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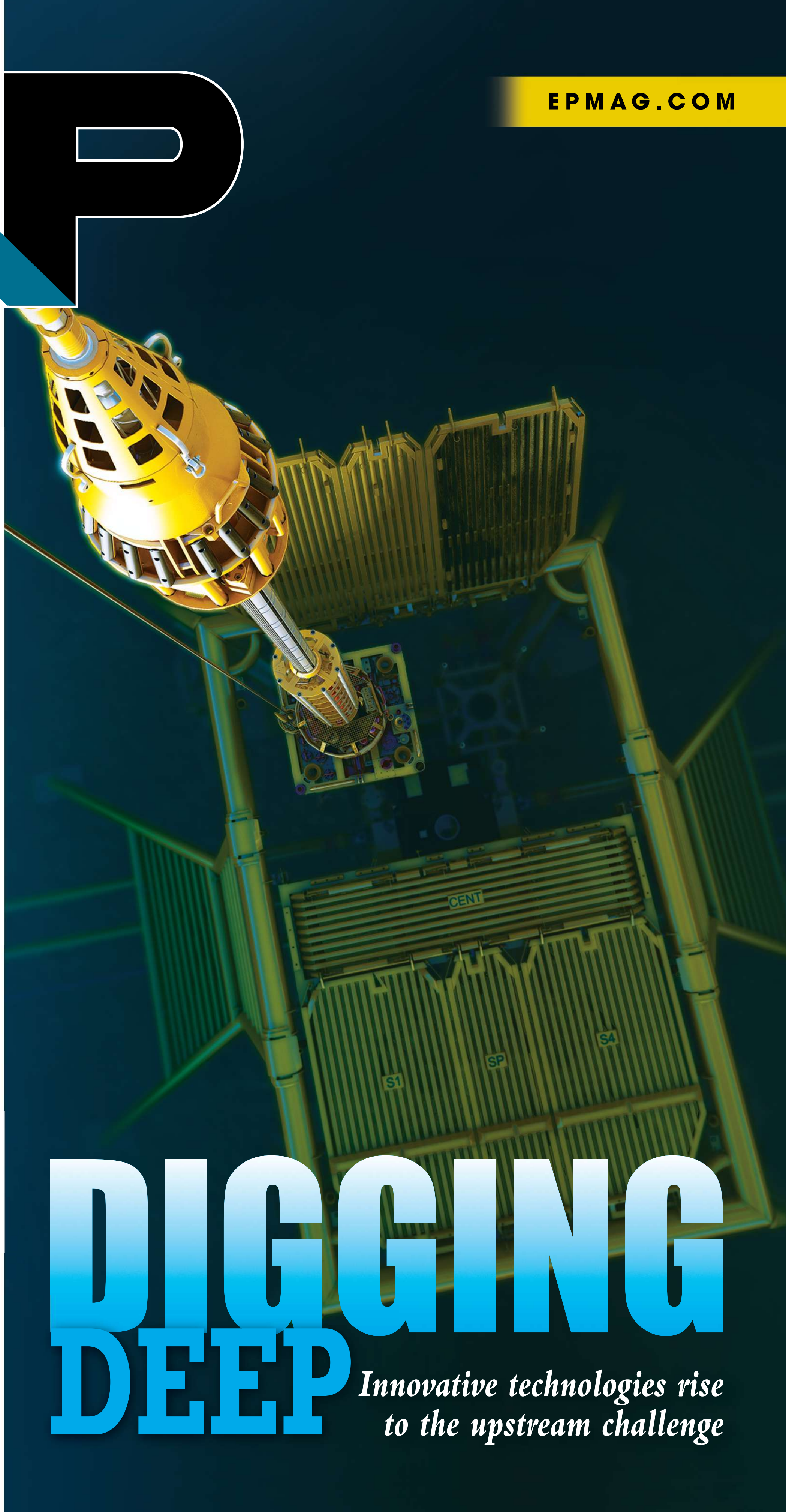

DIGGING DEEP

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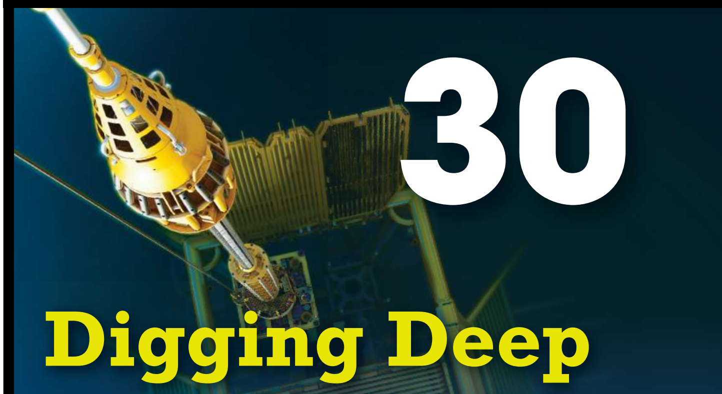

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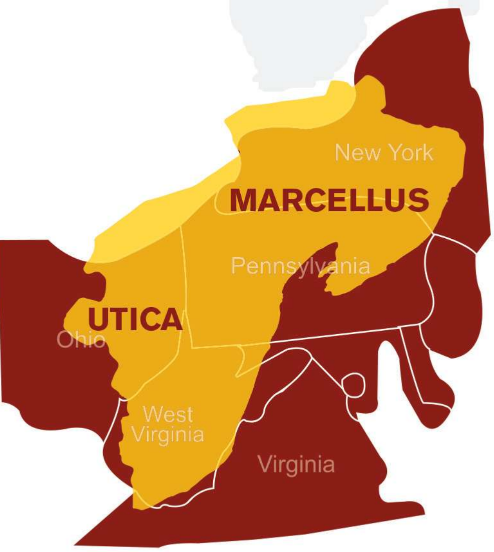

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COMING NEXT MONTH The January issue of ***E&P*** will take a close look at activity in the U.S. Gulf of Mexico. Other features will examine data processing and interpretation, HP/HT drilling, surface production systems and MODU innovations, and regional reports will focus on unconventional development in China and in Canada. 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 FMC Technologies' Riserless Light Well Intervention system is shown being lowered from a purpose-built intervention vessel onto a subsea well. New technologies are helping to overcome upstream challenges. Left, the Mediterranean is becoming a hotbed for E&P activity. (Main image courtesy of FMC, left image courtesy of Repsol, cover design by Laura J. Williams)

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Pulse validates new riser design in Gulf of Mexico

Pulse, an Acteon company, has designed, manufactured and installed a powerful motion and strain monitoring system to verify the design of the first lazy-wave steel riser system to be installed in the Gulf of Mexico.

Congo well test exceeds SOCO's expectations

SOCO EPC, operator of the Marine XI Block offshore the Republic of Congo (Brazzaville), has successfully completed testing the exploration well Lidongo X Marine 101 ST1. The well significantly exceeded pretest expectations.

CNOOC announces first oil from GEAD in North Sea

CNOOC Ltd. announced in a press release that the Golden Eagle Area Development (GEAD) in the U.K. North Sea commenced production. The GEAD includes development of the Golden Eagle, Peregrine and Solitaire fields.

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Challenges, opportunities remain for frack sand industry

By Velda Addison, Associate Online Editor

Experts talk about the sector's past, present and future.

Thailand launches bidding round for 29 blocks

By Ravi Prasad, Special to E&P

The deadline to submit bids for the onshore and offshore blocks is Feb. 18, 2015.

Panel: Arctic E&P requires technology innovation, collaboration

By Velda Addison, Associate Online Editor

Although Arctic exploration has slowed, thoughts are still on the region, and oil and gas companies are still targeting arctic resources.

BHP Billiton looks toward Mexico

By Emily Moser, Hart Energy

The company is eager to leverage its decades of deepwater knowledge with Mexico's state-owned company.

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A price perspective

Most of us can't help checking what the oil price is doing. Up? Down? Did my marginal project just become subeconomic and on the backburner?

With the Brent crude price dropping below $80/bbl as I write (since yesterday it fell a further $3/bbl to $77/bbl, a four-year low), it is suddenly the dominating factor for the industry. Since June the price has plunged by nearly a third. Combined with cost concerns, suddenly things don't feel so good.

How does this impact the E&P sector? Nearly 3% of global oil production (now at 94.2 MMbbl/d) is vulnerable to cuts if a sub-$80/bbl price continues, according to the International Energy Agency (IEA). Oil demand, meanwhile, is forecast by the IEA to continue its growth curve, with figures for 2014 and 2015 put at 92.4 MMbbl/d and 93.6 MMbbl/d, respectively. By 2025 it is forecast to hit 99.1 MMbbl/d.

The projected growth will rise from a five-year annual low of 680 Mbbl/d this year to an estimated 1.1 MMbbl/d in 2015 as the macroeconomic backdrop is expected to improve.

All this brings breakeven points sharply into focus. With 2.6 MMbbl/d of oil estimated to come from projects with a breakeven price of more than $80/bbl, this represents 2.8% of the 93.2 MMbbl/d produced in third-quarter 2014. According to the IEA, some Canadian production has the highest breakeven rates, but there are other high-breakeven price "offenders" out there too, from China, Malaysia and Nigeria to onshore U.S., onshore Russia and the U.K. North Sea. In the U.S., more than 4% of shale oil production needs $80/bbl to break even, says the IEA, while 8% of deepwater oil is the same (representing some 1.05 MMbbl/d).

But the picture is mixed, and it depends on individual project characteristics. For example, the IEA points out that for ultradeepwater (more than 1,500 m [4,921 ft]), the results are—"perhaps surprisingly"—that little of that current output (less than 1%) requires an $80/bbl price.

It also is worth remembering that to meet the forecast growth in global oil demand and replace declining output from existing conventional fields, up to 30 MMbbl/d more conventional oil needs to be found and produced by 2025.

I also came across an illuminating chart from a presentation by Seadrill that illustrates the breakeven situation is not quite as dire as some say. Some details are not so surprising—Middle East onshore, for example, has an average breakeven price of $27/bbl, while offshore shelf projects are on a $41/bbl average and heavy oil projects at $47/bbl.

But onshore Russia, onshore rest of the world and deepwater breakeven prices sit at $50/bbl, $51/bbl and $52/bbl, respectively, with ultradeepwater slightly higher at $56/bbl. At the higher end, North American shale sits at $65/bbl, oil sands at $70/bbl and Arctic projects at $75/bbl.

These are averages, and there are instances that are higher or lower. But as always, in times of rising price panic, a little perspective is always advisable… E&P

All risk is local

Companies must engage with communities to be successful.

Jim Sisco, ENODO Global

In today's globally interconnected world, societies are the convergent point for the majority of risks that companies face. For multinational corporations operating in frontier markets, local populations have the ability to impact political risk, economic risk and even transfer risk. Companies attempt to influence or mitigate these risks by establishing bilateral investment treaties with host nations, sifting through macroeconomic data to identify trends, using statistical regression modeling to predict threats and hiring high-profile individuals to advantage negotiations. These activities, although useful for traditional risks, provide little to no warning of threats that emanate from indigenous populations.

Local populations now have the ability to almost instantaneously aggregate and mobilize around an idea, ideology or common cause. Communities, groups and even individuals use social media, litigation, protests and violence to promote their ideas or achieve their objectives. They target companies in the mineral and oil extraction industries daily across the world. Reports of protest over fracking, litigation regarding environmental damage and attacks against employees and infrastructure are common. These activities significantly impact all aspects of operations and have a cascading effect on costs throughout the company. An example from a 2009 Harvard Kennedy School study illustrated how community conflicts shut down power lines for a project and forced a company to suspend operations at a cost of $750,000 per day.

New measures

Security managers within oil and gas and mineral extraction industries are feeling the pinch. They seek solutions to counter an increased number of threats, including cyber intrusion and supply chain disruptions caused by communities, while simultaneously attempting to maximize profits. Traditional approaches focused on increased physical and technical security measures are costly and ineffective. The January 2013 attack on the Tigantourine gas facility near In Amenas, Algeria, provides a deadly example of how traditional security measures can fail to safeguard assets and personnel.

Security is merely a deterrent. However, security providers continue to introduce high-tech multimillion-dollar technical solutions to safeguard operations from community-based threats. At IRN's Oil & Gas Security Summit, Shell's Nigerian security manager said he receives several proposals each week for high-end technical solutions. How can unmanned aerial vehicles, satellite change detection or unattended ground sensors safeguard operations in remote areas where company assets and personnel are unavailable? These "solutions" merely provide a snapshot in time, are reactive in nature and do not allow companies to forecast or mitigate threats. At best, they direct company assets to an ongoing situation.

"All politics is local" supports the idea that politicians must be attuned to their constituents' concerns. The same idea holds true for extraction companies regarding risk: "all risk is local." The majority of threats to extraction, production and distribution emanate from local communities in which companies operate. Unfortunately, security managers tend to view community engagement as a corporate social responsibility (CSR) or public relations function. Additionally, some fail to recognize the benefits that derive from community engagement or to incorporate community engagement activities into their overarching security plans. A study conducted by the Canadian Centre for Social Performance and Ethics determined that, even on a scale of profitability, corporations that rate highest on ethical conduct and CSR are most profitable in the long term.

Organizations and companies are starting to realize this concept. The World Bank mandates community impact assessments as part of their donor requirements. Larger oil companies have established entire divisions focused on community engagement and create global memorandums of understanding for sustainable community development in host nations. Although generally understood, the benefits are not being realized in real terms. With so much attention and billions of dollars spent annually on these initiatives, why are companies experiencing continued community-based production threats? Because they are largely seen as dysfunctional, out of tune with communities and inadequate, leading to intense struggle over such benefits by groups that fuel conflict.

Companies sign formal agreements with host nation governments expecting them to distribute revenue and

deliver basic services to their citizens. In frontier markets, governments are at best ineffective and at worst corrupt. They focus on increasing and maintaining patronage networks to remain in power and fail to deliver basic services to rural communities. A U.S. Department of State foreign service officer commented on a recent analysis of Colombian society, "Any company that gives back to the local community and takes care of the locals better than the government can only enhance its ability to make a profit in the future."

A tailored plan

Tailored community engagement and development activities provide the most cost-effective solution to mitigate production risk and maintain stable operating environments. Designing effective community engagement strategies and CSR activities requires a comprehensive understanding of local communities. Diverse cultures, ethnicities and religions reside within many local populations and influence their social structures, identities, narratives, traditions, customs and norms. Each community, village, tribe or hamlet is a microcosm of the national or regional population, with nuances that must be understood to effectively engage them and design CSR activities that create utility. With a comprehensive understanding of a target community, companies see the world through the community's eyes, which uncovers their true grievances and basic needs. With this understanding, companies are able to engage in meaningful dialogs to resolve conflict and create effective development programs that create utility without dependency.

Too often, companies fail to develop a comprehensive understanding of local dynamics before they design and implement engagement strategies or CSR initiatives. Therefore, companies often outsource development activities, relying upon nongovernmental organizations (NGOs) or local nationals to provide this understanding. Unfortunately, NGOs take an American-oriented Western development approach, which focuses on top-down implementation and technical solutions. And local nationals are often government representatives that do not represent the community's interests. When combined, these factors increase existing social tensions and fuel conflict.

Compounding these issues, companies are sometimes viewed as proxies of the government, which hampers or prevents engagement or dialog. And just as all risk is local, successful negotiations are built on personal relationships. It is no coincidence that shortly after hiring Ali Khedery, the former adviser to five U.S. ambassadors in Iraq, ExxonMobil was able to negotiate entry into the Kurdistan region for oil exploration and production. For the same reason, companies often require neutral third-party actors to act as mediators. These parties assist companies to sign a social license to operate with the community.

Host governments don't always distribute the wealth to communities impacted by oil and gas operations.

The majority of investment over the next 10 years will occur in frontier markets, primarily focused on natural resource extraction. Exploration and production are pushing into remote areas in close proximity to indigenous populations and their communities. These remote areas have minimal infrastructure to support operations. This provides companies the ability to sign a social license to operate and create enduring partnerships through mutually beneficial development projects. Signing a social license to operate with communities establishes the framework to align corporate and community goals and creates enduring relationships that promote stable operating environments throughout the life cycle of the project. With the majority of threats emanating from communities, having a social license to operate is not only beneficial but required. E&P

Acknowledgment
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Petrobras E&P manager talks presalt

The company is placing its bets on presalt, hoping to boost its overall production and generate massive cash flow.

Velda Addison, Associate Online Editor

Brazil's Petrobras has proven it is a presalt production powerhouse. The company's top presalt producer flows an average of 34,000 bbl/d in the Sapinhoá Field in the Santos Basin. Earlier this summer, Petrobras broke a previously set record when its presalt wells produced 546,000 bbl on July 13, which was 5% more than the June 24 record.

In the months since, Petrobras has declared the presalt Santos Basin accumulations Guará South, Tupi Northeast and Florim commercial, with expectations that the fields will add more than 1.2 Bboe to recoverable reserves. Petobras also has confirmed the extension of the Jupiter discovery after drilling operations confirmed a hydrocarbon column of about 313 m (1,027 ft), with rocks showing good porosity and permeability conditions.

The deepwater giant is placing its bets on presalt, hoping to boost the company's overall production and generate massive cash flow. Crucial to achieving its goals are platforms capable of tapping the vast offshore deposits. Solange Guedes, corporate E&P executive manager for Petrobras, provided insight into what has been key to the company's presalt accomplishments and the challenges ahead.

Solange Guedes, corporate E&P executive manager for Petrobras, speaks at a recent Proef meeting. (Source: Petrobras)

What drilling technologies have been crucial to your success?
Several types of technology are contributing to the strong results we are seeing in the development of the presalt layer. In well construction, we can highlight the use of new drillbits that increase the penetration rate, the use of state-of-the-art dual-derrick and dual-activity drilling rigs with high racking capacity, the implementation of serialized drilling and completion campaigns, and the use of state-of-the-art directional tools, which allow the construction of better trajectories as well as real-time tracking of well-bottom parameters at our Decision Support Center. It is also worth noting our intensive use of smart completion of satellite wells in ultradeep waters.

Regarding our subsea systems for transporting output, we have pioneered the implementation of many technologies, most notably the use of riser support buoys, the use of steel catenary risers with lined pipes installed using the reel-lay method, the installation of the first steel lazy-wave riser totally composed of clad pipes and pipes featuring a metal liner (Sapinhoá North), the installation of a flexible riser in deeper waters (Lula Pilot), and the first use of flexible risers with an integrated traction wire monitoring system (Sapinhoá Pilot).

In our production platforms' processing systems, we can highlight the unprecedented use in deep waters of a process for separating CO_2 from the current of produced gas and the subsequent reinjection of the removed CO_2 back into the producing reservoirs. The deepest offshore well in which we are reinjecting CO_2 is located in the Lula Pilot area. Finally, it is worth emphasizing the first use of alternate water and gas injection technology in ultradeep waters, also in the Lula Pilot area.

What presalt development challenges do you foresee five to 10 years from now? What is Petrobras doing now to prepare for these challenges?
Presalt production will be decisive for Petrobras to achieve the targets established in its 2014-18 Business


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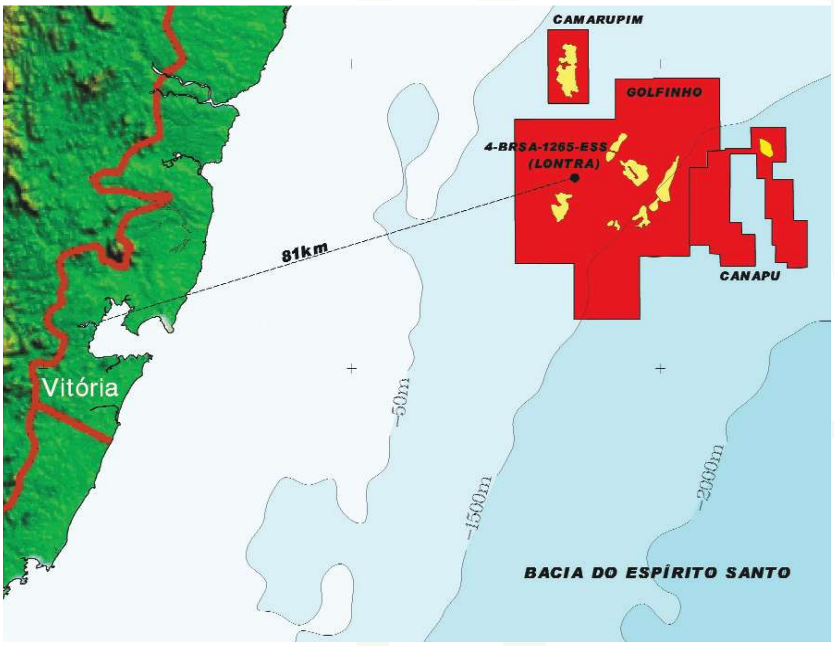
and Management Plan. From now until the end of 2018, 20 new production units will be installed in the presalt, 19 of them in the Santos Basin, raising presalt production to 52% of the company's total.

Before the end of 2014, two new platforms will come onstream: the FPSO vessel *Cidade de Mangaratiba* in Iracema South and *Cidade de Ilhabela* in Sapinhoá North.

In 2015, the FPSO vessel *Cidade de Itaguaí* will come onstream in the Iracema North area. An additional seven units are scheduled for 2016: FPSO units *Cidade de Maricá, Cidade de Saquarema, P-66* and *P-67*, to be installed in Lula; *P-74* and *P-75*, in Búzios; and *Cidade de Caraguatatuba*, in Lapa.



Petrobras announced the discovery of a hydrocarbon accumulation in deep waters of the Espírito Santo Basin post-salt in October. (Source: Petrobras)

In 2017, there will be another five systems: *P-68* and *P-69* in Lula, *P-76* and *P-77* in Búzios, and *P-70* in Iara.

In 2018, we will have one new unit in the Campos Basin presalt in Parque das Baleias and another four in Santos Basin: *P-72* in Tupi Northeast, *P-71* in Iara, *P-73* in Iara Surround and one unit in Carcará.

What are your production targets for 2020? Are you on course to meet these targets?

In 2020, we will reach 4.2 MMbbl/d of oil and 5.2 MMboe/d. Yes, we are [on course]. To reach this goal, Petrobras plans to put 35 new production units into operation between 2014 and 2020.

What role will production from nonpresalt areas play in these goals? There is much focus on offshore and presalt operations.

In addition to presalt, post-salt production has also been fundamental to Petrobras in achieving the targets established in its Business and Management Plan for the coming years. The company has focused its efforts on maintaining the sustainability of the production in the Campos Basin fields. We have improved the efficiency of old systems, particularly through the Campos Basin Operational Efficiency Improvement Program (known by Portuguese acronym Proef), which added 63,000 bbl/d last year. In the same basin, over the last six months we have also started up the following new systems: *P-63* in Papa-Terra, *P-55* and *P-62* in Roncador, and *P-58* in Parque das Baleias (which also has post-salt wells).

We will also be starting up *P-61* in Papa-Terra in the second half of 2014. These systems will add to our production in the Campos Basin in the coming months as the respective production wells are interconnected. The attention we have continuously paid to the Campos Basin led it to produce 1.531 MMbbl/d in 2013 against 1.693 MMbbl/d in 2009, the year in which it reached the highest production volume in its history.

In addition, it is worth stressing the high operational efficiency of our onshore systems in the north, northeast and Espírito Santo areas, which reached 94% in this year's first quarter. Thanks to our excellent performance in managing the reservoirs in the mature fields in these areas, using new and rewarding water and steam injection techniques, our onshore and shallow-water (depth up to 300 m [984 ft]) production reached an average of 369,000 bbl/d in 2013.

In 2014 our production stability in the north and northeast regions will be guaranteed, above all, by: increasing the density of our production network in the Urucu River and East Urucu fields in the Amazonas Operations Unit; the drilling and intervention of new wells, and the expansion of water injection in the Canto do Amaro and Ubarana fields in the Rio Grande do Norte and Ceará Operations Unit, which will increase the reservoirs' oil recovery factor; the project to expand water injection in the Fazenda Bálsamo cluster in the Bahia Operations Unit; and the expansion of the water injection system in Carmópolis Field in the Sergipe-Alagoas Operations Unit.

What are some of your exploration plans for the coming quarters?
Our plans continue to be in line with Petrobras' 2014-18 Business and Management Plan. Regarding exploration, Petrobras intends to focus its efforts on Brazil's sedimentary basins in a selective, risk-sharing manner. The company also plans to discover and appropriate reserves in Brazil, maintaining a reserves-to-production ratio of at least 12 years. It is worth noting that, during 2013, the company participated actively in three bidding rounds held by ANP—two under a concession regime (11th and 12th rounds) and one under a production-sharing regime (first round/Libra). Regarding the latter, we highlight our acquisition of the Libra Block, which presents excellent petroleum potential, through a consortium with Shell, Total, CNPC and CNOOC. In the coming years Petrobras will continue to carry out exploration activities in these areas.

In addition, the National Energy Policy Council has approved direct hiring of Petrobras to produce, under a production-sharing regime, the surplus volumes in four presalt areas contracted under the "cessão onerosa" regime—Búzios, Iara Surround, Florim and Tupi Northeast.

Regarding production, so far in 2014 the company has brought into operation platforms P-58 in Parque das Baleias and P-62 in the Roncador Field, both in the Campos Basin. Each has the capacity to produce up to 180,000 bbl/d. Before the end of the year, the company will install platform P-61, associated with the tender assisted drilling support platform in Papa-Terra Field, the FPSO vessel *Cidade de Mangaratiba* in the Iracema South area of the Lula Field in the Santos Basin presalt and the FPSO vessel *Cidade de Ilhabela* in the Sapinhoá North area. With the startup of these five production units in 2014, added to the other five installed in 2013, the company will add 1.3 MMbbl/d to its installed capacity. E&P

The FPSO vessel *Cidade de Ilhabela* will come onstream in Sapinhoá North before year-end 2014. (Source: Petrobras)

The need for collaboration in exploration

Operators and service providers working together can improve upfront subsurface characterization and revitalize exploration activities.

Maurice Nessim, Schlumberger PetroTechnical Services

Due to growing global demand for energy, the upstream industry today is under mounting pressure to balance two apparently conflicting business objectives: ramp up exploitation of existing resources and continue making new discoveries to replace declining reserves.

Exploration challenge

According to a recent survey of energy companies worldwide, over the past five years oil and gas reserves have grown an average of 6%. This sounds like good news until it comes to the fine print. That growth came primarily from a more than five-fold increase in reserve purchases, not from new discoveries made with the drillbit. Indeed, 2013 was the worst year for global exploration in two decades, and 2014 has not seen much improvement.

Conventional discoveries have been declining steeply since 2008. More than 50% of new oil and gas reserves are now found in deep to ultradeep waters, where the cost of an exploratory drilling rig is exceptionally high. In addition, on average 33% of all exploration wells fail to find commercial hydrocarbons. Nearly 75% of these are attributed to improper assessment of reservoir charge and seal, even when a viable trap exists.

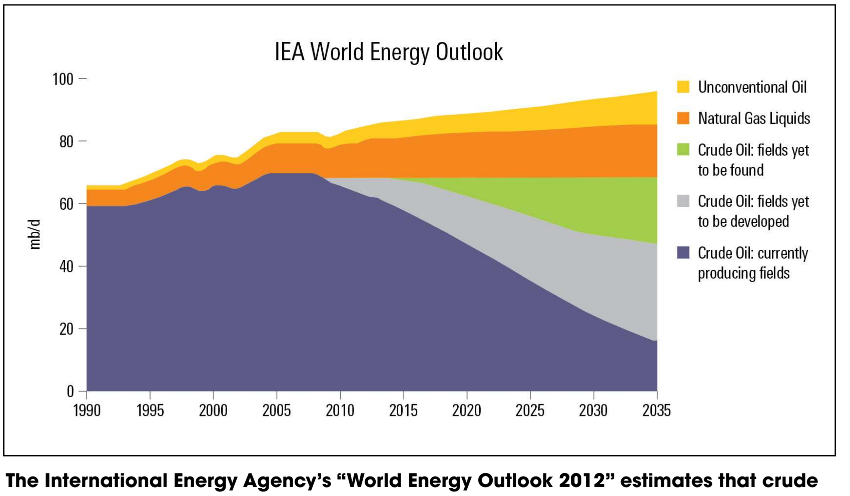
Because of growing exploration complexities and risks and long cycle times from investment to cash flow, industry spending on exploration and development today is seriously out of balance. Rising investments in development have remained more than four times greater than incremental increases in exploration spending over the past five years. As a result, future reserves are increasingly at risk.

What's more, many operators are shifting capital from conventional to unconventional plays. It is often said, "Conventional reservoirs are hard to find, easy to produce. Unconventionals are easy to find, hard to produce." This familiar saying highlights a general undervaluation of "exploration"—or upfront subsurface characterization—in the unconventionals. Historically, shale reservoirs have been "characterized" by the drillbit. Studies have shown, however, that even in mature shale plays where well productivity has doubled or tripled over the past decade, 30% or more of all perforation clusters fail to contribute any hydrocarbons to production. This is like drilling three nonproductive wells out of every 10.

Interestingly, these numbers are similar to the percentage of commercial failures in conventional exploration. What both scenarios have in common is a need for more effective science upfront—before further development.

Personnel shortage

Given the imbalance in industry spending and the ongoing shortage of experienced petrotechnical personnel worldwide, it's not surprising that the lion's share of



The International Energy Agency's "World Energy Outlook 2012" estimates that crude production from fields that are currently online will drop dramatically over the next 25 years. To prevent a production gap between supply and demand, exploration activities to find future fields must continue. (Source: International Energy Agency)

skilled internal resources today are assigned not to exploration but to development and production projects.

According to the Schlumberger Business Consulting's Oil & Gas 2012 HR Benchmark Survey, the U.S. alone will need more than 10,000 new geoscientists by 2020 to support projected growth in production. Among independents and national oil companies (NOCs), geophysicists represent the single largest percentage of petrotechnical vacancies. Yet advanced seismic analysis and interpretation are critical both to deepwater exploration and unconventional reservoir characterization. To mitigate staffing difficulties, 24% of independents and 40% of NOCs said they plan to outsource certain E&P activities.

