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WORLDWIDE COVERAGE
NOVEMBER 2014
VOLUME 87 ISSUE 11
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COVER STORY: GLOBAL ENERGY INDEPENDENCE TRENDS

MARCELLUS-UTICA MIDSTREAM
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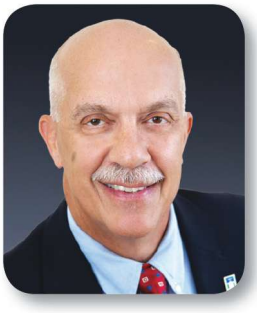

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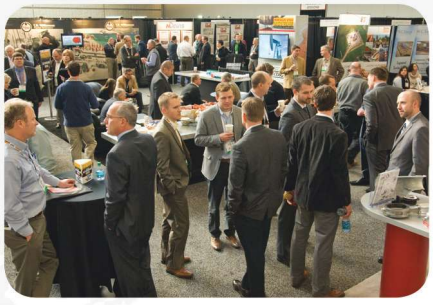

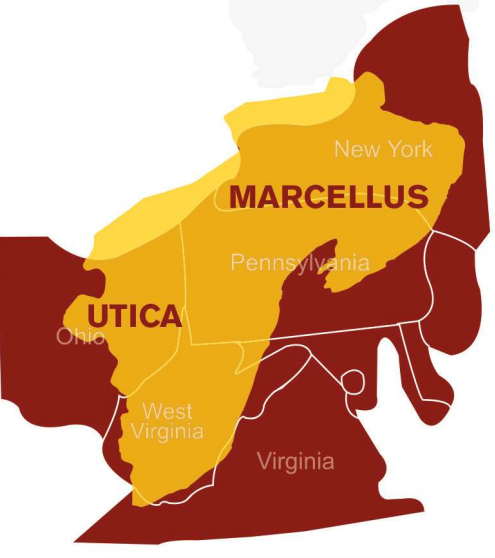

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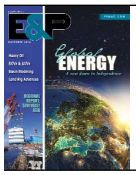
COMING NEXT MONTH The December issue of ***E&P*** will examine the "holy grails" that remain in the upstream industry in terms of technical challenges. Other features will review technology gains in recent years as well as providing a construction and shipyard update, and regional reports will focus on the Eagle Ford Shale and the Mediterranean. 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 The changing global energy landscape is making exporters out of importers and reshaping our view of energy independence. Left, Southeast Asia is rapidly embracing the floating LNG trend. (Left side image courtesy of Petronas; cover design by Laura J. Williams)

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CNOOC starts production at Enping Field
The Enping 24-2 oil field in the Pearl River Mouth Basin of the South China Sea has commenced production. There are two wells producing about 8,000 bbl/d of crude oil.

Eni signs PSCs for offshore exploration in Vietnam
Eni signed two production-sharing contracts with Petrovietnam for the exploration of blocks 116 and 124 located off the coast of Vietnam.

Statoil makes small gas find in Barents Sea
While drilling in the Barents Sea, Statoil Petroleum's wildcat well 7220/2-1 encountered a gas column of about 85 m (279 ft) in the Stø and Nordmela formations.

AVAILABLE ONLY ONLINE

Evolving technology could add up to 3 MMbbl/d by 2030
By Caroline Evans, Hart Energy
EOR methods currently being tested could lead to a 100% increase in recovery rates.

More drilling pushes demand for sand higher
By Velda Addison, Associate Online Editor
Operators in North American shale plays are using more than 5 MMlb of frack sand per well.

Philippines opens licensing round
By Steve Hamlen, Special to E&P
The government is offering a total of 11 onshore and offshore blocks.

'Transformational' shale revolution takes over industry
By Ariana Benavidez, Associate Editor
The unconventional revolution is making a big impact, bringing benefits along with concerns.

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Your name in lights

It's time to start preparing your entries for *E&P*'s Meritorious Awards for Engineering Innovation.

I've been writing for *E&P* since its launch 15 years ago, and during that time these pages have been full of amazing technological advances. These nifty tools and techniques rightfully get credit for helping solve challenging problems and, often, bringing in revenue.

But the people who develop these technologies don't always get the credit they deserve. That's why, since 1971, Hart Energy has offered its Meritorious Awards for Engineering Innovation (MEAs). These awards have showcased game-changing technologies that demonstrate the ability to solve some of the industry's biggest challenges.

Here's how they work: By visiting *epmag.com*, entrants can request an account. Once they receive their log-in details, they can enter as many products in as many categories as they wish as long as all entries are complete by Jan. 31, 2015. There is no charge to enter.

For those of you who have entered in the past, you'll note that we've expanded the seven categories we had last year and have added five new ones. New categories include onshore rigs, water management, subsea systems, floating systems and rigs, and marine construction and decommissioning. A full description of each category can be found at the MEA link.

Our judges include respected professionals with technical backgrounds who have extensive knowledge of the categories they are judging. Judges are carefully selected to avoid potential conflicts of interest.

So why should you enter? These awards carry a considerable amount of prestige. Technologies that win MEAs are deemed by an expert panel to be the best of the best and to have made a significant impact on the industry. I've seen MEA awards prominently displayed in the lobbies of major companies. I've had people thank me profusely when I give them their awards, even though I had no hand in the judging and simply administered the process. Small companies stand just as much of a chance as large companies since the entries are judged strictly on the merits of the competing technology. And oil companies that have developed a technology or technique stand as great a chance as service companies. Shell, for instance, won an award for its virtual source technology a few years ago.

Please take a moment to review the information on our website. The process is all done online and doesn't take a tremendous amount of time. Help is an email or phone call away. Who knows—you might be making space in your own lobby soon! E&P

Handling NGLs

The safe transportation of 'wet gas' can present a different set of challenges for operators to overcome.

Trotter Hunt, HGA

The term NGLs is used frequently, but what are they and how do they differ from dry gas in both value and handling considerations?

What are NGLs?

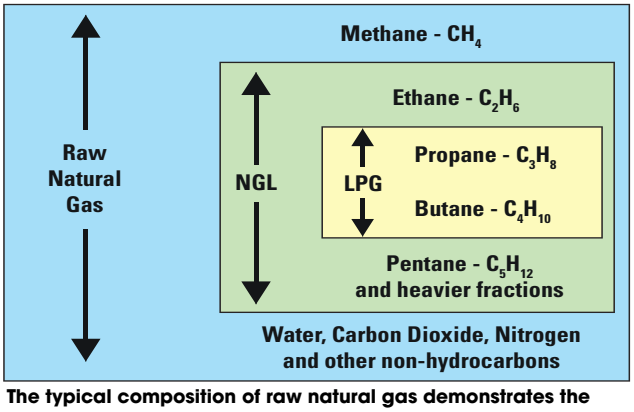
The pressure and high temperatures found in deep underground gas reservoirs mean that some low-boiling point hydrocarbon compounds—which would be liquids at normal temperatures and pressures above the ground—become gases under the ground. These gasified liquids then become part of the flow of gas when piped up from the reservoir and condense out of the gas as the pressure and temperature drop.

Natural gas, as sold to the consumer, is methane. Wet gas—a term for raw gas—typically contains 5% to 20% of gases and "gasified liquids" that are not methane. The other hydrocarbons in the methane stream are either liquid at normal temperatures and pressures (known as condensates) or gases that can be relatively easily turned into a liquid with application of moderate pressure or freezing.

NGLs vs. methane

Historically, NGLs are more valuable separated from the gas stream than the total gas stream if the NGLs remained part of the stream. For example, ethane is important feedstock for the chemical industry (ethylene), and propane is used in the chemical industry (propylene) and in home heating and cooking. If not sold separately, the fractionates can be mixed together to form liquid petroleum gases (LPGs), which must remain pressurized to be liquid. LPGs can be held in relatively thin-walled steel bottles and therefore are sold worldwide for various uses including domestic cooking and as a transport fuel.

Relationship of LPG to NGL and Raw Natural Gas



The typical composition of raw natural gas demonstrates the relationship of LPG to NGL and raw natural gas. (Source: HGA)

That said, depending on the value of natural gas vs. NGLs, suppliers and processors may elect to reduce extraction levels or bypass processing. This economic environment creates two issues for transmission, distribution and utilization of domestic natural gas.

First, a decreased level of processing causes the presence of larger amounts of liquefiable hydrocarbons in the gas stream, resulting in a greater potential for liquids to drop out of the gas phase while in transit to end-use equipment. This increases the potential for problems in pipeline and local distribution company operations with compression, measurement, pressure regulation, overpressure protection devices and potential interference with odorization.

Second, problems also can occur in end-use applications such as flame extinguishing, over-firing in home appliances or physical damage to gas turbines used to generate electricity.

With the advent of horizontal drilling and hydraulic fracturing in the mid-2000s, upstream operators are now able to access significantly more recoverable oil and gas than previously attainable. Over time, they have focused their resources on the most profitable fields, which are those that contain either oil or rich gas. Rich gas is the term for wet gas that contains comparably higher levels of NGLs than normal concentrations.

Challenges in handling NGLs

As the overall volume of NGLs and percentage of NGLs in the production streams increase, operators face a variety of challenges in handling the NGLs.

Existing infrastructure is typically designed to handle dry gas. Most pipelines have been designed throughout the years with a variety of means to capture small incidental volumes of liquids to protect downstream facilities. Putting rich gas—high in NGLs—into pipelines that are not designed to handle it can result in a variety of issues.

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Transporting NGLs presents myriad challenges that can be overcome through effective planning. (Source: HGA)

At high velocities, liquids become entrained, forming a mist. The mist may coalesce on the walls of the downstream pipeline and begin to collect in low spots of the pipeline system. Eventually, liquids can be swept along by the gas flow until reaching an exit point on the system—a customer meter and burner. Liquids reaching a burner are a serious safety concern.

Hydrocarbon liquids in sensing lines to the equipment used for controlling pressure can cause erratic pressure variations in the delivered pipeline pressure. Such variations can impact nearby regulating stations, upsetting large portions of a gas distribution system. This results in potential adverse impacts on system reliability or safety, including overpressure protection devices. Hydrocarbon liquids present in a pipeline may not only cause operational and safety problems but also result in significant measurement error and unaccounted volume/energy losses. Additional reliability and safety concerns for local distribution companies and end users due to NGLs include the impact to polyethylene plastic piping, plastic piping components and current handling/pipe joining methodologies.

Two-phase pipelines are an option but bring challenges. Some pipeline companies have installed various two-phase (gas and liquid) lines to accommodate the presumption of liquid formation. These special lines are located in proximity to and upstream of liquids handling infrastructure such as condensate removal facilities or a processing plant.

The design of a two-phase pipeline to handle both gas and liquids involves calculations similar to those used for a single-phase pipeline. The key difference is that pressure drop is much more difficult to determine when both gas and liquid are flowing in the same pipeline, especially if the pipeline is carrying a two-phase multicomponent stream—gas, oil and water. Flow of the two phases can take several forms, and pressure drop can vary widely, depending on flow conditions. Changes in elevation over the route of a two-phase line are much more significant than in a single-phase pipeline. Besides pressure drop, liquid holdup is an important consideration in design of a two-phase pipeline.

Gas treatment and separation can be accomplished at various points in the system. Produced gas can be partially treated at the wellhead to remove liquids through simple, rudimentary physical separation equipment. Gas processing entails two separate and distinct functions prior to the produced gas being deemed marketable. The gas will first be "treated" to remove major contaminants such as CO_2, H_2S and water vapor from the hydrocarbon gases if necessary. Then, if there are sufficient levels of NGLs, the NGLs will be removed from the hydrocarbon stream. These functions can be done separately or in an integrated facility. They can be done at the wellhead, at the terminus of gathering systems or on a transmission pipeline near production areas. There are pros and cons associated with each treating location.

Collaborative approach required

To provide the most efficient, safe and cost-effective handling, a holistic approach is needed so that consideration can be given to items such as existing infrastructure capability, future field development plans, gas stream characteristics and opportunities for equipment standardization. To do this, technical competency in several key areas is required, and there are several important project aspects that must be considered; the characteristics of the gas that will be handled, the anticipated drilling plan and the existing infrastructure available are a few of the key items. Typically there are additional constraints that also must be taken into consideration such as regulatory requirements and business commitments, including gas quality to be delivered. Having a knowledgeable and qualified team is key to successfully developing an optimal approach. E&P

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Diving back into the deep

ConocoPhillips is targeting deepwater reserves as a strategic growth area as it looks to hit ambitious future production targets—but it also has to fill in some technology gaps along the way, along with the rest of the industry.

Mark Thomas, Editor-in-Chief

ConocoPhillips has an active program underway to tackle areas of technology it has identified where continual improvements—rather than complete "blue sky" concepts—are required for it to produce in increasing water depths and higher pressures and temperatures around the world.

The U.S. operator has sunk a lot of its time in recent years into establishing its core position in the North American unconventionals sector, with deepwater areas—while certainly not ignored—on something of a slow burner. As it looks to the long term, however, the company has adjusted its focus accordingly.

According to John Vicic, a man with long industry experience who is manager of the operator's deepwater technology program, "For ultimate growth, we are looking to deepwater."

Technology challenges

Vicic was speaking in a special U.S. Gulf of Mexico (GoM) focus session at the Offshore Northern Seas (ONS) event in Stavanger, Norway, organized by INTSOK, the Norwegian government and industry-backed oil and gas trade organization. In his presentation titled "Deepwater Technology Gamechangers," he outlined how ConocoPhillips—which is now a fully focused upstream operator with the spinoff in 2012 of its refining operations to Phillips 66—is focused both internally and via various industry collaborations on identifying and tackling the most pressing technology challenges.

Last year it spent heavily to ramp up production, specifically in the U.S., but that was thanks largely to continuing growth in its Lower 48 unconventional assets in the Permian Basin, Eagle Ford and Bakken shale plays. As a result, it grew its total production by about 7% in its Lower 48 segment last year, including 24% growth in domestic crude oil production. By year-end

ConocoPhillips has several deepwater projects around the world now coming to fruition, most recently the Shell-operated Gumusut-Kakap semisubmersible production facility offshore Sabah, Malaysia, which came onstream in early October and will eventually peak at 135,000 bbl/d. ConocoPhillips has a 33% stake in the project. (Source: Shell)

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2014 ConocoPhillips expects to be producing up to 1,600 MMboe/d as a company worldwide.

Upping its game

Vicic, however, said the company believes deepwater holds the key to future production growth. He admitted that in recent years it had essentially been a "nonoperating partner" in its deepwater U.S. GoM projects. But, he continued, it has now stepped up its game.

Highlighting the largest oil and gas discoveries made by the industry in recent years, he pointed out that the vast majority had all been made in deepwater where—although the wells are very expensive to drill—they required the fewest wells due to their impressive reservoir productivity, especially when compared to unconventional bores.

Faced not only by the extreme water depths but also reservoir pressures ranging from 8,000 psi to 25,000 psi and temperatures of between 66 C and 191 C (150 F and 375 F), ConocoPhillips has undertaken detailed analysis of the technology gaps, he said.

In the exploration arena Vicic flagged up ongoing efforts to try to "translate" the experience gained offshore Norway with chalk and carbonate reservoirs and with HP/HT fields in the GoM. He also highlighted the increased need for more capable AUVs and ROVs to work and monitor in the extreme depths for extended periods of time, mentioning Liquid Robotics' Wave Glider autonomous unit as an example.

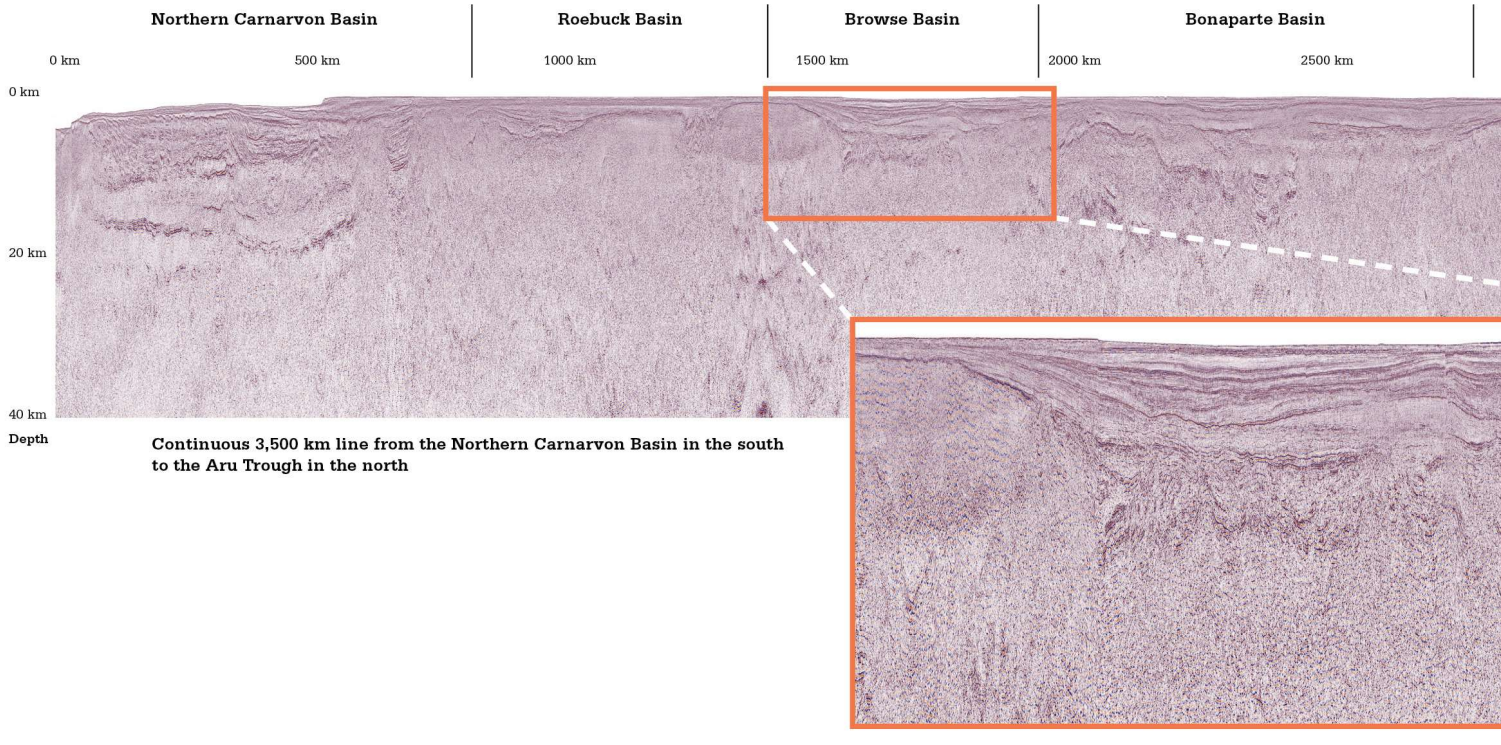
Developing digital oilfield solutions with integrated sensing was another key area of focus, he said, as well as creating real-time data centers.

In terms of drilling and completion advances, Vicic also highlighted that the company is evaluating and qualifying managed-pressure drilling for future deepwater drilling systems for efficiency and better well control.

Flow assurance focus

In the production sector he listed several key issues to be tackled to specifically improve flow assurance, including advances that would be required when dealing with

Expanded insight into Northwest Australia a



Continuous 3,500 km line from the Northern Carnarvon Basin in the south to the Aru Trough in the north

asphaltenes, hydrates, scale and corrosion. Asphaltenes, in particular, were highlighted by Vicic as an aspect of flow assurance that he felt would be crucial to deal with.

He also acknowledged the potential for improved subsea boosting and processing solutions, both on the seabed and downhole. "It's the key—we are working on it by ourselves and also with others," he said.

Virtually every presentation at ONS this year included ongoing efforts by the industry to control spiraling costs. Vicic was no different, pointing out that goals such as greater standardization are required by operating companies along with more industry collaboration.

20K collaboration

As an example of the latter, he highlighted the recently announced 20K joint development project, to which ConocoPhillips belongs along with BP, Shell and Anadarko, all working with FMC on next-generation standardized subsea production equipment. "This is looking at everything from the wellhead to the HIPPS [high-integrity pressure protection system]," he said. With the program expected to initially cover "about a three-year period," it is focusing on items including 20,000-psi trees, jumpers, flowlines and HIPPS. "We are also as a company working on 20K drilling systems," he added. With an expected 3% to 5% production growth rate for the company in 2014, ConocoPhillips is looking to maintain that rate beyond 2017-18 and is focused on organically growing its portfolio. That will increasingly see it take more operator positions in developments than it has in recent years.

In the GoM, Vicic admitted that the company is not really an operator at present (although it is elsewhere), but overall he commented, "We are just coming back into deepwater—I think we're one of the leaders. We're the second-biggest leaseholder in the GoM, and most of that is in deepwater and high-temperature leases."

Testing deepwater potential

This was echoed by ConocoPhillips' CEO Ryan Lance, who spoke at the Barclays CEO Energy Conference.

Lance waxed lyrical on the company's North American unconventionals portfolio of the Eagle Ford, Bakken and Permian before taking time to highlight how it is testing out the potential of its deepwater assets in the GoM, Angola, Senegal, Nova Scotia, Norway, Myanmar, Australia's Browse Basin and Malaysia.

In the latter, for example, it expects to be producing more than 60,000 boe/d by 2017 from its deepwater assets, including the Gumusut-Kakap and KBB developments, with the former having only recently started flowing oil via its semisubmersible production facility and the latter due to start production during fourth-quarter 2014. It also has Siakap North-Petai in Malaysia, which began flowing recently. "This is very high-margin oil production offshore Sabah Island in the deepwater province," Lance said.

GoM focus

In the U.S. GoM the company is currently involved in the appraisal of four major discoveries, Lance said. "We are really focused on the Lower Tertiary, the Paleogene where we've had four discoveries, Tiber where we own an interest—we will be appraising that this year," he said. "[At] Gila, the most recent of the Tertiary-Lower Paleogene discoveries, we have a rig coming to do some appraisal this year as well. [At] Shenandoah, which was another 2009 discovery pre-Macondo, we have drilled an appraisal well. [We] found over 305 m (1,000 ft) of net pay. So we are pretty excited about what the upside and opportunity looks like at Shenandoah. And finally Coronado, which was also a discovery a few years ago, and we are on that particular asset right now doing appraisal testing as well. So we are excited about what the deepwater Gulf of Mexico has in store."

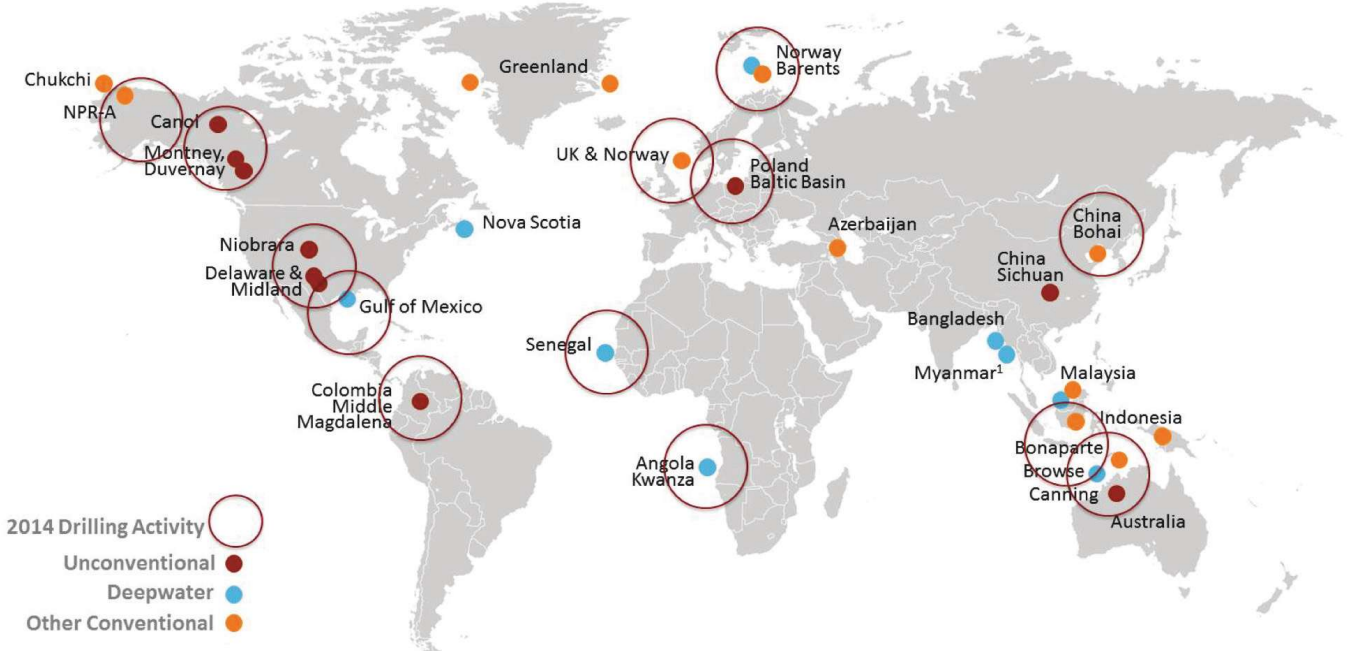
Across the Atlantic

Lance also highlighted what the company is doing across the Atlantic off the west coast of Africa in the conjugate margin to the subsalt Santos Basin offshore Brazil. In the frontier Kwanza Basin offshore Angola ConocoPhillips has two blocks, 36 and 37, where it is the operator with 50% and 30% stakes, respectively.

ConocoPhillips spudded an initial exploration well (Kamoxi-1) in Block 36 during August. With a four-well commitment, it will drill two wells in each block. Blocks 36 and 37 are adjacent to Blocks 20 and 21, where the play-opening Orca, Lontra, Mavinga, Cameia and Bicuar discoveries have been made by Cobalt International Energy.

"You can see they're offsetting some of the recent discoveries in Angola, which have kind of de-risked the petroleum system, which is good. We are playing that subsalt carbonate reef buildup play that's been successful in the Santos Basin on the Brazilian side," Lance said.

For ConocoPhillips (like many of its peers) deepwater remains by its very nature a technology-intensive discipline but one which—for those companies that develop and harness their capabilities—enables them to compete strongly for frontier opportunities around the world. E&P



In 2014 ConocoPhillips has had an active drilling program underway testing its global portfolio not only in deepwater but also its unconventional and conventional assets. (Source: ConocoPhillips)

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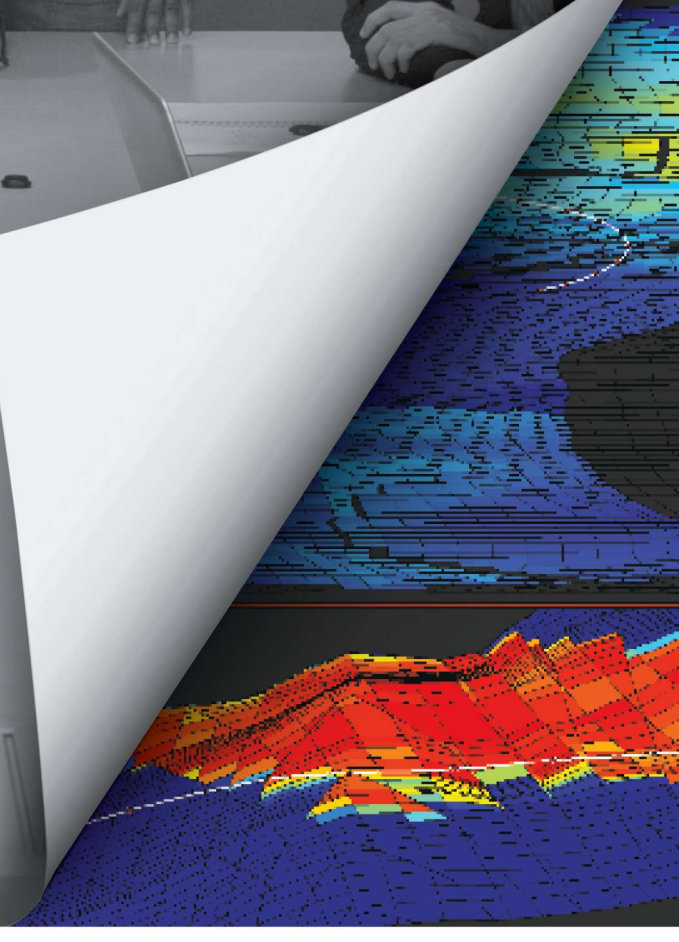

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Using metrics to drive change

Women will continue to be underrepresented in top jobs unless companies monitor their progress.

Eve Sprunt, Contributing Author

It is often said that perception is reality. Unfortunately, many women in the petroleum industry continue to think that their career opportunities are not as good as those of their male peers. A survey that was conducted in November 2013 and January 2014 of 1,200 women and 6,000 men around the world by *oilandgasjobsearch.com* highlights some major differences of opinion between women and men (see *oilandgasjobsearch.com* for details). In that poll, 67% of men but only 41.9% of women taking the survey thought that both genders have equal opportunity to be promoted. Furthermore, 86.5% of the women believed that their male counterparts with the same level of experience and qualifications received at least 10% higher compensation, and 35.9% of those women thought that the differential was more than 25%. Without convincing publicly available information to the contrary, many women, including young women who are contemplating a career in oil and gas, are left with the impression that significant discrimination against women persists in the petroleum industry.

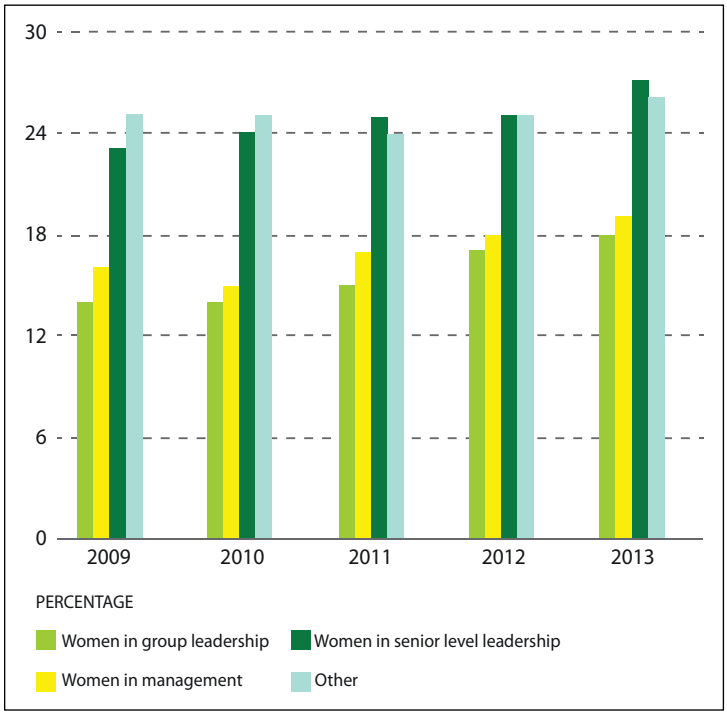

FIGURE 1. This breakdown of women's roles is useful but lacks granularity. (Source: BP)

A few companies like BP have begun to share data to demonstrate that the percentage of women in higher level positions has increased. However, the information that BP provides on its website is insufficient to enable women to adequately compare career opportunities (Figure 1). What are the definitions of the four categories? What is "other"? How broad is the compensation range for the various categories? Within the categories, are the women clumped near the bottom end of the compensation range? It is a nice start, but more transparent metrics are needed to enable current and potential female employees to effectively understand the status of women within BP and to make informed comparisons of the status of women in different organizations.

Like their male colleagues, women are acutely concerned about their ability to advance. The reason most often cited by both men and women for leaving an employer is insufficient opportunity (Sprunt *et al.*, 2014). A chance to do more interesting work and insufficient opportunity were the two top reasons women left the petroleum industry (Sprunt *et al.*, 2013). "A chance to make a difference" was one of the top factors that would incentivize them to return. Women's perception of the career opportunities open to them is a major factor in recruiting and retention.

Workplace barriers that women continue to encounter are frequently in the press and much discussed by career women. For example, an academic study documenting gender bias in the evaluation of fictitious resumes for a position as lab manager that was published in the Proceedings National Academy of Sciences (Moss-Racusin *et al.*, 2012) was the focus of an article in the *New York Times* (Chang, 2012). In that study, two versions of a fictitious resume were created that varied only in whether the first name of the applicant was Jennifer or John. Even though everything else was identical, Jennifer was perceived as being less competent and was offered a salary 13% lower than John. The bias in hiring decision was not related to the age or sex of the person evaluating the resume; women were equally guilty of down-rating other women.

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The researchers reported that previous studies found similar bias in other occupations.

In another study with more than 600 participants, Tamar Kricheli-Katz observed that when women compete for high-status positions, they are held to higher standards than men (Nakagawa, 2014). Her research found that as women penetrate high-status occupations, high-status men may experience "identity threat," prompting them to evaluate women more negatively than before.

Some professions can use "blind" auditions to eliminate gender bias. Through the use of blind auditions, the top five orchestras in the U.S., which each have about 100 musicians and have not expanded in size, transitioned from having fewer than 5% women in 1970 to 25% in 1997, with some now well above 30% (Rice, 2013). In the blind auditions the candidates were hidden behind a screen on the stage so that the selection panel could not see them. The evaluators' biases were so ingrained that those auditioning were told to remove their shoes before they walked across the stage so that the distinctive sounds of a woman's shoes would not influence the selection.

Some female industry contemporaries have noted that in the 1980s they were unable to even get interviews until they started providing only their first initials on their applications. Unfortunately, the nature of the work in the petroleum industry does not lend itself to blind auditions. What can be done instead?

Taking stock

There is an old business adage that states, "You can't manage what you don't measure." Dan Ariely (2010), a professor of psychology and behavioral economics at Duke University, takes that a little further. He wrote, "Human beings adjust behavior based on the metrics they're held against. Anything you measure will impel a person to optimize his score on that metric. What you measure is what you'll get. Period."

