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COMING NEXT MONTH The February issue of ***E&P*** will provide an update on the rapidly evolving field of hydraulic fracturing. Other features will examine reservoir characterization, drilling fluids and oilfield chemicals, water management, subsea production systems, and the regional report will focus on Australia. 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 LLOG Exploration's Delta House semisubmersible production platform was installed in Mississippi Canyon Block 254 in October 2014. Left, the gravity-based structure for the Hebron Field will tower 120 m (394 ft). (Source for main image: InterMoor; source for left-hand: ExxonMobil Canada Properties; cover design by Laura J. Williams)

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OMV has produced first oil from its Maari redevelopment drilling campaign in New Zealand. The Maari Growth project aims to increase reserves, production and recovery from the producing Maari Field.

TAG's Cheal-E6 well intersects hydrocarbon-bearing sands

The Cheal-E6 step-out well, located in the onshore Taranaki Basin of New Zealand, has intersected more than 9 m (29.5 ft) of net oil- and gas-bearing sands in the Mt. Messenger Formation.

DNV GL releases new recommended practice for subsea lifting

The completion of a joint industry project to improve existing standards and regulations around subsea lifting operations has resulted in a new recommended practice.

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Mozambique undertakes new licensing round to boost gas, oil output

By Obafemi Oredein, Special to E&P

The country is offering 15 blocks, including 11 offshore.

Oil, gas technologies investment tops $7 billion

By Velda Addison, Associate Online Editor

A report shows that E&P technology investment, led by spending in North America, has reached about $7 billion since 2003.

The U.K. needs to do its homework

By Rhonda Duey, Executive Editor

Vast shale deposits are beckoning, but the geology needs to work.

Canada faces obstacles in developing LNG

By Paul Hart, Hart Energy

An active drilling program and existing production are among Canada's strong points, analyst says.

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Exploration still the key to the door

With the focus on cost-efficiency and belt-tightening all round, it's easy to neglect that this industry needs to keep finding oil and gas. It will come from various sources—aspects such as EOR techniques are crucial to "finding" reserves where they already exist but that remain locked underground. Every extra percent released from known reserves is a new discovery.

But having spent time with pre-eminent explorationists at a recent event in London, the importance of identifying new and neglected plays and the use of the latest seismic technologies remains arguably the most vital factor. If we don't find new reserves, we're done.

Fortunately we have a good track record. Global oil reserves have risen consistently, standing at 700 Bbbl in 1981 and more than doubling to 1.67 Tbbl by 2012—despite 850 Bbbl being produced in between. In the past 30 years the industry has found 20 Bboe to 25 Bboe of conventional resources annually.

As Richard Herbert, COO, exploration at BP, said at the PETEX event: "The industry has been extremely successful in renewing itself and growing its resource base, and exploration has played a big part in this."

He highlighted the dramatic change brought about by unconventionals, which have raised estimates for oil-in-place by about 50% from 30 Tbbl to 45 Tbbl.

Although the OECD world has limited forecast growth, the non-OECD world's energy demand is still soaring, fed by population growth and rising incomes.

Conventional offshore areas such as Brazil and West Africa will continue to play their part, along with growing global gas resources longer term, but Herbert pointed out, "Having said all of that, when you add together all the conventional resources that have been found in the last decade, they still don't match the enormous quantities of resource that have been unlocked in North America in unconventional resources."

Putting that in perspective, with the U.S. having grown its Lower 48 production from almost zero to 4 MMbbl/d of tight oil, the impact has been enormous. "It's akin to adding another OPEC country, bigger than any other apart from Saudi Arabia," Herbert said.

Another explorationist also used the Saudi Arabian analogy. Alistair Milne, Shell's vice president, Sub-Saharan Africa, calculated the industry needs to add 700 Bbbl of oil reserves just to replace the next two decades of production, saying, "To meet this demand the world will need to add new production of some 40 MMbbl/d of oil in this decade from fields that haven't been developed yet!" This is like adding four times what Saudi Arabia produces today to meet that, he said.

I'm an optimist myself, and with evolving exploration technologies opening up fresh opportunities, the industry should be also.

BP's Herbert agreed, "The future of exploration is difficult to predict. But I do believe that explorers have to be optimists, and the industry has a long and distinguished track record for finding the oil and gas that the world demands," he said. E&P

Mark

Shale gas—catalyst for commercial growth

The demand for leading-edge process simulation tools is on the rise.

Paul Taylor, AspenTech

The "shale gale" has swept in a new era across the energy industry. Is it the catalyst for economic growth, increased jobs, improved government revenues and a boost for manufacturing profitability? Environmental debate aside, exploration of shale offers a viable means to help lower gas prices and meet energy demands across the globe. So what does the future hold for this unconventional energy source?

On the one hand, the abundant supply of shale gas and its success in the U.S. provides tremendous impetus for industries such as refining and petrochemicals while also reducing operating costs for associated industries, including steel producers and manufacturers. On the other hand, shale gas is still an untapped resource for many regions that have relied on conventional oil and gas feedstock, so the potential for commercial growth is enormous.

Shale a boost for business

A good example of the positive effect of shale gas in the U.S. is that gas has become an attractive alternative feedstock when compared to relatively high-priced crude oil. Consequently, U.S. naphtha and petrochemical producers now enjoy a major cost advantage over foreign competitors who are dependent on liquid feeds. By comparison, the Middle East still has the most feedstock advantage. However, gas availability is rapidly becoming an issue. As a result, many petrochemical sites are turning to liquid feedstocks, hence eliminating their competitive advantage.

Saudi Arabia, for example, has committed to plans to exploit its unconventional gas reserves. Kuwait and the UAE also are reviewing the potential for the resource. Although not significantly affected by shale gas, Qatar is looking to end its indexation to oil prices and move to more flexible agreements. Overall, it is unclear how the Gulf Cooperation Council countries will be affected by unconventional gas resources. However, in the long term, shale is almost certain to play a role in the Middle East's energy portfolio as more traditional feedstocks continue to experience price fluctuations and market volatility.

Vast shale gas reserves exist across Europe, and the economic benefits of shale gas could encourage exploration. It is true that European shale gas deposits are geologically more difficult to extract than in the U.S. Drilling can be land-intensive, and this could be disruptive or expensive in densely populated Europe. However, with the appropriate surveying techniques, technologies and skills, companies are making exploitation commercially feasible today.

The U.K. introduced tax relief for investors in shale gas to boost interest in such projects. Investment programs have already taken effect, with Total announcing that it had taken a 40% interest in two shale gas exploration licenses in the U.K. Total's shale gas projects also cover the U.S., Argentina, China, Australia and Denmark.

While the U.S. has enjoyed significant benefits from the shale boom, Russia has substantial recoverable shale oil resources. Russia has more technically recoverable shale oil resources than the U.S. (75 Bbbl vs. 58 Bbbl, according to the Energy Information Administration). Natural gas is not simply another form of carbon fuel—it burns 50% cleaner in terms of CO_2 emissions compared to coal and 25% cleaner than oil. When used with the latest power generation technologies and distributed generation that minimizes transmission losses, the actual carbon savings compared to coal can approach 70%. With this in mind, China faces significant environmental challenges with its heavy dependence on coal, so the Chinese government has issued development plans outlining a move toward shale gas instead of coal as a means to reduce emissions and exploit financial opportunities. Crucially, China has almost twice the recoverable shale gas reserves as the U.S. In essence, countries that can exploit their shale reserves sustainably in the future will reap considerable economic rewards.

The revolution in unconventional oil and gas also has helped to further entrench the supermajors' dominance in the oil and gas industry. According to Wood Mackenzie, the ranking of top 20 energy companies is virtually unchanged. The top four companies are Saudi Aramco, Gazprom, the National Iranian Oil Co. and Exxon Mobil. Rosneft, Shell PetroChina, Pemex, Chevron and Kuwait Petroleum Corp. all feature in the top 10.

Tools for the job

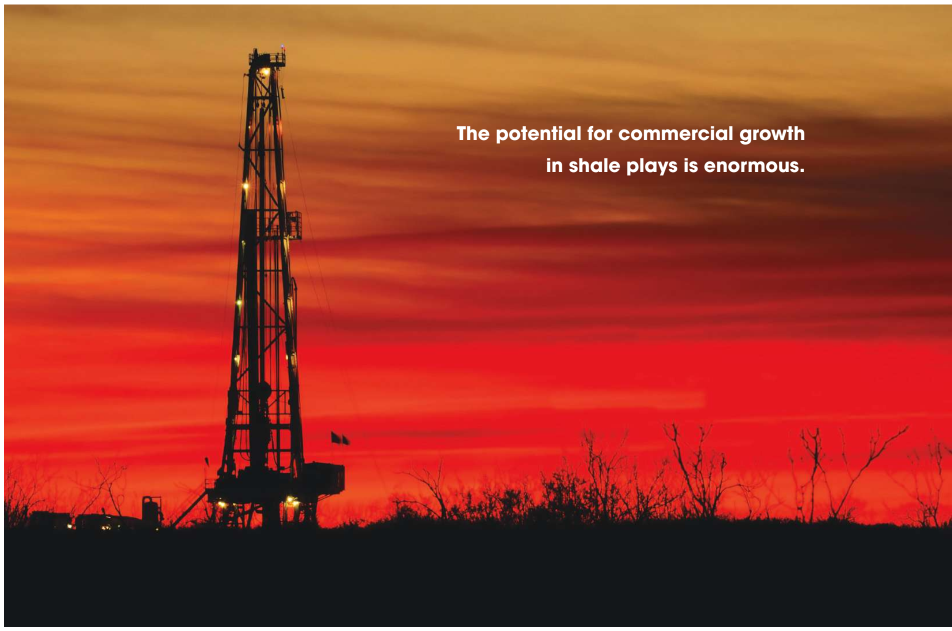
The creation of jobs as a direct result of shale gas reflects the high demand for engineers and expertise across key disciplines, from chemical engineering and operational management to executive leadership.

This natural gas shale gale has the potential to support millions of jobs globally and contribute billions of dollars to GDP. To support the expansion of production within the shale gas industry, significant growth in capex and employment is expected. According to a recent IHS report, in 2010 alone shale gas industry activities contributed more than 600,000 jobs to the U.S. economy, and by 2015 IHS projects the industry to grow by a further 45%, adding an additional 270,000 jobs. In fact, by 2035 it estimates that shale gas activities will contribute 1.6 million jobs to the overall U.S. economy. The majority of company executives are optimistic about their growth prospects for the long term and are already planning further growth in the oil and gas industry. The need for engineering expertise is positive news for employment prospects, and many engineering operators are rapidly recruiting and training to gear up for growth.

The growth in business correlates with the need for appropriate skills. More and more companies are investing in leading-edge technologies to help equip engineers to meet demand and operational objectives. Extraction of natural gas from unconventional shale formations has become more technologically and economically viable due to improved horizontal drilling and hydraulic fracturing techniques. On a separate point, the demand for leading-edge technologies is subsequently on the increase, including process simulation tools. This is, therefore, a crucial component for companies wanting to transport and process gas reserves. Software technology helps to facilitate the need for improved cost efficiencies. The adoption of engineering software solutions enables companies to bring new gas and liquids processing facilities to market faster with a higher return on investment. The software reduces capital costs through steady-state and dynamic process optimization and lowers operating costs by integrating simulation models with plant data for operations planning and decision support. In an operational context, software solutions optimize manufacturing and supply chains subject to economics, feeds, constraints and demands while providing the agility to react to changing market conditions. Maximizing assets for optimal profitability is vital when margins are tight in highly competitive markets. Process industry software helps optimize unconventional shale play opportunities by aligning inventory and distribution with market demand.

Future prospects

The long-term effect of shale gas is predicted to reap substantial rewards. Lower energy costs will mean that manufacturing becomes cheaper and that investment across industry will be widespread, including growth in chemicals, engineering, technology and employment. Government policymakers and commercial investors who reject shale extraction technologies as niche developments must consider the longer term implications. Market growth means a flourishing economy, job prospects and valuable skills development and potentially a balanced approach to energy portfolios where the reliance upon traditional energy sources has been consigned to feedstocks from powerhouse energy-rich regions. The unconventional could soon become conventional.



The potential for commercial growth in shale plays is enormous.

Predicting the dynamics of the oil and gas industry and the commercial outlook is complex. Nevertheless, for the foreseeable future one simple fact is certain: Energy demand across the globe will continue to grow. Powered by leading technology, harnessed with industry skills and investment, and regulated by rigorous environmental policies, shale gas will play a vital part of energy portfolios and will continue to be a catalyst for profitable growth. E&P

Icebreaker

Independents as well as majors are reviving Alaska's oil and gas production.

Darren Barbee, Oil and Gas Investor

At the end of the road and the end of a shift, workers in Alaska's Prudhoe Bay, the largest oil field in North America, come to Deadhorse. Alaska has a plentitude of colorful place names, such as Cold Bay, Abyss Lake and Red Devil. But Deadhorse comes closest to embodying Alaska's slumbering oil and gas industry.

In 1988, the state produced 738 MMbbl of crude, equal to about 25% of all U.S. production. In 2013, Alaska's yield had fallen to 188 MMbbl, about 7% of U.S. output.

Yet Alaska is poised to break out of its slump. Newcomers are believers, set on unlocking the state's resources in what former Gov. Sean Parnell called "The Alaska Comeback." Companies are working diligently to find oil and gas, and some, such as Miller Energy Resources and NordAq Energy Inc., are set on becoming Alaska pure-plays. Partly, Alaska's optimism is traceable to the reform of its paradoxical tax system on North Slope production. Enacted in 2007, the old law linked higher taxes to higher oil prices. Levies could hit up to 75% of net profit.

Bob Swenson, deputy commissioner for Alaska's Department of Natural Resources, said the state's previous tax regime was onerous before changes were made last year. Since then, the More Alaska Production Act (MAPA) has capped the nominal tax rate at 35%. It rewards production instead of the former system's emphasis on lease capital investments.

The law can help defray a large slice of costs. From June to October 2014, Miller Energy received tax credits, in cash, of about $56 million.

Though Alaska is home to the largest oil companies in the world, smaller companies are having a big impact. Independent oil companies are boosting oil production in Cook Inlet, and a new independent-led project on the North Slope is beginning to take shape.

Cook Inlet offshore oil production also is increasing. Production rose to 15,486 bbl/d in third-quarter 2014 from 13,677 bbl/d in the previous quarter. The increase reflects the trend in oil production over the past two years.

Swenson said companies including Repsol S.A. and ConocoPhillips have drilling programs underway. In late October the latter announced a new drillsite at Kuparuk that is expected to produce 8,000 bbl/d of oil at peak production. The drillsite is one of the key projects announced since the passage of MAPA, said Trond-Erik Johansen, president of ConocoPhillips Alaska.

Miller Energy Resources' Osprey platform is 5.6 km (3.5 miles) southeast of the Kustatan production facility in Cook Inlet. The platform sits in 18 m (60 ft) of water and is designed for 21 wells producing 25 Mbbl/d of oil. (Source: Miller Energy Resources)

"This is in addition to the two rigs we have added to our North Slope drilling fleet as well as the newbuild drilling rig currently under construction," he said. "The positive investment climate we now have in Alaska has been an important factor in the increased investment levels."

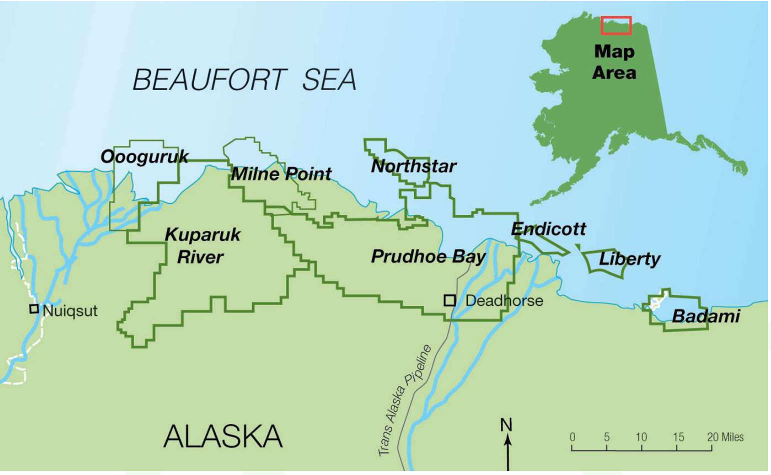
Operators have plenty to shoot for. Alaska has produced 16.2 Bbbl of oil in its history, largely from the North Slope. What remains is 5.6 Bbbl of discovered conventional resources, another 19.2 Bbbl of undiscovered crude and 5.5 Bbbl of unconventional resources.

Party favors

Ambition is easily transmitted among independents on the North Slope. And Alaska likes independents—a lot.

Stephen Hosmer, CEO of Royale Energy Inc., said Parnell has been aggressive in trying to recruit independent producers to the state.

"I was recently invited into the governor's office with a



Activity on Alaska's North Slope accounts for most of the state's oil and gas production. The area contains more than a dozen of the largest U.S. oil fields and several of the largest gas fields. (Source: *Oil and Gas Investor*)

group of independent producers," Hosmer said. "I've never been invited to the governor's office in any other state. That shows a certain level of commitment to the industry."

Parnell's support of smaller independents is what will help create new productive fields. "I think he's being rather visionary in that regard," Hosmer said.

Royale announced in June that it was targeting two potential drilling sites reviewed by Netherland Sewell & Associates. Geological and geophysical data, including a 3-D seismic survey, "concluded the targets contain 17.8 to 325.3 million barrels of oil in place," the company said. Recovery ranges from 14% to 42% of oil in place.

Hosmer said Royale was ready to drill until a former partner was unable to fulfill its responsibility to fund drilling of the first two wells. Plans to drill are on hold until winter of 2016.

"We're very excited about getting the project underway but rather disappointed that we didn't get it done for this winter," Hosmer said. "We are fully committed to Alaska and to testing this property's concept."

Hosmer said he finds that most people in Alaska are excited to work in a "more stringent environment." That includes a great deal of regulatory oversight.

"I've never worked in place that has the regulator working constructively with industry as much as they do in Alaska," he said.

Unlocking Alaska

Carl Giesler Jr.'s years in business have taught him that the best way to create value is to "buy right."

"You realize value when you buy something, not necessarily when you sell it," said Giesler, CEO of Miller Energy Resources Inc. "So we're very careful on how much we pay for acquisitions."

Alaska's frequently low sale prices were just part of the appeal to Miller in making the 5,270-km (3,275-mile) journey from Houston.

The company's leaders are so convinced of Alaska's potential that they are selling the last of their Lower 48 assets in the southern Appalachian Basin in Tennessee. The company's Tennessee assets are worthwhile but represent only a small part of Miller's production and value.

"From an investor perspective and overall value creation perspective, we felt it was better to segment them out, sell them and become a pure-play Alaska company," Giesler said.

In September Miller reported average net production increased by 144% from fiscal year to fiscal year, to 3,313 boe/d from 1,360 boe/d.

Giesler said Miller's aim is to create an oil and gas company where shareholders can focus their investments in Alaska. Alaskan operators such as Exxon Mobil, Apache Corp., ConocoPhillips, Caelus, Hilcorp and others are either far-flung giants or private companies.

"We are the only pure-play Alaska E&P company," he said. "If you're an investor and you want exposure to Alaska, we're it."

Miller wants to make the case that Alaska is one of the best places to be, not just in the U.S. but also worldwide, to explore for and develop oil and gas.

The company has access to a solid resource base and the operational and financial skills needed for development.

"Over time we've been trying to simplify and lower the cost of capital so that it's just an easier way to invest," Giesler said.

There is much on the company's plate, he said. Miller is studying a master limited partnership for monetization of its midstream assets. In September it entered into a nonbinding letter of intent to buy substantially all of Buccaneer Energy's operating assets for about $40 million to $50 million. Buccaneer Energy has proved reserves of about 1.9 MMboe and produces about 1.7 Mboe/d.

The company also made a $9 million offer in May to acquire Savant Alaska LLC's Badami Unit on the North Slope.

Earlier in the year, Miller won a bid to acquire an exploration license on 168,000 acres in Cook Inlet on the Iniskin Peninsula.

Giesler said Alaska has been a good partner, and Miller will look for opportunities that make economic sense. "If we can continue to unlock the value of our resource, I think it will show in our stock price." E&P

Digging for downhole data

Cost is the most common issue involved in deciding if and how to collect data.

Richard Mason, Chief Technical Director

The basics still count when it comes to well data collection—and the methods used to obtain it. For downhole information, operators overwhelmingly employ wireline logging, a long-time industry staple that produces high-volume descriptive data that can be compared against a large library of existing logs and interpretive knowledge. Wireline logs prove especially useful when operators are delineating new acreage.

The largest proportion of wireline data collection still involves the tried-and-true triple-combo log, which provides information on density, porosity and resistivity—the holy trinity of downhole data. The main advantage to the triple-combo is the ability to string together different logging tools in a customized manner and convey the tool assembly through the drillstring.

Operators employ a number of variations, including quad-combo and through-the-bit logging services, with the latter used to overcome conveyance obstacles associated with making the curve and performing successfully in horizontal laterals. Through-the-bit logging tools reduce the cycle time for logging because of quick conveyance through the drillstring and deployment from the end of a pass-through drillbit. Drillers maintain full surface pressure control during the process.