When Schlumberger surveyed its clients early this year, the clients said their second-greatest technical and operational challenge was the shortage of experienced personnel. Four of their other top 10 challenges were related to conventional and unconventional exploration. To overcome their challenges, 60% indicated they would collaborate with oilfield service companies and consultants to apply new technologies, and 43% said that the willingness of outside firms to work closely with their internal personnel is a critical factor in selecting the right provider.

Collaborative business models

In response to growing complexities in exploration and subsurface characterization, the upstream industry needs to evolve new, more integrated and collaborative models of engagement between energy and service companies.

Increasingly, the current transactional model, in which customers simply submit an order for delivery of a standard technology or service, no longer solves the problem at hand. This approach may have worked when the solution was well known and understood. However, the greater the unknowns, risks and uncertainties, the greater the need for internal and external experts to put their heads together; integrate data, technologies and workflows; and jointly develop new customized solutions to unique problems.

Under collaborative integrated business agreements, operators and service company petrotechnical experts form cross-company teams that combine the best local knowledge with global analogs and experience. They work together toward common goals, complement one another's capabilities, eliminate duplication of effort, and facilitate technology transfer. This collaborative approach enables integrated, unified teams to work together to reach common, jointly defined goals. Consider the following model of collaboration in action.

To replenish its reserves and meet growing production targets, an NOC needed to revitalize exploration activities throughout the country. Basin evaluation and prospect generation workflows had not been refined or standardized, technological capabilities and in-house expertise were limited, and cycle times were long. The company's portfolio needed more high-quality opportunities to support its long-range objectives. The NOC decided to join forces with Schlumberger PetroTechnical Services to create a dedicated exploration center in-country coordinated by project managers and staffed by personnel from both organizations.

Together, the companies established a collaborative environment with its own high-performance computing infrastructure running software and standardized analysis, workflows, and interpretation processes. A core multidisciplinary team of 21 experts worked side by side with several hundred explorationists sharing tools, knowledge and best practices. First, they analyzed decades of core and well data, built a regional framework from 2-D and 3-D seismic surveys, and rigorously documented and refined existing exploration opportunities in complex onshore and offshore reservoirs. In this efficient, high-energy working environment, joint

Operators face mounting pressures when working to boost production and add to their reserves base. Advances in technology and expertise can alleviate the pressure faced by increasing complexity, risk, cycle time and costs, thus helping operators better manage their risks for maximum reward. (Source: Schlumberger)

teams came up with innovative interpretations, revised traditional assumptions, applied advanced petroleum systems concepts and identified additional economically viable prospects.

Throughout their six-year collaboration, teams worked together on more than 100 projects. Beginning with prospect generation, reservoir characterization and complex well design, eventually they expanded into field development and even mature field optimization studies. Overall, they reduced previous exploration cycle times by about 50% while reenergizing the NOC's exploration portfolio with 225 viable exploration well locations. The company drilled 61 of those prospects and booked proved reserves of more than 3 Bboe.

By the end of this collaborative engagement, the NOC had accelerated the learning curves of new geoscientists, documented lessons learned and ensured the effective transmission of new tools, workflows, models and concepts to future teams and exploration initiatives.

Benefits of collaboration

In complex deepwater and unconventional resource plays, the quality of subsurface characterization performed upfront has a direct impact on the success—or failure—of all subsequent appraisal, development and production activities. Exploration, therefore, is the foundation of the entire reservoir life cycle.

As geological complexities, costs and risk profiles continue to increase dramatically, oil and gas companies require a step-change in exploration risk assessment and mitigation. New, more collaborative working relationships between operators and oilfield services providers promise to compensate for shortages of internal expertise, accelerate entry into new basins and plays, improve acreage evaluations, limit reservoir uncertainties, broaden portfolios of opportunity, shorten cycle times, maximize drilling schedules, ensure safe drilling operations in challenging environments and boost the industry's overall chances of success in reserve replacement worldwide. E&P

More than 600 top drives destined for 2014 North American delivery

Delivery averages 14 weeks in third quarter.

Richard Mason, Chief Technical Director

The collapse in oil prices may foreshadow a different tale in 2015, but the North American top drive manufacturing sector is currently on target to deliver 636 units in 2014, a majority in the 500-ton category.

Hart Energy's Market Intelligence program surveyed six North American top drive manufacturers at the beginning of the fourth quarter of 2014 to develop a better understanding of how new rig construction is impacting the component side of the business. Currently more than 200 new rigs are under construction in the U.S. with 170 to 175 units destined for the domestic market. The largest drilling contractors continued to announce newbuild contracts during their third-quarter 2014 earnings calls, though the downturn in commodity prices indicates the rig manufacturing industry may be peaking on new construction.

- **North American manufacturers expect to deliver 636 top drive units in 2014**
- **500-ton units for 1,500-hp rigs are the most requested units**
- **Current manufacturing capacity is estimated at 700 units**
- **Delivery ranges from four to 22 weeks, depending on model and manufacturer**

Survey respondents estimated current North American top drive manufacturing capacity at 700 units annually, or nearly two units per day. Capacity utilization in 2014 therefore was more than 90%, though additional manufacturing capacity could be added if greater demand warranted. Chinese drilling equipment manufacturers have also entered the top drive market. The consensus among North American manufacturers is that quality is improving for Chinese units, although imported equipment is beset by challenges surrounding readily available parts and the ability to service units in North America.

Top drive manufacturers build a range of models, including 250- and 350-ton units, which are used on 1,000-hp and 1,200-hp rigs. There are a few 150-ton units manufactured for smaller rigs, while 800-ton and 1,200-ton units are destined for custom-built land rigs with larger masts supporting greater hoist capacity or for offshore rigs. The greatest demand is for units in the 400-ton to 600-ton category, with 500 tons being the most requested model as the contract drilling industry expresses preference for 1,500-hp rigs.

During third-quarter 2014, top drive delivery averaged 14 weeks among the six manufacturers in a range spanning four to 22 weeks.

"We have begun to increase our production rate in order to increase market share, and we can deliver most models in four weeks," a Canadian manufacturer told Hart Energy surveyors. "In some sizes, I am eight weeks out."

A Texas-based manufacturer said, "Depending on the order, we can usually deliver in 16 weeks, but certain units we are now running 22 weeks for delivery due to backlog."

According to manufacturers, about 430 new top drives are destined for newbuild or upgraded drilling rigs. For the latter, contractors are upgrading older Kelly-drive rigs to adapt to higher spec drilling requirements in tight formation plays where horizontal laterals typically extend 1,372 m (4,500 ft). However, there is a move underway to push laterals out beyond 2,286 m (7,500 ft) when acreage positions permit as operators transition to a model of enhanced completions that entails longer laterals, more stages packed more closely together and greater proppant volume.

Of note, 206 top drive units are destined as replacement units for older, worn-out equipment as heavy usage creates greater wear and tear. Horizontal drilling currently hovers near the 80-percentile range of the weekly U.S. rig count.

The increased demand on top drives is evident in repair and service issues. Manufacturers cited issues with motors, obtaining replacement parts in a timely manner and the downtime associated with repairing active units that experience mechanical issues. Other issues surrounding the top drive market also include problems with gearboxes, seals and the software/electronic controls. Furthermore, a tight rental market makes equipment hard to come by if something happens to an existing unit. E&P

Reducing the noise

Efforts are underway to replace the airgun with a kinder, gentler source.

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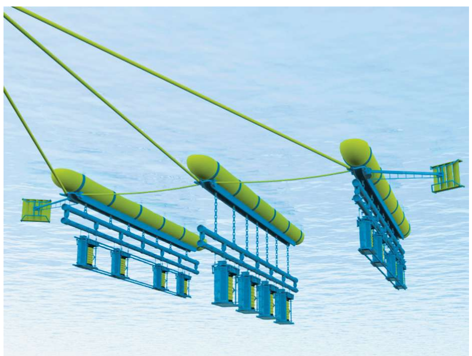
In the world of seismic datasets, marine seismic is the gold standard. "Almost as good as marine" is the highest compliment that can be paid to a land survey. But trouble has been brewing in paradise.

For years the sound source for marine surveys has come from airguns, which emit instantaneous large volumes of air, making a noisy, explosive-type bursting sound. Unlike other seismic technologies that need updating or changing due to obsolescence, there is nothing wrong with airguns from a technical standpoint, according to Bill Head, ultradeepwater manager for the Research Partnership to Secure Energy for America (RPSEA).

"Present-day difficulties with airgun use have little to do with geophysics or sufficiency of energy," Head said, "but with compliance with U.S. court-determined opinions resulting in regulations surrounding the interpretation of the 1972 Marine Mammals Protection Act. RPSEA has been seeking to test seismic source alternatives as it relates to good seismic signal, exploration productivity and safe use within current or future regulation."



Marine vibrators, like this prototype from PGS, will help reduce the impact of noise on marine life during seismic surveys. (Source: PGS)

Anyone familiar with marine seismic knows the tale—regulators and nongovernmental organizations have become increasingly vocal in their opposition to the use of airguns, resulting in somewhat onerous requirements such as having a marine mammal observer onboard all working vessels to look for the presence of marine life and also the use of passive acoustic monitoring systems to detect mammal activity in the area of a shoot.

Despite scientific studies that show no real evidence of negative impacts on marine mammals, the industry has shouldered these regulatory burdens and done its part to "save the whales," so to speak. But it also has been busy behind the scenes looking for an alternative to airgun sources.

RPSEA and others have been examining this concept in detail. The RPSEA concept is a joint industry project (JIP) to manage and test at least two "marine vibrators." An independent JIP sponsored by ExxonMobil, Shell and Total contracted with PGS, Applied Physical Sciences and Teledyne Webb Research to develop and test marine vibrators. In 2012 this JIP asked RPSEA to include these designs in its tests. The RPSEA project, which kicked off in September, is expected to last two years and fund demonstration trials of two newly developed marine vibrators. RPSEA also is considering other designs, including one created by the original inventor of the airgun. Each trial will use a full-scale full-power prototype, yielding data on both performance and reliability. The objective is to find a marine source that can provide the type of seismic illumination to which the industry has become accustomed. Deliverables will include data made available to the geophysical community, regulators and science-oriented environmental organizations for evaluation.

BP and CGG also are planning to collaborate in an R&D project on new types of "marine vibratory seismic sources," according to a press release, and are in fact hoping to improve on technical performance while also focusing on environmental sensitivity.

It's nice to see the industry so actively engaged in this type of research. "Being good stewards of the oceans is a natural thing," said Jacques Leveille, senior vice president of technology and communications for ION. "To that end, we'll continue to evolve and improve our source technologies so that we're meeting the needs of the industry in an environmentally safe way." E&P

Rhonda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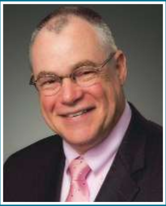
A pause in newbuild land rigs?

Lower oil prices may cause manufacturing to peak in 2014.



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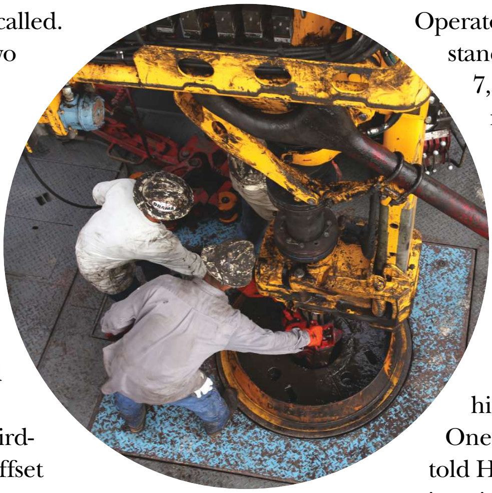
How long before the irresistible force of demand for new higher spec rigs meets the immovable object of lower commodity prices?

Evidence of an impending collision surfaced in November when Hart Energy surveys of contractors and operators in the Marcellus produced comments that operators were postponing plans to order new rigs, shopping rigs on order to other operators or discussing cancellation of existing orders. The survey moved to the Bakken, where additional order cancellations came to light, including comments from one contractor that a rig manufacturing representative had left his office just 10 minutes before Hart Energy called. The representative was marketing two recently completed rigs following order cancellations.

In all, early reports are small beans—maybe a dozen cancellations overall. In contrast, a survey of domestic rig manufacturers at the end of third-quarter 2014 found 200 rigs under construction, including 175 for the domestic market. Meanwhile, publicly held drilling companies were reporting recent newbuild contracts during third-quarter earnings calls—enough to offset cancellations in the two markets Hart Energy surveyed.



A crew changes pipe on a rig. Time will tell what the future holds for the newbuild land rig market. (Source: Brian Hendershot)

Defining the future, which really amounts to the first half of 2015, has become difficult since the industry is less than six weeks into the oil price sell off. Operator comments on 2015 plans span the spectrum from bravely drilling through a perceived V-shaped downturn to reducing 2015 capital spending in marginally economic areas.

Early projections among sell-side analysts suggest sustained lower oil prices may idle up to 200 mostly vertical rigs in 2015 based on breakeven economics. Operators at Hart Energy's Executive Oil Conference in November reflected prognosticating ambivalence as well, though an emerging consensus indicated a reduction in vertical Wolfberry drilling while moving forward cautiously on horizontal work pending additional market signals.

Such uncertainty complicates the newbuild rig scenario. A stimulating factor in new rig construction involves the move to enhanced completions. Operators are pushing laterals from the standard 1,372 m to 2,286 m (4,500 ft to 7,500 ft) when acreage positions permit. This effort has resulted in full utilization of higher spec 1,500-hp units. With higher spec rig capacity fully subscribed, operators have been signing multiyear-term contracts for new rigs in 2014 to meet the greater demands on rig capability that longer laterals create.

Anecdotally, the demand for higher spec units appears to be intact. One privately held drilling contractor told Hart Energy that his company had just signed contracts with a major for four higher spec 1,500-hp units already in the manufacturing queue.

Meanwhile, the industry as a whole is grappling with the shock of suddenly lower oil prices in a market that had encouraged rapid expansion in expensive tight oil developmental. For what it's worth, the 30% fall in oil prices from the June 2014 peak is about average for pricing pullbacks over the last decade. Many operators seem to favor the notion that recovery will reflect historical patterns and occur over the next three to six months, certainly by the first half of 2015.

For the time being, it appears that the impressive newbuild effort in 2014 may reflect the near-term peak in land rig manufacturing. E&P

Editor's note: *Scott Weeden is currently on medical leave.*

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Artificial lift in the Marcellus examines all options

Extent of field complicates selection of methods.

Kevin Brady, Multi Products Co.; **Ryan Tyree** and **Sean Rooney**, Range Resources-Appalachia LLC

Range Resources pioneered the Marcellus Shale play in 2004 with the Renz #1 well in Washington County, Pa. Since that time Range has grown to be one of the largest lease holders in the Marcellus with more than 1 million net acres and has more than 600 producing wells in the core area of the play in southwest Pennsylvania.

As a production team, we have faced many new challenges and obstacles in developing the Marcellus Field. Geographic diversity, the evolution of drilling and completion techniques, more prolific wells and longer laterals require us to be flexible and innovative with our approach to drilling and producing productive wells.

Due to high reservoir pressures and relatively low liquid volumes, our Marcellus wells produce naturally for up to three years before artificial lift is required. We have taken a proactive approach in analyzing the wells for their future artificial lift needs to ensure we can maximize production rates in older wells. Our main tool for candidate selection is Turner's critical flow rate model. Turner's calculation shows us that gas production in these wells can decline to around 11.3 Mcm/d to 12.7 Mcm/d (400 Mcf/d to 450 Mcf/d) before liquid loading occurs.

Our team analyzed a number of artificial lift options for these wells. We eventually narrowed our focus to two methods—gas lift and plunger lift—and are evaluating the potential of capillary strings as a third.

In our selection of artificial lift systems, rod pumps, electric submersible pumps (ESPs) and jet pumps were eliminated due to the relatively low fluid volumes produced in the wells. We looked closely at ESPs, but the added cost of this solution over the alternatives didn't make sense. Because ESPs work best with homogeneous fluids, we didn't feel that they were a good fit for our wells where we experience changing ratios of water, condensate and gas, which causes the overall fluid density to change and results in erratic production and slugging.

Gas lift was chosen as the solution for a small segment of wells where we had lower reservoir pressures and higher fluid volumes. So far this has only been a solution for a very small number of wells.

Our main choice of artificial lift has been plunger lift. With our proactive approach we target the plunger lift systems for installation when gas production declines to about 17 Mcm/d (600 Mcf/d), well above the Turner rate for most of our wells. We selected this production level to avoid allowing wells to decline to the point where production is severely impeded by liquid loading. The plunger lift systems provide an economical method of producing the produced liquids, thus stabilizing production and slowing the decline characteristics of the well.

The only drawback we see with the plunger lift systems is that they require some shut-in time while the plunger is falling. Although we run quick trip and bypass-type plungers, they still require some shut-in time, which cuts into the time that the well is producing. To counter this, we have been considering the use of capillary strings as an interim step to be used between the time a well is producing naturally and the time it is required to be on a plunger lift system. The capillary string would give us the ability to inject surfactants to lighten the density of the fluid column, which reduces the critical velocity needed to lift the fluids. Unlike plunger lift systems, there is no downtime while using a capillary string, so we can maintain production 24 hours per day. Our goal with the capillary strings would be to delay implementation of a plunger lift system until the wells have declined to a lower gas rate, possibly around the 5.7 Mcm/d (200 Mcf/d) range. The capillary strings would only be used in dry gas wells due to the separation issues that arise when surfactants are used in wells producing NGLs and condensates. Once a plunger lift system is installed, we feel that it can remain in place until well abandonment.

When examining wells for artificial lift, we try to keep an open mind and examine all options. The method that delivers good results in one well may not produce the same results in another. And we know we must be prepared to change artificial lift methods as a well's production characteristics change. E&P

Flying high

Legacy infrastructure, greenfield developments set to keep the ROV market flying high.

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Every week here lately it seems there are reports of some new sighting on Mars confirming there is more to the planet than red dust and rocks. One week it's a lizard, another it's a traffic light and the latest? A field artillery cannon. The little rovers that could—*Opportunity* and *Curiosity*—have wowed millions with the images and data that have been beamed down from millions of miles away. The technological sophistication necessary for these space explorers to operate is staggering and even more so when one considers that it is accomplished remotely via radio waves.

A little closer to home, a rover of a different sort—the ROV—is working to help take offshore oil and gas operations to the next level. While not as advanced as their space-exploring brethren, these subsea workhorses play a role in every stage of a field's life. The demand for their services is increasing as more subsea field developments go online and legacy fields are taken offline. How great is this demand?

ROVs have a role in every stage of an offshore field's life. (Source: Delta SubSea)

"We as an industry see it today as a $1 billion market, and that market space will be $2 billion in the next five to seven years," said Scott Dingman, CEO of Delta SubSea, independent provider of ROV services and solutions. "Between the existing infrastructure that's out in the deepwater and the planned projects that are currently sanctioned for deepwater, combined with the legacy infrastructure of shelf, deepwater shelf and just deepwater, I think there is a huge demand for ROVs."

It is a dual demand in that it requires both equipment and a talented crew. To keep the pace, the company uses frame agreements with manufacturers to ensure ROVs are available when needed within a 24-hour window. Without these types of agreements, the wait could be up to a year or more for a unit, Dingman noted.

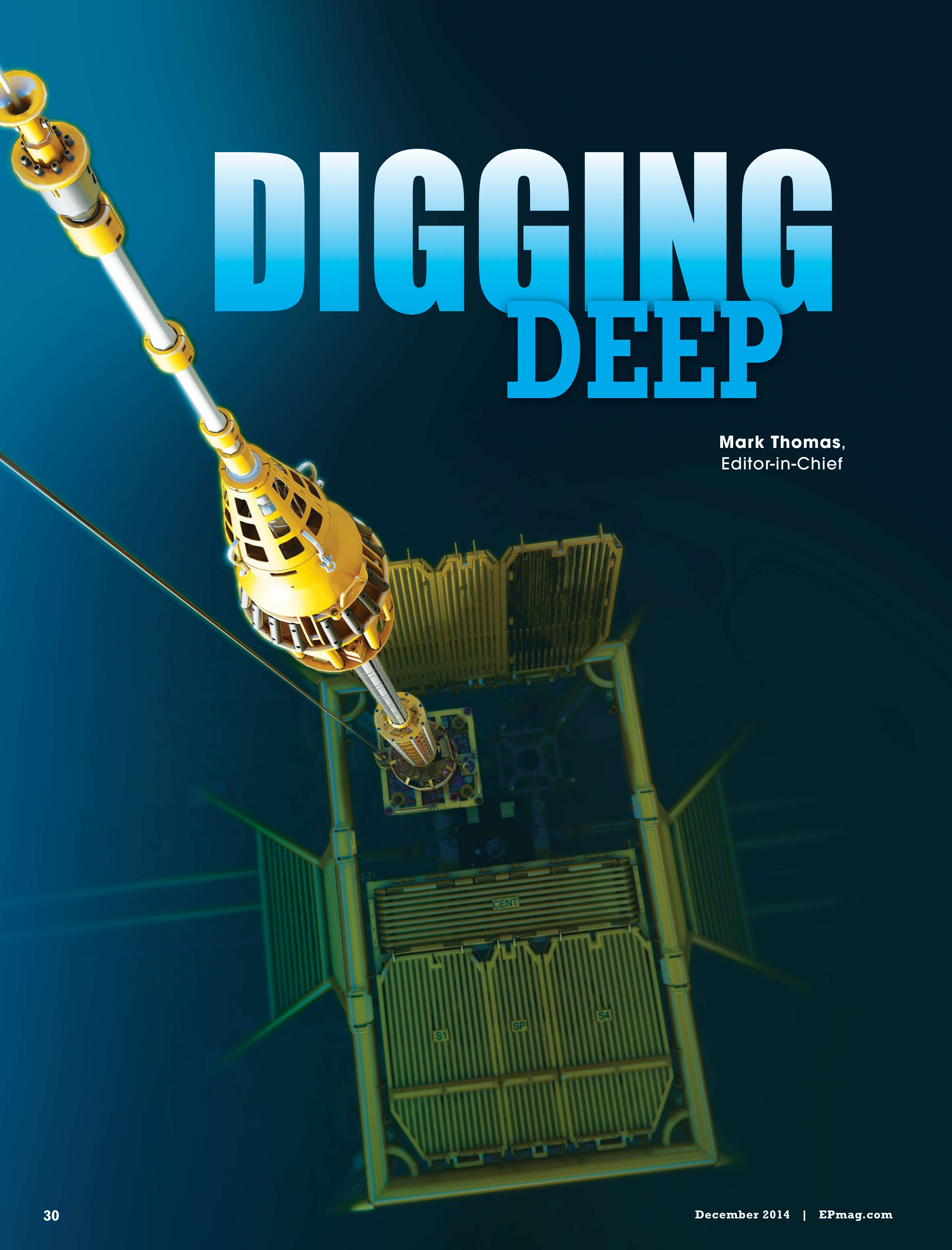
In addition to the 75% of its crew that has industry experience, the company recruits personnel with military and/or technical trade school experience for its in-house training program. The program uses hands-on simulator training and an on-the-job component to train recruits on how to fly and maintain the equipment. Finding the recruits is the greatest challenge, according to Dingman.

"We can find the equipment, but the challenge is personnel," he said. "We hired 150 people in the last 14 months. My growth expectation could be an additional 150 offshore operators in 2015. You start to run out of industry-experienced people pretty quickly at that kind of growth rate, especially when you factor in that we expect the market to double in five to seven years."

How will the labor pool impact the next generation of ROVs? "I think ROVs in the next 10 to 20 years are certainly going to become much more user-friendly in operation, troubleshooting and maintaining," Dingman said. "I also think you're going to see more non-tethered vehicles. You're going to see AUV/ROV vessels."

Will the next century see subsea fields inspected, maintained and repaired by robotic rovers similar to those currently at work in Martian fields? Time will only tell, but with a little curiosity and the right opportunity, anything is possible. E&P

Jennifer



DIGGING DEEP

Mark Thomas,
Editor-in-Chief

Finding and producing oil and gas anywhere in the world is nearly always a challenge, as is developing the technologies required to do it. It is only through continued technological innovation that it can be overcome.

For a global upstream industry currently dominated by issues such as the need to control costs, find the next generation of engineers and operate under increasingly burdensome regulation, it is worth keeping the long-term objective in sight.

As Khalid Al-Falih, CEO of the world's biggest oil producer, Saudi Aramco, reminded delegates at the recent Offshore Northern Seas (ONS) event in Stavanger, Norway, "To meet forecast demand growth and offset global output decline, our industry will need to add close to 40 MMbbl/d of new capacity in the next two decades."

The national oil company giant will invest $40 billion per year over the next decade to maintain its oil-producing capacity and increase its gas production. The bulk of that, said Al-Falih, "will be in upstream and increasingly from offshore with the aim of maintaining our maximum sustained oil production capacity at 12 MMbbl/d while also doubling our gas production."

With oil and gas still forecast to provide 60% of the world's energy through 2040 and with global liquids production predicted to reach 115 MMbbl/d by that year, the scale of the upstream challenge is clear.

'Man on the moon' mentality

According to Gerald Schotman, chief technology officer at Shell, what is required from the upstream sector is akin to what it took to put men on the moon and bring them back safely. Talking earlier this year at the SPE Intelligent Energy event in Amsterdam, he said, "I do believe that if you want to develop a field in 3 km (1.9 miles) of water, you need a 'man on the moon' mentality."

Schotman pointed out that man reached the moon using computing power that at the time "was like a pretty average calculator these days." He continued, "We have more computing power now, thankfully, and we face similar challenges in meeting energy needs and doing it safely and cleanly. None of us can handle this challenge by ourselves, so we need as an industry to cooperate on this. But we need to get going. Today it is not 'business as usual' but 'business as unusual.'"

Schotman highlighted the increased pace of technology development as a key factor, such as the industry's ability to get "better pictures" of what lies below the ground's surface. Seismic advances such as wide-azimuth technology have helped to dramatically improve the quality of the subsurface information, helping to open up new frontiers such as the presalt.

He flagged Shell's own significant progress, highlighting its Mars B Field development in the Gulf of Mexico (GoM): "The first well—Deimos—started as a completely dry hole. Now it is two discoveries."

Onshore, improved 4-D seismic data, visualization and interpretation have had great success, he added, but it is not just about the improved technologies.

Schotman commented, "It's much more than just finding resources. It's about economics, better planning and budgeting. Having more data is one thing, but it's also about using (them) better in the fields. Close connections with key developers in this space are crucial—we are cooperating with Intel, for example. They have a better understanding of us, and we have been able to benefit from this."

Innovation a 'contact sport'

The process is not easy, however. "Innovation is a contact sport," said Schotman. "It happens best when the best players get together on shared ground."

He highlighted some of Shell's partnering initiatives, such as its well known Game Changer panel and the company's continuous efforts to monitor innovation taking place in other industries. "Innovation involves getting hold of 'best in practice' anywhere," he said, "and getting over the 'not invented here' hurdle."

His comments were backed up elsewhere by Woodside Petroleum's Vice President of Technology Brian Haggerty. In his opinion general industry problems and the role of technology are inextricably linked, such as in today's cost-conscious environment.

Haggerty, speaking at the ONS event, said it was vital for operators to envisage the future and respond to it—"Innovation is required to stop rising costs," he commented.

Two years ago the company set up a division focused on dealing with issues such as productivity problems and remote stranded gas resources—an issue at the forefront of Australia's efforts to exploit the vast resources that lie off its western shores. According to Haggerty, these resources "are stranded only because we do not have an economic solution for them."

Woodside is focused on EOR techniques to help it increase its recoverable reserves. Haggerty highlighted Woodside's pioneering work with 4-D seismic on the reservoir of its producing Enfield development, the first dedicated time lapse survey to be carried out in Australia.

FLNG solutions

He also mentioned the study of options to reduce development costs such as the potential use of near-shore LNG solutions and the monetization of remote stranded reserves using floating LNG (FLNG) concepts.

On the near-shore LNG work, he said the solution could potentially save up to 25% in costs over a conventional onshore LNG plant, with the additional advantages of working with shipyards, which can provide cost and schedule certainty. In addition, there are the operational advantages of integrating the process, storage and offloading facilities.

Regarding FLNG, the company is pursuing the use of this fresh technology in partnership with Shell for its deepwater Browse project 425 km (264 miles) offshore Western Australia.

That potential megaproject, if it receives a final investment decision before the end of 2015 as currently planned, will see operator Woodside develop the Brecknock, Calliance and Torosa fields located in the Browse Basin. The fields hold nearly 425 Bcm (15 Tcf) of dry gas, with Woodside and its partners studying the use of Shell's patented technology on possibly up to three FLNG facilities.

Haggerty pointed out that Woodside has strong strategic FLNG relationships with more than 10 companies and that despite initially developing them for the Leviathan project in the Eastern Mediterranean offshore Israel (which it eventually stepped away from), it has "opportunities around the world for the potential use of an LNG-FPSO [vessel]."

Total's CLOV project offshore Angola started flowing in June. (Source: Total)

He also picked out next-generation LNG solutions as an area of focus for the industry to commercialize currently noneconomic remote gas resources. "Anything less than about 3 Tcf [85 Bcm] is a real challenge," he said. Designing and building a new generation of small and midscale FLNG units able to deal with this smaller scale of reservoir is, however, something that he feels will be tackled successfully.

Subsea advances

Also highlighted by Woodside's technology guru was the continuing challenge of developing and improving seabed production solutions such as subsea compression, separation, boosting and power requirements.

With the industry currently working or studying subsea tiebacks of almost 300 km (186 miles) for gas and 70 km (43 miles) for oil, there is now a need to start extending potential tieback distances up to 500 km (311 miles), he said. This can be applied to remote areas not only offshore Australia but in other, harsher environments such as the Arctic, where surface facilities may not be the best operational choice.

Subsea processing is seen by many within the upstream sector as a game-changing enabling technology, with recent seabed separation and boosting applications on deepwater fields offshore West Africa and Brazil acting as building blocks for its field-proven reputation for production-enhancing and reliable performance.

Multiphase pumps

Total is one of the industry's leading players in this area, with its most recent success coming to fruition earlier this year when its CLOV project offshore Angola started flowing in June. This is the French operator's fourth major project in Block 17, with the development of the

Sleuthing out solutions

Through industry's support of long-term research, solutions to today's upstream challenges are found by looking for challenges of the future.

