, which includes a complimentary, full-catered buffet and complimentary drinks.

Wednesday, 27 August

0730 Registration Opens – Breakfast in Exhibit Hall

Start your day off right with a hot and cold breakfast before you take a seat for an exciting and informative day of presentations. Use this opportunity to meet new contacts, including exhibitors, speakers and other attendees.

0830 Welcome & Opening Remarks

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

0835 Opening Keynote: Feeding the Beast in the East

This year Santos marks its 60th anniversary. It is engaged in natural gas developments throughout Australia and in Papua New Guinea, where first shipments of LNG are occurring now. With operations in the Cooper, Bowen-Surat and Gunnedah basins, it has a complete view of Australia's gas supply picture as well as of market demand in the greater Asia-Pacific region.

 Colin Cruickshank, General Manager, Development and Technical Services, Santos

0900 Technical Spotlight: Time Is Money

This seasoned U.S. shale operator details how to select criteria and evaluate data, to improve drilling and completion practices. Core analysis, logging and other techniques need to be weighed. The goal is to trim days and costs in a tight-gas play.

 Richard Stoneburner, Senior Advisor, Pine Brook Partners and (ret.) President, North American Shale Production Division, BHP Billiton Ltd.

0930 Panel: Cross-border Joint Ventures

These two companies have teamed up to create value in both Australian and U.S. shales. They will describe the details of their joint ventures in the Cooper Basin and Texas' Eagle Ford Shale: drilling plans, technology, deal structure and more.

- Phil Thick, Managing Director, New Standard Energy Ltd.
- **Gary Evans**, Chairman and CEO, *Magnum Hunter Resources Corp.*

1015 Networking Break: Morning Tea

1045 Panel Discussion: Cooper Basin Highlights

Intriguing things are going on throughout this basin, from the Nappamerri Trough to exploration in shales, coals and sandstones, to expanding oil production on the Western Flank. Icon Energy holds a 35.1% working interest in ATP-855-P in the Nappamerri Trough, with partners Operator Beach (46.9%) and Chevron (18%). Strike Energy has seven exploration permits in the southern Cooper Basin and is pursuing the Patchawarra coals.

- David Wrench, Managing Director, Strike Energy Ltd.
- Ray James, Managing Director, Icon Energy Ltd.

1130 Operator Spotlight: An Emerging Province In Northern Australia

Armour Energy Ltd.'s tenure covers major areas in the McArthur, South Nicholson and Georgina basins in the Northern Territory and northern Queensland. Here's a look at the company's results to date and strategy moving forward, as it works to commercialise multiple plays, including its gas discovery in the Barney Creek shale at the Glyde 1 vertical well.

• Robbert de Weijer, CEO, Armour Energy Ltd.

1200 Networking Luncheon in Exhibit Hall

1330 Afternoon Keynote: Riding Australia's Unconventional Wave

Senex Energy's CEO describes its plans for conventional and unconventional oil and gas resource plays such as the Patchawarra Trough in the Cooper Basin, where it holds interests in 1.2 million acres.

 Ian Davies, CEO and Managing Director, Senex Energy Ltd.



technologies driving growth in Australia.

1400 Geophysics Panel: Peering Beneath the Earth

As more operators use microseismic monitoring in their wells, how do they apply the valuable lessons learned from this data? Learn about factors that are often overlooked when exploring for unconventional gas.

Fracture Networks In Australian Shales

 Sudhendu "Kash" Kashikar, Vice President, Completions Evaluation, MicroSeismic Inc.

Predrill Data For Better Frac Design & Results

 John K. Davidson, CEO, Predrill Stresses International Ltd.

1445 Networking Break: Afternoon Tea

Enjoy some complimentary refreshments in the exhibit hall.

1515 Technology Roundtable: Best Practices in Resource-Play Drilling & Completions

Operators and service company representatives share their latest findings and discuss the challenges ahead in appraising unconventional resources.

- Kevin Schepel, Executive Vice President, Exploration & Production, ZaZa Energy
- Andy Shaw, Managing Director, Eastern Hemisphere Operations, Baker Hughes
- **Stephen Chauffe**, Vice President, Engineering and New Technology, *TEAM Oil Tools*

1600 Closing Keynote: Looking at the Big Picture

A leading operator details its plans for further production growth in tight gas and unconventional plays.

1630 Networking Reception

Celebrate a great first day at the conference by participating in a relaxing cocktail reception, which includes a fully-catered buffet and complimentary drinks.



New for 2014: DUG Australia River Cruise Dinner

1900-2200

Enjoy a three-hour dinner cruise with other **DUG** *Australia* delegates aboard a private chartered boat on the Brisbane River. Relax with complimentary drinks, dinner, live entertainment and network in this unique and relaxed environment — all the while enjoying the beautiful city view.

Thursday, 28 August

0730 Registration Opens – Breakfast in Exhibit Hall

Jump start your day with a complimentary, full-catered breakfast in the exhibit hall.

0830 Opening Remarks

• **Dale Granger**, Editor, *Oil and Gas Investor Australia*, *Hart Energy*

0835 Opening Keynote: Queensland Takes Center Stage

This state, long a powerhouse for vertical drilling activity and coalseam gas development, will only increase in importance as unconventional development and exploration expand. Learn about Queensland's new tenure arrangements for deep gas exploration and framework for unconventional gas.

 Honourable Andrew Cripps, MP, Minister for Natural Resources and Mines, Queensland Government

0910 Operator Spotlight: New Approaches in the Cooper Basin

A study of previous well results and practices provides new clues to successful development in the Cooper Basin—and more leads.

 Duncan Lockhart, Chief Technical Officer, Drillsearch Energy Ltd.

0935 Technology Spotlight: Tailoring Seismic Surveys

Australian reservoir targets demand pinpoint approaches when planning seismic surveys.

Mark Stanley, Regional Geophysicist, CGG

1000 Networking Break: Morning Tea

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1030 Spotlight: South Australia's Roadmap To Unconventional Success

South Australia holds substantial unconventional resource potential, and has a long history of conventional production. Now the state as developed a precise and functional guide that will allow its tight sand, shale and coalseam gas endowment to be developed efficiently and sustainably, while balancing social, environmental and economic impacts and benefits.

 Barry Goldstein, Executive Director, Energy Resources Division, DMITRE, South Australia Government



1100 **Panel: Commercialising Australian Gas Plays**

There is far more to making money than shipping gas to an LNG plant. Producers need to consider the economics of wells, technology employed, gas processing and pipeline infrastructure, and end-use customers as well. Here, two experts with experience in North America and Australia compare and contrast upstream value creation strategies and lessons learned.

- Glen W. Gill, CEO, Innovative Energy Consulting Pty Ltd.
- Lachlan Hughson, Finance Director, Antero Resources

1145 **Conference Adjourns**

Agenda content and timeline subject to change

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Handling reservoir complexities

Petrophysical properties within the reservoir are strongly controlled by depositional facies and a variety of post-depositional diagenetic processes. It's therefore essential that, to represent the reservoir's complexities, as wide a variety of trends be incorporated into the petrophysical model as possible.

Emerson's reservoir modeling software Roxar RMS, for

example, comes with fast and memory-efficient kriging and simulation algorithms that integrate a number of trends in the petrophysical model. These include large-scale compactional/depositional processes, intrabody trends, upward fining or coarsening, proximal-todistal and axis-to-margin lateral trends, facies-related trends, and cloud transforms. The kriging methods also include universal, Bayesian and colocated co-kriging with the kriging algorithms optimized to handle giant fields with thousands of wells.

Incorporating seismic data

The software also comes with a selection of methods that allow seismic data to be incorporated into petrophysical modeling. This includes a tool that allows interpreters to blend the seismic data and interpretations with stochastic modeling techniques to close the resolution gap between the two methods. An object-based facies modeling tool has been developed where data extracted from seismic are combined with geostatistical tools such as guidelines and trends to generate well-constrained sedimentary bodies.

The ability to access both deterministic and statistical techniques gives the modeler access to the gray area between seismic resolution and data-constrained statistical modeling, resulting in realistic property models that are conditioned to well observations and come with accurate volume calculations.

Another property modeling technique is a multipoint statistics tool that uses a pixel-based (grid cell by grid cell) approach for building stochastic facies realizations. This allows the user to condition 3-D training images of the interpreted heterogeneities in the reservoir in addition to wells and seismic volumes. Furthermore, the ability to execute petrophysical modeling jobs on parallel CPUs enables users to incorporate large seismic data volumes into petro-

physical modeling and reduce the computation time exponentially. The result is the incorporation of seismic into petrophysical modeling.

Upscaling— a Middle East example As mentioned before, one of the

As mentioned before, one of the biggest challenges in capturing petrophysical characteristics in the model and ensuring that they can be taken to simulation is the ability to handle giant reservoirs and to upscale models for simulation without losing their original petrophysical characteristics.

In one field example, RMS helped a leading Middle East operator upscale a geological model of 20 million cells into a simulation grid of only 2.5 to 3 million cells without losing the reservoir heterogeneities and petrophysical properties within the model.

The field in question was a complex carbonate reservoir in the Arabian Gulf that contained highly heterogeneous porous and dense layers including lithology limestone and dolomite with high-permeability streaks. Petrophysical properties that were modeled included the stochastic distribution of the rock type and porosity, the stochastic distribution of permeability, and the saturation conditioned to rock type.

The method applied to the model was a recursive algorithm that operates by merging two adjacent layers with minimal variation changes until a single layer model is generated. The algorithm uses model properties such as bulk vol-

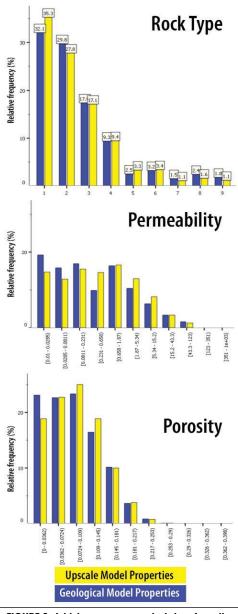


FIGURE 3. A histogram was undertaken from the upscaled simulation grid that shows close correlations to rock type, permeability and porosity.

(Source: Emerson Process Management)

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ume, porosity, permeability and rock type as input for quantifying the model's heterogeneity, and it was implemented as programming script within the software.

The workflow consisted of a layer coarsening script where quantitative parameters were generated to measure variation changes and determine where two cells could be merged while keeping maximum heterogeneity. Figure 1 illustrates how the heterogeneity is plotted vs. model layers, with the point of inflexion on the curve being the optimal point where the minimized model layers combine with the maximum retained heterogeneity.

At each stage, the layer coarsening script reports the total number of layers, the proportion of each layer and the combination sequence based on the original layer index.

The control lines, created through the programming script, also helped to define the columns and rows in the grid-building process. As can be seen in Figure 2, when evaluating lateral heterogeneity, the distribution of controls lines shows that the bigger cell sizes are on the flanks and the smaller cell sizes on the crest. Figure 3 shows a his-

togram that was undertaken from the upscaled simulation grid with very close correlations to rock type, permeability and porosity.

The result for the operator was a simulation grid of 2.8 million cells and a model that will enable reservoir engineers to conduct the fluid flow simulation process with an excellent approximation of the high-resolution calculations performed in the original model.

Furthermore, all of this takes places within an integrated workflow alongside other petrophysical modeling tools from 2-D interpolation to 3-D stochastic modeling conditioned to wells, facies and seismic data.

Rising to the challenge

Petrophysical modeling should always be based on combining all available data, especially well and seismic, with the geological interpretation of the reservoir. It should also come with the necessary capabilities to handle all types of reservoirs and models, no matter how large or complex.

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Wireline sensor expands capabilities of DFA

Analysis tool enables downhole measurement of in situ viscosity in real time.

Brian LeCompte, Murphy Oil; Vinay K. Mishra and Beatriz E. Barbosa, Schlumberger

Downhole fluid analysis (DFA) is a critical aspect of well development, delivering a wealth of data operators use to identify reservoir properties that lead to a better understanding of a field's petroleum system and, ultimately, commercial viability. Over the years DFA has evolved to include real-time *in situ* sensors placed in the well with wireline formation tester (WFT) tools to measure key reservoir fluid characteristics, including hydrocarbon composition, gas-oil ratio (GOR), CO₂, downhole fluorescence, water pH and density.

Conventional methods of obtaining formation fluid viscosity include laboratory analysis at surface and pressure-volume-temperature (PVT) correlations, which are limited by quantity, uncertainty and time as the data may not be available for several weeks or months. Surface vis-

cosity measurements also can be affected by irreversible alteration of the sampled fluid through pressure and temperature changes and by the effects of long-term sample storage.

The capabilities of DFA have recently been expanded to include a real-time wireline method for measuring formation fluid viscosity, an important parameter that influences fluid mobility, which is directly related to productivity and fluid displacement. By understanding the viscosity of downhole fluids, operators can more accurately analyze compositional gradients as well as vertical and lateral reservoir connectivity to estimate the economic value of a reservoir—a critical factor in appraisal and early field development. Accurate and timely viscosity data are important for optimizing the production phase of every well. Developed for both land and offshore applications, the viscosity sensor is particularly critical for the deepwater sector, where cost, risk and uncertainty are very high.

Murphy Oil deployed the viscosity sensor in a Gulf of

Mexico (GoM) field test to perform realtime *in situ* measurements by flowing low or noncontaminated reservoir oil using a WFT sampling toolstring. The sensor, only 5 cm in diameter, is installed in the Schlumberger InSitu Fluid Analyzer (IFA) system that provides accurate measurements of bottomhole flowing pressure, temperature and fluid properties, including *in situ* density, fluid composition, GOR and now *in situ* viscosity with the new sensor.

Comprehensive analysis of IFA measurements helps the operator more fully understand the reservoir's behavior. The new sensor measures viscosity in close proximity to other *in situ* sensor measurements, providing an integrated approach to decision-making for a broad range of formation issues such as assessing well connectivity and fluid gradients at different layers and depths.

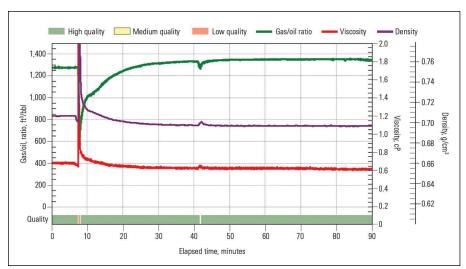


FIGURE 1. A DFA plot from one of the tested stations shows in situ fluid analysis results, including viscosities from vibrating wire (red), resonant rod density (purple) and GOR (green). There is no noise affecting the measurement as observed from the smooth viscosity curves and the vibrating wire quality flag. (Source: Schlumberger)

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DFA / LAB	Depth, ft	GOR, ft ³ /bbl	C ₁ wt%	C ₂ wt%	C ₃ -C ₅ wt%	C ₆₊ wt%	InSitu Density Sensor, g/cm ³	InSitu Viscosity Sensor, cP	Contamination, %	Fluorescence	Fluid Type
Well 1											
DFA 1	XX,240	1,423	13.17	1.91	5.21	79.7	0.692	0.60	<5	0.76	Oil
DFA 2	XX,440	1,101	10.43	1.43	5.39	82.75	0.714	0.81	<5	0.42	Oil
DFA 3	XX,675	52,029	85.54	0.1	3.1	11.25	0.288	0.20	<5	0.06	Gas
DFA 4	XX,110	612	5.54	1.59	4.93	87.94	0.779	1.30	<5	0.36	Oil
DFA 5	XX,140	536	4.8	1.49	4.62	89.08	0.78	1.30	<5	0.23	Oil
DFA 6	XX,150	na	na	na	na	na	0.979	na	<5	na	Water
Well 2											
DFA 1	XX,450	1,352	12.67	2.05	4.44	80.84	0.698	0.60	<5	0.75	Oil
PVT LAB	XX,450	1,160	10.86	1.13	6.06	81.95	0.684	na	3.8		Oil
DFA 2	XX,460	1,274	12.02	1.9	4.56	81.52	0.702	0.65	<5	0.64	Oil
DFA 3	XX,480	1,274	12.23	2.12	4.15	81.5	0.702	0.68	<5	0.5	Oil
PVT LAB	XX,480	1,187	10.37	1.1	6.41	82.12	0.698	0.60	2.5		Oil
DFA 4	XX,010	1,169	11	1.81	4.81	82.33	0.715	0.68	<5	0.47	Oil
DFA 5	XX,130	1,138	10.68	2.15	4.27	82.9	0.723	0.78	<5	0.54	Oil
PVT LAB	XX,130	990	8.87	1.23	5.87	82.14	0.721	0.72	2.4		Oil
DFA 6	XX,240	620	5.74	1.52	4.43	88.31	0.767	1.12	<5	0.22	Oil
DFA 7	XX,480	na	na	na	na	na	0.979	na	<5	na	Water
DFA 8	XX,150	na	na	na	na	na	0.985	na	<5	na	Water

na= not applicable

FIGURE 2. The table presents DFA results for all stations across both wells. Reservoir fluid samples also were collected at all stations and sent to a PVT laboratory for surface analysis. The PVT-laboratory-measured fluid properties results are available for three stations, which are noted for comparison with DFA data (bold). (Source: Schlumberger)

Stability with vibrating wire

The unique sensor employs a vibrating wire, a miniaturized device that provides real-time, *in situ* and high-accuracy data via specific physics of measurement created exclusively to determine fluid viscosity downhole, allowing reservoir managers to make decisions on the spot. The tool overcomes the limitations of existing technologies used to determine viscosity as secondary measurements such as the resonant rod that measures density. Under favorable conditions, it can generate an accurate viscosity output. However, the installation of both the resonant rod sensor and the viscosity sensor in the IFA offers the most reliable measurement of both density and viscosity, especially in challenging fluid conditions.

The viscosity sensor can operate in hydrocarbons ranging from 0.2 cp to 300 cp, with proven accuracy of 10% in environments up to 25,000 psi and 177 C (350 F), and provides accurate temperature measurement of flowing fluid. It delivers accurate viscosity measurements every second, enabling a real-time evaluation.

The calibration of the sensor is performed against standardized canon fluids in the engineering facility where it is built. The sensor was tested in 65 wells globally—40 drilled with oil-based mud and 25 with waterbased mud, with temperatures ranging from 32 C to 144 C (89 F to 292 F) and pressures from 643 psi to 24,442 psi (Figure 1).