We need simple, transparent metrics that can be collected annually and easily compared between organizations. The metrics should offer sufficient granularity to detect and monitor problem areas, including choke points beyond which women are underrepresented and also levels at which increased attrition occurs. Those responsible for hiring and for promotions should be held accountable to top management. The metrics should be shared with employees, stockholders and the general public.

Money is the ultimate metric for comparison. Reporting of the percentage of entry-level professionals who are female along with the percentages of women who are among the top 50% of employees by compensation, top 25% of employees by compensation, top 10%, top 5% and top 2% provides information that creates insight into the status of women and enables comparisons between organizations. If women persistently fail to advance into a higher bracket of top x% of employees by compensation, a barrier has been detected and should be investigated. The percent compensation metric can be collected at finer scales to pinpoint problem areas.

The percentage compensation metrics should be reported annually to employees, stockholders and the public. Public access to these metrics will drive change by placing pressure on management to address deficiencies. Knowing how women rank by compensation, not by ambiguous titles, is critical. Titles can be fluff. Money talks. E&P

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Drilling down on newbuild rigs

New rig construction cycle is underway with more than 200 rigs under construction in the U.S.

Richard Mason, Chief Technical Director

Need a new drilling rig? With more than 200 rigs under construction at U.S.-based manufacturing operations, another cycle of fleet retooling is well underway. More than 200 new rigs have been added to the domestic fleet over the last couple of years, according to Austin-based DrillingInfo. About 85% of the new rigs currently undergoing manufacture, or about 170 units, are destined domestically, with the remainder, about 30 rigs, headed overseas, mostly to Latin America.

Hart Energy's Market Intelligence program contacted domestic rig manufacturers in October 2014 to develop a sense of the newbuild market. This appears to be a crucial moment in the current cycle of expansion, assuming oil prices hold. For the first time since new rig construction began more than a decade ago, newer units with upgraded capabilities are displacing legacy units to meet demands for longer laterals and pad drilling.

That has placed an emphasis on 1,500-hp rigs or larger, primarily for the lifting requirements necessary to extend lateral length beyond a mile. New rigs typically entail upgraded fluid systems, high-capacity top drives, greater automation for handling pipe and other worker-unfriendly tasks, and integrated electronics and control systems to add efficiency to the directional drilling process.

Forecasting suggests demand exists for another 200 higher spec rigs over the next two years, led primarily by the accelerating ramp in the Permian Basin, where 550 rigs are active currently, including more than 330 drilling horizontally. Additionally, existing top-tier technology rigs with AC-variable-frequency drive (VFD) power systems are essentially maxed out on utilization, spurring interest in newbuild units as the industry moves into resource harvest mode in tight formation plays, including the Bakken, Eagle Ford and Marcellus shales.

That has led to conversations about when the market for newbuild slots will tighten. At some point in the newbuild cycle, delivery goes from six months to 18 months, and day rates respond accordingly.

Participants in Hart Energy's Market Intelligence survey program indicate rig rates for newbuild higher spec units run from $24,000 per day to $30,000 per day, depending on configuration.

Rig manufacturers told Hart Energy surveyors that domestic demand was greatest for 1,500-hp AC-VFD units, followed by larger 2,000-hp to 3,000-hp units. Demand for 1,000-hp to 1,400-hp units was listed as a distant third.

"Demand is good for the 1,500-horsepower units and the 2,000-horsepower units," one large Oklahoma manufacturer said. "We don't currently get many orders for small units. The 1,500-horsepower units with top drives and walking systems are in highest demand."

Manufacturers noted a split in interest among customers with domestic orders focusing on AC-VFD powered units while international orders customers seek traditional diesel-electric silicon-controlled rectifier rigs.

"Virtually all larger rigs ordered in the U.S. are AC power, while my foreign orders are almost always diesel electric," a manager at a large Texas-based rig manufacturing operation told Hart Energy. "I believe it has to do with what is known and understood for local service in those countries."

Average delivery time for newbuild units averaged four months across survey respondents. A majority of manufacturers said they are ordering components early to thwart future supply chain issues.

Virtually 100% of new rigs above 1,000 hp come equipped with top drives and self-mobilization capability and are destined for multiwell pad drilling programs in horizontal plays. About 50% of smaller independents are ordering skidded rigs vs. walking rigs to save on construction costs, participants in the Hart Energy survey said.

Manufacturers pegged domestic rig building capacity at about 320 units annually, with slightly more than 60% of slots currently filled. EP

- **New rig construction cycle underway**
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- **Domestic newbuild capacity pegged at 320 units**
- **Demand greatest for 1,500-hp AC-VFD rigs**

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Hyperspectral imaging will soon be available from space.

RHONDA DUEY
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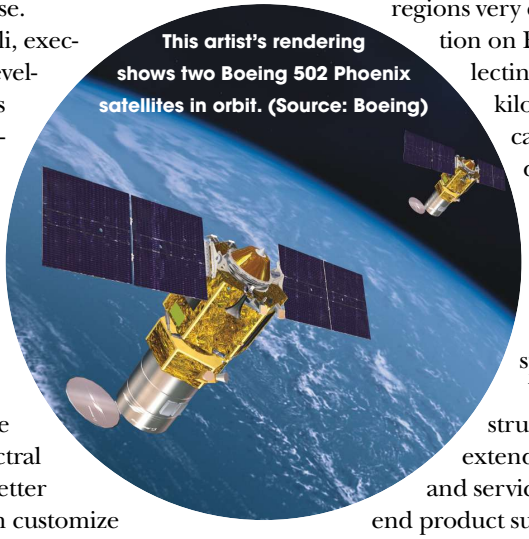
Many companies today offer advanced hyperspectral instruments that measure reflectance across the light spectrum, from ultraviolet to infrared. These systems record spectral signatures from surface-based plants and minerals, many of which are known to be associated with hydrocarbon and ore deposits, and they can also be used to detect oil seeps.

Currently, hyperspectral surveys are conducted by aircraft, but soon they will be available by satellite as well. Boeing recently announced that it had received an order from HySpecIQ for two small satellites that will carry the commercial remote sensing industry's first high-resolution hyperspectral payloads, providing much greater imaging fidelity than what is commercially available today.

Boeing will initially deliver two satellites that are expected to launch in 2018 as well as command and control operations, image processing, and data storage, according to a Boeing press release.



This artist's rendering shows two Boeing 502 Phoenix satellites in orbit. (Source: Boeing)

According to Joseph D. Fargnoli, executive vice president of product development for HySpecIQ, the plan is proceeding along two tracks. Boeing is building the space systems infrastructure, while HySpecIQ is engaging with commercial customers across a number of market verticals, including oil and gas.

"We're working with exploration geologists and production managers to really understand the information needs that hyperspectral can address," Fargnoli said. "By better understanding their needs we can customize our analytics platform to deliver meaningful information products."

He added that the company's goal is to find the best way to both acquire remote sensing datasets and integrate them through advanced analytics techniques to deliver a set of information solutions. "We found that users really appreciate the value of hyperspectral data when it's available, but that information has been costly and time-consuming to acquire using current aerial collection techniques," he said. "It takes several months to navigate the local licensing and regulatory processes, contract with local pilots and collect the necessary volume of hyperspectral data."

Using satellites in conjunction with aircraft or drones addresses these shortcomings in a cost-effective way. Even though the satellites are much farther away from the ground, they can be tasked to collect data in target regions very quickly and can revisit any location on Earth within a few days while collecting tens of thousands of square kilometers of data every day. "If we can acquire the data more frequently with a cost that compares favorably to airborne providers, we can get the economies of scale required to really transform this market," he said. "We will be able to unleash the power of hyperspectral on a much broader scale."

While the system is under construction, HySpecIQ is planning to extend its working relationships with oil and service companies to ensure that the end product suits their requirements. "We've developed our analytics inference engine with their applications in mind, but we also realize that we cannot anticipate all of our customer' information needs," he said. "As such, we are engaging with a number of early customers to better understand their needs and determine how hyperspectral imaging can be used to impact profitability and competiveness."

For more information, visit *hyspeciq.com*. EP

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Energy potpourri: Coho salmon, hot air, fracturing chemicals

The oil and gas industry isn't the only industry impacting water management issues and renewable energy.

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Senior Editor, Drilling
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Read more commentary at EPmag.com

What do coho salmon have to do with hydraulic fracturing? It really has to do with where coho salmon swim, spawn and grow—in water—and marijuana growers. California is going through a major drought, which has impacted developing the Monterey Shale. Because of the drought, marijuana growers have been withdrawing water illegally from creeks in Northern California and southern Oregon, where the coho salmon are having a tough time surviving.

The National Oceanic and Atmospheric Administration's Fisheries Service noted that the pot growers not only were stealing water but also clear-cutting forests and building roads that in turn resulted in sediment deposits in the streams, which also hamper the coho salmon.

Perhaps the industry could start a Save the Salmon campaign to reduce water use by illegal marijuana growers. Then there might be more water available in California for hydraulic stimulation.

The oil industry takes a lot of flak over what critics label as subsidies. Other industries—like ethanol and wind energy—get huge subsidies but little criticism from those same critics. As a matter of fact, without those subsidies both ethanol and wind energy would crater.

As comedian Henny Youngman might once have said, "Take my wind energy—please." That's what the state governments of Oklahoma, Ohio, Texas and Kansas are saying. Ohio is leading the way. With little fanfare, Ohio Gov. John Kasich signed House Bill 483 on June 16, 2014. The bill included provisions that will require a setback of 343 m (1,125 ft) from the tip of a wind turbine blade to the nearest property line. That effectively shuts down new wind projects in the state.

Ohio HB 483 and SB 310 have effectively hamstrung wind energy in the state. Both bills were signed by the governor.

Senate Bill 310, which also was signed by the Ohio governor, eliminates the in-state requirement for renewable energy. These bills put a major damper on wind energy development.

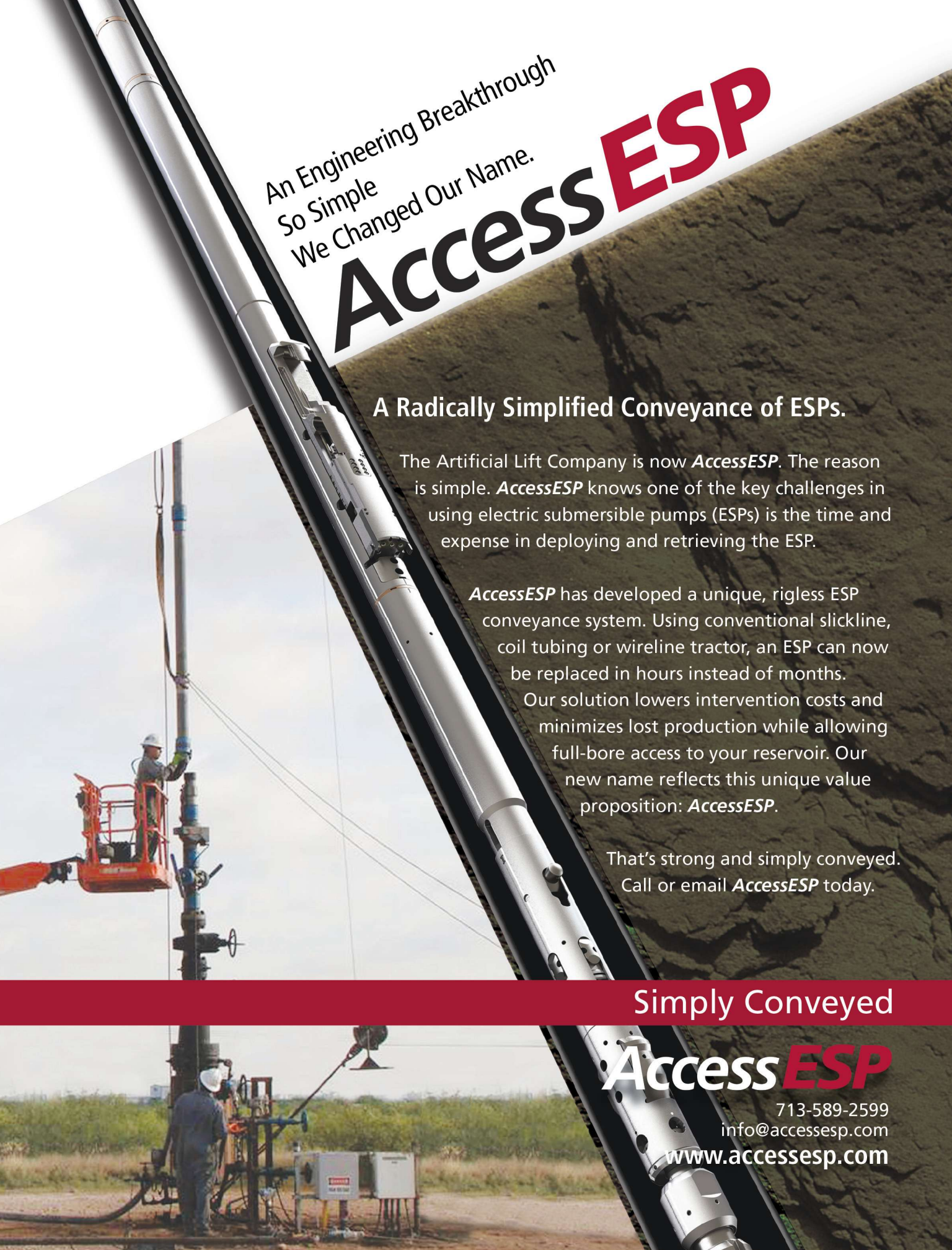
Oklahoma lawmakers are trying to change the state's subsidies, but a powerful wind lobby has undermined legislation to change them. On Sept. 23, Texas Comptroller Susan Combs issued a press release, saying, "It's time for wind energy to stand on its own two feet. Billions of dollars of tax credits and property tax limitations on new generation helped grow the industry, but today these give it an unfair market advantage over other power sources."

Without subsidies, wind energy is a lot of hot air.

And that brings me to some uplifting news for the oil and gas industry. On Oct. 1, Baker Hughes said it implemented a new policy of disclosing 100% of the chemistry contained within its hydraulic fracturing fluid systems without the use of any trade secret designations. All of the company's disclosure forms can be found at *fracfocus.org*.

As Derek Mathieson, Baker Hughes chief strategy officer, said in a press release, "We have a responsibility to provide the public with the information they want and deserve."

It's always nice to know the oil and gas industry is the bearer of good news. EP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Meeting the challenges of shale gas development

Federal research efforts to fully understand the potential of the U.S. shale gas resource continue to show results.

Jared Ciferno, National Energy Technology Laboratory

As shale gas plays mature and production data are collected, analyzed and published by public and private analysts, the evidence is clear that despite industry's best efforts, a large portion of the gas originally in place could remain unproduced unless the percentage of technically recoverable gas is increased.

Efforts to quantify recovery performance have begun for some of the more mature plays. For example, the University of Texas' Bureau of Economic Geology's comprehensive assessment of the Barnett Shale play published in 2013 puts the total for technically recoverable gas from the entire play at 2.4 Tcm of 12.6 Tcm (86 Tcf of 444 Tcf) in place, or 19.4%. The volume projected to be produced under the economic assumptions of the study is even lower. Other approaches have been employed to estimate ultimately recoverable gas volumes for the major shale gas plays, with some results averaging only 5.4%. So there appears to be plenty of room for improvement when one compares these recoveries with recoveries typical of "conventional" reservoirs (up to 80%). Improving recovery from shale gas plays is one of the major challenges we face in maximizing the potential national economic and environmental benefits of this resource.

While the geological differences between shales and conventional gas reservoir rocks may limit how close we can get to historical recoveries, producers have made enormous strides in increasing per-well EURs by lengthening horizontal laterals, increasing the number of fracturing stages and adjusting proppant concentrations. More work remains to be done if the full potential of the U.S. shale gas resource is to be realized.

Part of the mission of the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) is to accelerate the development of technologies that can maximize recovery of the nation's oil and natural gas resources while minimizing environmental impacts. Since 2007, NETL has funded 30 individual research projects focused on improving our understanding of how gas is produced from shales and tight sandstones and how hydraulic fracturing influences production. These projects, many of which were implemented through partnerships between research universities and producers, were carried out under the Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Research Program launched in 2007 by the Energy Policy Act of 2005. Although this program ended in 2014, work on already funded projects will continue through September 2016.

Earlier this summer, through traditional appropriations, NETL continued to build on this work by soliciting new research partners for work specifically focused on creating long-term research sites that could be used to monitor the nature of shale gas development and test technologies that have the promise to improve recovery efficiency and environmental performance. The sites will offer a unique opportunity to enable an open, collaborative and integrated program of science and technology development and testing.

In the 1980s a similar multiwell field laboratory in the Piceance Basin, the Multi-well Site funded by the DOE and the Gas Research Institute, was the scene of a wide range of experiments that provided important basic knowledge on how to maximize recovery from tight sandstone reservoirs. Hopefully, this new initiative will be equally successful in contributing useful findings over the long term.

The results of NETL's completed and ongoing unconventional natural gas research can be found on the NETL website: *netl.doe.gov/research/oil-and-gas/*. EP


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Long live the Third Coast

Technology, collaboration help the GoM defy expectations.

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Besides a fondness for the Mississippi River, Mark Twain and the offshore Gulf of Mexico (GoM) share something else in common: The reports of their deaths were greatly exaggerated. Discussions at last month's inaugural Hart Energy GoM Offshore Executive Conference clearly demonstrated that the U.S. GoM—from shelf to ultradeep—still has plenty of life left in it.

For two of the conference participants—Fieldwood Energy and Energy XXI—success has been found on the shelf through acquisitions, technology and collaboration.

Fieldwood Energy is the GoM's largest shelf operator. Never heard of it? The pure startup launched in early 2013 as a portfolio company of Riverstone Holdings. In the year since it has closed five transactions, with the largest two being the $3.75 billion acquisition of Apache Corp.'s GoM shelf business and a $750 million acquisition of SandRidge Energy's GoM and Gulf Coast business units.

Launched in 2005, Energy XXI splashed onto the GoM shelf with three major acquisitions from 2006 to 2007. In 2010, it acquired ExxonMobil's Grand Isle assets for $1 billion, and it recently closed on a $2.3 billion acquisition of EPL Oil & Gas. It operates 10 of the largest oil fields on the GoM shelf.

Technology and collaboration are playing a big part in the shelf's redevelopment

Technology and collaboration are playing a big part in the shelf's redevelopment. Better seismic data quality through reprocessing and new seismic acquisition data have changed how operators view the salt domes prevalent in the GoM, according to Energy XXI CEO John Schiller. Working with its partner Freeport-McMoRan has helped the company also better understand salt movement and how it is different than what was envisioned 20 years ago.

Mexico was a hot topic for attendees and presenters alike. With the passage of energy reform in the country that ended the 76-year oil monopoly held by Pemex, the energy sector is now open to competition for international operators like Shell and Statoil, to name a few.

While Statoil had representatives at the Offshore Executive Conference, it also had representatives meeting in Mexico, along with the energy ministers of Mexico and Norway, the CEO of Pemex and other industry partners to discuss the development of the Norwegian oil industry and lessons learned, according to a statement on Statoil's LinkedIn page.

A presenter at the GoM Offshore Executive Conference noted that development in the Mexican GoM today is where the U.S. GoM was 50 years ago. Stop for a moment and think about how far technology has helped advance the industry's knowledge on the safe and efficient exploration and production of hydrocarbons and how industry has evolved over the last half-century. Think about how far development in the U.S. GoM has come and how much farther it will go as we push forward into cracking the Paleogene. Where will the Mexican GoM be in 50 years? It is impossible to know. Perhaps we should give Mexican President Lazaro Cardenas some credit for his bold decision to toss out foreign oil companies so long ago. By doing so, he secured a basket full of potentially impressive nest eggs for the Mexico of today and ensured that the offshore GoM will live longer than ever expected. EP

ENERGY *independence*

In the early 1970s the U.S. found itself held hostage by the Arab oil embargo. Spoiled by years of cheap gasoline and superpower status, the country had to adjust to shortages it hadn't experienced since World War II. In response to the crisis, the concept of "energy independence" shone like a beacon of hope to a disgruntled population.

Forty years later, the shale gale has brought that beacon much closer to reality. But those 40 years also have witnessed a sea change in the way the world harnesses energy. Fossil fuels continue to be the primary source of energy, particularly in terms of transportation, but renewable energy is gaining a larger foothold, and even countries that have abundant fossil fuel resources often rely on other energy sources—Norway, for instance, generates most of its electricity through hydropower.

In the following pages we examine the concept of energy independence and how it fits into the modern global paradigm.

Independence day

Behind the flag-waving and rhetoric are some hard questions about the reality of U.S. energy independence.

Rhonda Duey, Executive Editor

In late September a tanker loaded with crude oil set sail from Valdez, Alaska, en route to South Korea. In the great scheme of things, this may not seem particularly newsworthy. But it could be a sign of things to come.

Even though the U.S. ban on crude oil exports does not include Alaska, no crude shipments have left that state for other countries in a decade. But Erik Nikolai Stavseth, an analyst at Arctic Securities ASA, told the *Los Angeles Times* that the traditional markets for Alaskan crude, oil refineries on the West Coast, have found new suppliers with the enormous rise in domestic production.

This is just the latest indication that the energy picture in North America has shifted drastically in the last few years, evidence of the "shale gale" that has opened up vast amounts of previously inaccessible hydrocarbons in provinces that only a few years ago were considered mature, declining or even dead.

It has taken the U.S. awhile to come around to this new way of thinking. Many in the country hope for an executive order from President Barack Obama to lift the ban on crude exports, a move which many don't expect until at least after the November elections and more likely in 2015. While U.S. operators anticipate

Lifting the ban on U.S. crude exports could turn the tide on that country's import/export outlook.

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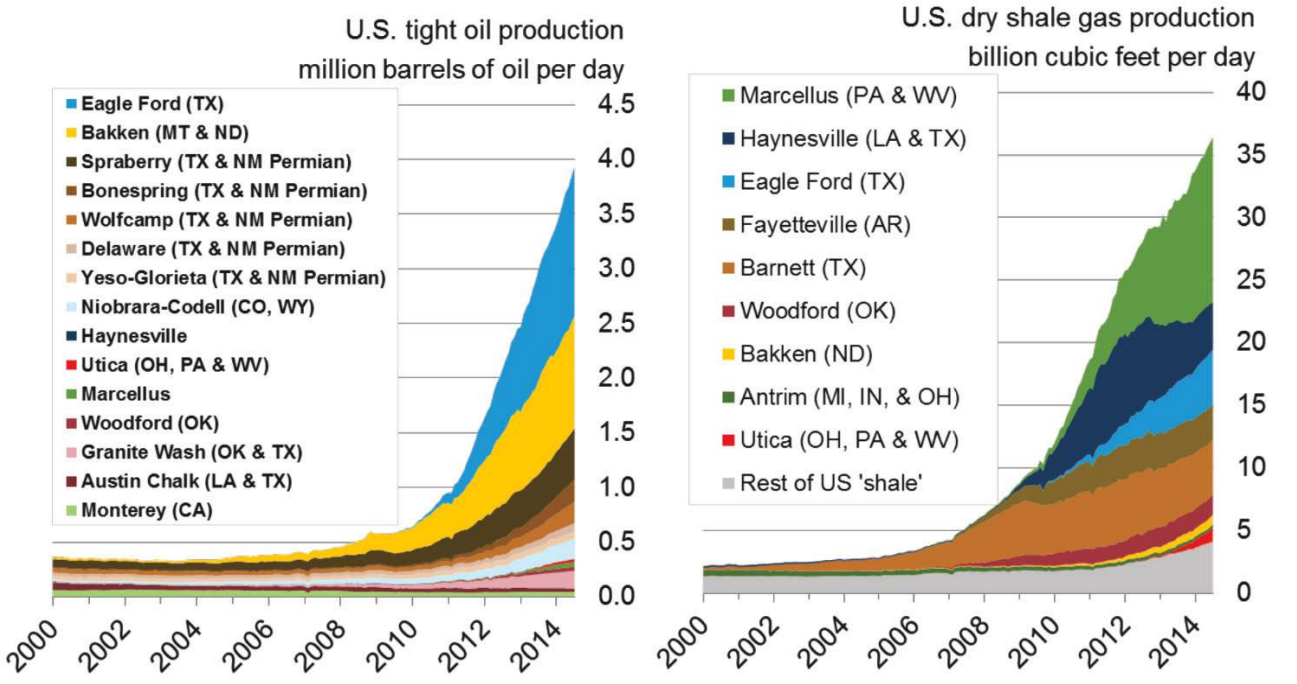

The U.S. has experienced a rapid increase in natural gas and oil production from shale and other tight reservoirs. (Source: U.S. Energy Information Administration)

the potential lifting of the ban, they face continued low gas prices, declining oil prices and refineries that are ill-equipped to handle the light crude being produced from shales.

Why the ban?

Turning the clock back more than 40 years, a country used to cheap gasoline suddenly had a wakeup call when the Arab oil embargo hit. Gas lines formed, thermostats were turned down and Americans were forced to face the fact that sometimes not-so-friendly Middle Eastern countries could control their energy destiny. The term "energy independence" seemed to be a pipe dream, yet politicians did what they could to ensure that what little domestic supply the U.S. did have would be available to the country in times of a crisis. So a ban on crude oil exports was enacted.

Four decades later the ban is a thorn in the side to many. "This whole ban on crude exports is very strange because we are the largest exporter of products today," said Daniel Yergin, vice chairman of IHS and author of *The Quest: Energy, Security, and the Remaking of the Modern World*. "This ban on crude oil exports is a relic of the 1970s, which was a very different world with price controls. It's an archaic remnant that didn't matter for years. Now it actually matters a lot because we're seeing a renaissance of U.S. oil production."

Added ExxonMobil CEO Rex Tillerson, speaking recently to the Greater Houston Partnership, "For decades now the U.S. has pursued energy policies based on the fear of scarcity. The thinking in Washington, D.C., and even some energy companies was that reviving domestic energy production was simply a dream. That's now the old way of thinking."

While there is a general consensus that lifting the ban would be good for operators and not so great for refiners, views differ as to the real short- and long-term consequences of such an executive action. "In the short term, we would expect the price of crude to temporarily increase," said Charles Dewhurst, leader of the natural resources practice at BDO USA. "Pricing differentials in other markets would likely disappear amid an easing of the existing U.S. refining backlog and a consequent amelioration of bottlenecks in pricing and storage."

Longer term, he said, there could be increased pressure for transportation solutions such as the Keystone XL pipeline. "In addition, the harmonizing of global oil prices and free trade principles would allow the U.S. economy to grow even stronger."

Lifting the ban will likely also be a matter of political timing in response to market factors, said Deborah Byers, energy market segment leader for Ernst & Young. "I think the industry is sensitive to the fact that exporting crude in the face of rising gasoline prices is not prudent. One thing to note is that refined product can be exported [already], and such exports have been rising. This may be the natural market result of our current policies."

If the ban is not lifted, domestic operators may be stuck watching prices further decline, said Jason Stevens, director of Morningstar's equity analyst team. "We think it's a matter of fact that the amount of light crude that will build up in storage in the Gulf Coast will begin to a) be tremendous and b) pressure Louisiana Light Sweet and West Texas Intermediate pricing. Without removing that ban, we'd expect price benchmarks in the U.S. to drop enough to discourage production adds over time."

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Energy independence

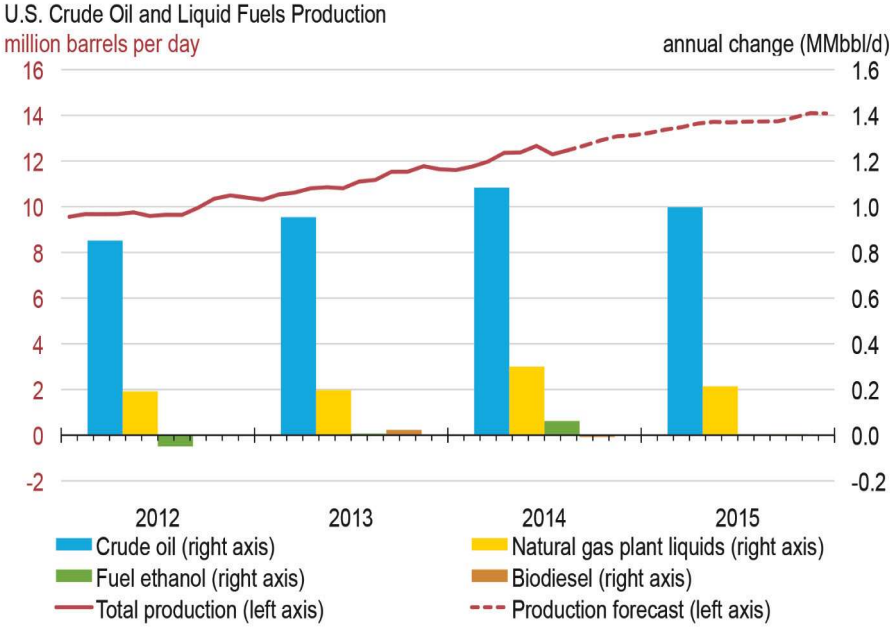
So could the pipe dream be real? Could the U.S. really wean itself from "foreign oil" and be self-sustaining?

Perhaps the better question is should this even happen? "There is nothing magic about the U.S. becoming a zero net importer of oil or energy in total," said Mark Schwartz, president of PIRA Energy Group. "We are already much less dependent on the Middle East and the rest of the world for oil, and this is already impacting our trade balance, domestic energy policy and maybe even Middle East political decisions. So the impact of reduced dependence
is very real even if we are still net dependent on some imports."

Added Don Paul, professor and William M. Keck Chair of Energy Resources at the Viterbi School of Engineering at the University of Southern California, "The past high level of dependence on imports from some OPEC members put the U.S. in a more complex geopolitical position, but the flattening U.S. fuel demand and growing domestic production has changed this balance materially."

The discussion also needs to be put in the proper context. Fear mongering has made Americans leery of oil coming from unstable countries, but there's much more to the picture than friends and enemies. "People used to talk about energy independence or reducing imports in terms of what it meant for security and trade," Yergin said. "What people didn't realize is what it means for a domestic economy. We estimate that already over 2 million jobs were supported by the unconventional revolution by 2012, and that number could reach 3.3. million by 2020."

Then there is the global aspect to oil. A protectionist approach is in no one's best interest, the experts noted. "What we need is energy interde-



Production of crude oil and liquids is projected to grow by more than 1.2 MMbbl/d in both 2014 and 2015. (Source: U.S. Energy Information Administration)

pendence, a global market in which the U.S. has more influence as both a major supplier and the biggest consumer," said Loren Steffy, a consultant, columnist and author.

Added Byers, "You can go around the political merry-go-round as to whether some imports are 'worse' than others. The reality is that all imports have balance-of-payment implications.

"But from an economic perspective, trade is not necessarily bad. Even if the U.S. imported little oil from the Middle East, as long as our allies need that oil, we will have to share some of the consequences of a possible cutoff in supplies. We are not an island."

LNG brings another component to the table. While oil has been a global market for decades, natural gas tends to be a domestic market due to transportation issues. But LNG exports could help minimize the disparity between low prices in North America and high prices in Europe and Asia.

"In terms of LNG—fantastic; let's do it," Stevens said. "By 2020 we imagine somewhere in the neighborhood of 10 Bcf/d [283 MMcm/d] of export capacity to be online, fully permitted and operational. But it's uncertain whether there is an additional 10 Bcf/d that can come from the U.S. without a significant price response."

LNG projects are not without their headaches. Already some of Australia's projects are experiencing severe delays and cost overruns. And progress has been nearly glacial on U.S. projects.

However, Steffy said, if companies are willing to spend the money, this could be a market to contend with. "Even with all of the expense, the U.S. is still one of the lowest cost producers of natural gas in the world. LNG exports could pave

the way toward a more global gas market, which would create greater price stability."

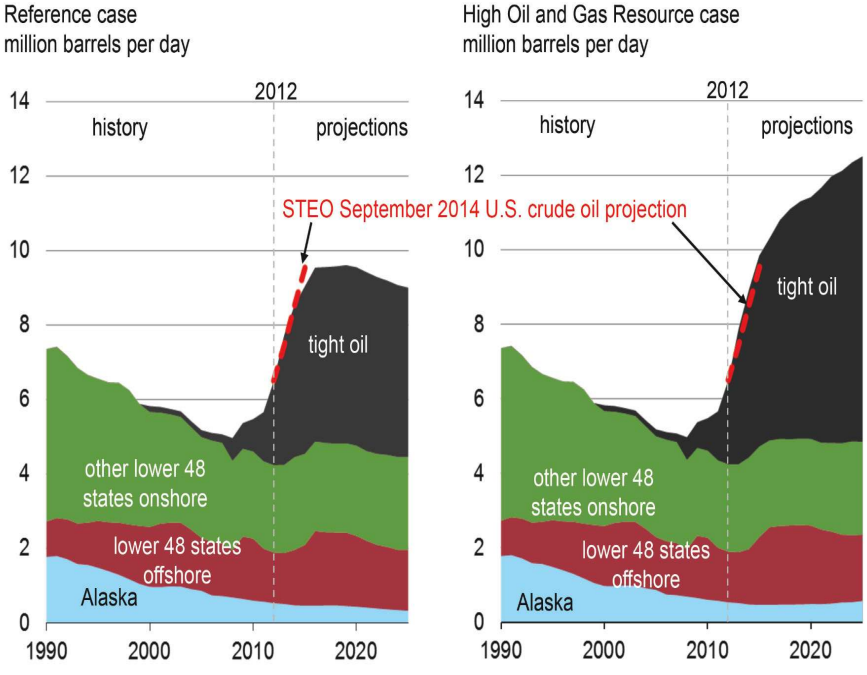
Added Yergin, "I think the U.S. will be a supplier to Europe and Asia. When I'm in Asia, I hear it all the time—Asia would very much like to have U.S. LNG in their supply portfolio."

Appreciating the reality

Amid the debate over oil exports and LNG terminals is a deeper sense of awe that this conversation is even taking place. Many Americans make comments like, "If I'd predicted this five years ago, people would have said I was crazy." The ability to extract hydrocarbons from shales has changed the traditional energy picture for the foreseeable future. And it has helped the world withstand geopolitical forces that could have destabilized it in the past.