By **Jennifer Presley**, Senior Editor, Offshore

It seems counterintuitive to go looking for solutions to tomorrow's challenges when the industry has so many today that first need solving. But it fits as that is where industry got its start—being counterintuitive is the essence of wildcatting, is it not?

Today's solutions and tomorrow's challenges were part of the discussion held as part of the International Energy Agency Gas and Oil Technologies Implementing Agreement workshop "Global Dialogue on Pre-Salt Innovation" held during Rio Oil & Gas 2014. The topic of R&D necessary to support technology innovation generated considerable discussion, particularly in the areas of what industry does not know now that it needs to know for its future presalt efforts.

Alex Moody-Stuart, South America marketing manager for Schlumberger, participated in the discussion as a panelist. He sat down with *E&P* and provided additional insight into how the company has approached R&D in the challenging presalt.

There has been a significant R&D effort in understanding the presalt. What are some of the lingering challenges that industry is working to overcome? As you said in your presentation, "What do we not know?"

Some of the major technical challenges are around increasing the efficiency of well construction, the reliability and maintainability of well systems, and increasing production and recovery factors. Well construction efficiency has a direct impact on saving the rig days during drilling and completion. Improving time between interventions saves on costs and increases production uptime. And we also need to save on intervention cost with the maintainability of well systems. And finally, production and recovery factor maximize the operator's return on investment.

How is Schlumberger working to address those challenges?

We are working on technology solutions supported by technical domain experts, both from the operators and our own, in the field. Through close collaboration with customers, our research and engineering (R&E) centers are continuously coming up with ideas that are then prioritized and put into an R&E portfolio that runs from concept through to the commercialized product. This of course requires continual updating to the market requirements to ensure relevance.

How are research efforts prioritized?

Research is prioritized based on the value the products and services will bring to our customers and to the company. This analysis includes key business and technical criteria including market size, technical requirements, competition landscape, technical risk and cost in product development, to name a few.

How is a business case made to support long-term research, to go "looking for a problem" that will need a solution?

Part is driven by immediate field requirements. For instance, we should spend so much on finding a solution to the time and risk incurred in drilling out fracture plugs. The technology may be an enabler to an existing system (for example, batteries used in our field systems) or apply directly but has to have a chance to be applicable to our oilfield services market (i.e., how might a given technology be used to address the major challenges mentioned above?). Our portfolio is confidential as the case on these investments is continual and long-term, where our return is linked to our ability to produce products and services that address a market need as soon as possible.

What are some of the successes of this type of research?

A few successes of this type of research include:

- Material and chemical research that resulted in dissolving aluminum (dissolving ball instead of drilling out fracture plugs);
- Real-time fracture diversion that improves fracture propagation (diverting fractures to harder-to-fracture zones in real time);
- Cement that heals itself (overcoming cracks that are caused by natural aging, chemical corrosion and mechanical deformation of the well); and
- A bit cutter that rotates, evening the wear and making the bit last longer. This not only allows us to drill faster but for a longer time between trips. ■

four fields concerned—Cravo, Lirio, Orquidea and Violeta—notable for its sheer scale. A total of 34 subsea wells are delivering two grades of oil to the project's FPSO vessel with the produced gas flowing by pipeline to the Angola LNG plant for liquefaction.

FMC supplied all the deepwater vertical trees, wellheads and control systems for the project as well as eight manifolds and two workover systems. It also supplied the world's largest subsea separation and pumping system for Total's Pazflor development in the same block, which began producing in 2011.

Wider industry acceptance of subsea processing now appears to have taken place, and the take-up is likely to be rapid. This was the case for FMC's Riserless Light Well Intervention (RLWI) from a monohull vessel. FMC built its first RLWI stack at a time when there was virtually no demand for the service, and its first customer only initially guaranteed 120 intervention days per year. Several years later the same customer required 900 intervention days per year. Key subsea technologies on CLOV included Total's first use of a helical-axial multiphase pumping system, which will help to optimize recovery by compensating for the gradual decline in the pressure from the two heavier oil Miocene reservoirs being produced (Orquidea and Violeta). OneSubsea supplied the Framo subsea multiphase pumping system, with a similar boosting system having also been supplied by Framo to Total for Pazflor.

Secondary from the start

This instance of the installation of secondary recovery equipment at the very beginning of a field's producing life is expected to become commonplace, with Total itself describing helical-axial multiphase pumps as an "essential solution of the future for improving recovery rates in mature

Dialing down the 'mega' in megaprojects

Standardization and being more selective are two areas where the industry should reset its approach toward megaprojects.

By **Edward Merrow,** Independent Project Analysis Inc.

Megaprojects are difficult. It isn't just their size—more than a billion dollars—but their complexity that drives the difficulty. Although the problems with megaprojects are now the talk of the town, the plain truth is that the industry has struggled with large complex projects for many years. Its track record on megaprojects in the 1990s was not good despite relatively forgiving market conditions that were characterized by a glut of engineering, procurement and construction (EPC) service providers. When the boom years finally arrived in 2004, they ended 20 years of low oil prices that had seen many of the EPC companies disappear. At the same time, the need for opportunities to cash in on the rising market drove the industry to deeper water and harsher climates and into the arms of highly dysfunctional governments. Not surprisingly, it made an already difficult situation much worse.

So what will the future bring? The cost/price squeeze in which the industry once again finds itself has already started to reduce the number of very large projects in companies' portfolios. Projects that would have been viable in 2004 are not viable today because the cost structure for projects in the industry has completely changed in the past decade.

Even with the reduced demand, megaprojects will face a rough go. The industry is in the midst of a historic changing of the guard as the baby boomers in OECD retire and it faces a generational gap of 20 years. During the 1984 to 2004 era, neither owners nor contractors hired because they were in the midst of an extended cost/price squeeze. The result is a demographic profile that leaves insufficient experience to do large projects well.

So how should the industry respond? First, the industry needs to consciously and deliberately adjust to the new situation. It adjusted to being a high-margin industry very well in 2004 to 2006. Adjusting back to being a relatively low-margin industry is much less fun, but it is essential. The adjustment means that minimizing capital cost must take precedence over schedule. At the same time, the owner teams must focus themselves on rigorous quality control as the EPC's design capabilities are compromised by inexperience.

Second, the industry will have to become much more selective about which projects are allowed into scope development so that scarce people resources can be dedicated to the projects with real promise rather than spread across any hydrocarbon accumulation a company happens to encounter.

Third, the industry must finally get serious about standardization. The industry has talked about standardization for years, but with few exceptions all it has done is talk. Effective standardization would address many of the industry's biggest challenges. Standardization reduces capital cost by about 20% by Independent Project Analysis Inc.'s measure. It also reduces the need for engineering services, and engineering services is the weakest link in the projects supply chain today.

Resetting the industry as a relatively low-margin business will not be easy or pleasant. But if it is done thoughtfully, it will ensure the industry's future while building a more solid foundation for better times in years to come. ■

oil fields," according to Francois Bichon, CLOV's deputy director, in a press statement at the time of the field coming onstream.

The multiphase system essentially prevents any loss of load and enables the rotor to evacuate a mix of several variable fluids at high speed. Total has two booster pumps installed, one of which is a reserve. It also plans incorporating two four-pump multiphase modules on its GirRI (Girassol Resources Initiative) project, also in the same block.

According to Frederic Garnaud, R&D program manager for production and development at Total, the GirRI pumps will be a world first, capable of a record differential pressure of up to 1,885 psi when they are installed in 2015. Speaking at the MCE Deepwater Development event this year, Garnaud said that by 2017 Total would be operating 500 subsea wells, eight FPSO units and two floating production units.

Linked to the subsea processing drive by the industry, Norway's Statoil and DNV GL are underway with a joint project to develop international standards for the technology to help with its eventual standardization in a bid to control costs.

The 'T' is the challenge

Also inextricably linked to the subsea arena are HP/HT projects. FMC Technologies is working with Anadarko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Petroleum Corp., BP, ConocoPhillips and Shell to develop subsea production equipment and systems to produce deepwater HP/HT reservoirs with pressures of up to 20,000 psi and temperatures of 177 C (350 F). The companies linked up in July with first-generation equipment likely to be built using existing metals as alloys continue to improve.

BP's Project 20K is the most well-known program in this area, with the aim of making advances in four areas—well design and completion; rig, riser and BOPs; subsea production; and well intervention and containment. BP also has teamed up with Maersk Drilling to build an ultra-HP/HT rig, and in June it also ordered four BOPs and two risers from GE Oil & Gas for the project. Maersk will reveal more details of its super-rig concept in 2015.

HP/HT is particularly relevant to the industry's efforts to open up the Lower Tertiary (Paleogene) play in the GoM. The challenge of how to best exploit these reservoirs using artificial lift or other enhanced recovery methods is one of the biggest currently being tackled by the oil and gas sector.

It is the "T" in HP/HT that is perhaps the biggest challenge. With temperatures between 204 C and 260 C (400 F and 500 F) being encountered, advances in equipment such as downhole sensors, elastomers and drilling fluids, for example, remain next on the list of solutions to be found. And the rewards could be substantial, according to Dr. Kevin Kennelly, vice president, upstream facilities at BP. Speaking at the MCE event earlier this year, he said simply, "We estimate there are between 10 Bbbl to 20 Bbbl of oil that we will be able to produce once we attain our 20K goals. That's the prospects that we have on our books that would be produced."

Innovative technologies, once more, are the key to unlocking the riches that lie beneath. E&P


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What's next for RPSEA?

JIPs may be the solution as the program struggles without federal funding.

Rhonda Duey, Executive Editor

The Research Partnership to Secure Energy for America (RPSEA) is arguably an example of the U.S. government getting it right when it comes to R&D funding for the oil and gas industry. The program was founded after the passage of the Energy Policy Act in 2005 to lead research in ultradeepwater (UDW) and unconventional technology development as well as aiding small producers. The project was to last 10 years and was given $375 million to fund the research.

A decade later, RPSEA can boast numerous projects that have been completed and new technologies that have been developed (see box). But there are still plenty of projects in the hopper, and as of September 2014, there is no more federal funding for RPSEA. What's a partnership to do?

"We were instructed by my board to stretch this so it lasts until the end of the program," said James Pappas, acting RPSEA president. "They were concerned that if we turned all of the project management over to the federal government, we would lose the industry support for the existing 30-plus projects that are still going on. Essentially the lifeblood of this program is the involvement we have throughout the projects themselves."

Some successful RPSEA projects

High-resolution 3-D laser imaging for inspection, maintenance, repair and operations
Results of this study validated that the terrestrial accuracies in 3-D laser scanning could be achieved under water.

Autonomous inspection of subsea facilities
The advanced autonomy developed by Lockheed Martin coupled with the Marlin AUV provides industry with a commercial capability to complete subsea inspections in hours instead of days.

Replacing chemical biocides with targeted bacteriophages in deepwater pipelines and reservoirs
Phages have similar inhibitory effects on active sulfate-reducing bacteria cultures as do currently used chemical biocides, are naturally "green" and have a longer lasting inhibitory effect.

Hanging on

With important projects in the balance, RPSEA staff determined that they had to find a way to survive until more funding might become available (which is at least six months from becoming a possibility). The organization has been restructured, and some staff has been let go. Other responsibilities have been turned over to the National Energy Technology Laboratory. But there's no talk of locking the doors and turning out the lights.

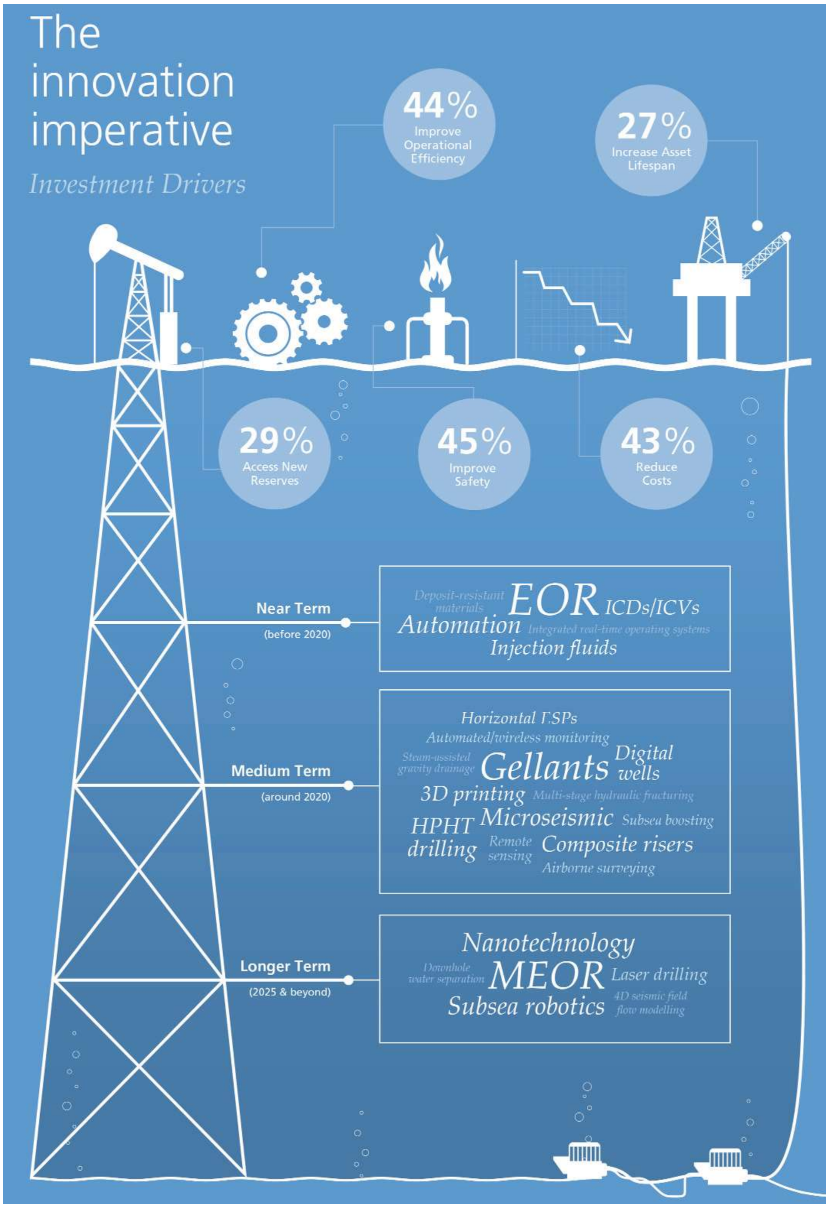

An AUV is positioned to be tested in a RPSEA project aiming to provide subsea inspection. (Source: RPSEA)

"The technical team is going to stay intact, for the most part," Pappas said. "We're going to follow the projects and continue to put the meetings together."

And help also has been offered by the industry that is benefiting from the technological advances. Pappas said that RPSEA was contacted about 18 months ago by companies that were involved in a specific project. "They said they would like to hire us to put together a joint industry project [JIP] together to carry the project all the way to commercialization," he said. "We put together a JIP that's going to get started in three or four months."

This set the stage for the next phase of RPSEA—marketing the ongoing projects to the industry to encourage additional JIPs. Industry participants provide the funding, and RPSEA provides the oversight and administration. "We looked at a few existing projects and also some of the projects that we wanted to do but couldn't when they cut our funding," he said. "We've gone back to the blackboard and regenerated those as JIPs, and we're marketing them right now."

On the UDW side, which is Pappas' responsibility, are several exciting technology projects that have piqued



A Lloyd's Register survey of 257 oil and gas executives and professionals determined several short-, medium- and long-term technology needs. (Source: Lloyd's Register)

industry interest. One of these is the Paulssen project, which has ramifications for both onshore and offshore development. The project involves a vertical seismic profiling (VSP) tool that was originally intended as a seismic-while-drilling tool but is showing promise in microseismic fracture monitoring as well. Pappas said the tool could be run outside casing or tubing to provide a 3-D microseismic picture. "If we can get something in the hole at the same time as we take measurements from the surface, we can visualize a 3-D picture, especially in a horizontal well," he said. "We could tie all of it together and give a much better indication of where the fracturing is actually taking place."

Another project involves a tool that could be placed over a BOP as a "last resort," able to cut anything to 18 in. and seal the well.

A third project entails finding an alternative to an airgun source for offshore seismic surveys. This technique, called a marine vibrator, would act similar to a land vibroseis truck, eliminating the need for the loud surface source that has become an environmental hot-button issue due to the potential effect on marine mammals. Pappas said that other techniques might be evaluated as well.

"We know that if we have a tool that seems to work, we can save time by having an independent group evaluate the effect on mammals while we're testing it offshore," he said.

Onshore the potential project list is huge. Kent Perry, vice president of onshore programs, said his group received more than 100 research proposals with a price tag of more than $200 million. That list was reviewed and shortened with the help of industry reviewers and advisers.

"We were about to place the contracts when the program budget was cut by the Murray-Ryan budget bill," Perry said. "What we are now attempting to do is fund the best set of projects with industry funding via a JIP."

While he couldn't go into specifics on the JIPs that are being marketed, he said many of them fall into "areas of current environmental concern" for shale development, including methane emissions, induced seismicity, water management, wellbore integrity and impact on shallow freshwater aquifers.

Cherry-picking

While the JIP route shows great potential for maintaining and reviving some of these projects, Pappas said his team has to be careful not to take on too much. "There's only so much we can do," he said. "If we're too successful, we don't have the staff to do it right now."

He's also concerned about the potential of competing with current RPSEA members like the Gas Technology Institute, the Southwest Research Institute and several universities. "We don't want to compete with them," he said. "We'll lose our members if we do. We need to find the right niche to keep everyone happy."

And he hopes this will be a short-term problem. There is a bill in Congress to resurrect the program, and if the bill passes, RPSEA will bid for the contract. "Assuming we get it, we'd be back in business with a large-scale $300 million to $500 million program," he said. E&P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Advanced analytics provide smarter prediction, production

Advanced analytics can evaluate short-term production, EUR and a financial forecast for a specific well design at a specific drilling location.

Jim Mackay, OAG Analytics

By now, most companies recognize that there are huge opportunities to use advanced analytics to improve decision-making and gain competitive advantage. Research shows that when companies embrace advanced analytics they can deliver profit gains that are 5% to 6% higher than those of their competition. One report even shows that companies enjoy an average benefit of $10.66 for every dollar spent on predictive analytics.

The oil and gas industry is ready for advanced analytics. In 2014, spending on domestic tight oil development will top $72 billion, with 30% growth by 2020. Yet despite all this money and attention, one in four wells performs significantly below expectations. Producers can't afford to be this wrong when they are spending $1.50 for every $1 that they get back this year.

Why advanced analytics?

Today's advanced analytics employ sophisticated data processing techniques to yield information from cross-functional datasets that are brought together from inside and outside the company.

There are thousands of multistage lateral wells with hundreds of data points per well in the mature shale plays, but only a subset have complete data and only for some of the parameters. Traditional analytics techniques can only measure correlations across complete datasets. This results in a lot of valuable data being ignored. Advanced analytics techniques extract much more information from these "sparse" datasets and measure correlations from the available data.

Predicting production in shale reservoirs

Predicting oil and gas production in unconventional reservoirs is an ideal application of advanced analytics. There is a huge amount of data available, and the industry has already proven that valuable insights can be derived.

Public information is available from organizations like FracFocus and state agencies such as the North Dakota Industrial Commission and the Texas Railroad Commission. This includes well location, design, production and geological information. Every operator also has lots of proprietary data about its wells and more detailed geological information.

Advanced analytics filter through millions of data points to better predict well production. (Source: OAG Analytics)

Of course this isn't news to the shale reservoir engineer who regularly uses these data to make critical decisions about where and how to drill expensive wells. But the inability to process all of this information combined with the inherent limitations of predicting average production for large acreage positions based upon a single well design forces engineers to make decisions using limited models.

Advanced analytics make it possible to instantly evaluate short-term production, EUR and a financial forecast for a specific well design at a specific drilling location. This allows reservoir engineers to evaluate far more well designs per well than what is possible making type curves with traditional tools.

Gaining new insights

Advanced analytics provide better accuracy and efficiency day to day. But the real value comes from the big strategic questions that operators struggle with, questions such as is there a single well design for a shale reservoir or should each well be designed individually to minimize dollars spent per barrel? Which completion design parameters are most important, and how do they relate to each other? What are the short- and long-term implications of pumping sand vs. ceramic proppant? How does this change when using multiple perforations per cluster? How are these factors impacted by different reservoirs?

Managed services approach

There are many moving parts to the typical advanced analytics project. These include collecting and preparing data, performing the analysis, creating ensembles of models, running simulations, generating reports and analysis, delivering interactive visualizations and then keeping the analysis evergreen by repeating the process as new data become available.

This approach requires months to years for even an experienced cross section of IT specialists, data scientists, user interface engineers and subject matter experts.

Rather than building all of this from scratch, OAG Analytics recommends going with a managed services approach. It automates the data extraction, transformation and load function. The models are then built and stored in a cloud infrastructure and made available 24/7. Prebuilt analysis and simulation are designed to help solve specific problems for the roles within an organization from the geoscientist to the reservoir engineer to senior management.

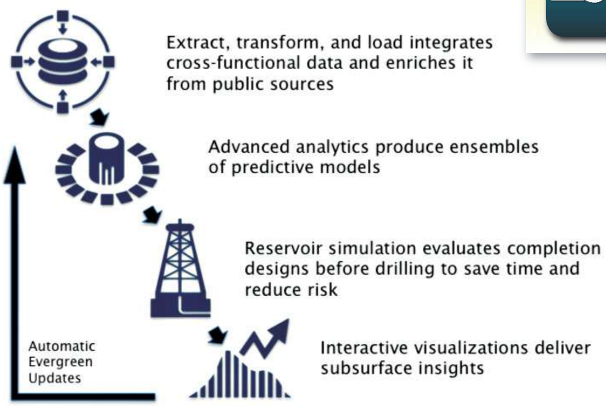
Preparing for advanced analytics project

Gather the data. Advanced analytics projects start with a detailed analysis of publicly available well data as well as all available geological and geophysical information. More comprehensive proprietary drilling, completion, cost and production data are then added to improve accuracy and provide more robust insights.

Although it may sound daunting to gather all this information, it's easy enough to get started by collecting information to gain some initial insights and then adding more data as they become available. Working with an analytics partner who knows unconventional data and is equipped to do a lot of the heavy lifting will get the process going much faster.

Understand the desired outcomes. As Stephen Covey points out, companies should "begin with the end in mind." What does a company hope to accomplish from the analytics initiative? Does it plan to incorporate the results into operating practices? Identify a set of goals and metrics that can be measured.

Test and continue testing. It is critically important to blindly test the predictive model against wells with known production. Continue to test as new wells are drilled. Rebuilding models from scratch as new data become available maintains and improves accuracy in volatile data environments such as unconventional reservoirs.



The typical life cycle of an advanced analytics project is used for well prediction. (Source: OAG Analytics)

Don't turn it into an IT project. Many vendors will want to sell a box of tools for a company to build its own advanced analytics solutions. Others provide analysis with no means to leverage the insights. Go with a managed-services provider that can stay on budget and rapidly deliver to the defined desired outcomes.

Analyze the results and look for areas to exploit and improve. An advanced analytics initiative is a journey. Initial results should enable a company to start asking questions that it didn't know it could ask. This leads to new learning and the desire to explore. Experiment by working with an analytics partner that will enable the company to test many hypotheses.

Periodically refresh the data. Advanced analytics are extremely adept at filtering out real data from "noise." But the analytics are only as good as the input data. As new information becomes available, rebuild the models. Automate the data refresh process as often as can produce measurably improved results.

Drive adoption through the organization. A company must define what it will take for it to trust the results. Once that's done, it can evolve the current processes to leverage them. Competitive advantage can only be gained if the business adapts.

Roll up the value to other parts of the company. Keep in mind that advanced analytics can go well beyond well production prediction and can also be used to provide a unique competitive advantage for evaluating acquisitions and divestitures, forecasting, reserve reporting, simulating well spacing scenarios and more.

Get started now

Advanced analytics are here to stay. New insights that are changing shale reservoir development are constantly being discovered. More data become available all the time. Companies must start considering how advanced analytics can help the organization gain efficiency and accuracy from the data it already has. E&P

A practical alternative for continuous product deployment

The world's first truly modular carousel finds success offshore Indonesia.

Deborah McCombie,
Aquatic Engineering & Construction Ltd.

As exploration moves into deeper water, the length of umbilicals and cables is increasing, requiring increased capacity reels. The largest reels are limited to a certain size to prevent compromising the safety of the vessel. Additionally, operators are seeking to reduce or minimize the number of subsea joints. Modular carousels offer operators another option in handling increased capacity reels.

Making the case for modular carousels

In late 2011, Aquatic Engineering & Construction Ltd., an Acteon company, investigated the commercial possibilities of building a 1,500-tonne modular carousel.

The business case was compiled through in-depth telephone research with leading oil and gas subcontractors as well as broader industry evaluation. It demonstrated that the 1,500-tonne carousel concept was positively received.

A high priority would be that using a modular carousel would require a decision made at an early stage of project planning; potential customers would need to consider the carousel "off plan." Incorporating a modular carousel at a later stage of a project would be more challenging.

During 2013, Aquatic invested in the design, manufacture, test and operation of its modular 1500Te carousel. This would be the first truly modular carousel in the market. Other similar products that claim to be modular are cut and welded back together during mobilization. As a modular carousel, it would be much easier to take apart and ship in 12-m (40-ft) containers. Aquatic's traditional powered reels have high utilization, and the new modular carousel aims to further serve and expand its market in an area where reels are no longer sufficient or optimal due to length and/or weight of umbilical, power line or flexible cables required.

Fast forward to 2014, and Aquatic's modular carousel has successfully completed its first project.

Modular Carousel Dimension and Weight	
Overall weight (including level winder tower & deck chutes)	350 tonnes
Fully loaded maximum deck load	1,850 tonnes
Reel diameter	12 m
Height under roof plate	variable
Hub diameter	variable
Grillage	14.5 m x 11.9 m
Heaviest assembly lift	112 tonnes (the grillage)
Product diameter	75 mm - 450 mm but could be modified to 600 mm if there was ever a requirement

The table shows the 1500Te modular carousel design dimensions and weights. (Source: Aquatic)

Product design, mobilization

The 1500Te carousel can handle a product load up to 1,500 tonnes, has a maximum reeling speed of about 1 km/hr (0.62 mph) and uses a built-in tensioner with a maximum line pull of 5 tonnes to maintain product tension on the horizontal reel at all times. The tensioner is mounted on a level-wind tower, which ensures proper spooling on and off the carousel. It has a reel diameter of 12 m and a variable hub diameter, which means that it can handle multiple products and can be mobilized onto most vessels of opportunity.

"Our innovative 1500Te fully modular carousel solution has been designed to maximize product capacity, minimize vessel days and maintain operational efficiency in demanding marine installation projects," Chris Brooks, president of Aquatic, said.

The carousel was successfully used to install 9.7 km (6 miles) of 8.5-in. diameter umbilical in the South Belut Field offshore Indonesia for ConocoPhillips. As the installation contractor, Kreuz Subsea engaged Aquatic Asia Pacific to mobilize the modular carousel system onto the *Seamec Princess* and transpool the umbilical prior to sailing to the field and laying off the vessel starboard side.

The project saw the Aquatic carousel mobilized for the first time after completing its factory acceptance test in Singapore. Logistically, the first offshore operation for the new carousel was more than sufficient to put it through its paces, requiring three different lengths of flexible product to be spooled onto the carousel at the start of mobilization. Each length was connected to the next using mid-section connectors, each 8 m (26 ft) long.

The Aquatic team met the challenges of this complex engineering operation, with representatives from Kreuz Subsea observing each stage. The entire operation from equipment mobilization to transpooling, offshore laying and demobilization was completed within three weeks.

"The 1500Te modular carousel is clearly a game-changer," Brooks said. "Designed for the widest possible range of vessels, clients and project variations to maximize its potential future use worldwide, this necessitated specific design and commercial requirements. Based upon our first project and current proposals, the carousel will be mobilized less often than our smaller pieces of kit and will be out on longer projects each time it is used."

Built for deepwater

Installation in deeper waters has become a recent trend in the subsea market, often being performed in depths ranging from 1,981 m to 3,048 m (6,500 ft to 10,000 ft). However, installation replacement or recovery work at this depth requires specialist equipment to accommodate the increasing length and weight of the items being installed. Aquatic's carousel system provides the strength and stability that can withstand the installation of the heaviest equipment in deepwater.

The carousel's capability and flexibility in all waters also are being proven on projects that demand increasingly long subsea tiebacks to processing platforms.

"It is not enough to have the right pieces of kit in the right places; customers expect this as a minimum," he said. "Today, clients are ever more demanding and require a total package that combines favorable contract terms, available kit, flexible teams to work with and, overall, people who are interested in forging long-term business partnerships for mutual benefit, not just to win projects here and there."

Future steps

According to Brooks, the company has established long-standing relationships with companies in both the Middle East/Africa and Asia-Pacific, and maintaining partnerships is at the heart of its strategy for the U.S.

"We understand that to do business anywhere, it's not possible to merely wave credentials at people. It is vital that trust and cooperation are maintained over a number of projects and negotiations," he said. "This doesn't happen overnight, but when it does develop, it harvests long-term rewards built on mutual trust and benefit. By developing existing partner arrangements and creating new partnerships with key regional players, we aim to improve our current prospects and position the business to capture growth and deliver significant improvement." E&P

Operational Evaluation Product >20K

	MULTIPLE REEL	FIXED CAROUSEL	MODULAR CAROUSEL
Continuous lay operation		•	•
Reduction in quantity of connections used		•	•
Large range of suitable vessels	•		•
Low product integrity risk		•	•
Reduction in need of offshore resources		•	•
Vessel multi-tasking (clear deck)	•		•

Operational Evaluation Product >20K

	MULTIPLE REEL	FIXED CAROUSEL	MODULAR CAROUSEL
Lower up-front engineering costs			•
Lower product fabrication costs		•	•
Lower vessel and equipment mobilization costs	•		•
Lower transpooling and deck preparation costs	•		•
Lower vessel time as equipment prep at quayside	•		•
Lower possibility of schedule slippage			•

In this operational evaluation, the versatility of the modular carousel is demonstrated over other types of deployment systems. (Source: Aquatic)

Mini-ROV minimizes inspection downtime, improves safety

In facing the challenge of reducing out-of-service time for mandatory hull inspections, one company finds success in a small package.