Sampling and DFA, including viscosity measurements, were performed in two deepwater GoM wells with the

objective of properly evaluating the reservoir and establishing important fluid characterization parameters and connectivity. Understanding connectivity is especially important in the GoM, where understanding reservoir compartmentalization is a major challenge for operators.

In both wells, the WFT was set on the wellbore wall at various depths, and reservoir fluid was pumped into the IFA flowline, where the *in situ* viscosity sensor and *in situ* density sensors made their DFA measurements. The objective was to obtain a clean sample of reservoir fluid with less than 5% contamination from drilling fluid and perform *in situ* fluid typing for reservoir valuation. On each station, carbon content, fluorescence, density, viscosity, pressure and temperature were measured as well as GOR, an

important indicator of whether the fluid was light or heavier oil.

In Well 1, fluid sampling and DFA were conducted at six stations, including four oil, one gas and one water station. *In situ* viscosity measurements were taken at the four oil stations. Well 2 involved a comparative study, with sampling and DFA performed at six oil stations and two water stations. Following the wireline operation, PVT lab analysis was done for three of the oil stations, with viscosity measured in two of those to compare lab data to the measurements provided by the vibrating wire sensor. The comparison showed good agreement between the two testing methods. DFA, performed with the vibrating sensor on the clean fluid in the flowline, confirmed contamination levels of less than 5% at all stations in both wells (Figure 2).

Determining reservoir connectivity

In Well 1, in situ viscosities in the four oil stations ranged from 0.6 cp in DFA station one at a deeper depth to 1.3 cp in stations four and five at shallower depths. In DFA station two, fluid cleanup started during the pump-out phase, and the in situ viscosities from both the vibrating wire and the resonant rod sensors began to stabilize after about 25 minutes of pumping. The viscosity measurement from the resonant rod later began to drift upward, a possible result of solids sticking in the sensor. Therefore, only the vibrating wire viscosity measurement (0.81 cp) was used from that station.



In Well 2, the DFA measurements across the upper reservoir indicated flowing oil from the top three oil stations and flowing water from the bottom station. Optical density, fluorescence and viscosity (0.58 cp to 0.68 cp) showed consistent compositional variance. The fluid was in equilibrium, and the tested oil zones likely were connected, a conclusion supported by other petrophysical logs and geological information.

In the lower reservoir, the DFA measurements, including pressure, mobility, downhole fluid properties and basic logs, revealed that the top two stations were oil, the next deepest station was water and the bottom zone consisted of oil. The optical density, viscosity and fluorescence measurements confirmed that the bottom sands had much higher viscosity than the upper sands. The water zone verified the presence of a barrier, most likely shale, meaning the upper and lower sands in this section were not connected. This provided the operator with valuable information to calculate accurate reserve and production estimates and determine if the well

was economical. In some cases the information can help operators plan a viable completion and production strategy that will differ from that used in a connected reservoir.

By measuring *in situ* viscosity in real time, the vibrating wire viscosity sensor represents an important stepchange in DFA, providing operators with a stable and precise method to better understand the reservoir's petroleum system, including connectivity and compartmentalization, and develop wells economically with reduced risk, cost and uncertainty.

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Rock physics modeling

Workflow combining kerogen maturation and petrophysical data offers insight into unconventional reservoirs.

Mohammad Reza Saberi, CGG

The Wolfcamp Shale Formation in the Permian Basin of Texas is a complete reservoir system of source, seal and reservoir. A deeper understanding of rock physics is necessary for successful exploration and production. Unconventional reservoirs are typically very complex to model, and rock physics provides insight into this complexity.

On a well located in the Wolfcamp Shale Formation, CGG applied a rock physics workflow that combines kerogen maturation information and petrophysical data to model seismic velocity. The maturation-oriented rock physics model reveals a relationship between kerogen maturity in shales and compressional-wave (P-wave) velocities. Therefore, by connecting kerogen maturation stages with elastic properties of seismic data, seismic volumes can be populated with kerogen maturity information.

Conceptual model

The presence of low-density kerogen and pores filled with hydrocarbons generated during different maturity levels is

the main characteristic of shale gas reservoirs. Proper consideration of kerogen content and its maturation history within lithology sequences can be very helpful in elastic property modeling.

The kerogen maturity model is based on shale samples at mature and post-mature hydrocarbongenerating stages. In the initial depositional environment, organic matter and stiff silicate minerals are deposited together. In this immature stage, kerogen, clay and clean minerals are the only constituents of the rock matrix. Mechanical compaction follows; porosity is reduced; and pyrite appears in available pore spaces, marking the transition from an immature to a mature state.

During this transition, characterized by a particular orienta-

tion of the clay particles—vertical transverse isotropy—hydrocarbon generation begins. As they are buried deeper, shales enter into a mature state where most porosity is lost due to physical and chemical compaction, and pores start to be occupied by pyrite.

At the mature stage, organic matter occurs in bed-parallel elongated lenses, is load-bearing and contributes to the rock's stiffness along with silicate minerals. In the final post-mature state, most pores will be occupied by pyrite. Organic matter is finely scattered and is no longer load-bearing. Figure 1 shows different shale source rock maturation stages resulting from this diagenetic process.

Porosity classification makes the rock physics model more flexible in studying different maturation states. Mineralogy is divided into three groups: clean (calcite, dolomite and quartz), clay and organics (kerogen and pyrite). For modeling purposes, total porosity is divided into hydrocarbon-filled porosity, bound water-filled porosity and free-water-filled porosity.

This new model is applied to the Pence #1 well in the Wolfcamp Shale to model measured velocity and decompose it into the velocities of the clean, clay and organics

groups. Required model inputs such as mineralogy and porosity come from stochastic petrophysical analysis of a conventional logging suite. Clay elastic properties are taken from previous rock physics studies performed in the same area along with rock physics parameters such as aspect ratios. Resulting velocities provide insight into the kerogen maturation stages along the well path.

When the system is immature, it is thought to be fully saturated with brine, while a post-mature system will be filled with hydrocarbons. Different types of porosity considered for calculation purposes are total porosity, hydrocarbon-filled porosity, bound water-filled porosity and free water-filled porosity.

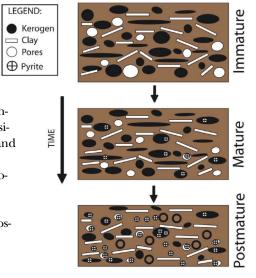


FIGURE 1. The conceptual model used for kerogen maturity evolution is based on shale samples. This is the basis for a new rock physics model. (Source: Ahmadov, 2011)



Rock physics modeling workflow

The following steps are followed to model P-sonic velocity:

- 1. Calculate porosities for the rock physics model (total, effective, hydrocarbon-filled, etc.).
- 2. Divide minerals into clean, clay and organics groups. Pyrite is in the organics group because of the occurrence of pyrite within kerogen with increasing maturity (Figure 1).
- Use Hill average method to model clean group elastic properties.
- 4. Use upper Hashin-Shtrikman bound to model the elastic properties of the organics group.
- 5. Use differential equation medium (DEM) and Gassmann methods to calculate saturated clean, clay and organics bulk and shear moduli. Here it is considered that clean and clay groups are saturated with brine while organics are fully saturated with hydrocarbons.
- 6. Apply upper Hashin-Shtrikman bound to mix the elastic properties of the clay and organics groups.
- 7. Finally, introduce spherical shale inclusions into the sand matrix using the DEM approach. This step ensures that both sand and shale act as load-bearing components.

Classifying mineralogy and porosity distribution among sands, clays and organics is helpful. Modeled velocities are in good agreement with measured ones. The main advantage of this model is the ability to decompose measured velocity into sand, clay and organics components. Measured velocity—sonic in this case—is an effective velocity coming from different lithologies and fluids with different elastic properties. Individual velocities for each group provide greater understanding of the maturation process in unconventional reservoirs. Some variations in the measured effective velocity may be more relevant to the clean group than to the clay or organics groups. Another advantage of this new rock physics model is that it provides a qualitative tool for determining kerogen maturity by segmenting parameters in the conceptual model into immature and post-mature states.

Figure 2 shows application of this improved rock physics model for the Pence #1 well. The final P-velocity track compares modeled and measured P-velocities using the new model. Furthermore, modeled velocity is decomposed into velocities for clean, clay and organics groups. These decomposed velocities clearly give more information on kerogen and sand content that cannot be deduced from the sonic velocity itself. Modeled velocity is well matched with measured velocity except for some intervals such as 3,213 m to 3,240 m and 3,255 m to 3,271 m (10,540 ft to 10,630 ft and 10,680 ft to 10,730 ft), where the organics

group velocity (velocity given at step 4) increases sharply and modeled velocity is overpredicted (Figure 2). This overprediction comes from kerogen content (organics velocity) and could be linked to assumptions made during modeling. Therefore, these can be interpreted as intervals with post-mature kerogen.

Successful development and production programs rely on an advanced rock physics relationship between petrophysics, maturation parameters and elastic properties. This rock physics approach for modeling elastic properties in unconventional reservoirs is based on a conceptual model driven by actual source rock samples. This model integrates information about the maturation process with petrophysics and can be implemented in seismic characterization studies for mapping mature kerogen intervals. Better understanding of rock properties contributes to more accurate determinations of commercially viable areas for drilling.

References available on request.

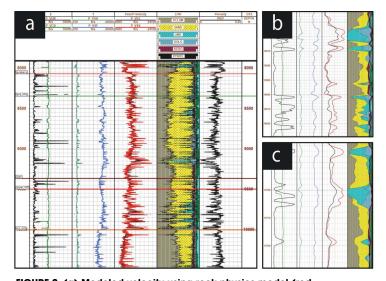


FIGURE 2. (a) Modeled velocity using rock physics model (red curve) is compared to measured velocity (black curve). Track 1 shows velocities for brine-filled clean (blue curve) and hydrocarbon shale (green curve) groups. Track 2 shows velocity components for hydrocarbon shale, which are clay (green curve) and organics (black curve) groups. (b and c) The images show two close-ups from the bottom sections of the logs between intervals 3,213 m to 3,240 m and 3,255 m to 3,271 m where velocities are overpredicted and organics group velocity is sharply increased. These intervals can be interpreted as containing post-mature kerogen (higher concentration of pyrite) based on modeling assumptions. Note that modeling for organics group velocity is independent of calcite and dolomite fractions. (Source: CGG)

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Trends shift in North American, international CT markets

Demand distribution in the U.S. has shifted slightly back toward workover operations. International dynamics are expected to mirror the North American CT market.

Alexander Robart, Amar Gujral, Aaron Holton and Merrick Levy, PacWest Consulting Partners

ver the past decade the North American coiled tubing (CT) services market saw a surge in demand as CT units were increasingly deployed for use during hydraulic fracturing operations. E&P companies began demanding CT units for several applications during frack operations, requiring CT units onsite throughout the entire completion and fracturing process.

By 2011, annual CT demand days reached a record, about double the level seen prior to 2007, and day rates exceeded \$80,000 in some regions due to constrained unit supply.

This surge in unconventional-related demand structurally altered the CT demand profile from largely workover-related to largely completion-related, with completion-related demand shifting from about 20%

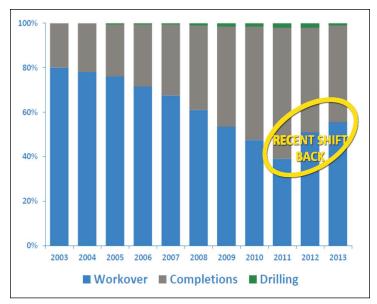


FIGURE 1. North America land demand profile indicates a recent shift back to workovers and away from completions. (Source: PacWest)

share of demand days in 2003 to about 60% share by 2011. With the count of U.S. wells fracked growing, it may seem puzzling that CT demand days then fell about 25% after peaking in 2011.

However, the decline in demand days was driven by three key factors: a substitution to alternative intervention platforms, efficiency efforts across the drilling and completion (D&C) value chain, and reduced CT calloff. Emerging technologies in D&C also may have reduced CT days demanded, but several new completion and frack techniques also add to CT demand, and such technologies still require monitoring to assess long-term impacts to the CT service market.

Witnessing how the North American CT market mirrored the rise in unconventional D&C activity, PacWest expects similar dynamics to take place internationally as key plays move beyond appraisal and toward commercial development phases in the coming years.

PacWest views China and the Middle East (particularly Saudi Arabia and Oman) as possessing the most promising development prospects among international markets, but barriers exist to guaranteeing a successful CT growth story abroad.

Historical CT market in North America

Historically, 80% of CT demand in North America was driven by workover-related operations on producing wells. During the period from 2003 through 2011, however, the increase in unconventional activity structurally altered CT demand. Service providers began using CT for a range of completions-related operations, including setting plugs or packers, tubing-conveyed perforating, certain sliding-sleeve operations and milling plugs, among others.

By 2011, the share of CT unit demand related to D&C increased to nearly 60% from 20% in 2003 (Figure 1). The demand distribution has since shifted slightly back toward workover operations due to several factors, including a growing producing well inventory across the U.S., many of which are beginning to require servicing.



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Current demand, market trends

PacWest segments the CT market into tiers based on tubing diameter: small CT units (less than 2-in. diameter) are primarily used for workover, wellbore cleanouts and short total measured depth completions, while premium (2 in. to 2% in.) and super premium units (greater than 2% in.) are used for workover and completions in extended-reach and HP/HT wells.

The current fleet of CT units across North America is still weighted toward small-tier units. The Intervention and Coiled Tubing Association (ICoTA) estimated there were 909 CT units across North America in 2013. PacWest estimates that 74% of this fleet was comprised of small-tier CT units. However, small units are currently in oversupply with an estimate less than 50% utilization since

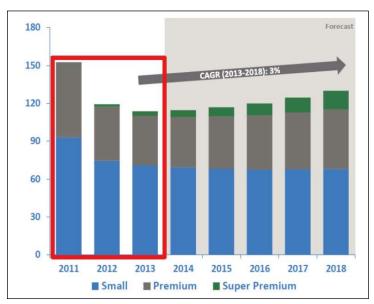


FIGURE 2. CT services demand days as shown by tier are expected to grow through 2018 by 3% year-on-year. (Source: PacWest)

2008. The number of small-tier units is expected to decline 3% between 2014 and 2018, driven by upgrades to higher spec units and redeployment of units abroad.

In contrast, PacWest anticipates the premium and super premium unit counts to increase 8% and 48%, respectively, from 2013 through 2018. Higher spec units are less susceptible to lockup and helical buckling associated with the extended-reach and HP/HT conditions in several unconventional plays.

When looking at demand days, PacWest expects a similar pattern. Small unit demand is expected to decrease slightly from 2014 through 2018. Premium unit demand days are expected to grow modestly, while super pre-

mium unit demand days are expected to grow strongly during the same period.

Although PacWest anticipates overall demand days to increase only 3% year-on-year through 2018, the market is not expected to recover to levels witnessed in 2011. The company estimates that CT demand declined nearly 30% from 2011 to 2013. This decline was caused by a combination of three factors: substitution (i.e. competition from snubbing units and, to a lesser extent, tractor-conveyed wireline); increased frack efficiencies; and a shift to call-off units and away from standby.

Future of the market: Competing, emerging technologies

As lateral lengths continue to increase, snubbing units will capture a larger share of completion-related demand from CT. CT and snubbing units offer a number of advantages over traditional workover rigs, including the ability to perform maintenance operations on a live well. E&Ps increasingly employ snubbing units for frack support despite these being more expensive. Snubbing units' jointed pipe design offers unlimited reach and the ability to operate in HP/HT wells. Depending on the well and circumstances, these benefits may outweigh the speed, safety and cost advantages of CT.

More efficient frack operations and the push to reduce surface equipment use have resulted in the reduction of billable CT days. "Batch" fracturing operations on multiwell pads will drive this shift as one of the largest enablers of frack efficiency gains.

In the first quarter of 2014, 72% of wells were completed either in a batch operation with a zipper frack (fracking wells in series) or back-to-back (fracking wells in parallel). More than 60% of wells in the Bakken, DJ Basin, Eagle Ford, Fayetteville, Marcellus and Utica were drilled on pads in the first quarter.

With respect to efficiencies, PacWest estimates batch completions on multiwell pads have reduced hydraulic fracturing days per well by approximately one day in plays such as the Eagle Ford, Marcellus and Granite Wash.

During the tight market conditions that prevailed from 2009 to 2012, E&Ps paid a standby rate to ensure availability of CT units. The prevailing dynamics resulted in increased utilization and day rates and an overall strong market for CT. However, CT capacity increases and reduced demand from substitutions and efficiency gains resulted in call-off and negatively impacted demand for CT.

In addition to competing platforms, there are a number of emerging technologies with the potential to disrupt CT unit demand in the future. Metallic and

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polyglycolic acid degradable/dissolvable frack balls that eliminate frack ball drill-out are becoming more widespread. Large internal diameter frack plugs and improved diverting agents are increasingly used, which could reduce plug and perf (PNP) support activities.

However, the industry may see some offset with coiled frack that continues to be tested in North America and increased use of PNP over sliding-sleeve completions.

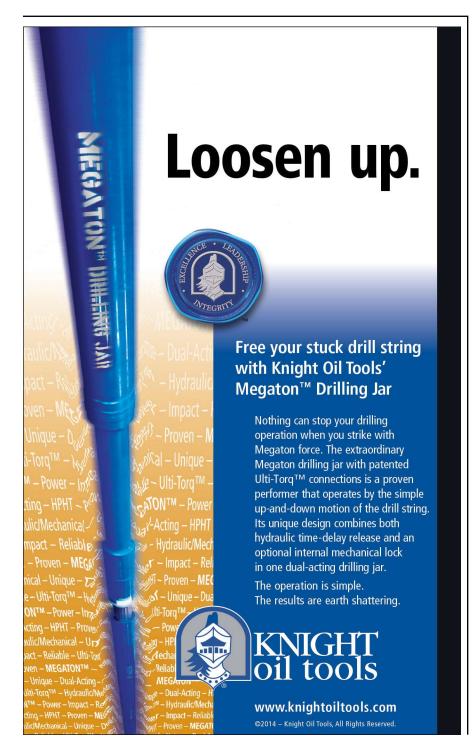
International CT adoption

PacWest expects the international CT market to follow a similar trend to what was witnessed in North America from 2003 to 2008. Similar to the North American land market, frack activity will be a major growth driver for international CT demand in the future. International frack capacity is forecast to grow to 20% per year through 2018 and will likely account for nearly three-quarters of global growth.