Hart Energy's Market Intelligence program surveyed participants in the downhole data collection business, including operators, seismic and wireline providers, and consultants, in December 2014. The surveys had a Permian Basin bias, though conversations were held with participants active in multiple plays across the domestic market.

Nearly 80% of those using wireline logging employ the practice openhole as opposed to cased-hole logging. In some cases such as horizontal laterals, operators run a single tool to collect openhole gamma rays. Otherwise, operators restrict data collection to the vertical well column.

The progression of logging services in a drilling program ranges from use in all pilot holes while delineating a play to a sample of holes in the vertical section of wells in close proximity when an operator reaches resource development mode.

Less frequently used data acquisition techniques include sidewall coring, chemical or radioactive tracers, 3-D seismic and microseismic. Microseismic data are rising in use, though the technique still has low market penetration. Microseismic is used to monitor the progress of completions and provide operators an opportunity to tweak completions to enhance productivity.

Now that the land grab is behind the industry, operators are joining together in best practices. Operators generally will share area 3-D seismic information during the resource development phase of unconventional plays. These data also are seeing greater use in reservoir characterization.

Cost is the most common issue involved in the decision to collect downhole data. Participants in the Hart Energy survey noted basic downhole data acquisition added about 1% to well cost.

"Wireline logging is still our most common data acquisition tool," a mid-sized Texas operator told Hart Energy. "The data portion is only around $10,000 per well. Most wireline cost is for the 'per stage' cost for perf [perforation] guns and setting plugs. Data acquisition usually runs us less than 1% per well."

Microseismic cost can reach $150,000 for each well monitored, though in pad drilling the cost is spread among multiple wells on a pad. Microseismic adds 3% to 4% per well to data acquisition costs.

Surprisingly, permanent downhole instrumentation remains limited in market penetration, primarily due to the expense of the process. Fiber optics used for instrumenting a wellbore can add $500,000, with no clear metrics on whether or not the investment pays for itself.

Few survey participants expect the use of downhole data to decline, even in a downturn. Operators are now looking to become more efficient with completions in a down market to maintain profitability, and downhole data are marketed as a way to add value. E&P

- **Triple-combo and wireline openhole logging remain the main sources for downhole data**
- **Basic data collection less than 1% of well costs**
- **Microseismic making gains but still has low market penetration**
- **Cost is main barrier to more detailed data acquisition**
- **Few survey participants expect the use of downhole data to decline in a downturn**

A studio approach to learning

Interactive engagement improves physics comprehension.

RHONDA DUEY
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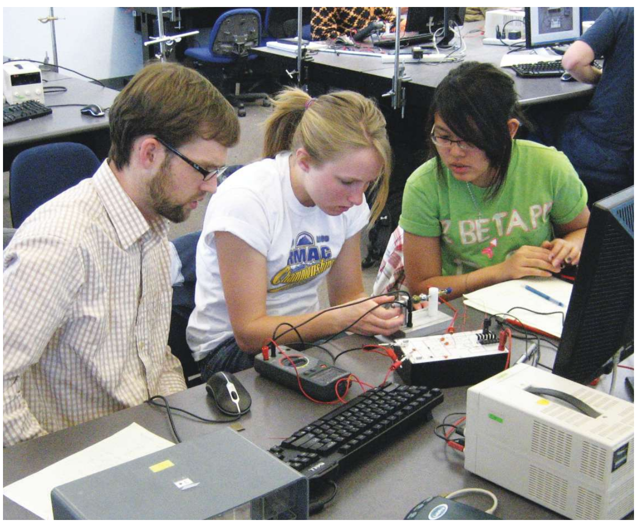
In the 1990s, the physics department at Colorado School of Mines (CSM) had a problem. Of the hundreds of students enrolled in calculus-based physics in a given term, as many as 40% of them either received failing grades or withdrew from the class to try again at a later date. Assessments such as the Force Concept Inventory, in which students are tested at the beginning and end of the class, showed in some cases no improvement in students' conceptual grasp of Newton's laws.

The concept of interactive engagement was taking hold during this time, and CSM decided to give it a try. Based on Studio Physics at Rensselaer Polytechnic Institute, the CSM Studio Physics concept began in 1997, with the first dedicated Studio opening in 2001.

"The idea is that any time people are trying to learn something, they learn by actually doing things," said Patrick Kohl, a teaching professor in the Physics Department at CSM. "STEM [science, technology, engineering and math] classes tend to be someone standing at the board lecturing at students. Only after they've gone home do they actually try anything."



A collaborative learning environment proves to be more conducive to retention than a traditional lecture approach. (Source: Colorado School of Mines)

Studio Physics labs are computer-equipped classrooms in which some or all of the students' time is spent in collaborative learning. Computer-centered activities provide a curriculum whereby students can learn the concepts of physics by working through problems together rather than simply being lectured to by a professor. Professors and teaching assistants are on hand as consultants, tutors and coaches.

CSM uses Studio Physics for all of its freshman-level physics students and has recently opened up a second lab for upper-division students.

The teachers rely on an online course management system to administer the lessons. Students log into the server to get started. "Even if we're just doing some calculus problems, that gets enhanced online," he said. "We can do things that we wouldn't be able to do with a worksheet.

"It takes a long time to code problems like that and test them out, but it's one of those things you do iteratively over many years."

Results have been positive, Kohl said. Both semesters of introductory physics have demonstrated much-improved test scores, retention and student satisfaction. The administration is so pleased with the outcome that it recently funded a Studio for the school's biology students.

Other departments are showing interest as well, and the concept seems to be catching on. "It takes some initial investment to put together a curriculum that's appropriate for the class, so interest doesn't always turn into action," Kohl said. "But it seems to be expanding more rapidly than it was before. People are starting to notice, including decision makers and check writers. That smooths out a lot of problems." E&P

Rhonda


Like you, he relies on
breakthrough technology

Drilling outlook

What will the oil prices mean for drilling activity?

RICHARD MASON
Chief Technical Director
rmason@hartenergy.com

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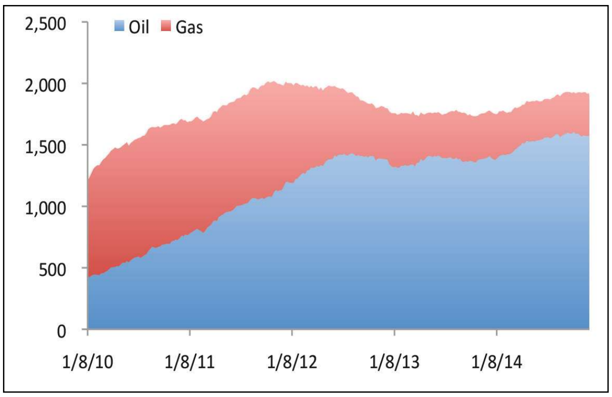
It's getting harder to ignore the 800-lb gorilla in the room with sub-$70 oil. So we'll pass on the topic of technology this month to address the issue of greatest interest to the industry, which is how the recent downturn in commodity prices will impact drilling.

Sentiment deteriorated rapidly in December 2014, primarily over future uncertainty in business conditions. Operators were reformulating 2015 capital spending plans with early estimates from the sell-side financial houses speculating on a spending downturn from 8% to 15%, depending on which side of the $70 line oil settles on in 2015.

Oil prices had been kind to the industry over the last three years but not so much lately, with oil dropping 30% from its peak in June 2014 to the post-OPEC meeting low below $70 in December.

Projections of field activity for 2015 have followed a similar trajectory. Early prognostications centered on a 200-rig decline in a sub-$80 world. When domestic pricing dropped below the $70 marker, those projections ballooned to 500 rigs, with the carnage slated for first-half 2015.

If the issue is balancing global crude supply, then U.S. land drilling is not the only geographic sector facing pressure. Higher cost oil sands and offshore projects also will contribute to the cutbacks that create a rollover in global production, giving domestic drillers time to hunker down for the year to 18 months it takes production to overshoot to the downside. Look for a new round of consolidation opportunities in a tough environment.



Will rig count fall to mid-2013 levels or those of early 2010? At $80 oil, analysts expect the former. At $70 oil, analysts expect the latter. (Source: Baker Hughes Inc.)

But if the brunt of supply rebalancing involves North American tight oil, the question becomes more acute. In this case, the last man standing will be companies who have acreage in the core tight-formation oil plays where breakeven costs are below $50. Outside the core, it's a matter of incrementals as marginal areas fade and emerging plays stop emerging.

Even with a drilling cutback in the first half of 2015, domestic oil production will continue rising in 2015—and likely 2016—though at rates measured in hundreds of thousands of barrels per day instead of a million barrels or more, prolonging the agony.

Operators have minced few words in announcing their intent to lean on service companies to reduce costs. But roughly half of the decline in domestic well costs over the last three years stems from competition associated with a previously oversupplied service sector. Oil service companies were on the threshold of realizing pricing improvements in third-quarter 2014 when the commodity price decline unfolded.

At peak this past summer, monthly domestic oil and gas revenues stood on the threshold of $40 billion, just a couple billion dollars shy of the 2008 peak. Now monthly revenues are closer to $30 billion, or about mid-2013 levels when rig count of 1,700 land units was 175 units lower than mid-December 2014.

Forecasts of a 200-rig decline are tough but livable. A 500-unit decline would signal a return to levels last seen in the spring of 2010, in which case the only good news is the worse it gets, the greater the recovery. E&P

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

Finding the right balance in automation

Controllers can be standalone solution or act as RTU.

Mark Scantlebury, Extreme Telematics Corp.

Over the past decade the oil and gas industry has moved more rapidly to adopt full automation systems, which are typically termed SCADA. By using a remote terminal unit (RTU) and a wireless communication system, producers can reduce the amount of windshield time for their operators.

The monitoring and control of field operations can be brought back to a central location where fewer people can monitor more field assets. Field operators can then be dispatched to problem wells as opposed to spending their time driving to sites that do not necessarily need attention. On the whole, this is much more effective and allows producers to lower their cost of operation. The question is, what have we given up?

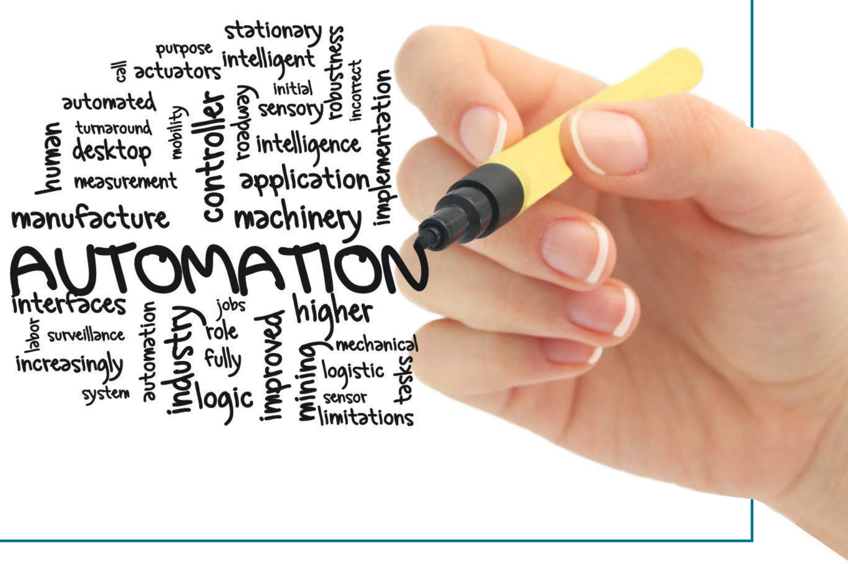
The reality is that these systems are usually more complex, they become more challenging to maintain, and control is taken away from the field operators who may know the well sites best. Too many times, I hear of frustrated operators that want to make a simple change to the system but are forced to call up an operator at the plant or connect to the system using their laptop and an unreliable cell connection. They feel like these systems are more of a burden than a benefit and are getting in the way of doing their job. Often times, operators end up putting standalone controllers in place of an RTU when it fails or does not work as expected.

Controls companies have lost sight of the user experience for some of their users. Why should producers have to choose between the flexibility and elegance of full automation at the plant vs. the simplicity and usability of a built-for-purpose controller that stands alone at the well site? The answer is that you don't have to choose because there are solutions that give you the best of both worlds.

Standalone controllers in plunger lift applications were slowly disappearing as producers started using programmable RTUs that included a plunger lift application. These RTUs were part of end-to-end SCADA systems that include radios and a plant- or web-based human-machine interface. Operators became frustrated and pushed back, forcing controls manufacturers to look for alternative solutions.

As a manufacturer of application-specific plunger lift controllers, Extreme Telematics Corp. felt this pain and designed a line of controllers with a communications port that speaks MODBUS, a standard protocol in the oil field. Not only can these controls be used as a standalone solution, but now they can act as the RTU or in conjunction with another RTU at site to be part of the full solution.

Producers have seen a number of benefits as they adopt these smarter, more connected controllers. They still get the benefit of a connected well site with management from the plant, office or home, but now operators onsite can directly check the status of the system and make changes right at the wellsite. These controls are simple to install and configure, have more safety functionality and optimization routines, and don't require any custom application development. This allows operators to focus on what they do best: ensure that each well site is producing the best it can. E&P

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New year, new mission for Red Hawk

Red Hawk spar finds a new GoM mission as part of the Rigs-to-Reefs program.

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January delivers a new year, fresh starts and a change in job descriptions for one Gulf of Mexico (GoM) spar. At the time of its installation on Garden Banks (GB) Block 876 in 2004, the Red Hawk spar was the world's first cell spar production platform. With its decommissioning 10 years later, the platform celebrated another first with its reefing at Eugene Island Block 384 when it joined the ranks of the Rigs-to-Reef program as its first spar.

The Rigs-to-Reef policy allows obsolete, nonproductive offshore oil and gas platforms to be converted to artificial reefs to support marine habitats, according to the U.S. Bureau of Safety and Environmental Enforcement (BSEE). BSEE's role in the program is to ensure that when an operator is no longer producing oil or gas from a well, the well is correctly decommissioned. Operators work with state agencies to receive permits to add platform structures to designated artificial reefs.

The decommissioning of Anadarko Petroleum Corp.'s Red Hawk spar was successfully carried out by the Acteon subsidiary Intermoor in October. According to the company, the project represents its first work in ballasting and deballasting.

The Red Hawk spar is the deepest floating production platform to date to be decommissioned in the GoM. Work was split between the original spar site at GB 876 at a depth of 1,585 m (5,200 ft) and the reefing site at a depth of 131 m (430 ft), according to a press release.

The company developed the engineering procedures and performed the work to disconnect the mooring lines from the floating facility. It also ballasted the hull prior to and during the topsides removal and deballasted it to prepare the hull for towing. Ballasting and deballasting were performed from a nearby derrick barge. The spar was then towed to the reefing site, where it was flooded and laid on the seabed in a controlled manner. After recovery of the mooring lines, the company assisted with the as-laid survey of the reefing site.

The Red Hawk spar was laid down in October at its new home in the GoM's Eugene Island Block 384. (Source: Intermoor)

"Through thorough engineering and efficient offshore operations InterMoor enabled Anadarko to facilitate the safe and efficient removal of the platform. Multiple departments were involved—project management, project engineering, advanced analysis group, subsea group, operations and shore base," Dusan Curic, project manager at InterMoor, said. "We also managed multiple subcontractors throughout the project."

One subcontractor on the project was McDermott International. The company's *Derrick Barge 50* assisted in the decommissioning. The barge is a dynamically positioned heavy lift vessel that removed mooring lines for the Red Hawk and provided accommodation and decommissioning support services, according to McDermott.

Dominic Savarino, McDermott's vice president and general manager, Americas, cited the project as "yet another example of our efforts to improve asset utilization beyond the requirements of our existing backlog."

As the renaissance continues in the GoM, we're sure to see more aging platforms receive extensions on their usefulness by providing support for marine life to flourish. E&P

Jennifer

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The Tubular Bells production platform in the Mississippi Canyon area of the GoM began producing for operator Hess in November 2014. The Miocene-aged field was brought onstream just three years after formal project sanction and features the first classic-design spar built in the U.S. It also came in on budget. (Source: Hess)

The GIFT that keeps on giving

By **Mark Thomas,**
Editor-in-Chief

"I'll be back."

Those were the immortal words of Arnold Schwarzenegger in the hit '80s movie The Terminator. *He wasn't kidding.*

For the oil and gas business in the Gulf of Mexico (GoM) in the months and years immediately following the Macondo tragedy in 2010 anyone uttering a promise similar to that on behalf of the U.S. Gulf would have been quickly consigned to the "extras" list.

But fast-forward to today, and the GoM is indeed back—and back with a vengeance. Declining offshore production is forecast to rise, and a succession of major or significant fields have been brought onstream both on time and on budget despite the despondent air of gloom within the industry caused by concerns over a falling oil price and rising costs.

Can this renaissance be sustained? The answer appears to be yes, with the GoM starting the year with a bang and ending it with a resounding boom.

But don't take our word for it—here are the views of a cross-section of some of the Gulf's leading players, with a broad portfolio of interests ranging from the traditional shallow-water shelf out into the ultradeep frontier.

One of the loudest proponents of the Gulf's emerging renaissance over the past four years has been Brian Reinsborough, president and CEO of one of the most recent entrants to the sector—privately held Venari Resources LLC.

Since the Dallas-based company started up in 2012, it has received commitments of $2.4 billion from Warburg Pincus and other private equity investors, and it's a participant in some of the GoM's largest oil finds in the Lower Tertiary play, including the large Shenandoah Field operated by Anadarko Petroleum in deepwater Walker Ridge Block 52.

Reinsborough, a former president of U.S. operations for Nexen, recalled, "I wrote the business plan for Venari in the middle of the drilling moratorium. At the base of its principles was that, at the darkest moments of the industry, I wanted to get into the Gulf of Mexico, and I wanted to get into it big. That was based on a future that I felt that the industry would eventually emerge into. That was the genesis of Venari."

His company's strategy is currently that of a non-operator. Speaking at Hart Energy's recent Offshore Executive Conference (OEC) in Houston, he outlined the importance of the company's focus on the subsalt in the GoM, principally in the Lower Tertiary. "It's an area that I feel has a tremendous amount of potential left, and the industry is now not only beginning to see it but understand it. And we want to be part of that.

"We call ourselves a subsurface operator, and we invest very heavily in seismic and try to influence in the front end of the business cycle in exploration and appraisal. And we leave the heavy lifting of the developments to some of the best operators in the industry."

Leaving the Gulf a mistake

Someone whose company has been in the GoM for a lot longer than two or three years is Tracy Krohn, CEO of W&T Offshore. He said he's long since learned that leaving it for dead is a mistake.

"We think that there's a tremendous future in the Gulf of Mexico. I've been in this business for three decades. We've carried the company on the basis that the GoM is always going to have an abundance of resources. I've heard the death knell for the GoM several times: 'The Gulf is dead, the Gulf is dead, long live the Gulf.' Every time that's occurred it's been a situation of opportunity for us, so we've always looked at the GoM as there's going to be another well, there's going to be another deal.

"We've been in the shallows since 1985 and in deepwater since the turn of the century. We've found hundreds

The Chevron-operated Jack-St. Malo semisubmersible platform began producing in the Walker Ridge area early in December. One of the highest-profile projects of 2014, the semisub unit is the largest of its kind in the GoM and has a production capacity of 170 Mbbl/d of oil and 1.2 MMcm/d (42 MMcf/d) of gas. Technology innovations include using the industry's largest seafloor boost system and the largest capacity high-pressure deepwater subsea pumps. Jack-St. Malo is the third ultradeepwater project in the Lower Tertiary (Paleogene) trend, following the Cascade and Chinook fields and Shell's Perdido Field. More than 500 MMboe of reserves will initially be recovered over a planned production life of 30 years from Jack-St. Malo. (Source: Chevron)

of millions of barrels of oil in the GoM over a long period of time."

Price-dependent

Krohn is the first to admit, however, that the industry's fortunes can be price-dependent. "The price moves downward, and activity slows down. We always get caught in these cycles," he said. "The oil production goes up for a longer period of time, and then it crashes down. That's how domestic U.S. production has been for 100 years, so we get caught in one of these down trends—and I'm not sure we're in a down trend. I would rather refer to it as a correction at this point in time, based on a number of different things."

W&T looks at the GoM daily, he continued, from the basis of what the company can do with the available pool of cash that it has. "We have the same issue that Shell does. We don't have a $35 billion budget; we have a $650 million capex budget, but it's the same problem. What do you put in there to accomplish your goals, and where do you best apply it?"

Gift that keeps on giving

"The GoM continues to give," he added. "We find new production and new technology; we find new fields. We find it with the drillbit, we find it through exploitation, we find it through EOR and we find it through better imaging techniques. We intend to be there for the rest of our existence. It's just a great province, and you can actually own the reserves, unlike elsewhere where there are PSCs [production-sharing contracts], for example. So here you have more control and more predictability."

W&T has recently made discoveries in 2,134 m (7,000 ft) of water, but it relies on a relatively simple process for its activities, according to Krohn. It tries to find a single point injection and ultimately capture 2 MMbbl to 3 MMbbl in reserves. For the company, it's economically viable to have a well produce 5,000 bbl/d, he said. "For us, it's a significant (find). It doesn't cost a lot of money. We do see those increasingly on the shelf and in deepwater."