Jennifer Presley, Senior Editor, Offshore

For offshore rig and vessel operators, time spent out of service is money lost. To alleviate some of the pocketbook pain, Ensco found a way to streamline the mandatory hull inspection process, trimming it from weeks of downtime spent in dry dock to very little downtime and no dry dock.

Hull inspections are critical to ensuring a vessel's safe and continued operation. All classed vessels are required to have their hull inspected a minimum of two times every five years, with no more than 36 months between the inspections. This means that roughly every two to three years the vessel needs to go into dry dock.

An alternative is to request permission from the society the vessel is classed with to perform an underwater inspection in lieu of dry docking (UWILD). UWILDs are performed by divers while at sea, eliminating the need for dry docking while limiting the amount of time a vessel spends out of service.

Earlier this year, Ensco performed its first UWILD using not a diver but a small submersible ROV video camera called the VideoRay Pro 4.

ROV UWILD

The VideoRay Pro 4 system was deployed for an external hull inspection of *ENSCO DS-1* drillship offshore Angola, according to Sachin Mehra, vice president of asset management for Ensco.

"We first learned of this technology about two years ago. We carried out a series of tests on some of our rigs with the VideoRay Company and with class societies, participated in a joint industry project and performed a technology trial to make sure that it would be suitable and accepted by the class societies," he said.

The VideoRay Pro 4 enables surveyors to perform general and close visual inspections without the need for divers, minimizing safety issues and logistical challenges. (Source: VideoRay LLC)

"It took us almost a year to validate the technology and then communicate to the fleet that this technology was available. The rigs started purchasing the equipment, and in May we had our first successful inspection. It was more than a year and half from the time we conceived the idea that we achieved success."

While this inspection was just for the external hull, Mehra is certain the system has more to offer.

"We believe that we have great potential to replicate our success using the ROV to inspect inside the hull because of the large size of the drillships' ballast tanks, but we need to work with class societies to make sure that the tank inspections are credited to us when we perform the inspection with the mini-ROV," Mehra said.

Benefits

For Ensco, the benefit of using the system is two-fold: simplified deployment without a diver means safer inspections and a reduced need for the rig to log out-of-service periods. Deploying the VideoRay is as easy as lowering the lightweight (about 14-lb) submersible system into the water and minding the umbilical while a trained operator runs the system.

Safety precautions for the mini-ROV include shutting down the thruster closest to where the ROV is to prevent it from being sucked into the thruster. The other is keeping an eye on the ROV's umbilical during operation to ensure that it is not damaged or destroyed.

"When we perform UWILDs the conventional way, we use divers. There is an inherent risk with divers because you need to mobilize a large spread of people and diving equipment, which is a challenge for remote locations," he said. "Then there are safety concerns. For example, divers cannot be in the water while thrusters are running, which means some of the thrusters must be shut down, thus increasing the risk to station-keeping.

"Depending on the day rate of the rig, this could become quite costly. By using the mini-ROV, the logistics is simplified because it is a very small piece of equipment, and there is no need for large expenses to mobilize it to the rig. It is simpler to get one person to the rig to operate the ROV than it is to mobilize an entire diving spread to the rig," he added.

"Secondly, we have been able to show that we can do this inspection without taking any out-of-service period, which is a huge benefit to Ensco because the rig keeps on working. We are able to provide undisrupted service to our clients while performing this inspection, which is probably the biggest gain."

Next steps

The mini-ROV provides the opportunity for surveyors to perform general and close visual inspections. It also is equipped with a thickness measurement probe that can perform thickness measurements of the hull plating. For internal tank inspections, the ROV again demonstrates the safety and cost savings benefits.

"For internal tank inspections, we avoid having to completely de-gas the tank, and no one has to work in a confined space," he said. "Typically, when we do a tank inspection with a man entry, it takes us about one and a half days. With this ROV, you can do the inspection quite easily by simply filling up the tank and dropping the ROV inside."

Ensco is in discussion with several companies to develop the technology necessary to inspect the welds.

"We still have some work to do on the technology for weld inspection," he said. "The ROV technology does not have that capability at this particular moment, so if we continue doing the UWILDS with the current mini-ROV technology, we may have to perform limited diver's work.

"As part of the inspection, we have to do nondestructive testing of the welds, and the current technology cannot do that. We've had great success with the inspection of *ENSCO DS-1*, but we know the limitations of this technology and realize that to replicate that success going forward, we need to develop new inspection technologies." E&P

The submersible ROV was used to inspect the external hull of the *ENSCO DS-1* drillship offshore Angola, resulting in safer inspections while reducing out-of-service periods. (Source: Ensco)

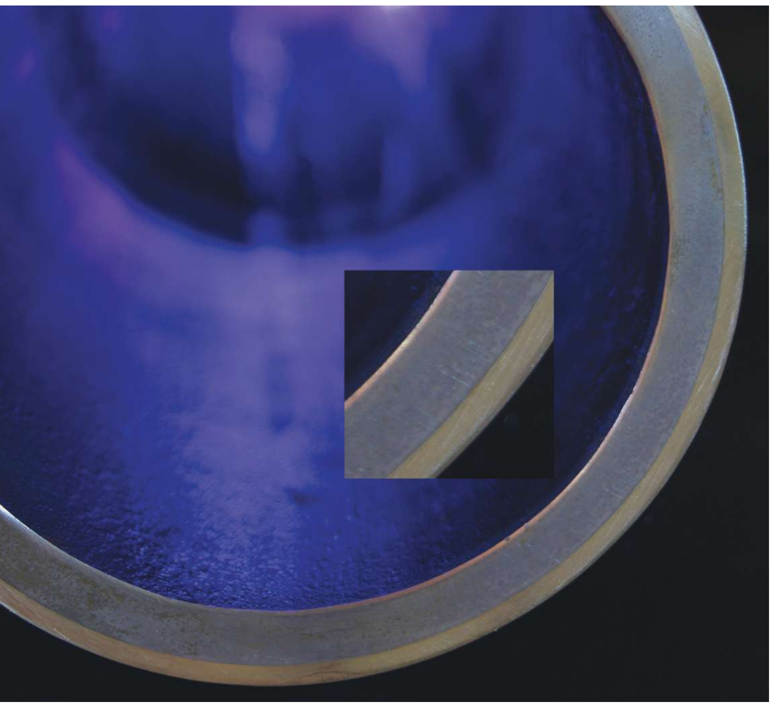
Nanomaterials aid corrosion resistance

New metals science addresses harsh oil and gas environments.

Christina Lomasney, Modumetal

When speculators first tapped the oil fields in Texas, they recounted stories of oil spewing from the ground like a geyser, allowing for the rapid development of this vast resource. The same was true in major oilfield operations around the world. Today, however, it's clear the era of easy, cheap oil is over. In fact, the International Energy Agency estimates that more than 70% of our remaining oil reserves consist of heavy crude oil, often high in sulfur or CO_2 content. The same is true of natural gas, of which more than 50% of the global supply is highly corrosive.

This paradigm shift in the oil and gas industry necessitates the availability of cost-efficient corrosion-resistant metals for E&P equipment. Unfortunately, existing materials are insufficient to withstand these extreme environments, leaving operators struggling to efficiently manage component degradation in the forms of corrosion and wear. Ultimately these challenges lead to increased operations and maintenance costs as well as more operational downtime.



Nanolaminated materials have crack-arresting characteristics at the interface of the layers. (Source: Modumetal)

To address oilfield component longevity and improve return on assets, oil and gas producers are quickly searching for alternative materials that can better withstand today's more aggressive environments.

Exploring the options

Oilfield operators generally have two options when assessing materials. The first is to select a low-budget material with the understanding it cannot withstand highly corrosive environments and will thus require regular replacement. A frequently used option in this camp is hot-dip galvanized metals, which come in at a compelling price point but offer subpar performance. On the flip side, operators may opt for a higher performance material and the hefty price tag that comes along with it. Options here typically include tungsten carbide and diamond-like carbon materials.

Recently, a new choice has emerged in the form of nanolaminated materials, a new breed of metal designed to address this growing challenge. While the lamination technique can be found as far back as 2750 BC with the construction of the Tower of Gizeh, modern materials science has opened the door for new alloys with nano-scale layers, which allow precise control over the composite materials' properties. Using commonly available raw materials, alloys with unprecedented levels of performance in corrosion resistance, strength, hardness, wear resistance and fracture toughness can now be constructed.

Building a new class of materials

The key to tapping the potential of nanolaminated materials lies in a novel production process. Traditionally, when developing alloys engineers can control just two of the primary factors impacting the performance of metals: alloy chemistry and alloy microstructure. Alloy chemistry encompasses the types of materials from which the metal is composed. Bronze, for example, offers the benefits associated with the properties of its primary components: copper, zinc and possibly tin.

Another example is steel, which derives benefits from the properties of metals like iron and carbon. Alloy microstructure refers to the organization of an alloy. Microstructure is typically designed by heat-treating a metal or through mechanical working such as tempering to impact the crystallinity or grain size of the metal.

Modulation represents a third factor that can be uniquely controlled through the production of nanolaminated materials. Modulation essentially means piling nano-scale layers—between 10 and 100 nanometers in thickness—of homogenous alloys on top of one another to provide those materials with an interface. This unique layering process enables producers to optimize specific properties and build materials that are stronger, harder and otherwise more resistant to structural or mechanical failures.

To understand how this new class of alloys improves corrosion resistance and metal asset performance for oil and gas operators, it is important to first examine the corrosion process. Corrosion occurs when two metals or alloys come into contact, creating what is known as a galvanic couple. The coupling causes the alloys to exchange electrons, an interaction that generally results in one metal being protected at the expense of the other. Nanolaminated materials use the same raw materials found in conventional alloys, but by layering them at the nano-scale, producers can significantly delay the progress of corrosion or prevent the corrosion process from beginning.

In addition to their performance benefits, nanolaminated materials of this caliber also are revolutionizing metals engineering. Established production techniques use tremendous amounts of heat as the input form of energy. However, the use of heat does not allow for the control of metal formation on a small enough scale to effectively produce nanolayered structures. In contrast, the use of an electricity-based process can achieve this desired result. Furthermore, this electrometallurgical technique operates near room temperature, reducing costs and enabling efficient scalability.

Putting nanolaminated materials to the test

Nanolaminated materials have demonstrated exceptional performance in the field across a number of applications. In one example, a U.S. Department of Defense (DoD) customer operating in an aggressive marine environment found that even state-of-the-art corrosion-resistant coatings couldn't prevent critical fastener components from deteriorating rapidly. After employing a cost-competitive nanolaminated alloy coating solution two years ago, corrosion in the operating environment has ceased. From an economic standpoint, the customer achieved a savings estimated at more than three times the value of the current component systems. When combined with the avoidance of potential asset failure, this estimate jumps to millions of dollars.

Considering the serious corrosion challenge the oil and gas industry is facing today, these nanolaminated alloy coatings have the potential to significantly impact the industry. As the U.S. DoD case study above illustrates, nanolaminated materials deliver unparalleled corrosion resistance, but they also offer performance advantages in addressing fatigue and wear.

Next-generation metals will prolong the life of oil and gas assets. (Source: Modumetal)

Oil and gas assets will often exhibit cracking after heavy use. To combat this issue, nanolaminated materials possess crack-arresting characteristics at the interfaces of the layers. Additionally, the interface itself can serve to deflect, blunt or halt crack proliferation—up to 100 times improvement as compared to traditional alloy performance.

Leading oil and gas companies are deploying nanolaminated coatings in topside field trials on rigs around the world. One early adopter estimated the longevity and performance improvements enabled by nanolaminated alloys could save more than $250 million throughout the life of the field. The improved performance also will lead to more operational uptime and, thus, higher oil production rates over the lifetime of the field.

Nanolaminated alloys have the capacity to cost-competitively address the problems of corrosion, fatigue and wear for the oil and gas industry, providing oil producers with a unique approach to curb rising costs associated with harsh production environments. Modumetal Inc. is helping to lead this charge, working alongside industry leaders such as ConocoPhillips and Chevron to deploy these next-generation metals to the field. E&P

Blink and you'll miss it

The oil and gas industry is notoriously slow when it comes to technology uptake. Someone apparently forgot to tell that to the exploration folks.

Rhonda Duey, Executive Editor

What on earth is going on with exploration technology development? It's like R&D on steroids. Technologies seem to go from great idea to new launch to old hat in months, not years. It's future shock all over again.

From geology to geophysics to petrophysics and well testing, the past few years have seen tremendous technological strides. Here are a few of the most notable.

Geophysics

At the recent Society of Exploration Geophysicists (SEG) annual meeting, Saudi Aramco held a special event outlining its strategic research initiatives in geophysics. It was not meant to be a roadmap for future R&D, said Panos Kelamis, chief technologist-geophysics technology for Aramco's EXPEC Advanced Research Center. "This is not a vision," Kelamis said. "The train has left the station."

A worker deploys an RT System 2 wireless remote unit in the rugged terrain of Kurdistan. (Source: Wireless Seismic)

The event outlined several areas of current investigation. The first is automation, which seeks to improve efficiency and data quality while reducing acquisition, processing and interpretation cost. Saudi Aramco is involved in a major industry collaboration to build a commercial automated shallow marine seismic system using AUVs that can be positioned and retrieved anywhere on the seafloor. The hope is that increased automation will lead to increased use of seismic data in reservoir monitoring. This, in turn, will require processing and interpretation automation to handle the massive quantities of data.

The second area is to bring geophysics closer to the reservoir. This increases seismic data fidelity and provides better vertical resolution, something which will be of great use to engineers in their field development schemes. Already Aramco is drilling holes to bury geophones beneath the near surface, which in the Middle East is notorious for wreaking havoc with surface seismic signals.

Advances in seismic acquisition have already astonished the industry within the past few years. On land the push has been to increase sampling capability, and a variety of techniques have become routine, including slip-sweep acquisition and simultaneous source acquisition, in which multiple sources are implemented at the same time with the cross-noise later filtered out in processing. Wireless acquisition systems also are becoming more routine as some of the early bugs have been worked out. In fact, earlier this year Wireless Seismic set a record for real-time wireless recording of seismic data, using 11,000 active channels with real-time data transmission from a live patch of 6,400 channels on a survey in Kurdistan.

Geophones also are getting a new look. Shell and HP partnered several years ago to create sensors based on microelectromechanical systems. The criteria for performance were a low noise floor and higher fidelity in the form of low-frequency data as well as ease of deployment and wireless functionality.

Another type of sensor was announced at the 2014 SEG meeting. Silicon Audio launched a new seismic sensor that is the same size and shape as a conventional geophone but uses a laser to read the motion of a vibrating proof mass, achieving a high signal-to-noise ratio and recording lower frequencies than traditional geophones.

Strides are being made in the borehole as well. Sercel recently launched a vertical seismic profiling (VSP) system specifically designed for HP/HT environments. And fiber optics continue to play an important role. Paulssen Inc. announced Optic-Seis, a permanent or redeployable borehole seismic system for microseismic as well as 2-D, 3-D and 4-D VSPs. These are HP/HT tools that can record up to 1,000 three-component levels and can be used in both vertical and horizontal wells. And a new company called GeoOptics, a division of MagiQ Technologies, is developing a fiber-optic seismic sensor to aid in microseismic monitoring.

Though microseismic isn't an exploration tool, *per se*, it has its roots in exploration technology. This is a technology that has simply exploded on the scene over the past few years since it helps address fracture monitoring in shale plays. Several companies offer a combination of surface and buried arrays, and Paulssen is working with the Research Partnership to Secure Energy for America to develop a downhole tool.

In the marine environment, the biggest acquisition news is being shared by two types of technology—broadband seismic and nodal seismic. Broadband is typically a towed-streamer application and can include hardware and/or processing aspects—it delivers a broader frequency image than is obtained by conventional methods. Nodal seismic systems are deployed on the seafloor and provide data of much higher quality due to the quieter environment and the full-azimuth nature of the data recorded. These aren't totally new systems, but their acceptance has grown as the equipment has improved and deployment costs have come down.

The ability to do simultaneous source shooting will help reduce nodal costs even further, said Paul Brettwood, vice president of technology and strategic marketing for ION. "One of the constraints with seabed is that you compensate for the sparse receiver sampling by doing a huge number of shots," he said. "But if you can have three or four vessels out there firing at once, your time to shoot that dataset will be reduced significantly."

The GeoWave II downhole seismic tool can conduct safe and efficient VSP and hydraulic fracture monitoring surveys in the most hostile well environments. (Source: Sercel)

Acquisition schemes offshore have improved tremendously, particularly with the advent of wide-azimuth (WAZ) seismic, which often uses multiple source boats shooting from a variety of directions. More recently Schlumberger advanced the concept of coil shooting, where the vessels shoot in a circular rather than a linear pattern. That company also introduced IsoMetrix, which is basically a combination of broadband and WAZ since it provides finely sampled data in all directions.

The processing arena is undergoing some of the most notable advances, made possible in part by continually improving compute power. Reverse time migration, which was a new technique just a few years ago, is now routine, although more recent efforts have improved the highest frequency at which data can be processed.

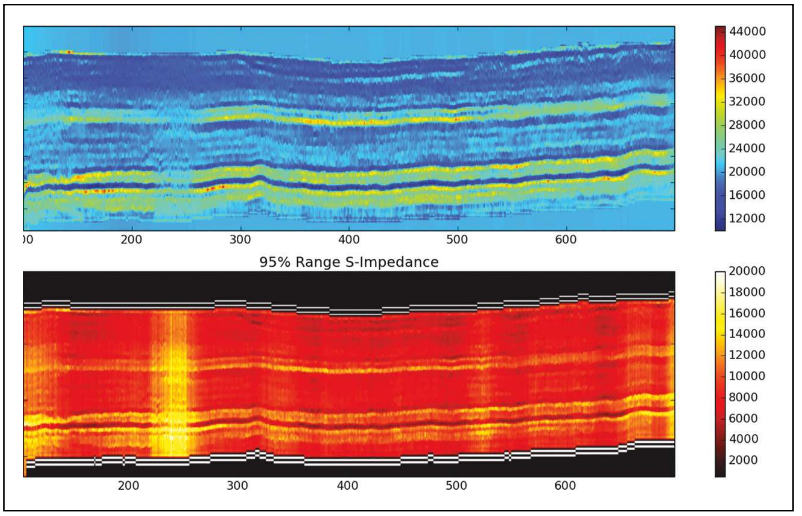
Another advancement has been in bandwidth preservation. "In the past you would do surface-related multiple elimination and various other things, and you would lose bandwidth in every stage of the process," said Jacques Leveille, senior vice president of technology and communications for ION. The goal, Leveille said, is to redesign algorithms so that bandwidth is preserved at every stage. An example is accurate velocity determination using nonparametric tomography. "It's not using the predetermined shape of a curve," he said. "You let the data tell you what shape this thing has." Processing the data that way allows one to use the broader band data in rock property determination.

To that end ION launched PrecisION, an inversion algorithm that performs analytical processes in the Eigen domain, a domain in which usable data is more readily separated from noise.

There is another recent breakthrough in processing—full waveform inversion. A year ago it was an interesting theory that people were trying to figure out. Now it's offered by all of the major service providers. "We're actually deriving a model that's constrained by the data," he said. "You're building the model as you process the data."

Another fairly recent arrival on the scene is uncertainty modeling. Both Roxar and ION have tools that include error bars to indicate the level of uncertainty present in the model.

In the interpretation arena, quantitative interpretation is becoming a more common tool. Quantitative interpretation enables interpreters to quantify reservoir conditions such as geomechanical properties, lithology, and rock and fluid properties. It is a sought-after tool in shale plays where this knowledge is so important.



Inverted shear impedance (top) and its 95% confidence range (bottom) are shown. (Source: ION Geophysical)

And on top of all of this, seismic contractors are trying to figure out ways to reduce cycle time. "There's always a drive to reduce cycle time to get the end product to the oil company more quickly," said Brettwood. "There's an even greater drive within the unconventionals because they are punching holes every few days, and they need the information in time to impact the drilling decisions. If we're going to have any impact at all from geophysics, it has to be delivered quickly."

Multiphysics

The third area of Saudi Aramco's investigation is "multi-geophysics," more commonly referred to as multiphysics. This is not a totally new concept since seismic data have been integrated with well logs, gravity and magnetics, and electromagnetics for many years. But the next step is to develop technologies for joint inversion of these data types.

This is definitely an area of key interest. CGG, for instance, recently formed a new multiphysics business line to combine its airborne business with its GravMag Solutions group. Repsol launched its Sherlock Project in 2009 to characterize the elements of petroleum systems and fluid behavior to improve recovery and production rates. It is made up of a variety of tools that integrate knowledge from geology, geochemistry and high-resolution analytical chemistry.

"We're experimenting with multiphysics," Leveille said. "It goes back to the compute power and the algorithms and efficiency and also the cleverness of the algorithms since we will be using more measurements."

One new area of development that fits in nicely with the multiphysics concept is digital rock physics (DRP). Pioneered by companies such as Ingrain and FEI as well as Stanford University, DRP combines 3-D pore scale imaging and computation to compute rock matrices from thin sections of cores or cuttings. This provides a quantitative understanding of the reservoir at the pore scale.

The compact and stackable Manta node goes where traditional streamer seismic often cannot, in depths up to 3,000 m. (Source: Seabed Geosolutions)

Petrophysics and sampling

One way to characterize a reservoir is to bring rocks and cuttings up from the wellbore. Another way is to stick a logging tool down the hole.

Well logging has been around since 1927, but the tools continue to see huge improvements. Some of the holy grails with logging tools are depth of investigation and the ability to withstand high temperatures and pressures. There also are constant efforts to improve the value of the information gleaned from the tools.

Schlumberger, for instance, introduced the dielectric scanner, a tool that directly measures water volume and

rock textural information. This allows operators to determine the volume of hydrocarbons in carbonates, low-resistivity or low-contrast shaly and laminated sands, and heavy oil reservoirs as well as water salinity and clay volume. Its Litho Scanner high-definition spectroscopy tool provides accurate mineralogy and total organic carbon from quantitative elemental spectroscopy. The tool allows for the detailed description of complex reservoirs by measuring multiple elements.

Baker's high-definition induction log service provides formation resistivities at six depths of investigation ranging from 10 in. to 120 in. This is useful in thinly bedded reservoirs and in the presence of deep drilling fluid invasion. And its Nautilus Ultra service provides a comprehensive logging suite that can withstand high pressures and temperatures.

Formation testers also have seen major enhancements. Halliburton recently introduced its CoreVault system, which keeps rock samples in a sealed container, preserving 100% of the fluid in the core for analysis. This enables more accurate estimates when making decisions about the reservoir.

Schlumberger's Quartet downhole reservoir testing system allows operators to isolate, control, measure and sample their reservoirs in a single trip. The system combines several tools, including the SCAR inline independent reservoir fluid sampling tool, which collects samples directly from the flow stream. Wireless telemetry allows the operator to interact with the downhole tools.

WellDog and Shell recently announced a collaboration to commercialize WellDog's downhole testing technology, which uses Raman spectroscopy to measure chemicals at specific depths using lasers. Industry response to date indicates that the tool holds the promise to help operators optimize completions in shale plays.

Overall, the pace of technological change seems to reflect the pace of the industry in general. And the lines are beginning to blur. "Going from the grand scale to the pore scale is becoming more routine," Leveille said. "It's truly geoscience as opposed to the various discrete disciplines, and it's already getting mixed in with engineering." As for the next few years? "It's going to be a wild ride," he said. E&P

2015 MEA AWARD CATEGORIES

ALL-NEW CATEGORIES

ONSHORE RIGS: pad drilling, mud pumps, power generators, top drives, rig equipment, BOPs, pipe handling and automation

WATER MANAGEMENT: brine, frack water, produced water, flocculation, reverse osmosis, recycling, ultrafiltration, oxidation, storage, wastewater, metal removal and biocides

SUBSEA SYSTEMS: christmas trees, BOPs, tiebacks, manifolds, processing (separation, compression and boosting), SSIVs, SURF (subsea umbilicals, risers and flowlines), pipelines, power supply and controls, ROVs/AUVs, IRM (inspection, repairs and maintenance), intervention, flow assurance, and metering and monitoring

FLOATING SYSTEMS AND RIGS: floating production and topsides systems and designs (FPSO/FLNG/GTL/ FSO/TLP/ spar/ semi-submersible/hybrids), drilling units (rigs/drillships/ hybrids), turrets, loading and offloading, mooring and positioning, people and cargo transfer, and safety and evacuation

MARINE CONSTRUCTION & DECOMMISSIONING: vessels and systems, pipelay and flowlines, platforms, subsea construction, marine transportation and installation, heavy lift, hook-up and commissioning, structure removal, intervention, and workovers

EXPANDED CATEGORIES

EXPLORATION: potential fields, geochemistry, seismic acquisition (land and marine), processing algorithms and software, reservoir characterization, interpretation software, and hardware

FORMATION EVALUATION: wireline logging, core analysis, cuttings analysis and well testing hardware and software

HSE: hardware, software and methodologies related to health, safety and the environment

DRILLBITS: natural diamond, impregnated, PDC, bi-center, milled tooth, hybrid, insert and hammer

DRILLING FLUIDS/STIMULATION: chemicals, drilling mud, additives, flow enhancers and green systems

DRILLING SYSTEMS: LWD/MWD, motors, coring, tool joints, fishing tools, drillpipe, whipstocks, subs, packers and rotary steerable systems

HYDRAULIC FRACTURING/COMPLETIONS: surface equipment, frack trees, hhp, plug-and-perf, sliding sleeves, cementing, perforating, horizontal drilling, stages, frack balls, zipper fracks and microseismic

INTELLIGENT SYSTEMS AND COMPONENTS: digital oil field, "smart" and real-time control and monitoring systems, remote operations, automation, intelligent agents, "big data," and networks & software

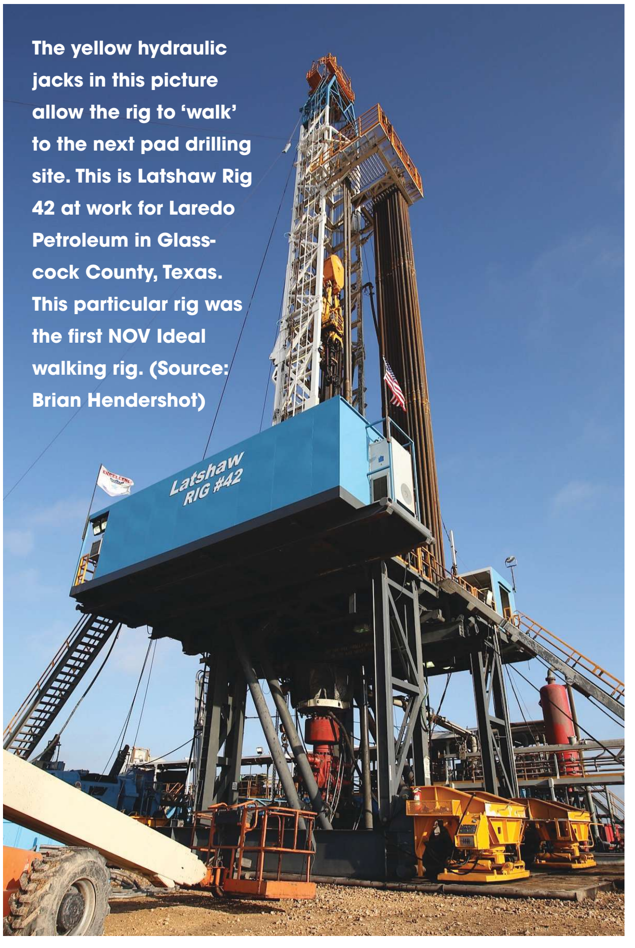
IOR/EOR/REMEDIATION: advances in all IOR/EOR and remediation methods, artificial lift systems, reservoir monitoring and modeling, stimulation, workovers, chemicals, CO_2, environmental advances, and containment and response systems

E&P

Drilling reaches new depths

Key technologies are revolutionizing the drilling environment.

Compiled by **Rhonda Duey**, Executive Editor, and **Mark Thomas**, Editor-in-Chief



The yellow hydraulic jacks in this picture allow the rig to 'walk' to the next pad drilling site. This is Latshaw Rig 42 at work for Laredo Petroleum in Glasscock County, Texas. This particular rig was the first NOV Ideal walking rig. (Source: Brian Hendershot)

Drilling technology has not lacked for ground-breaking improvements. Here are some of the game-changing technologies that have altered the drilling landscape.

MPD

As the drilling industry addresses the challenges posed by today's wells, a new approach has been introduced to handle the complexities and difficulties they present. The challenges posed by the need to drill such wells has led to the uptake of managed pressure drilling (MPD) techniques, which use adaptive drilling processes that create a closed loop for the drillpipe and annulus and have become a game changer in drilling the complex and challenging wells of today. MPD allows for early detection of influx or fluid loss and with the inclusion of intelligent control monitoring instrumentation and an integrated choke manifold can provide a degree of automation that can precisely measure and control fluid flow into and out of the well.

First introduced offshore in Asia-Pacific to help overcome drilling issues associated with fractured carbonates, its advantages have since been recognized and adopted rapidly in the last five years due to its applicability to today's drilling challenges. The automated influx or loss detection and control functionality of MPD make it a game changer, resulting in much smaller anomalies because it provides for a proactive rather than a reactive approach to dealing with drilling problems. MPD is an enabling technology in many areas such as offshore West Africa and Brazil, where formations present major drilling challenges. Weatherford is currently working with operators in these regions to bring the benefits of MPD to their operations to increase safety and help reduce hazard mitigation-related drilling costs. The technique also has been extremely beneficial in recent wells in offshore Trinidad, where the operator was experiencing issues with circulation losses and wellbore stability. Using MPD, the Weatherford system was able to help the operator successfully drill and complete wells, reducing drilling-related nonproductive time (NPT) by as much as 50%. These are but a few examples of the MPD applications worldwide.