"When you look at what is happening in the world, the crisis with Russia and the Ukraine, what is happening in the Middle East, what is happening in West Africa—we would be facing an oil crisis today had it not been for what happened with domestic oil production," Yergin said. "Prices would be much higher, and people would be talking about gas lines. There would be congressional hearings and investigation. All of these things would be happening, and we would feel much more vulnerable than we do.

"The impact of this is not just in terms of energy supply and demand. It has much more far-reaching impacts on our overall economy, our position in the world, our foreign policy and our security," Yergin emphasized. EP



Resource and technology assumptions have major implications for projected U.S. crude oil production beyond the next few years. (Source: U.S. Energy Information Administration)

An unconventional path to energy independence

Japan finds a path to energy independence by applying its technology prowess in unconventional ways.

Jennifer Presley, Senior Editor, Offshore

For Japan, the path to energy independence has never been a traditional one. Limited in its natural energy resources, for many years the country has relied on fossil fuel imports and adopted less traditional forms of energy like nuclear to meet its power generation needs. By doing so, the country has paid a great price—both financial and environmental—to support the more than 127 million people that call the island country home.

As the world's leading importer of LNG, Japan's 2010 imports reached about 93.5 Bcm (3.3 Tcf), accounting for about 31% of the global LNG trade, according to a Rice University Baker Institute Center for Energy Studies report.

After the March 11, 2011, earthquake and tsunami and the Fukushima nuclear accident that followed, the country's reliance on fossil fuels increased to offset the decline in power generation. More than 40 nuclear power plants were shut down because of safety concerns at the time. Nuclear energy consumption dropped from 292 terawatt hours (TWh) in 2010 to about 18 TWh in 2012, according to the BP "Statistical Review of World Energy 2014."

The total cost of power generation increased from 7.5 trillion yen in 2010 before the Fukushima Daiichi accident to 9.6 trillion yen in 2011 and 10.6 trillion yen in 2012, according to an Institute of Energy Economics Japan (IEEJ) report. Fuel cost for thermal power generation rose sharply, from 3.7 trillion yen in 2010 to 6.1 trillion yen in 2011 and 7.3 trillion yen in 2012, almost doubling in the two years from 2010 to 2012. The cost of purchasing natural gas and fuel oil increased the most, the IEEJ report noted.

High energy costs and a lack of natural energy resources has helped to propel the country over the decades into a leadership position in the development of innovative energy technologies. Japan—through its energy dependence—helped to advance energy technology R&D in a variety of areas to the benefit of many. Japanese companies have lent their design, construction and project management expertise to a number of the largest upstream oil and gas projects around the world. In doing so, they also harnessed the knowledge gained through those experiences and applied it in areas like the commercialization of methane hydrate or the conversion of waste plastic for oil.

Harnessing the 'fire in the ice'

It goes by many names—the "fire in the ice" or the "fiery ice from the sea" are a few of its more colorful names—but methane hydrate is a curious clathrate that has generated much interest in recent years, especially in Japan.

Consisting of a gas molecule trapped in an ice-like cage, hydrates can store considerable amounts of gas in a small space. A cubic meter (35 cf) of hydrate can hold about 160 cu. m (5,650 cf) of natural gas at standard pressure and temperature, according to a 2004 National Resource Council report.

Found throughout the world's coastal margins and polar regions, hydrates form at low temperatures and elevated pressures. When one of the conditions changes, the hydrate begins to dissociate, prompting the release of the gas molecule.

About 1.1 Tcm (40 Tcf) of methane contained in methane hydrate deposits in marine sediments has been confirmed in the eastern Nankai trough area off the Pacific coast of Japan. According to Japan Oil, Gas and Metals National Corp. (JOGMEC), this is equivalent to 11 years of the amount of LNG currently imported into the country. An additional 120 Mcm (4.2 MMcf) of gas in methane hydrate deposits has been discovered off the coast of the Aichi Prefecture in central Japan.

To access this resource, the country's Ministry of Economy, Trade and Industry launched in 2001 the Japanese Methane Hydrate R&D Program. Over the years, researchers from JOGMEC, the National Institute of Advanced Industrial Science and Technology and other institutions have participated in several international joint studies on hydrate production, including two onshore tests at Canada's Mallik Field. JOGMEC researchers also played an active role in hydrate R&D efforts in the Gulf of Mexico and Alaska.

In March 2013, JOGMEC announced the first successful production of gas from offshore hydrate deposits at an

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operation site located at the Daini Atsumi Knoll off the coasts of Atsumi and Shima peninsulas. About 120 Mcm of gas was produced over the six-day field test, at a rate of 20 Mcm/d (706 Mcf/d), according to a JOGMEC press release. A second offshore production test is scheduled for Phase 2 with the goal of establishing a technological platform toward future commercial production in Phase 3, which is scheduled for 2016 through 2018.

On Oct. 1, Inpex Corp. announced its participation in the formation of the Japan Methane Hydrate Operating Co. (JMH). Inpex, along with 10 other Japanese companies, formed JMH with the aim of participating in the medium- to long-term offshore production test of methane hydrate. The company plans to provide field operations support and share its findings among Japan's private sector companies, according to a release.

Plastic oil fields

When Hiratsuka-based inventor Akinori Ito sees a plastics-littered landfill, he does not see trash but opportunity. In looking for a way to recycle waste plastic into something useful, Ito invented the Blest Machine. It is a table top-sized machine that converts recyclable plastics—polypropylene (PP), polyethylene (PE) and polystyrene (PS)—back into oil. It does this through the pyrolysis method, according to the company website.

Ito, the CEO of the Blest Corp., said in a TEDxTokyo video presentation that on average 1 kg (2.2 lb) of plastic waste is converted to 1 l (0.26 gal) of oil. The recycled oil can be used as fuel for boilers and incinerators. For gasoline or diesel-fuel equivalents, the company recommends using PP or PE plastics. This "mixed plastic oil" requires further refining using an inline distillation unit to separate the equivalents from the oil. Purified oil from PS can be used as a raw material for plastics, according to the company.

A larger machine—the B-240 (NVG 220)—is capable of converting 200 kg (441 lb) of plastic waste continuously over a 24-hour period. The B-240 (NVG 220) machine was installed in a Whitehorse, Yukon, Canada, recycling center as part of a year-long pilot test in 2012. The results of the test conducted by the Cold Climate Innovation group of the Yukon Research Center at Yukon College were published earlier this year in the "Blest Plastic-to-Fuel Project" report. In it, researchers noted that the system met or exceeded expectations from both an environmental and economic standpoint.

"CO_2 emissions from the machine were 186 g per 1 kg of waste plastic processed, compared with as much as 3,500 g per 1 kg of plastic processed using traditional methods," the report said. "Economical investigations have successfully demonstrated that the Blest B-240 turns waste plastic that has a negative economic value (i.e., shipping costs exceed value of product) into a high-profit product. The B-240 (NVG 220) machine is capable of producing 1 l of fuel at a cost as low as [CA]$0.31 per liter; larger machines produce the fuel at [CA]$0.14 per liter." The B-240 (NVG 220) is sized for communities of up to 1,400 people, while the largest sized machine is capable of supporting communities up to 126,000 people, the report noted.

Through its support of thinking outside the traditional energy "box," Japan continues to walk an unconventional path toward energy independence. EP

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All forms of energy, new technology needed for energy independence

Finding newer and lower cost forms of energy that can be produced, refined and used in the most economical way is the goal for energy independence.

Scott Weeden, Senior Editor, Drilling

Energy independence is not about reducing or even eliminating imports of crude oil, although for the U.S. that is part of the equation. Having enough different sources of energy to make the economy more flexible and attractive to new business makes economic decisions easier and would lead to energy independence.

"In terms of independence a new source of local energy supply certainly enables the economy to import less and receive the benefit of ongoing lower energy costs, which is good for the overall economy," said John Kunasek, national sector lead for energy and natural resources, KPMG LLP.

"It's not just oil and gas. It is new forms of greener energy like solar and wind technologies. It is also technologies that enable us to perform more efficiently and be less energy intensive, which makes energy more abundant and overall cheaper," he continued. "Independence means flexibility. It also means the ability to access new resources more efficiently and effectively."

Lower cost energy equates to better business, which in turn means more jobs. "Is independence the most important thing? I would say no if it comes with a cost. You could be totally independent in terms of energy supply. But if it was at a higher cost, you would not be competitive with other economies that might be able to use energy at much lower costs," he explained. "I think the flexibility and access to all forms of energy are more important goals."

Cheaper, greener energy

The goal is to find newer and lower cost forms of energy, whether it is new supply or new technology that can be produced, refined and used in the most economical way.

"In terms of independence, I think of it in terms of more supply, more forms of energy, cheaper and greener energy. I think that is really what most customers want," Kunasek said.

"The opportunity is to have as much flexibility as possible and access to the most economical forms of energy. That would be the most optimum goal. That wouldn't necessarily be independence, but it would be free access to the most economical forms of energy that would be most important," he continued.

Global connectivity

However, energy independence also means access to markets. The U.S. government is now considering approving more crude oil exports and has allowed the export of LNG. The oil and gas industry is interconnected globally.

There is a debate over whether countries should be independent or interdependent when it comes to energy. "I don't know if the goal would be interdependency or independence. From our perspective, the goal would be efficient energy markets and the lowest cost energy to enable the maximum optimization of the economy," Kunasek explained.

Many countries with few natural resources would consider energy independence consisting of energy security. Japan and Korea are examples of countries that place an emphasis on energy security.

"Europe currently has a significantly higher energy cost structure. It doesn't have as much of its own domestic forms of energy. From a European perspective, the goal would be to get access to more forms of lower cost energy. That is obviously one of the opportunities driving the resurgence of LNG exports in the U.S.," he added.

The markets in Europe are more favorable in terms of energy prices, which is attractive for LNG imports. Both Eastern Europe and Europe have been relying for years on natural gas imports from the former Soviet Union. Russia increased its prices, and European countries are seeking alternatives.

"You have a much lower cost of natural gas coming out of the U.S. even when you add the cost to liquefy and transport the natural gas. The Europeans see a favorable opportunity to receive supplies from lower cost locations such as the U.S.," he emphasized.

Europe is faced with an infrastructure challenge, especially the Eastern European countries. Most pipelines run east to west from Russia. If more LNG, for example, is imported to Europe, there would need to be additional

infrastructure to move the natural gas from west to east. That is the main challenge for Ukraine to diversify its energy supplies.

Europe has "less flexibility in where it is getting its energy supplies, and prices are higher than what might be available on other global markets. The solution is to have better access to global energy supplies such as cheaper natural gas and have the infrastructure to get the supplies to their economies," he continued.

Huge resources, no independence

While countries with fewer natural resources are scrambling to find additional energy supplies, countries at the other end of the energy spectrum—Tanzania and Mozambique, for example—have huge gas reserves but are not energy independent.

"It is not only important to have known energy reserves in your country, but you also have to have the economy that needs the energy supplies, which are going to flow to the economies that have the greatest needs and the best markets," Kunasek said.

"Once you have the economy, it becomes more economical to build the infrastructure to be able to deliver the energy, whether it is to a refinery, gas plant or shipping terminal. That infrastructure is really critical because it requires a lot of capital, and it takes a long time to develop," he continued.

Those countries are independent in that they have available energy supply. "But if you're defining them as truly independent, they really need the markets to sustain the infrastructure that needs to be built to deliver it. If you truly want to be independent, you have to have the infrastructure to deliver it. It comes down to economics," he emphasized.

Grid parity

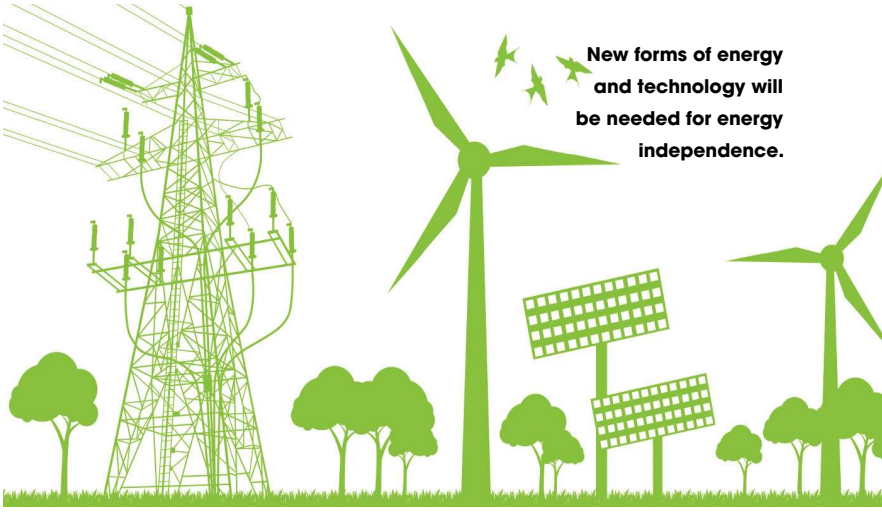
Even though economics are important, technology is another trend that is worth watching. For example, on the electricity side of the energy business, there is a trend around distributed generation and cheaper forms of localized energy supply.

"In some areas, costs associated with distributed forms of energy have grid parity with other forms of energy. Grid parity measures the economics associated with local forms of supply like distributed generation and the delivered cost of current electric energy. My point here is to watch technology and the cost associated with more localized forms of supply," Kunasek explained.

The electricity industry could follow the telecommunications industry. "If costs come down as technology breakthroughs continue to occur, you could see almost a leapfrogging effect over expensive delivery infrastructure and construction," he said.

For example, in rural parts of Africa, there are no telephone lines. However, wireless telephones are available in those areas. "With the costs low enough, you have localized supplies that don't need infrastructure, that don't need a wire or transmission line. In the U.S. the wireline telecommunications industry almost doesn't exist anymore. The wires are still there. If you look at Africa, they don't even have the wires; it's only cell towers.

"If you have a localized form of energy where it is needed and it is cheap enough, it will develop and take off. Eventually localized energy will happen similarly to what happened with telecommunications. In energy, there's a similar trend that is beginning to happen associated with delivered or distributed forms of generation.



New forms of energy and technology will be needed for energy independence.

You could achieve a higher degree of energy independence without the need for the delivery infrastructure," he emphasized.

These different distributed generation systems include commercial energy storage, solar, micro-wind and micro-generation. If the cost trends for these continue to go down, "then you could have that leap-frogging effect where you wouldn't need all of the delivery infrastructure," he added.

A lower cost form of distributed energy could be a significant technology breakthrough to give energy supplies to 1.5 billion people who don't have access to electricity. "It has the potential to change dramatically the energy footprint in the world," Kunasek concluded. E&P

What the data can tell us

A comprehensive study of several shale plays reveals remarkable granularity—from public data.

Rhonda Duey, Executive Editor

The unconventional revolution may have changed the landscape of the oil and gas industry, at least in North America, but it's also rewritten the playbook in terms of what operators thought they knew about producing oil and gas.

Shale reservoirs do not behave like their conventional brethren, and operators struggle with everything from flow physics to field development. It was with these uncertainties in mind that Siddhartha Gupta and Raj Banerjee of Schlumberger set out to study public data to draw some conclusions about unconventional reservoirs. Their findings are outlined in URTeC 1873063, "Leveraging the Power of Public Data to Solve Multiple Challenges in Unconventional Reservoirs."

The authors spent six months culling public data to determine their findings. "This is one of the few studies conducted involving the use of public data and the first to cover the spectrum of reservoir from completion to production," Gupta said. Much of that time was spent conditioning the data, he added. "Gathering unstructured data like weather patterns and pipeline information required significant time," he said. "Since this was a unique study, there were several moving parts involved in it, and planning the workflows so that each tied in seamlessly into the next was critical."

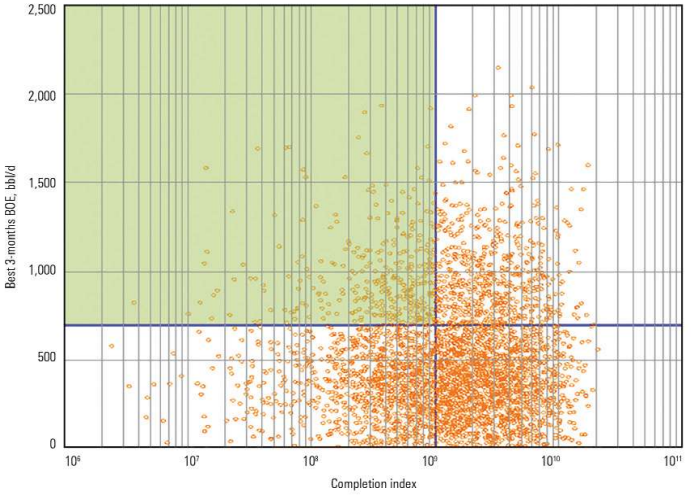


FIGURE 1. Screening for refracks allows operators to eliminate a large percentage of wells that will not benefit from the procedure. (Source: Schlumberger)

The goal was to develop a workflow that could honor a variety of data types without being overwhelming. "High well counts increase the volume of data, which makes it overwhelming to analyze on a typical spreadsheet," the authors noted in their abstract. "Integrating efficient data management with seamlessly integrated analysis tools makes it much easier to understand the data and interpret the results."

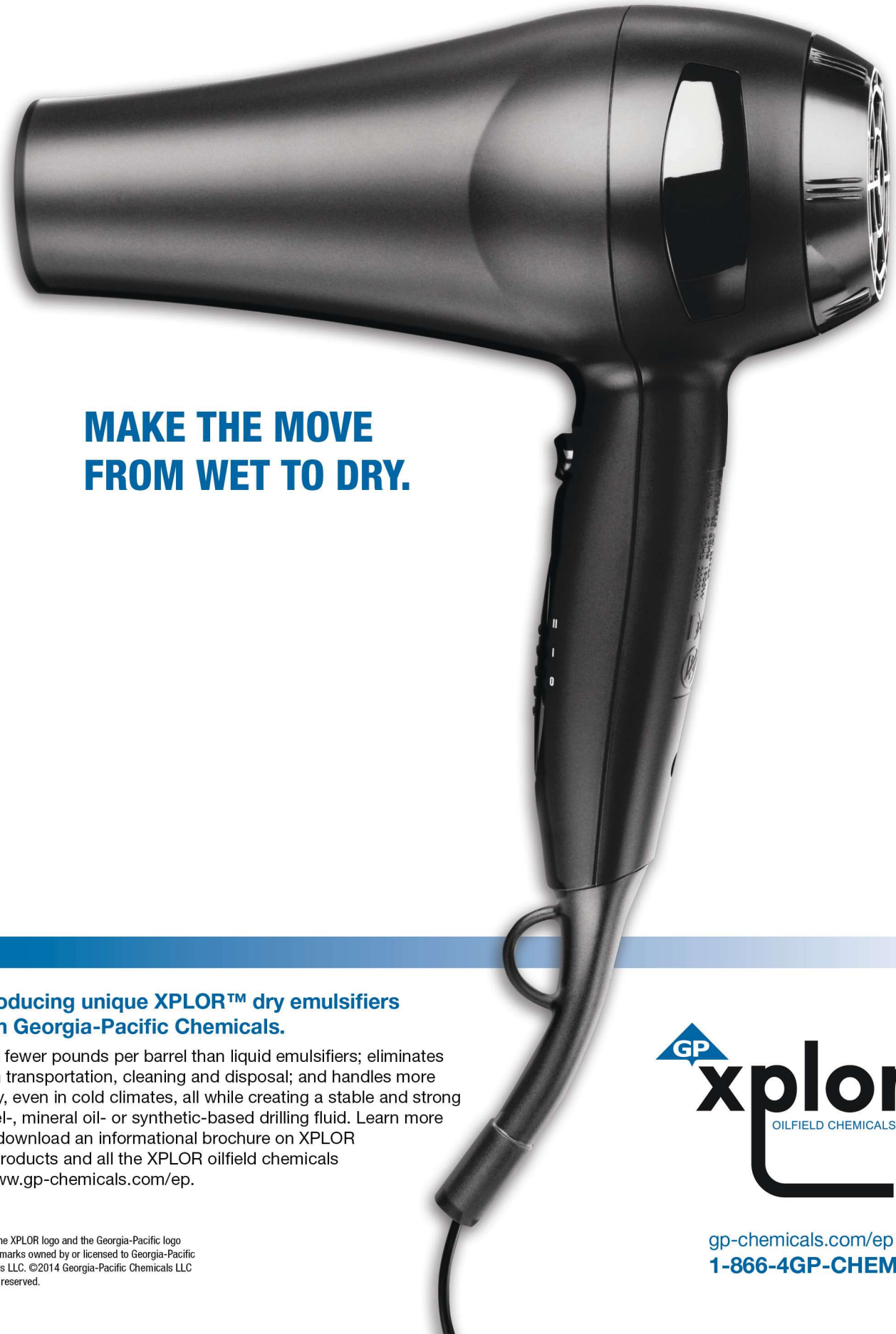
The study

The authors used the seven major shale plays in the U.S. as a starting point for the study. They examined data from more than 60,000 wells and 100 million data points. These data types included production rates; completion information such as proppant volume, fracturing fluid volume and stages; well locations; operating companies; and well test data. Part of the study was to determine why certain operators performed better in certain plays. "In almost all of the basins, the top five operators (in terms of average liquid or gas production per well) complete their wells with less resource consumption (proppant and fluid) than others while producing more hydrocarbons," the authors noted. "Either these operators are located in the better part of the basin, exposing them to a higher quality reservoir, or they are using engineered completion techniques to fracture their wells with less resource consumption [while] delivering a better well."

Certainly some operators do have a geographical advantage, they noted. In the Eagle Ford, for instance, the top five operators are located in the northeast corner of the field, and the sixth operator, whose acreage sits outside of this sweet spot, has laterals that average 1,463 m (4,800 ft) longer than the top five. "A longer intercept with the reservoir helps in offsetting the location disadvantage," they noted.

The Bakken, on the other hand, lacks this sort of explanation, leading the authors to surmise that the use of reservoir characterization and an engineered approach are the keys to success in this field.

This kind of analysis can be useful in identifying refrack candidates. Figure 1 shows a crossplot of a production



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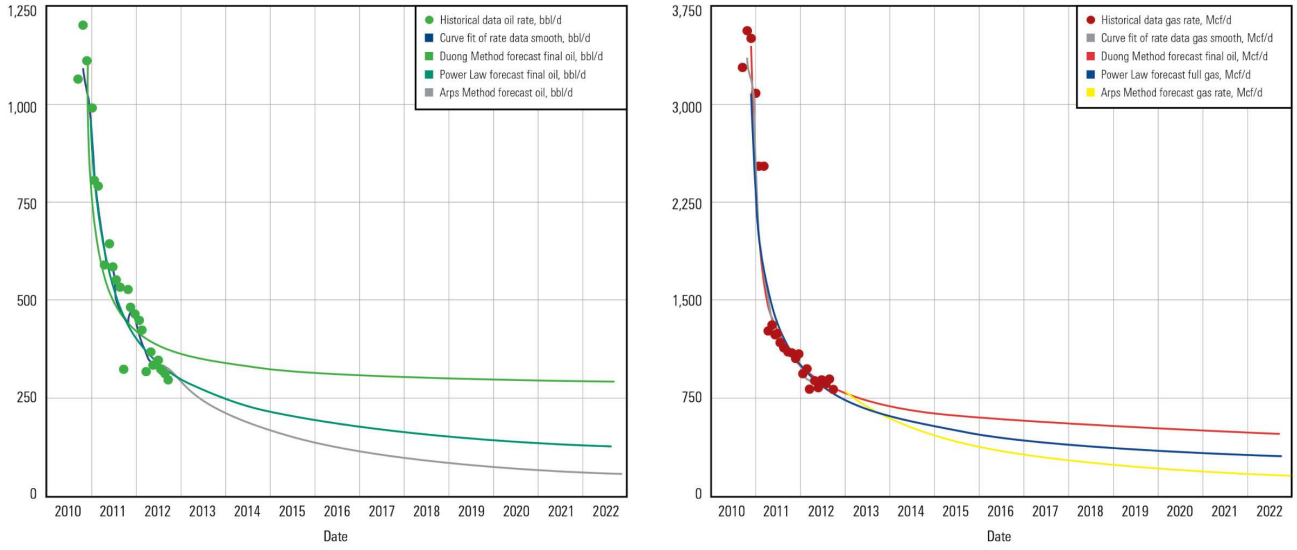

FIGURE 2. Oil (left) and gas (right) production is forecast for one well using the three techniques: green and red, Duong; purple and blue, power law; and gray and orange, Arps. (Source: Schlumberger)

index against a completion index. Wells in the highlighted quadrant are good producers even without optimal completions and are therefore good refrack candidates. The authors noted that this method can be used to eliminate 85% to 90% of potential refrack candidates that have already been completed optimally and therefore are unlikely to benefit from a recompletion.

Decline curve analysis

Decline curve analysis also is challenging in shale wells. The authors devised a fit-for-purpose technique in which a flow regime is applied to make sure the well has not yet reached boundary-dominated flow. For these wells, a Duong method and a power law technique are used, which provide more accurate results than the Arps technique. When applied to the entire 4,000-well population of the Eagle Ford Shale, these methods provided good curve fits (Figure 2).

Well trajectory

To determine trajectory effects, the authors used a transient flow simulator. Three wells were chosen and were toe up, toe down and undulating. Inflow and pressure-volume-temperature were maintained for all three wells.

A simulator was run for two hours, after which the flow dynamics were observed. The authors noted that the toe-up well had some gas buildup near the heel, although slugging was minimal. The undulating well had gas buildup in the low point of the well, and the toe-down well experienced liquid buildup near the toe that caused slugging along the entire lateral length.

"When drilling a well, these factors must be considered because chasing the dip of the formation can sometimes result in a well that has extreme slugging and does not drain effectively," the authors noted.

Next steps

Now that the first study has been completed, Gupta said, subsequent studies should go more quickly since the structure of the workflow is in place. The initial study was conducted using commercially available tools, mostly from Schlumberger, although a third-party application was used for the business intelligence tool that delivered the high-level visualization. He said that Schlumberger is currently expanding its data analytics portfolio to create "an end-to-end solution encompassing this study and other geological workflows that have been created by other Schlumberger groups." Schlumberger also offers consulting services for these types of studies, he added.

Since there was no operator directly involved in the study, Banerjee added that it's difficult to say that a study like this has augmented anyone's decision-making process. "However, all of the steps in this workflow are backed by technology highly relevant to the unconventional market, making it useful for any operator large or small," he said. "Independent companies have an even greater advantage in that their own production, completion and reservoir data are far more granular than what is available in the public domain. This makes it much easier and more valuable for them to do a study like this to refine their decision-making process." E&P

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A controlled subsea future

The next generation of subsea control systems will play a key role in the industry's advance into deeper, colder and more remote environments.

Steve Sasanow, Contributing Editor

When you put a group of subsea control technologists together in a small room to discuss the future of controls, one would expect a lively discussion about fiber optics, data flow, all-electric systems and the like.

What came out during a recent technology day in Aberdeen, Scotland, hosted by Aker Solutions were not so much desires but concerns. Has reliability gone into reverse? Are systems too complex? Would standardization have a negative effect on innovation? Will local content requirements in some countries further delay the implementation of new technology? Have operators really taken on board the need to reduce costs?

The purpose of the day was mainly to hear from the recently revamped and now more subsea- and deepwater-focused Aker Solutions (following its split into two separate entities, the other being Akastor, an oilfield services investment business that will develop the former group's other units) on what it is doing, mostly related to control systems.

Next-generation SEM

The company took the opportunity to announce the launch of its sixth-generation subsea electronics module (SEM), dubbed Vectus 6.0. Aker Solutions' vice president of control systems, Davy Benison, called it "a step change in technology" that has come after more than 30 years of subsea controls development. This is not just new electronics in a new canister but something quite different, combining new architecture with new hardware and software. The redesigned SEM incorporates three modules—the electronics module designed with no wiring (i.e. all plug-in circuit boards), an auxiliary electronics module for control of chokes and valves and a 24-v DC power supply module with a wide range of output power—200-v to 900-v AC and 280-v to 1,200-v DC.

In terms of quality, a key target is to eventually have zero failures and rework during final assembly as well as full traceability of all components and a database of all test results. Aker also is looking to improve reliability and manufacturability (with a standard repeatable build process and fully automated test operations).

The SEM from Aker Solutions has been designed to be 'future-proof,' meaning it is based on a platform that can meet and incorporate new technology needs. (Source: Aker Solutions)

Future-proof

The SEM is also meant to be future-proof, meaning based on a platform that can meet and incorporate new technology needs. The presentation included an image of Statoil's subsea factory concept as such a future example, something that Aker has been working on with the Norwegian operator for some years now.

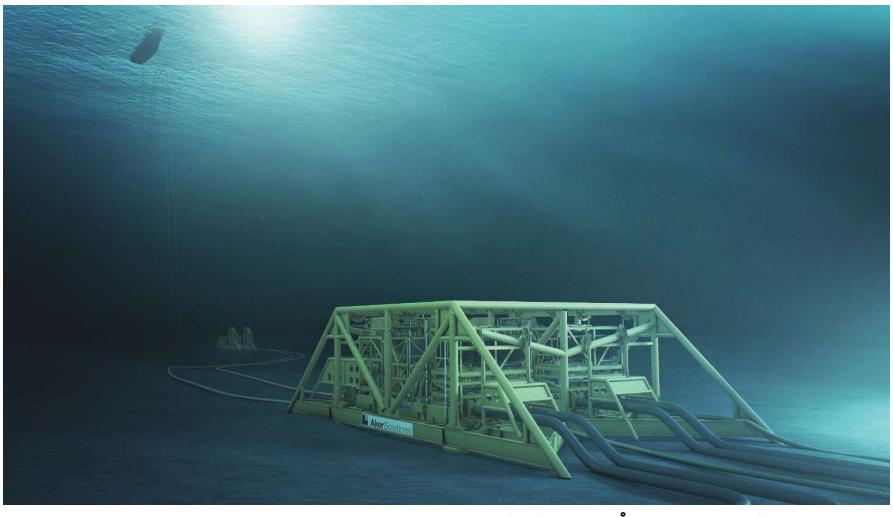
However, future-proofing is not as big a problem today as obsolescence. Aker Solutions' U.K. managing director, Matt Corbin, said at the technology day that he was pleased that a recent Statoil presentation had added the challenge of "older" to the standard "deeper, colder, longer" mantra.

Operator viewpoints

Also at the technology day were presentations given by technologists from Total and Shell.

Bruce Gardner, who left Aker Solutions six years ago to join Shell U.K., highlighted Shell's focus in keeping its current inventory of controls system (and wells) running at the lowest cost. Its acronym of the moment is AIPSM (Asset Integrity Process Safety Management).

The key technology for Shell with its aging systems is a backward-compatible low-power SEM that has been jointly developed with Aker Solutions.



Work in progress—the seabed compression module for Statoil's Åsgard Field offshore Norway is due to start up before the end of 2015. (Source: Aker Solutions)

Gregor Deans from Total, meanwhile, presented a wider technology menu including beyond 2025. Total's menu is as extensive as that of a Parisian brasserie, with the ongoing focus on deeper waters and long-distance tiebacks with a few items not yet in use. These include subsea chemical storage and injection to reduce the size of umbilicals and permanently located AUVs for subsea inspection and maintenance—the latter being something still under consideration for inclusion on the operator's large Kaombo development offshore Angola.

All-electric future

Total has of course been the champion of all-electric subsea systems—it has the only two electric trees in the water—and it continues to see this as a technology with a future. It will install its third Cameron/OneSubsea electric tree in early 2016, but this time the system will include an item previously missing on the past applications—an electric downhole safety valve, which is now qualified.

Also nearing fruition are solutions including compact separation, more subsea seawater treatment and injection (SPRINGS – Subsea PRocess and INjection Gear for Seawater) currently on a pilot in the Congo offshore West Africa, high- and low-pressure gas-liquid separation, high-power boosting, and long-distance dry compression.

New systems from subsea alliance

On another matter, the Aker Solutions-Baker Hughes Subsea Production Alliance formed earlier this year was said to be getting ready to launch two new systems—PowerJump, a horizontal seabed electric submersible pump (ESP); and PowerHub, a retrofit ESP installed by coiled tubing and hung off the top of the tubing hanger. Also in the cards is the completion of the qualification at the beginning of next year of Aker Solutions' MultiBooster multiphase pump.

Aker Solutions also revealed at its technology day that its Quad 204 project for BP west of the Shetland Islands in the U.K. sector is its largest ongoing controls program, with a modular control system capable of handling 100 wells and 60 new subsea control modules, including 14 for new wells.

Seabed compression

Offshore Norway, meanwhile, it is continuing to make good progress with the Åsgard Field's subsea compression system for operator Statoil. The manifold station, compression template and topsides module have all been installed, with delivery of the Train 1 modules due in December this year. The delivery of Train 2 and Train 3 is due by April 2015, it added, after which commissioning activity will take place with the aim of achieving first gas before the end of the year.

Åsgard is a flagship project for Statoil as it seeks to continue with its EOR initiatives to boost production levels from Norway's existing fields. In this case it is the producing but steadily declining (in terms of the reservoir pressure) Mikkel and Midgard fields that flow to the Åsgard B floating production platform about 40 km to 50 km (25 miles to 31 miles) away.

From Aker's perspective, it sees the subsea factory solution as the next step to achieve after the Åsgard compression project work is complete. E&P

Subsea Business Drivers:

- Deeper waters, aging fields, complex reservoirs, harsh fluids
- Need for increased oil recovery from existing and future fields
- Longer subsea step-outs (also driven by harsh environments)
- Need for reducing field development cost (capex and opex)

Surviving boomtown economics with working capital

Invoice factoring is enabling oil contractors, producers and startups with access to working capital, clearing the cash flow hurdles that stand between a new generation and its ability to capitalize on the gold rush.