Heavy hitters

One of Reinsborough's typical "heavy lifters" in the GoM is Shell Exploration & Production Co., currently the largest offshore producer in the area. According to Martijn Dekker, vice president of appraisal and hydrocarbon maturation, Upstream Americas Exploration for Shell, the Gulf always seems to reveal more resources than anyone thought possible.

Though rigs and regulations are mostly costing operators more and more, Dekker said the company is eager to keep exploring. "The GoM has an amazing capability to reinvent itself," he said. "To paraphrase Mark Twain, 'The rumors of the death of the Gulf of Mexico are highly exaggerated.'"

A couple of years ago Dekker said Shell's "thinkers" went beyond the present GoM conditions and imagined a working petroleum system in some of the deepest waters a mile or more down. "And boy, did that work out. We stepped into the deepwater," he said.

The company's high-profile startup of oil production in February 2014 from the Mars B development via the newbuild Olympus tension-leg platform (TLP) was Shell's sixth and largest floating deepwater platform in the GoM. Combined production from Olympus and the operator's original Mars platform is expected to be 1 Bboe. The Mars development sits in 896 m (2,940 ft) of water.

It also started up production from Cardamom Deep, which is helping to extend the life of its long-serving deepwater Auger platform.

Shell has another GoM project in the works that will reach nearly 3.2 km (2 miles) down to 2,896 m (9,500 ft)—its Stones Field that will be developed via an FPSO vessel, the *Turritella*. "That looks very good and is supposed to come online in 2016," said Dekker. "Our Vito and Appomattox fields we are hopefully going to take to sanction in the next couple of years," he added.

"Shell opened the deepwater book; we are definitely writing the next chapter, and we're writing the next sequel too."

An artist's impression of the FPSO *Turritella* is shown. The FPSO vessel is destined for installation on Shell's Lower Tertiary Stones Field in nearly 3 km (1.9 miles) of water. Due onstream before the end of 2016, it will be the deepest production facility anywhere in the world, surpassing Shell's existing ultradeepwater Lower Tertiary flagship in the vicinity, the Perdido development. A phased approach will see the SBM Offshore-supplied FPSO unit initially produce 50 Mboe/d via two wells, with later phases to see six further wells connected with multiphase pump technology used. Steel lazy wave risers also will be used for the first time on a disconnectable FPSO unit. (Source: SBM Offshore)

Unique qualities

So what are some of the unique qualities and advantages of the U.S. Gulf that enable it to survive and reinvent itself so well?

According to Dekker, there are three main things:

- Geology—"It's complex, but it keeps on giving;"
- The political and economic environment—"It's very stable. Also key is the combination of intense competition and collaboration. I think that's the cornerstone of human progress;" and
- People—"Skills and experience are unrivaled here. It makes the GoM and Houston a hotbed of innovation."

Also at the OEC, James H. Painter, executive vice president at Cobalt International Energy, added to this list.

"First, it's the margins. You'll find that there's not really a place that can compete with the margins anywhere that I've worked in the world. Because of the tax

55 finds by 2021 to sustain GoM plateau

Offshore production from the U.S. Gulf of Mexico (GoM) is forecast to hit a peak of 1.9 MMboe/d by 2016, which would see it overtake its previous highest level set in 2009, according to the latest survey by Wood Mackenzie.

But the long-term challenge to sustain this rise and replace reserves remains significant—just to replace the oil and gas extracted from currently producing fields between now and 2021 (4.2 Bboe in total) requires the industry to find up to 55 deepwater GoM discoveries (77 MMboe on average), the company estimated. EOR techniques also must play a major part in further improving recovery rates from the emerging plays, it added.

New developments and the continued expansion of mature fields will drive the forecast rise in output between 2014 and 2016 to the 1.9 MMboe/d figure before then leveling off for the remainder of the decade, as production from older fields continues to decline and a more limited number of new projects come onstream because of the current tightening of capex budgets by operators looking to control their costs. A total of 15 development projects are expected onstream between 2014 and 2016, but only eight are currently planned to start flowing between 2017 and 2020.

Production to recover

In recent years, deepwater GoM production has plunged from 1.8 MMboe/d in 2010 to 1.3 MMboe/d in 2013. The report, however, said that deepwater Gulf production will rise 18% per year from 2014 to 2016, with 2015 to see it climb 21% from 2014's level and 2016 then seeing the planned production startup of Anadarko Petroleum's Heidelberg Field and the continued ramp-up of output from Chevron's Jack-St. Malo project. Other new developments driving the rise include Delta House, Lucius and Big Foot.

Heidelberg (in Green Canyon Blocks 816, 859, 860 and 903) and Jack-St. Malo (in Walker Ridge Blocks 758 and 759) will produce a forecast 115 Mboe/d in 2016, the report stated.

The production growth forecast will be supported to a certain extent, it added, by the redevelopment and extension of mature fields, including Thunder Horse and Mars.

In 2016, it continued, the five fields (Delta House, Lucius, Big Foot, Thunder Horse and Mars) will account for 26% of output.

WoodMac's production forecast would entail the industry spending $17 billion in capex in 2014 to attain the 2015 target, some 30% more than in 2013. The Lower Tertiary play will make up 21% of the capex in 2014, rising to 53% of the total by 2021.

Long-term success

Of the forecast slowdown from 2017 to 2020, Imran Khan, Wood Mackenzie's GoM analyst, said that although only eight developments were expected to come online in that period (compared to 15 from 2014 to 2016), those eight would be important fields that could define the long-term success of the region. "Stones, Shenandoah and North Platte are part of the Lower Tertiary, which has garnered attention because of the potential to find large discoveries. However, the economics are currently challenging because of high costs, technological limitations and low recovery rates," he said in a prepared statement.

"Unless these obstacles are overcome, it will be difficult for the region to grow in the next decade. Not including yet-to-find reserves, we forecast that production will start to decline after plateauing out at 1.9 MMboe/d in 2021.

The current slide in oil prices does not help the long-term outlook either, especially if the downward trend continues for a protracted period."

Khan emphasized the need for the industry to sustain investment levels to support the production increase, with recent discoveries in deeper waters and emerging plays requiring more complex drilling and advanced technologies, both of which are highly capital-intensive. He commented, "A typical development well in the Lower Tertiary can cost $300 million as compared to the shallower, more established well-known plays such as the Upper/Middle Miocene, where development well costs are closer to $100 million."

55 finds required

Beyond 2021, the report also pointed out, some of the GoM's largest fields such as Mars and Mad Dog will have been producing for 15 to 20 years. "The impact from this depletion will be significant. Those fields currently onstream are expected to produce 4.2 Bboe between now until 2021. Based on the average deepwater GoM discovery size of 77 MMboe, almost 55 discoveries would be required to make up this amount.

"We believe this obstacle will potentially be overcome if recovery factors can be improved to take advantage of large resource volumes found in emerging plays. For example, if recovery rates double at the three large emerging fields—Appomattox, North Platte and Vito—their reserve base will increase to 2.5 Bboe."

The company's outlook also highlighted the increased level of competition from other regions around the world, including nearby neighbor Mexico, especially as the GoM is still suffering from a sustained level of cost increases. Costs are rising at 5% to 10% annually, it said, despite the recent softening of the rig market. Khan concluded, "Unless the technology to improve recovery rates is developed and costs are reduced, the operating environment will only become more challenging, and it will be difficult for the region to maintain a long-term production growth trajectory." ■

and royalty setup, whatever you get is yours vs. being more of a production-sharing agreement or regime as in different parts of the world.

"The second is the ability for technology to move quickly. You've got the service vendors; you've got the seismic. Everything starts in the GoM and then moves around the world, by and large, whether it's new seismic techniques or the newer drilling rigs or whether it's bit technology. All these things start in the GoM and then move out. And it's a relatively small number of companies that work the deepwater, so again your competitive pool tends to be fairly reduced."

Reinsborough agreed that the U.S. Gulf stands out for its high margins as well as the technology. "This is the incubator of technology, and we're seeing it unfold right in front of our eyes in terms of unlocking areas that we couldn't see 10 years ago in the subsalt. But also from our point of view, it's access. This is a very commercially driven regime, and that's great for small companies like ours that can enter into the market. It's also a transparent fiscal regime. It's completely above board, very predictable and a very stable political environment compared to many other areas."

The Technip-built hull for Anadarko Petroleum's deepwater Lucius spar is seen being transported by Dockwise's *Mighty Servant 1* barge. Lucius was due onstream before the end of 2014, with the operator opting for a 'design one, build two' approach that saw it repeat the process for its Heidelberg development, also in the GoM. This saw Anadarko apply lessons from the first project, which it says has resulted in significant cost savings and a shortening of the development cycle by up to 18 months. Heidelberg is due onstream mid-2016. (Source: Dockwise)

Highly ranked

These qualities make the GoM rank highly compared to E&P opportunities elsewhere in the world, but costs such as drilling day rates will need to be controlled.

This is so the industry can continue to further explore and exploit its undoubted reserves potential, with the Lower Tertiary Trend cited by many as key to its future. Thanks to ever-improving 3-D seismic processing, exploration in subsalt and near-salt zones is likely to be the next big thing as operators seek to understand more about the Paleogene formations. In the next decade, drilling activity will move south and west into ever-deeper waters as the industry continues to expand its search for fresh reserves, according to Reinsborough.

In addition, the Inboard Wilcox Trend alone is likely to hold billions of barrels of yet-to-find reserves, he added. "It's very attractive. In the subsalt provinces we believe there's 5.5 Bboe to 6 Bboe of yet-to-find resources, just in the Inboard Wilcox Trend. That's a good prize for us to go after. So when you stack all those up, I think the GoM ranks very high globally."

Cost and technology challenges

Numerous challenges remain, of course, including ones that are not just specific to the GoM—those of rising industry costs and a lack of standardized development approaches. These were elements touched upon by many of the speakers at the EOC.

"Most of the value destruction occurs in the appraisal phase when you drill too many wells before making the final investment decision [FID]," Reinsborough said.

He pointed out that costs are "our biggest pressure point right now. On a large-scale development, almost 65% of the capex is on drilling and completion costs. You have to get that down to have a good breakeven price. We've seen costs over the last five years going up by almost 10% compound annual growth rate over that period of time. There are typical wells right now in the subsalt Wilcox Trend that will cost a quarter of a billion dollars, so that's a big ticket."

He flagged rig day rates as the biggest factor, although the industry is starting to see those soften. But, he added, "We'd like to see more rig contracts come in under $400,000 per day, which would be more acceptable over time."

Knowledge transfer

One company that has been steadily increasing its GoM presence over the past few years is Statoil. "It's a core area in our portfolio, and we see a lot of potential. We're here on a long-term basis," said Ola Gussias, the operator's technology manager for U.S. offshore. The company is the world's largest deepwater operator and has over the past three years been busy researching the industrialization and standardization of the seabed for aspects such as subsea processing, where it visualizes an eventual "subsea factory."

It has been transferring much of its technology know-how from the North Sea to its operations in the GoM, which it entered in 2005, said Gussias. It's presently involved in nine producing fields, including Tahiti and Caesar-Tonga, and has another seven in the execution or concept phases. The technologies it is focused on include through-tubing electric submersible pumps, currently being developed alongside Chevron and Schlumberger. Early in 2014 it also announced a global technical efficiency program.

But it was standardization that many speakers touched upon, related to platform topsides facilities as well as interconnections both above and below the surface. The idea is, of course, to save both time and money.

"It's a balance between thoroughness and front-end design and good, tried and true management practices," said Stephen Pastor, asset president, conventional, for BHP Billiton. Pastor describes the GoM as "a heartland for BHP," and it was the first operator to resume production drilling in the region post-Macondo. "The more you can mature the front-end engineering and design process before you get to the FID, the better. Don't feel you need to blank-engineer everything or over-engineer everything. It's being smart about what you do and what you don't do."

Industry solutions

Much of the technology focus in the GoM right now is on drilling advances and HP/HT reservoirs and equipment.

Painter has total confidence in the industry's ability to overcome the engineering problems. "They're always solved," he said. He pointed out that the industry is today drilling wells in the GoM to a total depth of 10,670 m (35,000 ft). Key to their success will be "making sure you do it in the right way, each of the individual parts. The other part is about efficiency, so looking at ways to reduce cycle time is important."

With engineering problems, he continued, it essentially comes down to "time, effort and money." He recalled, "When Cobalt started nine years ago we were using 1.5 million-pound hookload rigs and drilling 25,000-ft [7,620-m] wells. Now we're using 2.5 million-pound hookload rigs and are looking for 3 million-pound hookload rigs, potentially in the future to drill 40,000-ft [12,192-m] wells.

BHP Billiton's Shenzi TLP came onstream in March 2009 and has been kept at or above its nameplate production capacity of 100 Mbbl/d of oil for the past five years through a sustained campaign of infill drilling. The facility sits in 1,300 m (4,300 ft) of water in Green Canyon Block 653 and is the second-deepest TLP in the world. (Source: BHP Billiton)

"So the industry always finds a way to break the technology barriers. It's the geologic barriers that tend to be a little harder for people to understand through time."

So how easy is it for the transfer of knowledge and technology to take place in the GoM?

It's not, according to Gussias. "It's not straightforward. Some of the principles could be transferable, but we have different operating conditions. We have over the last four or five years had a program called 'Cracking the Paleogene' that had the target to take the most promising technologies and tailor-make them for GoM conditions, especially the Paleogene conditions. There is a gap, and we have been working on filling that gap."

Value of seismic

Pastor pointed out the benefits of applying its 3-D and 4-D seismic experience, with which it has had good results in its homeland waters of Australia. "We certainly see more opportunities to apply 4-D seismic in the GoM. We're already onto that at the Atlantis Field, where we're getting some pretty positive results. We're pushing hard to do the same at Shenzi and some other assets.

"You can appreciate that there's tremendous value in that. When you're talking about wells that cost $150 million a piece on the low end and up to $250 million-plus on the high end, it pays to be really efficient and effective with how many and where you're placing infill wells as a function of understanding your drainage pattern. That's the one technology that's been most transferable, I'd say."

HP/HT

Regarding HP/HT wells of 20,000 psi and 25,000 psi,


DEEP WATER
WHEN YOUR CHALLENGE IS DEEP WATER...
THE SOLUTION IS HALLIBURTON.

Chain-reaction: LLOG Exploration's Delta House semisubmersible production platform was installed on the field in Mississippi Canyon Block 254 in October 2014. It is permanently moored via 12 preset chain/polyester mooring lines. The system, which also includes 12 suction pile anchors, was designed, fabricated, installed and hooked up in 1,356 m (4,450 ft) of water by Acteon subsidiary InterMoor. (Source: InterMoor)

Reinsborough said that this was a problem that has to be solved to unlock the Lower Tertiary. "It will take a collaboration effort between the operator companies and the service companies to solve it," he said. "But I agree that the industry has a tendency to solve these problems when there's a great value proposition behind it. The industry will get that right over time."

David Reid, deepwater appraisal manager at Shell Upstream Americas, agreed. "As we move forward, we're going to see a need for more robust completion technology," Reid said. "As we drill deeper we'll get into hotter temperatures and higher pressures. The drawdowns that we're going to see, the depths and pressures, are just going to be a lot larger. We're going to get into things such as ceramic screens and all this really great technology that you're going to see deployed into oil and gas."

However, water depth—once a challenge that seemed insurmountable beyond certain depths—is now barely even an issue, according to the experts at OEC. The greater technical challenge is well depth, again due to the HP/HT issue. "The rigs and the drilling capacity are there," Painter said.

Reinsborough agreed. "I don't think water depth is the limiting factor," he said. "I think drilling depth is. Drilling below the mudline, that's probably the bigger challenge for the industry. The industry can drill wells in 10,000 ft [3,050 m] of water and probably will go well beyond that in the next decade. But it's the drilling depth and the pressures and temperatures that occur that are going to be the challenging and potentially limiting factors."

Gussias pointed out, however, that although water depth was not an issue as such, phenomena such as deepwater loop currents were still a challenge.

Threats to the GoM

When it comes to the biggest perceived threats to the aspirations of companies in the GoM and what keeps oil company executives awake at night, it is the regulatory environment that rears its ugly head.

According to Painter, for smaller companies the regulatory environment is of concern due to changes "that could occur that are not within our control." The company has risk and mitigation plans for things that are within its control, he said, but outside issues such as "What are the things that could change through time, especially in a post-Macondo GoM?" cause sleepless nights.

Causing Pastor restless nights are "the confluence of increasing cost, regulatory requirements and other things. And scarcity of resource as we cream the curve in some of the easier-to-find significant oil pools in the Miocene and elsewhere in the GoM. We're getting into the Paleogene, which is tougher to crack, and so that whole idea, which I call scarcity of resource, just makes it more difficult to find oil fields with the size and productivity that are needed to underpin the $10 billion development costs we're tending toward nowadays for a single field."

Cost still an issue

It is the cost issue that still bothers Reinsborough. "Costs probably keep me up. But interest is still massive in the deepwater. The industry still feels there are large quantities of oil to be found in the GoM. So that's why you continue to see large investments. And quite honestly, we're in a high-margin business, and I think that requires a little education of the market that typically a standalone deepwater project in subsalt will have a breakeven in the $50/bbl range."

Reid pointed out what he now sees as a "leveling off" of costs and even a decline. "I think we're at a time where we'll see some softening. But it's still an expensive business to be in, and it's a risky business," he said.

Apache Energy's Cory Loegering, region vice president, GoM, said costs go beyond contractual prices. The regulatory environment has added a lot of costs, he said. Apache has to spend two weeks testing BOPs before it can even get on a well. "That's a clear cost. And then there's a retest of the BOPs every two weeks that's probably added 20% to our well costs," he added. "So the regulatory requirement has driven up costs and impacted us. But we will always be compliant and so will bear those costs."

Loegering went on to highlight Apache's current plans for the GoM since the large sale of much of its Gulf blocks to Fieldwood Energy and Freeport-McMoRan for $5 billion a couple of years ago. "I've gotten questions like, 'Are we still active in the Gulf?'" he said.

But with still around 650 blocks offshore, it remains the fourth-largest leaseholder in the GoM. With free cash flow generated from its international regions, Apache is now intending to spend it on North American assets, including the GoM. "We've already identified plenty of targets we want to chase," he said.

Loegering said Apache's focus for the Gulf is more clearly on exploration. "The way we look at the Gulf is kind of like the Bakken and Permian. Those plays really emerged into where they are today based on technology," he said. "Our approach to the Gulf is the application of the technology we already have. And that already exists."

Apache's GoM capex for 2014 was about $300 million, with Loegering saying he hoped in 2015 to spend substantially more. "We are pretty excited about the opportunities in the Gulf. Having really focused in the 1990s in the deepwater through to 2013 prior to the merger there was a lot that we learned and picked up. We are taking that technology and moving it to the shelf. There's a lot that's been left behind."

He added that Apache is retooling and reprocessing new seismic and "plans to hit the ground running in 2015, testing our new ideas. There's a real future here in the GoM—it really does keep on giving."

Looking ahead

So what lies in store for the GoM over the next five to 10 years? Much of the focus remains on the deepwater, according to Painter. "Cracking the Paleogene. Understanding the economics, getting the cost down and the production rates up. That's the next five-year plan for all of us in the deepwater GoM. Improve the economics and returns from the Paleogene."

Pastor agreed that the play is "the biggest material game-changing opportunity we have in the GoM." But he stressed the need for his company to continue to exploit the many opportunities in and around discovered resources in the Miocene through near-field exploration and "taking advantage of having infrastructure already installed that you can quickly and inexpensively tie back to." BHP has managed to keep its Shenzi TLP at nameplate production capacity for the past five years with a continuous infill drilling program.

The application of technologies such as 4-D seismic, subsea pumping and other EOR techniques such as miscible gas floods or better techniques for water injection would also be important. "I think there's a lot of value creation that can come from that, and I believe we need to apply an 'all of the above' strategy to extract the best potential." The GoM, he added, has huge fields such as BHP's Atlantis and Mad Dog, with the latter's Phase 2 to potentially deliver 750 MMbbl of recoverable oil and further possible upside beyond that (more than double Atlantis).

"It's a place we have aspirations to do a heck of a lot more. We see this as a place to exploit our capability and strengths by also pursuing low-risk, high-return infill drilling and brownfield expansion."

Reinsborough concluded, "The industry will move west and south in the GoM. I also think we'll see the push-out of infrastructure into these areas. We'll see a lot more hubs, a lot more subsea tiebacks. The industry tends to repeat itself, and if it unfolds the way we see it, then we'll see a broader infrastructure base and more subsea tiebacks as you go west and south." E&P

The *Saipem 7000* heavy lift vessel installs the three-deck topsides in a single lift onto the Tubular Bells spar hull. The completed topsides weighed about 7,000 mt. (Source: Hess)

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Fresh approach to Shelf life

Two of the key players on the GoM's conventional shallow-water shelf have shown there's plenty of life in the play yet.

Mark Thomas, Editor-in-Chief

When it comes to the Gulf of Mexico (GoM), while many of the big headlines go to the majors venturing out into the region's frontier deep waters, some of the most innovative work is being done much closer to shore.