MPD has evolved from a niche application system reserved for only extreme environments to being considered a go-to approach for many drilling conditions. The technique can minimize risk, reduce the number of trips, decrease NPT and optimize equivalent mud density.

MPD and its advantages have become so widely prevalent in today's well plans that operators are beginning to require it to be installed permanently on deepwater drilling vessels. For example, last year due to its experience in drilling presalt formations in deep waters off West Africa, an operator specified that a drillship under construction be equipped with fully automated MPD-ready facilities. Many others are following suit. As water

UR CONTROL

Onshore completions set records

Advances in technology have shaped the shale revolution.

By **Rhonda Duey,** Executive Editor

Horizontal drilling and hydraulic fracturing are not new technologies. But the combination of the two has kicked off one of the biggest revolutions in oilfield history—development of unconventional reservoirs. Unconventional reservoirs come in many shapes and sizes, but they mostly share the same characteristic of extremely tight formations that will not produce without the induction of fractures. In just a few years hydraulic fracturing has seen enormous strides.

From just a few frack stages a decade ago, companies are now experimenting with "advanced completions" that involve massive amounts of proppant and frack fluid, numerous stages and longer laterals. NCS Energy Services just set completion records of 94 stages and 104 stages in two wells in the Bakken in a multistage coiled tubing completion.

The technology also is expanding, with plug-and-perf operations being performed in cemented liners while ball-actuated sliding sleeves are often the technology of choice in openhole completions. Recent advances in the latter include degradable balls that eliminate problems with balls deforming during the stimulation process.

Proppants also have undergone some changes, though in many of the shale plays operators still use sand rather than ceramic proppants.

Most recently, completions are getting attention as operators attempt to maximize production. Weatherford, for instance, has introduced FracAdvisor, an integrated solution that provides optimized fracture design by calculating frackability along a horizontal or vertical wellbore, field or basin for enhanced telemetry perspectives and a more profitable fracture operation.

The new service analyzes the different attributes gleaned from the logging tools and places them side by side (or above and below, in the case of a horizontal section). At the bottom of the screen the tool shows the typical geometric perf design compared to what it considers to be the optimal design based on the attributes that have been identified.

"We can move where and how long the stages are to maximize the completion using the information to improve fracking like rock with like rock within a stage," said Jim Rangel, manager of petroleum consulting at Weatherford. "That's what this tool recommends." ■

depths of 3,050 m (10,000 ft) become routine, geological complexities such as subsalt formations, rubble zones, fractured carbonate reservoirs and narrow drilling windows become more common, and ultra-HP/HT, pore-pressure and fracture-gradient problems become the norm, so MPD will become the method of choice for tomorrow's drilling operations. This need is made more relevant and real each day by the tightening of regulatory requirements, the high risk involved and the financial impact of operational failure.

RSS

In 1997 the introduction of an effective rotary steerable system (RSS) for directional wells was a step-change for drilling. Directionally drilled wells could now be drilled smoother and faster due to the capabilities and technology advancement that went into the development of the AutoTrak rotary closed-loop steerable system (RCLS). The initial application of this new technology was directed at the high-cost offshore environment. RSS usage increased performance, improved hole quality, changed well design and generated significant value.

The focus on horizontal drilling in unconventional reservoirs created a new need for improved drilling technology. Development of unconventional reservoirs requires exposing as much reservoir as possible to fracture the formation and release the hydrocarbons. These horizontal wells can have lease boundary limitations, so to get maximum horizontal exposure, wells are drilled with a tight radius curve. The buildup rate (BUR) in many unconventional reservoir applications ranges from 10 degrees to 15 degrees per 30 m (100 ft). Previous RSS had a BUR capability that was typically up to 6 degrees per 30 m. Baker Hughes quickly recognized the need for an RSS that could drill higher build rates to deliver or exceed the performance operators had come to expect in conventional directional applications.

The AutoTrak Curve RSS was launched into the market in 2012 as a high build-rate system. From the beginning it was recognized that the drillbit is an integral component to achieve directional objectives, deliver good hole quality and optimize ROP. Key bit design

parameters are matched to the operational parameters of the AutoTrak for optimum directional response and performance. The fit-for-purpose polycrystalline diamond compact drillbits from Baker Hughes improve the build-rate capability of the drilling system while maintaining excellent borehole quality. The AutoTrak Curve RSS can also be run with a Baker Hughes Ultra or Ultra X-treme motor for enhanced drilling performance.

Pad drilling

Pad drilling is not necessarily a new concept. It has been used in arctic environments for years to minimize the impact of drilling operations on sensitive tundra areas.

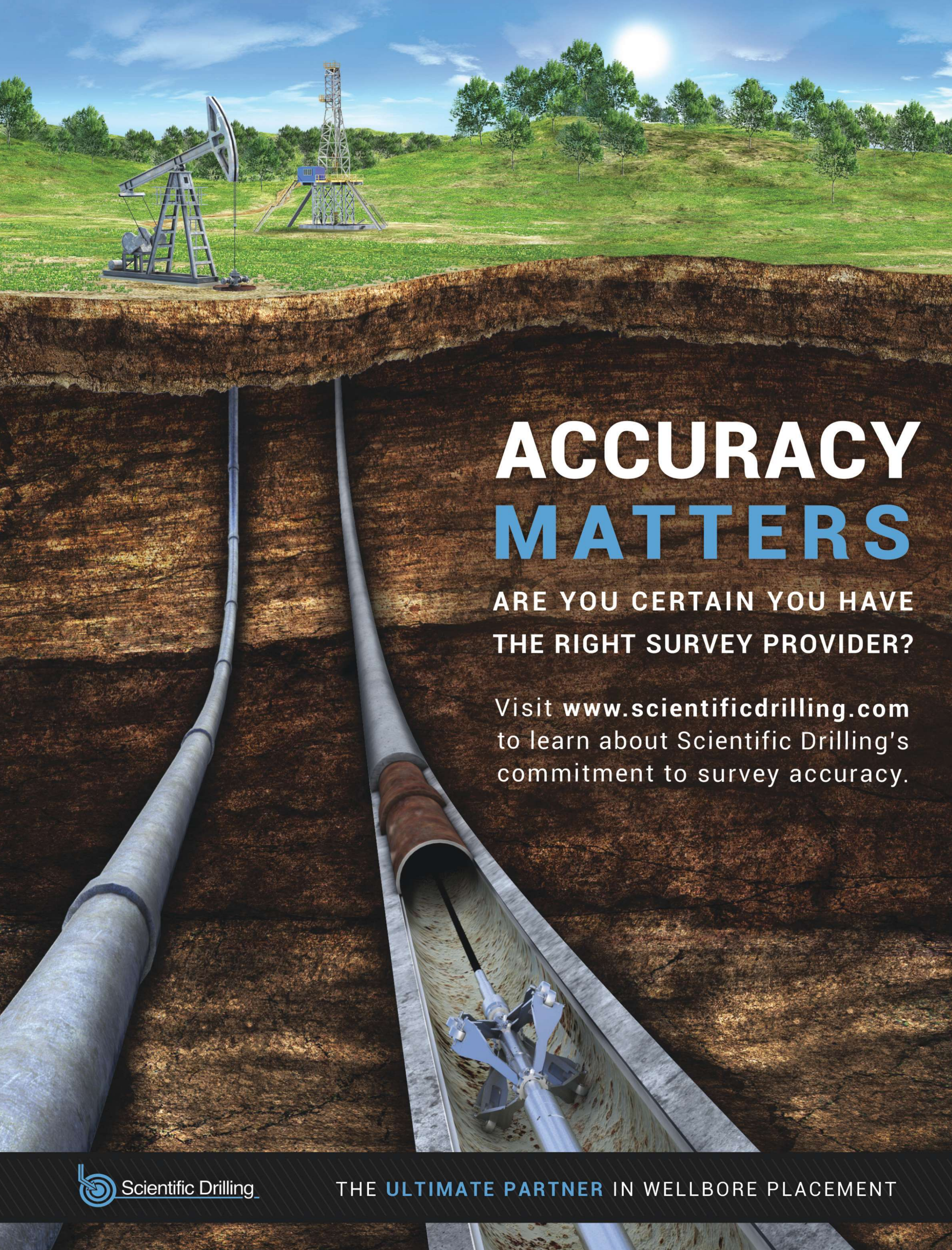
But its utility in unconventional drilling has been revolutionary. These resource plays, which require numerous wells to maximize reservoir exposure and production, benefit from the concept. Along with walking rigs, pad drilling has enabled shale operators to improve drilling efficiency by drilling multiple wells from a single pad.

Prior to the advent of pad drilling, moving a rig from one wellsite to the next required disassembly of the rig, transport and reassembly at the new location. "Today a drilling pad may have five to 10 wells, which are horizontally drilled in different directions [and] spaced fairly close together at the surface," the U.S. Energy Information Administration notes on its website. "Once one well is drilled, the fully constructed rig can be lifted and moved a few yards over to the next well location using hydraulic walking or skidding systems."

Walking and skidding rigs are truly one of the biggest drilling innovations to result from the shale gale. In addition to providing drilling efficiency, they diffuse some of the environmental concerns related to shale development since they enable rapid drilling in a confined space. New rig designs allow the rigs to move in multiple directions, and in the case of Patterson UTI's APEX Walking Rig, the rig can move in a circle with pipe racked back, which provides flexibility for well layout and location constraints.

Fluids

Drilling fluids are constantly undergoing upgrades as new chemistries are tested. One major step-change has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been in the advancement of water-based muds (WBMs) for unconventional plays. WBMs aren't always the best choice for these plays since the reservoirs tend to have clay content, which swells when coming in contact with water. But LWD imaging tools that aid in reservoir characterization aren't useful with oil-based muds.

Newpark Drilling Fluids has recently unveiled its Evolution system of WBMs, which overcomes not only issues with clay formations but also HP/HT conditions and deepwater wells. The formulae minimize environmental impact by reducing cuttings and remediation/disposal requirements while increasing ROP and reducing drilling time and cost.

Automation

The word "automation" is a hot topic across the spectrum in the oil and gas industry today. It's probably most applicable in the drilling arena, where things like pipehandling can easily be assigned to an intelligent system and where safety improvements can be quickly realized. But once "iron roughnecks" and other improvements are in place, what's the next step?

This was the question that the industry initiative to develop a Drilling Systems Automation Roadmap set out to address; this initiative is affiliated with both the International Association of Drilling Contractors and the Society of Petroleum Engineers (SPE). The primary objective was to provide a guideline to the future emergence of drilling systems automation across all aspects of drilling and completions technology. The secondary objective was to inform nonoil and gas industry professionals about the opportunities to support this type of technology development.

The identified technology gaps include:

- Systems architecture, which provides the framework to implement automation in complex systems and takes into consideration the situational awareness of well state, drilling and completion state, automation state, and other situations such as weather;
- Communications, which includes protocol standards and connectivity, with a future that could be defined by the Internet of Things;
- Instrumentation and measurement systems that would provide the necessary input for a fully automated system;
- Drilling machines and equipment that would enable true "factory drilling";
- Control systems that would be able to understand enough about the drilling process to automatically adjust parameters and provide adaptive levels of human and machine interaction;
- Simulation systems and modeling, in which accurate simulations drive instructions to machines;
- Human systems integration, which addresses the changing role of humans at the wellsite; and
- Certification and standards to identify which industry standards are most applicable to the automation process.

By 2025 the vision is to have well plans updated into an interoperable system that automatically drills the right well in the right location, installs the casing and isolation system according to the drilling plan, completes the well and updates remote operators in real time to changes taking place in the well.

The deepwater *Pacific Sharav* drillship was delivered by Pacific Drilling to Chevron earlier this year and began a five-year contract in the GoM in August. It was built to the operator's own specifications, with the dual load-path Samsung 12000-design vessel specially modified to accept a DGD system. (Source: Pacific Drilling)

Offshore

In the offshore rig sector the market's slowdown in 2014 has changed the dynamics for the main players after a period of several years in which they made hay while the sun shone and invested billions of dollars in high-specification newbuild floating and jackup units.

The ongoing slowdown in terms of utilization rates and day rates has prompted several of them to delay or not exercise options on further newbuild floaters they have with the Far East shipyards—Atwood Oceanics, for example, recently confirmed it was delaying the delivery of two

such units. But with the near-term situation for the jackup market in better shape and industry fundamentals indicating that the mid- to long-term future for high-spec rigs in both shallow, deep and ultradeepwater will remain positive, the rig contractors are not panicking. With a substantially upgraded high-spec rig fleet estimated to be worth about $16 billion, Transocean, for example, is still in a prime spot to benefit from the continuing increase in deepwater drilling over the coming years.

With deals such as its four-rig arrangement with Shell—expected to generate a 12% initial rate of return over the initial 10-year contracts—the company has a contract backlog reaching nearly $3 billion. Despite the shadow still cast by the Macondo tragedy in the Gulf of Mexico (GoM), which leaves it exposed to settlement payouts and lost revenue totaling an estimated $4 billion, Transocean is fully expected to sail on.

Ultradeepwater day rates are currently at a range of $375,000 to $500,000 due to the current excess rig supply situation, but some units are still coming onto the market now at day rates agreed upon a year or more ago well over the $600,000 mark. Opinions vary as to exactly when the deep and ultradeepwater rig market will start to strengthen again next year, but strengthen it will, especially with a significant number of older floater units nearing the end of their working lives.

Lower spec units at risk

According to Transocean's latest presentation, it is the older, lower specification floating rigs that are most at risk, with 160 of them more than 30 years old. Customers prefer high-spec rigs, it stated, as they are perceived to be more reliable and have better performance. The jackup market is in the same boat, with 216 units more than 30 years old and with customers actively replacing lower spec rigs with available high-spec alternatives.

According to Noble Drilling, a leveling off of the decline in day rates could occur in first-half 2015, with "early signs of improvement" already occurring, according to Jeffrey Chastain, Noble's vice president of investor relations, speaking during its most recent analyst presentation.

Chastain outlined the company's belief that this would occur based on the following:

- Numerous ultradeepwater contract awards during second-quarter 2014;
- GoM, Brazil, and West Africa driving improvement;
- New deepwater discoveries confirming attractiveness of areas;
- Stability of jackup sector through the first half of 2014;
- Early signs of capacity build in some regions;
- New capacity additions of concern—140 rigs on order;
- Standard vs. new capability; and
- Level of speculative orders a medium-term concern.

Another deep- and ultradeepwater-focused player, Pacific Drilling, chose recently in its own investor presentation to highlight some of what it sees as key industry trends impacting the offshore drilling sector:

- Challenges of remote drilling sites;
- Drilling deeper and with longer offsets;
- Greater drilling efficiency to reduce total well costs;
- Advances in well construction techniques, e.g. intelligent completions;
- More demanding downhole environments, e.g. HP/HT drilling;
- Increasingly demanding regulatory climate; and
- Increased client focus on safety.

It also pointed out that 90% of high-spec floaters actually operate in less than 2,286 m (7,500 ft) water depth on average, which highlights the push by operators to use the units that they feel will give them the best drilling efficiency.

High-spec tech

So just what are the latest high-spec units actually capable of? One unit that began operations during 2014 is a great example of what is considered to be a game-changing rig.

With conventional drilling in many cases not allowing economic completion of deep wells, dual-gradient drilling (DGD) is a technology whose time has come after decades of industry R&D.

Bits positioned to provide step-change in drilling performance in difficult formations

Contributed by **Schlumberger**

Smith Bits, a Schlumberger company, recently launched StingBlade conical diamond element bits. StingBlade bits have Stinger conical diamond elements optimally placed across the bit face, which are innovative polycrystalline diamond compact (PDC) cutting elements with a conical shape and thicker diamond layer. The conical shape enacts a highly concentrated point load on the formation, fracturing high compressive-strength rocks more efficiently while also generating less torque and vibrations than a conventional flat PDC cutter. The thicker diamond layer enhances impact strength and wear resistance. When placed across the bit face, Stinger elements enable StingBlade bits to yield a step-change in drilling performance over existing roller cone and PDC bit technologies, including significantly improved footage and ROP, higher build rates with better toolface control in directional applications, bottomhole assembly shock and vibration mitigation from enhanced bit stability, and larger cuttings for more accurate surface formation evaluation at the rig site.

Stinger elements are placed across the bit face of StingBlade bits based on the operator's application requirements and drilling performance objectives. StingBlade bits can have Stinger elements used in conjunction with conventional PDC cutters, or a StingBlade bit may contain only Stinger elements. Due to the enhanced impact strength of Stinger elements, they may be placed in areas where impact damage is observed on baseline bits run in the same application. Regardless of the application, all Stinger elements on StingBlade bits are oriented to do a significant amount of work on the cutting structure, typically being on profile and with their own unique path to fracture formations.

An operator planned to drill a 12¼ -in vertical section through the challenging Dampier, Heywood, Baudin Marl and Wollaston formations in the Browse Basin offshore Australia. These formations are composed of interbedded hard limestones and chert with high compressive strengths, which induce heavy damage to conventional PDC bits. This damage can slow ROP and requires the operator to pull bits prematurely, requiring additional time to drill the section.

The operator used a StingBlade bit to drill 1,516 m (4,974 ft) at 11 m/hr (36 ft/hr), equaling 97% more footage than the best run in the same section of an offset well while also achieving a 57% improvement in ROP. A second StingBlade bit was used to drill the remaining section to total depth at an average ROP of 16 m/hr (52 ft/hr). The two StingBlade bits enabled the operator to save more than five days of drilling time in the section.

There have been more than 250 runs in 14 different countries, both onshore and offshore, in conventional and unconventional applications in North, Central and South America; the North Sea and Europe; and Africa, the Middle East, Russia, Southeast Asia and Australia. An average of all runs has shown a 55% footage improvement with a corresponding 30% ROP improvement. In addition, many StingBlade bits have achieved directional objectives, receiving positive feedback from directional drillers and operators with respect to steerability and toolface control. ■

Taking advantage of the long riser in the water column as a tool for managed-pressure drilling (MPD), it has now emerged as a highly desirable way of implementing MPD in deepwater wells.

This year saw Pacific Drilling's *Pacific Sharav* delivered and start drilling for Chevron in the GoM, carrying out operations in the Keathley Canyon area. The drillship, built to Chevron's own exacting specifications, will work under a five-year, $558,000/d contract for the operator. The drillship is an upgraded dual load-path Samsung 12000 design, a dynamically positioned unit modified to accept a DGD system. It is able to operate in moderate environments in water depths of up to 3,658 m (12,000 ft), drilling wells to a total depth of 12,192 m (40,000 ft).

Chevron's vice president of deepwater exploration and projects in North America, Steve Thurston, stated in a press release earlier this year that Chevron worked with Pacific Drilling "from the very early stages in the design and specifications of the drillship capabilities to ensure the right fit with our drilling program and needs, building on lessons learned and capitalizing on a long-standing business relationship."

The drillship and its sister vessels are described by Pacific as featuring the most advanced drilling technology in the offshore industry, including dual load-path capability and the latest in DGD technology. The vessel and the technology onboard is the culmination of more than 15 years of R&D.

Dual-gradient 'prime time'

Robert Ziegler, head of Wells & Production Technology at Petronas, agrees that this technology's time is right now. In his opinion, DGD "is ready for prime time."

Presenting at the recent SPE Annual Technology Conference & Exhibition in Amsterdam, he pointed out that while plenty of innovation has been achieved in the area of pipe and riser handling on the latest sixth-generation rigs, the actual drilling process has not changed a great deal compared to earlier rig generations.

Among the leading deepwater drilling operators, the need for MPD in deepwater is becoming more and more apparent due to the wells that need to be drilled now and into the future, he said. With DGD taking advantage of the long riser in the water column to implement MPD in deepwater, Ziegler went on to highlight the ability to retrofit DGD systems using electrically powered mid-level riser pumping technology to existing deepwater rigs.

This is not just a concept, however—one such retrofit (on the *Scarabeo 9* semisubmersible) has been performed and field-proven on three commercial ultradeepwater exploration wells in the U.S. GoM. The pumped riser technology extends the benefits of riserless drilling by taking away mud overbalance at the mudline in deepwater drilling operations, according to Ziegler.

Noble Drilling's *Globetrotter II* deepwater drillship is a latest-generation dual-activity drillship but is built specifically to maximize drilling efficiency along with a reduced offshore footprint. (Source: Noble Drilling)

Thinking small

An innovative solution for smaller modular offshore rigs also progressed during 2014, with engineering house William Jacob Management (WJM) tasked by Pemex to bring down rig deployment costs and increase speed to production. The company was contracted in 2012 to provide fast-track engineering and design services for two platform drilling rigs to eventually be used for operations on the heavy oil Ayatsil Field in the Bay of Campeche offshore Mexico. WJM successfully completed the design work for the two 3,000-hp modular offshore rigs for Pemex in the second quarter of this year.

The platforms have an eight-leg jacket and deck and weigh about 11,650 tonnes for installation in 115 m (377 ft) of water. The company says its modular offshore rig facility (MORF) design is the first of its kind in size and configuration.

The rig's individual modules can function like a set of interlocking building blocks and be lifted in place by "leapfrog" cranes, which enables it to be configured for drilling and integrated production below.

The unit design has two main modules: the drilling equipment set (DES) and the drilling support module (DSM). The DES has the capacity to access 15 wells arranged in a 3-by-5 matrix and is capable of drilling wells up to 7,620 m (25,000 ft). The DSM is equipped with a pair of rig cranes that streamline installation. Thanks to their compact size, the modules can be delivered using the client's service fleet and then assembled using a combination of crane systems. The blocks containing the cranes are installed using the leapfrog crane package.

Once the rig cranes are operational, the installation is then completed using the rig's own cranes, effectively eliminating the need to contract a lift barge. E&P

Addressing ever-evolving production challenges

Latest technologies aid decision-making and boost efficiency.

Compiled by **Bethany Farnsworth**,
Associate Managing Editor

For every record-busting lateral length or ultradeepwater discovery, production technology has to evolve to meet the new challenges, helping operators keep an eye on efficiency to get the most bang for their bucks. In the last five years, trends have emerged to improve real-time monitoring, artificial lift and EOR. As these technologies pick up speed, the industry is keeping pace developing each technology to address new production challenges.

DAS

Fiber-optic sensing for downhole monitoring has been used since the '90s. Measurements came from single-point sensors, which provided data—temperature or pressure—from one particular point in the well and used the fiber-optic cable to transmit the information. Advances in fiber-optic technology, however, have expanded the range of applications for these cables.

Distributed acoustic sensing (DAS) allows fiber-optic cable to collect acoustic data along its entire length, creating a continuous sensor that can be as long as 50 km (31 miles). The sensitive, cost-effective technology provides real-time monitoring of well operations for the life of the well, including fracturing operations, leak detection and equipment condition monitoring.

DAS has been gaining ground in the industry over the past five years, making the transition into permanent flow monitoring applications and into development for subsea work. Shell and QinetiQ notably teamed up in 2009 to focus on DAS product development, performing the first field trial in February 2009 and announcing a collaboration in 2010 to exploit QinetiQ's OptaSense DAS systems.

Late last year, Shell and OptaSense revealed plans to develop the industry's first fully marinized and qualified DAS system. The Subsea-DAS system will be deployed in water depths of up to 3,048 m (10,000 ft) and will be able to provide acoustic data for myriad subsea and deepwater applications, including in-well

Shell and OptaSense are developing the first fully marinized and qualified DAS system, which will require the reengineering of OptaSense's existing DAS interrogator unit to fit into a pressure canister. (Source: OptaSense)

monitoring, subsea assembly condition monitoring and permanent reservoir monitoring. According to a press release, the marinization process will require the reengineering of OptaSense's existing DAS interrogator unit to fit into a pressure canister and testing of the modified opto electronics to ensure they meet the temperature, vibration, shock and electrical certifications required for subsea technology.

Most recently, in September 2014, the collaboration announced the delivery of the first permanent DAS in-well production flow monitoring system. The DAS-Flow system constantly monitors a well through on-demand measurements of flow along the length of the wellbore, a press release said.

"There is a high potential optimization value to be realized within the industry with the advent of more detailed flow information across individual well production and injection zones," Magnus McEwen-King, managing director of OptaSense, said in the release.

Silixa Ltd. also is active in the DAS market with its Intelligent DAS (iDAS) technology, with an investment in 2012 from Statoil Technology Invest and Chevron Technology Ventures to begin global commercialization of the technology.

Microseismic

Microseismic monitoring is a relatively new commercial process in oil and gas, and as it gains traction, companies have been working to optimize its use in completions evaluation. Rather than simply spreading perforation clusters out evenly, operators have found that using data to design the completion can help provide the most contact with the reservoir. Traditional frack design can leave some clusters unreached by fluid—where microseismic events are missing during fracturing. Operators can use microseismic monitoring to plan where to place clusters or to determine which areas will take proppant more easily, with less pressure.

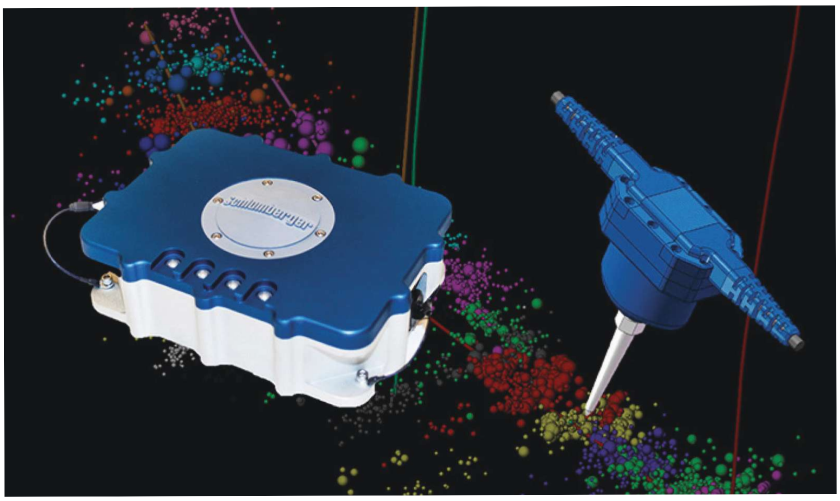
MicroSeismic Inc., the company that commercialized surface microseismic monitoring, continues to push forward in the industry. The company released several new technologies this year for real-time analysis for completion evaluation. With analysis in real time, operators can make adjustments at the well site to optimize production.

MicroSeismic Inc. also has recently launched technologies to optimize completions and manage reservoirs stage by stage. PermIndex, a microseismic-based permeability tool, gives permeability estimates for each frack stage as well as data-driven constraints for reservoir simulation to improve production forecasting. Using radial pressure fronts of microseismic events during fracking, PermIndex calculates effective system permeability and helps operators understand the reservoir permeability on a stage-by-stage basis without needing to run a production log. The FracRx service combines microseismic data with pump and geological data, which allows the technology to track the growth of the fracture network in all directions and then discern how the fracture area grows with injected fluid volume, a product announcement said. The goal is to increase asset values by optimizing the treatment of each well. Operators can identify and react to fault reactivation, better understand drainage near the wellbore, evaluate whether the treatment is opening existing fractures or creating new ones and make certain that the treatment is staying in zone.

MicroSeismic Inc. certainly isn't the only player in the game, though. Schlumberger launched a new microseismic surface acquisition system this year to optimize completion design: MS Recon. The system is for surface and shallow grid microseismic surveys and is designed to improve signal-to-noise ratio during acquisition for enhanced imaging of the fracture geometry. MS Recon has a geophone accelerometer and ultra-low noise electronics for a wide range of signal detectability, according to a product announcement. Field trials have shown that the MS Recon improves sensitivity to smaller microseismic events compared to a conventional system.

Pinnacle Technologies, a Halliburton service, came up with a tool that combines microseismic receivers with the company's downhole tiltmeter sensors to determine fracture height. FracHeight uses the measurements of formation movement associated with fracture dilation in addition to the microseismic data to help identify the cause of microseisms.

ESG Solutions integrated downhole microseismic with surface and near-surface induced seismicity arrays in its Hybrid Seismic Sensor Network to evaluate large- and small-scale seismicity for hydraulic fracture monitoring. This allows the system to capture large magnitude events and time-synchronize the data with downhole microseismic data, giving operators new information about fault activation and fracture effectiveness.



The MS Recon system is designed to improve signal-to-noise ratio during acquisition for enhanced imaging of the fracture geometry. (Source: Schlumberger)

"Accurate measurement of larger events allows clients to correctly assess the role of faults when interpreting fracture behavior and reservoir deformation," said Dr. Ted Urbancic, executive vice president of energy services at ESG Solutions, in a press release. "Larger events release more energy into the reservoir. In multiple cases, we have seen a handful of these larger events representing as much as 70% of the total seismic energy released over the stimulation program. This has a profound effect on the way operators evaluate their treatments and presents a unique view of hydraulic fracture stimulations not previously considered."

Game-changing technology: ESP system for unconventional plays

Contributed by **Baker Hughes**

Drilling, completion and stimulation activities in the unconventional resource plays have continued to mature over the last 10 years, increasing well construction efficiency by orders of magnitude. However, only recently have operators turned the same level of attention to the production phase of unconventional oil plays.

Unlike conventional oil wells, the production decline from unconventional reservoirs is dramatic—going from IP rates of 3,000 bbl/d or more to less than 50 bbl/d in just a year or two. After initially flowing at a controlled rate to unload the stimulation fluids, these wells require artificial lift to produce the oil-rich fluid.

Traditionally, producers install an electrical submersible pump (ESP) system or other higher-flow lift methods when production is high and then switch to a rod lift pump when the production rates decline. This approach was necessary because there was no solution that could handle the full range of production.

The Baker Hughes ProductionWave FLEXible production solution allows operators in unconventional oil plays to install ESP systems that deliver the same benefits as rod lift systems but with better economics and a smaller environmental footprint.

ProductionWave solutions with FLEXPump technology can operate reliably in a wide flow range from 2,900 bbl/d to 50 bbl/d to cover the entire productive life of a well. ESP systems also are more deviation-tolerant, allowing greater asset recovery in horizontally completed wells and eliminating the potential tubing wear and reliability issues associated with rod systems in deviated wellbores. Recently introduced FLEXlift Curve tight-radius ESP technology allows the system to pass through a 15-degree bend per 30 m (100 ft) to land closer to the producing zone and deliver higher recovery rates.