Tracy Groves, eCapital

Doing business in the oil field is reminiscent of gold rush days, with lots of risk, challenge and opportunity for a small business or contractor willing to work hard. It is an entrepreneurial and exciting place to be, and often it does not take long for both technical and hands-on workers to realize that they can make it big—as long as they can find a way to manage cash flow and navigate the more complex aspects of doing business with big oil companies. Accounts receivable (A/R) financing, also known as factoring, is playing an important role here, enabling oil producers to effectively manage cash flow in a volatile, demanding industry. It's a less traditional type of financing, potentially not as well understood in the rough and tumble environment of the oil field. However, it is optimized to support businesses based on invoices and contract assets. Factoring provides an alternative to options like bank loans or credit cards, which require time, financial review, and ongoing payments and management in an industry where most operators have minimum desk time for these types of administrative tasks.

Thriving takes planning

Independent contractors, producers and operators are enjoying the most substantial boom in American oil production in decades, yet all should assume complexity and long terms in getting paid for their oilfield work. While the payoffs are big, there are many costly steps between doing the work and actually getting paid, things like establishing insurance or covering housing, food, fuel, payroll or equipment. Sign-offs are required at every phase of work completed, and typically long payment terms with customers demand a cash flow strategy to pay workers and handle monumental working expenses. Adding wells or new employees compounds the financial challenge, and most businesses can only grow as much as their cash flow allows.

Oil workers also secure formal contracts called master service agreements (MSAs), which are required to work directly with the biggest oil producers and operators. Work can be completed as a subcontractor without an MSA, but direct relationships require MSAs outlining insurance requirements, agreed-upon services, payment terms and more. Greater success and higher income comes with multiple MSAs in place, although this adds complexity to running an oilfield business from a cash flow perspective. MSAs further demand a cash flow strategy to ride out 60- to 90-day payment terms common to these agreements. Subcontractors without MSAs face a similar issue since they are on the farthest end of the payment hierarchy.

Factoring provides a way for companies to avoid becoming cash-strapped during a boom.

Cash flow plan

A/R financing is optimized to support businesses based on MSAs and contract work and functions as a straightforward solution that provides consistent cash flow. While it may be new to some oilfield workers, factoring is a long-established financing method. It is a financial transaction where a business sells its accounts receivables (or invoices)

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at a discount to a factoring company (or factor), enabling the business to gain immediate access to its cash.

In contrast to bank loans or credit cards, which don't easily fit the oilfield business model, funding is tied to approved invoices, known in the oil patch as tickets.

The factoring process is not concerned with the contractor's credit and focuses instead on the oil company paying the ticket. Oil workers are granted rapid access to cash by selling their tickets to the factoring company at a discount in exchange for payment in as little as 24 hours. Contractors are paid quickly, and the factoring company takes on the role of the A/R department, easing the administrative load and leaving the contractor to focus on the job itself.

Startups qualify for factoring. Because the process is based solely on invoices, it requires no financial review or underwriting, and there are no predefined limits to factoring funds. Oil workers can choose which customers to factor, and the availability of immediate cash remains in step with new contracts, ideal for any firm in expansion mode. No interest accrues, and no debt is added to the company balance sheet.

Fueling the oil and gas business

The factoring process starts with the seller generating an invoice for work completed; that is, the oil worker completes the work, has the sign-offs and produces a ticket. Rather than providing it to their customer (the oil company that employs them), they agree to work with a factor and sell the ticket to them. The factor issues a notification to the debtor (the oil company being invoiced) that payment should be issued to them instead of the oil worker, which results in a simple change in the "remit to" address for payment. The factor in turn provides immediate funds to the oil worker in the form of a cash advance, typically a high percentage of the face amount of the ticket. When the debtor actually pays for the services invoiced, the factor pays the seller the remaining balance (the reserve) minus its discount fee for handling the transaction.

In addition to receiving customer payments quickly, the factor can act as the oil worker's A/R department and assist with back office support. This can be attractive for individuals or smaller contract firms in particular, adding value by creating a larger business image and handling tasks that are difficult to manage on the road or from the field.

Capitalizing on the boom

With long hours, desolate locations and demanding work schedules, this is an industry that many don't stay in for an entire career, making it even more essential to capitalize on the boom with staying power and financial resources. Garnering multiple contracts and MSAs makes the most of the boomtown opportunity at hand, yet a cash-strapped contractor may opt out of the additional insurance requirements necessary to win the next MSA, either because the working capital is not available or simply to protect the cash flow it does have.

Expanding with new MSAs compounds these issues exponentially with larger crews, increased operating expenses and additional equipment. It's a very lucrative problem, but it is still a problem. Waiting months for the money to come in can jeopardize any oilfield entrepreneur, adding potential for debt, stressing business operations or even losing the next job to a better-funded worker.

Factoring is optimized to support businesses based on invoices and contract assets.

Working capital strategies such as factoring are optimized for the oil field, eliminating the financial bottlenecks that come with complex payment processes and extended terms. Oil workers are bypassing stringent financial review, avoiding debt added to the business and receiving funds electronically, often within 24 hours of processing invoices. Most importantly, invoice-based financing is providing a means to maximize earning potential, ensuring that growth remains in sync with the business at hand and providing operating capital for winning new customers or tapping new wells. E&P

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Proppant type, additional factors impact production

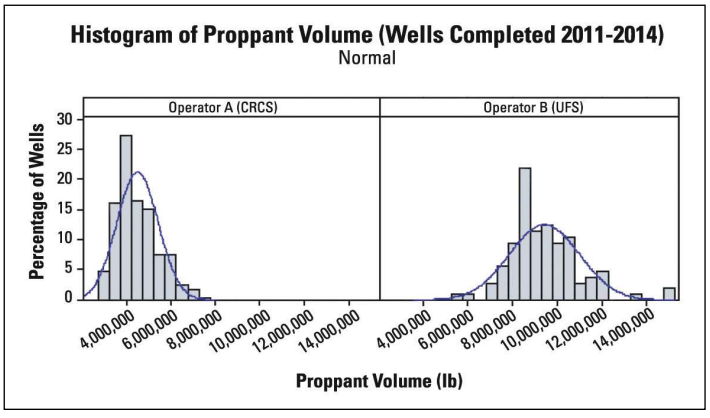
In a statistical analysis of Eagle Ford wells, CRCS shows improved results.

Andrea Hersey, Momentive Specialty Chemicals Inc.

As development of unconventional resources in the U.S. continues, the Eagle Ford Shale has emerged as one of the country's most active shale plays. Since the play's early beginnings, oil production has increased significantly, from an average of 352 bbl/d in 2008 to 8.38 Mbbl/d in April 2014, as reported by the Texas Railroad Commission.

The reservoir characteristics of the Eagle Ford make it a prime candidate for hydraulic fracturing. One of the highest costs incurred in the fracturing treatment is the proppant, which also has a significant impact on well performance. This emphasizes the need to find the optimal proppant type, design and volume based on well conditions and budget.

The main proppant types commonly used in fracturing treatments are uncoated frack sand (UFS), resin-coated sand (RCS), uncoated ceramic (UC) and curable resin-coated ceramic (CRCC). Traditionally, RCS, UC and CRCC are labeled "premium" proppants for their higher performance and price compared to UFS. RCS has two proppant types: curable resin-coated sand (CRCS) and precured resin-coated sand (PRCS). CRCS has the ability to control proppant flowback, minimize embedment, help prevent proppant fines migration and enhance long-term production. PRCS is an older technology with fewer benefits than CRCS.



This histogram shows proppant volume for wells completed in 2011 to early 2014 for Operator A and Operator B. (Source: Momentive Specialty Chemicals Inc.)

As oil and gas technology progresses, job sizes have increased, and proppant designs have changed. According to a study by PacWest Consulting Partners, the average proppant volume per well trend in the Eagle Ford rose about 50% from 2011 to 2013. In 2014, proppant volumes have been reported in excess of 14 million lb per well.

A three-part study was published that performed a statistical analysis of more than 2,500 wells in the Eagle Ford, finding that factors such as proppant volume and measured depth of the deepest perforation were statistically significant to impacting three-month boe production (SPE 158501).

Proppant trends

In a case study compiled by Momentive Specialty Chemicals Inc., a similar methodology was applied but with a narrower focus. Only two offset Eagle Ford operators were chosen so that specific completion details (such as proppant type and volume) could be correlated to production over a three-year period. These operators were chosen based on proximity to one another and their selection of very different proppant types. Operator A uses CRCS, while Operator B uses UFS. Both operators are in the same county in the oil and condensate window.

Production and completion details from all wells spanning 2011 to early 2014 were in the initial dataset for each operator. Of the more than 340 wells studied, only 3% were removed due to having less than three months of production. This was done to ensure accurate trend prediction and was the only change made to the dataset throughout the entire case study. The number of wells was roughly split 2:1 from Operator A to Operator B.

Each well was categorized based on the length of production time to ensure that wells completed in similar time periods were compared to one another. In theory, an operator should see production improvements over time based on ongoing completion optimization efforts since wells completed three years ago can be very different from wells completed three months ago. Each well was assigned a production time frame and only appeared in a single dataset ranging from three to 36 months.

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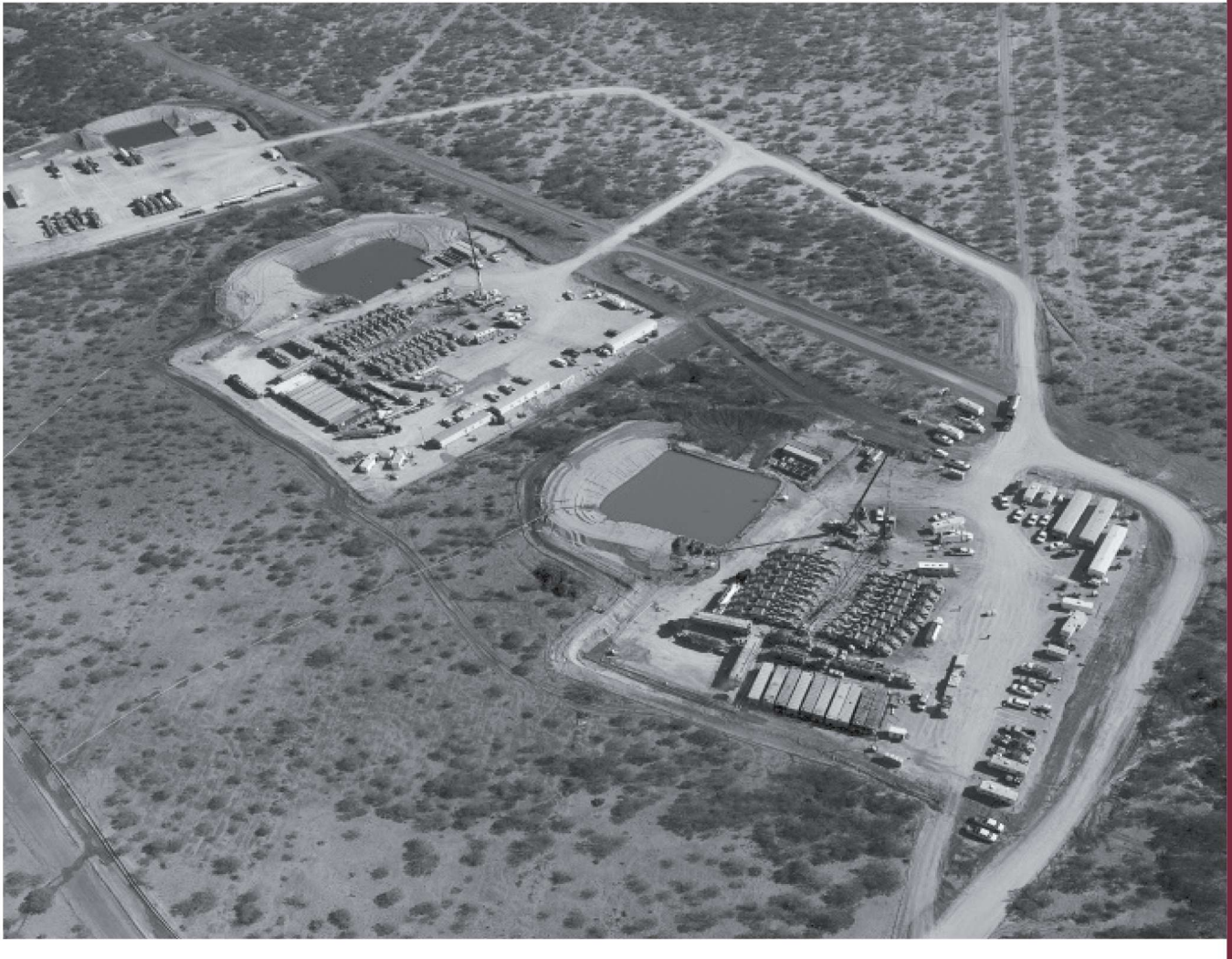

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Analysis was focused on comparing completion factors, cumulative production, decline curves and their resulting statistical correlations.

Completion factors such as proppant volume, production interval (the distance from the upper perforation to the lower perforation along the lateral) and true vertical depth (TVD) were averaged for each dataset. In addition to calculating averages, all data were loaded into statistical software to look at the data distribution to allow a more comprehensive analysis of the data.

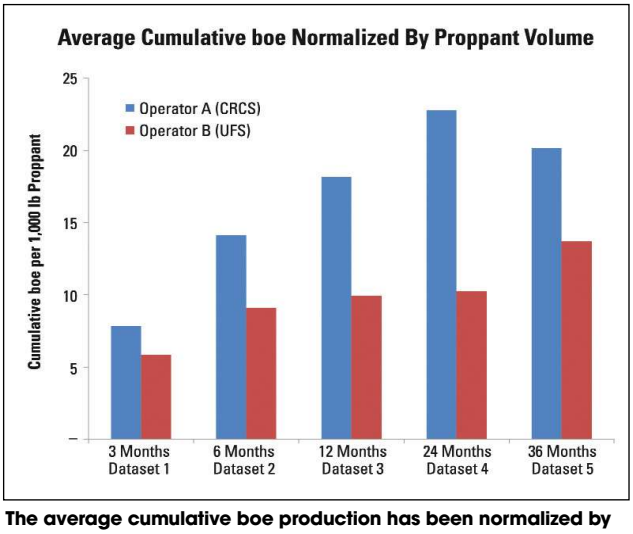
Main findings

The main takeaways from the histogram analysis of completion data are:

- Average total proppant volume per well for Operator B (~9 million lb of UFS) was more than twice the proppant volume per well of Operator A (~4 million lb of CRCS) and was the largest difference between operators over all the completion factors analyzed; and
- Operator B had 20% longer production intervals and 10% deeper wells than Operator A.

Next, cumulative production graphs and decline curves were generated that looked at three comparisons: each operator vs. itself, Operator A vs. Operator B and production normalized by proppant volume. Oil, gas and boe were analyzed independently, but only boe results will be discussed in this article. Main takeaways:

- Both operators showed production increases over time, which supported well segmentation by time frame;
- For wells with six months or less production, Operator B averaged 32% higher boe production with double the proppant volume of Operator A. Operator B averaged a 43% decline, while Operator A averaged a 24% decline;
- For wells with 24 months or more production, Operator A had 28% higher boe production with around half the proppant volume. Operator B averaged an 89% decline per well, while Operator A averaged a 70% decline per well;
- Cumulative boe/lb of proppant was roughly twice as high for Operator A; and
- Based on historical declines, if Operator A switched to Operator B's design, an additional 16 wells per year would have to be drilled to maintain the current production rate.



The average cumulative boe production has been normalized by proppant volume. (Source: Momentive Specialty Chemicals Inc.)

Finally, statistical analysis examined the cumulative production (oil and gas independently) for each well and compared against each completion factor as well as the interaction between factors. Statistical software was used to run regressions to determine which factors are significant and which will have a more positive impact on production.

Six months and 24 months were chosen as goalposts to represent short- and long-term production. CRCS had a greater benefit at both time frames. However, proppant volume also was very significant to upfront production.

Similar results were shown for gas; however, TVD was significant to both time frames, and deeper wells were shown to have more gas production.

Further testing

Further support of why CRCS has a positive impact on production is shown in laboratory testing. Tests showed that UFS generates 16 times more fines than CRCS when exposed to wet, hot crush testing under conditions similar to the Eagle Ford. This will significantly decrease the effective conductivity, which is evident in the long-term production results of UFS compared to CRCS (SPE 135502).

Based on the analysis, the additional upfront production seen by Operator B may be driven more by the increased proppant volume over Operator A. To maximize production and decrease decline rates, increased volumes of CRCS should be used. Although CRCS has a higher cost than UFS, further analysis shows that the return on investment by doubling the proppant volume of Operator A would be two months based on a 20% production increase.

There are many other factors (such as choke size and pump rate) that can impact production. However, out of the factors that were analyzed in this case study, proppant volume and proppant type were confirmed to be statistically significant to impacting the production. Although the strategy for developing an asset will vary from operator to operator, it is important to make sure that industry trends do not take the place of historical well analysis and experimentation. E&P

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The 'great integrator' in petroleum exploration

BPSM is becoming even more relevant as projects become more complex.

Allegra Hosford Scheirer, Stanford University

The discovery and exploitation of oil and gas in unconventional reservoirs has been called a revolution for the energy industry. Indeed, the unconventional revolution is transforming the petroleum industry across all sectors as demand for trained personnel, proppant and water for well operations, and scientific data skyrocket around the globe. Following the discovery of an unconventional resource play, operators focus on optimizing production efficiency. Detailed petrophysical analyses as well as sweet spot identification from seismic data are essential. Also critical are the collection and interpretation of organic geochemistry, geomechanical indicators of rock brittleness and stress regime, source potential and maturity, pore pressure, and depth of maximum burial. In short, the evaluation of source rock presence and producibility for oil and gas in unconventional reservoirs requires far more data than commonly employed during exploration for conventional stratigraphic or structural traps.

BPSM software

How does industry cope with the data deluge that accompanies the unconventional resource revolution? The answer lies in a familiar tool: basin and petroleum system modeling (BPSM). Developed initially to assist conventional exploration, BPSM software has become increasingly relevant for understanding the huge quantities of oil and gas that remain in organic-rich source rocks. As it does for conventional resource plays, BPSM for unconventionals predicts the thermal maturity of the source rock, physical properties of the generated oil and gas and subsurface properties such as temperature and pressure—important things to know when assessing the viability of a resource play.

What may have gotten lost in the rush to acquire data and optimize well performance, however, is that the BPSM goes far beyond providing traditional information to the investigator. BPSM, in fact, can serve as a holistic integration platform through all stages of the exploration and production process. For example, a key factor needed to assess the economic viability of an unconventional accumulation is "movability," or how easily the petroleum can be mobilized to flow into the wellbore. The generation of petroleum proceeds along a well-established path from liquid that contains dissolved vapor to gas that becomes drier as the remaining hydrogen-poor kerogen is depleted. Two factors related to this process are relevant to the basin modeler studying unconventional resources. First, fluids that migrate into conventional reservoir rocks tend to be lighter, leaving both light and heavy components behind in the organic-rich source rock. These components—commonly nicknamed SARA for saturates, aromatics, resins and asphaltenes—represent a high-viscosity fluid that is challenging to produce. Second, if the petroleum system remains active, retained SARA compounds undergo secondary cracking to successively lighter ones. One strength of BPSM is the ability to use kinetics that are different for the oil that is expelled and fills conventional traps compared to those for the oil that is retained in the generating source rock. BPSM is thus a robust tool to predict the composition of the fluid that enters the wellbore during hydraulic fracturing. This is

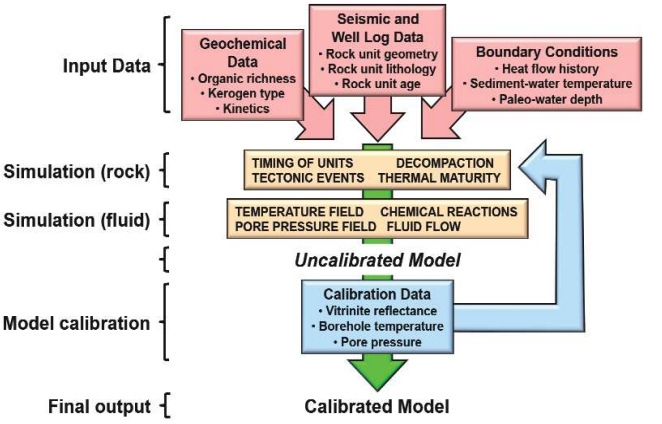

FIGURE 1. The BPSM workflow is a forward, iterative process that requires numerous and varied input data. Figure is modified from Peters et al. (2008). (Source: Stanford University)

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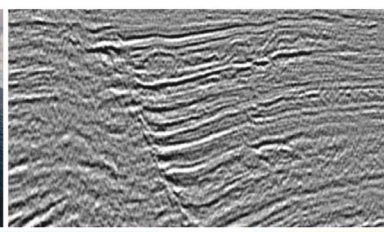

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particularly important in liquid-rich plays to determine if the liquid contains enough dissolved gas to provide reservoir drive, especially in the absence of pressure-volume-temperature data in regions in the early stages of unconventional development.

Data integration

Accordingly, just as exploration for petroleum in organic-rich rocks requires a multidisciplinary approach, this example shows that BPSM is a platform for integrating multiple and varied datasets within unconventional targets. Specifically, BPSM convolves the subsurface structure as defined by seismic data and well picks with source rock characteristics as defined by organic geochemistry (total organic carbon and hydrogen index) and subsurface lithologies that may be derived from core data or mud logs. Moreover, subsurface data such as temperature, pressure, porosity, permeability and principal stress are used to both define boundary conditions and calibrate the model. Because decisions are made every step of the way in the modeling process (Figure 1), BPSM projects act as archives or repositories both for data and for methods used in the project. Such archives become especially valuable when personnel changes occur or when priorities change within a company's play portfolio and the BPSM project is stored to be used at a later date.

Another key aspect of BPSM, like unconventional production targets, is that modeling projects are continually increasing in geologic complexity. However, the rapid pace of modern E&P operations in unconventional targets coupled with an aging workforce means that fundamental research on these systems may lag behind. Research in academic settings can fill the widening gap. The Basin and Petroleum System Modeling Industrial Affiliates Program at Stanford University is advancing the scope of traditional modeling programs across many geologic disciplines.

Experiments defining the kinetics of the opal-CT to quartz transition in silica diagenesis, for example, were incorporated into an existing software package and used to predict reservoir quality in the San Joaquin Basin in California. A synthesis of rock physics, seismic attributes and basin modeling in the Gulf of Mexico was recently completed on a pilot basis before a full 3-D model is attempted. Geostatistical realizations of lithologic facies in source and reservoir rock layers also are being tested with an objective to run BPSM in "batch" mode, in which hundreds to thousands of scenarios are tested sequentially. Finally, strike-slip faulting was recently incorporated for the first time in a 3-D BPSM project. In petroliferous settings where strike-slip tectonics are active, the thermal history and the generation-migration-accumulation of petroleum can be greatly influenced by motion along the fault (Figure 2).

These recent advances, combined with the utility of BPSM in unconventional settings, show that BPSM is becoming more relevant than ever in worldwide oil and gas exploration. In fact, BPSM can be used at all stages of exploration, from frontier settings where few wells and seismic data are available to extensively explored conventional basins now being revisited to a maturely explored province where wells are continuously being drilled. In this range of scenarios, basin and petroleum system models leverage the exploration effort because in near-real time they can be tested and updated with information such as formation tops, geochemistry, observed mud gas compositions, mud-weight pressures or bottomhole temperatures when the next well is drilled. BPSM serves as the "great integrator" in petroleum exploration, integrating data and disciplines across research teams and settings. E&P

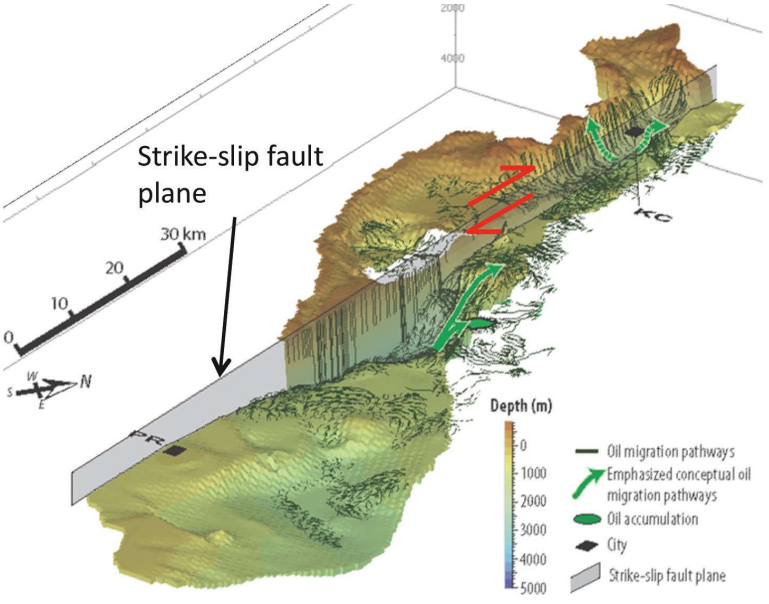


FIGURE 2. The inclusion of a strike-slip fault plane with motion through time (red arrows) is a recent advance in BPSM. Figure from Menotti (2014). (Source: Stanford University)

References available.

New opportunities evident in the Santos Basin

Recent data indicate additional unexplored presalt areas.

Senira Kattah and **Yermek Balabekov**, PGS

In a study examining the hydrocarbon exploration potential of the BMS-50/52 seismic survey area within the Santos Basin offshore Brazil, results are based on preliminary geological interpretation of 3-D multiclient prestack depth-migrated (PSDM) seismic surveys acquired and processed by PGS. Most of the survey area is expected to be offered in future presalt bid rounds by ANP, the Brazilian E&P regulatory agency. The BMS-50/52 surveys are within the presalt play polygon of the Santos Basin (Figure 1). Several recent multibillion-barrel light oil discoveries have been made in this play since 2006 after the Tupi (Lula) discovery opened a new frontier in the deep waters of the Santos and Campos basins. These recent discoveries have more than doubled Brazilian hydrocarbon reserves and, as the great majority of the BMS-50/52 survey area, much of the Brazilian presalt play remains underexplored and available for licensing. The seismic dataset used in this interpretation is made up of two surveys: Phase I, a conventional single-sensor PSDM seismic volume, and Phase II, a dual-sensor GeoStreamer PSDM volume. The 2012 dual-sensor broadband survey was acquired adjacent to the west of the conventional solid streamer survey shot in 2008. The surveys have a narrow overlap of 2 km (1.2 miles), which allows a comparison of the two datasets as well as the assertions of improved imaging and data quality arising from dual-sensor broadband data to be validated.

Survey implications

Implications of significant improvement on seismic imaging and geological interpretation of the BMS-50/52 surveys will be critical for:

- The unitization of the Carcará & Sagitário discoveries;
- The unitization of future discoveries in BM-S-50 or BM-S-8 that straddle block boundaries into open acreage;
- The identification and delimitation of the remaining hydrocarbon potential of the presalt play in the area;
- The identification and delimitation of the remaining exploration opportunities in the area, including potential older rift/prerift and post-salt plays; and
- A local to semiregional revision of the Santos Presalt polygon in the Santos Basin.

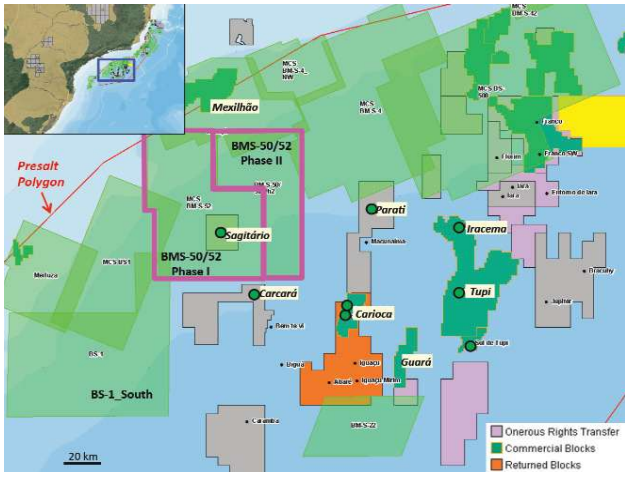


FIGURE 1. The BMS-50/52 survey covers some of the prospective presalt acreage offshore Brazil. (Source: PGS)

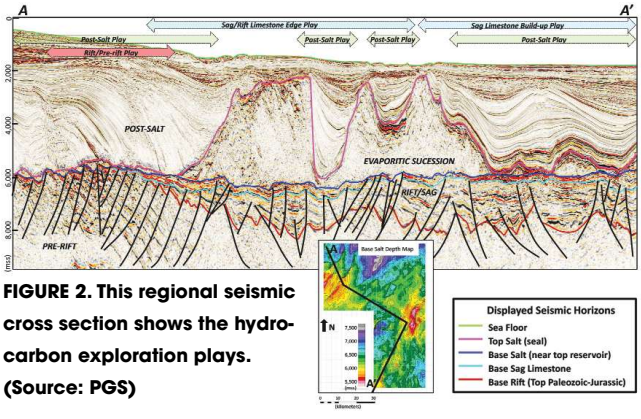
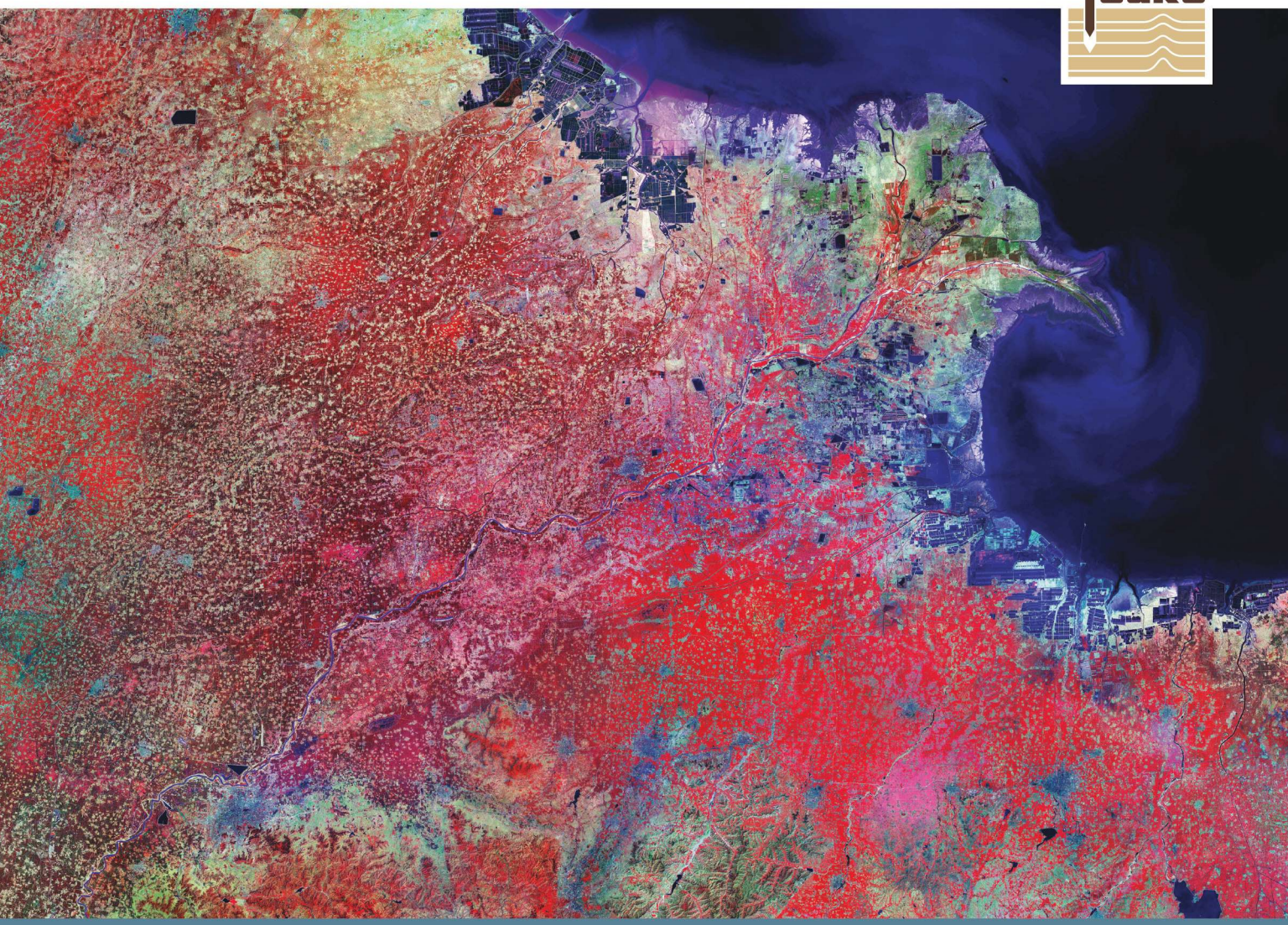


FIGURE 2. This regional seismic cross section shows the hydrocarbon exploration plays. (Source: PGS)

Presalt, adjacent hydrocarbon discoveries

The Santos/Campos presalt hydrocarbon play consists mainly of rift/sag-sourced oils accumulated in carbonate reservoirs of the sag phase and trapped in structural features or paleo-topographic/depositional highs beneath the base of the salt. The overlying thick evaporitic succession provides the main sealing unit for the accumulations.