Compared to some of the big hitters in the GoM, Energy XXI and Fieldwood Energy can both be considered youngsters. Houston-based Energy XXI was formed in 2005 as a special acquisition corporation after successfully raising $300 million during a six-week road trip to parts of Europe and across the U.S. as hurricanes Katrina and Ike barreled through the GoM. In the years since, it has grown to become a major player in the GoM, operating 10 of the largest oil fields on the shallow-water shelf.

Fieldwood, meanwhile, is even younger, having only started up in 2013 with minimal staffing, $5 million in invested capital and no properties. It is a portfolio company of New York-based private equity firm Riverstone Holdings LLC and has grown rapidly to become the largest operator on the GoM Shelf. Two of its most recent acquisitions were the $3.75 billion purchase of Apache Corp.'s GoM Shelf business and the $750 million gain of SandRidge Energy's GoM and Gulf Coast business unit.

The bosses of both companies have clearly defined strategies on how to maximize their returns from the shelf while also sharing more than a few of the same concerns on topics such as regulatory burdens, increased costs and the need to acquire both the right assets and the right people.

View from the top

Key milestones identified by Energy XXI CEO John Schiller, speaking at Hart Energy's recent Offshore Executive Conference (OEC), included three major acquisitions from 2006 to 2007, listing on NASDAQ in August 2007, a $1 billion deal with Exxon Mobil for its Grand Isle assets in 2010 and the $2.3 billion acquisition of EPL Oil & Gas.

With its main fields located offshore Louisiana, the oil-focused company has continued to build up proved reserves, which have increased 38%, and its reserve replacement ratio (up 510%), with each acquisition pushing a strategy that centers on developing only the core pieces of acquired portfolios and ditching the rest.

For Energy XXI, the steps to sustaining people, profits and the environment involve "a focus on acquiring the right assets [and] finding the right people," Schiller said. "Everybody knows that with offshore technology you have to have the best and brightest working for you. It's not a place where mistakes can be tolerated."

Positive revisions

Also crucial to achieving success are leadership and implementing the right technologies, which impact the industry's abilities to tap the estimated 7 Bbbl of new reserves believed to lie in the GoM within the next five years.

As the company produces proved reserves, additional downdip oil and gas booked as 2P and 3P upgrade to 1P and 2P, respectively. "That's why you see most of us in the GoM having consistently positive revisions on reserves," Schiller said, after pointing out the company has proved reserves of 246 MMboe and probable reserves of 96 MMboe and currently produces about 59,000 boe/d from its 252 blocks on the shelf.

Schiller spoke about how some technologies and techniques have led to improved E&P efforts in the GoM for the company. Among these are better seismic data, horizontal drilling and dump floods.

In the past, many shallow wells bypassed productive sands, focus was on high-decline gas in a low oil-price environment, 3-D seismic was limited, and horizontal drilling technology was not readily applied, according to Schiller. But times have changed as technology drives "better imaging, reduced risk profile, and greater drilling and extraction efficiencies" as "big fields get bigger" with "significant resource potential just below field plays."

Lessons from ultradeep

Reprocessing of seismic data alone has resulted in better quality, and "the new acquisition data are really changing how we look at these old salt domes," Schiller said.

He noted how work with partner Freeport-McMoRan in the ultradeep has taught his company about salt movement and how it is different than was envisioned 20 years ago. Today there is better definition of salt and greater ability to see seismic amplitudes updip as well as hidden amplitudes underneath overhangs that previously could not be seen.

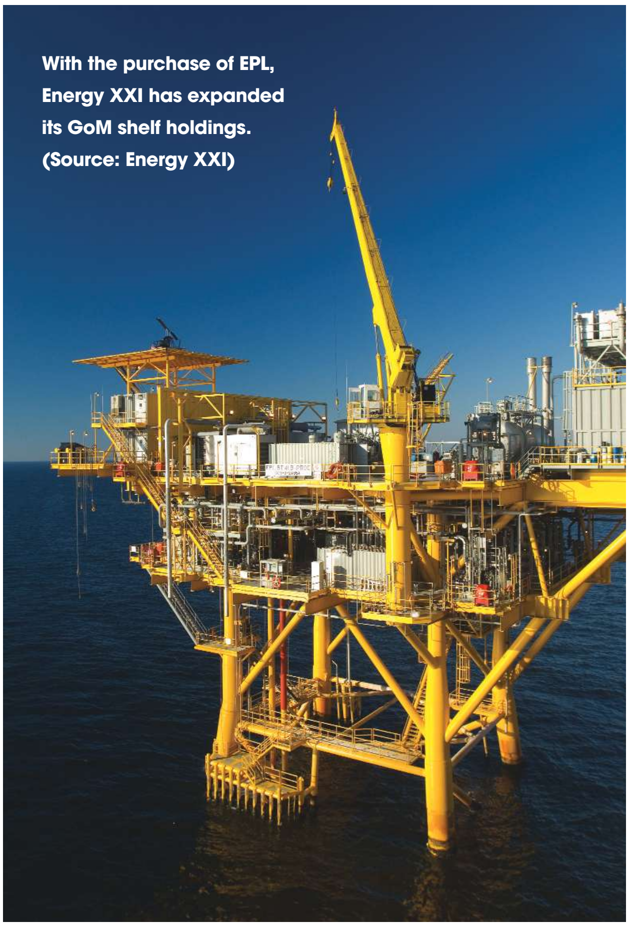
Using its Main Pass Field model as an example, Schiller described how the redefined salt model generated growth and opportunities for more growth.

"We drilled updip on it. At 1,463 m (4,800 ft) we got into a reservoir and put the well on at 1,200 bbl/d for a year," he said. "We started studying and realized we had two more downdip wells that had never been completed." Better seismic data helped send production up to 9,000 bbl/d. "[Seismic] is giving us better definition in the existing sands. It has also given us a lot better look at depth."

Energy XXI claims to have the largest seismic footprint among its GoM peers, having more than 42,476 sq km (16,400 sq miles) of 3-D data and ongoing seismic acquisition.

While better seismic data have proven beneficial on the geological front, horizontal drilling is enhancing oil recovery. The technique has been used in the GoM since the 1990s, Schiller said.

Typically, with vertical drilling, 200-psi drawdown leads to water coning and inefficient sweep, with late life recovery rates ranging from 40% to 50%, according to Schiller. However, with typical horizontal drilling, 3-psi to 5-psi drawdown leads to stable oil/water contact and enhanced recovery of original oil-in-place. Recovery rates for horizontal wells range from 55% to 65% in the GoM. "It's a much easier flow regime on the reservoir," he said.



With the purchase of EPL, Energy XXI has expanded its GoM shelf holdings. (Source: Energy XXI)

Real-world lab

Assets acquired from Exxon Mobil in the Grand Isle area provided just what Energy XXI needed to sift through to find what would work best. The area had been used as a kind of "big real-world lab" as Exxon Mobil studied, for example, how it was going to complete wells in West Africa or deal with water control, he said. "So we had pretty much every type of completion you could envision, from prepacked openhole screens to prepacked screens with slotted liners to regular gravel-packed screens and open hole."

To date, Energy XXI has drilled 19 horizontal wells, resulting in 16 successful horizontal completions.

"We're spanning the top of some 10- and 16-ft [3- and 5-m] sands. It's not easy. You've got to stay on top of your game. You've got to pay attention as you drill wells," Schiller said. "West Delta 73 is where we've had the most success. We've already drilled 11 wells here. We're just shy of 10 MMbbl of reserves, and we're averaging on the first 30 days about 400 bbl/d [net per well]."

West Delta 73

The horizontal drilling program in the West Delta 73 Field, which has seven platforms and 40 active wells at a water depth of about 67 m (220 ft), has resulted in nearly 33 MMboe of added proved reserves.

Energy XXI remains positive on the future state of oil and gas E&P in the GoM. "We think the economics are going to be good for a long time. There's going to continue to be a rebirth, I think, of the whole thing," Schiller said, while adding that the company is looking to continue containing costs. "We are much more efficient now."

He added that a lot more wide-azimuth seismic is going to be shot, and there will be "a lot more exploration around the salt."

The biggest hindrance, he added, is "government regulation and intervention. There's a lot more inspection," resulting in extra planning.

Four main GoM challenges

Fieldwood's CEO and President Matt McCarroll spoke at OEC about the four major challenges facing GoM producers, as he saw it: regulation, infrastructure, hurricanes, and staff and equipment.

Fieldwood Energy's Eugene Island 125 A-5 ST1 rig can be seen from a service boat. (Source: Fieldwood Energy)

Regarding regulatory challenges, he lamented the constant changes in the approval process. Permit and approval delays and uncertainty hamper the industry, he said, adding that rig inspection fees have gone up substantially from about $2,000 to $3,000 per rig to about $17,000 to $31,000 per rig, and companies are paying these fees to understaffed and uninformed agencies. In 2010 Fieldwood's predecessor company paid the federal government $1.2 million in processing fees. In 2014 it paid $8.6 million. "Despite increased fees," he said, "we're getting substantially less ability to conduct our operations."

Aging infrastructure

The second hurdle is the GoM's aging infrastructure. He pointed to older pipelines and devices as one reason for increased downtime. Increasingly, infrastructure owners are resistant to repairing their possessions, and as a result producers are having to take ownership of the pipelines and conduct the repairs themselves, McCarroll said. "Year to date, Fieldwood has experienced 31 pipeline leaks in pipes that we own and that others own that we use. We plugged three pipelines and made 28 repairs, resulting in a shut-in production of almost 2 MMboe. It's a big challenge, a big problem, and we're going to have to work hard to overcome it."

McCarroll said new technology that could extend the useful lives of pipelines, such as a poly-flow coiled tubing liner tested in Thailand and the North Sea, should be approved as soon as possible.

Hurricanes remain difficult to plan for, and he regretted a lack of a cost-effective and comprehensive risk-transfer solution in the GoM, a situation that has deteriorated since 2005. Additionally, Fieldwood has raised equipment levels, strengthened platforms and removed platforms sooner than in the past.

The final challenge McCarroll spoke about was the availability of trained staff and relevant equipment. "In the end, this is a people business," he said. "You can have all the new technology you want, but if you don't have good people to run the companies and work the operations offshore, you're not going to be successful."

Fieldwood currently operates 656 platforms and holds 650 Outer Continental Shelf blocks for a total of 2 million net acres. It produces about 115,000 boe/d. E&P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Heerema's *Balder* deepwater construction vessel at work installing Shell's new Olympus platform next to Shell's Mars platform in the GoM. (Source: Shell)

Jennifer Presley, Senior Editor, Offshore

A property's value is—as they say in real estate—determined by its "location, location, location." This is an adage that rings particularly true in the Gulf of Mexico's (GoM's) Mississippi Canyon Protraction Area (MCPA).

It is an area blessed with an abundance of natural resources and tales of storied successes and forgettable failures witnessed over its many decades of activity. The MCPA is home to many of industry's E&P bright spots—Blind Faith, Na Kika, Thunder Horse and Tubular Bells—that keep deepwater activity robust after having done so even in its darkest of days.

For Shell, the area has been especially bountiful as many of the company's deepwater development projects and prospects—Appomattox, Mars, Rydberg, Vicksburg, Vito and Ursa—are located within the MCPA's boundary lines. Three of the company's six tension-leg platforms (TLPs)—brought online in 2014, 1999 and 1996, respectively—produce hydrocarbons from web-like expanses of subsea wells that stretch far out on the seafloor from beneath the bright yellow legs of each.

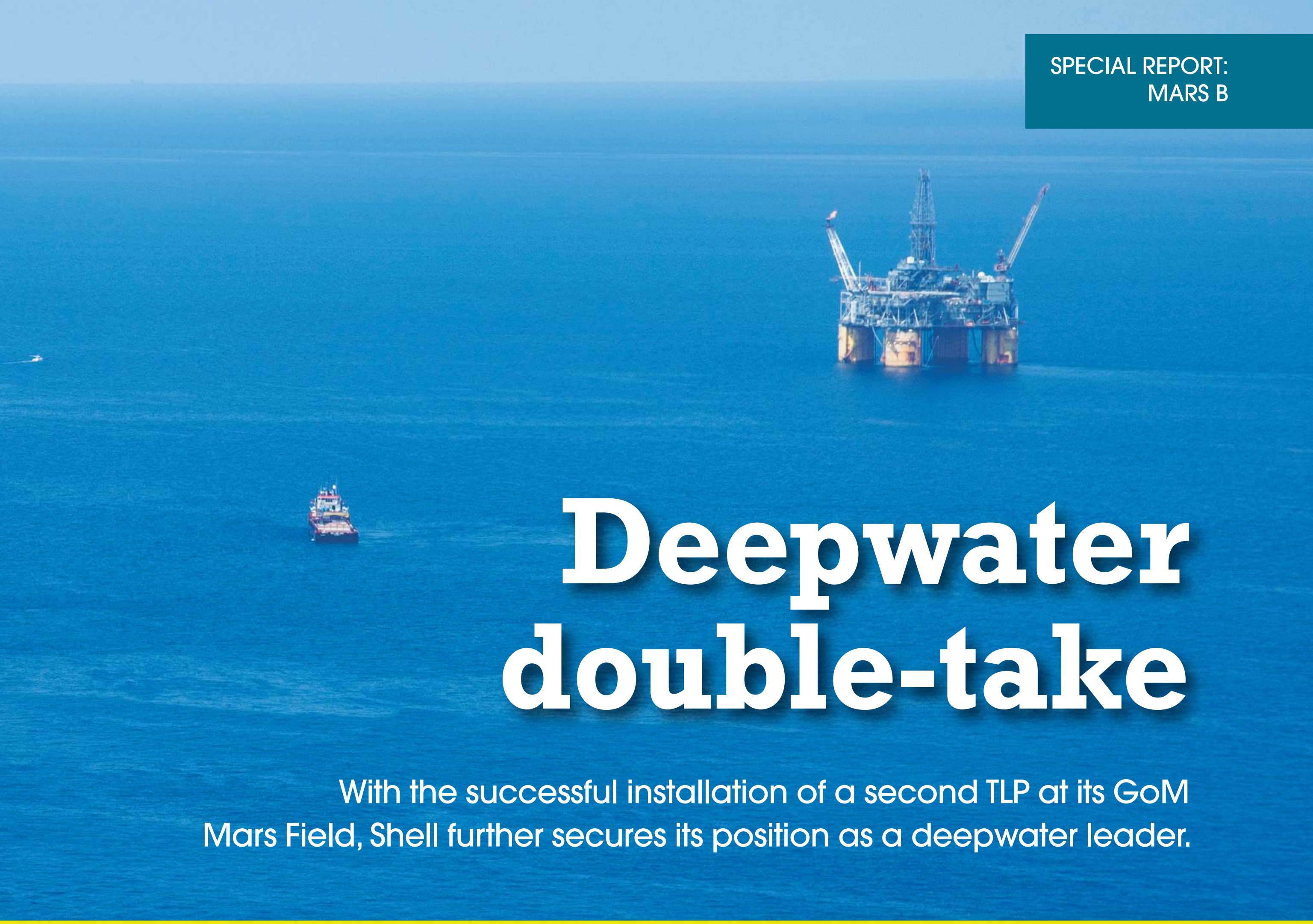
Shell delivered to the MCPA with the installation of its latest TLP the distinction of hosting the first project of its kind to expand an operating deepwater GoM field. When first oil flowed through the Olympus TLP in February 2014, the expected lifespan of that field—Mars—was officially extended to at least 2050. Not too shabby for a field discovered in 1989 and put into production in 1996.

Defying expectations

The Mars deepwater field lies roughly 209 km (130 miles) southeast of New Orleans in about 914 m (3,000 ft) of water. Shell holds a 71.5% and operator interest in the field with BP holding the remaining 28.5%. When Shell discovered the field, it was considered one of the GoM's largest discoveries.

"We realized early on after discovering the field that it was truly a deepwater giant with a very prolific resource base within the reservoirs that we could be looking to develop for many decades to come," said Derek Newberry, Shell's business opportunity manager during the development and construction phases for the Mars B project.

Initial estimates determined that the field would have nearly 700 MMboe of resources. In the 18 years since pro-



Deepwater double-take

With the successful installation of a second TLP at its GoM Mars Field, Shell further secures its position as a deepwater leader.

duction initially started, more than 770 MMboe have flowed through the Mars TLP that the company installed in 1996, according to a Shell-issued press release. It was the first TLP in the GoM to produce more than 100 Mboe/d, and it was designed to handle about 220 Mbbl/d and 6.3 MMcm/d (220 MMcf/d) during its economic life.

"The Mars Field really outperformed our expectations," he said. "Our estimate of the resource base continued to grow as we developed the deepwater giant. We recognized there would be benefits to adding more infrastructure."

Having significantly surpassed the original expectations, Shell announced in September 2010 that it had made the final investment decision to move forward with the Mars B Development Project. The project called for the installation of the Olympus TLP, development of the West Boreas and South Deimos subsea fields and the installation of oil and gas export pipelines to a new shallow-water platform.

"There are many things that are unique about Mars B," Newberry added. "It is worth highlighting that this is really the first time in the deepwater Gulf of Mexico where we've executed such a significant development and where we're putting in significant additional infrastructure to enhance infrastructure that was already there, the Mars tension-leg platform. This really is a first for a project of this magnitude in the deepwater Gulf of Mexico."

Mars B will enable production in the field to reach more than 1 Bboe, the company reported. And what does it mean for the field's life expectancy?

"With the Mars tension-leg platform, we were looking at an end of facility life in 2035. We have designed the Olympus tension-leg platform to be producing well into 2050 and beyond," he said.

Seeing clearly

The decision to move forward with Mars B was supported in part through the seismic technology advancements that helped reveal the truly prolific nature of the deepwater giant.

"When we looked at the geology in the area that surrounds the Mars Field, it showed great potential for further exploration discoveries," he said. "One of the keys to unlocking these exploration prospects that ultimately became discoveries was the advancement of seismic technologies."

A key piece was the 3-D seismic the company had acquired with streamers in the 1990s and into the early 2000s, he said. It was the advent of wide-azimuth (WAZ) seismic acquisition that really helped clear up the Mars picture. "Where the Mars Field is located there are large salt bodies, and it's very difficult to use seismic to see through the salt and understand what's underneath," he said. "With older versions of seismic technologies, if you imagine a table with some frosted glass and if you put a book underneath and look at it with conventional seismic down through that frosted glass, you get a rough idea for what the book may be, but you don't see it very clearly.

"What WAZ allowed us to do was move away from that table and see not through the frosted glass, but underneath the frosted glass without having to look through it. It really allowed us to look underneath the salt and get a more precise image of the subsurface and the potential exploration prospects that were there."

Mars B is made up of production opportunities from the Mars Field but also to two subsea fields—West Boreas and South Deimos—that are tied back by subsea infrastructure. The target reservoirs for Mars B are located at an approximate depth of 3.2 km to 6.4 km (2 miles to 4 miles) below sea level.

As an example of the persistence of technology, Newberry shared that based on conventional 3-D seismic data acquired in 2004, the company drilled the Boreas exploratory well but it turned out to be a dry hole.

"We did not find what we were looking for. The sand was not there; the hydrocarbons were not there. The persistence of technology and the development of new acquisition techniques allowed us to put seismic geophone nodes on the seabed. We went out with this new seismic technology in 2008 and discovered that the original well we had drilled missed the hydrocarbon pay zone by a few hundred feet.

"With these new data we were able to sharpen up the subsurface image and really enhance our understanding of the subsurface. We went back to the prospect and drilled the well in early 2009 that would become the West Boreas discovery. We drilled that pay in April of 2009. First production from the Olympus TLP came

LEFT: Dockwise transported the Olympus hull from Busan, Korea, to Ingleside, Texas, onboard the *Blue Marlin*. CENTER: The direct vertical access rig module was installed at Kiewit Offshore Services yard in Ingleside, Texas. RIGHT: The accommodations module is lowered onto the deck of the Olympus TLP. (Source: Shell)

from that West Boreas Field, from which we're currently producing about 40 Mboe/d."

Making Mars B

The Olympus and the Mars TLPs—located about 1.6 km (1 mile) apart—make for a staggering double landmark on the GoM horizon, with the Ursa TLP visible from its location several kilometers away to the east of the duo.

"I see the Mars B project as providing three significant pieces of infrastructure that we put out into the Gulf of Mexico," Newberry said. "The cornerstone is Olympus."

Olympus TLP. Crushing the scales at 126,000 tons, Olympus TLP is more than double the weight of Mars TLP. It stands more than 40 stories tall from the base of its hull to the top of its derrick and has a production capacity of 100 Mboe/d. As the largest jewel in Shell's deepwater GoM crown, the Olympus TLP was delivered to its final home in MC 807 more than six months ahead of schedule.

Fabricated by Samsung Heavy Industries, the Olympus hull departed South Korea onboard the Dockwise *Blue Marlin* bound for the U.S. in November 2012, arriving about two months later for integration of more than 27,000 tons of topside and derrick modules at Kiewit Offshore Services yard in Ingleside, Texas. The completed Olympus TLP departed for its final home a short six months after its initial arrival in the yard. The tow-out and transportation of the platform used for the first time ever synthetic rigging rather than the traditional steel wire rope. The use of synthetic rigging provided both operational and safety benefits to the project, according to a Samson Ropes press release.