The production stream in unconventional oil plays can contain high associated gas, fracture fluids and proppants. Wells in these plays also are prone to the buildup of scale, paraffin and other deposits and can typically yield emulsified fluids. These conditions can cause problems with artificial lift equipment, including gas locking, abrasive wear and pump plugging. ProductionWave systems address these challenges with a combination of technologies designed to increase system reliability, efficiency and flow assurance.

The presence of gas in the production stream is one of the most challenging issues in unconventional oil wells. ESP systems with advanced technology designed specifically to address the gas entrained in the fluid offer a better alternative. A full suite of gas mitigation solutions improves overall system reliability and ensures operators can keep wells on production.

ESP systems also reduce the potential for emissions from unconventional wells. Since the majority of ESP components operate thousands of feet below the surface, safety concerns are greatly reduced. ■

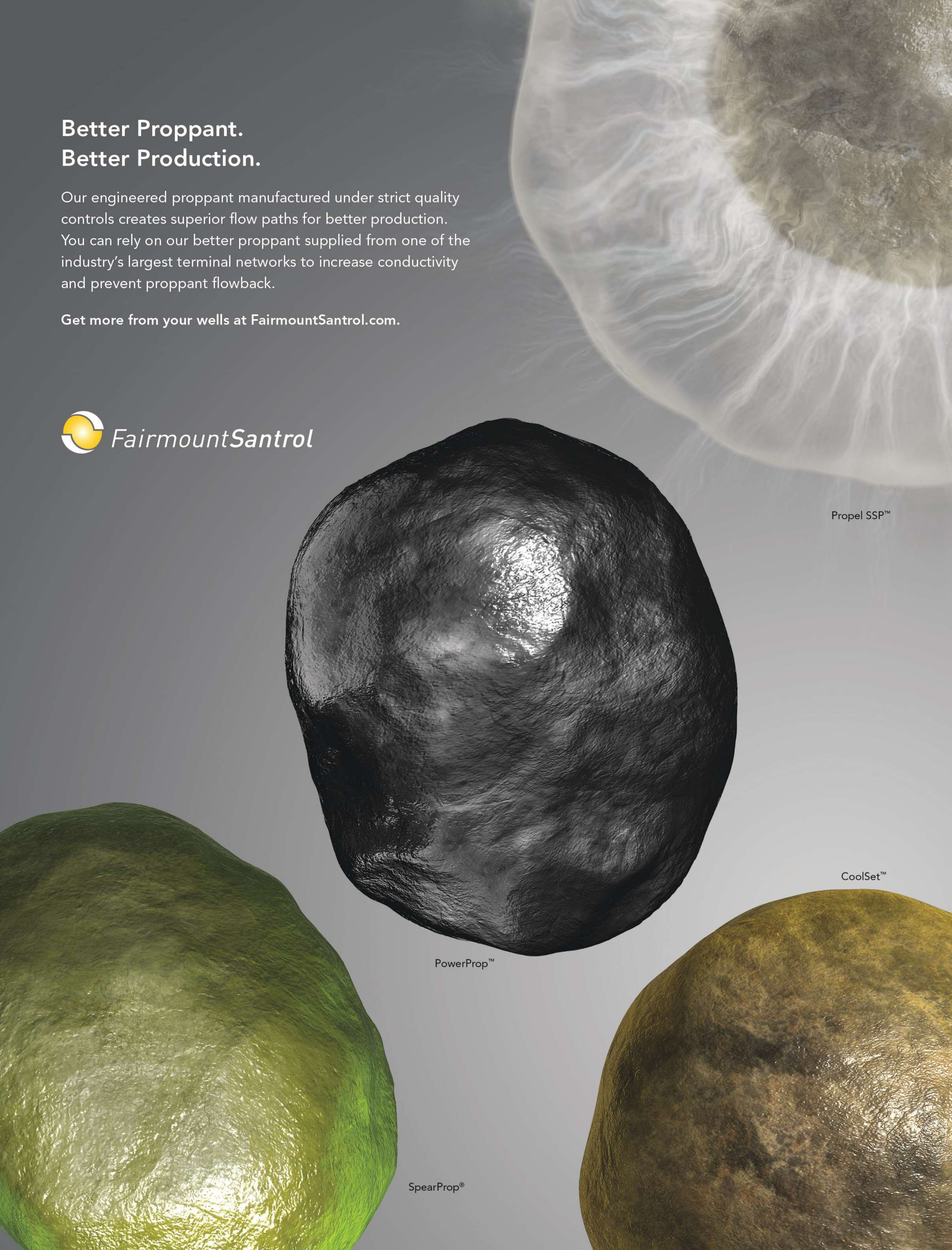
ESP advances

Electric submersible pumps (ESPs) have long been used in conventional wells for artificial lift, and as the industry is confronted with new lift challenges, innovators are adapting ESPs to solve problems in harder-to-produce areas.

One disadvantage of ESPs is the need for frequent intervention. Offshore, the limited availability of workover vessels complicates the matter. To reduce intervention time, cost and nonproductive time, rigless ESP stings have been adopted in the past few years. The technology was developed by Artificial Lift Co.—now AccessESP—and ConocoPhillips and commercialized in 2010. The first one in the Middle East was installed at a Saudi Aramco-operated field in 1,865 m (6,119 ft) of water by Artificial Lift Co. in 2012—an advance noted in the *E&P* year-end production review that year.

The Advantage Rigless ESP System from AccessESP is a through-tubing, slickline-conveyed lift system. The Advantage system includes a 134-hp permanent magnet motor and the company's wet connect system. This year, the company deployed its system for Total E&P Congo in the Republic of Congo. Total plans to include the Advantage system in future wells, a press release said.

Baker Hughes, which formed the Subsea Production Alliance this year with Aker Solutions, has taken a rigless ESP system into the deepwater of the Gulf of Mexico (GoM). In May, the company brought online two subsea ESP systems at the Cascade Field, operated by Petrobras America Inc. in the Lower Tertiary trend of the GoM. According to a press release, the subsea boosting system is in 2,500 m (8,200 ft) of water and employs two ESP systems that operate hydraulically in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series but electrically in parallel. They're housed in a replaceable cartridge placed on the seafloor, and no rig is needed for intervention. The system's designed to a working pressure of 12,500 psi, flow rates from 3 Mbbl/d to 20 Mbbl/d and 1.3 MW.

"We have successfully installed in-well and seabed ESP boosting systems offshore Brazil, in the Gulf of Mexico, in Asia-Pacific and in the North Sea," said Peter Lawson, Baker Hughes director of artificial lift technology, in the release. "This latest successful deployment of subsea ESP systems continues to increase industry confidence in ESP technology as a critical part of subsea production systems."

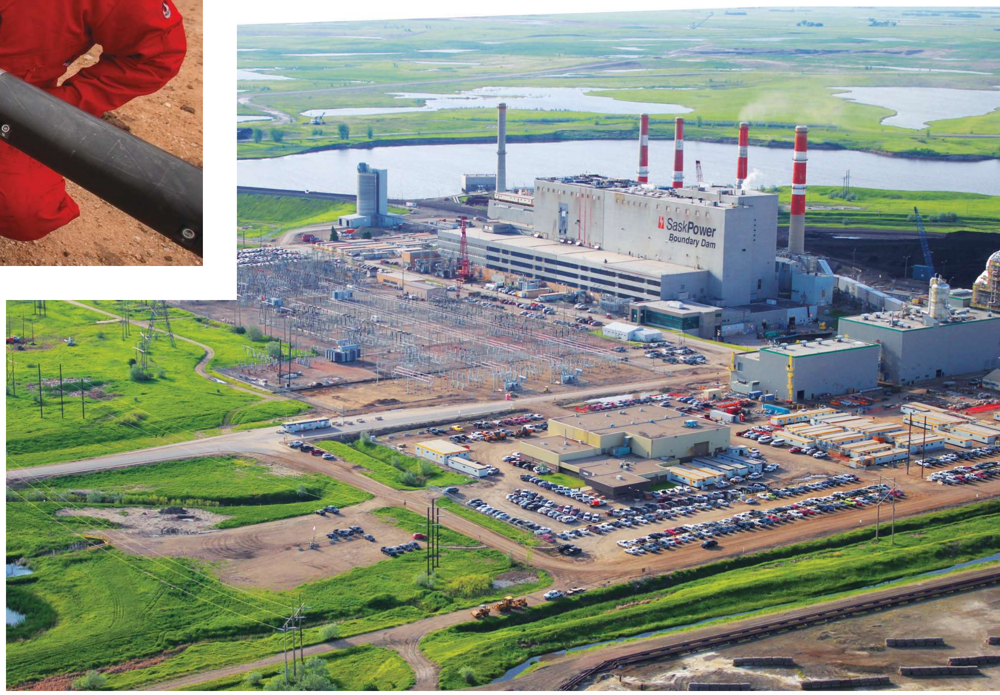
EOR

Though CO_2 EOR has been applied to reservoirs for decades, next-generation solutions have more recently been the focus of R&D with the goal of applying CO_2 EOR to new areas, such as residual oil zones and offshore fields. In 2010, the U.S. Department of Energy chose seven next-generation CO_2 EOR research projects that are now in various stages of progress. Four of these projects are working on techniques for mobility control of the injected CO_2, including two using nanoparticle-stabilized foams. The others focus on CO_2 injection for residual oil zones or developing simulation and modeling tools for CO_2 EOR.

Microbial EOR also is being explored. DuPont's MATRx EOR technology uses microbes and nutrients customized for each oil reservoir. The process exploits the native microbe population to maximize oil recovery by identifying microbes in each reservoir that facilitate bioplugging and reduce residual oil saturation, according to the company. The reservoir can then be inoculated with the favored microbes.

Glori Energy has extended its technology partnership with Statoil to optimize and expand its AERO System. The system stimulates the naturally occurring microbes in a waterflooded field's reservoir to improve water sweep and oil mobility. The system activates specific microbes that reduce interfacial tension between oil

LEFT: Artificial Lift Co. employees work onsite at a ConocoPhillips West Texas well to successfully pull and reinstate its Advantage Rigless ESP System. The system has been in continuous service for more than 180 days. (Source: AccessESP) BELOW: SaskPower's Boundary Dam coal-fired power plant in Saskatchewan, Canada, is the world's first large-scale power station with CCS technology. (Source: SaskPower)



and water. Biomass from microbial growth is produced where the oil is trapped, which results in changes of water flow patterns at the pore level and frees up more pathways for oil flow.

CCS

Five years ago, organizations like OPEC and the International Energy Agency predicted in their 2009 yearly outlook reports that carbon capture and storage (CCS) technology would become increasingly important in the coming years. Though large-scale commercialization and adoption is slow, progress is indeed being made.

Capturing CO_2 from power plants has environmental benefits, and combined with the economic benefits of using the CO_2 for EOR purposes, the CCS technology that has long been available is being put into use in larger applications. In September, SaskPower's Boundary Dam coal-fired power plant in Saskatchewan, Canada, began capturing CO_2, making it the world's first large-scale power station with CCS technology. The plant is expected to capture about 1 MMmt of CO_2 per year, which will be injected into nearby oil fields for EOR.

The Global CCS Institute recently released its annual review of the CCS sector, which said that the construction and operation of CCS facilities across a range of industries has doubled since the beginning of the decade. Mississippi and Texas are anticipated to launch CCS facilities in the power sector in 2015 and 2016, respectively. Mississippi Power's Kemper County Energy Facility in Mississippi will use a precombustion capture technique, while the Petra Nova Carbon Capture Project at NRG Energy's W.A. Parish power station in Texas will demonstrate a postcombustion technique. Kemper County, Petra Nova and Boundary Dam are all using capture methods from different technology suppliers.

"With large-scale CCS power projects now a reality, an important milestone in deployment of the technology has been achieved," The Global CCS Institute said in "The Global Status of CCS: 2014" report. "This means that it is time to move discussion onto how CCS can best be deployed as part of a least-cost approach to climate change mitigation. We can now move on from arguments about its 'experimental' nature or that it has not yet been applied at scale to fossil fuel power plants."

With a few more years and some more investment—Kinder Morgan Energy Partners just invested $1.7 billion to build new CCS projects for EOR use in the Permian Basin, and NRG's Petra Nova project was estimated at $1 billion—CCS could be the game-changer the industry's been waiting for it to be. E&P

Far from idle

Shipyard activity remained high in 2014 as projects kept rolling in and deliveries rolled out.

Jennifer Presley, Senior Editor, Offshore

In just a few short weeks, a new year will arrive and bring with it an end to a very busy 2014 for many in the industry. There are many uncertainties in the year to come, and questions and concerns cloud the horizon, making next steps difficult to predict. But for some the view of 2015 is clear.

In late October, Loh Chin Hua, CEO of Keppel Corp., noted in the company's third-quarter 2014 report that, "although fears of a short-term surplus in oil supply outstripping demand growth amidst an uneven global recovery have led to the recent fall in oil prices, they have not altered sound industry fundamentals. E&P investments have to increase to keep up with global oil demand set to rise by 1.1 MMbbl/d in 2015." He added that oil prices should recover and stabilize at a level that is comfortable to oil producers.

This is a position that echoes an earlier statement issued in August by Sembcorp Marine in its industry outlook when it noted that there is a strong underlying trend toward high-specification harsh-environment jackup rigs as well as deep and ultradeepwater floating units, adding that its pipeline for new projects is "encouraging" based on robust levels of inquiries.

For three of the largest builders of offshore vessels—Keppel Corp., SBM Offshore and Sembcorp Marine—2014 was a year full of deliveries and new contracts set to keep the projects pipeline flowing through 2017. A few highlights for each company follow.

Keppel Corp.

As one of the industry's leading designers, builders and repairers of high-performance mobile offshore drilling units, Singapore-based Keppel FELS (a subsidiary of Keppel Offshore and Marine, a wholly owned company of Keppel Corp.) offers a portfolio of proprietary designs and floating solutions for a wide range of operating environments.

Its KFELS B Class of jackup rigs entered the market in 2000 and has since gone on to become one of the company's most popular designs. In February the company secured contracts from two different operators for a total of four B Class rigs.

UMW Drilling 8 signed a contract for its third B Class rig worth $218 million. The first jackup—UMW NAGA 4—was delivered in February 2013; the second—UMW NAGA 5—is expected to be completed in 2014. Expected delivery date for the company's third B Class rig is third-quarter 2015 and is the 75th B Class rig ordered since 2000, according to a company release.

Fecon International Corp. secured contracts with Keppel FELS for three Class B rigs worth $650 million. As a new player to the offshore oil and gas industry, Fecon will use the new rigs to further its strategic growth plans into Africa, Middle East and Southeast Asia.

The cost-effective and high-performance KFELS B Class rig is able to operate in water depths of up to 122 m (400 ft) and drill to 9,144 m (30,000 ft) deep. Customized to Fecon's requirements, the three jackup rigs will each have a full 15,000-psi BOP system, 23-m (75-ft) cantilever outreach and be able to accommodate 150 persons, a company-issued release said.

In August the company delivered the XLE-2 class jackup rig to Maersk Drilling. The *Maersk Interceptor* is the world's largest jackup rig, according to Maersk. It is the second of four ultraharsh-environment jackup rigs to enter the Maersk Drilling fleet. The remaining two rigs are set for delivery in 2015 and 2016. The *Interceptor* commences drilling this month in the Ivar Aasen Field in the Norwegian North Sea for Det norske oljeselskap ASA. The XLE rig has a leg length of 206 m (678 ft) and is designed for year-round operations in the North Sea in water depths up to 150 m (492 ft). According to Maersk, uptime and drilling efficiency are maximized onboard the *Interceptor* through dual pipehandling. While one string is working in the wellbore, a second string (e.g. casing, drillpipe or bottomhole assembly) can be assembled/disassembled and stored in the setback area, ready for subsequent transfer for use in the wellbore and reducing nonproductive time. The drill floor features Multi Machine Control—a fully remotely operated pipehandling system allowing all standard operations such as stand building and tripping to be conducted without personnel on the drill floor, ensuring a high level of consistency across crews and an improved efficiency.

In October, the company announced that it will build the KFELS Super B class of jackup rig for $240 million

for BOT Lease Co. that will be operated by Japan Drilling Co. (JDC) based on a lease agreement with BOT. Named the Hakuryu 15, the rig is set for completion at year-end 2016.

A company release noted that what differentiates the Super B Class is its ability to drill to depths up to 10,668 m (35,000 ft) and that the rig's leg structure is uniquely designed to provide enhanced robustness for operations at 122 m water depth. The rig, adapted to JDC's operating philosophy, is engineered to operate in high ambient temperatures and features an offline stand building capability to handle drillpipes efficiently and a high-capacity hook load of 2 MMlb, boosting overall rig performance and productivity.

October was a busy month as Keppel Shipyard secured an FPSO conversion contract for Armada Cabaca Ltd. The yard commenced work on the FPSO conversion for Bumi Armada, which is scheduled to be completed in second-quarter 2016. The FPSO unit will have a storage capacity of 1.7 MMbbl and will be able to handle up to 80 Mbbl/d of oil and 3.4 MMcm/d (120 MMcf/d) of gas handling. Upon completion, the FPSO vessel will be producing for the Angola Block 15/06 East Hub Project located 350 km (217 miles) northwest of Luanda, Angola.

SBM Offshore

For this Netherlands-based company, the design and construction of FPSO vessels is SBM's primary business. Since supplying the mooring system for the first FPSO unit in 1976, the company has been involved in more than 40 FPSO projects worldwide, according to the company. With construction yards in Brazil and Angola, SBM is uniquely positioned to provide its services to the rapidly growing oil and gas industry in both countries.

This past year saw the delivery of two FPSO vessels from each of its yards. In July, the *N'Goma* FPSO vessel sailed away from the Paenal yard bound for its new home in the Eni-operated Block 15/06 offshore Angola. According to SBM, the *N'Goma* was converted from the FPSO unit *Xikomba* that was disconnected from Angola Block 15 in 2011, where it had operated for eight years. The *N'Goma* has a total oil processing capacity of 100 Mbbl/d of oil, gas handling capacity of 3.3 MMcm/d (115 MMcf/d) and water injection capacity of 120 Mbbl/d.

From SBM's Niterói yard, the FPSO unit *Cidade de Ilhabela* left the calm waters of Rio's Guanabara Bay in September for final verifications and sea trials. The vessel will operate under a 20-year lease contract for Petrobras as the production platform for wells in the company's Sapinhoás Norte field. The FPSO vessel has a total storage capacity of 1.6 MMbbl, total oil processing capacity of 150 Mbbl/d of oil, gas handling capacity of 4 MMcm/d (140 MMcf/d) and water injection capacity of 180 Mbbl/d.

With its work on Shell's Stones development in the Gulf of Mexico and Prelude FLNG project, the company's turret design group has had its hands full as of late. The largest piece of the turret for Shell's Prelude FLNG facility left the Dubai DryDocks World yard in August for the Samsung Heavy Industries shipyard in Geoje, South Korea. According to Shell, this piece of the turret weighs in at 4,300 tonnes.

"Prelude FLNG combines our many years of experience in shipping and in managing complex LNG and offshore projects. It's great to see our innovative designs and technologies become a reality as we reach significant project milestones like this," said Matthias Bichsel, projects and technology director at Shell.

A portion of the SBM-designed turret for Shell's Prelude FLNG facility left the Dubai DryDocks World shipyard in August. (Source: Shell)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The *N'Goma* FPSO vessel at Paenal shipyard in Angola was converted from the FPSO unit *Xikomba*. (Source: SBM Offshore)

"Designed in Monaco, built in Dubai, shipped to South Korea and for use off Australia, the turret is an example of the truly global nature of this project."

Shell reports that once complete, Prelude FLNG will operate in a remote basin around 200 km (124 miles) off Australia's northwest coast—for about 25 years—producing about 3.6 million tonnes of LNG a year to help meet rising global demand for cleaner energy.

Sembcorp Marine

For Singapore-based Sembcorp Marine, 2014 was a busy year spent acclimating to a larger area to work. In August 2013, the company commenced operations at its new Sembmarine Integrated Yard @ TUAS. Designed to maximize production efficiencies and operational synergies, the yard includes optimized docking and berthing facilities, an improved dock and quay ration, a centralized layout and integrated facilities, the company said.

Phase I of the new yard is equipped with four very large crude carrier drydocks with a total dock capacity of 1.55 million deadweight tonnes as well as finger piers and basin lengths totaling 3.9 km (2.4 miles). The 73.3-hectare Phase I yard facility forms the first of three phases of construction of the 206-hectare Sembmarine Integrated Yard @ Tuas. Phase II of the new yard, which spans 34.5 hectares, is expected to commence operations in the next three to four years, according to a company release.

In October, the company was awarded the distinction of being the "Shipyard of the Year" at the 2014 Lloyd's List Asia Awards for the first time based on its proven track record in ship repair, building, conversion, rig building, and offshore engineering and construction.

In October, Sembmarine's subsidiary PPL Shipyard announced that it secured a contract to build a new jackup rig from BOT Lease Company (BOTL). The rig, scheduled for delivery at the end of October 2016, will be built based on PPL's Pacific Class 400 (PC 400) design. This latest generation of high-specification jackup rigs is capable of operating in deeper waters of 122 m (400 ft) and drilling HP/HT wells to depths of 10,668 m (35,000 ft). The rig design features 2 MMlb hook load and the latest drilling equipment for improved drilling efficiencies along with offline handling features and simultaneous operations support, a release said. Dubbed the Hakuryu 14, this will be the second jackup rig built by PPL for BOTL.

The FPSO unit *Cidade de Ilhabela* will serve as the production platform for Petrobras' Sapinhoá North Field. (Source: SBM Offshore)

The first unit, named Hakuryu 12, is presently under construction with contractual delivery at the end of January 2015. PPL Shipyard also built the Hakuryu 10, a PPL Shipyard proprietary Pacific Class 375 series, for JDC—that unit was delivered in June 2008 and is currently chartered to Total E&P Indonesia, the release said.

Sembmarine, through its Jurong Shipyard subsidiary, was awarded by MODEC Offshore Production Systems a contract for a very large crude carrier conversion into an FPSO vessel as part of the TEN Development Project, a press release said.

When completed in fourth-quarter 2015, the TEN Development FPSO vessel will have a production and treatment capacity of 80 Mbbl/d of crude oil, 65 Mbbl/d of produced water and 5.1 MMcm/d (180 MMcf/d) of gas with an onboard storage capacity of 1.7 MMbbl.

The TEN Development FPSO unit will be operated by MODEC on behalf of its client Tullow Ghana Ltd., a wholly owned subsidiary of Tullow Oil Plc. The FPSO vessel will host multiple subsea tiebacks from three reservoirs—Tweneboa, Enyenra and Ntomme—in the deepwater Tano Block off the coast of Ghana.

Perhaps the biggest news of the year for the Jurong Shipyard was its award of the $696 million contract to convert a shuttle tanker into an FPSO vessel for OOGTK Libra GmbH & Co. KG, a joint venture between Brazil's Odebrecht Oil & Gas and Teekay Offshore.

The contract involves the conversion of the *Navion Norvegia* shuttle tanker to an FPSO unit that includes detailed engineering, installation and integration of topside modules, installation of external turret and power generation and accommodation upgrading as well as extensive piping and electrical cabling works. Scheduled for completion in third-quarter 2016, the FPSO vessel will have the capacity to produce 50,000 bbl/d of oil and 4 MMcm/d (141 MMcf/d) of natural gas and is expected to be chartered to Petrobras for work on the Libra Field in the ultradeepwater section of Brazil's Santos Basin. Operating as an early well-test unit, the FPSO unit will be on a 12-year charter once it begins its contract in late 2016. E&P

Activity in giant Eagle Ford continues to grow

The best may be yet to come for Eagle Ford, but the industry must address challenges of steep decline curves, needed infrastructure and shortage of personnel and supplies.

Staff Report

The sprawling Eagle Ford Shale has a lot going for it—great geology, close access to excellent midstream infrastructure and downstream markets, supportive landowners, and a favorable regulatory environment. But challenges lie ahead as the big unconventional play continues to evolve.

The Eagle Ford Shale spreads across 644 km (400 miles) from the Mexican border to eastern Texas. Since the first well was drilled by Petrohawk in 2008, activity has exploded in the area and shows no signs of slowing. To keep up, though, companies must continue to improve efficiency, attract skilled personnel and ensure they have the supplies and infrastructure needed to produce the play.

Progress and potential

Three industry experts addressed the play's potential and challenges during a wide-ranging roundtable discussion of the play at Hart Energy's fifth annual DUG Eagle Ford Conference & Exhibition in San Antonio in September.

Josh Weber, senior vice president, commercial and business development for Howard Midstream Energy Partners LLC; Tim Murray, managing director for GSO Capital Partners LP; and Phil Mezey, executive vice president, Southcross Energy Partners LP; started off by recounting their first exposure to the Eagle Ford following its late-2008 discovery.

Murray recalled that for him the Eagle Ford early on provoked "bittersweet memories of the Austin Chalk," an earlier Texas play that spurred a lot of industry excitement in the 1980s and 1990s before falling out of favor.

"That was a pretty wild pony," he said of the Austin Chalk. "You had some very high rates that fell off very quickly. Mix that with volatile oil prices, and it made for a wild ride."

However, he added the Eagle Ford has proved to be more akin to the Niobrara, "an established basin where there are other producing horizons that are a little tired, and it has brought in new excitement."

Considering the Eagle Ford from a financial perspective, Murray said that "the calculus has changed" for the play following the initial "land grab" for leases, followed now by producers' establishment of long-term, capital-intensive development plans. "It's been an interesting five to six years," he said.

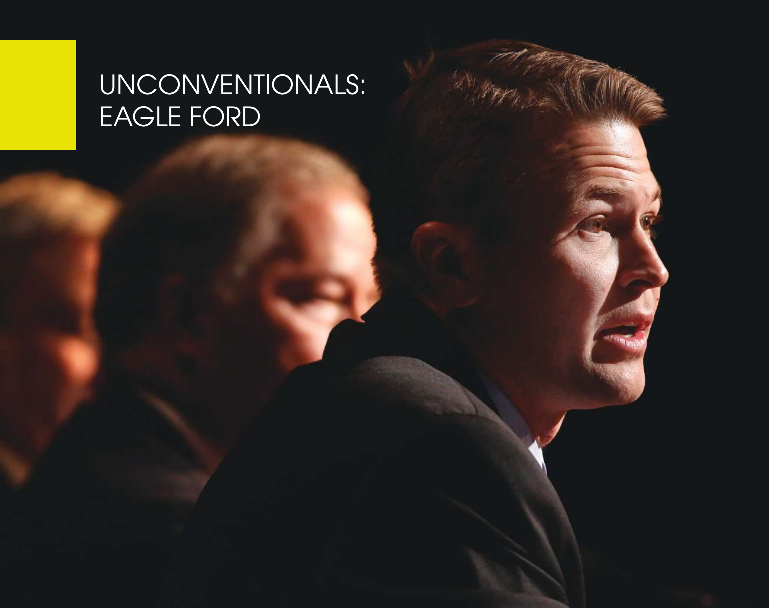
Mezey said he saw the Eagle Ford close up from its start. He told how the firm he was with at the time—chasing the Austin Chalk—had acreage adjacent to the Petrohawk discovery in the fall of 2008 that started the Eagle Ford on its way. "We were already having problems getting oil out, and we realized right away there were going to be some constraints" on midstream capacity. He was involved in building an initial Eagle Ford crude-gathering system that was sold to NuStar Energy LP. The Petrohawk well was good, but as horizontal wells got longer and fracking programs became bigger, "every well we saw was getting better and better."

The panelists agreed that all of those positives for the Eagle Ford have combined to make it a world-class play that now produces some 1.5 MMbbl/d.

"It has been a great place to work," Mezey said. "We know what the rules are, and they are consistent." That has been a contrast to plays in other states where regulation has been constraining and public support weak. The panel also agreed that the best may be yet to come for the Eagle Ford. Weber pointed to the growing market in nearby Mexico, a promising market that now looks even better with that nation's recent revamping of its energy law.

That demand could help open up the dry gas-prone southern side of the formation that has seen little activity in recent years due to low gas prices. The central and northern portions of the play, typically producing more lucrative NGL-rich natural gas and crude oil, have been the scene of most Eagle Ford drilling. However, those wells typically have good associated gas production.

Development of new midstream infrastructure on the Texas Coast, in particular improvements to the Houston Ship Channel and new processing, storage and docks at Freeport and Corpus Christi, will be a plus for the growing waterborne exports. The light liquids and rich gas typical



Josh Weber of Howard Midstream Energy Partners LLC told a crowd at DUG Eagle Ford that he sees promise in the growing market in Mexico as a potential market for Eagle Ford production. (Photos by Tom Fox)

of Eagle Ford wells feed into the growing export market for NGLs and the promise of condensate exports. New condensate splitter capacity is another plus for the play, the panelists agreed.

Mezey discussed the variables that could make the Eagle Ford export market even stronger, including Mexican and Caribbean demand and the prospect of new Asian customers following completion of the Panama Canal expansion.

Exports are the key to the Eagle Ford's future progress, Murray said. If current strict limits on crude exports remain in place, the play "could hit a brick wall a year from now with all this light crude." Gulf Coast refineries have been geared to run heavy and sour imports, and processing the Eagle Ford's light, sweet crude and condensate isn't economic. That production should be allowed to seek its own market, he added.

Collaboration necessary

Growth in the Eagle Ford over the past several years has been incredible. However, competition for people, products and technology in U.S. unconventional plays is intensifying, and other basins are competing for those resources in the Eagle Ford.

"If we don't collaborate and optimize our productivity on a per-well basis, these resources will be allocated to less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mature basins. Mature basins such as the Eagle Ford must continue to focus on productivity and efficiency in wells to stay out in front," said Tammi Morytko, vice president, southern U.S. geomarket, Baker Hughes.

"From a service company perspective, we believe the answer is collaboration at the well site and during the planning stage, which is the key to growth and retention of economics for our producers," she added.

Fit-for-purpose optimization and real-time monitoring of stage effectiveness are factors that can be delivered in many processes and technologies. "I think we can agree it is time for fewer handoffs, more science, more collaboration and superior economic outcomes as a result," she continued.