The survey area includes and is surrounded by important presalt hydrocarbon discoveries. The Sagitário discovery (1-BRSA-1063-SPS well) in the exploration block BM-S-50, announced in February 2013 by Petrobras and its partners, is located in the central-western portion of the Phase I sur-



52

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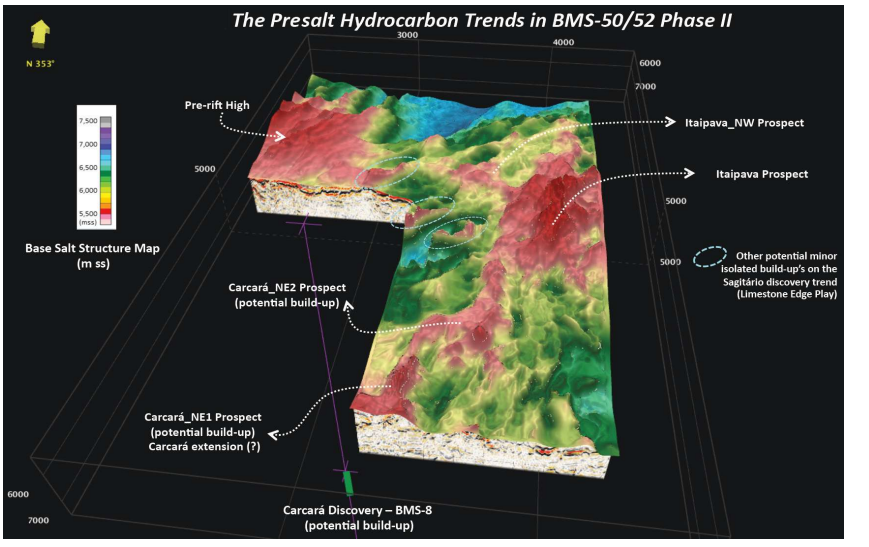


FIGURE 3. Phase II of the survey employed dual-sensor streamers. (Source: PGS)

vey. In adjacent areas, there are two major presalt hydrocarbon discoveries worthy of mention: Parati (1-BRSA-329D-RJS well), the first hydrocarbon success in the Santos presalt play announced in 2006 by Petrobras and its partners in the BM-S-10 block, and the Carcará discovery (1-BRSA-532A-SPS and 4-BRSA-971-SPS wells) also announced by Petrobras and its partners in the BM-S-8 exploration block. Carcará extends into open acreage within the southern portion of the BMS-50/52 surveys. To the north of the surveys there also is an important post-salt gas/condensate field, Mexilhão, covered by the PGS MultiClient BS-400, BMS-4 MC3D seismic surveys.

Hydrocarbon exploration trends

Several horizons can be easily mapped in the seismic volumes. However, Phase II data show much improved subsalt imaging. These new seismic data allow for more confident geological interpretation of the data. The following horizons were mapped: seafloor, top salt, base salt (top reservoir), base carbonate reservoir, base rift (top of the Paleozoic) and top basement (Figure 2). These horizons, combined with improved imaging of faults and delimitation of the main tectonic compartments, allow a better understanding of the structural and stratigraphic evolution of the BMS-50/52 area. Several paleo-depocenters of the rift/sag succession might indicate that the main Santos source rock is likely to be present throughout most of the study area, most likely within the hydrocarbon generation window and potentially with the same high generation potential as the main presalt heartland in Santos. This would have to be confirmed by some well measurement, but the presence of commercial hydrocarbon in Sagitário and the observation of a very large hydrocarbon column in Carcará may provide support to the presence of this robust source rock in the area. Consequently, billions of barrels of oil and gas/condensate could have been generated in the depocenters of the BMS-50/52 area. In the south-central portion of the survey, the generated hydrocarbon is potentially trapped in four-way closures at the base salt and sealed by the thick overlying evaporitic succession, similar to Carcará and Sagitário. Post-salt and rift/prerift plays may take more importance in shallower water depths to the north.

Exploration plays

The hydrocarbon exploration plays (Figure 2) within the survey area are:

- Post-salt in the northern segment, most likely a moderate-risk gas/condensate trend with hydrocarbons trapped mainly in Albian limestones in structural traps or Upper Cretaceous to Lower Tertiary turbidites in combination or stratigraphic traps;
- Rift/prerift in the central-western area, most likely a high-risk gas/condensate trend with hydrocarbon accumulation within small fault traps in siliciclastic reservoirs of the Paleozoic (prerift) layers to the Lower Cretaceous rift succession. During the Late Barremian to Aptian, this area was a sub-aerially exposed paleo-high where the sag/rift carbonates are absent or inexpressive;
- Sag/rift limestone edge (or Sagitario trend), with light oil accumulated within structural traps beneath the base salt in microbial platform limestones and occasional isolated microbialite buildups. This hydrocarbon play has a southwest-northeast orientation and is most expressive

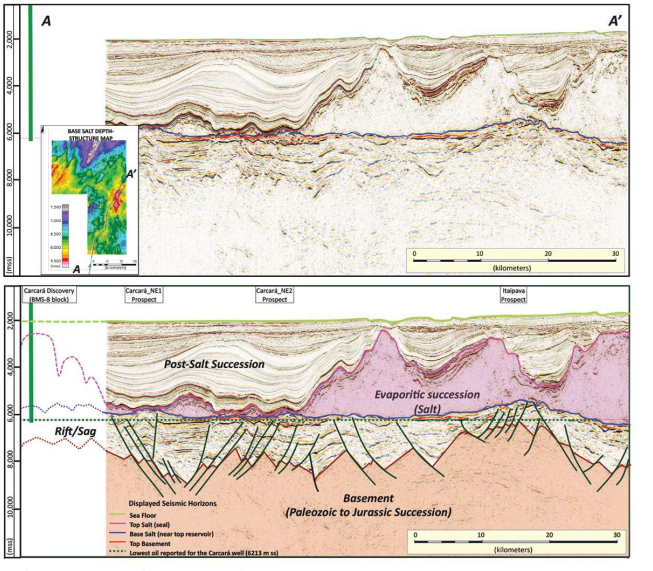
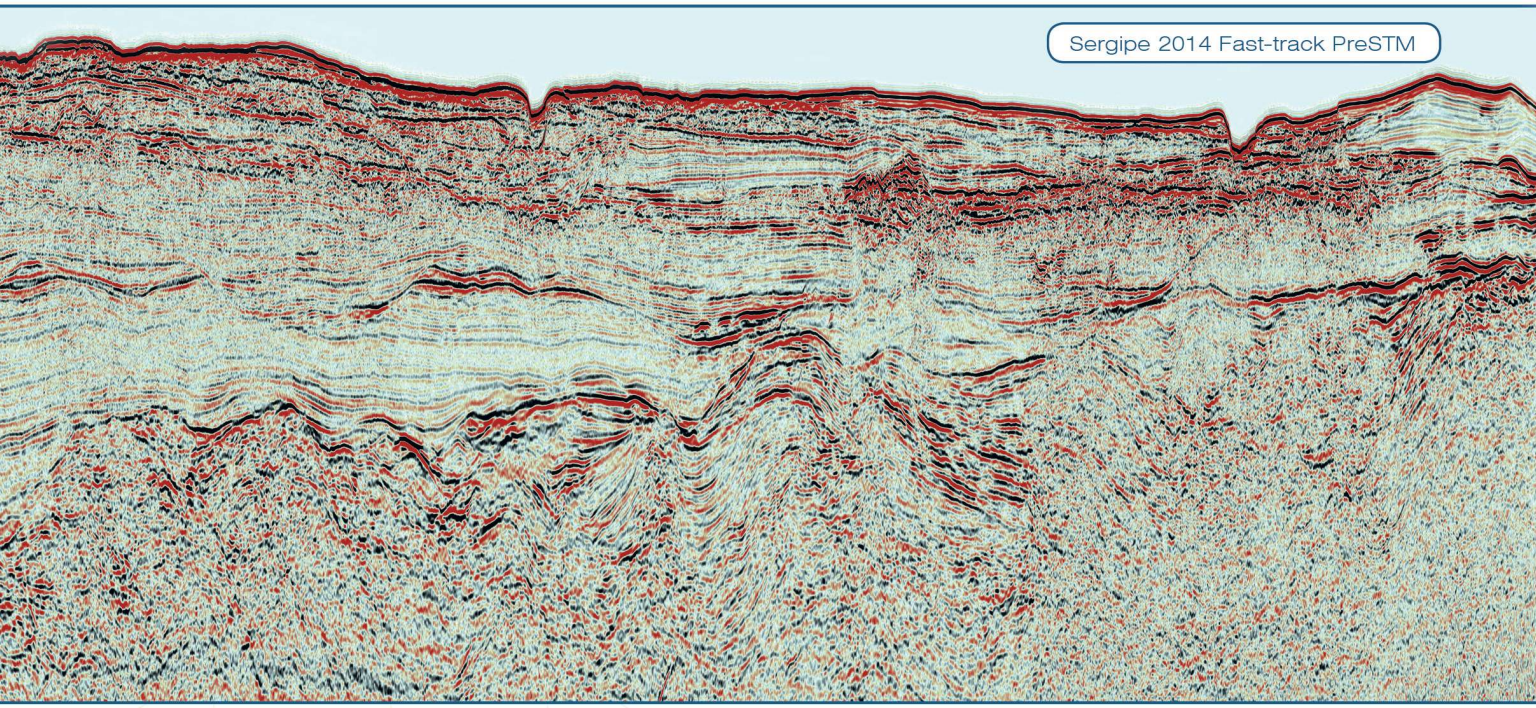
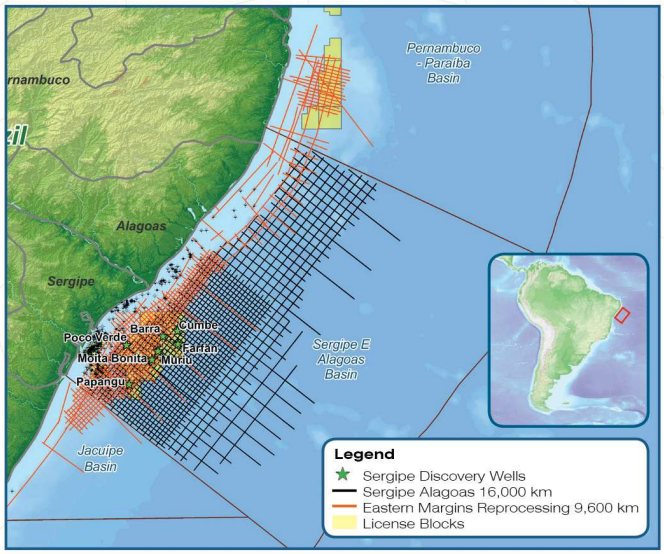


FIGURE 4. This fullstack PSDM cross section (top) shows the south-southwest/north-northeast trend through the Carcará-Itaipava exploration area. Analogues to the Carcará well are seen in the bottom image, which are four-way closures beneath the base salt and represent great exploration opportunities. (Source: PGS)

Brazil: Eastern Margins

Long Offset 2D Multi-Client Seismic Data





Spectrum has available 16,000 km of newly acquired Multi-Client 2D seismic data offshore Brazil in the Sergipe and Alagoas basins along the eastern margin of Brazil. The new acquisition program will tie key wells in the basins, including the recent Barra, Muriu, and Farfan discoveries. PreSTM will be available in Q4 2014 and PreSDM data will be available in Q1 2015.

To supplement the new acquisition in the active exploration area, Spectrum has completed the reprocessing of 9,600 km of data through both PreSTM and PreSDM and is offering this data to industry ahead of the expected bid round in 2015

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in the BM-S-50 area. A moderate risk should be assigned to this trend since the seismic imaging under the thicker salt is still quite challenging in the current Phase I PSDM dataset when compared to the recent dual-sensor streamer seismic survey; or

- The Carcará North/Itaipava sag limestone, a potential light oil southwest-northeast-oriented trend that extends from the Carcará discovery in BM-S-8 to the Itapaiva Paleo-High in the eastern-central segment, totaling a few hundred square kilometers of individual closures beneath the base salt and relief reaching 300 m to 400 m (984 ft to 1,312 ft, Figures 3 and 4). In this trend, oil is accumulated on paleo-topographic highs (potentially representing very large microbial buildups). This trend is the largest-reward and lowest-risk play and is most expressive in the Phase II survey. The depositional features are analogous to other large presalt features in Libra and Sapinhoá (Guará) and are clearly identifiable in the dual-sensor streamer dataset, even under very thick evaporitic layers.

The BMS-50/52 area has a large hydrocarbon exploration potential, with possibilities for significant light oil discoveries. Geological and geophysical interpretation of the survey area reveals a great diversity of potential hydrocarbon accumulation styles, including presalt, post-salt and Paleozoic rift plays. Presalt exploration trends in the southern part of the survey area are the lowest-risk, most attractive opportunities, and the newer seismic data afford improved subsalt imaging and identification of potential reservoir sweet spots. Most of the Carcará/Itaipava trend is on open acreage expected to be offered in future ANP bid rounds. Other frontier plays are identified within more proximal shallow-water areas. High-quality seismic data together with the better understanding of the petroleum systems in the area will provide important input for the unitization of Carcará, Sagitário and any other future discoveries that may straddle block boundaries. E&P

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Modeling with geostatistics, basin modeling techniques

Methodology characterizes sweet spots using petrophysical, mechanical and static fluid properties.

Jeffrey M. Yarus and **Jordan M. Yarus**,
Landmark, a Halliburton Company

Unconventional resource plays have come front and center in the exploration and development arena, particularly in North America. Effective modeling efforts of these resources are struggling to keep pace with exploitation, principally due to lack of understanding shales and the need to minimize costs. Currently, the industry is in a state of trial and error, with only immature research results available to help improve defining the physical characteristics of source/reservoir sweet spots and the appropriate methods to stimulate them. Traditionally, reservoir geomodeling has focused on present-day descriptions of static rock properties in the subsurface in a localized area but has no capability to describe the means by which the reservoir arrived at this current state along with the distribution of fluids. The state of petroleum is usually determined in a regional basin model, which simulates, through time, a variety of conditions and variables with all of the processes acting on rocks and fluids post-deposition.

Traditional workflows and methods for identifying good and poor reservoir quality in shales have not been successful, principally due to our lack of understanding shales and the difficulty of remotely identifying their quality with current tools (Figure 1). The emphasis has been to reduce costs through "factory drilling," a method involving a succession of laterally drilled wells from a common pad and a common completion recipe.

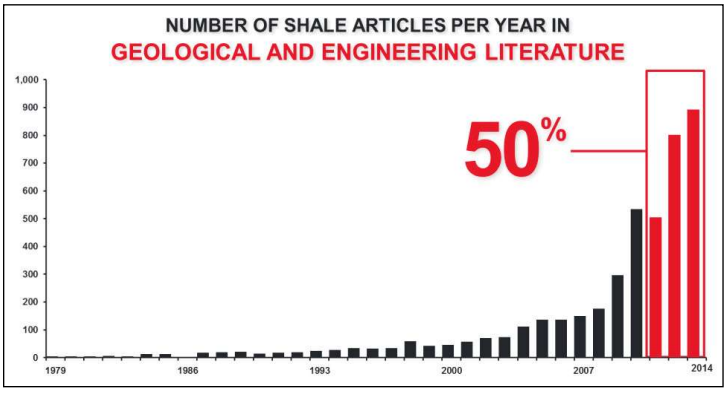

FIGURE 1. Of the shale literature published in the last 35 years, half of what the industry now knows about shales has been published in the last three years. (Source: Landmark)

Because of the relatively short time frame within the basin history in which the shale resource was deposited, a calibrated dynamic version of the regional basin model at the scale of a reservoir is feasible. The advantage of doing so is to recreate its entire history and its constitutive fluids to determine when the hydrocarbons were generated, where they currently reside, their quality and their current phase (gas, liquid-rich, oil).

Static earth model

The contribution of the static earth model is to provide a 3-D representation of the current distribution of petrophysical and mechanical properties in the context of the present-day structural framework for a variety of downstream operations such as well planning and flow simulation (Yarus and Chambers, 2006).

Figure 2 represents a sample earth model showing the distribution of matrix porosity calibrated to seismic acoustic impedance, total organic carbon (TOC), brittleness and the structural framework in which it was built. Two directions of natural fracturing are present in portions of the model where rocks are most brittle.

Dynamic basin model

Basin modeling concerns the simulation of sedimentation, burial, erosion, uplift, thermal calculation, pressure calculations, diagenesis prediction, etc.—all of the processes acting on rocks and fluids during the development of a sedimentary basin. The modeling process is generally applied to entire basins or large portions of them.

Typical reservoir modeling concerns the present-day description of the rock and fluid properties in the subsurface in a highly localized area, with no means to calculate or describe the events by which the reservoir arrived at this state. Here we describe a workflow for performing "basin" modeling at the reservoir scale, providing a link

between present-day and the historical process that acted on the rocks and fluids.

Model building, burial history

In parallel to a static geocellular earth model, a basin modeling study is performed over the corresponding area. If the area is relatively small such that thermal, pressure and other effects are more or less uniform over the study area, a one-dimensional basin model might be sufficient.

The primary objective of the basin modeling study is to determine the burial history of the reservoir, specifically, its pressure (stress) and temperature histories.

The burial history information from the basin study can be applied to the reservoir model. The reservoir structural model is assumed to be correct, and a temperature gradient and overburden is determined. The objective of this step is to provide both rock and fluid properties through time and ideally arrive at a solution that calibrates to present-day conditions.

The effective stress, temperature and other properties derived from the basin model are applied to the reservoir grid. The basin model provides these properties for a number of discrete time points in the past. The output of this process is the through-time representation of the rock properties on the reservoir at the resolution of the original earth model. At this point, geomechanical and other production evaluation-oriented rock properties can also be calculated from the same process.

Deriving fluid properties

The distributions of petroleum fluid properties are arguably a more important attribute because they address the fundamental economic basis of the oil and gas industry. In the same way that each element in the model was assigned a lithology ID that led to the calculation of rock properties, a source type ID is also assigned to calculate source fluid properties, a source property calculator that includes *in situ* fluid and rock-fluid reactions that occur within the source through time. By applying the burial history (Figure 3) to the model, the sediment and source maturities of expelled and adsorbed masses can be calculated. The masses of the fluid components can then be combined with the historical pressure and temperature information to provide pressure-, volume- and temperature-based fluid properties. These would include phase state fluid densities and fluid viscosities.

Calibration and sweet spot identification

The end results of this workflow are a suite of both rock and fluid properties described at the resolution and scale of the original reservoir model. Combined, this can provide a comprehensive set of properties to not only prepare the static reservoir model for dynamic simulation but also for well planning. Additionally, sweet spots can be determined based on a combined set of rock and fluid properties, further contributing to drilling and completions strategies.

Better development

While shale resources have the capacity to dramatically change the balance of energy independence globally, identifying precisely how they work and how they can best be commercially exploited is still unclear. The distribution of static properties in an earth model integrated with rock and fluid properties from dynamic burial history can significantly improve sweet spot identification. As part of a complete workflow from static modeling to dynamic modeling through production, an understanding of the through-time history of the reservoir will provide a more solid foundation upon which to build a knowledge base for better drilling programs and economic forecasting. E&P

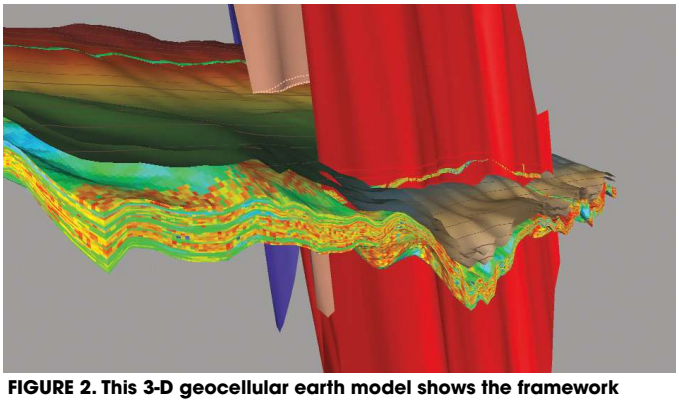

FIGURE 2. This 3-D geocellular earth model shows the framework and distribution of matrix porosity calibrated to acoustic impedance, porosity and TOC. (Source: Landmark)

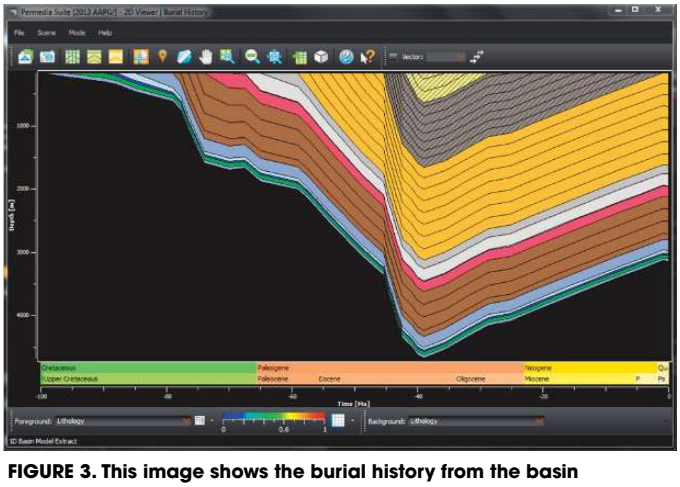

FIGURE 3. This image shows the burial history from the basin model. (Source: Landmark)

Fully automated MPD system controls well in western Canada

An MPD well control system can detect and control influxes at minimum size before they reach the threshold kick-tolerance stage.

Koray Kinik, **Ferhat Gumus** and **Nadine Osayande**, Weatherford

The constant bottomhole pressure (CBHP) method of managed-pressure drilling (MPD) provides several advantages over conventional drilling, which include enabling drilling with lower density drilling fluids to increase ROP, allowing dynamic formation integrity testing (FIT) and adding dynamic well control capabilities.

One of the major challenges while drilling through narrow pore-fracture windows has always been controlling gas kicks due to gas solubility and mud compressibility. Continuous closed-loop monitoring of the well and automated early kick detection and control minimizes the influx volume before it reaches the "well control" threshold and threatens the integrity of the well.

All well control methods share the common objective to overbalance the flowing formation and circulate out the kick fluids from the well without exceeding the surface or subsurface pressure limitations of the well. MPD provides significantly improved well control capabilities; however, the industry remains hesitant to accept MPD as a well control tool. Weatherford's Microflux control system, which offers fully automated kick detection and control, was used in an MPD well control case study.

Case study: Dynamic well control with MPD

A kick was taken while drilling a well in the Montney Formation in Alberta, Canada. The Montney is a tight-gas reservoir with pore pressure gradients ranging from 0.55 psi/ft to 0.70 psi/ft. The well was planned with a 2,591-m (8,500-ft) long horizontal lateral after the buildup section in this formation. The kickoff point was at 2,190 m (7,183 ft). The 7-in. intermediate casing shoe was set at 1,992 m (6,535 ft) measured depth (MD)/true vertical depth and tested to 18.67 lb/gal equivalent by a conventional leak-off test.

The section was being drilled using the CBHP method, holding surface backpressure (SBP) during the connections to compensate for the loss of annular friction. During the kick event, 10.3 lb/gal oil-based mud was being circulated, and the well was overbalanced with a constant 10.95 lb/gal equivalent bottomhole equivalent circulating density. Prior to the event, the mud logging unit was measuring 200 to 500

The project site in Alberta, Canada, was targeting the Montney Formation. (Source: Weatherford)

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During drilling of the buildup section a drill-break was observed at 2,458 m (8,063 ft) MD, with the ROP increasing from 6.1 m/hr to 24 m/hr (20 ft/hr to 80 ft/hr) followed shortly by a sudden increase in return flow. The MPD system detected this increase in return flow through the coriolis flow meter and a 35-psig spike in the standpipe pressure sensor (t_o in Figure 1). Return flow was compared with the flow-in by the algorithm to confirm the influx. The system then automatically activated the well control module (t_1 in Figure 1).

The well control incident began with the stepwise addition of SBP while simultaneously monitoring the change in the return flow, with the goal of regaining the wellbore vs. pore pressure overbalance. Figure 2 shows the SBP, standpipe pressure and choke position data recorded during the event. A total of 510-psi SBP was required to reestablish the steady state flow-out vs. flow-in balance, which in turn resulted in a 235-psi increase on the standpipe pressure (t_2 in Figure 2).

After verifying this condition for 20 seconds, an additional 100 psi was added to the SBP as a safety factor. The time difference between detection of the kick by the automated MPD system and regaining control was three minutes, and the additional gain of 1.88 bbl was safely circulated out of the well at full circulation rate.

Simulating kick event

While the MPD system's automated early kick detection and control minimized influx volume and allowed fast regain of pressure control, one might ask if conventional well control methods might achieve the same results. This prompted an in-depth engineering study of the event to yield a quantitative one-to-one comparison with conventional well control methods.

The study began by first reproducing the kick event in a simulation environment using a commercially accepted transient multiphase well control simulator. Throughout the simulation work, the same drilling parameters and drilling fluid properties as were employed during the field operation were used as

Fig. 1

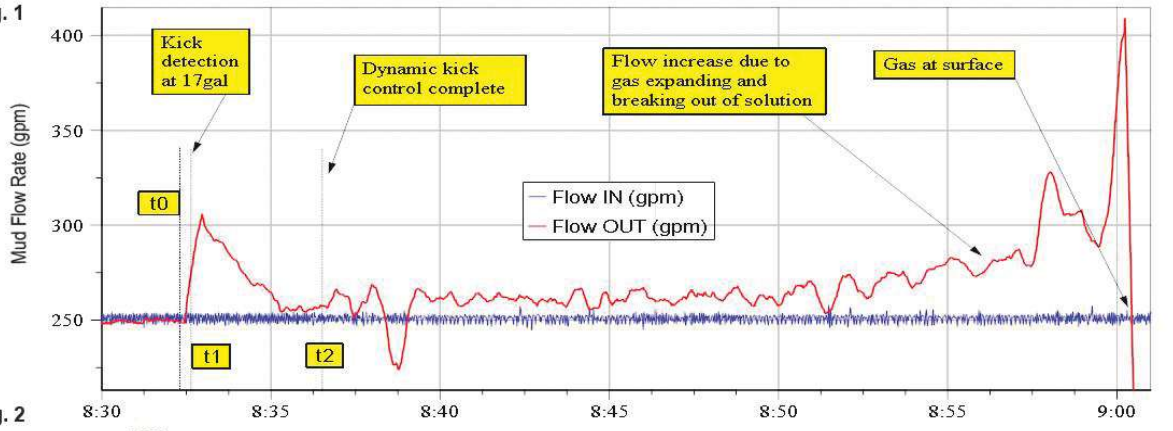
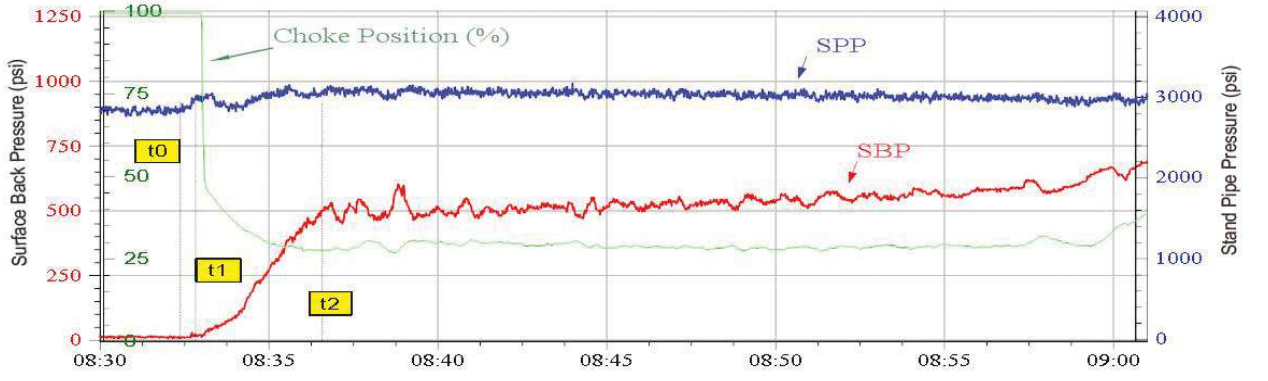


Fig. 2



FIGURES 1 and 2. In these field data, return flow was compared with the flow-in by the algorithm to confirm the influx. The system then automatically activated the well control module. (Source: Weatherford)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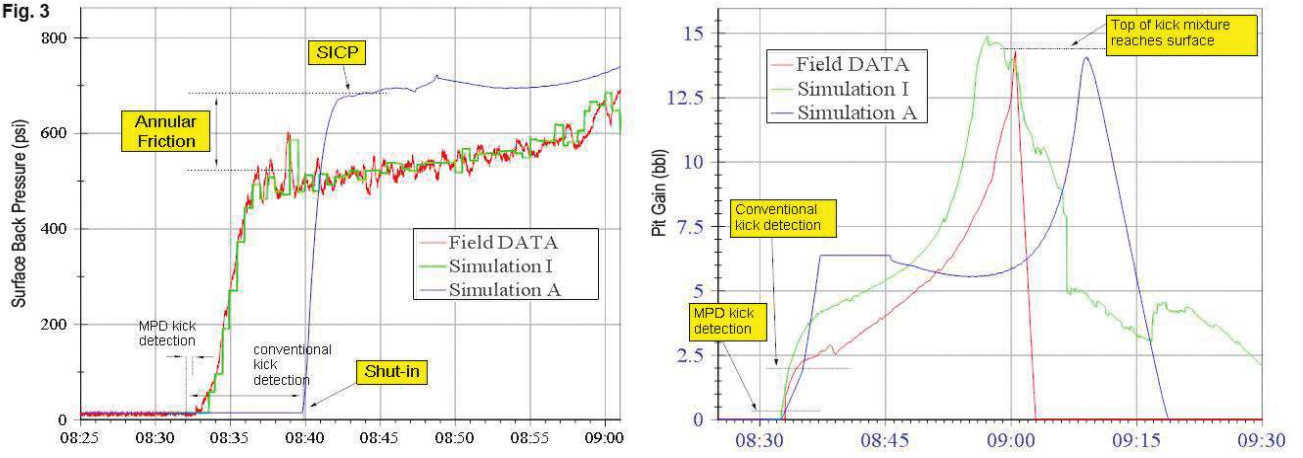

FIGURE 3. Kick data vs. validation with simulation are shown. Annular pressures are on the left. Pit gains are on the right. (Source: Weatherford)

inputs. Using the geological data for the Montney Formation available from public sources, input values for formation porosity and temperature were estimated as 10% and 79 C (175 F), respectively.

In the initial simulation (Simulation I), the SBP data recorded by the MPD system during a kick of 1.88 bbl were tracked by dynamically manipulating the annular pressure at the surface. A close match in annular surface pressure was achieved between the simulation output and the data recorded from the field event (Figure 3).

In the next simulation (Simulation A), the identical initial-size-kick of 1.88 bbl was controlled, but this time it was done by employing the driller's method of well control (i.e., detecting the kick based on pit gain and shutting in the well). Iterative conventional well control simulations were run to find the input parameter: total response time needed to control the identical size kick. Total response time is the cumulative time spent for pump ramp-down, flow-check, BOP closure and any operational delays. The simulations revealed that a total response time of two minutes would be needed to complete the detection and control of a kick of less than 2 bbl, reflected by achieving an identical maximum pit gain (Figure 3).

A sensitivity analysis was then conducted to study the effect of total response time on the pressures at the surface and at the casing shoe during the application of a conventional driller's method of well control. During an actual well control event, total response time is the only operational variable that can be managed and therefore was selected as the input parameter for the sensitivity analysis. Simulations were run for response times of two, five, eight and 12 minutes. As might be expected, the simulations showed that kick size (as reflected in pit gain) at shut-in is a strong function of total response time, with the volume of fluid lost from the well increasing dramatically the longer it takes to respond to the kick.

A one-to-one quantitative comparison was conducted positioning dynamic well control with MPD vs. the conventional driller's method of well control. Assuming a pit level alarm setting of 2 bbl and total response time of 12 minutes for the conventional response, the comparison demonstrated how automated early kick detection and control minimizes kick size and, hence, the surface pressures needed to circulate out the kick. The most notable differences using MPD were a decreased kick volume at the surface by 67 gal, a decrease in peak pressure at the shoe by 4.85 lb/gal equivalent and a significant decrease in peak pressure at the surface by 1,570 psi.

The precision and accuracy of the dynamic kick control during the event constitutes a field proof example of the pressure control capabilities of the MPD system. Such accuracy is crucial in CBHP drilling in hydraulically challenged sections where kick tolerance is lower than the safe control limitations of the conventional well control systems. In those sections, the maximum allowable surface pressure is often a more restrictive criterion than the rating of the surface equipment; the risk of triggering an underground blowout is real. Therefore, the merit of an MPD system becomes detecting and controlling influxes at minimum size before they reach the threshold kick-tolerance size. E&P

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Enhancing flow for Canadian crudes

New DRA improves the movement of heavy oil through pipelines.

Lacy Rosson, Baker Hughes

The growing global demand for oil and gas and the corresponding drop in new sources of light, sweet crude from conventional reservoirs has operators ramping up their E&P efforts for heavier and harder-to-extract crude stocks. While technological gains have allowed operators to produce heavier crudes and refiners to profitably process them, problems persist in getting them from the field to the refinery.

Heavy crudes are notoriously difficult to transport via pipeline due to their low API gravity (<20°) and high inherent viscosities (upward of 10 cu. cp at surface temperature and pressure). Solutions to this problem have included the addition of large amounts of diluent or heat to reduce the crude's viscosity and enable transportation. However, these solutions are economically prohibitive in many cases since the volume of diluent or heat generation required is quite high to sufficiently lower the viscosity and overcome frictional pressure in a pipeline. As a result, overall transmission efficiency is diminished, as is the total volume of heavy crude transported via pipeline.

Reducing drag

Drag reducing agents (DRAs) are chemical alternatives that have been used in production and pipeline applications over the past two decades. DRAs are high molecular-weight polymers that are added to the pipeline at a continuous dosage of just a few ppm and act to interrupt the frictional pressure drop, or drag, generated when the flowing crude comes into contact with the pipe wall.

While research continues into understanding the precise mechanism of drag reduction, it's understood that the polymer molecules disrupt the formation of turbulent eddies that form at the contact point between the oil and the pipe wall. Lower turbulence translates to lower drag and improved flow of heavy oil through the pipes, with lower pumping requirements.

Conventional DRA technology is not a flow-boosting solution for all crude types, particularly for those that contain precipitated asphaltenes. Canadian crudes are characterized as being asphaltenic, which lowers the drag reduction efficiency of many DRA polymers.

This limitation prompted Baker Hughes to develop its FLO ULTIMA series of DRAs, which comprise a long-chain latex polymer specifically designed to dissolve in high asphaltene-content crudes with a gravity of less than 23°API and improve the flow of heavy oil through pipelines.