Given these assumptions, the international CT unit count is expected to grow 10% per year through 2018. Although conventional well workover requirements will drive the majority of supply, increased frack activity in countries such as China, Russia and Argentina will drive growth in higher spec CT. In total, nearly 650 units are expected to be added internationally from 2013 through 2018 to meet growing demand.

Taking a closer look at the potential for unconventional activity driving the use of CT abroad, China and the Middle East possess the most promising development factors among international markets. This view is based on a combination of measurable factors such as geology, oilfield services capacity and infrastructure along with qualitative factors such as commerciality, regulatory landscape and development constraints.

Local governments will have to work with E&Ps and service providers to ensure that the local supply chain infrastructure is in place to accommodate completions-driven growth. In addition, international markets will have to import technology know-how and experienced crews to replicate the North American CT story abroad.





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Self-supporting riser boosts use of CT interventions

A single permanently installed self-supporting riser can be used for drilling, completion, testing, production and abandonment of wells.

Dr. Keith Millheim and **Charles Yemington**, Atlantis Offshore Ltd.

ncreased use of self-supporting risers offers a novel integrated approach to drilling, coiled tubing (CT) intervention and production for deepwater satellite wells. Features of the new approach include improved safety and environmental protection; simplicity and high reliability; and reduced cost for intervention and support for conventional or CT drilling, production and abandonment. The reduced cost and better availability of intervention can improve the economics for many marginal reservoirs.

Variations of self-supporting risers have been used for many years. Placid installed one for production in Green Canyon in the 1980s. More recently self-supporting risers have been installed for production off West Africa and in the Gulf of Mexico (GoM) and used for drilling offshore China.

A prototype modular exploration and production system riser was installed on a simulated wellhead in 1,000-m (3,280-ft) water depth in the GoM in 2006. It was recovered for analysis after five years, during which it rode out two named storms and an eddy current. Forensic analysis showed no significant signs of wear, fatigue or other degradation.

In the past, CT intervention in deepwater satellite wells typically required a mobile offshore drilling unit (MODU), with the associated problems of cost, scheduling and logistics. Using a self-supporting riser engaged to the wellhead or tree can avoid the need for a MODU in favor of a lower cost, more easily scheduled CT intervention vessel and can provide improved safety and environmental protection.

Moving into deepwater

In their progression to deepwater, operators have probably passed over more oil than they have produced because the economics have favored larger reservoirs. The financial risk of satellite wells, in part due to the dif-

ficulty of downhole intervention, has deterred operators from developing marginal reservoirs.

Reduced cost of reentry for workover can make marginal reservoirs commercially attractive by reducing the risk of having to abandon a well before it nears its full potential. In the future, the option to install a self-supporting riser on a deepwater satellite well for downhole CT intervention at any point in the life of the well can significantly improve the commercial practicality of deepwater satellite reservoirs.

This approach to CT intervention offers many advantages. Rig time is not required for riser installation or removal. Lightweight components make the riser suitable for installation and recovery by a light construction vessel or a specially outfitted workboat.

Other advantages include simplified logistics and avoidance of at-sea vessel-to-vessel transfer of a completion and workover riser between a supply boat and a rig. Reentry can be done by a MODU or by a lower cost or more readily available CT vessel. For simple downhole tasks, it may be practical to operate the CT spread from a specially equipped workboat.

Seabed reservoir isolation

Provisions for reservoir isolation at the seafloor would normally be an integral part of the self-supporting riser mounted on a wellhead or tree. In addition to providing another level of environmental protection, this allows the CT contractor to safely use a conventional CT BOP and injector at the surface while fully conforming to regulatory requirements and practices, including those that resulted from the *Deepwater Horizon* incident.

The recent frequency of 100-year storms has led to more stringent design requirements for surface facilities, making them more expensive. Surface facilities may be widely separated, particularly in deepwater. If the distance to a host is prohibitive, using a self-supporting riser can make it practical to produce marginal reservoirs and take the wells through their entire life cycle without a host platform or large FPSO vessel. Conventional surface facilities will remain the standard for



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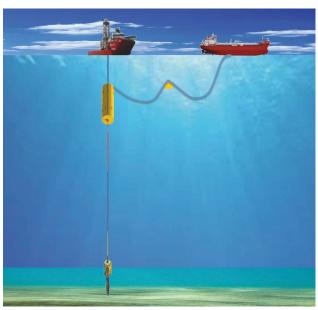
development of large deepwater reservoirs. The selfsupporting riser offers a safe, low-cost alternative for drilling, production, workover and abandonment of isolated deepwater wells.

Self-supporting riser

A single permanently installed self-supporting riser can meet all riser needs for the life of a marginal reservoir. The cycle begins with exploratory drilling. If no oil is found, the riser can be recovered and reused in another location just as drilling risers are. If indications are promising, the same riser can be used for well testing, including through CT production tubing.

If the test is satisfactory, the self-supporting riser and the well test vessel can remain for early production while a surface facility is designed and built. If the well test indicates that the reservoir does not justify a dedicated surface facility, the riser and well test vessel can be used to deplete the reservoir.

Either way, the same self-supporting riser can remain



A single permanently installed self-supporting riser can meet all riser needs for the life of a marginal reservoir. (Source: Atlantis Offshore)



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in place for CT intervention, including replacing electric submersible pumps (ESPs), sidetracking, extending the well depth, cleanout or other workover and abandonment—all without the cost and complication of scheduling a MODU. There is a further benefit of reducing risk by having an additional layer of reservoir isolation capability and fewer personnel offshore.

Reservoir isolation capability at the bottom of the selfsupporting riser allows both drilling and CT contractors to use surface BOPs. It also can allow using a lower cost near-surface tree and significantly simplified control system for isolated wells.

Drilling, completion, well testing, production

When a single self-supporting riser is left installed from the beginning of the life cycle of a deepwater well, a shallow-water semisubmersible or ship-shape rig can be moored over it, use the riser for drilling and completion and leave it in place. For well testing, a relatively small vessel with a test tree can engage the top of the self-sup-

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porting riser and produce through a dynamic flexible pipe, as shown in the illustration.

Depending on the results of the well test, it may be appropriate to remain onsite for early production of a promising reservoir or even until a marginal reservoir has been depleted.

A 15,000-bbl/d surface production facility can be installed on a converted 80-m (262-ft) vessel that need not be suitable for extreme weather. If a weather window is closing, the production vessel can simply shut in at the seafloor, drop the flexible production pipe and control umbilical and motor away. The self-supporting riser is not affected by surface conditions unless attached to a surface vessel.

For CT operations, motion isolation is required between the riser and the intervention vessel to prevent coupling of vessel motion into the riser. In the well test or production mode, a "lazy-S" flexible pipe sufficiently isolates the riser structure from the vessel unless the vessel makes excessive excursions, in which case the flexible pipe can be quickly disconnected from the vessel and dropped into the water.

Producing to a 15,000 bbl/d dynamically positioned FPSO unit with easy disconnection and reconnection allows many maintenance tasks for surface production equipment to be done at a shore facility by motoring to a dock. The option to do shore-side maintenance of surface production equipment is particularly attractive when production must be shut in for either downhole intervention or maintenance of surface equipment. Dockside maintenance of surface production equipment significantly improves the logistics and results in fewer personnel offshore for reduced risk.

Intervening or producing through a self-supporting riser with seafloor reservoir isolation makes it practical to use an intervention vessel or early generation MODU for downhole work, ESP replacement or abandonment, as shown by the vessel directly above the well in the illustration.

Quick disconnect capability with the riser left standing in place also greatly reduces the time for a dynamically positioned CT vessel to respond to a closing weather window—simply pull out of the hole, shut in at the seafloor, disconnect and motor away. The self-supporting riser is isolated from surface conditions and, when used with a surface ship that is free to depart, offers an approach that is not exposed to extreme surface conditions.

Acknowledgment: Engineering development of self-supporting riser use for both CT intervention and well testing was funded in part by the Research Partnership to Secure Energy for America (RPSEA) through a contract with the U.S. Department of Energy.

F5: The Next Generation of Downhole Motors



Quest for the most efficient field-frack network

Consistent stage spacing and frack volume deliver maximum reservoir connectivity.

Tim Willems and Joe DeGeare, NCS Energy Services

S ince the beginning of the unconventional resources boom, there have been two primary methods used for completing hydraulically fractured wells—plug and perf (PNP) and openhole completions.

PNP has been the most widely used method for multistage completions while openhole, which uses swellable packers and ball-drop sliding sleeves, became an alternative more recently.

Tens of thousands of unconventional wells have now been completed using these two methods, which have proven especially effective in the early production life of the wells.

However, as the unconventional segment matures, operators are seeking the means to address the wells' steep declines in production. Analytical tools and techniques are improving, and operators are realizing that production can be significantly improved with drilling and completion programs designed for maximum reservoir connectivity. This has given rise to the concept of an "efficient field-frack network," which combines optimum well spacing with consistent stage spacing.

Efficiency for all wells

The field-frack network concept is a starting point for optimized field development because it takes the inconsistency and unpredictability out of the frack-delivery mechanism regardless of formation type, proppant type, pumping program and other variables. Whatever the completion design, it must be delivered precisely and predictably, or a significant percentage of the reservoir will remain unstimulated. Figure 1 illustrates an ideal frack network for a single lease section with four evenly spaced wells, each having frack stages of equal volume. Such a network ensures maximum reservoir coverage. The goal is to repeat this pattern across the entire lease acreage.

Unfortunately, it is not possible to achieve either consistent stage spacing or uniform frack volume when using PNP, the limitations of which are well known and documented. To minimize stimulation cost and time,

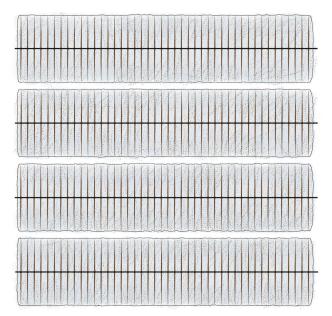


FIGURE 1. This illustration demonstrates an ideal frack network for a single section of a lease with consistent frack spacing and frack volumes. (Source: NCS Energy Services)

PNP attempts to stimulate multiple perforation clusters simultaneously, but with frack fluids being bullheaded down the casing, there is no practical way to predict or control which clusters actually fracture, how big each fracture is and how proppant is distributed. Variable frack gradients along lateral sections (Figure 2) ensure that all fracks are not equal.

Studies using radioactive tracers have revealed that many clusters are not stimulated at all, while others receive varying amounts of treatment. A comprehensive study of production logs from a number of unconventional reservoirs reinforces that finding, concluding that about a third of all perforation clusters do not contribute to production. Yet another study indicated that a higher ratio of fluid enters the first perforation cluster, while a higher concentration of proppant enters the lower perforations.

When multiple parallel wellbores are completed using PNP, the effect of the inconsistent frack pattern is multi-

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plied, with gaping areas of the formation unreached by the stimulation, as illustrated in Figure 3. Although it has been the go-to workhorse for many years, PNP simply cannot deliver the predictability and control needed to optimize reservoir connectivity.

With openhole packers and ball-drop sleeves, frack ports are typically located halfway between the packers, suggesting consistent spacing between fractures. But again, because of variable breakdown pressures, the frac-

tures can initiate anywhere between the packers or even at a packer where the formation already is stressed. There might be a single large fracture, or there might be multiple small fractures; there simply is no way to

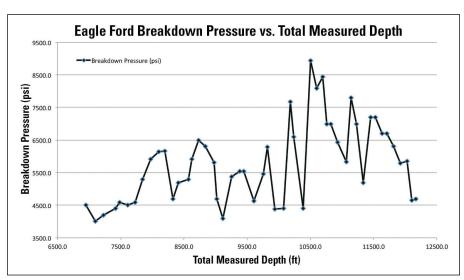


FIGURE 2. Variable breakdown pressures are recorded across a lateral in an Eagle Ford well. (Source: NCS Energy Services)

predict or control the fracture location and volume.

Adding to the uncertainty is another shortcoming of openhole packers: interstage communication during stimulation that can deplete the energy being applied to

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the target stage. In a number of openhole completions, recorded downhole pressures have revealed that interstage communication is quite common. In one project involving 13 openhole completions, recorded downhole pressure measurements confirmed interstage communication in 80 of 185 (43%) of the stages.

CT method delivers

The Multistage Unlimited completion system (Figure 4) from NCS Energy Services combines cemented casing sleeves and a coiled tubing-deployed (CT-deployed) tool assembly to deliver predictable frack spacing and volume.

The casing sleeves match the specifications of the host casing string and are inserted in the casing string at the desired stage spacing. All sleeves for a given well are identical and therefore can be installed in any order. Unlike conventional ball-drop sleeves, these sleeves are full-drift at all times, so they permit normal cementing operations. The fracture-isolation assembly comprises a casing-sleeve locator, a resettable isolation bridge plug

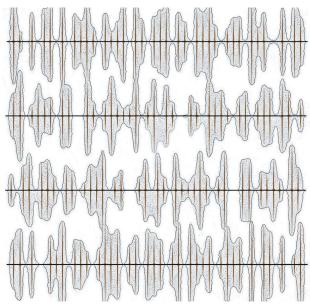


FIGURE 3. Inconsistent frack spacing and frack volumes leave much of the reservoir unstimulated. (Source: NCS Energy Services)



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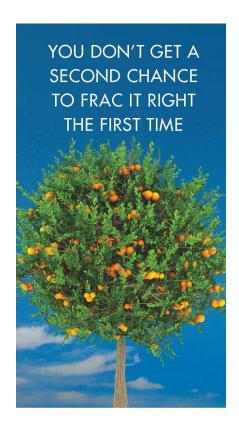
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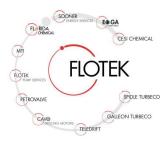
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and a sand-jet perforating sub that can be used to add stages in blank casing. During stimulation, the fracture-isolation assembly is run on CT to locate the lowest casing sleeve. The isolation bridge plug is then set inside the casing sleeve, where it grips and seals inside the inner sleeve. An increase in wellbore pressure from the surface forces the bridge plug assembly and inner sleeve down, opening six large frack ports at the top of the outer sleeve. Fluid and proppant are then pumped down the CT/casing annulus into the formation, while the CT serves as a dead string to provide real-time frack-zone pressure. Next, a pull on the CT can unset the bridge plug, and the assembly can be moved up to locate the next sleeve. This sequence is repeated until all stages have been stimulated. Then the frack-isolation assembly is pulled from the well, leaving an open, production-ready wellbore.

With cement sealing the annulus, fractures initiate only at the frack-sleeve ports, maintaining the designed stage spacing. Single-point injection allows the amount of proppant for each fracture to be controlled so propped volume can be consistent for all stages. Premature screenouts can be avoided by monitoring actual frack-zone pressure in real time via the CT dead string. By observing the formation's pressure response, the pump rate and sand loading can be adjusted on the fly to ensure a fully propped fracture. With the circulation capability at hand, sand loading can be aggressive because excess proppant is easily circulated out before moving on to the next stage.

More stages, greater control

Since being introduced in early 2011, more than 46,000 cemented casing sleeves have been run through the Multistage Unlimited system. The technology has enabled operators to increase the number of stages while controlling spacing and propped volume—for example, 92 sleeves in a single Eagle Ford well, 86 sleeves in a Bakken well and 53 sleeves in a Permian Basin well. The system also has been used to complete multiple wells with 3.2-km (2-mile) laterals. In the Permian's Bone Spring Formation in West Texas, the system has boosted production by more than 100% compared to equivalent PNP completions, while in the Bakken it has increased production 73% compared to openhole completions.

References available on request.

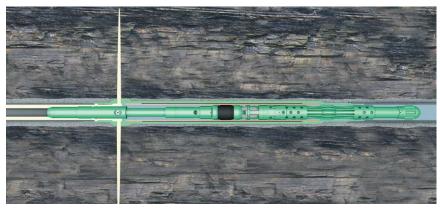


FIGURE 4. The Multistage Unlimited frack-isolation assembly deployed on CT isolates the target stage and shifts the cemented casing sleeve. The frack is pumped down the CT/casing annulus. (Source: NCS Energy Services)





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Sustainable frack fluids transform water from burden to benefit

New hydraulic fracturing fluids are transforming former waste streams into cost-saving alternatives to freshwater systems.

Andrey Smarovozov, Scott Nelson and Harold Hudson, Baker Hughes

ydraulic fracturing is a water-intensive process that competes with other human, agricultural and industrial uses for a growing share of limited global freshwater resources. Water for hydraulic fracturing operations typically has been sourced from surface water or freshwater aquifers and piped or trucked to well sites.

Historically, produced water from hydraulically fractured wells has been injected into disposal wells. However, mounting concerns about freshwater deficits plus environmental concerns and regulations, droughts in water-scarce areas and growing transportation costs are now driving the demand to reduce the volumes of freshwater required for hydraulic fracturing and, instead, reuse produced water for subsequent fracturing operations.

The solution sounds simple: By reusing a former waste stream, the industry can virtually eliminate the need for freshwater in fracturing operations while reducing disposal and trucking costs, saving millions of barrels of water and millions of dollars per field. The reality is far more complex. The challenge is to reuse water to create fracturing fluids that have the properties necessary to maximize production across a well's or field's life cycle and that also can address operators' short- and long-term environmental and economic needs.

Reuse Interim storage (frack tank, impoundment pond) Recycling Technology Reject \$1.00-\$10.00/bbl Pretreatment Hydrocarbons Acquisition Disposal Well Surface/Ground \$0.50-\$3.00/bbl Flowback/Produced Water \$0.25-\$1.75/bbl 80-150 bbl load \$0.50-\$8.00/bbl Haul to dispose 1 MM-6 MM Wellhead \$0.50-\$10.00/bbl + gal/well Water, Fluid, Proppant

This diagram represents the all-in cost of water for hydraulic fracturing. (Source: Jeffries, GE, NETL)

While no single solution exists for converting all produced or flowback water into reusable products consistently and economically, leading service companies are applying their knowledge of reservoirs and fracture systems; fluid chemistry expertise; and understanding of social, environmental, logistical and economic requirements to develop integrated water strategies, products and services tailored to specific geologic, weather, economic and regulatory considerations.