In just under a year from its arrival in Ingleside, the Olympus TLP began first production from two subsea wells completed by the *Noble Bully*.

Designed for a service life of 45 years, among its many technology advancements made to adhere to more stringent specifications, the Olympus TLP features a direct vertical access rig that stands just under 61 m (200 ft) tall. The rig has the ability to skid over all 24 well slots and can be made secure for a 1,000-year storm. It has a maximum static hook load of up to 2 MMlb, almost double the hook load of the Mars TLP, according to a Shell Offshore Technology Conference paper. Tenaris Hydril provided its Wedge 623 Dopeless and Blue Riser connections.

Subsea and export systems. The second piece of the infrastructure puzzle was the subsea development of the West Boreas and South Deimos fields, according to Newberry.

"The fields are located approximately 3 miles [4.8 km] to the west, northwest of the Olympus TLP, with a single-

The tow-out and transportation of the platform used for the first time ever synthetic rigging rather than traditional steel wire rope. (Source: Shell)

production manifold on the seabed," he said. "Ultimately, we will have six subsea wells drilled from that manifold. It is tied back via a subsea system. It's two flow lines and then an umbilical, which has the controls for the wells that is tied back to the Olympus TLP, and currently that's where we have our production from."

Outfitted with six 15,000-psi rated enhanced vertical deepwater trees, the West Boreas Field was the first to use this type of tree system, according to an FMC Technologies-issued release.

"The third piece is our export solution. We have dedicated oil and gas export in pipelines that depart from Olympus TLP to the West Delta 143 Complex," he said. "There were two shallow-water platforms there originally, and as part of Mars B we added a third shallow-water platform, which was West Delta 143C. That's the infrastructure: our cornerstone with the Olympus TLP, our subsea system for production and our export solution with dedicated pipelines and shallow-water platform."

Operating differently

The Mars B Development is one of the most technologically advanced fields in the GoM. When first oil flowed in February, the switch flip to commence production occurred onshore, not off. "I was on Olympus when we opened the subsea well. It was a very special moment, to see a venture of this size with many millions of man-hours to get to that point. It was a tremendous feeling to see production start up," Newberry said. "It was a unique startup in that we have a fiber optics cable that connects an onshore operations control room to the control room on the Olympus. We actually opened up production offshore via technology at One Shell Square in New Orleans."

Located at One Shell Square is the Olympus Integrated Operations Center (IOC). It is connected via fiber-optic link to the Olympus Remote Control Room (RCR), providing a way for shore-based operators to monitor in real-time the data and activities underway on the Olympus TLP.

The IOC is a place where the offshore operations team can work more closely with the onshore engineering and technical support teams and, according to the company, helps create a more efficient operation. In one example the company provided, a group of 11 engineers who would traditionally perform the platform installation work offshore were able to perform 75% of the work from the RCR. The IOC concept works so well that the company plans to design all offshore production platforms using this concept.

For personnel working onboard the Olympus platform, understanding the systems in place is critical for its safe and continued operation. To help communicate the myriad of operation procedures, Shell contracted with Wood Group ODL to develop customized eLearning and competence solutions for the platform. Included were facility-specific system operating manuals and procedures. ODL developed and published more than 50 eLearning courses specific to the platform, according to an ODL-issued press release.

The eLearning courses cover facility-specific modules to educate operators about all systems, equipment, instrumentation and controls, and procedures for startup and shutdown of the facility. To enable effective operation, troubleshooting and equipment maintenance, ODL also developed materials that included interactive learning exercises, a library of site-specific photos, narrated videos, animations and 3-D illustrations aimed at enhancing the operators' overview of the facility and piping.

Growing deeper

Shell's other major GoM deepwater project for 2014 was its Cardamom subsea development. Located 362 km (225 miles) southwest of New Orleans, the Cardamom Field is in water more than 820 m (2,700 ft) deep. Oil from the 100% Shell-owned Cardamom subsea development is piped through the company's first TLP, Auger. The Cardamom development includes five subsea wells and—when at full production of 50 Mboe/d—will increase Auger's total production capacity to 130 Mboe/d, a Shell-issued press release said. Cardamom is the Auger platform's seventh subsea development since production first started in 1994.

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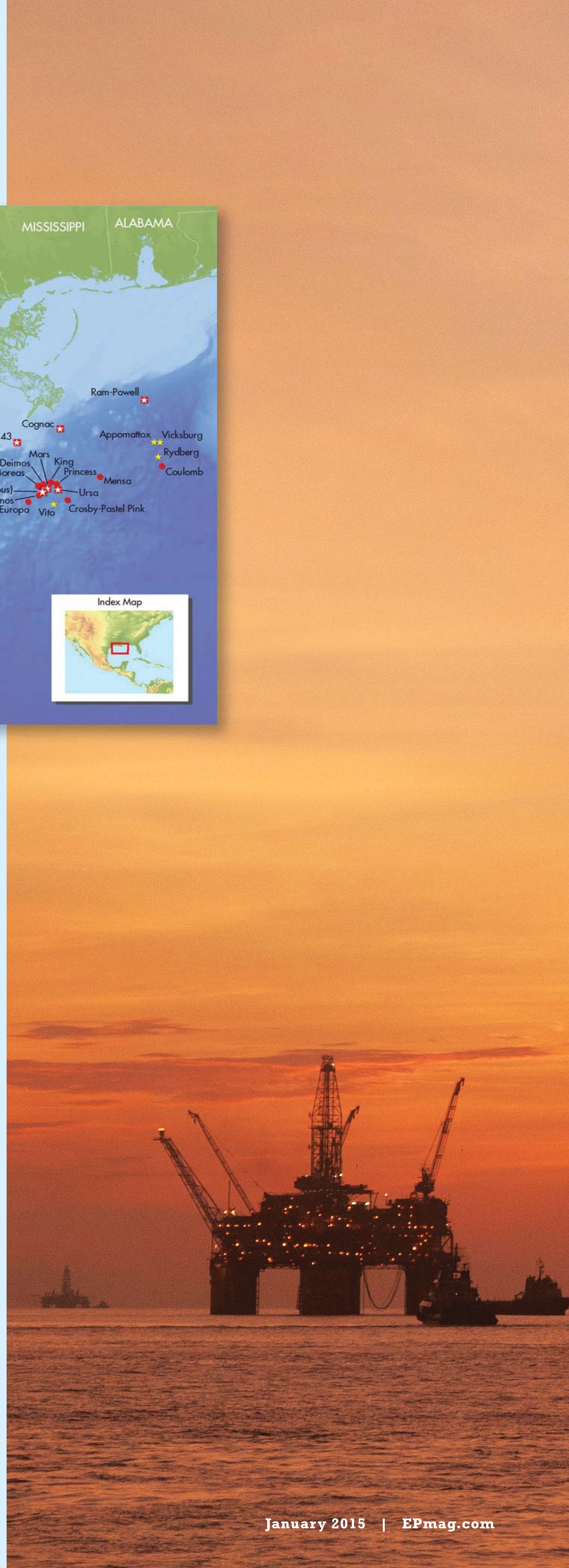
Shell has extensive operations in the deepwater and ultradeepwater GoM. (Source: Shell)

In July 2014 the company announced its third major discovery in the Norphlet play with the successful completion of the Rydberg exploration well. Located 120 km (75 miles) offshore in MC block 725 in 2,280 m (7,479 ft) of water, the well was drilled to a total depth of 8,038 m (26,371 ft) and encountered more than 122 m (400 ft) of net oil pay, said the company in a release. This discovery is the company's third in the Norphlet play, joining Appomattox and Vicksburg, which are, according to a press release, in the concept selection phase of development.

Shell's efforts do not end at the line separating deepwater from ultradeepwater. In addition to its Perdido Development in the Alaminos Canyon Protraction Area, the company's Stones Project in the Walker Ridge Protraction Area is set to push the boundaries of technology further. Located 320 km (200 miles) southwest of New Orleans in 2,896 m (9,500 ft) of water, initial production of the field will start with two subsea production wells that will be tied back to the SBM-retrofitted FPSO vessel *Turritella*, the company reported. Six additional subsea production wells are planned for the field, which is estimated to hold more than 2 Bboe in place.

While the Olympus TLP is the latest and largest jewel in its deepwater crown, it is certainly not the last, with projects like the *Turritella* on the board as Shell continues to further establish its leadership position in the GoM. E&P



The sun sets on another highly productive day on the Mars Field. Shell's Olympus platform is in the foreground with the company's Mars platform in the background. (Source: Shell)

What's lurking in your basement?

Imaging the basement helps to better map regional exploration potential.

Chris Friedemann, NEOS GeoSolutions

As all geoscientists know, the basement is the foundation upon which all other sedimentary layers rest—hence its name. Given its role as the foundation of the geologic column, basement understanding can often provide explorationists with critical insights into the relative productivity, prospectivity and economic potential of shallower horizons deposited above it, including in the reservoir zone(s) of interest.

Among other things, the basement, along with burial depth, acts as one of the primary heat sources that naturally matures kerogen-rich source rocks in subsurface hydrocarbon kitchens. Oil is the first hydrocarbon type to be liberated from kerogen as increasing levels of heat and pressure are applied in the kitchen; oil generation is followed by the subsequent liberation of wet-gas/condensate, dry gas and, when overcooked, CO_2 and graphite. Knowing which hydrocarbon type one will be dealing with is an important factor in exploration decisions and in project economics, especially in shale plays.

The conventional wisdom that has prevailed in the petroleum industry is that thermal maturity varies in a straightforward linear manner with burial depth. The shale boom of the last decade has dramatically changed this conventional wisdom, as the most astute explorers now realize that variations in basement topography, fault networks and composition can all cause localized distortions in the burial depth vs. thermal maturity relationship.

For example, a senior technical adviser for one of the world's largest pressure pumping companies stated at a Denver Rocky Mountain Association of Geologists luncheon several years ago that one of the key elements in identifying sweet spots in the Niobrara shale play of the Denver-Julesburg (D-J) Basin was "identifying the location of basement faults that have been reactivated and that, over the course of geologic time, have acted as conduits for hydrothermal fluids that affected the thermal maturity of the Niobrara."

Houston-based NEOS GeoSolutions recently delivered the results from a 7,770-sq-km (3,000-sq-mile) multiphysics survey in the D-J Basin and, among other things, confirmed that this technical adviser was correct, as basement-related features, including intrusive complexes and fault-driven graben structures, underlie three of the D-J Basin's more prolific fields: Wattenberg, Hereford and Pony. Interestingly, this same multiclient survey identified at least seven similar basement-related features that, at present, do not have significant exploitation or production operations underway.

Basement analysis

In a different play several hundred miles away, a similar analysis of nonseismic datasets helped to map variations in the structure of the basement, including both topographic variations and fault regimes. An inversion of magnetic and gravity data constrained by several well control points and seismic lines helped to map subtle basement topographic changes throughout the area of investigation, while an analysis of various magnetic derivatives helped to identify basement faults, including "pop-up" features (horst blocks) that appear to have affected the location of sweet spots in the overlying reservoir intervals.

Figure 1 depicts the results of these analyses, with one of the magnetic datasets overlaid on a topographic map of the base-

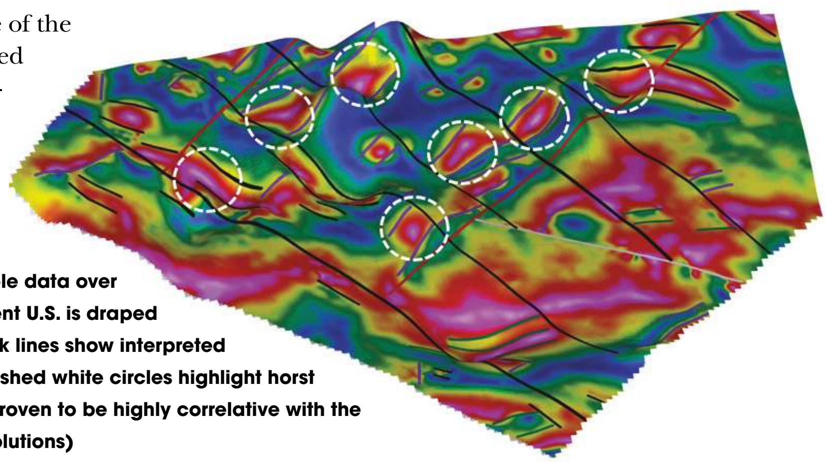


FIGURE 1. This tilt derivative of magnetic reduced-to-pole data over roughly 2,500 sq km (1,000 sq miles) in the midcontinent U.S. is draped on a topographic map of the basement. Red and black lines show interpreted faults (determined by analyzing multiple datasets). Dashed white circles highlight horst block 'pop-up' features in the basement, which have proven to be highly correlative with the best producing wells in the area. (Source: NEOS GeoSolutions)

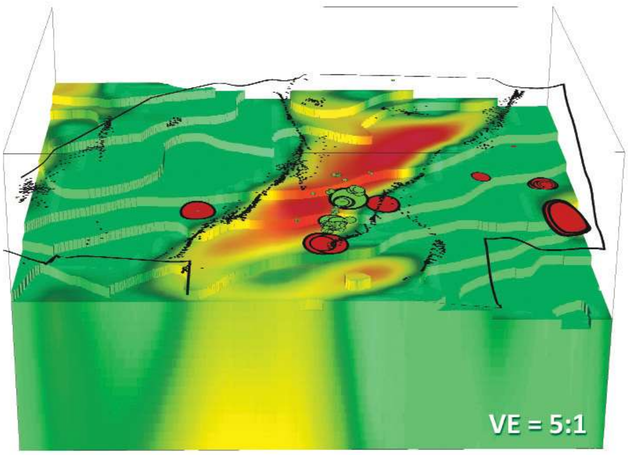


FIGURE 2. Marcellus oil (green spots) and gas (red spots) production-proportionate circles are draped on a basement model. Basement composition and structure correspond to the Btu content of production. (Source: NEOS GeoSolutions)

ment. The seven dashed white circles highlight the most productive intervals (which roughly measure 3.2 km or 2 miles wide by 6.4 km or 4 miles long). These high-production sweet spots are believed to be present because of subtle anticlinal draping over the basement horsts, whose bounding faults periodically reactivate, forcing the horsts upward. As these movements occurred over the course of geologic time, the overlying reservoir intervals were positively impacted both structurally (as more hydrocarbons were trapped in these structural highs) and through increased permeability and natural fracturing within the reservoir intervals overlying the horsts.

On another project in the Appalachian Basin, which involved sweet spot mapping in the Marcellus and Utica shales, NEOS undertook a multimeasurement geological and geophysical study over a four-county area of investigation in northwest Pennsylvania that spanned roughly 6,475 sq km (2,500 sq miles). The comprehensive interpretation involved integrating newly acquired airborne gravity, magnetic, electromagnetic (EM), radiometric and hyperspectral datasets with ground-acquired magnetotelluric and legacy seismic and well information.

It is commonly thought that the productivity of Appalachian reservoirs depends upon having abundant organic material, a suitable thermal regime (primarily related to burial depth of the shales) and localized natural fracturing. The project therefore initially focused on mapping variations in these properties. Well log and core data were analyzed to map total organic carbon variations. Gravity and magnetic data (calibrated by well and seismic information) were inverted to generate a series of 2-D structural cross sections and, ultimately, a regional 3-D model of the subsurface from which isopach and burial depth maps of the target shale horizons could be extracted. Lastly, magnetic, EM and seismic data were analyzed to identify zones of enhanced fault-induced natural fracturing.

Thermal profile

Adding to this list of factors, a chief geophysicist at one of NEOS's clients speculated that changes in basement composition were altering the thermal profile across the area such that the normal "hotter with depth" linear relationship was no longer valid. He hypothesized that these changes in the region's thermal profile were responsible for differences in production rates and especially the Btu content (i.e., liquids vs. gas) of the flowstreams obtained from newly drilled wells.

To test this theory, NEOS undertook an analysis of several multiphysics datasets, in particular, gravity, magnetic and EM, and applied workflows that included simultaneous joint inversions and Euler deconvolutions. The results, depicted in Figure 2, proved the hypothesis of this chief geophysicist: Compositional changes in the basement were in fact occurring and driving differences in the economic potential of the wells being drilled. The analysis suggested that a failed rift had developed across the area of investigation millions of years ago, introducing a new rock fabric with a different lithological makeup than the surrounding basement rock.

When the Marcellus Shale was subsequently deposited millions of years later, different portions of the source rock were subjected to different thermal regimes on an areal basis depending on where they were deposited, helping to determine whether wells subsequently drilled were more gas-rich or liquids-prone. As a consequence of this new insight, the project helped to better predict the flow rates and Btu content of newly drilled wells compared to more widely acknowledged geological and geophysical factors such as structural setting (e.g., burial depth or shale thickness) or acoustic attributes (e.g., brittleness, fracture density).

This isn't to say that structural or acoustic insights aren't valuable. But it does imply that a multiphysics approach, in which a variety of geophysical measurements are analyzed at depths of investigation ranging from the basement to the near surface, may provide a more constrained subsurface model and valuable set of related interpretive products than an approach that relies on only one or two geophysical measurements or properties.

These multiphysics projects are helping explorationists better understand the role that basement faulting might play in influencing sweet spot locations in unconventional shale reservoirs as well as the impact basement composition variations have on the relative liquids vs. gas content of the flowstreams from newly drilled wells. E&P

Improving efficiencies in drilling operations

Filtration system addresses limitations in current solids control systems.

Alister Kirkness, Cubility

For many years, the first line of defense in the maintaining of drilling fluids and the separation of rock particles in drilling operations on both onshore and offshore rigs has been solids control systems.

Shale shakers are the primary method of solids control today and consist of vibrating screens where the drilling fluids and drilled solids—that return from the well—flow onto the screens. Through vibrating G-forces, the solids phase is then filtered out for overboard discharge or for treatment on the rig or onshore.

The cleaned mud is then incorporated back into the active fluid system and reused to drill the well. It is this mud that cools and lubricates the drillbit, carries drill cuttings to the surface, controls pressure at the bottom of the well and ensures that the well remains stable.

Yet despite recent technology advances in vibration patterns, more efficient screens and more powerful motors, primary solids control remains a major issue when drilling many wells and particularly when it comes to deeper and extended reach wells where the control of low-gravity solids content is so vital.

For example, the high G-forces used by standard vibrating type shakers tend to break down the drilled solids into fine particles. This reduces the amount of solids that are removed and increases the solids content in the drilling fluid—in particular low-gravity solids. This leads to a decline in drilling fluid efficiency, a negative impact on penetration rates, and increased wear and tear on both the surface and downhole equipment.

Another drawback of solids control technologies today is that high volumes of mud are often lost with an increase in drilling waste. This has implications from both a cost and operational standpoint.

Finally, many solids control technologies can lead to a poor working environment, with personnel exposed to high noise levels and vibrations as well as the emission of oil and other vapors. In areas such as the North Sea—a region well known for its stringent HSE standards related to waste and employee conditions—this can be a significant drawback.

It's time to look to other technologies for separating and treating drilling fluids on offshore facilities and to look at alternatives to the types of equipment currently being used to control drilled solids, which have been prevalent in the industry since the 1930s.

One such alternative is the MudCube from Norwegian-based company Cubility. The MudCube is being applied on offshore installations and offers benefits over the traditional types of equipment widely used today.

Vacuum-based filtration system

The MudCube is essentially a vacuum-based filtration system that removes solids from the drilling fluid. The system is now field-proven and being used on a global basis by many of the major operators.

Rather than noisy vibration-based shale shakers and rather than relying upon high G-forces to separate mud and the drilled solids, drilling fluids are vacuumed through a rotating filter belt using high airflow to separate the cuttings from the fluid more effectively. The rotating filter belt carries drilling fluid and drilled solids forward while air—at 20,000 l/min (5,283 gal/min)—is pulled through this filter belt, taking with it the drilling fluid.

In this way, the cleaned drilling fluids are returned to the active mud system, and the drilled solids are discharged either directly overboard (if they meet environmental discharge regulations) or to a cuttings handling system.

In addition, water-knives are installed on the inside of the vertical part of the filter belt to remove any cuttings or sticky clay that may have stuck to the belt, and pneumatic micro-vibrators are installed underneath the filter belt to create resonance and improve conductance. The solids removal efficiency of the MudCube is often higher than 90%.

There are a number of immediate benefits to drilling operations from using the MudCube when compared to the vibrating types of treatment processes used by the industry for many decades.

First, the improved separation capabilities of the MudCube lead to better quality mud, fewer chemicals required to maintain its properties and more mud recycled back to the mud tanks to be reused for drilling.

With the cost of oil-based mud on the Norwegian Continental Shelf around $1,300 per cubic meter, it is estimated that the reduced cost of drilling fluid per well can be as much as $150,000. An operator and mud company, for example, recently reported the reduced use of premix chemicals as bringing savings of up to $270,000 when using the MudCube as compared to similar operations with standard type shakers.

As well as cost savings, there also are significant operational benefits of high-quality drilling fluids. The stable mud properties with low equivalent circulating density and solids content result in improved drilling efficiencies on the rig and a decrease in nonproductive time. Effective solids control also results in higher ROP, reduced stuck-pipe incidents and improved wellbore stability.