The specific polymer design delivers high drag reduction in heavy crudes with less heat and lower diluent volumes, reducing corresponding HSE risks and treatment costs. The heavy crude DRA has been shown to reliably reduce frictional pressure in crudes that are restricted by viscosity or operating pressure and increase the flow rate in pipelines by more than 50%. Hydraulic engineering professionals routinely work with pipeline operators to calculate the precise amount of heavy crude DRA required to increase a given pipeline's throughput.

These specialized DRAs reduce pressure in the pipelines without coating the inner walls or adversely affecting the composition of the crude oil. This serves to enable operators to bypass pump stations

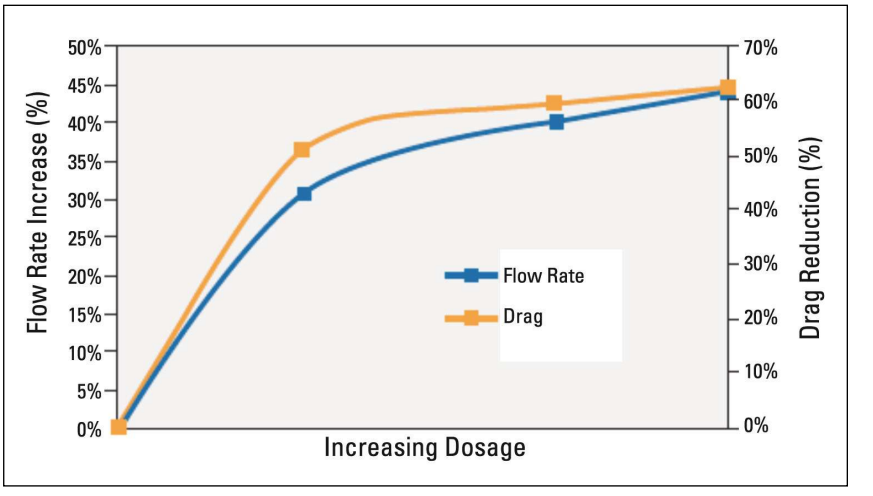
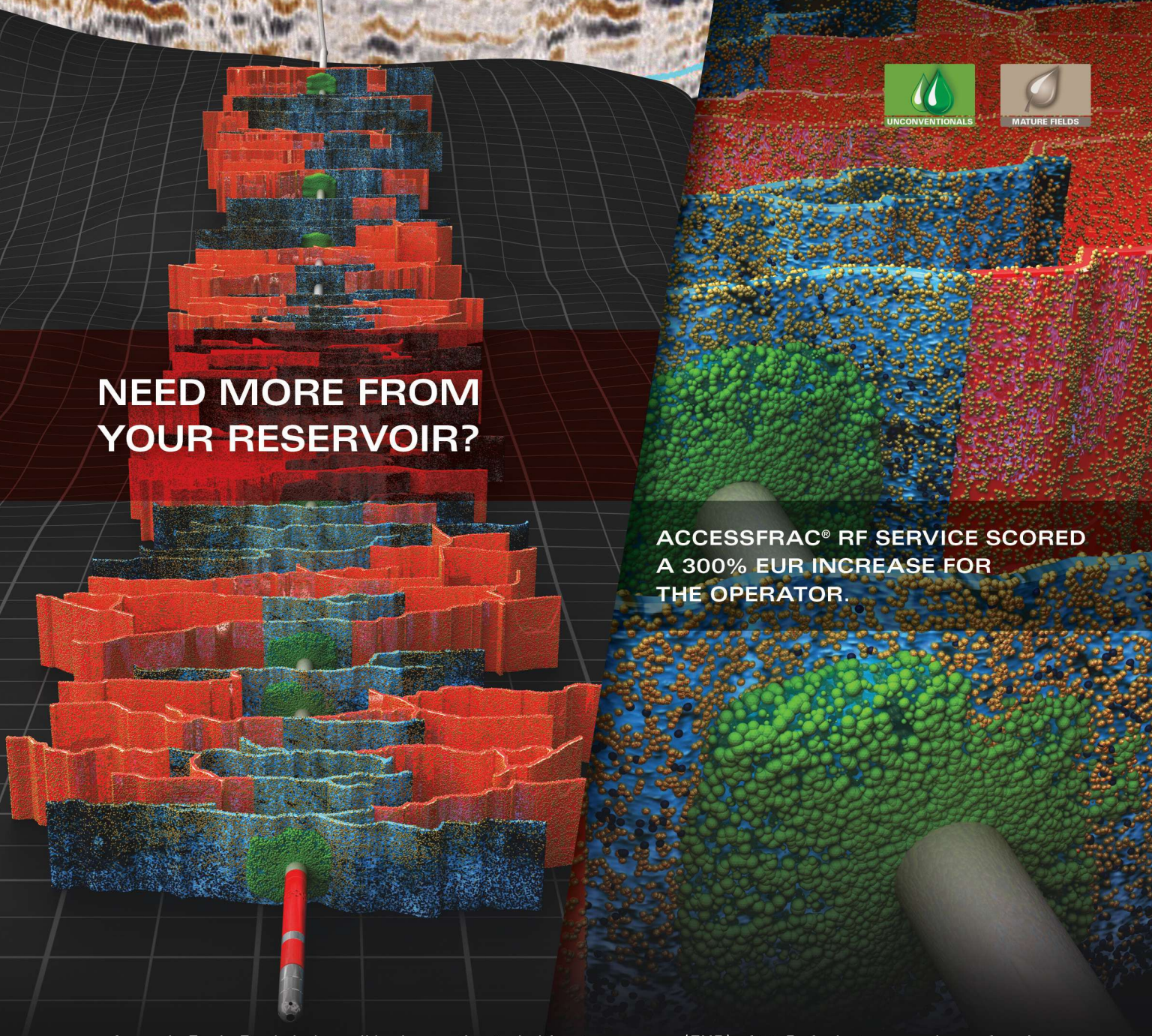


FIGURE 1. Even at a low dosage, the heavy crude DRA dramatically boosted the flow rate of Canadian crude into the refinery, with a corresponding reduction in drag in the pipeline. (Source: Baker Hughes)



An early Eagle Ford shale well had an estimated ultimate recovery (EUR) of 1.1 Bcfe, but was underperforming compared to offset wells. The operator thought it should be doing better. He was right. Halliburton's **AccessFrac® RF** service was performed to contact previously undrained portions of the reservoir. The result? The EUR went from 1.1 Bcfe to 3.5 Bcfe. A 300% increase.

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and effectively optimize power usage to lower overall opex while increasing the pipeline's efficiency and throughput.

Boosting throughput

A U.S. Gulf Coast refiner required a drag reduction solution that would allow multiple crude feedstocks to be transferred through a 6.9-mile (11.1-km) pipeline delivering into the refinery. The refiner had made equipment upgrades to process a larger proportion of heavy oil and, therefore, wanted to increase the amount of heavy asphaltenic Canadian crude in its feedstock.

However, the viscous nature of the crude coupled with the drag generated in the pipeline caused a significant drop in flow rate compared to lighter crude oils. This resulted in decreased throughput of the economically favorable heavy Canadian crude slate and a corresponding drop in profitability.

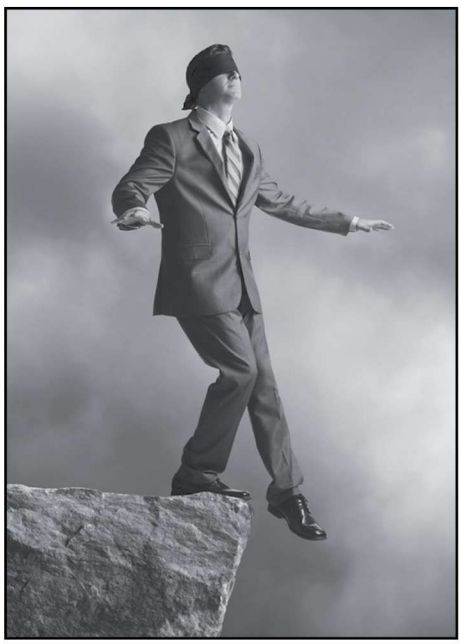
The refiner approached Baker Hughes to help increase its Canadian crude throughput using the new technology. The refinery agreed to trial the new heavy oil DRA using Baker Hughes injection equipment in the transfer pipeline to the refinery.

The heavy crude DRA was injected into the pipeline at different dosage rates to optimize the flow rate of the pipeline (Figure 1). Results from the trial showed a 44% increase in the flow rate and a 62.5% reduction in drag.

As a result, the refinery was able to transport the heavy Canadian crude much more efficiently, increasing the amount of crude it could process. And, in turn, it was able to increase its profitability through a much faster speed to market using the new DRA solution.

Growing need

Boosted flow efficiency provided by the FLO ULTIMA heavy oil DRA is not limited to pipelines in and around refineries but is possible to use in the entire pipeline network between Canada's oil sands and the U.S. Gulf Coast. Much of this infrastructure has been in operation for many years or even decades and as a result has been



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pressure de-rated. The heavy oil DRA allows the pipelines to pump the same amount of crude at lower pressures, thus extending the working life of these assets.

At the same time, pipeline operators are increasing their capacity to keep up with the growing volumes of heavy oil being imported to the U.S. from Canada. For the week ending Sept. 5, 2014, oil imports from Canada to the U.S. Midwest climbed to 2.21 MMbbl/d, according to the U.S. Energy Information Administration (EIA). This marked the largest crude shipment to the Midwest from Canada since the EIA began reporting weekly data.

The January 2014 startup of TransCanada's Gulf Coast Pipeline Project, originally the southern leg of the delayed Keystone XL pipeline extending from Oklahoma through Texas, promises easier access to heavy Canadian crudes for Gulf Coast refiners. Canadian crude imports into the Gulf Coast hit an all-time high of nearly 6.2 MMbbl in June 2012, according to the EIA. As more of this heavy crude enters the U.S., technologies such as the new heavy oil DRA will be a vitally important contribution to an operator's strategy to get crude to refineries across the continent as efficiently, safely and cost-effectively as possible. E&P

The viscosity of Alberta's heavy oil causes issues in transportation.

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Lines drawing in Alberta's oil sands

Operators hope for certainty in SGER decision.

David Godkin, Contributing Author

Supporters call it the most significant regulation aimed at curbing greenhouse gases in Alberta's, and perhaps Canada's, history—the first carbon pricing regulation imposed on the oil and gas industry in North America. Others call the Specified Gas Emitters Regulation (SGER), set to expire in December, "low hanging fruit" for a government and industry still reluctant to take a bite out of emissions from Alberta's oil sands.

The SGER was introduced by Alberta in 2007 to circumvent federal regulations widely expected at the time. It requires large facilities, including most oil sands operators, to cut greenhouse gas emissions 12% per barrel from pre-regulation levels. For every tonne of greenhouse gas that falls short, firms must pony up 15 Canadian dollars (US$13.44) to the Climate Change and Emissions Management Fund (CCEMF).

To meet the emissions reduction target, oil companies may also choose to improve facility operations, buy emission performance credits (EPC) from another facility that has surpassed its targets or purchase credits from an Alberta-based offset project. Because any combination of these can be used to meet the target, the fixed CA$15 paid to CCEMF acts as a price cap. A facility has nine years to reach the full 12% and is expected to maintain that reduction rate.

According to an impact assessment published in Calgary in 2013, under SGER Alberta companies cut GHG emissions by just over 40 MMmt of CO_2 equivalent from 2007 to the end of 2010. Of this, 70% was achieved through offset credit purchases and CCEMF payments. Management plans for accelerating GHG reduction through facility improvements and EPCs include use of natural gas, waste heat and vapor recovery, solvent addition and cogeneration, and minimizing steam to oil ratio in facility design.

What success looks like

In Canada the provinces own the resources while the federal government provides public oversight and environmental review. Interestingly, Alberta's oil patch companies "see regulations as one of the tenets of the strong system that we have that has attracted international investment," said Greg Stringham, president of the Canadian Association of Petroleum Producers (CAPP). "They can see that those rules are very open, and they understand them."

Emissions from oil sands production are a key target of both government regulation and opposition. (Source: CAPP)

The real challenge in Alberta, Stringham said, is the uncertainty that occurs when governments dither over what their policy and subsequent regulatory framework should look like. And certainty—or lack of it—will be the mindset of Alberta oil producers when the SGER comes up for renewal next year. Leaked proposals would see intensity reduction levels increase to 40% from 12% and the penalty for failing to meet that target rise from CA$15 to CA$40 per tonne. More modest expectations range from the status quo to a doubling of the existing numbers, which still would not lower general acceptance of the regulation by industry, Stringham asserted.

"The industry has paid into that fund now close to [CA]$400 million," he said. "The framework is well established with quite a good level of certainty and acceptance."

Since 1990, the overall emission intensity of the oil sands, he added, has been reduced by 28%. "That's actual

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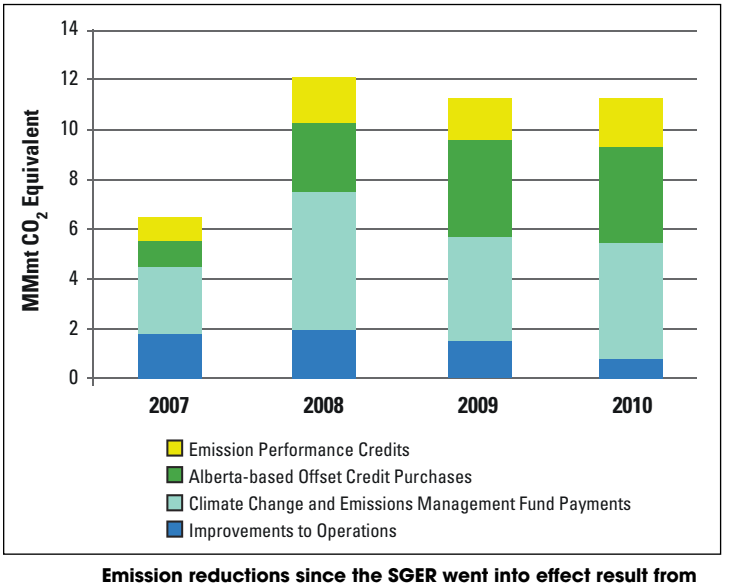
reductions; that's not including today's CCEMF payments or offsets," he said. SGER builds on those reductions by also limiting the purchase of offset credits solely to companies operating in Alberta, "so there are no international trading or caps going on," Stringham said. "So the only true alternatives are payment into the fund or actual GHG reductions through implementation of new technologies."

Not that the SGER has won overwhelming support. This summer, former premier Dave Hancock heard rumblings from oilpatch companies that the levy was having a negative impact on investment and cost margins. Others, like Andrew Leach, an oilpatch analyst and associate professor at the Alberta School of Business, have said the hurdles oil producers have to jump to meet the current target are comparatively small.

"Its average costs are really low," Leach said. "It requires a small percentage reduction over historic emissions intensity at your own facility."

Leach estimates the average cost to be CA$1.60 or even less per tonne of carbon emissions over the life of an industrial project. Less than ⅒ mt of carbon emissions intensity per barrel produced at an oil-sands project works out to "cents or tens of cents per barrel," nowhere near the types of investments major abatement initiatives like carbon capture and storage might achieve "from more stringent policies."

Meanwhile, provincial auditor general Merwan Saher vented his displeasure, not with the regulation itself but with the way the government's Department of Treasury Board and Finance has overseen its implementation as a core part of the province's climate change strategy.



Emission reductions since the SGER went into effect result from several interrelated factors. (Source: Cenovus Energy)

"We found no evidence that the department regularly monitored performance between 2008 and 2012 against the 2008 strategy targets … (and) the department's processes to ensure the accuracy and completeness of the plan's data were ineffective."

A national strategy?

This is not the first time the oil patch has had questions about the impact new rule proposals might have on industry's bottom line. In 2009, then-Premier Ed Stelmach introduced a tougher royalty regime intended to give the province a larger share of the oil sands largesse. It was a big change that came in the midst of falling investment that many felt would only fall further with the royalty reductions. When the sky did not fall and investment stabilized, industry realized it could adapt.

Similarly, proposals to change the SGER are unlikely to alter industry confidence. Shell, Cenovus and Suncor have each come out and said all of their current projects will still be viable between CA$45 and CA$65 a tonne. "None of these proposals on the table have imposed average costs even remotely near that range," said Leach. Compliance costs also can be deducted from corporate income tax and royalty payments so the net impact on CA$80 bitumen barrel would be under CA$1.

But even higher emissions targets would be mitigated by the nine-year precompliance period. Leach expects the average cost to be closer to CA$14 to CA$15 per tonne, or CA$1.20 or less per barrel. "And then there is some question as to whether it would apply to upgrading," he said. At the same time, he cautioned that oil-sands projects vary greatly in scope and profitability: SGER may impact Canadian Natural Resources Ltd. in the Grouse Oil Sands at 50,000 bbl/d more than Teck Resources Ltd.'s Frontier Oil Sands Mine at 277,000 bbl/d.

The good news, said Stringham, is the breathing room the SGER gives companies to continued advances in mitigating GHG at facilities. Use of solvents instead of steam and waste and heat recovery are just a few of the mitigation techniques that have picked up significantly in the seven years since the regulation was introduced. He expects those to accelerate after the new regulation is renewed in 2014.

In fact, Stringham is so bullish about the SGER framework he thinks it should be expanded into a national strategy, in part because environmentalists have persuaded the world, including the U.S., that Canada's carbon reduction policy is limited to Alberta. They forget, Stringham said, "that 100% of the oil sands development that they're so focused on is right here in Alberta." E&P

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2014: A pivotal year for AUVs

Market forecast shows AUV use by industry is primed for take-off.

Eduardo Ribeiro, Douglas-Westwood

AUVs are on their way. With vast scope for their application, AUVs are finally gaining pace in the commercial sector. The technology, which has its origins in military activities such as mine counter-measure and rapid environmental assessment, also has a strong presence in research activities, from research mapping to environmental sensing. In fact, the military and research sectors have strong links that enable collaboration; therefore, some units can be used across the sectors. The two sectors currently form 97% of AUV demand. However, Douglas-Westwood's "World AUV Market Report 2014-2018" forecasts an annual growth of 36% in the commercial sector, predominantly driven by deepwater oil and gas activities, expanding the share of the total market from 3% in 2014 to 8% in 2018.

Overview

AUVs have no umbilical connecting them to a host support vessel (as opposed to ROVs) as these have the advantage of carrying both onboard power and the computer capability to travel a preset path through the water, using a combination of internal and external positioning sources as well as sensors that give direction, depth, altitude and speed. AUVs, however, do not provide real-time data such as video. They are used by civilian researchers and academics, commercial survey and inspection companies, and by the world's militaries to either provide information about the seabed; identify objects on the seabed or in the water column; or provide a means of observing physical, chemical and biological processes. AUVs can be used to survey an area in a regular pattern or to follow a linear feature such as a pipeline.

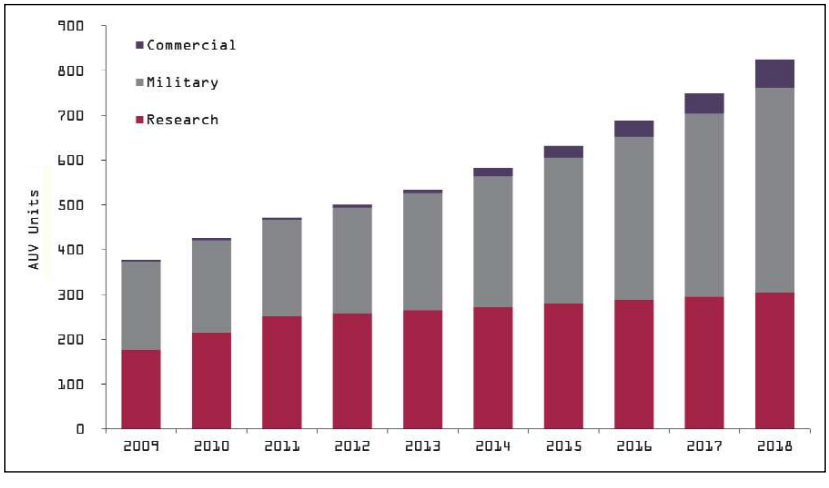
The benefits of AUVs include operability in a wide variety of water depths and where surface vessels cannot be used due to surface restrictions/obstructions. They have a wide range of deployment options ranging from manual to dedicated vessels and can help reduce threats to personnel by increasing either the distance between hazard and operator or by performing reconnaissance in advance of manned operations.

Key developments

There are some key developments that should enable strong commercial uptake from 2014. These include sensors, battery endurance and positioning. Multiple sensors form a key component and continue to increase in data quality and resolution. Endurance also is under constant development, with rechargeable batteries powering the majority of AUVs now in use, while nonrechargeable batteries offer greater endurance but at a significant cost.

A small number of AUVs use fuel cells, but their use is not widespread due to concerns with the storage and disposal of the chemicals. Even small AUVs typically now have quoted endurance of more than 10 hours, with larger vehicles in the 50- to 70-hour range. High endurance is central as it enables AUVs to offer vast reduction in time lost in operations in addition to the time savings when turning from one survey line to another when compared to a survey vessel towing sensors in deepwater.

Unmanned launch and recovery is a goal of many developers as that phase of operations is perhaps the riskiest for the personnel involved. The launch and recovery require-



The global AUV demand forecast shows a steady increase in the number of AUV units used in the commercial, military and research sectors from 2009 to 2018. (Source: Douglas-Westwood)

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ment and methodology for AUVs vary. Smaller units are routinely deployed from the beach or small craft, whereas larger vehicles require the use of either a vessel's deck crane or a dedicated launch and recovery system. This is an area in which many operators think there should be further improvements.

Commercial applications

The oil and gas industry is historically conservative when adopting new technologies; however, the above developments will act as enablers for commercialization, with 2014 expected to be a pivotal year. Growing energy demand globally will be met by supply from increasingly deep waters as easy-to-reach reserves mature.

Mature offshore fields and remote areas represent higher capex per barrel, while oil prices are stabilizing. The result is that oil and gas companies are striving for the most cost-effective solutions. AUVs are widely accepted to be cost-effective and have been proven as an optimum solution in harsh environments.

Although shallow-water E&P will remain dominant during the next five years, most commercial demand for AUVs is expected to come from deepwater in the "Golden Triangle" of Brazil, Gulf of Mexico (GoM) and West Africa. Deepwater capex is expected to double over the next five years, with $260 billion to be invested as the market continues to recover from the global economic downturn.

Growth in maintenance markets is a key indicator for life-of-field inspection (LFI) and pipeline inspection. Offshore drilling is expected to boost oil and gas site survey activities, the main commercial application of AUVs, accounting for almost a third of commercial demand. To a lesser extent, AUVs also are expected to increase utilization rates in shallow waters.

With increasing regulations and costs, LFI is a long-term goal for deepwater and remote production facilities inspection, run by unmanned or hybrid (AUV-ROV) vehicles. The application is still in precommercial stages but has great potential to demand a number of units for installations in Angola, Nigeria, Brazil, South Asia, the North Sea and the U.S. GoM since LFI using AUVs is more applicable in deeper waters. Site surveys also will drive demand again in the Americas and Asia, while Africa should be the largest market, demanding 47% of the units in 2018.

The chart shows Douglas-Westwood's demand forecast for AUVs. The combined sectors account for 97% of global AUV demand in 2014. The commercial sector is expected to show exponential growth, more than tripling demand from 2014 to 2018. The total number of units across all sectors is expected to exceed 800 by 2018, an increase from about 600 in 2014.

North America will remain the overall leading region in the next five years, demanding most AUV units. However, other regions will become more active in all sectors, which should mean a decrease in the proportion of active units for the region, mainly driven by military activities in developing economies such as China and Brazil that are increasingly investing in their navies.

Turning point

Douglas-Westwood has forecast that the military sector will remain the largest AUV market in the next five years, driven by military investment from the developing economies. The sector is likely to direct less investment into AUV R&D, while commercially driven developments grow. The ocean research sector also will remain strong with increasing attention to topics around environmental issues, resulting in a growing demand for data from environmental sensing and research mapping, including from deepwater and the Arctic. As AUV technology matures in such applications, it should enable continued growth in those areas that are unsuitable for conventional access methods.

For the commercial sector, 2014 could be a turning point in AUV market uptake. The commercial use of AUVs has seen only moderate growth in recent years. The technology has evolved, and while oil and gas operators remain risk-averse, opportunities in the commercial sector could increase, enabled by developments in areas such as battery endurance, navigation systems, tracking systems, vehicle stability, data and imagery.

Barriers may be primarily in launch and recovery systems for larger units and data transmission as AUVs do not offer real-time data. These areas should be progressively addressed by developments such as unmanned launch and recovery systems, hybrid vehicles and docking stations for in-water charging, and improved through-water data transmission.

The increased economic challenges of deepwater oil and gas developments lead to a desire to introduce cost-effective approaches. AUVs have been proven to be optimum cost-effective solutions for surveys and inspections as opposed to the higher costs of vessel-based activities. Factors include operation and time costs and reducing direct human involvement in activities in high-risk environments. Douglas-Westwood expects further increases in AUV use in deep waters and under-ice as an alternative to ROVs.

AUVs are still considered an emerging technology and require more uptake and investment before posing a significant substitution risk for surface vessels and ROVs. However, 2014 is expected to represent the first year of significant growth, which should allow the technology to be the industry eyes in the deepest waters. E&P

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ROV demand rests on rising talent

Closing in on the skills and technology gaps is key to meeting demand for ROV services.

Moray Melhuish, ROVOP

As the subsea industry's landscape continues to change apace, new horizons are surfacing for the ROV sector. The market is experiencing an increase in activity from the sharp rise in demand for subsea installations and intervention. This, combined with the industry's ongoing journey into increasingly challenging and remote environments, opens up a plethora of exciting new opportunities.

However, it also exposes the ROV sector to an almost unprecedented challenge—its ability to keep up with the sheer scale of demand and, crucially, provide a quality service that delivers high industry value.

While the shift toward creating subsea factories (SFs) is an exciting prospect for enhancing recovery from mature and marginal fields, the standardization of complete subsea processing is likely to further increase the growing demand for ROVs.

This is because the introduction of SFs will create more subsea structures that will subsequently require installation, inspection, maintenance and repair. They could also impact the AUV sector in that it may experience an increase in demand for survey work pre-installation.

But just as expertise and know-how is central to underpinning the success of SFs, exactly the same applies to ensuring the future sustainability of the ROV sector. To put this into perspective, NASA wouldn't send someone to the moon without ensuring that person was a trained and experienced astronaut and fully competent of flying a shuttle that is highly equipped for the mission.

However, like the energy industry as a whole, a critical shortage of ROV skills is looming due to the aging workforce and the quickly growing demand for ROV services.

The International Marine Contractors Association estimated a shortfall of about 2,000 ROV personnel from 2012 to 2017, while analyst reports have said that ROV expenditure is expected to more than double by the end of this period, with rig use anticipated to be the primary driver behind the increased need for ROV services.

These are believed to be very conservative estimates, serving as another stark warning that urgent action is required to attract the next generation of ROV pilots and personnel. Yet the ability of the ROV sector to keep up with demand is limited by the number of companies bringing fresh talent into the sector and, in particular, those training new offshore recruits.

Attracting talent of the future is key to meeting increasing demand for ROV services. (Source: ROVOP)

New initiatives

Companies like ROVOP have recognized the need to invest in ROV pilots and technicians of the future by introducing their own training initiatives. Established at ROVOP's headquarters in Westhill, Aberdeenshire, Scotland, and incorporating a $400,000 simulator, ROVOP's ROV Academy is developing the skills of offshore personnel at all levels through a comprehensive and structured training program that includes all ROV-related study, practical experience and associated training.

The closure of Royal Air Force bases in northeast Scotland also has produced an influx of potential trainees with suitable pretraining experience and aptitude. The ROVOP Academy brings individuals like these, after they have completed their training at a recognized ROV training school, to ensure they are equipped with the best knowledge and highest standard of experience required to progress their careers within the company as well as to manage the competence and training of ROVOP staff at all levels.

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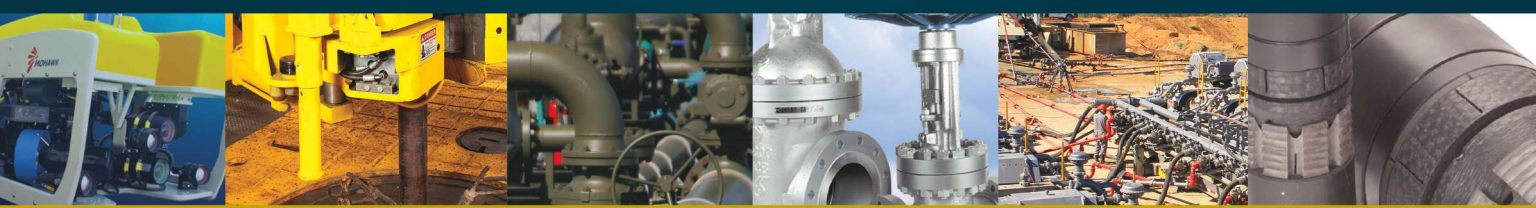

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ROVOP has established an ROV Academy, which includes a $400,000 simulator. (Source: ROVOP)

genuine value and creating tangible results. Often, savings measured in millions of dollars are achieved due to the considerable increase in efficiencies, especially when the day rate of a host vessel is taken into account.

ROVOP was founded on three basic yet fundamental principles—to provide the most skilled operators in the industry, best-in-class equipment, and an unparalleled quality and delivery of service.

Through these values, ROVOP has established a track record and has grown its team to more than 130 people within three years. This is a positive indication of the huge appetite that exists to fill the skills gap in the market.

As the subsea industry becomes increasingly pivotal to ensuring global security of energy supplies—accelerating the demand on the ROV sector—and with major subsea projects operating a cost base that can easily run to $500,000 or $1 million a day, careful selection of an ROV provider will help reduce risk and increase the efficiency of a project, saving considerable time and cost.

Technology investment

But just as people power should remain at the forefront of the agenda for consolidating the ROV sector's position for future sustainability, ongoing investment in advanced technology is fundamental, particularly with the subsea industry venturing farther into ultradeep water and harsher environments while exisiting subsea infrastructure requires ongoing maintenance.

Technical advances in ROVs such as the ability to configure them according to project requirements, including specific tooling and sensor needs, have left the older models behind and, if not obsolete, certainly struggling to keep up with the rapid pace of change. No matter how well it has been maintained, a veteran system cannot compete in terms of the advanced diagnostics, system reliability, performance, repairability, automated functions and deployment of advanced survey equipment and subsea tooling.

Up-to-date ROV controls are ergonomically designed, and the systems have an array of automatic pilot functions built in. These can include auto heading, auto pitch, auto roll, auto depth, auto altitude, station keep (or dynamic positioning) through the entire water column, auto displacement and auto track, which can be invaluable in pipeline or cable survey tasks.

Using the latest control system technology, the sector can even use automatic manipulator functions to reduce human error in ROV operations, which ROVOP plans to introduce to its fleet later this year once full tank trials are complete.

While there are still gaps in technology, these are being addressed by manufacturers focused on improving reliability, operability and maintainability of the equipment. Furthermore, improvements in heave compensation technologies used in launch and recovery are helping to avoid downtime by preventing equipment damage in heavy weather. In some instances, they are also increasing the operating envelope.

Increased efficiency

Operators need to control costs while improving safety and environmental performance to make many subsea oil and gas fields viable, particularly mature basins. With this in mind, and with the ever-increasing demands on the ROV market, it has never been more vital that the subsea sector focuses on efficiency and works together with the operators to make sure the industry continues to prosper.

Collaboration and knowledge sharing is essential to both addressing and overcoming the challenges ahead and, ultimately, to breeding the next generation of talent and technology. E&P

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Much ado about little…

Europe's unconventional activity and reserves are hard to define. For some, it's a region on the cusp of an energy revolution. For others, it's a go-slow zone.

Mark Thomas, Editor-in-Chief

Even the supporters of Europe's shale potential seem half-hearted. An oil and gas industry-backed online information site states underwhelmingly, "The International Energy Administration has estimated that Europe could hold trillions of recoverable cubic meters of shale gas across several member states. It is as yet uncertain exactly where reserves are located, how large they are or whether they are commercially viable." To paraphrase: "Europe could have lots of shale gas, but then again it might not, and we're not sure where it is anyway."

Thus is the current state of the industry in Europe. One thing that is safe to say is that it is in a nascent stage. This is not to dismiss the fact that there is already real activity underway. Countries such as Poland have seen a good number of early wells drilled, but when the approximately 50 to 60 unconventional wells in that country are compared to the 400,000-plus wells drilled in the U.S., it pales into insignificance.

The key word remains "potential" for Europe, especially if not including Russia in the conversation. Much of the difficulty for the continent is because of its very fragmented identity—the U.S. is of course one single massive country and market, and it is no accident that activity is advancing more rapidly in other similarly large countries such as Russia, China and Australia.

Europe, by comparison, is not a single cohesive market, despite the existence of the EU. In the long term, it is highly likely that shale gas and oil will be developed, but that development will vary greatly from country to country.

On the one hand, there are those countries that are fervently anti-hydraulic fracturing, such as France, where a total ban remains in place and looks unlikely to be removed. On the other, there are those countries, including the United Kingdom and Poland, that are politically at least strongly in favor of it.

Current status

So what is the current status? The European Union decided to defer the decision on whether to carry out shale exploration activity to each member state, meaning the national governments retain the right to decide if and where they want to search. As a result, the countries where activity is currently moving are the U.K., Poland, Germany, Romania and Denmark. Bulgaria, France and Spain remain subject to moratoriums at present.

U.K.

The U.K. has significant shale gas potential. Last year the Department of Energy and Climate Change (DECC) published a study by the British Geological Survey (BGS) on the volume of gas in the Bowland and Hodder shales in the north of England. That study concluded the total amount of gas in place there was 37.6 Tcm (1,328 Tcf).

More recently it did a similar study on Scotland's potential in the Midland Valley Basin, which raised the total claimed U.K. shale reserves figure to about 42 Tcm (1,409 Tcf) of gas and 6 Bbbl of oil for the Bowland and Midland Valley basins combined.