Sustainable solution

Based on a matrix that addresses a water's "fingerprint" (chemistry and total solids) and which crosslinked fluid systems will work with which water fingerprint and expected bottomhole temperatures, Baker Hughes developed a new family of four BrineCare fracturing fluid systems. These systems enable operators to use untreated or minimally treated produced or brackish water-based fluid for each water profile and temperature range an operator is likely to encounter.

The fluids are compatible with total dissolved solids (TDS) levels greater than 300,000 ppm, total hardness levels beyond the 50,000-ppm range and bottomhole temperatures ranging from 27 C to 177 C (80 F to 350 F) to create effective fracturing fluids that perform as designed and are environmentally responsible and economically feasible.

To formulate the fluids, scientists analyze the produced or brackish water in the laboratory to determine its profile

and match it to the appropriate fluid system. They then pretest the proposed fluid under the candidate job conditions to ensure its ability to execute the designed fracture treatment. Lab tests are followed by field testing prior to pumping the job.

Reducing all-in cost of water

The first performance indicator for the hydraulic fracturing fluids created from produced water is the extent to which they help increase oil and gas production. The value of these fluids is also heavily weighted on

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their ability to reduce the "all-in" cost of water, which encompasses the entire water life cycle from acquisition to transportation to both the well and disposal sites to recycling and finally to injection into a disposal well.

According to IHS CERA, water costs can consume up to 10% of a well's capital budget. Disposal costs account for more than 80% of water management dollars. The true cost of water is rarely reflected in acquisition prices, especially in water-scarce areas. The all-in cost of using fresh water, for example, ranges from \$2 to \$24 per barrel, despite its relatively low acquisition cost. Eliminating various portions of the oilfield water service cost cycle is critical to sustainable hydraulic fracturing operations.

Sources of water for hydraulic fracturing operations, in addition to fresh surface water, include produced water from wells within the field, load water that has been recovered from previous fracture stimulation operations and, increasingly, brackish waters from saline aquifers that exist in almost every shale basin in the U.S. Using recycled water not only conserves freshwater resources, but it also can sig-

nificantly reduce transportation and injection costs, particularly when trucks are used. In the Marcellus, for example, one producer estimates that 25% of its typical well costs are associated with water transportation. A University of North Dakota study estimates that 56% to 84% of total water costs in the Bakken are associated with transportation.

Produced-water frack fluid field applications

The ease of applying a fracturing fluid that has been prequalified for use with produced water was demonstrated recently in New Mexico's Delaware Basin. The operator wanted to conduct a 10-stage fracturing operation using a conventional plug and perf completion on a well in Eddy County. In addition to oil and gas production, farming and ranching have been staples of the Eddy County economy since the early 1900s. Periodic drought conditions often put water use at a premium. In an effort to minimize water sourcing costs and simplify logistics, the operator wished to use produced water to build the fracturing fluid for the well.





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An initial analysis of the operator's produced water sources determined that TDS ranged between 250,000 ppm and 300,000 ppm, and water temperature ranged from 57 C to 68 C (135 F to 155 F). Based on these properties, it was determined that a 27-ppg crosslinked fluid incorporating a buffer to lower the pH could be used for the application.

Using the operator's produced water, 42,913 bbl of fluid were mixed and pumped over a three-day operation. Water quality was closely monitored as it tended to fluctuate throughout the job, especially when the operation began to draw water from the bottom of a large storage tank being used. Near the end of the application, a freshwater cut was added to ensure sufficient water volume to complete the job. These varying water chemistries throughout the multistage stimulation treatment did not affect the performance of the BrineCare fracturing fluid system that was selected for the treatment of the well.

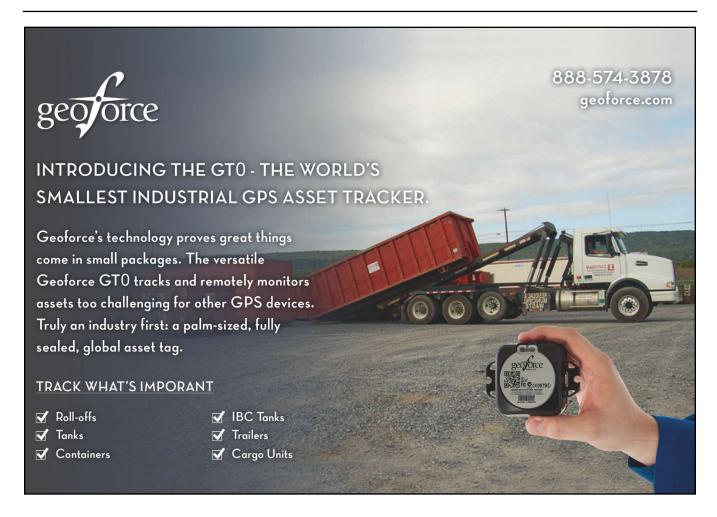
After stimulating and bringing the well online, production rates were compared to offset wells with similar depth

and lateral lengths. The target well delivered 20,156 bbl of oil and 7.9 MMcm (279 MMcf) of gas in its first five months of production. These results were consistent with the offset wells, which had been stimulated using freshwater fracturing fluids. To date, prequalified produced-water fracturing fluids have been applied on seven additional wells in the Delaware Basin's Brushy Canyon and Bone Spring formations with similar results.

Additionally, these prequalified fracturing systems have been used successfully with produced water in the Tubb formation (77 C [170 F]/55,000 ppm TDS); the Uintah Basin (74 C to 82 C [165 F to 180 F]/125,000 ppm to 200,000 ppm TDS); the Pinedale Anticline (93 C to 121 C [200 F to 250 F]/10,000 ppm to 15,000 ppm TDS); and in the Midland Basin's Canyon, Wolfcamp and Spraberry formations (71 C [160 F]/75,000 ppm to 90,000 ppm TDS).

Acknowledgment

Danica Hurd and Brian Callaghan contributed to this article.





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New kit for Eldfisk

Departure of topsides from shipyard brings Eldfisk II project one step closer to finish line.

STAFF REPORT

Scattered across the North Sea like broken strands of pearls stand drilling and production platforms that have served for more than 40 years as visual clues to the hydrocarbon treasures that lie beneath the Norwegian Continental Shelf (NCS).

With the installation of the topsides that departed Kvaerner's Stord yard in May, ConocoPhillips Skandinavia AS and its project partners—Eni Norge AS, Petoro AS, Statoil Petroleum AS and Total E&P Norge AS—will add another pearl to the Eldfisk strand.

Eldfisk at a glance

Discovered in 1970 and in production since 1979, the Eldfisk Field is located about 300 km (186 miles) offshore in the southern Norwegian North Sea. It is a part of the Greater Ekofisk Area (GEA). Water depths for the area range from 70 m to 75 m (230 ft to 246 ft). It is the second-largest of four producing fields in the GEA and one

of the largest on the NCS, according to Conoco Phillips.

The field—according to the Norwegian Petroleum Directorate (NPD)—produces from the Ekofisk, Hod and Tor formations from the early Paleocene and late Cretaceous ages. The fine-grained and dense reservoir rock has a high porosity and can be found in depths ranging from 2,700 m to 2,900 m (8,858 ft to 9,514 ft). The field consists of three structures: Alpha, Bravo and Øst Eldfisk.

The original development plan for the field was approved in 1975 and consisted of three facilities: Eld-fisk A, B and FTP. A and B are combined drilling, well-head and processing facilities. The FTP is a wellhead and processing facility connected by a bridge to A. The Eldfisk E facility, installed in 1999, supports water injection efforts in the field as well as in the Ekofisk Field where water is transported via pipeline to Ekofisk K.

The FTP also receives production from the Embla Field. Discovered in 1988 and online in 1993, the Embla Field was developed with an unmanned wellhead facility remotely controlled from Eldfisk. Oil is produced from

a complex segmented sandstone reservoir located at a depth of 4,000 m (13,123 ft), according to the NPD. Embla was the first HP/HT field to be developed in the area.

Eldfisk II project

On June 9, 2011—the 40th anniversary to the day that oil production first began from the Ekofisk Field—the Norwegian parliament or Storting approved the development and operations plans for the Ekofisk South and Eldfisk II projects.

The goal of the Eldfisk II project is to increase the oil recovery rate by approximately 6.5% to an expected recovery rate of 28.5% by the end of 2028. It is estimated that the project will see an increase in production of 220 MMboe to 283 MMboe from the field. In addition, ConocoPhillips stated in a release that the Eldfisk II



The Eldfisk 2/7 S integrated topsides departed Kvaerner's yard in Stord for the Eldfisk Field in May. (Source: Kvaerner ASA)



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represents total partner investments of \$5.8 billion to \$6.7 billion.

The ambitious Eldfisk II project plans called for the:

- Installation of a new integrated platform—the Eldfisk 2/7 S—containing a wellhead, process and accommodation module with 154 single-bed cabins;
- Installation of a bridge to Eldfisk 2/7 E;
- Drilling of 40 new wells for production and water injection;
- Conversion of Eldfisk 2/7 A to a wellhead platform and conversion of Eldfisk 2/7 FTP to a bridge support;
- Modification of main systems on Eldfisk 2/7 B;
- Installation of new hydrocarbon transport pipelines and a tie-in pipeline from the Embla field; and
- Installation of power and fiberoptic cable for transmission of up to 20 MW between the Eldfisk 2/4 Z and Eldfisk 2/4 S platforms.

International construction project

Construction of the various Eldfisk II components occurred in several locations scattered across Europe. Topsides construction began in 2012, with first steel being cut in February of that year at Kvaerner's Stord shipyard. Kvaerner's subcontractors in Gdynia and Gdańsk—Vistal and Energomontaz-Polnac in Gdynia and Mostotal Pomorse in Gdańsk—started fabrication and construction of components in 2012. According to Mostotal Pomorse, its work on the project included installation grillage, pipe supports, electro attachments, cable transits and surface

protection of all structural assemblies. The 154-cabin accommodation module was fabricated by STX Finland.

Subsea 7 is managing the subsea and pipeline elements of the project, including:

- Fabrication, installation and tie-in of 24-in. oil and 30-in. gas Wye structures downstream of the Eldfisk 2/7 B platform;
- Installation and tie-in of 24-in. oil export pipeline P2016S going from the Eldfisk 2/7 riser to the Wye structure downstream of the Eldfisk 2/7B platform;
- Installation and tie-in of 30-in. gas export pipeline P2018S going from the Eldfisk 2/7 riser to the Wye structure downstream of the Eldfisk 2/7B platform; and

• Subsea rerouting of the Embla pipeline P2040 to the Eldfisk 2/7 S platform.

The Eldfisk 2/7 S platform jacket was built at the Dragados shipyard in Cadiz, Spain, and was shipped directly to the Eldfisk Field.

Field prep, next steps

In April and May of 2013, the *Saipem 7000* heavy lifting vessel conducted lifting work at the field. Included in this work was the installation on May 6 of the 96-m (315-ft) high and 13,000-mt (14,330-ton) jacket, according to the ConocoPhillips release. Due to its size, the jacket was skid-launched from the barge before being lifted and then placed into its final position. Other projects completed in 2013 included installation of the bridge link-



The *Maersk Innovator* is set to drill new production and injection wells as part of the Eldfisk II project. (Source: Maersk Drilling)

ing the jacket to the Eldfisk Complex, the drilling template to allow predrilling through the 2/7 S jacket and a new waste heat recycling unit built in Stavanger's Rosenberg yard.

The *Maersk Innovator*—one of two ultraharsh environment jackup drilling rigs in Maersk's fleet—is set to start drilling the new production wells. According to ConocoPhillips, a total of 35 new wells will be drilled over the next few years. Four production wells and one well for reinjection of drill cuttings was predrilled by the *Maersk Gallant*.

First oil and gas from the new facilities is expected in 2015 with a capacity 70 Mboe/d estimated, according to a Total release.

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Decontamination of mercuryimpacted process equipment

Tests of new chemical solution developed to remove mercury from contaminated hydrocarbon processing equipment during decommissioning deliver impressive results.

Ron Radford and Patrick Laine, PEI

Throughout the oil and gas industry, the impact of mercury in produced hydrocarbons is an emergent issue. This is not only the case for unconventional resource plays but also for conventional plays as they near the end of their economic production and as process systems require decommissioning. Produced mercury ultimately contaminates hydrocarbon processing equipment and transportation systems like those found on offshore production platforms, offshore gathering platforms or subsea pipelines.

The dismantling, removal and disposal of these systems present unique challenges and risks to decommissioning personnel and to marine ecosystems. Global conventions provide guidance for decommissioning of oil and gas facilities in international waters, but specific regulations with regard to residual mercury concentrations in production systems (either as scale or complexed in the grain-boundary of metals) is not currently available.

Mercury adsorbs and chemisorbs to carbon steel surfaces, primarily through amalgamation and diffusion into the scale, making carbon and stainless steel excellent mercury scavengers. Fortunately this process is somewhat reversible depending on many factors.

However, mercury complexed and incorporated into steel surfaces is not easily affected by typical hydrocarbon chemical decontamination chemistries and methods. The research group at PEI has concentrated efforts on understanding sorption dynamics of mercury in steel pipe and in the development of effective chemical decontamination solutions. Pilot studies based on steel coupon samples from impacted pipelines are a key component of evaluating mercury decontamination methods and identifying the most cost-effective technology for application to mercury-impacted pipelines.

Oil and gas companies across the globe are faced with significant decommissioning challenges, including operations in the Gulf of Thailand and Gulf of Mexico (GoM). Particular attention should be considered in decommissioning strategies for process systems previously or currently exposed to mercury-contaminated hydrocarbon streams. Two key considerations required for development of safe decommissioning strategies (including decontamination) are: 1) an understanding of the nature and distribution of mercury along with depth profiles in pipelines and process equipment and 2) consideration of mercury decontamination goals.

Mercury assessment

Decommissioning preplanning should consist of attempts to determine the extent and type of mercury contamination present in process systems and pipelines. It is recommended that operators perform routine mercury sampling and analysis of process streams that include periodic mass flux and loading studies so that a substantial and meaningful body of data exists by the time decommissioning is considered. In situations where production has been shut in, assessment and characterization may consist only of establishing the amount of mercury in steel and remaining process fluids. Assessing the nature and distribution of mercury throughout process systems in this event becomes more challenging and can be based on many assumptions. The probability of negative effects to costs and schedules is directly correlated to the number of assumptions that must be relied upon. Predicting deposition of mercury in process systems can be accomplished by computational modeling; however, models should be verified with process stream mercury concentration data and representative steel test coupons. The appropriate selection of hydrocarbon/mercury removal chemistries, residence times and application methods depends on accurate mass flux, loading and distribution data. Likewise, the integration of data from mercury assessments, mass flux models and mass loading studies provides planners the insight needed to develop appropriate rate decommissioning plans.

Chemical decontamination

A critical step in decommissioning and chemical decontamination planning is determining objectives and establish-



ing measurement performance criteria. Criteria that might be applied to pipeline decontamination are not strictly established or based on existing regulatory requirements. Some may be based on regulations such as decontamination for disposal or recommendations and conclusions from an environmental impact assessment. Most criteria applied to decontamination efforts are based on those established by companies for safe decommissioning and thus related to safety and environmental impact.

Since decommissioning can include temporary measures for systems that may go back into service after some period of time, it is important to note there are some differences in objectives and chemical selection. Chemical decontamination methods and chemistry used to prepare process systems for reuse—i.e. temporary decommissioning—differ substantially from those used for permanent decommissioning of process systems (subsea pipelines that will be abandoned post-decontamination or topside process equipment planned for metals recycling, for example). This is in part because most chemistry that is used to oxidize or otherwise remove mercury from the scale oxide layer and into the steel profile is not suitable for use in equipment going back into service. If the objective is preparation of equipment for reuse, the target may be to remove hydrocarbon-soluble mercury and particulate mercury or to convert mercury to a nonvolatile species rather than removal. Chemistries used to meet decommissioning objectives can consist of strong oxidizers and inhibited acids designed to penetrate the oxide layer into the metal substrate. Total mercury removal is possible for systems scheduled for permanent decommissioning, but as the chemicals used for this purpose are aggressive to mercury, they typically are aggressive to other metals as well.

Recent studies

Two recent projects are briefly described below. An offshore study included a mercury mass loading and chemical reduction component to support decommissioning of a 16-km (10-mile) section of 24-in. subsea pipeline located in the GoM.

A key goal was to develop a set of chemistries that could be used in a chemical pig-train to remove up to 75% of the mass of mercury from the pipeline. Bench scale chemical reduction tests were conducted with test spool coupons from the production platform, gathering platform and dehydration plant to evaluate the efficacy of mercury removal technologies.

Data (mercury mass per area) from test spool coupons were integrated with results from measurement and monitoring of mercury in process and waste streams to develop a robust mercury flux model (production platform to

dehydration plant). A combination of thermal desorption experiments and sequential acid digestions can be used to quantify mass and depth in metallic coupons. Six chemistries (a combination of mineral acids, surfactants and chelants) were tested and evaluated on coupons from the production platform with an average mercury mass loading of 13 g per sq m (per 10.8 sq ft). Coupons were inserted into a Silconert stainless steel chemical reaction chamber and subjected to each test-case chemistry for predetermined residence times while process and chemical parameters were continually monitored.

A second recent study involved an onshore processing facility where experiments were performed on carbon steel test spools collected from process piping subjected to 20-plus years of process conditions. Results indicated the mass loading potential of steel pipe exceeds estimates reported in previously published studies. Research performed on a test spool from a butane process stream measured mercury mass loading rates greater than 70 g per sq m. This is important to note as recent thermal desorption experiments were conducted by increasing temperature over time from 25 C to 400 C (77 F to 752 F) in a quartz-tube furnace. Results indicated field steam-out temperatures are ineffective in removing mercury from steel but may still be effective in volatilizing hydrocarbon-soluble mercury and volatile mercury species.