Tim Murray of GSO Capital Partners LP compared the Eagle Ford to the Niobrara—an exciting horizon in an established basin—during a panel discussion at DUG Eagle Ford.

Recent trends in large completions, frack volumes and logistical challenges coupled with inflation are causing completion costs to increase. The cost is expected to rise by more than 25% during the next year. On a macro basis, productivity or dollars per boe is flat to declining due to steep decline curves and ineffective fracturing results, she explained.

"A variety of industry reports acknowledge that 60% of frack stages are ineffective. These ineffective stages equate to more than $40 billion of annual spend. Improving the performance of those ineffective fracks will result in significant increase in production as well as dollars/ boe. That's what really matters," she emphasized.

Challenges facing industry

With ever-increasing demand for horizontal completion and production capacity, the industry faces challenges in finding enough people, creating enough infrastructure and producing enough sand and water.

"It is challenging to find qualified people. Land drilling has seen a 400% increase in volume and activity for logistics since 2010. Keeping up with supply and moving supply around is a real challenge. Sand and water are continual constraints from the mines to the wellbore. Horizontal frack stages are estimated to increase by 173% from 2010 through 2016. We are certainly constrained to continue to do business as usual," Morytko said.

"Continued growth in rig activity is straining both the service and E&P companies. Rig counts are not growing out of control; however, the intensity, size and length of horizontal completions are driving twice the consumption of people, horsepower and supply. The Permian growth is affecting the basins due to its pull on personnel and supply," she continued.

"We'll see constraints not only growing in the Eagle Ford but other basins unless we develop more infrastructure and get creative to address the per-

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sonnel, equipment and supply issues that are required to recover these hydrocarbons," she emphasized.

Meeting challenges

The U.S. unconventional success has been driven by a great focus on efficiency. The current market was built on a step-change in efficiency improvement, mainly to drilling optimization. However, the rate of change is slowing, and incremental improvements will have much smaller economic benefits than those previously realized.

"It's easy for operators to get trapped in a cost-reduction mindset vs. focusing on the unrealized productivity gains. We believe we are at a critical inflection point for operating companies. As service companies, we must stand up and help with this change," Morytko explained.

"We feel we must combine our successful approach to efficiency gains with a focus on improved productivity. Our productive improvement on a per-well basis will come from unique applications of completion and reservoir technologies," she continued.

That brings the emphasis back to collaboration. Improving productivity on a per-well basis will take a collaborative effort as well as service companies applying expertise. "You don't have to look far to see the incredible advancements in reservoir tools and completion technology. There are tools that allow stage fracture optimization.

"There are tools that collaborate with several diagnostic technologies to tell the whole story and devise a much more fit-for-purpose plan of attack to recover those hydrocarbons. True system-based applications focus on the risk-reward economics aligned around initial production and ultimate recovery," she said.

Tammi Morytko from Baker Hughes said Eagle Ford operators must focus on efficiency and productivity in wells.

"It is all about intelligence and collaboration to yield the right productivity signal for our customers. It is what they need to demand in this environment. There is so much we can offer from collaborating from the start of the project and throughout the life of the recovery process. We've only begun to scratch the surface of what is possible. Together, we'll be stronger and create new beginnings for greater profitability for all," Morytko concluded. "We have to think differently to create new possibilities."

Enhanced completions boost EURs

Pioneer Natural Resources was working South Texas for years before the Eagle Ford emerged. Pioneer was busy drilling Edwards Trend gas wells on a nice leasehold position that later turned out to be smack in the heart of the Eagle Ford play.

"It's been a phenomenal play for us," said Timothy L. Dove, Pioneer's president and COO. "In essence, when it comes to the Eagle Ford Shale, we had zero-cost basis to enter the trend."

Pioneer concentrates its efforts in the Eagle Ford's condensate window, where it produces liquids-rich gas at high pressures and high volumes. Today the operator makes 135,000 boe/d from its 215,000 gross acres, about 68% liquids. It's a stunning growth trajectory from the 4,000 boe/d it produced in 2010.

In 2012, Pioneer moved from the exploration phase of its Eagle Ford assets to field optimization. "We are in continuous development, continuous improvement mode," Dove said. "Now we're in the process of optimizing our well spacing and completion designs. We are making sure that we are reaching out and touching all of that rock volume that we need to stimulate for maximum production."

Today Pioneer is drilling 100% of its Eagle Ford wells on multiwell pads. Last year, it implemented a two-string design, which saves $750,000 to $1 million in drilling cost per well vs. a three-string design. Additionally, between 2011 and the first half of 2014, it dropped its cost-per-foot from $265 to $201. During the same period, total distance per day increased from 151 m to 223 m (496 ft to 730 ft).

Another area of effort is determining effective downspacing for the reservoir. "Understanding stimulated rock volume is crucial," Dove said. "We want to get close to that point where we have constructive interference." Among the technologies that Pioneer uses to hone its well spacing are microseismic, 3-D seismic, tracers, geochemistry and frack modeling. Initially, Pioneer located its wells 300 m (1,000 ft) apart. Now it has downspaced in pilot areas to between 53 m and 91 m (175 ft and 300 ft) apart, including staggered laterals in upper targets.

On completions, Pioneer has been focused on optimizing its treatments. This ranges from pumping more bbl/min per perf cluster to reducing the spacing between clusters. The volume of proppant pumped per foot is also increasing. Today the typical Pioneer well features 21 stages spaced 15 m (50 ft) apart, pumped at 16 bbl/min with 1,200 lb of proppant per foot.

The results have been stunning: In some areas, Pioneer has realized a 20% to 30% EUR increase with minimal increase in drilling and completion costs. "These completions make sense and make money," Dove said. "We have seen quite outstanding results so far."

Increased production

More drilling activity and better drilling efficiency have led to significant crude oil production increases in the Eagle Ford, according to a release from the Energy Information Administration (EIA). These increases have occurred despite the region's relatively high well decline rates. By using new recovery techniques to offset natural declines, companies in the region could further increase production.

Horizontal drilling combined with an increasing number of hydraulic fracturing stages in tight formations like the Eagle Ford typically enhance IP rates when compared to past results, according to the release. These higher IP rates are often accompanied by initially larger decline rates before gradually leveling off to a consistent level of decline for the remaining years of the well's life.

IP rates have steadily increased since 2009, and first-year decline rates in the Eagle Ford have ranged between 60% and 70%, according to the EIA. Decline rates during the second year of production have risen from 30% for wells drilled in 2009 to nearly 50% for wells drilled in 2011 and 2012. Since 2013, many producers have been using more proppant when fracturing new wells, which appears to have increased IP rates but was followed by a steeper drop in production, the EIA said in the release. E&P

Reservoir mapping-while-drilling optimizes landing

The novel system reduces drilling risks while maximizing reservoir exposure in geologically complex wells.

Uche Ezioba, Schlumberger

In their quest to develop new oil and gas resources to feed the growing global appetite for energy, operators are challenged with drilling into reservoirs that are deeper, thinner and more geologically complex. Fortunately, new drilling technologies continue to be developed to increase the odds of drilling success in challenging hydrocarbon pockets that might have been technically or economically infeasible just a decade or two ago.

One technology area that has shown particular promise is the development of bed-boundary mapping tools to measure reservoir properties as a well is being drilled.

However, because these tools only provide a depth of measurement of a few feet around the wellbore, they have shown limited success in drilling applications where the operator needs reservoir information farther afield. This includes reservoirs with narrow pay zones or those that contain faults, unconformities, and injected or channel sands.

This limitation prompted the development of the Schlumberger GeoSphere reservoir mapping-while-drilling service. The service expands on the bed-boundary mapping potential of conventional tools using an LWD system consisting of a transmitter and an array of multiple subs in the bottomhole assembly. These subs can detect deep, directional electromagnetic (EM) measurements more than 30 m (100 ft) from the wellbore to reveal subsurface-bedding and fluid-contact details at a significantly greater distance than conventional bed-boundary tools (Figure 1).

Landing on target

The ability to land the wellbore into the reservoir's targeted zone of interest is critical to delivering a well that will achieve its long-term production potential. The service maps structural shifts at a reservoir scale, providing a precise true vertical depth of the top of the reservoir to reduce the risk of shallow or deep landings. It also affords a clear, real-time view of formation boundaries and fluid contacts, which reduces the risk of losing lateral exposure and creating sumps while exposing more of the lateral section of the wellbore to the reservoir.

Steering with certainty

The reservoir-imaging ability of the service improves steering in challenging downhole environments such as discontinued sand bodies. The service's ability to estimate structural dips helps operators avoid unplanned reservoir exits and adjust drilling trajectories ahead of geological variations such as water zones and geological sidetracks. This eliminates sudden and erratic changes to the well's trajectory, resulting in a smoother wellbore that is easier to complete.

Mapping the field

The 30-m-plus depth of investigation afforded by the service reveals subsurface beddings and fluid boundaries that allow for mapping of the reservoir top and base and provides data on the presence of lateral heterogeneities, subsurface unconformities and reservoir geometry. These data can be integrated with surface seismic data to refine reservoir models and improve the understanding of sweep efficiencies in horizontal wells.

Well- and field-scale benefits

The reservoir-scale view afforded by the GeoSphere service provides the operator with vastly improved depth of investigation that can optimize landing, improve geosteering to stay in zone and refine geological maps in real time.

FIGURE 1. A typical GeoSphere deployment consists of a transmitter (bottom) linked to two receiver strings containing subs (top). (Source: Schlumberger)

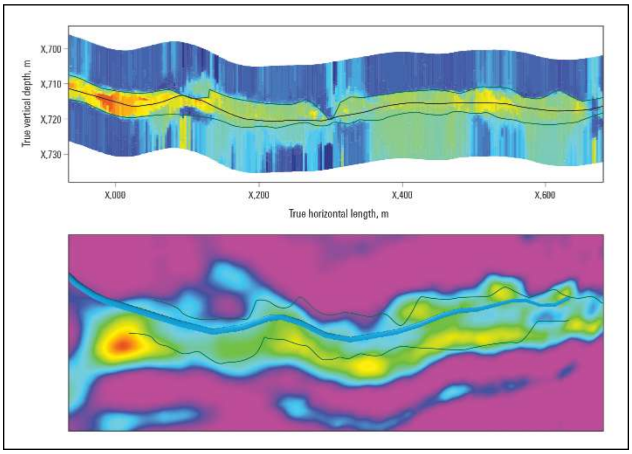


FIGURE 2. In the first well drilled, data from the GeoSphere service (top) and a seismic acoustic impedance on the same level (bottom) led to reservoir exposure of 815-m MD, which provided a net-to-gross ratio of 0.98. (Source: Schlumberger)

The mapping data provided by the service can be integrated into 3-D reservoir models to enhance the evaluation of layered formations, which allows operators to refine completion design, regulate flow control management and enhance depletion profiles before completions are run. In addition, by indicating fluid contacts, the service helps optimize injector and production well development by influencing infill drilling decisions to eliminate bypassed pay zones.

Optimizing placement of North Sea wells

The GeoSphere reservoir mapping-while-drilling service proved useful to an operator in the North Sea that was challenged with steering two production wells within a glauconite-rich sandstone reservoir. The target reservoir sands were 2 m to 15 m (7 ft to 16 ft) thick and comprised post-depositionally remobilized sand capped by unstable shale. Although initially deposited as gravity flow sands, over time they were remobilized under burial, which led to sand fluidization and injection along weakness zones such as faults and low-competent stratigraphic levels. This made a determination of the exact stratigraphic location of the sand difficult.

These steering challenges, coupled with the reservoir's low resistivity, made conventional landing methods and bed-boundary mapping tools less than ideal since they could only provide a depth of investigation of less than 2 m. As a result, the operator was not confident that timely trajectory adjustments could be made to account for the complex geology of the reservoir such as sudden structural dip changes.

What's more, the operator was concerned that if it could not accurately map the internal variations of the reservoir's structure, then it would not be able to define geological interpretation to optimize future field developments. The operator had a historical basis for its lack of confidence in conventional tools since previous wells drilled in similar reservoirs have been marginally economical, with net-to-pay ratios below 0.5 and an increased need for sidetracks.

Recognizing the need for accurate reservoir steering to optimize well positioning, the operator decided to deploy the GeoSphere service to steer into the two planned horizontal production wells. The deep directional EM measurements from this service and surface seismic measurements were overlain in real time while drilling to provide important look-ahead information for optimized landing. These combined measurements made it possible to steer away from reservoir structure shifts well ahead of when they would be encountered. With more informed steering, the wells were placed within the thin reservoir away from unstable shale and drilled completely to total depth.

The first well was drilled in a single run, achieving a horizontal section of 815 m (2,674 ft) measured depth (MD) with a net-to-gross ratio of 0.98. Actual reservoir exposure exceeded planned exposure by 65 m (213 ft), and the tortuosity of the well was kept within requirements (Figure 2). The second well was also drilled in one run, achieving 260 m (853 ft) MD with a 0.96 net-to-gross ratio (Figure 3). The two horizontal wells were accurately steered in the reservoir—96% in zone—and with no sidetracks. Both wells were tested at up to 8,000 bbl/d with minimal drawdown.

Understanding of the reservoir and its heterogeneity was also greatly improved. The information from the GeoSphere service was critical in refining the reservoir model and, ultimately, in making decisions for the long-term management of the field.

Because of the successful well positioning and the valuable reservoir mapping data acquired during drilling, the operator plans to run the reservoir mapping-while-drilling service for future campaigns. E&P

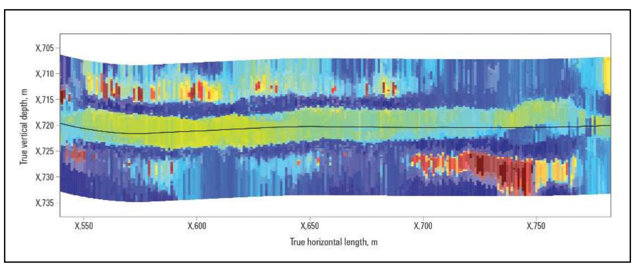


FIGURE 3. Data from the second well (above) showed that a 260-m MD was achieved with a 0.96 net-to-gross ratio. (Source: Schlumberger)

Lease, ownership data digitized for Texas oil counties

Online platform allows users to search geographically indexed lease, ownership and royalty records from Texas' top 100 oil-producing counties.

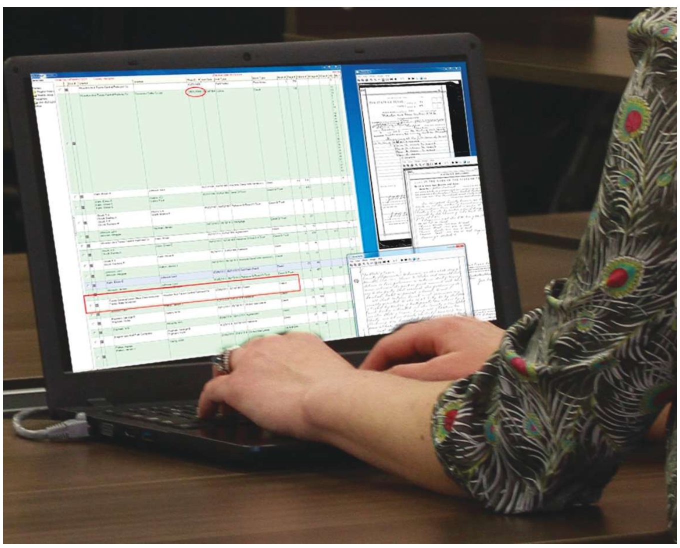
Nic Franklin, Digital Abstract

The Lone Star State's size is usually a plus. In recent years, it has meant a laundry list of shale plays and a wide selection of strong college football programs. But that size is a burden for those hungry for oil and gas ownership data.

Few counties digitize their land records immediately, which means budgeting and waiting for landmen to trek out to remote courthouses and retrieve new records or relying on outdated data from current providers.

Digital Abstract & Title, an oil and gas tech startup from the Texas Panhandle, started as a title plant for a handful of local counties, but it's changing the game with a subscription-based platform called Blackacre that rolled out Texas-wide in November 2014.

Creating this service has been exhausting in capital and workforce demands, but the technology piece has been by far the most difficult, which is why no one has rolled out such a system before. Blackacre's online platform allows a user to search geographically indexed records on virtually any device connected to the Internet.



Modernized, indexed data are gathered on a weekly basis by Digital Abstract's team. A patent has been filed to protect the company's data-structure display mechanisms. (Source: Digital Abstract)

A team of full-time employees is making a circuit in Texas' top 100 oil-producing counties each week, ensuring every bit of new data is loaded into Blackacre's platform.

People and companies interested in these data include:

- Oil and gas companies updating their existing paper abstracts;
- Brokers looking for recent oil and gas leases to know what is not available to lease and to see where competitors are going;
- Landmen looking for oil and gas releases to find open production and lease it before competitors find it;
- Investment groups looking for mineral ownership transactions to find new owners interested in selling their minerals for a lump sum instead of monthly cash lease payments in the future; and
- Anyone negotiating royalties on mineral rights contracts to see what competitors are offering in that area.

Geographic indexing

Of course, not all data are created equal. County land records are generally not geographically searchable, and searching by name and date is far less helpful than tracking by a specific legal description. In layman's terms, clients are usually interested in a specific section of land—a specific plot—and only Blackacre allows them to search by section.

That's because Texas is notoriously difficult to index. By Texas law, courthouses are not required to index the legal description of documents filed, though one document can reference another with a legal description or it can reference a document that references a document with a legal description, and that chain gets deeper and deeper over time. For more than 100 years, abstract companies have stepped in with methods that have changed little despite the advent of computers and the Internet.

Digital Abstract cut its teeth by digitizing the land records of five counties in the Panhandle back to sovereignty and indexing them geographically. That task took dozens of indexers working around the clock for 18 months. Although Digital Abstract dominates the title and abstract business in those Panhandle counties, a bigger realization came to light. No one else Texas-wide was responding to the need to quickly digitize records and make them geographically searchable.

Oil, gas leasing background

If someone wants to know about a specific piece of land, he or she can see the original oil and gas lease document with a legal description. But as it is passed around, dozens or hundreds of other documents can reference that oil and gas lease document—including the release—and none of them are specifically named in the legal description. Instead, these dozens, hundreds or thousands of documents may only reference a previous document.

From a technology standpoint, that's a nightmare, but Digital Abstract developed cutting-edge computer code to connect these documents together like a spider web. Clients need proof of every change that happened to that section, but they are really hunting for the original lease and the release. Blackacre shows the lease and, with a click, hides everything that happened between the lease and release. If the clients have been using paper, a week's worth of work happens instantly. Even the very best servers kept running out of memory with instruments with thousands of referencing documents, so major resources went into developing code to simplify the process enough to make the technology functional.

Royalty data covered

The original focus was on data that could be used to track ownership, but royalty data also are being digitized in a novel way. Finding information about royalties on one specific lease is easy, but aggregating royalty information across entire oil plays is entirely new. With Blackacre, anyone considering mineral rights contracts can see at a glance how much it would cost to get into a play. Access to that information means a more informed decision when negotiating royalties.

Track trends from anywhere, anytime

With the current antiquated system of data retrieval, all mineral rights data must be specifically sought out based on hunches or specific interest, and they were never searchable Texas-wide by section. With Blackacre, trends can emerge based on fresh data, even if the subscriber is not necessarily interested in that particular area. Reports alert subscribers of any new activity in the area they specify in real time. To get that same information, companies would have to pay someone to go to 100 courthouses every week, and they would need to have a geographic search tool in place. Blackacre subscribers can access these data at any time.

Big bet by investors

Doing something that no one else is doing, especially in a mature industry like the oil and gas space, involves a leap of faith. But Digital Abstract's investors are a collection of lawyers and oil men whose professional lives have all centered around Texas' oil and gas industry. The goal was to create tools the industry has been missing. While it's true that every piece of data in this system came from a document publicly available for free at the courthouse, Digital Abstract has turned public data into searchable, deeply indexed data. The Blackacre platform delivers and displays the information in a way people can build entire businesses on. The attorneys at Fish & Richardson have filed patent applications for Digital Abstract & Title to protect Blackacre's data structure display mechanisms. With the continuing need for data, Digital Abstract continues to add counties in Texas and expand its data collection into other states. E&P

RSS delivers precise placement of complex wells

Baker Hughes has released its AutoTrak eXact high-build rotary steerable system (RSS) designed to help operators drill complex 3-D wells with improved directional control and borehole quality. The system combines high buildup rate capability and advanced LWD services. This helps optimize completions, improve drilling efficiency and maximize production potential. The RSS uses closed-loop steering control, giving it the ability to deliver precise wellbore placement with high borehole quality for more efficient drilling, better log quality, easier casing runs and improved production, according to a product announcement. The system can drill shorter curve sections up to 12 degrees per 30.5 m (100 ft) compared to conventional systems that offer 5 to 6 degrees per 30.5 m build rates. The shorter curves maximize reservoir exposure and help avoid risk by reducing directional work in troublesome formations. The AutoTrak eXact system also provides access to real-time formation evaluation and reservoir data to help geosteer wells and optimize placement. *bakerhughes.com*

AutoTrak eXact RSS combines high buildup rate capability and LWD services. (Source: Baker Hughes)

Tool for slickline operations simplifies inventory

Peak Well Systems has developed the Multi-Action Pulling (MAP) Tool to simplify offshore slickline operations and reduce inventory. The tool is able to pin up, release or recover a wide range of downhole equipment fitted with external fishnecks without the need for any additional specialized tooling. This simplifies inventory, the company said, which improves operational efficiency and reduces overall cost. The MAP Tool features a latch system to tackle a range of external fishnecks with varying threads and lengths. Powerful latch fingers and an adjustable core extend the reach of the pulling tool, giving it a short-, medium- and long-reach capability. Three different run options—jar up, jar down and double jar down modes—are available to release the fishneck in hole and eliminate the risk of prematurely shearing the pins. The company said the tool replaces the functionality of six different tools currently used. A fully adjustable core means it can adjust its reach to suit any fishneck, and an external latch release sleeve allows the tool to quickly release at surface with no special tooling required. *peakwellsystems.com*

Surfactant builds viscosity in completion fluids

The Armovis Complete viscoelastic surfactant (VES) from AkzoNobel has been designed for use in HP/HT wells. Its rheology effectively disperses, transports and places gravel for well completions in poorly consolidated reservoirs, according to a company product announcement. The VES improves viscosity in high-density brines across a range of bottomhole temperatures up to 191 C (375 F). Completion fluids containing Armovis Complete can be used in a wide range of heavy brines including pure bromides of potassium, calcium and zinc and mixed chloride/bromide brines; the tool has proven performance in brines as heavy as 17 ppg. This new VES is suitable for deviated and horizontal well completions as it is more tolerant to challenging well conditions than current gravel packing technologies, the company said. Armovis Complete is easy to mix into the completion fluid and immediately builds viscosity topside to disperse gravel, recovers viscosity quickly after a high-shear situation and imparts viscosity to the saline fluids at surface temperatures, maintaining stable viscosity as fluids are heated while pumped and placed in the well. Once diluted in the target brine, Armovis Complete exhibits shear-thinning behavior, which reduces injection pump pressure. In addition, the elastic properties of the fluid enhance retention of the gravel in the bulk fluid during pumping and should enhance gravel placement downhole. *sc.akzonobel.com*

Drillbit design increases ROP by redistributing energy to cutters

Tercel Oilfield Products released the MicroCORE Cutting System, a new polycrystalline diamond compact

The MicroCORE Cutting System is designed to deliver more energy to the efficient areas of the cutting structure for higher ROPs and higher quality wellbores. (Source: Tercel Oilfield Products)

(PDC) drillbit design. The system redistributes high energy consumption from the center of the drillbit to the more efficient areas of the cutting structure, the company said in a press release. The technology was developed in collaboration with Total. By replacing the compression failure mechanism in the center of a traditional cutting structure, the MicroCORE system delivers more energy to the cutters, resulting in higher ROPs and better quality wellbores. It also allows operators to recover core fragments from the well that are undisturbed by the shearing action of the cutters, providing good samples for core analysis. Global field-testing has shown the system consistently sets new benchmarks in ROP and distance drilled. *terceloilfield.com*

Rheometer moves from lab to field without network connection

Fann Instrument Co. launched the RheoVADR variable automated digital rheometer, which can record test data without being connected to a computer or network, according to a press release. The standalone RheoVADR records speed, viscosity, dial reading and temperature with each test using digital controls to minimize operator handling. The new rheometer is lightweight and portable, which makes it suitable for use in either the lab or the field. API standard drilling fluid and cement tests are preprogrammed into the instrument, and test routines can be customized. The tool captures data in a standard CSV file that can be read by spreadsheet programs such as Microsoft Excel. Test results can be recorded on a USB flashdrive. *fann.com*

System recovers stuck pipe quickly and cost-effectively

The HyPR hydraulic pipe recovery system from Churchill Drilling Tools was created for the rapid and cost-effective recovery of stuck pipe. Stuck-pipe situations cost operators significant amounts of money each year in nonproductive time, incurring mobilization wait times and uncertain recovery attempts and delays. The HyPR tool is designed to cut that cost by enabling operations to resume more quickly, a press release said. The system offers a simple method to recover the drillpipe and begin side-tracking right away. It also delivers a clean cut for operators wanting to maximize bottomhole assembly recovery options. The HyPR consists of a full-strength sub strategically positioned in the drillstring that can be severed in about an hour by launching and pumping through one of two HyPR dart options, which lands inside the profiled sub. Either option takes just a few minutes to arrive and will part easily under a small loading, simultaneously producing a perfect fishneck for subsequent operations. The expected mode of use is to set a kick-off plug before coming out of hole with the recovered pipe. However, the system also provides excellent jarring and internal wireline access for further recovery operations, according to the release. *circsub.com*

High-definition camera withstands hazardous, explosive environments

Moog Inc. released its EXO explosion-proof high-definition network camera system designed for the most hazardous explosive environments, according to a company product announcement. Using the segregation method Moog Class I and II, Division 1 camera systems allow users to install cameras wherever a need for surveillance exists where even containment-protected systems cannot be installed. Division 1 hazardous environments are typically classified where there is a presence of explosive gases or combustible dust either temporarily or permanently. Segregation is achieved by keeping a constant flow of clean air inside the camera. Moog segregates the air on the inside of its EXO system from the explosive air on the outside. The camera system captures 1080P full HD video and operates within constant fumes and dust by using its self-monitored purge mechanism. The pan-and-tilt mechanism is constructed of aluminum rather than plastic components, which helps it withstand high shock, vibration and wear environments. The board level components of the unit are able to withstand higher and lower temperature thresholds as well as power surges. *moogs3.com* E&P

The EXO explosion-proof camera system is designed to endure high shock, vibration and wear. (Source: Moog Inc.)

Mediterranean warms up

Oil and gas companies are pursuing E&P plans in the Mediterranean Sea from the Spanish shores to the Israeli coast.

Velda Addison, Associate Online Editor

The Mediterranean Sea has given birth to some of the world's largest hydrocarbon finds in recent years, transforming the energy scene in environments that have been geologically and at times economically and politically challenging.

Yet the region continues to attract oil and gas companies, with colossal finds such as the Leviathan and Tamar discoveries in the Eastern Mediterranean serving as promising signs of lasting potential. Still considered a frontier area, most of the region's possible lush deepwater areas have yet to be tapped, but companies are pushing forward with plans in the Mediterranean from the Israeli coast to Spanish shores.

In some instances, businesses are facing challenges before the drillbit reaches the seafloor. Fearing drilling could harm beach tourism, the fishing industry and sea life, some residents in the Balearic Islands offshore Spain have taken to the streets in opposition to drilling in the Gulf of Valencia, as others support the move and the economic benefits such efforts could bring. In other parts of the region, geopolitical risks continue to threaten the regulatory progress of projects. Yet other regions are poised for growth with few of the aforementioned barriers.

But just as in other parts of the world, there are geological challenges, which vary, as regional energy demand grows, providing incentive to proceed with developments.

Mediterranean-focused Energean Oil & Gas has taken the lead offshore Greece, having revived production from the Prinos Field as it pursues further exploration opportunities in Greece and other parts of the Mediterranean region.

"Many areas in the offshore and onshore Adriatic have proven hydrocarbon systems but have not been available to the international exploration community for a quarter century and more for a variety of mostly political reasons," Hank David, new business development manager for Energean, told *E&P* in an emailed statement. "During this time, these areas have laid fallow or have been subject to exploration and exploitation efforts almost exclusively by state-run oil companies, most of which were underfunded and lacked up-to-date technology and tools. Consequently, this large area remains today underexplored. Suddenly, and simultaneously, massive amounts of this acreage are now hitting the market."

These include acreage offshore Croatia, Greece and Montenegro—all of which have recently had or have licensing rounds underway. Studies have shed light on possible petroleum systems in these areas, with billions of barrels of oil in place on the Italian side of the Adriatic and the potential for just as much on the eastern side.

"Oil companies have taken great risk, and at great expense, venturing into the deep waters of the south Atlantic and east Africa over the last several years to test unproven plays, with mixed results," David continued. "Here is an area of political stability, in the heart of the European market, with abundant new acreage availability not only in deepwater but also in shallow water and onshore, where oil is proven and seeping out of the ground. Energean sees this as a great opportunity and is uniquely positioned to take full advantage."

Greece

Energean CEO Mathios Rigas said the Prinos Field's potential was initially estimated at 60 MMbbl. However, production since 1981 has nearly doubled, exceeding 115 MMbbl of oil with 850 MMcm (30 Bcf) of gas having been produced. In addition, the Katakolon Block has initial estimates of between 3 MMbbl to 6 MMbbl of oil.

The stock tank oil-initially-in-place (STOIIP) for the Prinos oil field is 289 MMboe, while it's 16 MMboe in Prinos North and 39 MMboe in Epsilon, with recovery factors at 38%, 24% and 1%, respectively.

The company, which has more than 30 years of offshore operator experience, has unveiled a $225 million development plan that aims to recover 30 MMbbl of 2P reserves and increase production to 10 Mbbl/d within the next couple of years, according to Rigas. The program includes drilling seven wells in the main Prinos Field, one well in the currently producing satellite oil field of Prinos North and seven more wells in the undeveloped Epsilon satellite field.