In Scotland the play can be considered stacked like some shale plays in the U.S. such as the Spraberry and Wolfcamp, according to the report. The BGS pointed out that while it did not examine the hybrid conventional, tight oil and tight gas potential of the play, "evidence of numerous oil and gas shows in wells suggests that tight oil/gas could be a complementary resource in the Midland Valley of Scotland."

Unproven

The U.K. remains, of course, almost entirely unproven, with analyst Wood Mackenzie saying that with only six wells targeting shale plays drilled so far, "much remains to be seen from the initial well results in order to prove the commercial viability."

The list of companies who could join the search may well grow as the government recently launched its 14th onshore licensing round. Licenses are available in areas that include the Bowland and Midland Valley basins.

According to Wood Mackenzie, a number of barriers still remain to be overcome to reach commercial production. "Fundamentally our view hasn't changed since we assessed the commercial viability of U.K. shale gas in 2012, when we forecast production from the U.K. alone was

unlikely to have a material impact on the U.K.'s gas price dynamics out to 2025," said Lindsay Wexelstein, head of U.K. upstream research, in a statement. "The launch of the long-awaited 14th U.K. onshore licensing round is a significant step in the development of the U.K.'s shale gas industry as it could spur the investment and exploration activity required to test the unproven subsurface."

14th round

The 14th licensing round is the first one for six years, and it is expected that licenses will be awarded in the next 12 to 18 months. Backed by a British government that is publicly committed to developing shale resources in the face of increasing energy prices, declining North Sea output and threats to energy security due to events such as those in the Ukraine, the U.K.'s Business and Energy Minister, Matthew Hancock, commented recently in a statement on the licensing round that "ultimately, done right, speeding up shale will mean more jobs and opportunities for people and help ensure long-term economic and energy security for our country."

A program to try to better inform the public (and counter the very proactive environmental campaign against any fracking in the U.K.) has seen the BGS also release a series of maps to help illustrate the relationship between groundwater and fracking. While the report acknowledges that water is a "resource that needs effective long-term protection," the maps illustrate the distances that separate shale gas deposits and water aquifers. The Bowland Shale, for example, lies at least 800 m (2,625 ft) below principle aquifers. This means it is highly unlikely that hydraulic fracturing could have any impact on aquifers since the micro fractures created by the process typically extend less than 180 m (591 ft) upward from the wellbore, it said.

DECC has to date awarded 334 landward licenses for onshore petroleum and gas exploration. A report by the U.K.'s Institute of Directors also has suggested that shale gas development could bring with it investment of as much as £3.7 billion (US$5.9 billion) per year and create up to 74,000 jobs.

Most of the current shale exploration activity is being driven by Cuadrilla Resources Ltd., which plans to drill up to four exploration wells at its proposed Roseacre Wood and Preston New Road sites in Lancashire, England.

IGas Energy, meanwhile, is expected to announce initial gas-in-place estimates in the East Midlands, England, and the first results from the ongoing core analysis of its exploration well at Barton Moss. It will also commission an independent review of the combined group's assets since its acquisition earlier this year of Dart Energy.

IGas also is planning the acquisition of 3-D seismic across some of its acreage with a view to submitting applications for multiwell sites for drilling and hydraulic fracturing of gas from shale in first-half 2015.

Poland

The Polish Parliament's Lower House voted recently on a set of amendments to its existing Geological and Mining Law, which will clarify licensing procedures for investors as well as offering greater security.

The new provisions are expected to come into effect Jan. 1, 2015. Poland also is looking into a new tax bill on shale gas development which, to encourage investment in its nascent shale gas industry, will probably only be brought into effect around 2020. In March this year the government gave its full backing to shale gas, with Prime Minister Donald Tusk saying that shale gas extraction would be exempt from tax until 2020 and Minister of the Environment Maciej Grabowski stating that shale gas was his priority this year.

The country's potential shale reserves are believed to be extensive, but much more exploration drilling remains to be done. In 2012 the Polish Geological Institute issued estimates for its shale gas resources, with the conservative range put at 346 Bcm to 768 Bcm (12.2 Tcf to 27 Tcf) while the higher end estimate was up to 1.9 Tcm (67 Tcf).

A separate study that year conducted by Saponis Investments SP, however, indicated a potential 376 Bcm (13.3 Tcf) of shale gas in just three concession areas in north-

Cuadrilla Resources is looking to drill up to four shale exploration wells in the U.K. next year on two sites in the county of Lancashire in northern England, while IGas Energy is shortly expected to announce results from its first well at Barton Moss, near Manchester, also in the north of England. (Source: Cuadrilla)

ern Poland, painting a much more optimistic picture than that of the Polish Geological Institute. There are currently more than 100 concessions for shale gas covering 88,000 sq km (34,000 sq miles), with at least 60 wells drilled so far and up to 40 more planned by year-end—making it by far Europe's most active actual shale explorer at present.

Denmark

Although a recent entrant into the shale gas sector, Denmark has a supportive government and also a public that, according to surveys, appears to agree that shale gas should be a part of the country's future energy mix. One Danish local council—Frederikshavn—recently decided to allow exploration drilling for shale to take place for the first time in the country.

Germany

Germany is estimated to hold significant resource deposits, and with its ongoing strategy to phase out nuclear power, shale is seen as a significant potential new energy source. In 2012 the country's Federal Institute for Geosciences and Natural Resources estimated that between 70 Bcm and 230 Bcm (2.5 Tcf and 8 Tcf) of shale gas reserves could be extracted. Last year the U.S. Energy Information Administration (EIA) came up with a figure for Germany—with no drilling having yet taken place, of course—of 481 Bcm (17 Tcf) of technically recoverable shale gas reserves.

Germany is heavily dependent on gas imports from Norway and Russia and is keen to achieve better energy independence if it can. However, the current government is firm in saying that shale gas development will not take place until concrete evidence has been demonstrated that the process is safe. Despite this, earlier this year the region of Lower Saxony said it was in favor of hydraulic fracturing and put forward a draft proposal for a decree on the permission of exploration and extraction of natural gas through fracking.

Romania

Romania lifted its moratorium on fracking last year, with the country's National Agency for Mineral Resources now underway with a study to determine the level of potential shale gas resources. The EIA estimates Romania's unproven wet shale gas technically recoverable resources at 1.4 Tcm (51 Tcf), which makes it the third-largest in Europe behind France and Poland.

Chevron has been present in Romania for some time and holds a number of concessions, mainly in the counties of Constanţa and Vaslui. It also began actual exploration work in late 2013. The operator has gone on record as saying that its investment in Romania alone could total $600 million over the next 15 years. State company Petrom also is undertaking preliminary analyses of its concessions.

Above-ground challenges

Throughout Europe it is largely the above-ground challenges that remain most daunting. The process of obtaining planning permission to drill, frack and test wells is strewn with red tape and necessary environmental procedures, supplemented often by vigorous anti-fracking campaigns in densely populated areas. It is also much more expensive than in the U.S. as a lack of pipeline infrastructure in some parts of Europe such as Poland means a well can cost up to three times more than in the U.S. More powerful rigs and pumps also are needed as most of Europe's shale lies deeper than in the U.S., further meaning more fracking fluids also are needed.

The U.K. is also a good example of the red tape issue. Wood Mackenzie said that successful bidders on licenses will have to undertake extensive public engagement and consultation exercises before planning applications are even submitted to local councils. The industry is essentially heavily regulated by four layers of oversight, including the U.K. Environment Agencies, the Health and Safety Executive, the Mineral Planning Authorities and DECC. The onshore industry also already has to comply with 17 different EU directives. Each well also requires up to nine separate environmental permits and has to reach binding agreements on noise, hours of operation and other local social issues.

But Wood Mackenzie also highlighted positive moves by the U.K. government to lure and support shale gas developers. "The U.K. government has introduced fiscal incentives that will support the development of succinct shale gas pads," the analyst said. "Given land access issues in the U.K., these are likely to be more palatable development concepts for local communities and planning authorities, but their viability will depend on the geology and presence of commercial shale gas reserves."

The pad allowance cuts the tax on a portion of production income from 62% to 30% at current rates, according to the U.K. treasury department.

Positive moves like this indicate that Europe's time is coming, but it will be a slow process. Experts have gone on record as saying that up to 300,000 wells may be required to get the potential shale gas reserves out but that up to 1,000 will first need to be drilled before Europe truly understands its shales and whether they can be produced commercially. E&P

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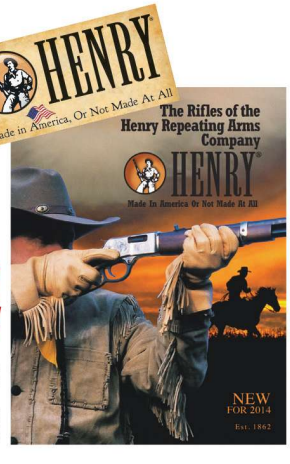


Technology captures, transforms flare gas

A new solution offers a small-scale alternative to traditional GTL approaches.

George E. Boyajian, Primus Green Energy Inc.

Flaring produces about 400 MMtons of greenhouse gas emissions annually, according to the World Bank-led Global Gas Flaring Reduction (GGFR) partnership. While flaring is less damaging to the environment than directly venting natural gas into the atmosphere, it does produce CO_2 and a host of other harmful pollutants. Until now, the only solution to the flaring problem has been to build expensive transmission pipelines to transport the natural gas to distant markets. But since the oil in a petroleum reserve is about 30 times more valuable than the associated natural gas, oil companies have chosen to flare much of the associated gas they produce rather than investing in the infrastructure to collect, process and market it.

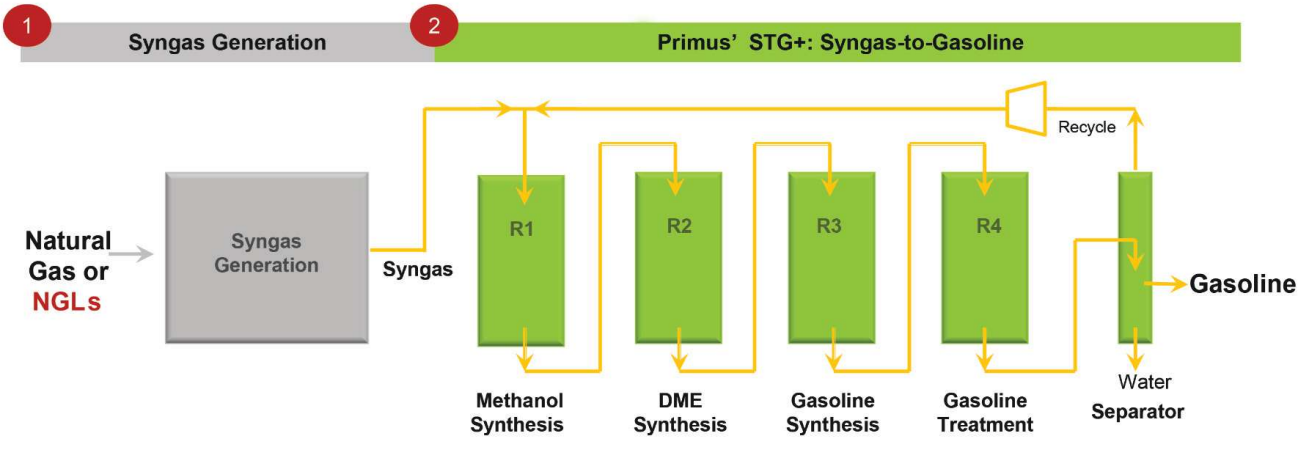
This may be about to change, however, with the deployment of syngas-to-gasoline (STG+) technology, which transforms natural gas directly into liquid transportation fuels such as diesel and gasoline as well as organic solvents.

In addition to producing fuel, the STG+ process also can be used to produce a synthetic crude in situations where there is no demand for fuel or where the demand for fuel is not large enough for the amount of fuel product that can be produced. The ability to produce a synthetic crude that is compatible with the oil being produced at the wellhead also allows the operator to take advantage of existing petroleum infrastructure and logistics for transportation to market.

The STG+ technology also can be used in "stranded" gas situations in which a natural gas resource is stranded for physical or economic reasons—i.e., the resources are too remote or too small to justify the expense of developing dedicated pipeline infrastructure. Small-scale plants could unlock the economic potential of these stranded natural gas assets, allowing smaller producers to make transportation fuels for local markets.

The technology

The STG+ process involves two stages. The first is to create syngas (a mixture of carbon monoxide and hydrogen) from natural gas through a standard steam reforming process. After being scrubbed to remove unwanted sulfur and CO_2, the syngas then enters the second stage, a liquid fuel synthesis train consisting of four catalytic reactors that transforms the syngas (in the case of gasoline) into methanol; dimethyl ether; heavy gasoline, which is gasoline containing compounds known as durenes whose high melting point can cause drivability problems due to carburetor icing; and durene-free light gasoline, which is what is used in a car's gas tank. By adapting process settings



This schematic shows the process by which associated gas that might otherwise be flared can be turned into gasoline. (Source: Primus)

or changing catalysts, the process also can produce diesel, aviation fuel or organic solvents. (The "plus" in STG+ stands for the multiple end products.)

While other gas-to-liquids (GTL) technologies can turn natural gas into fuels, the flexibility and efficiency of the STG+ technology makes it economical even at the small scales required in an oilfield situation. Fischer-Tropsch, which was invented in Germany in the 1920s and used by the petroleum-starved Nazis to make fuel from coal to power their war effort, is the most widely used GTL technology. But it is only profitable at enormous scale, in part because it requires two steps: The process creates a synthetic crude from natural gas or coal, but that synthetic crude must then be refined to create end products such as diesel and lubricants. For instance, the world's largest GTL plant, Shell's Pearl plant in Qatar, is said to have cost more than $19 billion.

The other competing technology is ExxonMobil's methanol-to-gasoline (MTG) process, which was used for about 11 years at a plant in New Zealand in the 1980s and 1990s before being abandoned when a drop in oil prices made it uneconomic. The MTG technology can produce fuel without any extra intermediate steps but has other limitations, including the fact that it only produces one end product—gasoline—and that the gasoline it produces has a high content of durenes. While the STG+ process is based on MTG, it uses a four-reactor rather than a three-reactor process to improve the quality of the end product, with the innovation minimizing complexity through proprietary innovations concentrated around the composition and makeup of the catalytic reactors themselves.

Advantages

STG+ is cost-effective at smaller scales. This is made possible by its high efficiency. It has yielded very high efficiency rates at demonstration scale, converting each MMBtu of natural gas directly into more than 5 gal of high-quality gasoline blend stock drop-in gasoline. Researchers at Princeton University who compared the process with Fischer-Tropsch and MTG have found that STG+ is more efficient and cost-effective in general but especially at scales of 10,000 bbl/d or less, enabling a business model of smaller, geographically dispersed plants. This efficiency also contributes to a low-cost end product. The cost of fuels produced through STG+ is comparable to the cost of fuels produced from oil at about $65 per barrel. Since oil is currently trading at a higher price, the price would have to drop significantly for fuels produced from the process to be rendered uncompetitive.

Flaring is an increasing problem in areas like Iraq that lack enough infrastructure to move associated gas. (Source: NASA)

Finally, the process holds an advantage over competing processes in that it can directly yield a range of end products, including diesel, gasoline and organic solvents, and that those end products can be used directly in the tank. The fuel produced is also of very high quality: The gasoline product, for instance, has a 90+ octane rating, contains less than 1 ppm of sulfur and zero benzene, and meets or exceeds other standards.

As a solution to the flaring problem, the technology holds another advantage. By eliminating the need to build a natural gas pipeline infrastructure, the use of the technology at the wellhead eliminates leaks from downstream natural gas transmission lines, which are a large source of "fugitive" methane emissions.

A growing problem

According to the GGFR, flaring increased from 138 Bcm (4.9 Tcf) in 2010 to 140 Bcm (5 Tcf) in 2011, the most recent year for which statistics are available. This increase can be expected to lead to more pressure to monetize assets that are now being wasted as well as more pressure to address the environmental consequences of flaring. STG+ technology holds the potential to be an effective, low-cost solution to the flaring problem, not only in the U.S. but in the many countries around the world where flaring has become an issue. E&P

Enabling upstream operational excellence

IO brings quantifiable value to businesses in a sustainable manner.

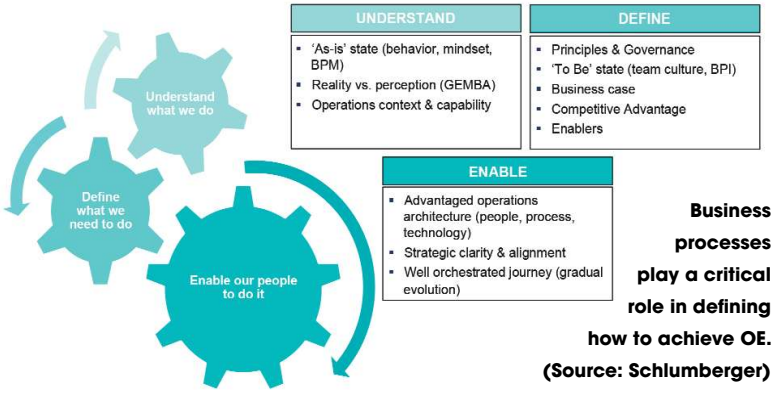
Janin Girie and **A. Ghaffar B.M. Dawam**, Upstream PETRONAS; and **Juan Carlos Gonzalez Bonilla**, Schlumberger

Upstream operational excellence (OE) can be defined as the execution of value-driven performance in an efficient, best-in-class, collaborative manner across the upstream value chain. An OE program should provide a framework for participants and other stakeholders to understand why and how performance needs to improve. The road to achieving this excellence begins with what people are doing in their roles, including understanding business processes in the context of decision-making; identifying strengths and weaknesses based on performance measures and industry's best practices; and redesigning processes as needed to align with corporate strategic goals, which typically incorporate relevant best practices and LEAN concepts.

Four underlying themes should resonate throughout an OE program. The first is advantage. In every arena in which a business operates, a competitive advantage must be secured, or at least anticipated and planned. This "edge" is imperative for the creation of value.

The second theme is integration. Building advantage through strategic and operational links among core teams and across domains results in a coherent investment plan that maximizes the value extracted through a collective, or integrated, effort.

Leadership, the third theme, involves management's focus on strategic initiatives and the recognition of the importance of integrating people, processes and technology. The fourth theme is continuous improvement. An organization needs strategies to meet or exceed industry's minimum performance standards and then to lead by example. Combined, these themes underlie the business of delivering excellence in operations.



Business processes play a critical role in defining how to achieve OE. (Source: Schlumberger)

These themes also form the basis of integrated operations (IO). IO refers to the development by a business of organic decision-making capabilities through the orchestration of key upstream operations across domains and organizational teams. Although IO employs digital field solutions for better data capture, visualization, analysis and automation, the real benefit lies in the ability of an organization to leverage solutions that add value at the business portfolio or corporate strategy levels. The benefit for operators is to their processes and people—that is, what is actually done with the large volume and detail of information that digital fields generate in terms not only of data but also of decision outcomes, interpretations and knowledge (both tacit and implicit), and who does the work.

IO makes a particular impact on production, integrated activity planning and logistics, and monitoring. If an operator spends billions of dollars on marine logistics and can streamline its activities through IO by 3% to 5%, millions of dollars can be saved. Likewise, a reduction in the number of unplanned shutdowns through better control and constant surveillance creates significant savings. Surveillance enables production engineers in the head office to see in real time what is going on in any part of any field. Smarter production decisions can be made, and workforce resources can be streamlined and realigned.

IO basics: business processes

Achieving excellence by integrating operations requires understanding what is done by whom, when, and to what level of efficiency. Processes need to be examined, understood, evaluated and then improved as part of the IO initiative. Management and operations personnel need to have this visibility to better understand areas of improvement and to assess current and future needs. It is also important for personnel to have the agility and capability to manage operational challenges proactively.

Business processes are the lifeblood of any operator's organization. The visibility, efficiency and effectiveness of these processes enable operators to exceed their goals and differentiate themselves in a fiercely competitive market. A process-centric approach to IO delivers value directly to the owners of these business processes. Key to this

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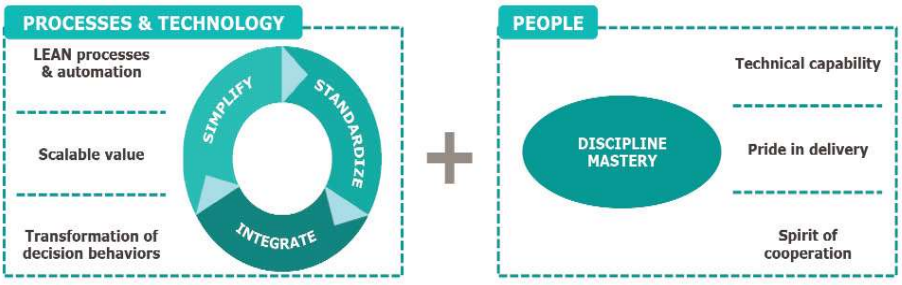


IO is the enabling component of the OE journey: a combination of real-time awareness technology, simplified processes and collaborative mindset that fosters cooperative decision-making to achieve common objectives for HSE, asset integrity and optimized production. (Source: Schlumberger)

approach is examining the process layer independently of technology and organizational structures to understand the interactions among domain and discipline professionals. The upstream business stakeholders can then understand the current state of affairs and decide what they would like, ideally, before addressing the issue of organizational or technological constraints. This fundamental process-centric approach empowers the business stakeholders to take direct ownership of their processes independently of the underlying dependencies.

Operational linkages

Understanding how disciplines and domains are interrelated across the upstream value chain presents opportunities for integration. In a typical IO scenario, constant data gathering and the transmission of information are used to manage potential production, well or reservoir problems and to establish key performance indicators as organizational benchmarks. Real-time field data are leveraged to deliver enhanced production analysis, optimization and detailed reservoir management.

Asset teams are alerted to potential problems, allowing resources to always be focused exactly where they are needed and improving asset management efficiency. Modeling and analysis are done with real-time data to define possible solutions. In turn, optimization occurs when the alternatives are assessed on the basis of all possible data, capability constraints, risks and economics to inform decisions that improve the reservoir and production system. The results enhance asset management by creating an organic decision-making system designed to increase reserves, optimize reservoir drainage, improve production and operations and lower costs and capex.

By combining well operations, production management and integrated engineering models, engineers can gain insight into historical conditions to optimize present production and forecast future production. This insight plays an important role in driving maximum asset team efficiency during production optimization. The ability to use a common platform for data management, modeling, simulation and production management activities greatly improves multidisciplinary collaboration.

Managing people

Stakeholders typically have very different responses to challenges driven by varying perceptions of what IO is and, more importantly, what the implications (real or perceived) are to their daily routine, job function, career progression and responsibilities. The initial adoption of an IO initiative in one asset does not guarantee successful integration into daily work activities and continued use. Nor does it presume successful diffusion throughout an organization.

The initiative must be supported by an appropriate company structure that is governed by the dynamic nature of the company's objectives, functions, workflows, roles, responsibilities, solutions and operating systems. Essential themes to be embedded in this structure are ownership, knowledge, integration and collaboration.

Every IO project has long-term and significant organizational implications, so it is important to maintain focus on how the project will impact the wider company. Attention must also be paid to how these changes will affect an asset team's working practices. Senior management must be committed to the implementation of any changes and ensure that all business units are aligned. Pan-organizational integration sometimes means that one segment of the business may appear to be at a temporary disadvantage in relation to others. It is important that each segment's management team keep broader operational goals in mind and cooperate fully to reach them.

Automating routine tasks that were previously manually undertaken could mean that certain employees' daily jobs change or are even eliminated. Appropriate and timely planning and communication should be put in place prior to any IO integration. Managing human factors such as these is crucial to fully realizing the value of IO in a wider context. The attitude should always be that IO is a continuous process, one that is constantly monitored and evolving and one that becomes part of the rhythm of a company for years to come.

Governance

Governance used to mean telling people what to do. However, governance increasingly means facilitating what people do. This revised meaning involves policy setting,

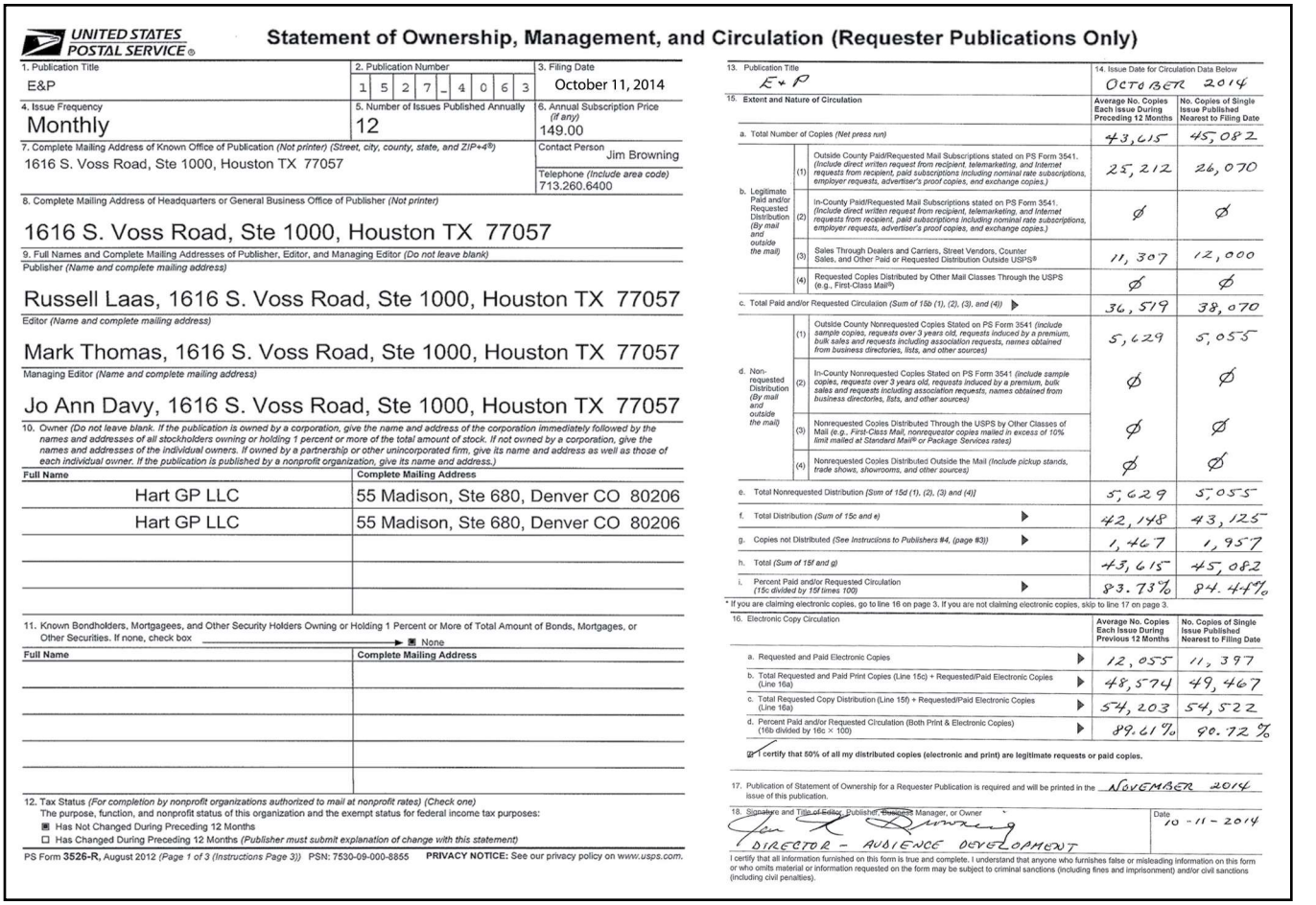
compliance assurance, group portfolios, performance management and group-level strategy development. Added value relates to a company's ability to integrate and its consistency in doing so that arises from common policies and strategies across the core business.

It is crucial that companies consider their operations holistically—that is, how the operational elements of the organization interrelate and how asset teams are integrated. IO ensures that people and work processes are tightly aligned to enable optimal collaborative decision-making and to build value through these strategic linkages. Combining automated and optimized workflow processes with the right blend of corporate values and vision is central to achieving operational excellence.

Once an IO project has been successfully implemented, the benefits are wide-ranging and profound. Operators are able to make decisions centrally, across a number of assets. Quick, accurate control and monitoring of equipment and facilities is simplified and has positive implications for HSE. Medium-term production decisions are also aided—for example, well pressure drawdown for sand control balance or fluid breakthrough, testing, well-rate estimation and optimization of production through the ideal configuration of artificial lift strategies. Longer-term benefits include simpler infill well planning and a better means of defining the reservoir depletion strategy.

Quantifying value

OE delivers value by impacting both the top and the bottom lines of an organization. However, this value has to be quantified for the organization to show the specific impact that will be made. IO not only brings quantifiable value to the business but does so in a sustainable way. A compelling business case is needed to provide the motivation for and prioritization of any IO program. This case involves assessing current business processes and performance, designing the future process and a solution to support it, identifying the benefit drivers and calculating the ROI. Altogether, these themes and concepts provide a clear direction for achieving excellence in upstream operations. E&P



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Inspection tool offers solution for unpiggable pipelines

The RTD DTI Trekscan pipeline inspection tool from Applus RTD is the first free-floating inspection tool designed to traverse back-to-back one-dimensional bends with an optimum speed of 1 m/sec (3.3 ft/sec). It can run in pipelines previously considered to be unpiggable, a company press release said. Standard tool configuration has a maximum battery life of up to 3.5 hours at 1.25 m/sec (4.1 ft/sec). For data storage, the maximum standard tool configuration allows 64 km (40 miles) of data based on a 2.5-mm axial sampling. The bidirectional tool measures the return echoes of a transmitted ultrasound beam. The amount of time it takes to receive an echo provides highly accurate information on the remaining wall and enables detection and sizing of metal loss anomalies. The standard configuration of the tool comes in 6-in. and 8-in. sizes and weighs 33 lb. Its maximum operating temperature is 40 C (104 F). *applusrtd.com*

Perfluoroelastomer enables sealing solutions in subsea, subzero applications

Greene, Tweed launched Chemraz 678, a perfluoroelastomer designed for chemical resistance and rapid gas decompression (RGD) resistance in extreme low-temperature environments. The Akron Rubber Development Lab has independently qualified Chemraz 678 to the ISO 23936-2 global standard for RGD resistance. Under the standard's stringent testing conditions, Chemraz 678 passed with the best possible score of "0000"; this score means that after the conclusion of testing, no cracks were observed in the material. Chemraz 678 delivers chemical resistance with a wide temperature range of -40 C to 230 C (-40 F to 445 F). This new material also provides compression set and thermal shock resistance, allowing it to be used in a wide variety of industry applications. *gtweed.com*

This perfluoroelastomer provides chemical and RGD resistance. (Source: Greene, Tweed)

Drilling motor delivers reliability, durability in demanding environments

The TiTAN22 performance drilling motor from Scientific Drilling International (SDI) is engineered to support the most demanding drilling environments to deliver reliability and durability across a wide range of applications, according to the company. The design features SDI's Ti-Flex titanium flex shaft and supports the highest torque power sections and most robust bearing assemblies in the industry to provide reliable drilling performance in all sections of the well, a product announcement said. Features include enhanced weight-on-bit capacity for increased ROP, a driveline for the ultrahigh-torque applications, full rotational capacity in any section of the well, a short bit-to-bend for directional versatility and a design system matched for optimal polycrystalline diamond compact bit performance. The TiTAN22 is suited for drilling extended reach laterals, laminated formations and factory drilling in shale reservoirs. *scientificdrilling.com*

The TiTAN22 drilling motor was designed to provide reliable drilling performance in all sections of a well. (Source: Scientific Drilling International)

Actuator helps operators reduce unplanned production downtime

GE Oil & Gas has introduced the dual-seal pneumatic actuator, which uses a dual-sealing system to help operators reduce unplanned production downtime by improving the reliability, efficiency and maintainability of well operations, according to a press release. The tool is suitable for a wide range of production tree and flowline applications. The actuator is designed to deliver reliable open/close performance for control of wellbore or pipeline fluids and hydrocarbons. A benefit of the tool is the redundant diaphragm/piston sealing system that

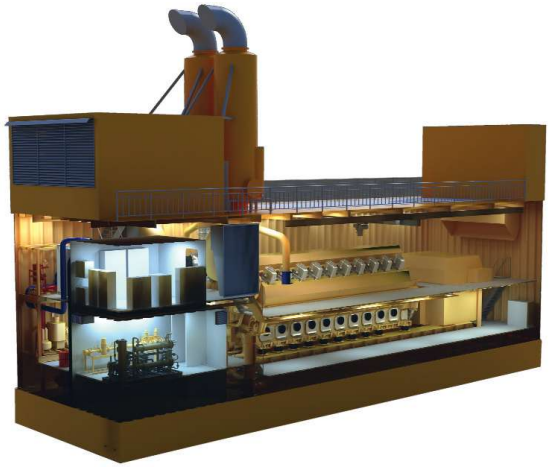
provides a secondary sealing system to maximize uninterrupted production and increase reliability. The modular design allows the use of smaller actuator sizing depending on available supply pressures up to 250 psi. The patent-pending bonnet connection on the actuator allows operators to easily install and remove the actuator from the valve for improved efficiency. The top shaft functionality is designed to reduce field maintenance time. *ge-energy.com*

Technology removes H_2S from sour oil, condensate, water

AMGAS Services Inc. has introduced CLEAR, a chemical-free technology used to remove hydrogen sulfide (H_2S) from sour crude oil, condensate and water. Access to and use of freshwater is becoming more difficult as unconventional shale production across the U.S. increases. AMGAS CLEAR allows operators an option for disposal or reuse of sour water in well servicing and production applications. Sheldon McKee, director of business and product development for AMGAS, said the technology has shown it can reduce disposal and operational costs by as much as 50%. The process allows H_2S removal without introducing any chemical into the produced fluid, thereby leaving no converted sulfides after treatment. The process was designed to prevent chemical overtreatment or undertreatment in sweetening operations but can be even more important when treating sour water in restricted areas. *am-gas.com*

Module meets main power needs of FPSO units, fixed platforms

The Cat Offshore Power Generation Module is a turnkey scalable single-lift modular power plant product from Caterpillar Oil & Gas that includes full integration into the FPSO or platform structural design, a product announcement said. The product leverages an array of Caterpillar engine technology with the vessel design knowledge of Deltamarin, which was integral to the development of the tool. The module was designed to meet the needs of FPSO unit and fixed production platform main power applications in cases where a gas turbine is not ideal. Available from 4 MW to 17.3 MW per module, the module meets current and future emission regulations to maximize flexibility and reduce operating costs. The module is fully tested and certified to be easily integrated in the vessel systems. The modular layout is easily expanded to provide power for future upgrades and is a fully self-contained unit, which provides a single-lift capability. Remote monitoring enables the power module to be managed from the vessel's main control room or an onshore location. *catoilandgas.cat.com*



The Offshore Power Generation Module was engineered for FPSO and fixed production platform main power applications when a gas turbine is not ideal. (Source: Caterpillar Oil & Gas)

Extended-range ESP technology manages steep production decline

Baker Hughes released the FLEXPumpER extended-range pump, which expands the operating range of a single electrical submersible pump (ESP) system. The new pump operates efficiently in a wider flow range to improve production and reduce operating costs, particularly in the dynamic production conditions characteristic of unconventional resource plays, a Baker Hughes product announcement said. As production rates from unconventional oil wells decline, operators typically switch out pumping units or even artificial lift production methods to accommodate the various flow ranges. The FLEXPumpER technology can operate with a flow range from 2,900 bbl/d to 50 bbl/d. The production stream in unconventional oil plays also can contain high levels of gas entrained in the fluid, which can impact ESP system efficiency and reliability. The design features advanced turbulence mitigation technology, which increases pumping efficiency and reduces gas locking, as well as a specialized bearing system to withstand the high temperatures generated in the pump during short-term operation with gas slugs. Additionally, specialized developments in the diffuser provide abrasion resistance by reducing the buildup of abrasives that can cause erosive wear. *bakerhughes.com* E&P

Southeast Asia focuses on the FLNG factor

Field development activity in Southeast Asia is moving along at a reassuringly steady pace, with the region—and the wider Australasian area—on course to play a key role as a nurturing ground for a growing fleet of FLNG projects in the coming years.