Functional and molecular speciation of mercury is key. One of the main objectives of this study was the development of a chemical solution and process that would remove hydrocarbon, iron oxide/sulfide scale and mercury in one chemical step.

This study was successful in meeting objectives, including the development of a chemical solution that was 99% effective in removing mercury down to 1 mm over four hours of residence time at 60 C (140 F).



A thermal desorption chamber is used to induce desorption of mercury from steel test coupons cut from hydrocarbon process systems. (Source: PEI)

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Bakken remains hot topic for US operators

Conference panelists discuss the ever-increasing production activity in the Bakken.

STAFF REPORT

The Bakken is easily one of the most important sources of oil in the U.S. and is located in eastern Montana, western North Dakota and parts of Saskatchewan and Manitoba, Canada, in the Williston Basin. Oil was first discovered in the play in 1951, but operators' profits didn't start booming until the past decade when operators began using horizontal drilling.

The Bakken region accounted for a little more than 10% of total U.S. oil production in November 2013, according to the U.S. Energy Information Administration (EIA). Furthermore, Wood Mackenzie predicts that oil production in the North Dakota and Montana sections of the Bakken and Three Forks formations will grow to 1.7 MMbbl/d in 2020.

While that goal hasn't quite been met, North Dakota Bakken oil production was 914,003 bbl/d in March 2014 with 7,240 producing wells (126 bbl/d of oil per well), according to the North Dakota Department of Mineral Resources. According to February 2014 data on the EIA website, North Dakota is the second largest oil-producing state in the U.S. behind Texas.

In an April 2013 assessment, the U.S. Geological Survey (USGS) estimated mean undiscovered volumes of 7.4 Bbbl of oil, 190 Bcm (6.7 Tcf) of associated/dissolved natural gas and 530 MMbbl of NGL in the Bakken and Three Forks formations in the Williston Basin. This represents a significant increase over the estimated mean resource of 3.65 Bbbl of undiscovered oil in the Bakken Formation released in a 2008 USGS assessment.

At Hart Energy's recent DUG Bakken and Niobrara conference in Denver, multiple presentations, panels and sessions focused on the increasing activity in the plays.

Technological improvements

Harold Hamm, the CEO of Continental Resources Inc., said he's excited about the constant innovation happening in industry technology. "In 2000, we were running out of oil and gas, and then along came technology—horizontal drilling—and that saved us," he said.



Harold Hamm, chairman and CEO of Continental Resources Inc., discussed the importance of technological improvements to drive Bakken growth at Hart Energy's DUG Bakken and Niobrara conference on April 3 in Denver.

In a speech at the conference, Hamm expressed his confidence in technology's ability to solve future problems as it has in the U.S. for centuries.

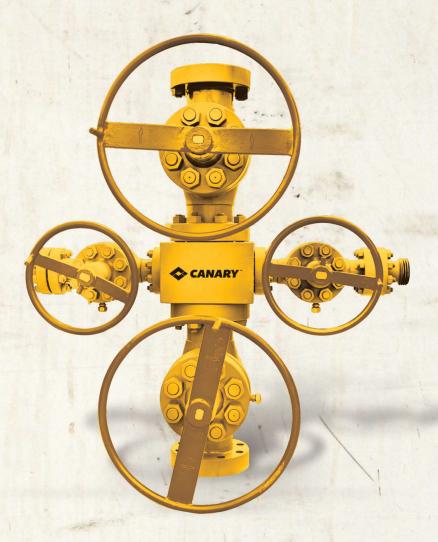
Technology certainly has had a hand in the success of Continental Resources. According to Hamm, dynamic company growth has been fueled by completions and production in two areas where horizontal drilling technology has made a difference—North Dakota's Bakken and Three Forks and the South Central Oklahoma Oil Province (SCOOP) area in Oklahoma.

In 2007, Continental's Bakken production was 8,580 boe/d, and in 2013 it was 88,250 boe/d.

"Back in 2009, people would ask us about how much of the Bakken has been developed so far, and I said back then maybe 12% to 13%," Hamm said. "Now with the Three Forks and the lower benches, you can just about double the amount of wells being drilled. I'd have to say that now we're less than 10% developed."

Continental's Hawkinson project is a new Three Forks development, and the company just completed an industry-first 402-m (1,320-ft), four-formation density test. At

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Hawkinson the 14-well program is underway, and other tests are currently drilling or in the completion stage. Formations to be tested include Tangsrud, Rollefstad, Wahpeton, Mack, Lawrence and Hartman, with the concept of 402-m spacings vs. 201-m (660-ft) spacings.

The company had about a 14,000 bbl/d initial rate from the prospect, Hamm said.

In 2009, the company had a goal to triple production during the next five years. "We accomplished that in about three and a half years," he said. "Our next goal is to again triple production over the next five years, and that would put us at more than 300,000 boe/d and about 1.5 billion [barrels] on crude reserves.

"However, one of the biggest challenges remaining for the Bakken is infrastructure. We'd like to see the According to Chris Wright, CEO of Liberty Resources, "My personal belief is that the sometimes myopic vision of well costs using well as a unit cost as opposed to perbarrel cost has led to massive lost value opportunities in the Bakken. There's just huge EUR upside. Most Bakken operators could increase their EUR by 50%.

"Fracturing is a different game now. Most of the changes in expenditures are not to buy more of the same thing but to spend more to increase frack intensity. The job, to us, is to bring our plumbing to get out as much oil as we can."

One of Liberty Resources' early clients, Brigham Exploration, made great gains by using greater fracturing intensity than other nearby operators. In one of the areas where it was operating, it had 50% more EUR than



From left to right, Richard Mason, chief technical director at Hart Energy, discusses completions and cost control with Tom Lantz, COO of American Eagle Energy Corp.; Chris Wright, CEO of Liberty Resources LLC; Francisco Fragachán, director of sales and marketing for pressure pumping at Weatherford; and Adam Anderson, vice president for the Western U.S. at Baker Hughes.

president and Congress pass the Keystone pipeline legislation, but we don't think it will happen before 2016 and the elections. We think it will have to be built at some point, and we like to think that the president would include the passage of this pipeline as part of his legacy."

Improved efficiencies

With the dramatic transition during the last decade from vertical wells to horizontal wells on single pad sites, a panel of E&P professionals said operators should now focus on finding the best ways to get more from each hole they put into the ground.

its neighbors, and in its "better areas" it had 60% more uplift vs. the average of its neighbors.

"If we increase our well EUR in our area by 10%, it's a \$2 million increase in the PV-10 of that drilling location," Wright said. "A 50% increase is a \$10 million increase in PV-10 of a drilling location for spending an extra few million."

Francisco Fragachán, director of marketing and sales for pressure pumping for Weatherford, warned about steep production declines and wondered, "Is this due to reservoir quality or completion quality? EIA data indicate that sustained production from a rig point of view is that it takes 2.5 'rig times' to sustain production.

"It's an indication that there are opportunities for us to improve our completion effectiveness vs. efficiency. When you look at Eagle Ford statistics, it says that only 64% of the clusters are contributing to production. There's a space for improved production and drainage."

Adam Anderson, vice president of Western U.S. for Baker Hughes, agreed. "It strikes me how little we know about what we're doing with so many of these formations. In terms of frack effectiveness, I think the prevailing wisdom is shifting toward more frack effectiveness, and in simple terms, we need to break more rock."

Tom Lantz, COO of American Eagle Energy, said, "Bigger is not necessarily better, and I think it remains to be seen what the optimum design looks like, including refracturing, and we have to recognize the importance and variability, which will lead to different designs.

"Production from operators tends to vary across a field. One of the overriding predictors is the geology, and at the end of the day, the variability of each play can end up being part of the overall well production figures."

But more fracking isn't the only answer to improved productivity, Anderson said. "Productivity data in some fields vary, but early on in the Bakken sliding sleeves and openhole technology seemed to make sense and were efficient because of the formation's natural fractures and because of nonpad drilling."

For self-described "small guys" like Liberty, Wright said that "sleeves are fast and efficient, but for our company, which is about dollars per barrel, we've been using plug and perf from the start because our goal is to touch more rock by pumping multiple clusters with a small number of perfs and pumping at a very high rate."

In regard to batch completions, there is a more prevalent trend toward zipper fracks and horizontal stimulation done on pads. Anderson said the trend adds greater efficiency to the operation. "For a service company, it certainly makes more sense to go out and do the operation once instead of waiting on other services," he said.

On the topic of refracturing, Fragachán said that new spacings and perforation sites on the original well make



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a big difference. "We have to get back to some kind of mechanical isolation between stages so you can get better stages to more closely replicate the initial completion," Anderson said.

However, Wright added, "It's hard in a horizontal well compared to older vertical wells because we've got a bunch of stages, and it's tricky and expensive. We got into the Bakken by refracking someone else's well with nine-stage sliding sleeve completions and more than doubled the production, which told me that the Bakken is highly frack-dependent and that most of these wells are short on plumbing."



Jim Volker, chairman and CEO of Whiting Petroleum Corp., said the company is capturing all but 5% to 7% of gas associated with oil production.

Anti-flaring rule in North Dakota

The Bakken Shale has for several years been a strong-hold of crude oil, rocketing North Dakota to second place in the rankings of the oil-producing states. Now the Bakken could add to the already accelerating growth of U.S. natural gas production, according to a recent report from Barclays Commodities Research.

The report cites a new rule in North Dakota that requires producers to cut natural gas flaring by 95% by 2020. In January, North Dakota captured only 64% of natural gas associated with crude oil production.

The report expects the newly captured volumes to result in greater gas output as midstream infrastructure catches up with the rapidly growing play.

"If gas output were to remain at January 2014 levels for the rest of the year and the share of captured gas were to rise from 64% to 75%, the output boost would amount to 140 MMcf/d [4 MMcm/d]," the report stated. "Assuming that production growth matches last year's pace in 2014 but captured volumes rise to 75% over the course of the year, the state's natural gas output could rise 250 MMcf/d y/y [7 MMcm/d year-over-year] in 2014. Similar production growth and a further increase of captured volumes to 85% would yield y/y production growth of 330 MMcf/d [9.3 MMcm/d] for 2015."

Gas capture 'the right thing to do'

Whiting Petroleum Corp. has flared down its Williston Basin operations, capturing all but 5% to 7% of gas associated with oil production, according to CEO Jim Volker. That's low, considering the average across the basin is 30%. The environmental payoff is good, but the company also has figured out how to make the newest antiflaring rules pay economically as well.

"We think it's not only the right thing to do for the environment, but it's the right thing to do for the shareholders," Volker said during a question-and-answer session at the DUG Bakken and Niobrara conference. Volker pointed to the company's 50% ownership of the Robinson Lake gas processing plant in the basin, which processes associated gas from both Whiting and from third-party operators. The company typically charges 20% to 25% to third-party companies, Volker said, "just as any midstream company would."

The company is expanding the Robinson Lake plant from 1.4 MMcm to 1.7 MMcm to 2.8 MMcm (50 MMcf to 60 MMcf to 100 MMcf) gas capacity. The economics have been great for the company. "Basically, it's a little like having a 20% to 25% free net operating profits interest in all the other wells that we're gathering gas from," Volker said. "A lot of people think midstream is somewhere typically between an eight- and 10-year payout. I think ours is going to be half of that. So that adds appreciably to the value we've created on that gas."

Another hot topic discussed during the session was longer laterals. When asked if he thought lateral sections could go longer than 3,048 m (10,000 ft), Volker said that it's already happening in the Bakken.

"Over in the Parshall Field east of the Sanish where we're the operator, another operator is going that far and having good success," he said. "I think it's more predominantly a land issue than it is a technical issue. We have the ability to both drill that far horizontally and to frack that far by doing more stages. So there's really no technical limit to that. It really has more to do with the size of the drilling spacing units that you put together originally."



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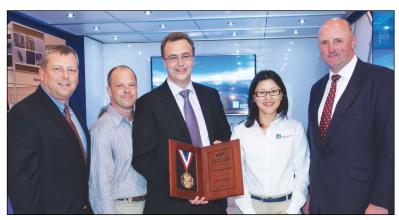
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Lloyd's Register won a drilling award for its BOP risk model. Shown from left to right are Russell Laas, Pieter van Asten, Duco de Haan, Therese Baas and John Wishart.



Evolution Petroleum Corp. won a production operations award for its gas-assisted rod pump technology. Shown are Daryl Mazzanti (left) and Rich Eichler.



Halliburton won a drilling award for its FlexRite multibranch inflow control system. Shown from left to right are Loc Lang, Andreas Grossmann, Rhonda Duey, Gorm Liland and Mac Upshall.



Schlumberger won a production operations award for its PIPESIM steady-state multiphase flow simulator. Shown from left to right are Mark Thomas, Mack Shippen and La Shawnta Beedles.



Schlumberger won a drilling award for its ONYX 360 rolling PDC cutter. Shown from left to right are Chad Harkness, Robert Ford, John Zhang, Mark Thomas, Robert Ledeboer, Malcolm Theobald, Eric Wilshusen and Chuck Muren.



Schlumberger won a field development award for its InSitu viscosity tool. Shown from left to right are Vinay K. Mishra, Mark Thomas and Abhishek Agarwal.



Schlumberger won an HSE award for its CoilScan real-time coiled tubing pipe inspection service. Shown from left to right are Rich Christie, Mark Thomas, Teoman Altinkopru and Andrew Zheng.



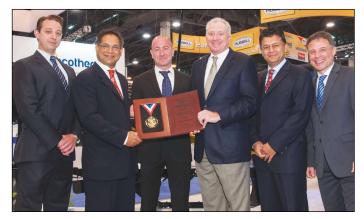
Schlumberger won a completions award for its ELEMENTAL degradable alloy fracture ball. Shown from left to right are Don Aldridge, Manuel Marya, Mark Thomas and Isaac Aviles.



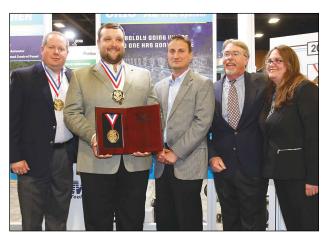
Schlumberger won a drilling award for its MicroScope HD imaging-while-drilling service. Shown from left to right are Mark Thomas, Uchechukwu Ezioba and Emmanuelle Regrain.



Schlumberger won a completions award for its Moment Tensor Inversion system. Shown from left to right are Michael Donovan, Mark Thomas, Joseph Elkhoury and Bill Underhill.



Liquid Robotics Oil and Gas, a joint venture with Schlumberger, won a systems integration award for its Wave Glider technology. Shown from left to right are Chris Carter, Sudhir Pai, Mark Thomas, Rod Nelson, Saqib Zia and Fabian van der Werth.



Team Oil Tools won a completions award for its ORIO XL frack sleeve. Shown from left to right are Michael Harris, Kenny Anton, Stephen Chauffe, Byron Cowart and Amy Logan.

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Baker Hughes won an HSE award for its bifuel fracturing service.

Shown from left to right are Scott Lambert, Jad Lutfi, Pierce Dehring,
Scott Weeden, Harold Brannon and Douglas Stephens.



Baker Hughes won a drilling award for its SeismicTrak seismicwhile-drilling service. Shown from left to right are Randy Gold, Amr El Hosary, Holger Mathiszik, Scott Weeden, Howard Simpson and Mathias Schlecht.



Baker Hughes won a drilling award for its IRev infinite revolution impregnated bit. Shown from left to right are Dean Fuller, Chris Charles, Robin Robinson, Scott Weeden, Johnathan Howard, Connie Burch, Edwin Reek and Dave Watson.



Baker Hughes won a systems integration award for its WellLink Vision mobile application. Shown from left to right are Bryson Wolfe, Kurt Surine, Marina Nance, Sven Haberer, David Smith, Darrin Willauer, Rustom Mody, Scott Weeden, David Craig and Tommy Denney.

AWARD PRESENTATIONS NOT PICTURED

PGS TOWED STREAMER EM 10m Dual-sensor Seismic Streamer 20m EM Streamer Water depth < 400m

GEOSCIENCES WINNER

The electromagnetic streamer has 44 configurable dipole receivers increasing in length with offset to maintain a high signal-to-noise ratio. The dual-sensor seismic streamer provides deghosted receiver data for optimum results. (Source: PGS)

HSE WINNER DET-TRONICS FLEXSONIC ACOUSTIC GAS LEAK DETECTOR

The FlexSonic acoustic gas leak detector operates on the principle of sound analysis of both amplitude and frequency across the full sound spectrum. (Source: Det-Tronics)



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Tool cuts tubulars without chemicals, explosives

Cutting-wheel design can reduce nonproductive time and improve efficiency of pipe recovery operations.

Mary Hogan, Associate Managing Editor

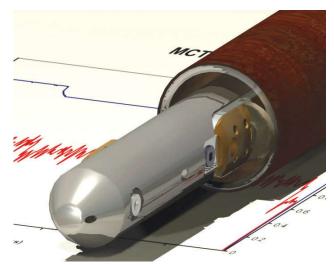
When Weatherford first introduced its Motorized Cutting Tool (MCT), the technology was able to cut downhole tubulars without using chemicals or explosives. Able to make multiple cuts per run, the tool also can cut in any deviation and facilitates fishing by displacing the tubing cleanly. "The rolling cutting wheel works with hydraulic pressure to actually displace the material of the tubulars, leaving a smooth cut without flaring or debris," according to Weatherford's website.

The tool won Hart Energy's 2009 Meritorious Award for Engineering Innovation in the remediation category.

While traditional cutting methods can have low reliability and can present considerable risk to wellsite personnel, the MCT electrohydraulic tool is the safest and most efficient device of its kind in the industry, according to Weatherford's website. The tool provides real-time feedback and monitors data from the surface for a positive indication that the cut has been made before coming out of the well.

"Our industry has progressively considered and evaluated the transportation and handling of hazardous substances in view of environmental and security concerns," said John "JW" Segura, global product line manager of perforating, pipe recovery and mechanical services for Weatherford. "The Weatherford Motorized Cutting Tool addresses the need for mechanical devices that can replace explosive and chemical products to sever small tubulars in regions where we and our clients recognize the necessity for such a product."