"Energean investments and scientific surveys have proven that there is significant scope for extracting additional production by means of drilling of new wells and through the extended use of enhanced oil recovery techniques," Rigas said. "In order to execute the new drilling program, Energean has purchased the tender assist drilling rig Glen Esk from KCA Deutag and will be utilizing its own drilling crews to drill the wells."

Plans are for the new rig to be renamed Energean Force, which will begin drilling early next year. Two new unmanned self-installed platforms will be placed in the Prinos North and Epsilon oil fields, which will be connected to each other and to the existing Prinos platform complex through pipelines, he said.

Energean is evaluating data and considering whether to pursue additional blocks offered as part of Greece's licensing round, he added, calling the offshore region south of Crete "a real frontier with deep and ultra-deep waters, requiring high-risk exploration investment that could potentially prove a new hydrocarbon play" and the Ionian Sea part of the Adriatic region with producing oil fields offshore.

Fold and thrust belts worldwide have proven to be prolific hydrocarbon provinces, but these rewards have not come easy, David added.

"Tortuous terrains and contorted stratum make for difficult and expensive seismic acquisition and processing, which historically have failed to provide a quality image of the subsurface," David said. "Add hard rocks into the mix (carbonates), and the situation becomes even more challenging and expensive with regards to imaging and drilling through a fractured and cavernous substrate. The Alpine Dinaride/Hellenide system will be no less challenging. But these challenges are partly why the remaining potential is still there."

Exploration success onshore nearby Albania has led to hope of the play's southern extension into western Greece, he added, turning to the onshore Ioannina Block in northwest Greece. Here, the exploration program will include geophysical subsurface imaging including seismic acquisition and processing and the acquisition of a full-tensor gravity gradiometry survey over the entire block.

Spain

Interest also has picked up offshore Spain, where Schlumberger recently reprocessed more than 6,500 km (4,039 miles) of 2-D data from 2011 to 2012. The company said the reprocessed data—which spans the east coasts of France and Spain to the west coasts of the Sardinia and Corsica islands—offer increased resolution and improved subsalt imaging over the Valencia Trough around the Balearic Islands and into the Provincial Basin.

Production from the Prinos Field in Greece has exceeded its initial estimated potential. (Source: Energean Oil & Gas)

According to Olga Shtukert, senior geophysicist of multiclient exploration services for Schlumberger, the Valencia Trough and North Balearic basins have demonstrated high hydrocarbon exploration activity since the 1980s. However, the deep waters of these basins are still considered frontier areas due to a combination of multiple geological and geographic complexities.

"The challenge of the basin is the imaging of the subsalt intervals. The Upper Miocene Messinian salt package is typically over 800 m [2,625 ft] thick and seen to exhibit classic extension (salt welding and rollover anticlines), translation (salt pillows) and contraction (salt diapirs)," Shtukert said. "The tectonic mechanism is critical for the area. Main rifting in the Mesozoic and additional rifting episodes in lower Miocene may have led to localized potential source rock deposition in synrift successions. The post-salt interval is affected by gravity sliding, growth faulting and normal faulting tectonics."

The reprocessed survey has allowed for better interpretation of the subsalt intervals and fault units due to enhanced velocity analyses and demultiple algorithms, Shtukert added. And the updated data have pointed to some hydrocarbon prospects. As part of the effort, four levels of hydrocarbon plays were observed:

- Postrift post-salt: Ebro Group with biogenic gas expected within clastic turbidite deposits in the Plio-Pleistocene;
- Postrift presalt: San Carlos Group with Deltatic/turbidites deposits in the Miocene age;
- Synrift: Basal Tertiary Group with Deltatic/canyon sands in the Lower Oligocene; and
- Proven prerift with carbonate buildups in the Mesozoic.

"The proven hydrocarbon reservoirs on the western Mediterranean are allocated to the Mesozoic age and represented by Upper Jurassic limestones and Lower Cretaceous shallow marine carbonates (limestones and dolostones)," she said. "We mapped several potential leads of Mesozoic age on the reprocessed data. Also several potential leads of clastic Tertiary reservoirs have been justified and mapped."

For Madrid-based Repsol, the greatest potential in the Spanish Mediterranean lies near its Casablanca asset, offshore the Tarragona/Ebro Delta region, where the company said improvements in subsea images make it very attractive to produce from smaller structures.

"The strategy in the Spanish offshore is being geared toward new ideas thanks to better technology that allows us to have more precise images and drill in deeper waters. The potential in Mediterranean waters is in areas of the Tarragona coast and areas of León Gulf," Repsol told *E&P*.

The Casablanca platform draws about 8 Mbbl of oil from six wells—Turbot, Boqueron, Barracuda, Squid, Seabass and Montanazo, the company said on its website.

Repsol has deemed its Lubina-Montanazo development as one of its 10 key projects, with a planned investment of $20 million euros (US$248 million) between 2012 and 2016. Of the 200 Mboe/d increase in production projected for Repsol's 10 key growth projects worldwide, Lubina-Montanazo is expected to contribute an additional 5 Mboe/d, according to the company's strategic plan.

Some of the greatest potential for Repsol in the Spanish Mediterranean lies near its Casablanca asset. (Source: Repsol)

"Lubina and Montanazo are currently producing 4,200 barrels a day," Repsol said before addressing potential prospects in the Lubina-Montanazo/Casablanca area. "Currently Repsol is finishing the static model; that shows some interesting zones. Spain is not an oil country, but thanks to new technologies it shows some interesting areas."

But "the biggest obstacle is that Spain is not a country with a strong tradition in this industry so the regulatory procedure is less streamlined," Repsol said. "However, the government is taking legislative steps that are generating more opportunities."

Media outlets have reported in recent months on residents protesting drilling plans in areas such as the Gulf of Valencia and other parts offshore Spain, including the Canary Islands, a popular tourist destination.

Israel

Meanwhile, Noble Energy continues to make progress offshore Israel. Speaking during its third-quarter 2014 earnings call, Noble Energy CEO David Stover said the company has executed letters of intent for regional gross daily volumes of more than 42.5 MMcm/d (1.5 Bcf/d) with total volumes of more than 226.5 Bcm/d (8 Tcf/d) of gas from the Tamar and Leviathan fields for customers.

"These agreements highlight the long-term demand for Tamar and Leviathan gas, and all parties are focused on completing them as soon as possible," he said, later adding "We anticipate we could be in position to provide around 200 million cubic feet per day [5.7 MMcm/d] at off-peak hours to Egypt as soon as regulatory approvals are received. The compression project at the Ashdod onshore receiving terminal, which handles gas for Tamar, remains on schedule to be complete by next summer. Once complete, peak capacity at Tamar will be 1.2 billion cubic feet per day [34 MMcm/d]. This is part of a multiyear expansion at Tamar, which will increase capacity to 2 billion cubic feet per day [57 MMcm/d] by 2017 to meet growing demand in the Eastern Mediterranean."

Looking back, Stover said volumes, particularly from Leviathan, are significantly higher than what was talked about a year or so ago. The initial phase of Leviathan called for about 24 MMcm/d (800 MMcf/d), but Noble is planning for a capacity of 48 MMcm/d (1.6 Bcf/d)—and that is just the first phase. It's not just Leviathan; it's Tamar also.

During the Johnson Rice & Co. Energy Conference, he described Noble's East Mediterranean finds as discoveries that have gotten bigger. "When we initially found Tamar we were targeting a 3-Tcf [85-Bcm] opportunity, but it's turned into a 10-Tcf [283-Bcm] discovery," he said noting that production has averaged 23 MMcm/d (750 MMcf/d). "Downtime is measured in minutes and hours rather than days."

The focus at Leviathan, which ballooned from 453 Bcm (16 Tcf) during appraisal drilling to 623 Bcm (22 Tcf), is getting letters of intent and regional contracts in place for gas, he added. Already, a contract is in place with BG for an LNG facility in Egypt, and another contract is lined up with Jordan. The field is set to go onstream in late 2017 or early 2018.

Then there is the potential for deep oil.

"We're still excited about deep oil prospectivity over there, but the timing is going to be dependent on when we bring a rig capable of drilling the deep oil prospect in to go along with the additional Leviathan and Tamar development and then in what sequence we do those things," Stover said during the third-quarter call. "That all has to fit together."

Noble anticipates a deep oil test in the Levant Basin in 2015, according to its website, which pointed out multiple prospects have been identified in the company's acreage.

Energean also is journeying farther east into the deepwater offshore Israel, having farmed in to the Sara/Myra licenses. "And to do so, taking advantage of an existing wellbore suspended only 1,000 m [3,281 ft] above an attractive Oligocene/Eocene-age prospect, makes the economics of the project very attractive, especially for a deepwater venture," David said, noting the company has formed a joint venture with Ocean Rig.

"The coming of age of the deepwater Levant Basin offshore Israel and Cyprus is now well known. It is proving to be a world-class natural gas resource. But interestingly, exploration in the basin is still in early days. Not only has the full extent of the Miocene gas play yet to be realized (primarily due to the inaccessibility of offshore Lebanon), but the entire sedimentary section below the gas play in the deepwater remains undrilled," David said. "Only one well has even attempted to test a deeper, older play, and that well failed to meet its objectives.

"Decades of exploration on the shelf and onshore in Egypt and Israel have proven working petroleum systems in the Paleogene and Mesozoic sections, and recent very deep drilling in the deepwater offshore eastern Nile Delta have also proven a working Oligocene-age gas/condensate system," David continued. "It is more than reasonable to project one or more viable petroleum systems in the pre-Miocene section into the deepwater Levant Basin offshore Israel." E&P

For additional information on these projects and other global developments:
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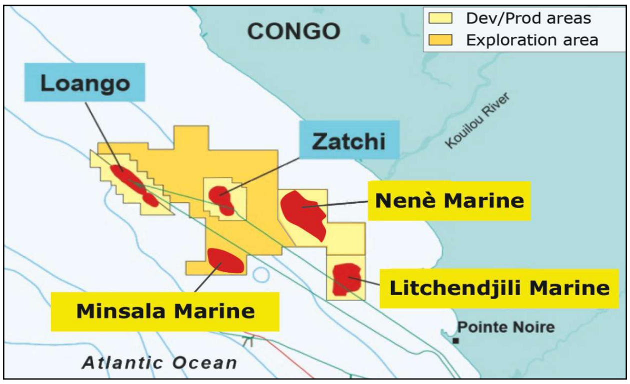
AFRICA

Eni makes 1 Bboe presalt find offshore Congo

Eni has made a new oil discovery in the Minsala Marine exploration prospect in the Marine XII Block offshore Congo 35 km (22 miles) from the shoreline and 12 km (7 miles) from the recent Nenè Marine discovery, Eni said in a news release. The discovery was made through the Minsala Marine 1 well. Eni preliminarily estimates the potential of Minsala Marine discovery at about 1 Bboe in place, of which 80% is oil, the release said. Eni through its own subsidiary Eni Congo SA is operator of Marine XII with a 65% stake.



Eni made a discovery in the Minsala Marine prospect 12 km from the recent Nenè Marine discovery. (Source: Eni)

Survey confirms viability of leads in Chad

Preliminary findings from an airborne gravity/magnetic survey of BDS 2008 in southern Chad confirm the viability of leads in two focus areas identified by ERHC's technical team after analysis of previously collected data, ERHC Energy Chad said. The aerial survey evaluated the hydrocarbon potential within ERHC's Block BDS 2008 in the area north of Esso' Tega and Maku discoveries in the Doseo Basin and a second area east of and on trend with OPIC's Benoy-1 margin discovery in the Doba Basin, the release said.

AUSTRALIA

Statoil gains offshore operatorship in Australia

Statoil has been awarded a 100% equity share in a large exploration permit located in the prolific Northern Carnarvon Basin on the Northwest Shelf of Australia, the company said in a press release. The permit WA-506-P covers an area of more than 13,000 sq km (5,019 sq miles) situated 300 km (186 miles) off Western Australia in water depths of 1,500 m to 2,000 m (4,921 ft to 6,562 ft). Statoil has committed to collect 2,000 km (1,243 miles) of 2-D seismic and 3,500 sq km (1,351 sq miles) of 3-D seismic data within three years.

ASIA-PACIFIC

CNOOC finds oil, gas in Bohai

CNOOC Ltd. made a mid-to-large discovery in the Jinzhou 23-2 structure in Bohai offshore China, according to a press release. Jinzhou 23-2 structure is located in the north part of Liaodong Uplift of Bohai. The well Jinzhou 23-2-3 was drilled and completed at a depth of 1,097 m (3,600 ft) and encountered oil and gas pay zones with a total thickness of 68.4 m (224.4 ft). The oil production of the well tested at about 260 bbl/d. The exploration success of Jinzhou 23-2 not only demonstrated the structure belt has excellent reservoir quality but also proved good exploration prospects in the north part of Liaodong Uplift.

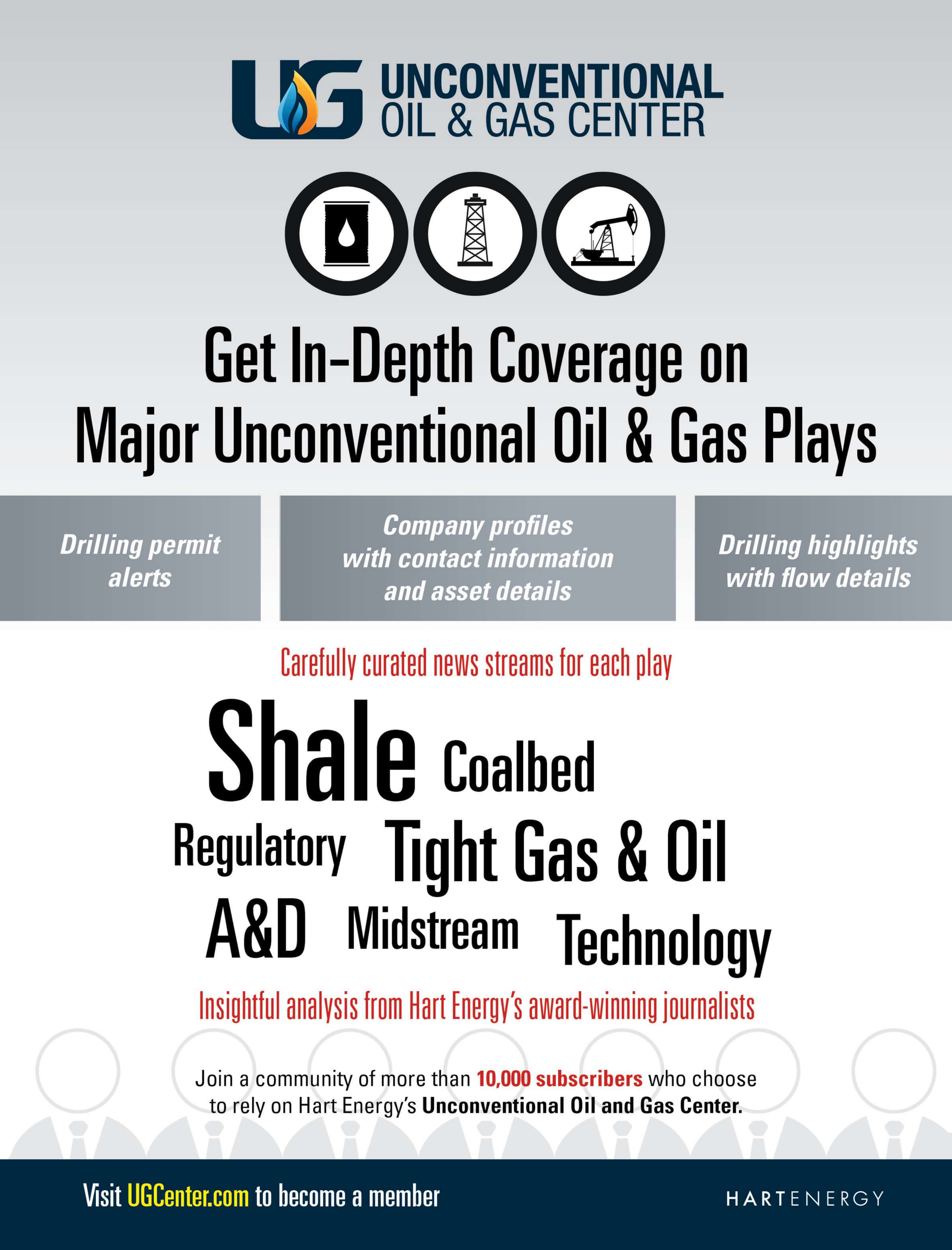
Eni strikes gas offshore Indonesia

Eni has made a gas find in the Merakes exploration prospect in the East Sepinggan Block, where the company is operator with a 100% stake, according to a news release. The block is located offshore East Kalimantan (Borneo), 170 km (106 miles) south of the Bontang LNG Plant and 35 km (22 miles) from the offshore Jangkrik Field, also operated by Eni. The find was made through the Merakes 1 well, which was drilled at a water depth of 1,372 m (4,501 ft). The well encountered a significant accumulation of gas in the lower Pliocene clastic sequence. Merakes has crossed a hydrocarbon column of 60 m (197 ft) in high-quality sandstones.

GULF OF MEXICO

Repsol makes oil find in GoM

Repsol has made a new discovery of high-quality oil in the U.S. Gulf of Mexico, the company said in a news release. The find was made 352 km (219 miles) from the Louisiana coast in an ultradeepwater well named León, located in Keathley Canyon Block 642. The well found more than 150 m (492 ft) of net oil pay within a column of more than 400 m (1,312 ft). The well was drilled in water 1,865 m (6,119 ft) deep and reached a total depth of 9,684 m (31,772 ft).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HARTENERGY

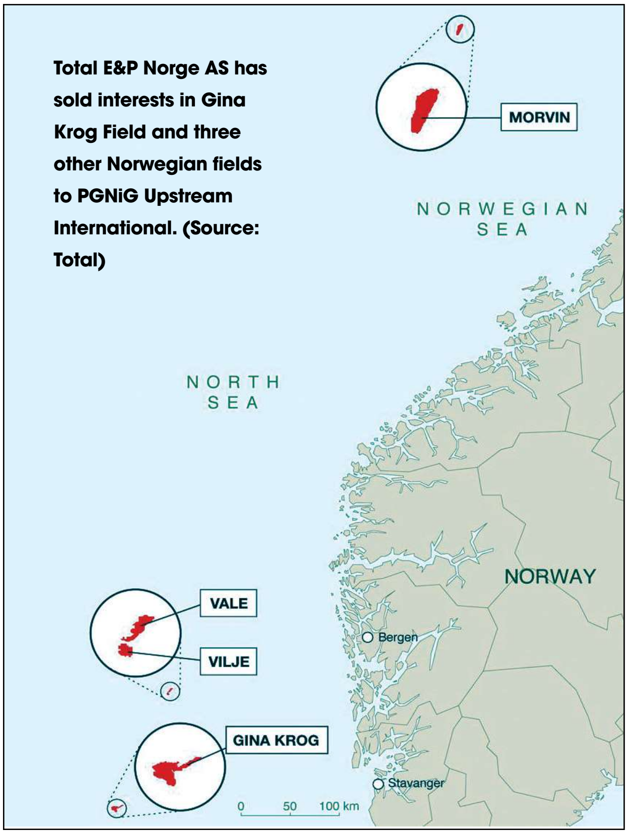
Hess plans Stampede Field development

Hess Corp., together with its project co-owners, will proceed with the development of Stampede, an oil and gas project operated by Hess in the deepwater Gulf of Mexico, according to a press release. The plan initially calls for six subsea production wells and four water injection wells from two subsea drill centers tied back to a tension-leg platform. A two-rig drilling program is planned, with the first rig commencing operations in fourth-quarter 2015. First production is expected in 2018.

EUROPE

Total sells interests in Gina Krog, other Norway fields

Total's wholly owned subsidiary Total E&P Norge AS has signed an agreement to sell to PGNiG Upstream International an 8% interest in the Gina Krog Field in Norway together with its interests in the mature fields of Vilje (24.243%), Vale (24.243%) and Morvin (6%), Total said in a press release. The consideration for the transaction is $317 million, with an effective date of Jan. 1, 2014. The transaction is subject to the approval of the Norwegian authorities. Following the sale, Total E&P Norge AS will retain a 30% interest in the Gina Krog Field alongside Statoil (58.7%) and Det Norske (3.3%).



Total E&P Norge AS has sold interests in Gina Krog Field and three other Norwegian fields to PGNiG Upstream International. (Source: Total)

GDF Suez, BP discover central North Sea Field

GDF Suez E&P UK Ltd. and BP have made a new exploration discovery in the U.K. Central North Sea. The discovery, which spans GDF Suez-operated Block 30/1f (License P1588) and BP-operated Block 30/1c (License P363) was flow-tested at a maximum rate of 5,350 boe/d. The discovery, referred to as Marconi by GDF Suez and Vorlich by BP, is located in the Central North Sea. Exploration well 30/1f-13AZ encountered hydrocarbons in a Palaeocene sandstone reservoir in Block 30/1c (License P363 operated by BP), and a subsequent side -track into Block 30/1f (License P1588 operated by GDF Suez) confirmed the westerly extension of the discovery.

SOUTH AMERICA

Petrobras hits hydrocarbons in Espírito Santo Basin

Petrobras has made a discovery of a hydrocarbon accumulation in the deep waters of the Espírito Santo Basin postsalt by drilling well 4-BRSA-1265-ESS/4-GLF-42-ESS, known as Lontra, at a water depth of 1,319 m (4,327 ft), according to a press release. The well, which is 81 km (50 miles) offshore the city of Vitória in Espírito Santo state in Brazil and lies within the Golfinho concession area, confirmed the presence of gas and condensates as supported by log data and cable tests.

First Libra well confirms oil discovery

The first extension well in the Libra area, known as 3-BRSA-1255-RJS (3-RJS-731), has proven the discovery of high-quality oil in the northwest portion of the structure, the Libra consortium said in a news release. The well is located in the presalt Santos Basin about 170 km (106 miles) off the coast of the state of Rio de Janeiro and about 4 km (2 miles) southeast of the discovery well, 2-ANP-2A-RJS. The oil-bearing interval was observed by means of fluid profiles and samples, which will subsequently be characterized through laboratory analysis.

MIDDLE EAST

Kurdistan approves Akri-Bijeel FDP

The field development plan (FDP) for the Akri-Bijeel Block in Kurdistan has been officially approved by the Minister for Natural Resources, according to a press release from MOL Group. The FDP relates to two commercial discovery areas in the Akri-Bijeel block, the Bijell and the Bakrman areas. MOL Kalegran Ltd., a 100% subsidiary of MOL, is the operator of the Akri-Bijeel Block. The FDP is based on two commercial discovery areas. The development will be done in two phases. E&P

HARTENERGY

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PEOPLE

MicroSeismic Inc. appointed **Rick Luke** CFO.

McCrometer promoted **Melissa Aquino** to the position of president. Former president **Kerry McCall** is moving to the role of chief flow technology executive.

DNO ASA has chosen **Jeroen Regtien** as COO.

Noble Energy has selected **David L. Stover** to be president and CEO.

Total SA appointed **Patrick Pouyanne** CEO, succeeding **Christophe de Margerie**, who was killed in a plane crash. **Thierry Desmarest** has become chairman of the board until year-end 2015.

BG Group named **Helge Lund** as CEO and as an executive director.

Statoil's board of directors appointed **Eldar Saetre** as acting president and CEO.

Energy XXI tapped **Bruce W. Busmire** as CFO.

Robert Hvide Macleod has joined Frontline Ltd. as CEO.

Greene's Energy Group has named **Robert Fraser** (left) as regional business development manager for the Middle East, Africa, Asia-Pacific and countries surrounding the Caspian Sea.

Canada Energy Partners Inc. has appointed **Winston R. Purifoy** as a director of the company.

First Integrated Solutions has chosen **Bob Glatley** (left) to serve as sales and technical support manager.

Brett Smith has taken on the role of executive general manager for safety, people and systems for Senex Energy Ltd.

Charles O. Holliday has become chairman of the board of directors of Royal Dutch Shell.

Peter Farthing (left) has been selected to be Ennsub's sales and marketing manager.

Alfonso Leon has resigned as executive vice president and CFO of Apache Corp.

Walter Dale (right) joined Bosque Systems as the executive director of solutions business development.

Glori Energy Inc. added **James C. Musselman** to its board of directors.

Federico Casavantes (left) has taken on the role of vice president of marketing for EV.

Survivex has promoted **Chris Hardie** (right) to finance director.

Magne Reiersgard and **Arild Reksnes** have changed responsibilities at Petroleum Geo-Services ASA. Reiersgard became executive vice president of marine contract, and Reksnes became executive vice president of operations.

Ray McGlynn has been appointed as sales manager for offshore oil and gas for BMT Group Ltd.

HOLT CAT has named **Jim Campbell** (right) as senior director of public affairs. **Howard Hicks** has retired as vice president of public affairs.

Powell Valves is restructuring its customer service team and has made the following appointments: **Kate Boggs** (left) has become manager for capital projects quotation and management; **Katie Rominger** (top right) has been appointed manager for customer service, distribution and maintenance, repair, and operations; and **Jeff Sizer** (lower right) has been named manager for international customer service and business development.

Terje Vastveit has been chosen as Far East regional manager of Cubility AS.

Michael Briningstool (right) has joined the Wm. Powell Co. as manager of shipping/receiving and store operations.

Ian Peters has taken on the role of international downstream leader of Centrica on an interim basis.

SBI Offshore Ltd. tapped **Mirzan Bin Mahathir** to join its board of directors.

Andrew L. Fawthrop joined the board of directors for VAALCO Energy.

Nordic Energy appointed two new directors to its board: **Don Nicolson** has become nonexecutive chairman, and **Jeremy Kane** is now a nonexecutive director.

COMPANIES

Polyflow LLC opened its new manufacturing plant in Midland, Texas—the first reinforced thermoplastic pipe facility in the Permian Basin. The new integrated design, manufacturing and service facility will help the company serve its customers in West Texas, New Mexico, South Texas and the Midcontinent region.

Hoover Container Solutions Pty. Ltd., a subsidiary of Hoover Group Inc., has moved to a larger renovated facility in Perth, Western Australia, to accommodate its expansion in the region. The new distribution and service center allows Hoover to handle all intermediate bulk containers, ISO tanks and offshore equipment destined for oil and gas platforms, mining sites, islands and supply bases north of Perth. The complex hosts two large wash bays and workshop that have in-group sump pits and underground storage tanks. A concrete hard stand has numerous ground tanks that capture all rainwater that will later be used for the rinsing of tanks. In the future, the facility also will provide recertification, repairs and maintenance at a National Australian Testing Authorities certified level.

HB Rentals, a Superior Energy Services company, has officially opened its new service location in Ciudad del Carmen, Mexico. The location supports HB's range of service offerings that include accommodation modules and operating essentials such as water, sewage, power, lighting and communications systems. The company will be able to respond more quickly to the needs of its Mexico-based clients and reduce project expenses by eliminating importation and transportation costs. E&P

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To intervene or abandon?

Integrated service offering helps operators make the decision.

Ian Smith, Weatherford

As offshore oil and gas fields continue to mature, operators are faced with growing dilemmas regarding how to manage their late-stage, low-production wells. A number of wells are stockpiled for abandonment, with the majority still in the U.S. Other major producing regions with significant numbers of idle wells include the North Sea, Asia-Pacific and Sub-Saharan Africa. Worldwide, this number of abandoned wells is growing at a rate of 8% to 10% per year.

Well decommissioning and abandonment is an inevitable part of the asset life cycle that represents a pure cost to the operator with no promise of boosted profits from increased production. While abandonment has traditionally been viewed as an isolated activity, it shares many operational synergies with late-stage workovers. Both operations are performed on older wells that have integrity issues, a lack of data for accurate cost estimating and limited deck space for intervention equipment and personnel on board.

The decision to extend a well's productive life with a workover or abandon the well altogether depends on several factors, including the market price of oil and the regulatory requirements in place at the time. To that end, service providers can play a critical partnership role not only in helping operators make this decision but also in offering services that maximize resources and minimize costs and safety risks for both operations.

The Weatherford Well Intervention and Abandonment group, for example, has designed its service offerings to help operators make more informed decisions about which path to pursue. The business unit provides an integrated operational planning and execution service supported by engineering support from reservoir analysis and petroleum consulting to determine remaining reserves and the best intervention processes to economically recover them. The service also provides synergies in the form of the same personnel, application expertise and equipment to help operators extend production to maximize late-life recovery and transition to decommissioning and abandonment operations.

Going rigless

Rig-free technology is one example of a synergistic service offering for late-life well intervention and abandonment. Weatherford's rigless hydraulic pulling and jacking unit is engineered to ensure that jobs can be performed in the small spaces allotted and in short time frames. The unit integrates a variety of intervention services and products, including tubular running services, wireline, cutting and cementing tools, pumping equipment, and fishing and re-entry tools. And by using this unit for late-stage interventions and abandonment instead of drilling rigs, the operator is free to use the rigs to drill new wells.

In well abandonment applications, rig-free technology helps the operators execute the operation as quickly, safely and cost-effectively as possible. At the same time, the execution experience and application expertise of the field personnel help ensure that well abandonment is done correctly. This assurance avoids the need to revisit the abandoned well some time later to address a leak, which is often a significantly more expensive endeavor than the initial abandonment operation.

In some cases, the longer an operator delays abandonment, the more money it may have to spend to upgrade the offshore structure or to address well integrity and environmental risks ahead of actually abandoning the well. Rigless intervention also offers a proven alternative for operators who are idling wells and delaying abandonment for some future time to extend production.

This scenario has proven effective in many aging offshore assets, including a deepwater Gulf of Mexico well in which old chrome tubing had to be pulled out and replaced with new tubing. Weatherford's intervention services were deployed on a pulling and jacking unit, which included the use of wireline to perform diagnostics and transport perforating guns downhole, slickline to carry tools and the bottomhole assembly, cutting tools to sever the pipe and equipment to cement the wells. The execution of this job avoided the use of rigs (and their associated high day rates), minimized downtime and allowed the wells to come back online with a 300% to 400% boost in productivity.

This is but one example of how operators can make safer and more cost-effective intervention and abandonment decisions for their maturing assets. The first and most critical step is to partner with a well services provider who brings excellence in operational planning, execution and a commitment to doing the job the right way the first time. E&P