Furthermore, as mud properties have been field-proven to be stable throughout the entire well when using the MudCube, there are corresponding low maintenance requirements for rig circulating equipment. For drilling rigs costing millions of dollars a day, the financial benefits of this are clear.

In addition to improved mud properties, there also is reduced and cleaner waste to dispose of. Due to less drilling fluid being lost, the MudCube generates substantially drier cuttings with lower oil content and substantially cheaper disposal. In the Gulf of Mexico, for example, the regulatory limit for oil on cuttings to allow for the disposal of cuttings directly to the sea is 6.9 %—something that the MudCube can deliver.

Alongside improved drilling fluids and reduced and cheaper waste, the MudCube has a lower deckload than traditional shakers and, when taking into account the potential to replace other equipment, can save up to 25 tons on existing facilities and much more on newbuilds. Much of the operation of the MudCube also takes place remotely, leading to improved efficiencies and cost savings.

Finally, the use of vacuum and airflow as opposed to high G-forces leads to a much-improved HSE environment with significantly less noise and vibrating and very limited exposure to oil vapor and mist.

From reduced waste and less fluid lost to fewer chemicals, reduced maintenance, and personnel and HSE savings, it is estimated that the savings from a MudCube on a typical rig can be as much as $8 million per annum.

In operation

Since its 2012 introduction to market, the MudCube has been adopted on a number of offshore rigs in the North Sea, Middle East, Far East and North and South America.

The MudCube has been adopted on a number of offshore rigs in the North Sea, Middle East, Far East, and North and South America. (Source: Cubility)

In one such installation on the Maersk Giant rig—a jackup drilling rig based in the North Sea—three MudCubes replaced four traditional shale shakers. Since the installation, the Maersk Giant has embarked on an ambitious drilling program in the North Sea with the MudCubes used in the drilling of 13 wells to date.

Benefits to the operators include improved working conditions and no costly HVAC upgrades to the shaker room, improved drilling efficiencies with less drilling fluid being lost and more returned to the mud tanks for reuse, and the cuttings having a low mud content for easier and cheaper disposal.

A new alternative

With the intensity of drilling operations, the need to monitor the bottom line and stringent environmental and HSE controls, solids control and waste management technologies are a critical element of optimizing drilling fluid performance and improving drilling efficiencies.

Operators now have an alternative solution when making their decision. E&P

Advanced aeration in hydraulic fractured water impoundments

Methodology provides a new approach to water management.

Tom Daugherty, Arcadian Technologies LLC

The water we have on earth is all we have. New water is not created as years pass. The hydrologic cycle explains the circuitous route that water takes. Water that is here now is consumed, transpired or evaporated and then journeys away, only to come back again as precipitation or groundwater to start the cycle again. In municipal water treatment, water is simply a transport mechanism. It was clean to start with prior to washing clothes or flushing the toilet. Reclamation facilities exist to return the water back to its natural state and discharge it to a local water body. And the water cycle goes on.

DO

By merely looking at water one cannot tell if it has oxygen in it other than the hydrogen and oxygen molecules. But the molecule is not the oxygen that improves water quality and allows aquatic biota to survive. Dissolved oxygen (DO) must be present in ample concentration to support robust water health and is widely understood as a powerful oxidant. Even a stagnant pond can be brought back to life in short order by effectively infusing DO into the water. In nature, the cascading of a mountain stream over rocks enriches the DO level, ensuring trophy species of fish thrive. Healthy DO levels promote beneficial biologic activity from naturally occurring microbes. Increasing DO in flowback impoundments initiates a plethora of water quality improvements.

Evaporation

Many centralized treatment ponds also are known as evaporative ponds or pits. Two key components to evaporation in a water impoundment are heat (sunshine) and surface air movement (wind). Other factors include altitude, vapor pressure at the water surface and vapor pressure of the surrounding air (Potts, 1988). One can discover myriad evaporation formulas based on geography, latitude, climate and the like, but the aforementioned factors are in play regardless of the play. During interviews with three different evaporation pit operators, it was discovered that none deployed any scientific methodology to determine evaporation rate but all were convinced that their aeration methods helped.

Advanced aeration improves evaporation

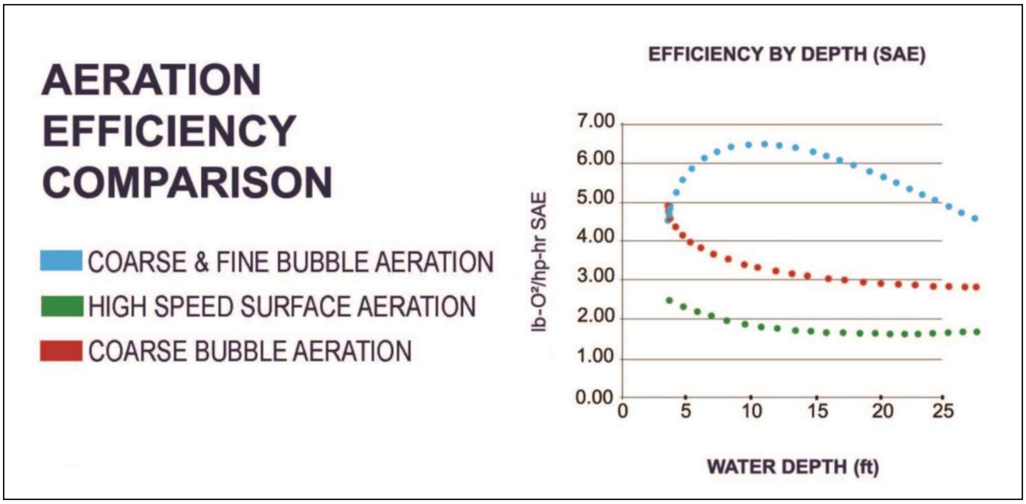
There are multiple phenomena occurring when fine bubbles and coarse bubbles are introduced in a subsurface fashion in a water impoundment. Firstly, the rising bubbles cause surface disruption and may add momentum to the air, increasing the rate at which the humid air is removed from the surface, a critical aid to evaporation (Brutsaert, 1982). Secondly, when air is introduced into water, bubbles are formed, and diffusing vapor in the water migrates to the interior of the bubble (Burkard and Van Liew, 1994). The resultant migrant vapor in the bubble reaches 100% relative humidity and is released during the breakup process at the surface (Helfer, Lemckert & Zhang, 2012). The combination of coarse and fine bubbles delivered from the water pit floor, effectively oxygenating and destratifying the entire water column, is considered advanced aeration.

As mentioned earlier, a casual observation of existing fractured water impoundments notes some sort of surface aeration, weeping systems, periodic air jamming or other air sparging. By field practice, the operators realize the advantages of using air in water management.

Scorecard for aeration efficiency

In 1984 the American Society of Civil Engineers adopted aeration efficiency standards. The Standard Oxygen Transfer Efficiency (SOTE) test was developed to put all vendors/methods on an even playing field. The key to SOTE is evaluating the efficiency of introducing oxygen into a body of water. The trial is recorded at sea level in clean water at 20 C (68 F). Bubble size is the single biggest factor to determine SOTE. Fine bubbles (less than ⅛ in.) tend to rise more slowly, providing better oxygen transfer efficiency. Coarse bubbles (greater than ¼ in. and often 1 in. to 2 in.) are more effective at mixing. Other factors in analyzing an aeration system are flow rate, depth, temperature, elevation, layout, alpha and beta factors, and maintenance. Chart 1 shows Standard Aeration Efficiency (SAE) for various aeration types at different water depths. The higher SAE rating is the most desired as it takes into account implied utility costs. The measurement is pounds of oxygen per hp-hr expressed as lb-O_2/hp-hr.

When advanced aeration is introduced to an impoundment, many water quality parameters begin improving in correlation to residence time or exposure. Fine bubbles can effectively introduce DO into the target water body. Assuming anaerobic conditions, a transformation from anaerobic (DO < 1.0 mg/l) to aerobic (DO > 1.0 mg/l) water occurs. Sulfate-reducing bacteria (SRBs) are susceptible to the oxidation potential of DO (Characklis, L., Lee, W. 1994). Initiating the oxidation of SRBs inhibits the formation of hydrogen sulfide (H_2S), a colorless gas that is corrosive, poisonous, flammable and explosive. Effective infusion of DO also begins the oxidation of H_2S, which helps mitigate multiple issues, including odor (Sharma, K., Yuan, K., 2010). With increased DO, the pH level in the water body begins to move toward stabilization. This is valuable when it is understood that a target pH value between 7.0 and 8.0 is optimum for maximum H_2S removal (Chen, K., Morris, J., 1972). The water body also begins stripping CO_2, light hydrocarbon gases and volatile organic compounds due to redox, which is a reflection of its oxidative and reductive capacity.



The combination of coarse and fine bubbles provides the highest aeration levels for produced and flowback water. (Source: Arcadian Technologies)

DO transforms metals such as iron and manganese to their oxidized state. This allows them to be filtered out or settled to the bottom of the pit. Guar residues and other organics also begin oxidizing, which fosters increased light transmissivity or clarity to the water. The surface disruption caused by advanced aeration also reduces surface matting and encrustable formations. This benefit is twofold as it allows deeper access to the water body by UV rays and provides a naturally corralled surface area for potential skim harvesting of migrant hydrocarbons. These documented water quality improvements offer contaminant load reduction for downhole reuse or follow-on treatment trains such as electro-coagulation, reverse osmosis and the like.

Anaerobic water pits cause certain treatment chemicals to be oxidized or partially consumed. The "serendipitous uptake" by nontarget contaminants wastes chemicals and money. This can cause the chemicals to be less effective than expected, leading to costly overdosing. Increasing DO with advanced aeration will optimize subsequent chemical use and increase operator control and understanding of water pit behavior.

Taking control of fractured water impoundments is a critical first step in subsequent treatment, recycling, evaporation or other intended reclamation of the water. Cost control and process improvement are to be gained by addressing the water chemistry early on in the process, promoting improvement each step of the way. A cursory observation of the literature coupled with the data presented in the chart suggest that using subsurface aeration deploying coarse and fine bubbles would offer the water quality benefits outlined herein. Notwithstanding nuances from site to site, advanced aeration merits serious consideration in the continuum of water management.

At press time Arcadian Technologies just completed installing a full-scale advanced aeration system for a client in the Uintah Basin. The company also is partnering with an instrumentation company to provide online real-time water quality parameters from the installation site. These data will afford regional drillers valuable information to consider reclaimed water for downhole reuse. E&P

References available.

Subsea valve controls blowouts

Valve leverages use of ambient water pressure to close and reopen the valve.

Thomas J. Ring, Deep Sea Innovations LLC

Leaks can occur at any depth of water where a well is located, posing a risk to operations, personnel, finances and the environment.

A newly developed valve technology by Deep Sea Innovations LLC can quickly close a leaking well at any depth and allow the well to be reopened at any time thereafter for further production. The financial consequences of an environmental disaster would no longer be a concern for those operating wells offshore.

This valve, called the Intensifier, is compact enough to be stored on any drilling or production rig, avoiding the wait for any specialized equipment to be shipped to a leak site, and its installation is quick and reliable. There should not be a need to conduct extensive environmental cleanups that result in the expense of drilling kill wells and subsequently drilling another production well. This valve technology is designed to change an uncontrolled risk to a finite, calculable and reasonably priced risk, providing higher coverage at lower cost.

How it works

The Intensifier has only one moving part that is not connected to any other part of the valve. The valve's simplicity of design affords a high level of reliability in performance and maintenance. The valve leverages the use of ambient water pressure to close and reopen the valve, and it has no practicable limit to the depth at which it can operate. For shallow-water sites, accumulators can be used to provide the needed force to operate the valve to close the well or reopen it.

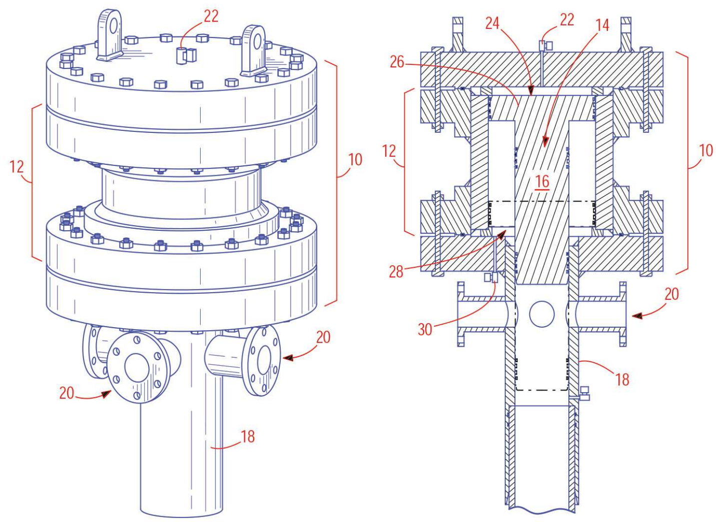


FIGURE 1. This patent drawing shows perspective and a cross section of the valve. (Source: Drill Right Technology)

Analysis shows how water pressure exerts force onto the sidewall of the chamber that contains the valve's piston, which can freely move within its housing despite the external ambient water forces. The resistance to the ambient water force allows the piston to move to close and reopen the leaking well. The valve is scalable to operate at any depth and overcome wellhead pressures.

The Intensifier is shown in perspective and cross section in patent drawings in Figure 1. A valve capable of closing a leak at about 1,524 m (5,000 ft) of water would be about 48 in. wide and about 84 in. tall, weighing between 6 and 8 tons.

The upper portion (10) of the valve defines the sealed chamber (12), which contains a movable piston (14). The arm (16) of the piston is movable within the engagement cylinder (18). The cylinder defines vent openings (20) that are positioned symmetrically around the cylinder.

The engagement cylinder is lowered over the leaking riser. Additional weight is required to place the valve properly. The leaking oil or gas flows through the engagement cylinder and out the vents, providing stability for the engagement of the valve to the riser. The engagement cylinder at this point may be optionally secured to the riser.

In operation, a valve (22) on top of the cylinder is opened to permit either pressurized ambient water or pressurized fluid from an accumulator into the portion of the sealed chamber above the piston head (26). The pressurized fluid exerts a force onto the head of the piston, causing the arm to move downward within the cylinder, thus closing the vents and shutting off the flow of oil or gas through the Intensifier valve. A dashed line below the vents illustrates the closed position of the piston.

The valve can be reopened simply by opening a valve (30) on the upper portion of the valve and leaving the valve on the top of the Intensifier open. The pressurized fluid that enters the lower portion (28) of the chamber and the pressure of the oil or gas on the bottom of the arm (16) will move the piston upward to unblock the

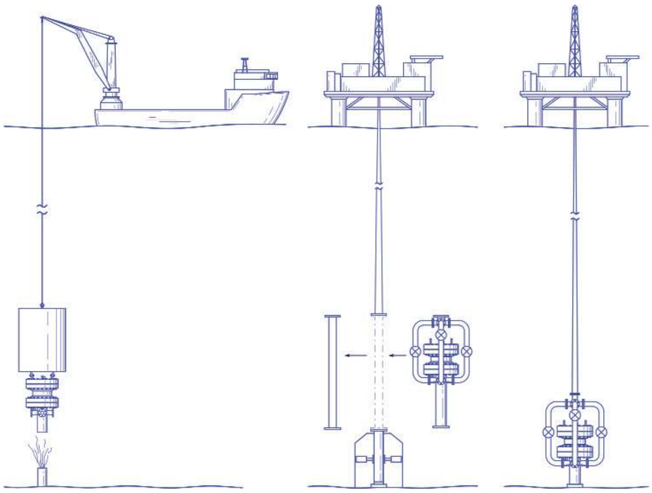


FIGURE 2. The Intensifier valve can be used in a variety of applications. Shown here, from left to right, are emergency response/well recovery and well capping for future production, positioned in tandem with BOP for production and as a production BOP. (Source: Drill Right Technology)

vents and permit the oil or gas in the well to recommence flowing through the vents.

Subsequent opening and closing of the vents can be achieved using accumulators. For example, to reclose the valve, an accumulator can be attached to the upper valve and activated while the lower valve (30) is open. To close the intensifier again, an accumulator can be attached and activated through the lower valve while the upper valve is open.

Extremely high forces can be generated by this valve. For example, a 25-in. diameter head on the piston in about 1,524 m of water will exert more than 1.1 MMlb of downward force on the piston. With a 9-in. diameter arm, a closure force in excess of 17,000 psi can be exerted against the wellhead pressure. By varying the dimensions of the valve, whatever force may be necessary to close a well can be generated.

The valve technology not only offers financial benefits by avoiding disasters but also can provide savings in E&P within the oil and gas fields of the world. E&P

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The Australian American Chamber of Commerce is hosting their 7th annual AACC Energy Conference and Workshop, scheduled February 4-5 at the Westin Hotel, Memorial City in Houston. The conference has become the premier venue for industry executives and leaders who want to better understand Australia's oil and gas markets.

Each year more than 300 senior-level industry representatives from E&P companies, engineering/construction firms, product/service providers and financial firms headquartered in Australia, the U.S. and Asia converge in Houston. The event is a unique opportunity for attendees to network together, hear from top Australian government officials, and to discuss the business opportunities and challenges in Australia.

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BREAKING *through* BARRIERS

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Energy Conference Agenda

"Breaking Through Barriers"

THURSDAY, FEBRUARY 5, 2015

8:15 - 8:30 am WELCOME/OPENING REMARKS

8:30 - 9:00 am MORNING KEYNOTE
- Anup Sharma, Chief Information Officer, GE Oil and Gas

9:00 - 10:00 am USING TECHNOLOGY TO BE SUCCESSFUL IN REMOTE ENVIRONMENTS
- Wayne Gerard, Co-Founder and Chief Executive Officer, RedEye Apps
- Diana Hoff, Vice President Technical, Engineering and Innovation, Santos

10:00 - 10:20 am BREAK

10:20 - 11:20 am ENCOURAGING INVESTMENT: SUCCESSFUL POLICY AND INDUSTRY INITIATIVES
- Rick Wilkinson, Chief Technical Officer, Australian Petroleum Production & Exploration Association (APPEA)
- Tim Shanahan, Director Energy and Minerals Institute, University of Western Australia
- Barry Goldstein, Executive Director of Energy Resources, Department of Manufacturing, Innovation, Trade, Resources and Energy State Government of South Australia (invited)

11:20 am - 12:50 pm LUNCH & KEYNOTE
- The Hon. Ian MacFarlane, Minister for Industry, Australia (invited)

12:50 - 1:10 pm BREAK

1:10 - 2:10 pm BEST PRACTICES IN GAS MARKET FUNDAMENTALS
- David Wrench, Managing Director, Strike Energy Ltd.
- Kenneth B. Medlock III, Ph.D., Senior Director, Center for Energy Studies, Rice University-Baker Institute

2:10 - 2:40 pm AFTERNOON KEYNOTE
- Melody Meyer, President, Chevron Asia Pacific Exploration and Production Company

2:40 - 2:50 pm BREAK

2:50 - 3:50 pm OPERATING SUCCESSFULLY IN AUSTRALIA
- David Banks, General Manager, Eagle Ford, BHP Billiton
- Representative from Woodmac (invited)
- Ian Davies, Managing Director and Chief Executive Officer, Senex

4:00 - 5:00 pm EXECUTIVE CONVERSATION
- The Hon. Kim Beazley, AC, Australian Ambassador to the United States of America

5:00 - 5:05 pm CLOSING REMARKS
- Andrew Bowers, President, Australian American Chamber of Commerce
- Meath Hammond, 2015 Energy Conference Co-Chair

5:05 - 7:00 pm WINE RECEPTION

Half-Day Workshop Agenda

"Capitalizing on Australian Oil & Gas Growth"

FRIDAY, FEBRUARY 6, 2015

8:40 - 9:00 am WELCOME

9:00 - 10:00 am AUSTRALIAN MARKET OPPORTUNITIES

Insight into excising and future opportunities for oil and gas exploration, production, services, equipment and technology companies interested in doing business in Australia.
- Jerry Eumont, Managing Director, IHS
- David Evans, Chief Operating Officer, DrillSearch
- Ajay Singh, Director Worldwide Projects, Apache

10:00 - 10:30 am NETWORKING BREAK

10:30 - 11:45 am CONCURRENT SESSIONS

Session 1: UPSTREAM TECHNICAL EXECUTION

Representatives from the Australian federal government and Australian state government and Australian state government geological surveys will highlight tenure opportunities in their respective regions and the process for bidding, securing and maintaining prospecting, exploration and production rights.
- Tom Bernecker, Leader Offshore Acreage Release and Petroleum Promotion, Geoscience Australia
- Dorothy Close, Director Regional Geoscience, Northern Territory, Department of Mines and Energy
- Peter Green, Manager Petroleum & Gas, Geological Survey of Queensland, Department of Natural Resources and Mines
- Elinor Alexander, Director of Geology and Exploration, Department of State Development, South Australia

Session 2: EXECUTING YOUR COMMERCIAL STRATEGY

Pursuing commercial opportunities in Australia. Understand the fundamentals of entering Australian supply chains, setting up operations and partnering with Australian industry.
- Jody Rowe, Principal, Rowe Strategic Management Group
- John Pope, President and CEO, Well Dog

11:45 - 12:00 pm CLOSING REMARKS

12:00 - 12:45 pm BUSINESS NETWORKING

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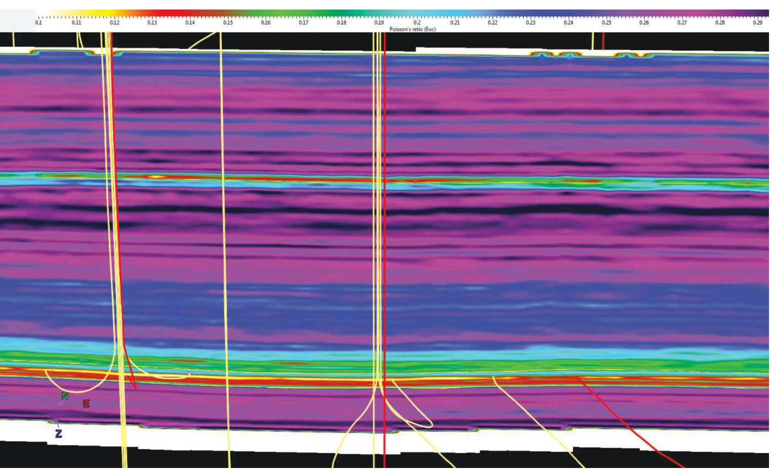
Reservoir characterization for unconventional plays

QI quantifies reservoir conditions and incorporates other sources of rock property data.