Since its introduction, the tool has experienced much success in worldwide operations. The MCT-A 1.69-in.-diameter cutting tool now provides about 40 cuts per year in Weatherford's Italy operations alone. "Weatherford's Italian clients ask for the service specifically because of the ease of operation and the quality of the severed top of the pipe," Segura said. In California, Chevron recognized the MCT-A as a premium cutting device that reduced the amount of hazardous chemicals



Weatherford's MCT cuts downhole tubulars without using chemicals or explosives and is able to make multiple cuts per run. (Source: Weatherford)

used at its locations and shared its approval on a Weatherford Real Result.

Following a successful commercialization of the MCT-A, Weatherford continued on a path of additional mechanical services that include an MCT-B version for larger tubulars. "Currently, the MCT-B cuts 3.5-in.-diameter tubing with plans for extending the cutting range further," Segura explained.

The tool remains a leader in its category and has not been eclipsed by newer technology. "There are other cutting devices on the market but none that cut in the range of pipe the Weatherford MCT performs well within and none [that have] the utilization frequency of the MCT," Segura added.

The company is currently working on commercializing additional mechanical service products, including well isolation devices for tubulars and casing-throughtubing services. "Additionally, Weatherford continues to provide technology in other pipe recovery services, including Free Point Indication and ultradeep well pipe recovery," Segura said.

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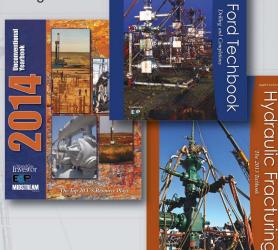
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Failure is not an option

Systems engineering practices are just as applicable to the oil and gas industry as they are to aerospace.

Carri Karuhn, Aerojet Rocketdyne

or more than 70 years Aerojet Rocketdyne has conquered some of mankind's greatest challenges in space, on land and at sea. It has provided rocket engines for more than 1,600 launches since the inception of the U.S. space program, including the Apollo mission that landed the first humans on the moon. The company's space shuttle engines helped successfully launch crew and cargo to the International Space Station (ISS) 135 times, a flawless record of success. Its propulsion systems also have played a vital role in placing commercial, military and government satellites into orbit and have powered space-probe missions to nearly every planet in the solar system.

The Mars Curiosity rover is presently moving around the surface of the red planet performing valuable experiments to determine whether life could have existed there thanks to a power source developed by the company's engineers.

What about the energy industry?

When Aerojet Rocketdyne set up a booth at the Offshore Technology Conference in Houston in May, it's no wonder the most common question was, "What are rocket scientists doing at an offshore oil and gas show?"

The company is using its engineering expertise to reduce downtime by increasing reliability, enhancing safety and developing fault-tolerant operations.

"The aerospace and offshore oil and gas industries have a lot in common in terms of being able to successfully work in extreme environments under the most harsh conditions, including extremely high pressures and temperatures," said Mike McKeon, program director of Extreme Engineering at Aerojet Rocketdyne.

The rocket engine manufacturer is not new to the industry. For the last 14 years Aerojet Rocketdyne has been bringing its systems engineering expertise to the oil field, helping drillers, operators and equipment manufacturers solve problems and reduce downtime, from correcting drilling systems and dynamic positioning problems to resolving issues with well control systems.

Having already applied expertise to systems spanning the seafloor, production and deepwater drilling rigs, Aerojet Rocketdyne engineers also have served as an objective third party to identify root and contributing causes and recommending systems safety and reliability risk mitigation strategies to address issues affecting the rigs in question.

"Systems engineering takes a high-level look at the program and then orchestrates the overall program," said McKeon. "You start by looking at a rig as one large system with many contributing systems—the drilling system, the power system, the vehicle-management system. You define the function of each system, document their requirements and then proceed with synthesizing and testing them to ensure they are all integrated and working together. This occurs from the conception of a rig to oil production."

Space station on Earth

McKeon likened the complexity of a rig to the ISS, which Aerojet Rocketdyne helped design and develop. For example, the power system on the ISS feeds everything else—from the environmental and life-support systems to the vehicle control system. This makes it imperative that the power system interfaces properly with the other systems. This requires control documents—a certain set of detailed requirements and testing. Because robust systems engineering technology was built into the station, it has operated continuously 354 km (220 miles) above the Earth since its first components were launched in 1998.

"Like most everything in the space industry, failure is not an option," said McKeon. "It's not like you can call a maintenance truck and have it there within the hour if something goes wrong. Same with a rocket launch. There's nowhere to pull over on your way to space. All the systems must fit together, work together and be designed correctly. Oil rigs have interfaces that need to be managed in the same way. We bring that aerospace rigor and discipline to the offshore oil and gas industry, where failure also is not an option."

David Haas, deputy program director for extreme engineering at Aerojet Rocketdyne, used a phone system as an example. "Consumers demand certain requirements on a phone," he said. "When it rings, they need to be able to answer it, speak into it and hang up. But the phone also needs to be designed and tested against detailed requirements. Will it work in temperatures greater than 120 F



[49 C]? Is it required to work after a drop? At what height? And if it falls in the water, at what pressure will it continue to operate? Detailing requirements is key to testing."

With increasing dependence on robotics and automation, Haas predicted the offshore oil and gas industry will need systems engineering even more, especially as it begins operating in extreme depths.

Reducing downtime

Aerojet Rocketdyne recently brought its approach to a major drilling contractor that was losing millions a year due to system downtime on offshore rigs operating across the globe. The problems were myriad—from hydraulic leaks and valve malfunctions to solenoid failures and water seepage in electronic equipment deep below the ocean surface. The contractor contacted the company to identify the root causes and recommend solutions to the issues.

Aerojet Rocketdyne engineers identified several contributing factors, including a lack of upgrades to the baseline system as it began drilling in deeper water and experiencing higher well pressures. In addition, the delivered systems had been built independently of one another, not designed from a concise set of top-level requirements. Furthermore, data from previous incidents had never identified the root causes of the downtime so that the problems could be addressed properly.

Aerojet Rocketdyne engineers provided a systems engineering focus such as working with the contractor to document every state of the system from the beginning of its life cycle to the end. This could include, for instance, recording how many times a valve is opened or closed or the kind of environmental conditions the system had endured, from extremely high temperatures to low pressure. "Those identifiers will ultimately help predict maintenance and repairs before the system stops working properly," said McKeon.

"The team also identified ways to detect, isolate and recover from a system failure much faster. In all, the customer indicated that the systems engineering focus applied by our engineers may reduce system downtime by as much as 40%."

Aerojet Rocketdyne also is collaborating with Scotlandbased Kelvin TOP-SET to reduce cost and potential downtime. In 2012, for instance, a major offshore production platform was experiencing a problem. The rig had been impacted by failures, resulting in a series of emergency shutdowns. Not only were the shutdowns costly, but they were potentially deadly as well.

Surface and subsurface safety values on its production wells had failed to close, opening the possibility of a chain reaction that could have resulted in catastrophic platform failure, causing a major spill, multiple fatalities, regulatory fines and penalties, and a tarnished reputation.

Aerojet Rocketdyne and Kelvin TOP-SET were asked by the oil company to identify the root causes and recommend solutions to the problems. Together, each company brought its own expertise.

The two companies identified a number of issues. For instance, Aerojet Rocketdyne identified design flaws; data retrieval issues; use of nonoriginal equipment manufacturer parts; and deficiencies in maintenance, internal communications, control-room monitoring, operating procedures, operations readiness and assurance, control instrumentation reviews, risk assessment skills, and staff competence at critical failures.

In addition, Aerojet Rocketdyne identified insufficient understanding of major accident hazards and incident reporting as well as fatigue and difficulties in coping with increasing workloads.

Kelvin TOP-SET's investigation and root cause analysis, meanwhile, discovered a lack of operational readiness prior to start, work priorities misaligned and insufficient resource capability due to unattractive employee value proposition for remote extreme work locations.

The two companies offered their recommendations, which were implemented, enabling the offshore production platform to keep workers safe, avoid a future disaster and potentially save millions in downtime.

David Ramsay, president of TOP-SET, said he is convinced of the value of using rocket science extreme engineering in the offshore environment. "It doesn't take a rocket scientist," said Ramsay. "But it helps."



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Submersion and directed flow cooling solution for oil, gas

Immersion cooling technology can save energy and space and enhance reliability.

Herb Zien, LiquidCool Solutions

The global energy infrastructure is embracing digitization as offshore drilling rigs, shale platforms and refineries realize the importance of replacing simple pressure gauges and flowmeters with digital sensors and high-speed communications networks to move real-time data back to headquarters.

While new technologies are improving safety and productivity, the industry quickly is realizing the numerous failure points that make legacy technologies unsustainable for upstream facilities. Oilpatch computing systems require hardening to survive extreme temperatures, salt air, dirt and other pollutants. Additionally, every kilowatt-hour of electricity converted to heat needs to be dissipated and the waste energy recycled.

Keeping cool

The usual method of cooling electronics by circulating air around components achieves none of these objectives. Fans used to circulate massive amounts of air waste energy and expose computing equipment to corrosion and air pollutants. Mechanical refrigeration systems to maintain humidity levels and cool equipment in hot weather conditions require maintenance and waste even more energy.

Liquid cooling, if applied intelligently, can be an ideal solution, but not every approach to liquid cooling is applicable to oil and gas industry conditions. Cold plates, which are water kits installed directly on processors in the computer chassis, do not save much energy and invite

trouble when a leak occurs. Cold plates were developed to move heat away from hot chips but only use liquid to remove some of the heat. Fans still are needed in the computer chassis to finish the job. The pumps, fans and heat exchangers in each computer case are subject to failure.

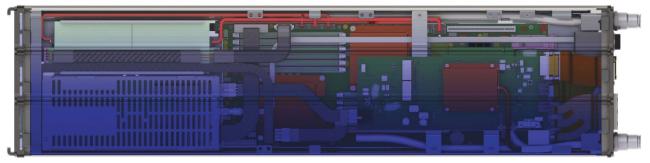
Other cooling solutions meant for extremely high-density systems involve refrigerants that remove heat by evaporation. This refrigerant vapor then needs to be condensed. These two-phase systems add complexity and cost and do not add much value unless rack power densities exceed 100 kW.

If the thermal load is less than 100 kW per rack, a single-phase cooling system where all electronic components are submerged in a nonconducting dielectric liquid is a viable alternative. This technology decouples electronic components from the environment and offers a long list of important benefits for oil and gas applications. There are no moving parts or heat exchange barriers in the information technology (IT) device chassis; electronics are isolated from oxidation and air pollution; there is no noise, vibration or extreme temperature fluctuation; fans and mechanical refrigeration are eliminated; there is no need for humidity control; and heat is recovered in a convenient form for recycling.

Considering options

When considering total immersion systems, there are three main considerations: scalability, maintainability and cost efficiency. The devil is in these details.

There is a system on the market that resembles a rack tipped over on its back with modified servers inserted



LiquidCool Solutions' Total Liquid Submersion Server is shown. (Source: LiquidCool Solutions)



	Air-Cooled Systems	Cold Plates	Two-Phase Refrigerant Systems	Tipped Rack Tank Version	Two-Circuit Approach	LiquidCool Solutions
Ship by transport plane	Yes	Yes	Yes	No	Yes	Yes
Rapid setup in the field	No	Yes	No	No	Yes	Yes
Fans required	Yes	Yes	No	No	No	No
Mechanical refrigeration required	Yes	Yes	No	No	No	No
Humidity control required	Yes	Yes	No	No	No	No
Energy usage	High	High	High	Low	Low	Low
Hardened for extreme temperatures	No	No	Yes	Yes	Yes	Yes
Hardened for polluted air	No	No	Yes	Yes	Yes	Yes
Ability to distribute computing resources	No	No	Yes	No	Yes	Yes
Ability to recycle waste heat	No	Yes	Yes	Yes	Yes	Yes
Water in the white space	No	Yes	No	No	Yes	No
User-friendly rack management	Yes	Yes	No	No	No	Yes
Easy to maintain	Yes	No	No	No	No	Yes
Scalable	Yes	Yes	No	No	Yes	Yes
Cost efficient	No	No	No	No	No	Yes

This table summarizes the benefits and challenges associated with the universe of cooling solutions for oil and gas applications. (Source: LiquidCool Solutions)

vertically into slots in the tank. The tank is filled with a coolant similar to mineral oil. This approach requires a relatively large amount of floor space, which limits mobility and scalability in a multirack environment, and the system is not fully sealed, which leads to fluid contamination in certain environments. Moreover, the system is heavy and must be assembled in the field, making its deployment for most oil and gas applications expensive, time-consuming and logistically challenging.

Yet another version includes off-the-shelf mother-boards, which are mounted inside sealed hot-swappable cartridges that are flooded with a dielectric fluid. There is a secondary circuit with water snaking through a channel inside one wall of the cartridge to transfer heat from the dielectric fluid. This two-circuit approach adds cost, introduces water to the white space and interferes with maintenance.

The third version of total immersion combines a sealed enclosure and standard-size rack, an approach that places special emphasis on scalability. Additionally, the design makes it possible to cool any electronics, not just servers. By placing special emphasis on equipment maintenance and rack management, it is possible to hot-swap a rack-mounted IT device in less than two minutes without any loss of fluid.

The introduction of immersion liquid cooling technologies has been delayed by a perception that the equipment is expensive, difficult to maintain and messy.

Examining the myths:

- *Cost.* As long as liquid-cooled IT devices are manufactured a few at a time, they will cost more than air-cooled devices that are produced by the thousands. In fact, immersion cooling systems have no moving parts in the IT device chassis and, if properly designed, could cost less to manufacture when produced in volume.
- Maintenance. Fans are the root cause of most IT equipment failures, either because the fan itself fails or exposure to air causes electronic components to degrade. Eliminating fans reduces the amount of maintenance required. Additionally, rack-based immersion systems generally are designed to hot-swap devices quickly.
- *The mess.* In immersion cooling, electronics touch liquid, which is why this technology reduces the power to cool by more than 90%. So there will be some residue when an IT device is removed from a rack. However, proper maintenance procedures eliminate any mess.

When comparing the value proposition with legacy air systems or other forms of liquid cooling, immersion cooling saves energy and space, enhances reliability, operates silently and is easy to maintain in the field. Immersion cooling systems also simplify upgrades because there is enough cooling capacity in the chassis for future heat loads and only the internal boards need to be changed. Immersion systems cost less too, both up front and over time.

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Pump reduces maintenance downtime, increases rod load

Weir Oil & Gas released the SPM TWS600S HD pump, engineered to reduce downtime due to maintenance while improving rod load and high-pressure capabilities, according to a product announcement. The pump increases rod load by up to 6% when compared to the conventional TW600S pump to achieve a 15,000-psi rating with a 3-in. plunger or 20,000 psi with a 2.5-in. plunger and eliminates fluid-end proppant contamination potential in the power end, which increases power end seal life. The company has removed 10 lbs of reciprocating weight per cylinder compared to the previous generation pump while maintaining design safety factors. Lubrication has been improved through the use of a ported crankshaft and ventilated shell bearing, and maintenance time has been reduced by eliminating the necessity to remove the diaphragm seal to remove the packing nut. The technology can be retrofitted into existing pumps without modification. weirinaction.com

Mud skip/cutting box makes transport of drilling waste safe, efficient

Hoover Container Solutions, a subsidiary of Hoover Group Inc., has launched a new DOT/DNV-certified mud skip/cutting box for transportation and safe handling of hydrocarbon-contaminated drill cuttings to and from offshore platforms. The mud skips/cutting boxes have patented sliding doors and a removable crank handle, and the units provide a safe and efficient means for containment of drilling waste for transportation to treatment or disposal sites, according to a company press



Hoover's new DOT/DNV-certified mud skip/cutting box has a patented roll-back lid to prevent the need for individuals to climb on the units. (Source: Hoover Container Solutions)

release. The units are designed and manufactured to DNV 2.7-1/EN 12079/DOT 49CFR176.340 standards and have certified slings complete with shackles in accordance with DNV 2.7-1/EN 12079 standards. The design of its patented roll-back lid prevents the need for individuals to climb on the units, reducing the risk of accidents. It is equipped with two 4-in. ports available for vacuum services and a pressure relief valve. The units are stackable with standard drainage capabilities and have large sealed lids that allow units to be filled to maximum capacity while preventing spillage. hooversolutions.com

Autonomous MVT uses 5,000% less energy than traditional transmitters

Newgate Instruments has introduced the JT400, a new multivariable pressure transmitter (MVT) for pipeline monitoring and measurement that uses 5,000% less energy than traditional MVTs, according to a company product announcement. The new technology is an autonomous MVT that provides accuracy and offers analog/digital input/output, a local USB port for downloading data and up to 12 years of battery life with no recharging needed. It also has an explosionproof housing. The JT400 The JT400 MVT has a battery is solar-powered but can operate up to 200 days without sunlight, and it is constantly working, log-



life of up to 12 years with no recharging needed. (Source: **Newgate Instruments)**

ging data of 15-minute averages up to 30 days for periodic transmission or local download. The MVT is compatible with all pipeline equipment and can be installed to replace existing transmitters or on new natural gas wells. newgateinstruments.com

Drilling motor completes vertical, curve, lateral in one run

Baker Hughes launched the Navi-Drill Ultra Curve drilling motor to drill high-build rate curves with predictable and reliable directional control in horizontal



shale plays. The motor features reduced bit-to-bend length and improved toolface control, giving it the ability to complete the vertical, curve and lateral in one run, exposing more of the reservoir and increasing well efficiency and productivity, Baker Hughes said in a press release. Because the steerable motor has a smaller adjustable kickoff angle requirement, it can provide higher and more consistent buildup rates in the curve section and effective rotation for high performance in the vertical, tangent and horizontal sections. It also delivers precise directional steering control through the lateral section. The Ultra Curve motor extends footage and ROPs in the vertical section and improves the performance and directional consistency in the build section of wells, enabling more precise wellbore placement, improving overall drilling performance and reducing well costs, according to Baker Hughes. bakerhughes.com