Steven Hamlen, Contributing Editor

The fledgling use of floating LNG (FLNG) solutions that give operators access using pipeline infrastructure to remote gas field reserves that would otherwise be noncommercial is a recent phenomenon.

But the solution's relative immaturity is not deterring operators from embracing it on a growing number of projects all currently on the drawing board in Southeast Asia.

One of its biggest supporters is Japan's Inpex, with the company's operated Abadi development offshore Indonesia having made strong progress throughout this year. Inpex has a 65% stake in the project as operator and has the apparent perfect partner in Shell—perhaps the industry's leading proponent of FLNG technology—with the Anglo-Dutch major holding the other 35%.

The Abadi gas field is located in the Arafura Sea's Masela Block in eastern Indonesia, lying in water depths ranging from 300 m to 1,000 m (984 ft to 3,281 ft). The block, covered by a standard production-sharing contract (PSC), is situated about 800 km (497 miles) east of Kupang, West Timor, and 400 km (249 miles) north of Darwin, Australia.

Abadi green light

Inpex recently received environmental permission from the Indonesian government for the project to proceed. Approval by the Environmental and Social Impact Assessment moves the project a step closer to development.

The Indonesian authorities only granted approval in late 2010 for Inpex's Phase 1 development of Abadi, which includes the FLNG unit with a design capacity of 2.5 MMmt/year of LNG and 8,400 bbl/d of condensate. It is a true megaproject, with a price tag of about $14 billion.

Inpex is now conducting FEED work on the project, having last year demonstrated its commitment to the development by acquiring—along with Shell—the 10% stake held by Indonesia's upstream player PT EMP Energi Indonesia after the latter agreed to divest its stake.

The first phase of Abadi was originally expected to come onstream in 2018, but Indonesia's upstream regulator SKKMigas believes that target is not likely to be met, with 2019 a more realistic deadline.

The first topsides module weighing 2,000 tons is lifted into place on the *PFLNG1* FLNG facility at Daewoo Shipbuilding & Marine Engineering's yard in Okpo, South Korea. A further 20 modules weighing approximately 40,000 tons remain to be installed, with the facility (to be named *PFLNG Satu*) due for completion by year-end 2015. (Source: Petronas)

Inpex also is currently seeking to extend its original 20-year PSC for the field, which will end in 2028, to a 40-year deal. The Jakarta government wants the extension to be tied to a request for Inpex to allocate some output for domestic use, with those talks still underway. Energy and Mineral Resources Deputy Minister Susilo Siswoutomo has said that the government wants at least 30% of Abadi's production to be used domestically.

Shell's FLNG know-how

Crucial to the Abadi Phase 1 development is the use of Shell's proprietary FLNG technology. Shell has been advancing its technology since the mid-1990s; its high-profile Prelude FLNG development off Australia's northwest coast is its flagship project. Shell has stated several times in

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Marcellus Shale and Utica Shale

Shell's *Prelude* facility destined for offshore northwestern Australia is well underway at the Samsung Heavy Industries yard in Geoje, South Korea. The first modules for what will be the world's largest turret ever built, at nearly 100 m (62 ft) high and weighing 10,500 tons once complete, are now arriving in Geoje. (Source: Shell)

recent literature that it expects Prelude to be the first of many such projects, helping it to unlock natural gas resources including smaller and stranded fields as well as larger fields supported by several facilities.

Chilling natural gas to -162 C (-260 F) creates a liquid with 600 times less volume than in its natural state, with all the transportation advantages that come with it.

Citing the example of the Prelude FLNG vessel, Shell said the unit was "huge but compact." Once complete, it will have decks measuring 488 m (1,601 ft)—the length of more than four soccer fields—and 74 m (243 ft) wide.

The Prelude unit will be the largest floating offshore facility in the world. The vessel is under construction at Samsung Heavy Industries' Geoje Island yard in South Korea. It has been designed with double the capacity of the Abadi unit—the Prelude unit will have a production capacity of 5.3 MMmt/year: 3.6 MMmt/year of LNG, 1.3 MMmt/year of condensate and 0.4 MMmt/year of LPG.

Abadi Phase 2

Back on Abadi, however, with reserves originally estimated at 283.3 Bcm (10 Tcf) of natural gas, things are moving fast. Based on those first reserve base estimates and the partners' previous expenditure on Indonesian exploration, when Inpex and Shell originally examined their development options for the field, the use of an FLNG vessel was the natural choice to get production flowing. This was to recoup their initial investments as soon as possible even though the field was realistically close enough to shore to pursue a more traditional pipeline-to-shore solution.

Following further exploration and appraisal success since that time, the partners now have a proven and probable (2P) reserves base that is much higher, at 524.1 Bcm (18.5 Tcf) of gas. As a result, they are looking at larger scale options for Phase 2 than another FLNG unit could currently provide.

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Hence Inpex and Shell are studying a more conventional concept for Abadi's second phase. This involves an offshore fixed platform that would transport the gas via a pipeline to an onshore LNG plant with a proposed capacity of 5 MMmt/year of LNG. The onshore plant could be expanded to two LNG trains, both with a capacity of 5 MMmt/year. This plan is currently being considered for location on the islands of either Aru or Tanimbar. The latter would only require 150 km (93 miles) of export pipelines compared to Aru Island, which would need about 600 km (373 miles) of pipeline.

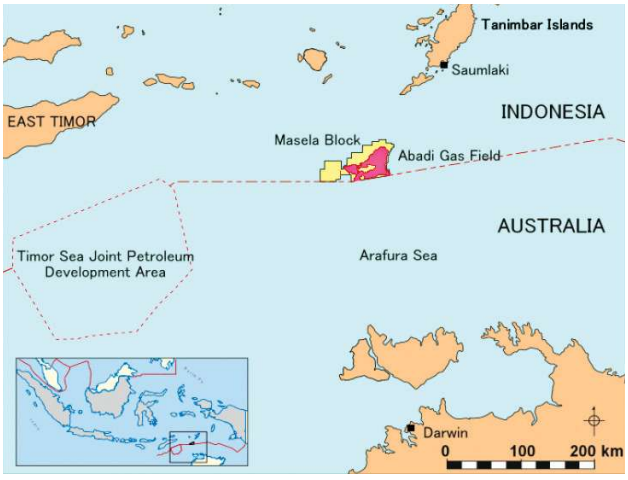
Using this conventional development model, Inpex and Shell say they are confident that they can save up to 25% compared to using a FLNG solution for the full field development of Abadi.

Petronas pitches in

Malaysia's state-owned Petronas also is pursuing its own FLNG solutions for its remote gas fields. The operator recently reported the lifting of the first topsides module for its *PFLNG1* unit at the Daewoo Shipbuilding and Marine Engineering (DSME) shipyard in Okpo, South Korea. The lifting of this first module marked a milestone for the facility, as it signifies that the *PFLNG1* facility is near completion—something that has enabled Petronas to get a jump on its rivals to the point where it has said in a press statement related to the lifting of the first module that the unit would be "the world's first FLNG facility in operation." The pioneer facility will be used to produce gas from the Kanowit Field located 180 km (112 miles) offshore Sarawak, Eastern Malaysia.

Technip and DSME were appointed to jointly develop the *PFLNG1* facility, which again is smaller than Shell's Prelude and Inpex's Abadi units. *PFLNG1* will have an LNG producing capacity of 1.2 MMmt/year, with the vessel having relatively diminutive dimensions of 365 m (1,197 ft) in length, 60 m (196 ft) in width and a height of 33 m (108 ft). The *PFLNG1* facility is only 14 m (46 ft) narrower than Shell's Prelude unit in terms of width but 123 m (404 ft) shorter in length, so it will have only a third of the latter's LNG production capacity (and around half that of the Abadi unit).

Once the construction and installation phases are completed in 2015, *PFLNG1* will be moored on the field, although no firm first production date has yet been given by Petronas. "Once operational, the *PFLNG1* will change the landscape of the LNG business and at the same time play a significant role in Petronas' efforts to unlock and monetize gas reserves, especially in Malaysia's remote and stranded fields," Petronas said in a press statement. A further unit also has been chosen by Petronas for its second



The Abadi gas field occupies much of the remote Masela Block offshore Indonesia, bordering Australia's waters, where the Abadi FLNG unit is expected to arrive in 2019. (Source: Inpex)

planned FLNG project in its domestic waters. It issued a design, build and installation contract for the *PFLNG2* unit earlier this year. The unit will be located in deepwater off the coast of Sabah, with the engineering, procurement, construction, installation and commissioning contract going to a consortium of JGC Corp., Samsung Heavy Industries Co. Ltd., JGC (Malaysia) Sdn. Bhd. and Samsung Heavy Industries (M) Sdn. Bhd.

The facility, if it proceeds as planned, will be moored on the Rotan Field in Block H and be slightly larger than the company's first unit, with a planned production capacity of 1.5 MMmt/year of LNG.

FLNG not the only show in town

Southeast Asia also has a host of other development projects on the boil with not an FLNG facility in sight. Petronas has made a $14 billion commitment to revamp its mature assets and develop marginal domestic fields via EOR techniques. The company's executive vice president for E&P, Wee Yiaw Hin, said the sum was needed to undertake 10 EOR projects that the operator has in the pipeline. It also has $337.1 million in hand for its E&P Technology Center to develop new EOR technology, added Wee, who sees the potential for the application of EOR techniques on 50% of Malaysia's producing fields.

In Indonesia, meanwhile, SKKMigas expects that the much-delayed Banyu Urip oil field in the Cepu Block, East Java, will start full production in early 2015 as development work finally nears completion.

Development work at Banyu Urip was 92.5% complete as of mid-September, with the early production facility (EPF) already producing 30,000 bbl/d of oil, according to SKKMigas. Output at the field, which holds an estimated 450 MMbbl of oil, will increase until it reaches a planned peak of 165,000 bbl/d by mid-2015. That peak is expected to last for about three years.

The project is 45% owned ExxonMobil, while Indonesia's state-owned Pertamina holds 45% and regional player Badan Kerja Sama Blok Cepu has 10%. E&P

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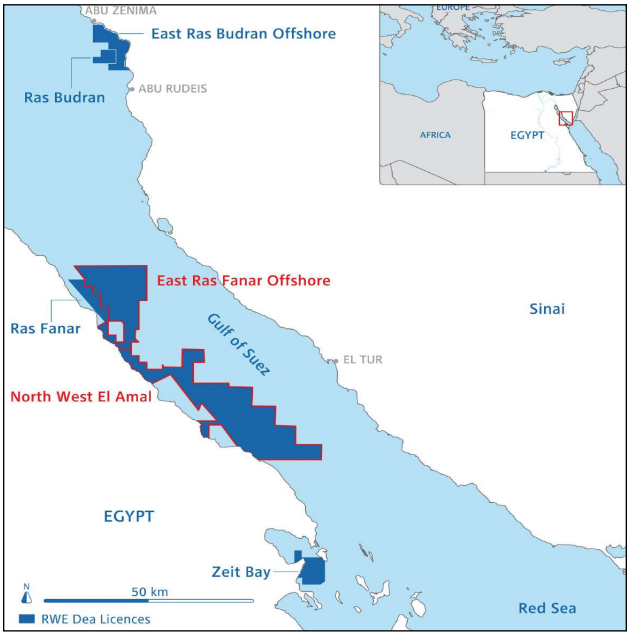
AFRICA

RWE Dea wins two Egypt concessions

In the International Bid Round 2013, RWE Dea has been awarded two new offshore concessions with operatorship by the Egyptian General Petroleum Corp. The concessions are located in the Gulf of Suez. Dea will hold a share of 100% of the East Ras Fanar Offshore and 50% of the Northwest El Amal concession, with Edison International SPA holding the remaining 50%. The upcoming work program for the concessions will include seismic reprocessing, two exploration wells at East Ras Fanar Offshore and one well at Northwest El Amal.



RWE Dea has been awarded two concessions in the Gulf of Suez. (Source: RWE Dea)

BG, Ophir discover gas in Kamba prospect

The Kamba-1 well in Tanzania's offshore Block 4 has resulted in gas discoveries of 29.2 Bcm (1.03 Tcf) in the Kamba and Fulusi prospects, according to an Ophir Energy press release. BG Group operates the Block 4 license, and Ophir holds a 20% interest. The Kamba-1 well encountered an 18-m (59-ft) gross gas column in the Fulusi prospect, and the Kamba-1ST well established another gas column of 140 m (459 ft) with high net-to-gross good quality reservoir sands. The Kamba-1 result provides critical mass for an LNG train to be supplied from the fields in Block 4 and also takes the overall resource volume to the threshold for a future potential third LNG train to be from Blocks 1 and 4.

ASIA-PACIFIC

Shell starts production from Malaysia platform

Shell has started oil production from the Gumusut-Kakap floating platform off the coast of Malaysia, the latest in a series of Shell deepwater projects, a company press release said. The Gumusut-Kakap Field is located in waters up to 1,200 m (3,900 ft) deep. The platform is expected to reach an annual peak oil production of about 135 Mbbl/d once fully ramped up. With oil production now underway, work on the gas injection facilities is continuing with an expected startup during 2015. Oil is transported to the Sabah Oil and Gas Terminal onshore at Kimanis, Malaysia, via a 200-km (124-mile) pipeline.

CNOOC confirms South China Sea find

A deepwater gas discovery has been confirmed by China National Offshore Oil Corp. (CNOOC) in the northern part of the South China Sea. The operator said it found a high volume of gas flows in the Lingshui 17-2 well. It is likely to be several years before the find is developed, however, due to a lack of infrastructure in the area. CNOOC also is planning further exploration and appraisal wells in the area to continue building enough recoverable reserves in the area for a potential hub development. The well was drilled 150 km (94 miles) south of China's southern Hainan Island in an approximate water depth of 1,500 m (4,921 ft).

AUSTRALIA

Senex finds oil at Martlet-1 in Australia

The Martlet-1 exploration well on the western flank of the South Australian Cooper-Eromanga Basin has encountered a Namur oil accumulation, Senex Energy Ltd. said in a press release. The Martlet-1 exploration well is located in PEL 104, in which Senex has a 60% interest and Beach Energy Ltd. has a 40% interest. Martlet-1 encountered good oil shows in the target reservoir, and subsequent evaluation of logs indicated net pay of up to 6 m (20 ft).

SOUTH AMERICA

Petrobras makes gas find at Espírito Santo

Petrobras discovered a new gas accumulation at Espírito Santo Basin post-salt. The discovery took place during

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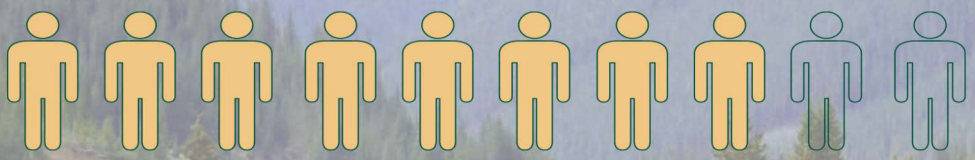

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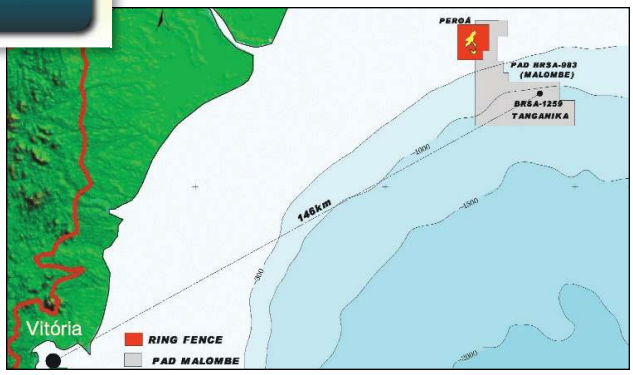

The Tanganika well discovered a new gas accumulation in the Espírito Santo Basin post-salt. (Source: Petrobras)

drilling of well 3-BRSA-1259-ESS/3-ESS-222, informally known as Tanganika, at a water depth of 1,043 m (3,422 ft) located in the Malombe discovery evaluation plan 72 km (45 miles) off the coast of the Espírito Santo state in Brazil. The discovery was confirmed through logging carried out in reservoirs located at a depth of about 2,880 m (9,449 ft). The well has reached a total depth of 2,996 m (9,829 ft).

Petrobras confirms Sergipe-Alagoas potential

While drilling extension well 3-BRSA-1022-SES (3-SES-181), Petrobras found gas, according to a company news release. The well is located in the Poço Verde Discovery Evaluation Plan area (concession BM-SEAL-4) in the ultra-deep waters of Sergipe-Alagoas Basin. The well is called Poço Verde 1 and lies 58 km (36 miles) off the coast of Aracaju, Sergipe, Brazil, at a depth of 2,196 m (7,205 ft). The reservoirs found have good porosity characteristics, confirming project expectations. The Poço Verde accumulation is being explored as part of the Sergipe-Alagoas Basin deepwater development program.

NORTH AMERICA

Chevron sells Duvernay interest

Chevron Corp.'s wholly owned subsidiary Chevron Canada Ltd. has reached agreement to sell a 30% interest in its Duvernay shale play to Kuwait Foreign Petroleum Exploration Co.'s wholly owned subsidiary, KUFPEC Canada Inc., for $1.5 billion, according to a press release. The Duvernay is located in west-central Alberta. The agreement creates a partnership for appraisal and development of liquids-rich shale resources in about 330,000 net acres in the Kaybob area of the Duvernay. Following the closing of the transaction, Chevron Canada will hold a 70% interest in the joint venture Duvernay acreage and will remain the operator.

GULF OF MEXICO

Shell starts up Cardamom in deepwater GoM

Production is now underway from the Cardamom development, the second major deepwater facility Shell has brought online in the U.S. Gulf of Mexico (GoM) this year, following the startup of Mars B in February, Shell said in a news release. Oil from the Cardamom subsea development (100% Shell) is piped through Shell's Auger platform. When at full production of 50,000 boe/d, Auger's total production capacity will increase to 130,000 boe/d. Cardamom is Auger's seventh subsea development, Shell said. The field is 362 km (225 miles) southwest of New Orleans in water more than 820 m (2,700 ft) deep.

EUROPE

Statoil finds gas in Pingvin prospect

Statoil, together with the PL713 partners, has made a gas discovery in the Pingvin prospect in the Barents Sea, the company said. The discovery is a play opener in a frontier area of the Barents Sea northwest of Johan Castberg. The discovery well 7319/12-1 proved a 15-m (49-ft) gas column in the well path. Statoil estimates the recoverable volumes in Pingvin to be in the range of 30 MMboe to 120 MMboe. Statoil is operator with an interest of 40%. The partners are RN Nordic Oil AS (20%), North Energy ASA (20%) and Edison International Norway Branch (20%).

RUSSIA CIS

SeverEnergia launches third stage of Russian field

SeverEnergia, a joint venture between OAO Novatek and OAO GazpromNeft, has launched the third stage of the Samburgskoya gas condensate field. The launch of the third stage, which exceeds 2 Bcm/year (71 Bcf/year) of natural gas, will enable the field to achieve peak production capacity of about 7 Bcm/year (247 Bcf/year) of natural gas and more than 900,000 tons of gas condensate per year. The Samburgskoya Field is located in Yamal-Nenets Autonomous Region within the Samburgskiy license area in Russia.

MIDDLE EAST

Edgo secures awards for Tajikistan blocks

Edgo Energy has secured licenses for the Qarordon and Surkhsimo blocks (formerly called Karadum and Kyzil-tumshug, respectively) in Tajikistan and also has signed a service agreement with Klarenco, a subsurface interpretation company, the company said in a news release. Klarenco has completed an integrated data review of all historical geological, seismic, E&P well logs in the areas, which included the interpretation of the data collected during a 2-D seismic survey on the Surkhsimo license in 2011. E&P

PEOPLE

PT Pertamina tapped **Muhama Husen** as acting president director and CEO succeeding **Karen Agustiawan**, who tendered her resignation in August.

Chris Mawtus was named CEO of Well-Centric Oilfield Services.

The Australian government has chosen **Stuart Smith** as the new CEO of the National Offshore Petroleum Safety and Environmental Management Authority.

Endeavour International Corp. appointed **David C. Baggett** chief restructuring officer.

Chevron Corp. chose **Mary A. Francis** to be corporate secretary and chief governance officer. **Rhonda I. Zygocki** has retired from her position as executive vice president of policy and planning for the company.

Eland Oil & Gas promoted **George Maxwell** to the role of CEO. The company has appointed **Louis Castro** as CFO.

Jason Crew (left) was named CEO of Summit Power and became a member of the board of directors. **Eric Redman**, the previous CEO, has assumed the role of co-chairman of the board of directors.

Phil Longorio (left) has become CEO of Scientific Drilling International following the retirement of **Bill Wade**.

Linc Energy Ltd. has made **Peter Bond** executive chairman of the board. **Craig Ricato** has been chosen as CEO and managing director, and **Michael Mapp** has been selected as COO.

Continental Resources appointed **Jack Stark** (left) as president and COO.

Patricia Vega has taken on the role of president and CEO of GE Oil & Gas for Latin America.

Mark J. Larsen will retire from his roles as president and COO of U.S. Energy Corp. effective Dec. 31, 2014.

The Commonwealth Scientific and Industrial Research Organization appointed **Dr. Larry Marshall** as CEO to replace **Dr. Megan Clark**.

Musabbeh Al Kaabi is succeeding **Maurizio La Noce** as CEO of Mubadala Petroleum.

Lloyd's Register Energy chose **Joanna Pohorski** (left) to become senior vice president, compliance services.

Kristina Kazarian joined Deutsche Bank as a director and lead research analyst covering the master limited partnerships and natural gas sectors within the bank's markets division.

Cubility AS named **Jose Limia** (left) regional manager for North America.

The Atlantic Council tapped **Cynthia Quarterman** as a distinguished fellow to serve as the council's leading expert on responsible energy development.

Peter Lamell joined the Australia and Asia Pacific advisory team for 8over8.

Jonah Energy added three new members to its executive team—**C. Mark Brannum** as vice president, general counsel and corporate secretary; **David Honeyfield** as vice president and CFO; and **Rory O'Byrne** as vice president and chief human resource officer.

ProSep has hired **Ryan McPherson** (right) as general manager for the Middle East.

RigNet Inc. named **Pal Jensen** to the position of vice president for energy maritime.

Harkand made **Alan White** (top right) the new head of engineering services for Europe. Harkand's global head of ROVs, **David Rhodes**, (lower right) has been elected vice chairman of the International Marine Contractors Association's Remote Systems and ROV Division Management Committee.

Kevin C. Clement has taken on the role of executive vice president and president of saltwater gathering operations for SandRidge Energy Inc.

Decom North Sea elected four new directors: **Torleif Gram**, **Tim Eley**, **Paul Caruana** and **Stuart Wordsworth**.

Charles Slack became principal technical specialist for Parsons Brinckerhoff and will manage onsite drilling operations for oil and gas projects in New Mexico and West Texas.

CWC Energy Services Corp. has promoted **Karen Dilon** to the positions of vice president of finance and controller.

Teledyne Oil & Gas has expanded the management team at Teledyne Impulse. **Angelica Gomez** has been made quality manager, **Carlos Vargas** became materials manager, **Dana Forseth** has been named manufacturing manager, **Jeff Matson** is now project manager and **Saied Rahimi** became engineering manager.

DNV GL has appointed **Alex Imperial** (right) as regional manager for South America.

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COMPANIES

D&L Oil Tools has opened a new 5,760-sq-m (62,000-sq-ft) facility expansion in Tulsa, Okla., to house quality assurance, shipping and receiving, assembly, saw and raw materials, engineering, and a new warehouse for the downhole tools company.

Benthis relocated to a new technology center, which contains 1,246 sq m (13,410 sq ft) of corporate office space and 1,657 sq m (17,840 sq ft) of space for the company's workshop and maintenance center. The maintenance center will be used for U.S.-based portable remotely operated drill (PROD) spreads, and a specialized test well will be set up for PROD testing, training and demonstration.

Expro opened a new facility in Macaé, Brazil. The 20,000-sq-m (215,278-sq-ft) facility combines operational product lines, an employee training and development center and technology to meet the demands of the company's business.

80:20 Procurement Services Ltd. has established new operations in Stavanger, Norway, to provide services such as outsource and consultancy procurement offerings to major operators within the region. E&P

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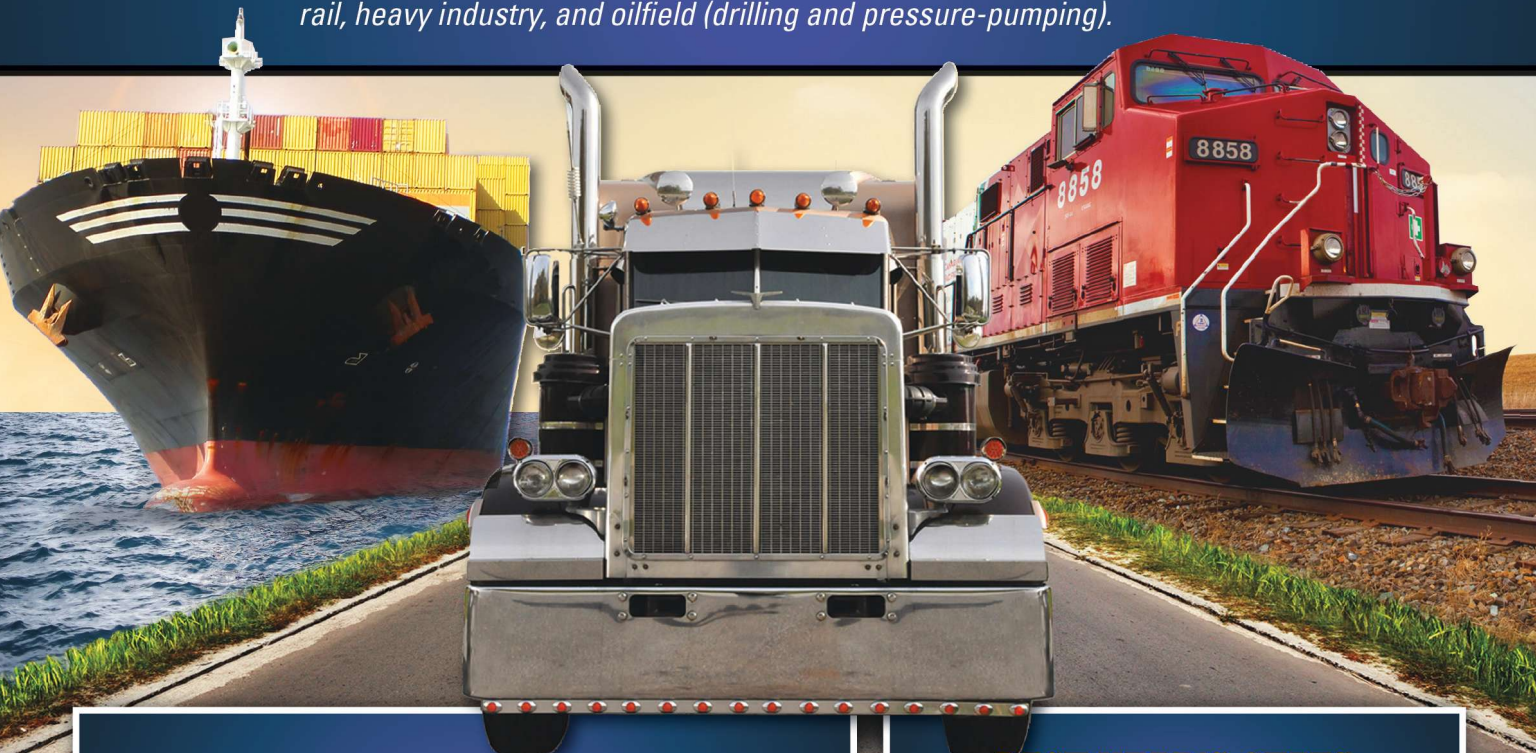

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Ripple effects

Natural gas development boosted a community's efforts to showcase itself as a place to live, work and raise a family.

Holly White and **Christopher Knarr**, RETTEW

Burned-out volunteers, inconsistent communication and stagnant budgets due to a sluggish economy: a snapshot of one rural community in northern Pennsylvania. While the residents, business owners and local officials of Blossburg Borough were passionate about community projects, the imminent closing of a local school highlighted the need for a solid plan to thrive.

Founded in 1802, Blossburg Borough is nestled in Tioga County, Pa., an area known for its mountains, forests, panoramic views and other natural resources. The town originally depended on coal mining, railroads and manufacturing, and it has recently seen a boost from burgeoning energy production.

The Marcellus Shale's abundant natural gas production has benefited surrounding communities like Blossburg Borough. (Source: RETTEW)

As the Marcellus Shale play's abundant natural gas production has gained speed, its benefits have exponentially impacted surrounding communities. In 2011, Hydro Recovery opened a produced water treatment plant in Blossburg, hiring about a dozen local workers. In 2012, Pennsylvania Gov. Tom Corbett signed Act 13 into law. The regulation assesses fees on unconventional gas wells drilled in Pennsylvania, distributing those fees annually to municipal governments. The borough's leadership wanted to funnel the new funding into a comprehensive plan to harness the economic possibilities.

In the past 20 years, Blossburg had successfully accomplished several community improvement projects such as walking trails and a community swimming pool rehabilitation. While the projects were successful, the process was uncoordinated, and none were features of any long-term goals or a comprehensive plan.

Many in the borough wanted to enhance and promote their community, showcasing its possibilities as a place to live, work and raise a family. The first step in accomplishing that, along with its newfound growth from the energy industry, was to formulate a comprehensive plan to prioritize and drive improvements.

The borough selected RETTEW as its consultant to lead the comprehensive planning process, bringing its experience working with municipalities in both project planning and implementation. After detailing the process scope, outlining a budget and outlining expectations, the group created a list of the community's issues and assets to be examined during the planning process.

After reviewing past planning documents, conducting interviews, touring the area and holding meetings with local officials and the public, RETTEW divided the planning into three stages: visioning, goal setting, and plan and strategy development. As those involved identified the borough's most important assets and concerns needing attention, the team developed and prioritized specific projects. The public and community stakeholders then voted to select the top three issues to be resolved and the top three assets to enhance, protect or promote.

Those involved identified major themes to carry throughout the comprehensive plan and resulting projects, which included combining a growing economy with the rural hometown feel of Blossburg, increasing employment and furthering the stewardship of natural and cultural resources. From the process, five projects were identified as top priorities for the borough.

The community-driven effort finalized the plan in June 2014 and outlined projects including a park and recreation master plan, a capital improvements program, the formation of an active partnership with the school district, a local branding effort and development of a communications program. The community is already well on its way to completing the first five projects.

The renewed fervor within Blossburg as the community works to move forward is one of the many ripple effects locales throughout the Northeast and Midwest are seeing because of E&P in natural gas. E&P

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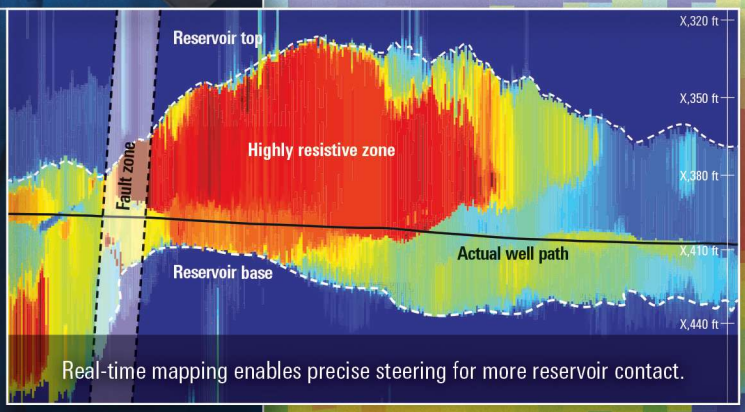

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