Scott Singleton, ION Geophysical

Throughout the modern history of exploration geophysics, the evaluation of conventional reservoirs (i.e., those driven by porosity and fluid saturation) primarily involved the imaging of stacked seismic data to identify trapping mechanisms such as anticlines and faults from which hydrocarbon accumulation can occur. This concept started to evolve in the early 1990s when prestack time migration (PSTM) became commonplace and the concepts and pitfalls of amplitude vs. offset (AVO) started to become widely known. Shortly thereafter, exploration for Class II AVO anomalies became in vogue after the easy Class III "bright spots" were discovered and drilled, some of which only turned up high porosity sands or fizz gas.

These experiences demonstrated that additional diagnostic information was needed. In quantitative interpretation (QI) the objective is to quantify reservoir conditions, including internal and external geometries, elastic and geomechanical properties, lithology, and fluid content. This can be achieved through the development of reservoir-specific rock physics models and their use in the inversion of seismic gathers. These inversion products are then calibrated using other sources of rock property data such as well logs, core and drilling, and completion engineering data.



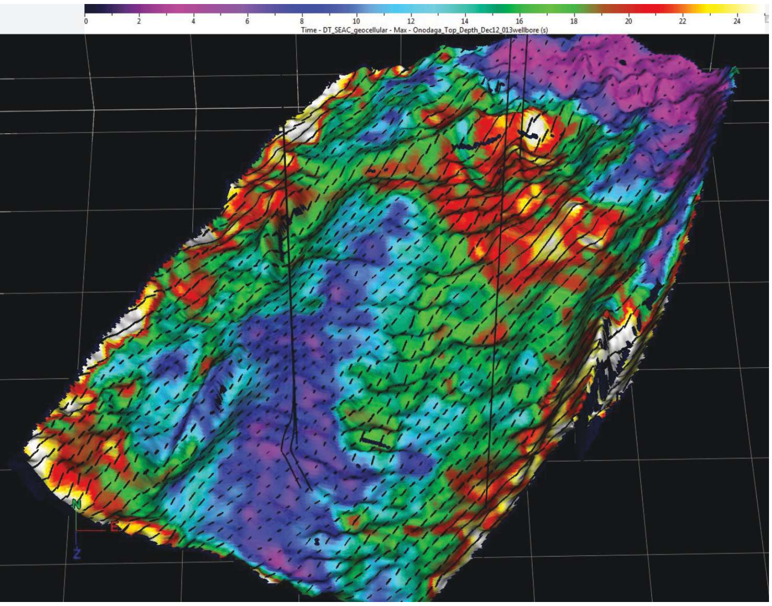
Rock properties from seismic: An inline section shows Poisson's ratio (PR). Several laterals can be seen leading into the inline section at the top of the Lower Marcellus just below the Cherry Valley Limestone. The Lower Marcellus is characterized in this prospect as having low PR, whereas the Onondaga Limestone just below the Marcellus has high PR. (Source: ION)

A new way of doing business

Beginning in the last decade, these quantitative tools were modified so they could be applied to unconventional resources such as tight oil and gas. These reservoirs have low porosity and permeability and often require enhanced recovery techniques such as hydraulic fracture stimulation to achieve economic recovery levels. Thus, QI techniques designed for porosity-driven plays are not suitable for unconventional plays.

This is conceptually easy to understand: Conventional plays consist of a matrix rock with pores. The matrix can be granular sandstones or porous limestones; it is not important as long as rock properties such as bulk moduli are known. Complexities may occur if clays or calcites are present in siliceous granular rocks. Fluids such as water, gas or oil inhabit the pore space. Models can be generated for any combination of porosity and fluid content. More complex models allow for clay variations, calcite variations or specific geometries such as laminated reservoirs.

In unconventional plays this paradigm does not exist. The rocks are typically mudstones with some degree of lamination where the lamina can consist of shales, silts or limestones. (True pure shale formations are usually not appropriate reservoirs because they are typically high in clay content and have difficulty fracturing and maintaining the fracture after fluid pressure is removed). In this scenario, the rock properties are an average over some vertical interval, which will vary between log resolution and seismic resolution. The properties of interest are porosity, total organic carbon and volume of clay because these three properties typically have the greatest impact on acoustic and density readings from logs or seismic.



Shear stress from seismic: This Marcellus prospect has considerable structural relief on the east and north (right and top) due to proximity of the Allegheny thrust belt. Knowledge of the stress profile within the prospect is critical to successful completions of lateral wells. Analysis showed that an anticline in the lower center of the survey contained a low stress profile (blue colors and short-azimuth vectors in black) and thus was an optimal location for placing laterals. (Source: ION)

Fractures: to be or not to be

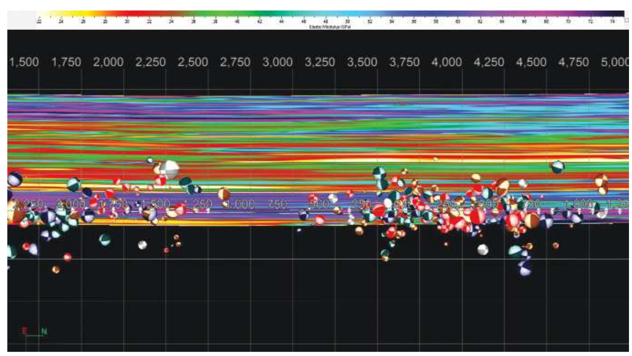
Because fine-grained reservoirs often have single-digit porosities and nanodarcy permeabilities, some other means of fluid transport from matrix to wellbore must be found. These pathways are fractures. Creating fractures is, of course, the purpose of hydraulic fracturing, but what about natural fractures? Natural fractures can be excellent connectivity pathways, but under some circumstances they can be too good. If there are water-bearing formations in the vicinity of the organic-rich shale and either natural or induced fractures connect the wellbore with these formations, the well will be watered out. An additional danger is losing pumped fluid pressure via high-conductivity fracture systems.

Realizing the importance of natural fracture networks, seismic acquisition has advanced considerably in an effort to detect and characterize these fractures. A case in point is full-azimuth acquisition (FAZ). In offshore environments with complex structures such as subsalt, FAZ data allow the complete wavefield to be sampled and imaged. However, onshore unconventional shale plays typically exhibit directional anisotropy to some extent. This anisotropy is due to vertical fracture sets in one or more directions and is known as horizontal transverse isotropy (HTI). The principle is that seismic waves will slow down if they cross fractures, and thus the difference between seismic wavefield velocities in orthogonal directions (parallel and perpendicular to a set of fractures) acts as a proxy for the direction and intensity of fracturing. This principle applies to normal compressional (PP) seismic data as well as multicomponent converted (PS) seismic data.

Microseismic: the sounds of breaking rock

The importance of fractures in unconventional plays has led to the development of another related technology—listening for acoustic signals generated by the injection of fluids into a rock mass during well completion. These signals provide evidence of the change in stress state of rocks in the vicinity of the wellbore. With the injection of fluids into a rock mass the pore pressure increases, thus decreasing its cohesive strength and allowing movement to occur along planes of weakness in rocks that are already critically stressed. Pressure waves caused by fluid injection can travel some distance away from the wellbore, thus allowing breakage of critically stressed rock beyond the fluid-injected rock mass. It is for this reason that a direct correlation of microseismic events with fluid injection or of proppant placement remains problematic.

Nonetheless, the amount of information that can be determined from a microseismic event is remarkable. As in normal surface seismic acquisition, if proper geometries exist (meaning detection of an event from multiple locations, thus allowing sampling of the full wavefield)



Integration of microseismic and rock properties: Microseismic data are displayed in front of an inline section of Young's modulus, which is a proxy for brittleness. Most of the microseismic is constrained to the brittle layer near the base of the section, but some occurs both above and below the brittle layer, most likely associated with faulting. Focal plane solutions ('beach balls') are shown. The color of the event indicates the source mechanism from Hudson diagrams. Red is opening, brown is closing, and blue and green are shear sources. (Source: ION)

then not only can the magnitude of the event be determined (which is related to the area of slippage) but the sense of motion (strike, dip and rake of movement) and the type of event (opening, closing or strike-slip) also can be quantified. Armed with this treasure trove of data about the well completion, engineering and log data from the wellbore can finally be integrated with geophysical data away from the wellbore.

Bringing it all together

To accomplish the integration of diverse data types, ION developed the ResSCAN concept. These programs incorporate leading-edge multicomponent (PP and PS) survey design, acquisition, processing and analysis with the express purpose of defining the rock and fracture properties of an unconventional prospect. In the processing sequence, vertical transverse isotropy, primarily from layering effects, is removed during migration. This is followed by HTI anisotropy calculation via elliptical velocity inversion of both PP and PS data (using the AZIM and SEAC algorithms, respectively). The results of HTI anisotropy calculation are used to kinematically remove the effects of anisotropy on the azimuthal gathers, thereby flattening them, and also are used quantitatively to assess the magnitude and azimuth of fracturing and/or local and regional stress in the project area.

Rock properties are calculated via prestack joint inversion of PP and PS data, which act to constrain density estimations. These results are calibrated with logs and core, and the fracture data are calibrated with image logs, borehole breakout data and completions pressure data. The rock physics models are used to assess and interpret seismic rock property changes away from the wellbore.

As a final step, these data are fed into a geocellular grid along with overburden stress and the principle horizontal stresses to create a geomechanical static model. Simulations can be run using the completion data, attempting to reproduce the observed microseismic event cloud. Once this is achieved, simulations can then be run at proposed drilling locations to predict completion success with the goal of maximizing EUR while minimizing cost.

Seismic pattern recognition in shale resource plays

New computing techniques help identify sweet spots.

Rocky Roden and **Deborah Sacrey**, Geophysical Insights

Various approaches have been developed for workflows to exploit unconventional resource plays. For example, Slatt et al. (2008) describes a workflow that includes characterization of multiscale sedimentology and sequence stratigraphy, relating stratigraphy to log response, seismic response, petrophysical and geomechanical properties, and organic geochemistry. Newsham and Rushing (2001) tie together geology, petrophysics and reservoir engineering with geomechanics. Britt and Schoeffler (2009) describe a shale play in terms of mineralogy, rock mechanics and geomechanics and how these approaches can be used to optimally complete and fracture stimulate any unconventional reservoir.

The essential elements of unconventional shale resource plays are described as:

1. Reservoir geology: thickness, lateral extent, stratigraphy, mineralogy, porosity and permeability;
2. Geochemistry: total organic carbon, maturity and percentage of kerogen (richness);

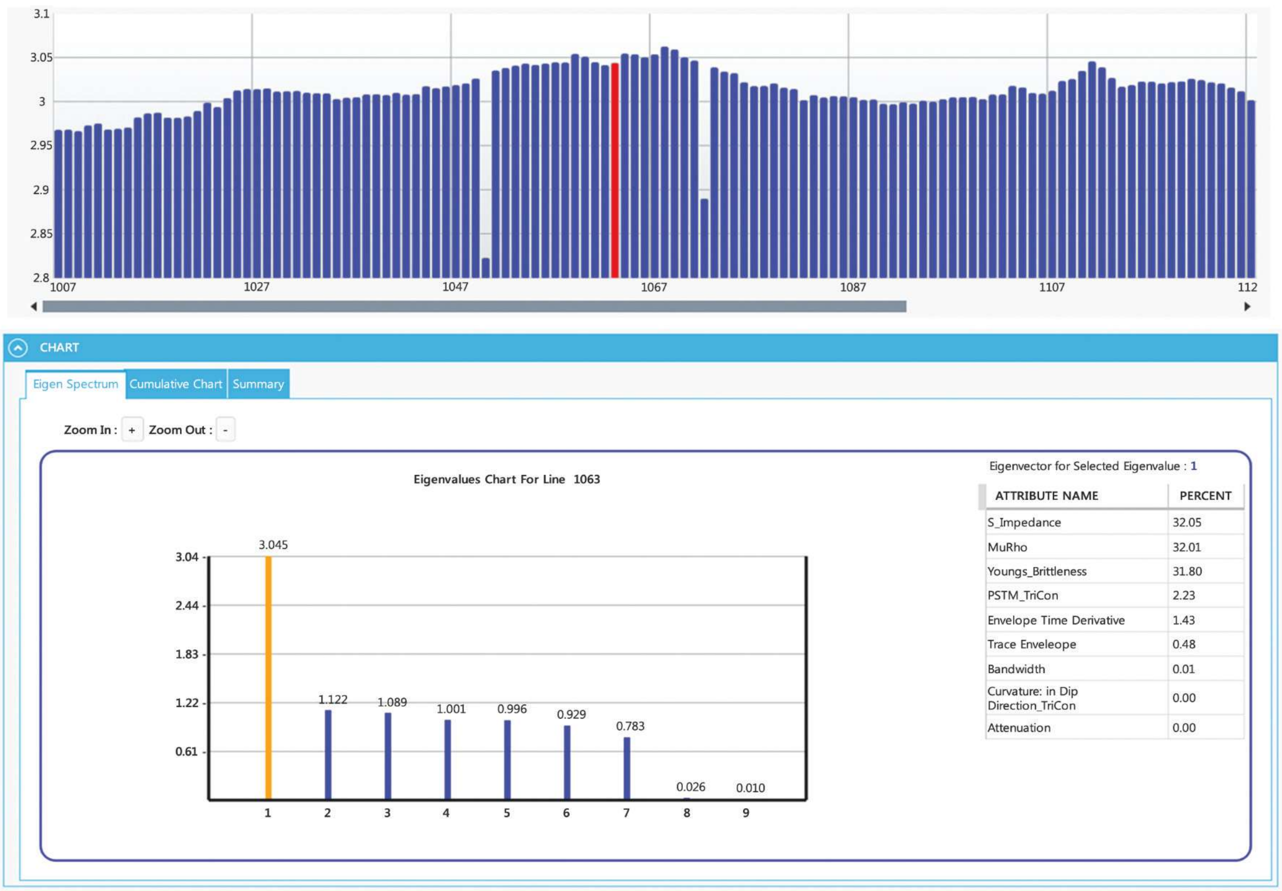


FIGURE 1. PCA in the Paradise software displays highest eigenvalues for 3-D inlines in the upper portion with selected largest eigenvector (red); then all eigenvalues for the inline are shown in the lower left from largest (yellow) to smallest. The lower right portion shows the attributes and their proportion for the eigenvector corresponding to the largest eigenvalue. (Source: Geophysical Insights)

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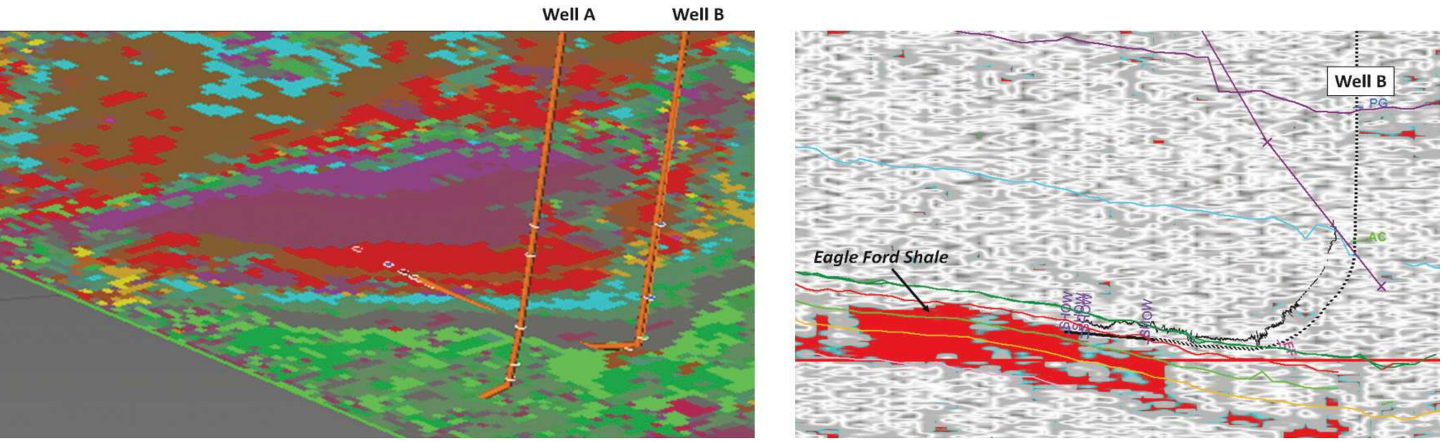


FIGURE 2. (Left) SOM classification from the Paradise software shows the Eagle Ford interval displaying dry hole Well A and good Well B; (right) vertical seismic display through Well B indicates shows as the well entered the Eagle Ford interval. (Source: Geophysical Insights)

3. Geomechanics: acoustic impedance inversion, Young's modulus, Poisson's ratio (Vp/Vs) and pressures; and
4. Faults, fractures and stress regimes: coherency (similarity), curvature, fault volumes, velocity anisotropy (azimuthal distribution) and stress maps.

There is, of course, overlap in these various categories, and how these various elements are interrelated also depends on the objective, which might be to define sweet spots to drill, optimize drilling locations, define completion operations or even determine economic viability.

Seismic attributes

In shale resource plays, conventional seismic data are one of the few tools geoscientists have at their disposal to interpret regional trends and guide locations and orientation of infill wells. In shale resource plays the interpretation of seismic data can be quite challenging because of resolution issues and anisotropy, and even though shales make up 70% of sediments, knowledge of shales as reservoirs is limited. Seismic attributes are often generated to help interpret the seismic properties of shale resource plays, which, of course, are a valuable guide to understanding the geology. Seismic attributes such as amplitude, dip, frequency, phase and polarity are measurable properties of seismic data. Attributes can be measured at one instant in time/depth or over a time/depth window and may be measured on a single trace, on a set of traces or on a surface interpreted from seismic data. Seismic attributes reveal features, relationships and patterns in the seismic data that otherwise might not be noticed (Chopra and Marfurt, 2007).

There are literally hundreds of seismic attributes in dozens of categories. In shale resource plays some of the most commonly employed seismic attributes are listed in Table 1. Often in shale resource plays seismic attributes are calibrated with well logs, microseismic results, production data and completion information.

CATEGORY	TYPE	INTERPRETIVE USE
Geometric Attributes	Coherency/Similarity, Curvature	Faults, Fractures, Folds, Anisotropy, Regional Stress Fields
AVO and Seismic Inversion	Poisson's Ratio, Young's Modulus, Lambda Rho, Mu Rho	Brittleness, TOC, Porosity
Instantaneous Attributes	Reflection Strength, Instantaneous Phase, and Instantaneous Frequency	Lithology Contrasts, Bedding Continuity and Thickness
Amplitude Accentuating Attributes	RMS Amplitude, Relative Acoustic Impedance, Sweetness, Average Energy	Porosity, Stratigraphic and Lithologic Variations
Spectral Decomposition	Continuous Wavelet Transform, Matching Pursuit	Layer Thicknesses, Stratigraphic Variations

TABLE 1. These are typical seismic attribute categories and types employed in shale resource plays and their associated interpretive uses. (Source: Geophysical Insights)

SOMs

The next level of interpretation requires pattern recognition and classification of subtle information embedded in the seismic attributes. Taking advantage of today's computing technology, visualization techniques and understanding of appropriate parameters, self-organizing maps (SOMs, Kohonen, 2001) efficiently distill multiple seismic attributes into classification and probability volumes (Smith and Taner, 2010). SOM is a powerful nonlinear cluster analysis and pattern recognition approach that helps interpreters identify patterns in their data that can relate to desired geologic characteristics as listed in Table 1. Seismic data contain huge amounts of data samples and are highly continuous, greatly redundant and significantly noisy (Coleou et al., 2003).

The tremendous amount of samples from numerous seismic attributes exhibit significant organizational structure in the midst of noise (Taner, Treitel and Smith, 2009). SOM analysis identifies these natural organizational structures in the form of clusters. These clusters reveal significant information about the classification structure of natural groups that is difficult to view any other way.