Mobile BWT system provides alternative to retrofitting fixed systems

The fully containerized mobile InvaSave ballast water treatment (BWT) system from Damen Shipyards Group provides ship owners with a cost-effective alternative to retrofitting fixed BWT systems, according to a Damen press release. Ship owners sometimes do not want to retrofit a BWT system if their ships operate on fixed routes or their ships are old, making the system prohibitively expensive, said Gert Jan Oude Egberink, Damen's manager for BWT. Ports also may need to provide backup in case a ship's onboard treatment systems fail. The mobile solution means ballast water only needs treating at the point of discharge compared to fixed onboard BWT installations that also need to treat ballast water at intake. The company can deliver the system as a separate mobile container, which can be put on board or moved around the port on a truck. The system has been successfully tested in the waters of the Wadden Sea and the

Wrench system improves safety in makeup, breakout of flowline connections

IJsselmeer in the Netherlands. damen.com

The Superior Safety Wrench System (SSWS) from Concentric Pipe and Tool Rentals LLC, a Superior Energy Services company, is a next-generation tool designed to eliminate the use of sledgehammers in the makeup and breakout of high-pressure temporary flowline connections, the company said in a press release. The SSWS—for land and offshore operations—is composed of two main parts: a heavy-duty aluminum wrench-style head

and a quick-latch adjustable torque-assist device. The wrench head adjusts from 1 in. to 4 in. to create an even distribution of impact load on all three union lugs. The quick-latch feature evenly distributes torque, allowing the union to contact the seal evenly without compressing or compromising the seal, and it extends 14 in. to 22 in. in length. The SSWS includes safety features and provides a cost-efficient alternative to similar tools, the release said. Its design eliminates the risks of sledgehammer use such as injuries from swinging sledgehammers with poor form, holding a target while it is hammered, releasing sledgehammers midswing and fragmenting because of a worn-out sledgehammer or target. The efficiency of the system also can reduce rigup and testing time. concentricpipe.com

Hydraulic jar ensures performance in high-debris environments

Peak Well Systems launched the Peak Hydraulic Jar with an inverted upstroke feature for high-angle standard wireline or wireline fishing operations when installed as part of a standard or fishing toolstring, the company said in a product announcement. The jar's design ensures minimal debris influx during upstroke to achieve high performance even in high-debris environments. The internal workings of the hydraulic jar are located in the upper section of the assembly; any debris that enters the outer housing falls to the bottom of the tube and away from critical working components. The hydraulic jar can be deployed with other Peak products for variable and sustained jar forces and performance in high-angle deviated wells. The jar has minimal working parts, making it simple to redress in the field. <code>beakwellsystems.com</code>



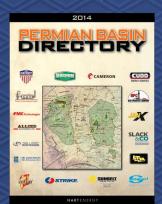
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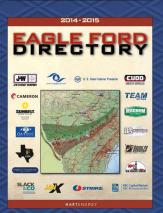
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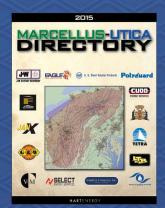
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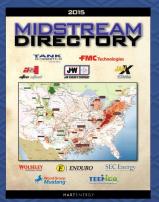
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Money, hydrocarbon flow continues in Middle East

Despite the risks, the region's proven hydrocarbon reserves continue to attract.

Velda Addison, Associate Online Editor

ention the Middle East and the words "persistent instability" may come to mind.

But the region with perhaps the greatest risks has the most to offer—conventional oil and gas assets with budding unconventional opportunities that have some companies loosening grips on clenched wallets.

Pockets of safe places to operate have emerged, as has the realization by some Middle Eastern countries that fiscal changes are needed to hold the attention of oil and gas companies, especially considering there are more E&P opportunities worldwide than available capital. Favorable geological characteristics combined with the supply-altering potential of massive discoveries—such as in the offshore Levant Basin and Persian Gulf—is the region's cash flow assurance. Barclays predicts spending in the Middle East will outpace others in the firm's 2014 Global E&P Spending Outlook.

Research revealed E&P spending stood at about \$10 billion in 2007, then skyrocketed to about \$25 billion in

2008 but began to descend, landing at about \$18 billion by 2010. Spending has since steadily climbed, nearly reaching \$35 billion in 2013, with the 2014 estimate at about \$40 billion. Barclays said the Middle East will again be the fastest-growing oilfield services market at more than 14% in 2014, with Latin America and Russia following closely behind.

"Activity is likely higher than originally forecast, especially in the key markets of Saudi Arabia and Iraq," James West, oil services and drilling analyst for Barclays, told $E\mathcal{E}P$ in June, about six months following the outlook's release. He believes $E\mathcal{E}P$ spending could surpass 2014 levels by 10% to 15% in 2015.

Among the region's big spenders this year are Saudi Aramco and Kuwait Oil Co., which each plan to increase spending by 20%, as E&P spending by select Middle East companies continues to increase. Qatar Petroleum also recently announced that it will invest about \$10.6 billion to redevelop the Bul Hanine offshore oil field with hopes of reversing declining production and doubling oil production by use of IOR and other techniques. In addition to new offshore production and onshore liq-

uids processing facilities, the plan includes a drilling campaign of about 150 new wells through 2028.

The graph shows worldwide E&P spending. (Source: Barclays)

	2013A	2014E	+/-	%
U.S. Spending	143,989.3	156,163.6	12,174.4	8.5%
Canada Spending	41,738.2	43,068.8	1,330.6	3.2%
North America Spending:	\$185,727	\$199,232	\$13,505	7.3%
Middle East	34,791.0	39,812.0	5,021.0	14.4%
Latin America	74,590.0	84,159.0	9,569.0	12.8%
Russia/FSU	53,940.1	59,844.0	5,903.9	10.9%
Europe	46,684.3	50,312.6	3,628.3	7.8%
India, Asia & Australia	120,928.0	124,178.2	3,250.2	2.7%
Majors (Int'l Spending)	113,992.0	115,413.0	1,421.0	1.2%
Africa	25,241.0	25,337.1	96.1	0.4%
North America Independents (Int'l Spending)	19,395.0	18,547.0	(848.0)	-4.4%
Other	6,401.2	6,475.6	74.4	1.2%
Int'l Spending:	495,962.6	524,078.5	28,115.9	5.7%
Worldwide E&P Spending:	\$681,690	\$723,311	\$41,621	6.1%

Iraq

While Saudi Arabia is on course to be the biggest upstream spending by yearend 2014, according to West, concern remains elsewhere.

"We are concerned about oil development in the southern part of the country due to the instability and the exodus of many of the major oil companies; however, we are increasingly positive about development in Kurdistan (in the north) as many oil companies have moved in and an agreement between Baghdad and Kurdistan may come to fruition."

Thorsten Ploss, the Middle East and North Africa oil and gas leader for EY,

essentially sees two Iraqs when it comes to oil and gas development—the Kurdistan region and the rest of Iraq.

"While as a potential region there is still a lot of activity to be done to get back to the old levels, there is a lot of activity happening now to reduce flaring, so they have to revamp a lot of pipelines," Ploss said. "Of course, it is impacted by the security situation, which is not really improving. On the other side, if you look at Kurdistan, which is very safe to operate, the industry is facing issues."

The frenzy of exploration activity in the Kurdistan region—as companies risked breaking ties with the Iraqi government to pursue opportunities in the more stable Kurdistan region—has diminished as the dueling governments continue to clash.

"The companies we talked to are very hesitant because it is unclear how they can get the oil out of the country," Ploss said. "There is high uncertainty within the industry about how companies can capitalize on the crude if they produce it."

He specifically mentioned the recently opened pipeline to Turkey, where more than 1 MMbbl of Kurdish oil was sent destined for Europe. The move came amid continued opposition from Baghdad, with the Iraq Ministry of Oil, calling it an "illegally smuggled shipment." The government in Baghdad said it must approve all energy-related transactions. However, the Kurdistan Regional Government has taken charge of oil and gas resources in that area, claiming Baghdad has not given the region enough money.

The uncertainty has shaken investors' confidence. While Iraq has the world's fifth largest crude oil reserves, having surpassed Iran in production in OPEC in 2012 based on U.S. Energy Information Administration (EIA) estimates, the region could fall short of its 4 MMbbl/d by year-end goal due to political disputes and infrastructure constraints.

Iran

In neighboring Iran, where oil exports plummeted due to U.S.- and EU-imposed sanctions following Iran's illicit nuclear activities, talk of easing sanctions could lead to more crude in the market. Total production dropped from 4.2 MMbbl/d in 2011 to about 3.5 MMbbl/d of total liquids—including about 3 MMbbl/d of crude oil—in 2012 due to the sanctions, according to the EIA.

However, Iran appears to be well-positioned to fulfill oil export wishes. The National Iranian Oil Co. reported that oil production will hit 4 MMbbl/d by March 2015. Iran has more than an estimated 560 Bbbl of in-place oil reserves, with about 140 Bbbl of recoverable oil. In May, Iran announced China renewed its crude purchasing

deal that will see the country receive 400,000 bbl/d.

Yet more investment is needed for other major projects, including future phases of the 24-phase, \$60+ billion



Saudi Aramco is expected to lead spending in the Middle East with plans that include continued development of Persian Gulf fields, targeting unconventional gas and unleashing new hydraulic fracturing technology. (Source: Saudi Aramco)

South Pars offshore development. The field is believed to hold about 9.8 Tcm (325 Tcf) of natural gas—more than a quarter of the country's proven natural gas reserves—along with 7.5 Bbbl of proven oil reserves.

If sanctions are lifted, Ploss is confident companies will return given favorable contract terms on the horizon. "What is different now from the old times is that the Iranian government understands that the buyback contracts they had in the past were not beneficial for the industry," Ploss said. "It was only a one-sided benefit—for the government, not for the oil companies. They are now initiating new contracts. It's not only risk-sharing with oil companies, but also it's more profit-sharing with the oil companies.

"There is a clear understanding from what I've heard so far that the Iranian government will change the contract structure. This makes it far more attractive for oil companies."

Added West, "If sanctions on Iran are lifted this year, which we do not expect, this would bring more barrels

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to the market and could force other OPEC member countries to slightly alter their development plans to allow room for Iranian barrels to return to the market, although this would likely only have a marginal impact."

Saudi Arabia

Meanwhile, the region's biggest oil producer continues to make strides in production and technology, with Saudi Aramco leading the way. Saudi Arabia, home to the world's largest oil field—Ghawar with 70 Bbbl of estimated remaining reserves—has set out to boost its gas production. Saudi Aramco has put focus on Persian Gulf fields which include Karan, Arabiyah and Hasbah.

In addition, "There is a strong drive in Saudi Arabia to go into unconventionals because they need natural gas," Ploss said, noting more gas is needed for power generation.

Saudi Aramco is targeting the northwest, South Ghawar and Rub' al-Khali areas for unconventional gas and is devising hydraulic fracturing techniques.

"New hydraulic fracturing technologies are being developed to significantly improve cost efficiency, increase recovery rates, reduce environmental impact and enhance well productivity across shale, deep sandstones and carbonate formations in the Kingdom," Saudi Aramco said in an annual review released in May 2014.

These techniques include pulsed gas fracturing, plasma technology, CO_2 -based fracturing fluid, staged fracturing, microseismic fracturing and an innovative fracture propping concept.

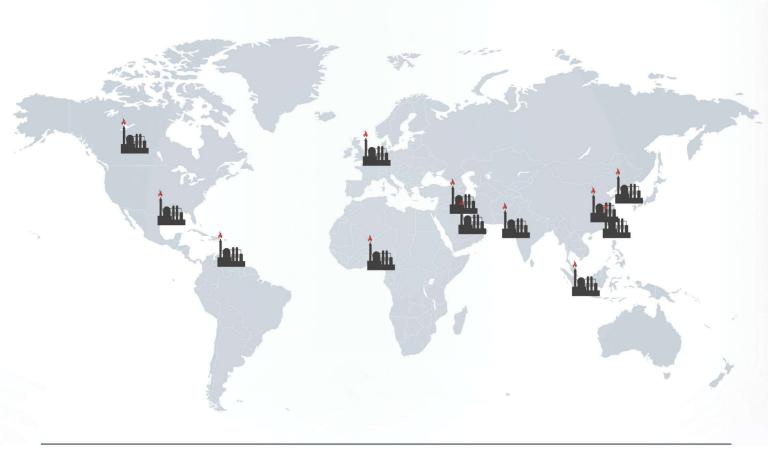
Saudi Aramco aims to maintain spare output capacity of more than 2 MMbbl/d, CEO Khalid Al-Falih said in a Bloomberg article. In the last decade, the company has grown its capital budget tenfold to about \$40 billion.

"What is clear is, if you look at activity, we haven't reached the peak for capex spending," Ploss said. "It will significantly increase. But you have to think in scenarios because if Iran opens up, there will be huge capex requirements."

Add emerging frontier areas such as the Levant Basin and Lebanon, where Ploss said seismic data appear quite promising for gas, to the investment climate of the region's known producing nations, and predicting future spending in the Middle East is comparable to shooting at a moving target.

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Middle East's technology development enters new phase

Innovation and collaboration are keys to ensuring sustainable future.

Dr. Patrick O'Brien and Ryan McPherson, Industry Technology Facilitator

ike several other regions around the globe, the Middle East is facing the challenges of a maturing province. Consequently, technology is set to play an ever more important role—both in terms of the deployment of existing technologies and the development of innovative new solutions.

One of the main challenges facing the region at present is maximizing production from its huge reserves. The United Arab Emirates alone has a production target of 3.5 MMbbl/d. Achieving this will require recovery rates far in advance of the global average, so the use of new processes and innovative technology could play a key role.

Collaboration in technology development has the potential to leverage funding as well as the technical expertise of those involved. This may be particularly important in mature provinces where operators can require new technology in a short time frame to produce small or more technically demanding remaining reserves



GA Drilling's prototype 4-in. diameter PLASMABIT (50-kW power) drilling system generated high levels of interest at the ITF's event in Abu Dhabi. The system is part of a JIP and is based on using focused electric plasma energy. The first applications of this technology are likely to be in operations where steel removal is necessary such as plugging and abandonment. (Source: GA Drilling)

economically. A collaborative approach may be the only cost-effective way to tackle some of the issues.

In addition, as the industry continues to mature, a degree of global convergence with respect to technology needs is becoming apparent. In producing provinces internationally, difficult-to-access reserves require enhanced reservoir characterization, and mature assets present life extension issues. Hence the transfer of technology developed in other regions to the Middle East could have a significant role to play alongside indigenous developments.

Evolving relationships

In the past, activity in the region has been dominated by the national oil companies (NOCs) and the supermajors. Generally there has not been a history of problem-sharing and collaborative working between them.

Over the last 10 years, however, a number of regional research centers have been created in the Middle East, including the Qatar Science and Technology Park, the Petroleum Institute in Abu Dhabi, Sultan Qaboos University in Oman, Kuwait Institute for Scientific Research and King Abdullah University of Science and Technology in Saudi Arabia, all of which work alongside a number of the NOCs, international oil companies and international service companies across the region.

In addition, a broader range of players from around the world are entering the region, including some of the smaller European-based operators as well as others from China and Korea. This shifting landscape has the potential to influence the technology development framework and may help pave the way to new partnerships for collaborative working.

Since establishing a base in Abu Dhabi three years ago, the Industry Technology Facilitator (ITF) has been working to facilitate increased collaboration among operating companies as well as between operating companies and the wider technology development community within the region and further afield.

Technology challenges

ITF's annual general meeting was recently held in Abu Dhabi for the first time, and as part of the meeting some



Ways to improve drilling efficiency are a continuous area of focus around the world. DURA Drilling's high-speed dual-drilling string technology (featuring both an inner and an outer drill-string) was showcased to Middle Eastern ITF members as they look to collaborate on technology that will help enhance the region's reservoir recovery rates. (Source: Dura Drilling)

technology developers currently seeking collaborative support were invited to present to the attendees. One of the technical areas that the meeting focused on was drilling efficiency, including a number of potentially game-changing technologies being showcased.

These included DURA Drilling's high-speed dual-drilling string technology. The system, which comprises an inner and outer drillstring, integrates three technologies: casing while drilling, microhole drilling and high-speed diamond drilling. The company's co-founder, Charley Able, believes the concept complements conventional drilling techniques and will be valuable for wells that are difficult to drill or not viable using conventional technology like low-cost data wells, extended-reach wells and wells that require drilling through basalt or other hard rock types. The company is currently seeking investors and customers with potential pilots and demonstration projects.

GA Drilling presented details of its PLASMABIT drilling system. The contractor previously received funding via the ITF for a feasibility study of continuous casing-while-drilling technology that forms part of the overall PLASMABIT system. The system as a whole is based on focused electric plasma energy and is designed to eliminate sources of tripping and friction, enabling a high ROP in both rock and steel materials.

Industry partners engaged with the ongoing PLASMA-BIT Joint Industry Project (JIP) believe the first applications of the technology are likely to be in operations where steel removal is necessary such as plugging and abandonment. The company is seeking additional sponsors for future phases of the JIP, with the technology generating high levels of interest.

EOR knowledge database

Another discussion topic at the meeting was EOR. ITF has already launched one JIP in the Middle East in this area to create an EOR knowledge database.



A number of the ITF's Middle East-based members have expressed a high interest in CO₂ injection for EOR—an approach with obvious associated environmental benefits already receiving much attention around the world.

However, one of the challenges with respect to EOR in this region is that many currently available technologies have been developed for sandstone rather than carbonate reservoirs. This may be an area in which a JIP could potentially make an important contribution.

Surface Active Solutions (SAS) also presented at the meeting, outlining details of its surfactant-particle technology for boosting EOR efficiency. Proof-of-concept experiments have demonstrated the technical feasibility of using an advanced surfactant-particle technology to increase oil recovery, and it could also result in a significant reduction in surfactant use compared to surfactant-only treatments. SAS has submitted a proposal to the ITF for a project that aims to quantify the increased oil recovery potential vs. treatment costs and derisk commercial use of the surfactant-particle technology.

Produced water

Issues around treatment costs, regulation and water scarcity make produced water a significant challenge in the Middle East.

Another of the technologies presented at the ITF meeting was ProSep's Osorb Media, a reusable solution that removes free, dispersed, emulsified and dissolved hydrocarbons from oilfield water and gas streams. ProSep said the compact system has demonstrated maintaining oil in water levels of less than 5 ppm and generates no waste for handling or disposal. The company is seeking joint industry support for a 12-month project aiming to identify, evaluate, optimize and field-test an offshore media regeneration package.

Last but not least, Sustainable Pipeline Systems Ltd. (SPS) provided details at the ITF meeting of its spiral-wound pipe technology, Helipipe. Onshore pipeline technology currently requires multiple operations with 12-m (39-ft) sections of pipe that are manufactured in a factory, shipped to a coating plant, transported to the construction location and manually welded together. Helipipe offers the potential for significant logistical and cost savings through continuous production of pipe in the field, eliminating the need for manual welding.

Onshore there also is the opportunity to design pipe with sufficient flexibility to eliminate bend stations. SPS is engaged with a number of operators, each interested in different conditions and diameters of pipe. A JIP to begin the process of developing specifications is planned for launching later this year.

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HIGHI IGHTS

For additional information on these projects and other global developments:



AFRICA

Taachui well hits gas offshore Tanzania

Ophir Energy has recorded a new gas find offshore Tanzania with the Taachui-1 ST1 well. Operated by BG Group, the Taachui-1 ST1 has encountered a 289-m (947-ft) gross gas column within a target Cretaceous reservoir with total net pay of 155 m (508 ft). The well was drilled with the *Deepsea Metro 1* drillship close to the western boundary of Block 1. Estimates of the size of the find are up to 28 Bcm (1 Tcf). The well will be subject to a further drillstem test, and a further compartment identified to the west of Taachui has the potential to be of similar size. An appraisal well to confirm this is being considered by the block partners.

Tullow encounters oil in Kenya well

The Twiga-2 sidetrack encountered 62 m (203 ft) of net oil pay in the Auwerwer formation in Northern Kenya, Tullow Oil said in a press release. The initial wellbore was drilled near the basin-bounding fault and encountered 18 m (59 ft) of net oil pay within alluvial fan facies. A decision was made to sidetrack the well away from the fault to explore north of Twiga-1, and the discovery was made. The well is being deepened to evaluate the Lower Lokhone potential, and a testing program for this successful well is planned to be conducted later this year.

ASIA-PACIFIC

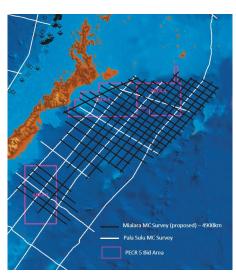
Premier discovers wet gas offshore Indonesia

The Singa Laut-1 well in the Tuna production-sharing contract area offshore Indonesia has penetrated 54 m (177 ft) of net gas-bearing reservoir-quality sands within the targeted Oligocene sequence, Premier Oil said in a news release. Gas gradients have been measured and gas samples recovered. The gas appears to be of similar quality to the liquids-rich gas found in the adjacent Kuda Laut well. The Singa Laut-1 well will be plugged and abandoned as a successful exploration well.

Searcher pursues surveys offshore Philippines

Searcher Seismic has plans to acquire two 2-D seismic surveys offshore the Philippines, one in the West Luzon

Basin and the other in the East Palawan Basin, the company said in a news release. The Pinatubo survey in West Luzon will cover about 4,400 km (2,734 miles)and include coverage over blocks 8, 9, 10 and 11 for the fifth Philippine



The Mialara multiclient 2-D seismic survey is one of two 2-D seismic surveys Searcher Seismic plans to acquire offshore the Philippines. (Source: Searcher Seismic)

Energy Contracting Round. The Mialara multiclient 2-D seismic survey in the East Palawan Basin will cover 4,900 km (3,045 miles), including coverage over bid round blocks 4, 5 and 6.

RUSSIA CIS

Max hits hydrocarbons in Zhana Makat

Max Petroleum has reached a total vertical depth of 997 m (3,271 ft) with its ZMA-E7 development well in the Zhana Makat Field in Kazakhstan, encountering hydrocarbons in Jurassic sandstone reservoirs in line with expectations, according to a company news release. Max plans to complete the well and place it on production as soon as practicable.

MIDDLE EAST

MOL finds oil in Pakistan

MOL's Ghauri joint venture (JV) has made a significant oil discovery in the Ghauri X-1 well located in the Punjab province of Pakistan, MOL said. The company said the potential for the Ghauri Block could be significant but that it was too early to give a forecast for the whole block. The JV is made up of Mari Petroleum Co. with 35% working interest as operator, Pakistan Petroleum Ltd. with 35% and MOL with 30%.

EUROPE

Cepheus well strikes gas in North Sea

GDF Suez has found a new gas resource in the southern





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- Bruce H. Vincent, President & Director, Swift Energy Company







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U.K. North Sea on the Cepheus prospect. After drilling the 44/12a-6 Cepheus exploration well, the operator said a gas column was encountered within a Permian Lower Leman sandstone. Drilling commenced in early March, and the well was deviated northeast from the tophole location in Block 44/12a toward the target location. The site is near the GDF-operated Cygnus Field development, where new platforms are being installed. Drilling at Cepheus was operated by GDF and partnered by Centrica North Sea Gas and Bayerngas E&P.

Claxton lands riser contract offshore Norway

Claxton has been awarded a multiyear contract with Det norske oljeselskap ASA, the largest single riser contract in Claxton's history, a news release said. Running from January 2014 until June 2020 with optional periods of 1+1 year, the contract includes high- and low-pressure



risers, auxiliary equipment and services offshore Norway. The scope of work includes the procurement of high- and low-pressure surface risers for the Ivar Aasen field development; the rental of a Claxton 18¾-in., 7,000-psi subsea riser for the Hanz Field; the rental of 18¾-in., 15,000-psi high and 30-in. low-pressure surface risers for exploration wells on the Norwegian Continental Shelf; options for other field development projects; and HP/HT work during the contract period, the release said.

NORTH AMERICA

COE acquires Canada gas assets

CQ Energy Canada Partnership (CQE), the joint venture between Centrica Plc and Qatar Petroleum International, has agreed to acquire a package of natural gas

assets in the Foothills region of Alberta from Shell Canada Energy for about \$46 million, a Centrica press release said. As part of the transaction Shell will receive CQE's interest in the Burnt Timber gas processing plant and its interest in the Waterton undeveloped lands in southwest Alberta. CQE estimates that the assets to be acquired have 2P reserves of 2.6 Bcme (90 Bcfe).

Royale contracts rig for North Slope drilling

Royale Energy Inc. has entered into a contract for a drilling rig to drill its recently announced North Slope Alaska shale oil play and the large 3-D conventional target announced last week, Royale said in a press release. Kuukpik Drill will provide Rig Number 5 for the full 2014-2015 winter season to drill two wells designed to test both the conventional target and the shale sequence.

GULF OF MEXICO

Apache sells interest in GoM developments

The Gulf of Mexico (GoM) subsidiary of Apache Corp. will sell nonoperated interests in the Lucius and Heidelberg development projects and 11 primary-term deepwater exploration blocks to a subsidiary of Freeport-McMoRan Copper & Gold Inc. for \$1.4 billion. The Lucius unit comprises Keathley Canyon blocks 874, 875, 918 and 919, and the company's working interest is 11.7%. The Heidelberg unit includes Green Canyon blocks 859, 903, 904 and 948, and the company's working interest is 12.5%. Apache's working interest in the 11 GoM primary-term blocks ranges from 16.67% to 60%. None of the company's producing operations are involved in this sale.

SOUTH AMERICA

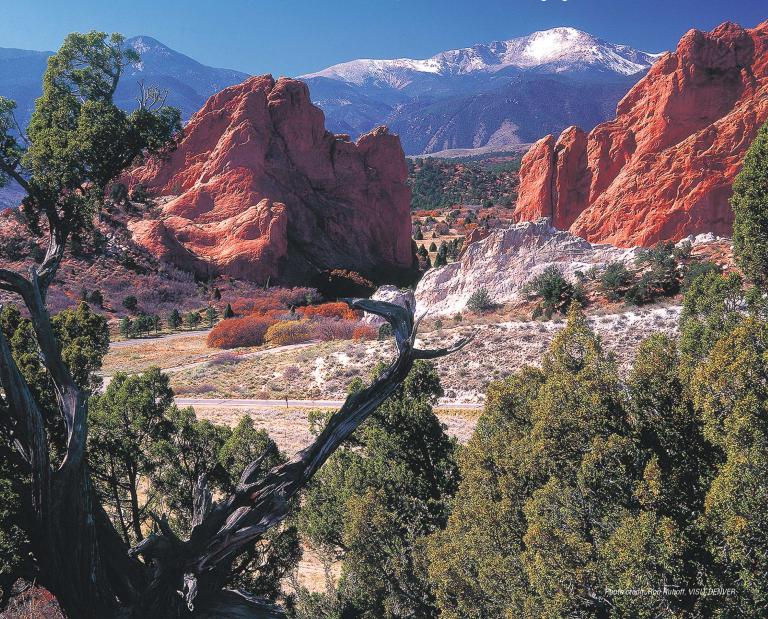
ExxonMobil finds oil, gas in Vaca Muerta

ExxonMobil Corp.'s affiliate ExxonMobil Exploration Argentina jointly with Gas y Petroleo del Neuquen has discovered oil and gas in an unconventional shale well in Neuquen Province of Argentina, a company news release said. Located in the liquids-rich area of the Vaca Muerta play, the Bajo del Choique X-2 well was drilled to a total measured depth of approximately 4,570 m (15,000 ft). The horizontal leg of the well extends for 1,000 m (3,280 ft). The well was completed in the Vaca Muerta Formation and flowed at an average rate of 770 bbl/d of oil on a ¹%-in. choke in its first flow test. Data analysis and additional studies are being conducted to fully evaluate this discovery.

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MOVE

PEOPLE

Hoover Container Solutions has promoted **Gabriela Blanco** to international client services manager. **Rod Branch** joined the company as vice president of human resources.

Jeff Foster will lead Microseismic Inc. as president and CEO.

Bristow Group Inc. has selected **John Briscoe** as senior vice president and CFO.

Gustavo Hernández García was chosen as CEO of Pemex E&P.

Ericson Manufacturing has appointed **Jeffrey D. Schad** as president.

Tullow Oil Plc has named **Dr. Michael Daly** as nonexecutive director.



Scott Rempel (left) has been tapped as vice president of business development and strategy for Wood

Group Mustang.

Rajib Roy has taken on the role of CEO for Quantum Spatial.

Mitch Thibodeaux has been made president of Superior Performance Inc.



Honeywell named **Vimal Kapur** (left) president of Honeywell Process Solutions.

Kevin Clark has been given the title of CFO of Max Petroleum Plc.

Aggreko appointed Chris Weston CEO.



Greene's Energy Group LLC has promoted **Ricardo "BJ" Rivera** (left) to district manager for Testco Production

BOP Testing and Guardian Wellhead Protection and Rentals.



Peak Well Systems has expanded its global sales management team with the appointment of **Graeme**

Copland (left) as regional sales manager for the company's Western Hemisphere region covering the North Sea, Continental Europe, CIS and SubSaharan Africa.

Shawn Maxwell (right) has become president and CTO of IMaGE, Itasca Microseismic and Geomechanical Evaluation products and services.



Apache Corp. has promoted **Tom Yelich** to staff vice president of business development and **Tim Custer** to staff vice president of land. **Annell R. Bay** joined the company's board of directors.

Earl Collins has assumed the position of president of Willbros Group Inc.

Michael Fournier has been named executive vice president and COO of the company, and Edward Wiegele has been named executive vice president of Willbros Group and president of engineering and technology.



Charles Packshaw (left) has joined the board of directors as a nonexecutive director for BMT Group Ltd.

Fastnet Oil and Gas Plc has tapped **Will Holland** to be CFO.

Reed Smith has added **Michael Yuffee** and **Gary C. Johnson** as partners in its Energy & Natural Resources Industry Group.

Swift Worldwide Resources has appointed **Rodney F. Nelson** as a nonexecutive board member.



Wellsite Rental Services has named **Blair Faucheaux** (left) controller. Eco-Stim Energy Solutions Argentina S.A. has expanded its team with the appointment of **Oscar Boch** as logistics and maintenance manager, **Martin Pons** as engineering manager, **Paula Bertoglio** as special projects manager, **Hector Sanchez** as operations manager and **Eduardo Dimarco** as coiled tubing operations supervisor.

Jerry Beeson (right) has taken on the role of vice president of sales for Circulation Solutions.





Paul Remson (left) has become vice president of risk management for Superior Energy Services.

InterMoor, an Acteon company, has appointed **Nick Knight** (right) as business development manager for InterMoor Marine Services Ltd.



AMEC has made **Jeff Reilly** group president of strategy and business development.

Chestnut Exploration and Production Inc. has hired **Victor Jordan** as its new senior production engineer.

COMPANIES

Peak Well Systems has opened a new technology center in Dubai, UAE, accommodating regional technical sales and engineering teams and a large assembly and testing workshop facility for after-sales support. Peak also will maintain a large inventory of rental tools in Dubai for rapid mobilization of advanced well intervention equipment throughout the region.

Master Rig International has consolidated its worldwide oilfield parts and service operations into one new facility





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Pipeline Plastics LLC is expanding its high-density polyethylene (HDPE) pipe operations with a new manufacturing facility in West Texas. The 3,716-sq-m (40,000-sq-ft) facility will be constructed on a 15-acre site in the Levelland, Texas, Rail Park. Production of HDPE pipe from the facility is expected by yearend 2014.

Aqualis Offshore opened an office in Shanghai, one of 12 offices in nine countries the company has established since beginning operations a year ago. The Shanghai office's main fields of activity will be construction supervision, marine warranty, jackup trials and commissioning, and transportation and rig moving, and it also will offer engineering design services with support from the company's other offices.

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High-definition exploration requires complementary systems

New interpretation and modeling processes are necessary to recover investments in broadband seismic acquisition and processing.

Arshad Matin, Paradigm

While 3-D seismic acquisition and processing are routinely cited as significant breakthrough technologies that have impacted oil and gas exploration, broadband seismic acquisition and processing have the potential to have a similar impact on the exploration and development of oil and gas fields. However, just like the rapid acceptance and adoption of 3-D seismic acquisition were predicated on the availability of supporting technologies like 3-D seismic migrations and 3-D interpretation and modeling systems, the true value of broadband seismic acquisition and imaging will not be realized without complementary technologies and systems.

Broadband seismic acquisition and processing procedures also have migrated to onshore acquisitions with high-density acquisitions and point source-receiver deployments.

The result? A wealth of new and greatly enhanced "high-definition" images are quickly coming online ready for high-resolution interpretation, characterization and modeling. But are the available interpretation and modeling systems equipped to fully take advantage of the information contained in these high-definition images?

Broadband seismic images are capable of recovering a level of structural and stratigraphic detail not present in standard seismic images, but recovering this detail is not straightforward with conventional interpretation and modeling systems. Time constraints coupled with less than optimized automated or computer-assisted picking methods generally result in an "underinterpreted" and "undermodeled" dataset.

New processes that move from surface-based to full volumetric interpretation and modeling solutions are now essential for fully optimizing the value of broadband seismic acquisition and processing. By doing so, the industry can address a number of limitations in the interpretation and modeling of reflector-rich datasets:

 Unrestricted interpretation. The interpreter has the freedom to add as many faults and interlayer reflectors as desired to the interpretation dataset without loss

- of time and without compromises to the stratigraphic model:
- *Solving the correlation challenge*. Interpreters do not lose time correlating stratigraphic horizons across heavily faulted datasets;
- *Validation.* By constraining the interpretation with 3-D chronostratigraphic modeling, interpreters can validate the data (horizons and faults) and the mapping potential enabled by the automated volumetric procedures without loss of time; and
- Discovery. By displaying and carrying out the interpretation on chronostratigraphic (depositional) slices, interpreters and modelers can augment it with unprecedented levels of stratigraphy and facies information not easily secured using standard seismic flattening procedures.

This new type of volumetric interpretation that merges automated volumetric interpretation and chronostratigraphic modeling procedures provides an opportunity to secure a higher return on investment from the high-definition images generated by broadband seismic acquisition and processing. Simultaneously, it forces the interpretation and modeling workflows to merge so their detail and complexity are proportional to the detail and resolution of data recovered using broadband methods. This merging also suggests that modeling technology must support cell resolutions that are coincident with those of high-definition seismic images. Consequently, interpreters and modelers must be able to easily work with giga-cell models to fully enjoy the resolutions of broadband seismic data.

Broadband seismic data are also an impetus for a new generation of quantitative seismic interpretation (QSI) solutions that drive a more unified and concurrent approach to transforming seismic amplitude data to elastic and rock properties. Success for these systems will be measured by how effective volumes of prestack interpretation can be integrated in the interpretation environment and how rapidly compute-intensive functions like seismic inversion can be carried out using all available multicore processors—CPUs and GPUs—at the desktop. Here, even fast voxel visualizations and rendering are essential components of a QSI system in pursuit of high-definition prospects.

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TAM Big Packers for Deepwater Operations:

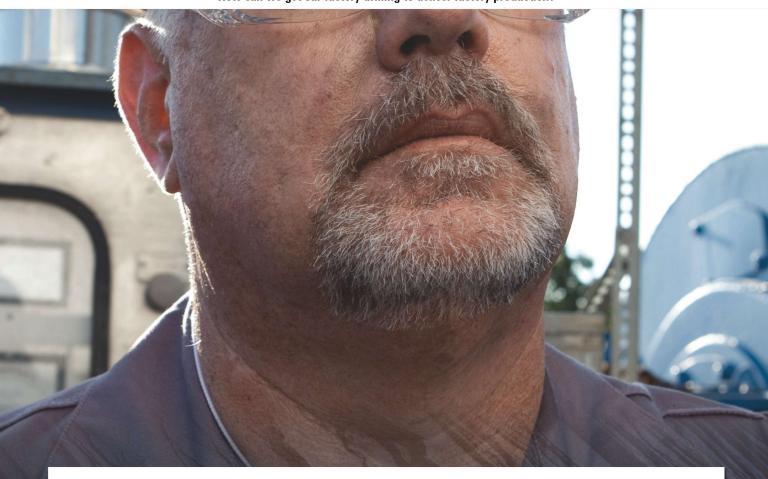
The stakes are high in deepwater operations.

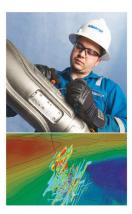
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