Principal component analysis

The first step in a seismic multiattribute analysis is to determine which seismic attributes to select for the SOM. Interpreters familiar with seismic attributes and what they reveal in their geologic setting may select a group of attributes and run a SOM. If it is unclear which attributes to select, a principal component analysis (PCA) may be beneficial. PCA is a linear mathematical technique to reduce a large set of variables (seismic attributes) to a small set that still contains most of the variation in the large set, in other words, to find the most meaningful seismic attributes. Figure 1 displays a PCA analysis where the blue histograms on top show the highest eigenvalues for every inline in that seismic survey. An eigenvalue is the value showing how much variance there is in its associated eigenvector, and an eigenvector is the direction showing the spread in the data. An interpreter is looking for what seismic attributes make up the highest eigenvalues to determine appropriate seismic attributes to input into a SOM run.

The selected eigenvalue (in red) on the top of Figure 1 is expanded by showing all eigenvalues (largest to smallest left to right) on the lower leftmost portion of the figure. Seismic attributes for the largest eigenvector show their contribution to the largest variance in the data. In this example S impedance, MuRho and Young's brittleness make up more than 95% of the highest eigenvalue. This suggests that these three attributes show significant variance in the overall set of nine attributes employed in this PCA analysis and may be important attributes to employ in a SOM analysis. Several highest ranking attributes of the highest and perhaps the second-highest eigenvalues are evaluated to determine the consistency in the seismic attributes contributing to the PCA. This process enables the interpreter to determine appropriate seismic attributes for the SOM evaluation.

Eagle Ford Shale evaluation

Once a set or perhaps several sets of seismic attributes are selected, these sets of seismic attributes are input into separate SOM analyses. The SOM setup allows the interpreter to select the number of clusters, window size and various training parameters for a SOM evaluation. Figure 2 displays the classification results from an evaluation of the Eagle Ford Shale. The seismic attributes employed in the SOM analysis are a combination of attributes from prestack simultaneous inversion, instantaneous attributes and a curvature attribute. The westernmost well A had few shows and no production in the Eagle Ford interval. Well B to the east was drilled into a cluster identified from the SOM analysis as the region in red. This well encountered good shows in the Eagle Ford. The vertical seismic display through Well B in Figure 2 shows how the well encountered good shows as it entered into the Eagle Ford interval. Therefore, the cluster associated with the red areas in Figure 2 is defining apparent sweet spots or optimal productive zones in the Eagle Ford.

The application of PCA can help interpreters identify seismic attributes that show the most variance in the data for a given geologic setting and help determine which attributes to use in a multiattribute analysis using SOMs. Applying current computing technology, visualization techniques and understanding of appropriate parameters for PCA and SOM enables interpreters to take multiple seismic attributes and identify the natural organizational patterns in the data. E&P

References available.

HP/HT testing is powering oilfield exploration

Harsher environments require constant lab improvements.

Dr. Rod Martin, Element Materials Technology

As the focus of global oil exploration shifts toward new terrains, the demands on its equipment are increasing. And as the pace of exploration shows no sign of slowing, new extreme conditions are being encountered all the time, with deepwater, corrosive wells and arctic locations just some of the places where polymers are exposed and must survive in service, sometimes for decades.

To ensure that these challenges can be met, materials testing companies are required to be ever-more inventive and responsive in their testing. They must be able to push materials to their limits while maintaining quality assurance for customers to ensure that components used *in situ* are able to reliably withstand the most extreme temperatures and pressures.

HP/HT conditions (along with factors such as high levels of hydrogen sulfide [H_2S], CO_2, high stresses and hostile fluids) are some of the most significant challenges to the integrity of materials in oil and gas production environments. Component manufacturers are turning to HP/HT and related materials testing to meet the challenges they are facing.

Changing requirements

HP/HT testing is conducted to qualify materials for use in components for oil and gas production environments. A range of industry standards exists for the purposes of materials qualification, but manufacturers are increasingly demanding custom tests with an emphasis on more extreme environments so that long-term reliability can be determined.

Industry accreditations such as ISO 23936 play a role as an international standard. This standard is broader than NORSOK M710 and is used to test polymer sealing materials, rubbers, plastics and H_2S, applications for both thermoplastics (part 1) and elastomers (part 2) with future parts for thermosets and composites. Such test standards will form part of a regular suite of tests and allow the rigorous testing of polymeric materials used for sealing, pressure barriers, hoses, flexible pipe and risers, or other purposes in components.

Many customers looking to qualify materials in more extreme oil and gas production environments increasingly need to exceed the parameters of the qualifications mentioned to represent actual service conditions and functional testing. Custom tests are therefore being carried out by a range of industry leaders such as Element Materials Technology to meet the new HP/HT testing demands.

Higher temperatures and pressures

In recent years there have been identifiable trends in the demand for scaled-up HP/HT materials testing, often called ultra- or extreme-HP/HT. HT materials testing was previously required for between 230 C to 240 C (446 F to 464 F); however, HT material testing is now being carried out at temperatures up to 315 C (599 F). Many polymers have defined thermal limits beyond which they will degrade or cease to deliver the polymeric properties for which they were chosen. This has encouraged material manufacturers to develop new compounds with higher limits, design engineers to reduce the impact of temperature on component function, and test experts to both better define the limits of current materials and explore the boundaries of new materials through innovative test methods and techniques.

A similar pattern can be seen in HP materials testing. While a base level of 5,000 psi is sufficient for many uses, tests are now conducted in ranges including 20,000 psi and even up to 35,000 psi.

The larger scale of testing demands has increased investment and expertise from those working in materials technology to ensure that testing quality is not compromised. Industry leaders such as Element Materials Technology are able to put their knowledge and skill sets to testing materials at the limits of that required by the E&P industry, relying on globally recognized experts and reputation for quality.

New advances in materials

Material innovations have opened up these new sites for

exploration, with opportunity to explore new oil and gas production environments. This means new testing parameters have become necessary. These tests include low-temperature rubbers, new grades of thermoplastics able to withstand the aforementioned high temperatures and pressures and variations of new materials for critical sealing applications.

Expert HP/HT materials testing, therefore, not only relies on the ability to scale up existing tests. As the polymers themselves are adapted to new conditions, trusted testing partners are required to interpret the results from these data, allowing further materials development for still further hostile applications.

HP/HT laboratories

Sites such as Element's Hitchin laboratory (formerly known as MERL Ltd.) have needed to develop capabilities to sustain clients.

Element Hitchin doubled its capacity in October 2014, allowing it to provide the NORSOK M710 and ISO 23936 qualifications on a greater scale as well as meeting the expectations of clients who wish to test at the unprecedented temperatures and pressures highlighted. This capability is being mirrored in the Element Houston facility.

Facilities such as Element Hitchin make use of an enormous range of technologies to deliver on the required materials tests, from a large number of custom vessels, which can be directed to a range of customers and requirements, to the agility to adapt and move vessels as necessary. This means that a great range of polymers can be qualified at the pressures and temperatures required. Facilities include the ability to monitor material performance after exposure to HP/HT fluids such as production gases and liquids, H_2S, and chemical treatments; to examine materials *in situ* while they absorb fluids; and to measure leakage, permeation and function of seals, liners and barrier layers at HP/HT and model these components under extreme conditions using materials data generated in the test lab.

The Hitchin laboratory also implements industry-leading design, making use of remote monitoring and regulation of vessel temperature and pressure. The system also includes a CCTV feed to allow staff and clients to view the laboratories remotely. Data acquisition and reporting also must meet the highest standards to ensure efficient servicing of customers.

The future of HP/HT

As oil and gas production develops in a climate of increasingly complex environments, innovation will become crucial to extracting maximum value. Oil and gas production will continue to rely on the ability of materials technology testing to qualify both large ranges of materials able to withstand normal conditions and materials that can withstand the highest temperatures and pressures.

Materials testing companies are becoming more inventive and responsive in their testing. (Source: Element Materials Technology)

Strategy is crucial in such a fast-paced environment. Tests that serve a client's needs today may be rendered irrelevant by advances in materials or testing techniques in a year's time, so building good relationships with testing companies at the forefront of the industry will allow customers to continue to innovate.

Custom tests that allow them to qualify materials and components for bespoke use in unique locations will see the parameters for testing pushed to limits that are currently infeasible. Ultimately, as the landscape changes in production environments, it is crucial that HP/HT testing remains reliable and adaptable to the needs of customers. E&P

MPD through CT

A combined solution for HP/HT cementing enhances safe and effective wellbores in extreme pressure profiles.

Elvin Mammadov, **Sheldon Sephton** and **Nadine Osayande**, Weatherford

Managed pressure drilling (MPD) methods that regularly enable drilling in difficult environments are proving to be an effective tool in cementing operations. In a vertical exploratory HP/HT well in British Columbia, Canada, MPD methods were applied through coiled tubing (CT) to successfully cement an openhole section to temporarily abandon the well after drilling and logging operations.

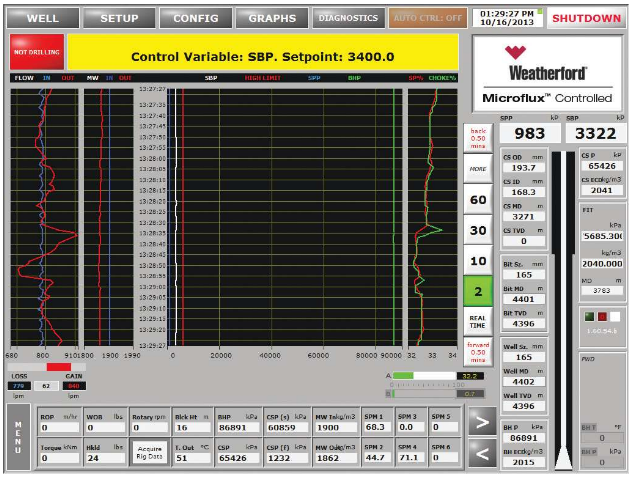
In HP/HT drilling environments, managing the bottomhole pressure (BHP) to cement an open hole is very difficult to accomplish with conventional methods, which are typically unable to respond quickly or effectively to counter fluctuations in wellbore pressure without exceeding the window limits. With excessive pressure, the fracture gradient is exceeded and fluid losses occur; however, an insufficient amount of pressure can precipitate a kick as formation pore pressure pushes gas into the wellbore.

By closing the loop, the MPD system provided early kick/loss detection and control while displacing kill fluids prior to cementing and while cementing. MPD allowed real-time flow detection and modeling to help avoid costly cement additives and higher cement weight, eliminate mud and cement losses (and related formation damage), and minimize high standpipe pressure.

The closed-loop cementing operations successfully maintained a constant bottomhole pressure to stay within an almost nonexistent .3024 kPa/m window. The real-time operations simultaneously balanced the hydrostatic pressure from pumping cement with the swabbing effect of retrieving the CT. Weatherford's Microflux control system managed this automatically by reading mass flow out of the annulus and adjusting equivalent circulating density (ECD) by applying annular surface backpressure (SBP).

The British Columbia project

MPD technologies were used to close the loop and thus drill the conventionally challenging exploratory HP/HT well vertically to 4,402 m (14,442 ft) measured depth (MD). After logging the well from 3,271 m (10,732 ft) to 4,402 m MD, the operator planned to cement the



Weatherford's MPD software operating panel, the Microflux control system, demonstrates pressure management data while cementing the HP/HT well in British Columbia. (Source: Weatherford)

165.10-mm openhole section from 3,825 m (12,549 ft) to 4,402 m through CT. A formation pressure gradient of 19.71 kPa/m and a fracture gradient of 20.01 kPa/m presented a very narrow pressure window and a significant risk of the wellbore either gaining from a formation influx or losing circulation while cementing.

After drilling concluded, the well was displaced with 2,020 kg/cu. m (126.1 lb/cf) kill mud. Prior to the cementing operation the kill fluid was displaced with a lighter 1,890 kg/cu. m (118 lb/cf) mud. During both displacements, MPD was used to maintain a constant bottomhole ECD of 2,015 kg/cu. m (126 lb/cf). The openhole section was cemented through CT while maintaining a constant bottomhole ECD of 2,015 kg/cu. m. No losses or gains were experienced.

The kill mud weight of 2,020 kg/cu. m was determined by a formation pressure equivalent to 2,010 kg/cu. m (125.5 lb/cf) mud density and formation fracture pressure equivalent to 2,040 kg/cu. m (126.1 lb/cf). Precise data on the downhole pressure regime were obtained by MPD in the drilling phase.

In conventional operations, a 2,040 kg/cu. m cement pumped into the annulus would fracture the formation and precipitate a well control event. If the kill mud den-

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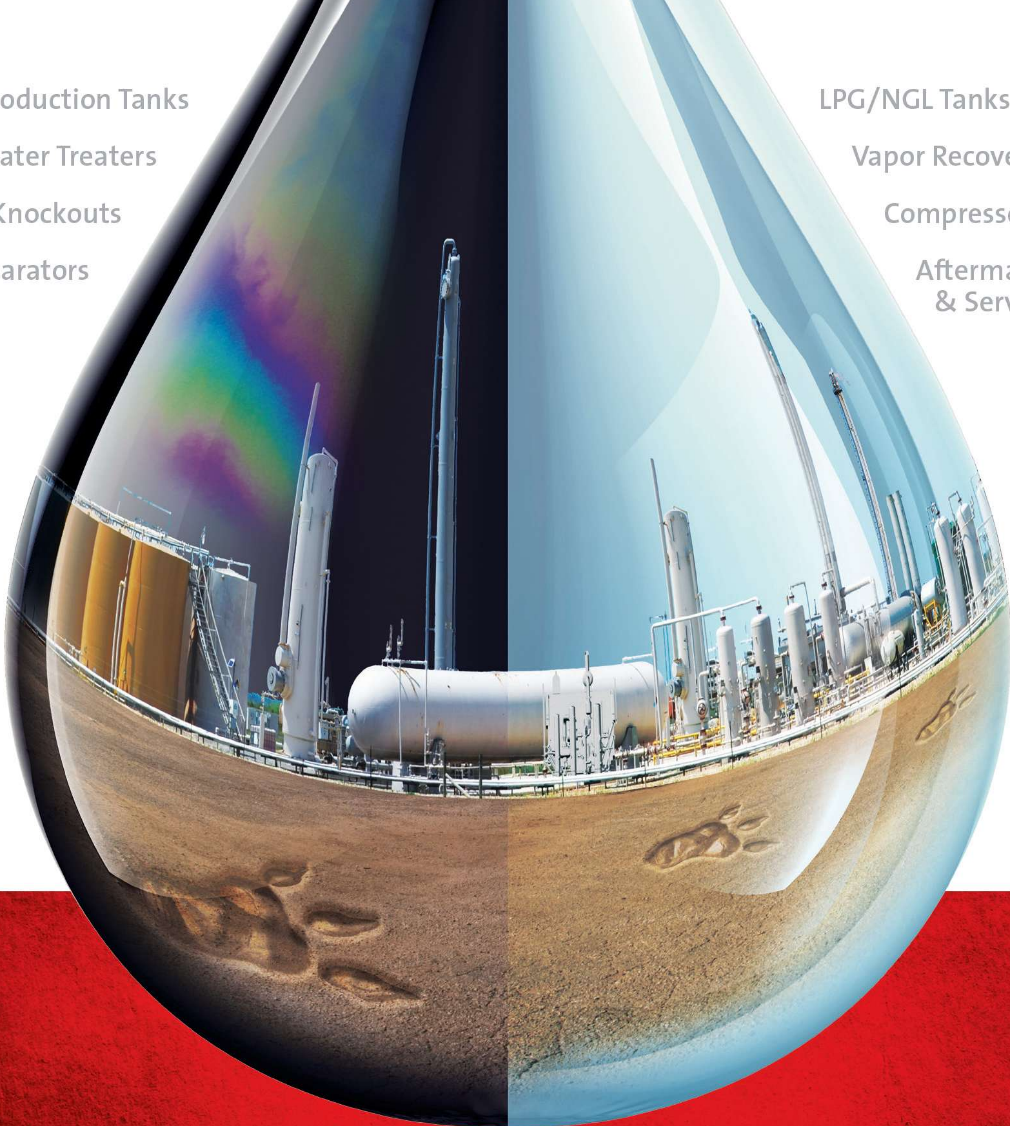

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Measured Depth (m)	SBP (BPa)	Cement Density	BH ECD kg/m3)
4402	3670	1885	2015
4350	3704	1885	2015
4300	3726	1885	2015
4250	3761	1885	2015
4200	3789	1885	2015
4150	3814	1885	2015
4100	3839	1885	2015
4050	3863	1910	2015
4000	3775	1910	2015
3950	3765	1910	2015
3900	3687	1910	2015
3850	3677	1910	2015
3850	3660	1910	2015

Open Hole Capacity without DS	0.02138 m3/m
Cementing Pump output	0.0026 m3/strk
Cementing Pump SPM	100 strk/min
Cementing Pump efficiency	93
Stroke Length	152.4 mm
ID of Liner	88.9 mm

The SBP ramp table for closed-loop cementing shows applied backpressure, increments and subsequent reductions in response to hydrostatic pressure changes. (Source: Weatherford)

sity was reduced enough to circulate the mud without exceeding 1,950 kg/cu. m (121.7 lb/cf) bottomhole ECD, the wellbore would be underbalanced and risk taking a kick.

Application of MPD allowed the lighter fluid to be safely circulated. As the process involved four different fluid densities in the annulus, managing the bottomhole ECD was a challenge even with MPD and involved precise calculation of annular frictional pressure across the four fluids.

Closed-loop cementing approach

A closed-loop cementing plan was developed for operational procedures, and prewell calculations were updated with real-time data. Key steps in the plan involved running in the hole with CT, displacing the kill mud with the lighter mud, pulling CT while pumping cement, circulating on top of cement after it was placed, tagging total organic carbon and pulling the CT out of the hole. At each step, the bottomhole ECD was held constant.

While running CT in the hole, the shut-in tubinghead pressure was equalized using invert mud, and the wellhead swab valve was opened prior to the trip. The tubing was initially run in the hole at 20 m/min (66 ft/min) while circulating invert mud at a minimum rate of 0.3 cu. m/min (11 cf/min). Every 500 m (1,640 ft) a pull test was performed. Tripping speed was reduced to 5 m/min (16 ft/min) while running in the openhole section to minimize any surging. The bottom was tagged to confirm the depth and determine cement volume.

The hole was displaced through the CT prior to cementing operations to replace the 2,020-kg/cu. m kill mud with 1,890-kg/cu. m mud. MPD was used to monitor bottomhole ECD to ensure that it did not fall below 2,015 kg/cu. m. While displacing with the lighter mud, the pump rate began at 270 l/min (71.3 gal/min) and was increased to 400 l/min (106 gal/min) based on drops in annular frictional pressure and hydrostatic pressure. Afterward, the pump rate was increased to the maximum to keep bottomhole (BH) ECD constant at 2,015 kg/cu. m; surface backpressure was increased gradually to 580 psi. Once the kill mud was circulated out of the well, surface backpressure was set at 580 psi using annular pressure mode of the automated MPD software. The lighter mud was circulated bottoms-up a second time to ensure that no gas was in the wellbore prior to the cementing operation. The MPD choke was set to 580 psi SBP on the second circulation.

When cementing through the CT, 3 cu. m (106 cf) of 1,910-kg/cu. m (119.2-lb/cf) invert pre-flush and 3 cu. m of 1,910-kg/cu. m invert spacer was pumped ahead of the slurry. The spacer was followed by 6.84 cu. m (241.5 cf) of the first cement slurry, a 1,885-kg/cu.m (117.6-lb/cf) thermal cement designed for the openhole interval from 4,402 m to 4,050 m (13,287 ft). Next was the second cement slurry, which consisted of 5.59 cu. m (197 cf) of 1,910 kg/cu. m thermal cement designed for the interval between 4,050 m and 3,825 m. Once 600 l (558.5 gal) of cement exited the CT nozzle, the CT was retrieved at 14.63 m/min (48 ft/min) while the two slurries were pumped. The MPD operations followed a SBP ramp table, which was precalculated to maintain a BH ECD constant at 2,015 kg/cu. m. Then a backpressure of 545 psi was applied, increased gradually to 560 psi and then reduced to 531 psi because of hydrostatic pressure changes.

The cement plug was displaced with an invert spacer and preflush followed by spacers. A SBP of 531 psi was applied to hold the cement plug and maintain the BH ECD constant at 2,015 kg/cu. m. SBP was increased to 548 psi once the spacers were circulated out of the well. SBP was maintained while drilling fluid was circulated for eight hours while waiting on cement to set.

At the end of eight hours, the top of the cement was tagged at 3,772 m (12,374 ft), successfully concluding the challenging cementing operations and verifying that closed-loop cementing was able to achieve the same pressure control and safety experienced in difficult drilling conditions.

Expanding the breadth

The ability to cement the HP/HT exploratory well using CT and MPD methods further enhanced the capacity to safely and effectively drill wellbores in extreme pressure profiles. The application of MPD provided a means to safely cement the well without kicks or losses, whereas conventional techniques presented the risk of a well control event. E&P

MWD, RSS tools extend operating envelope

New service provides operators with a fully integrated HP/HT logging and drilling solution.

Josh Ritchie and **Cesar Figueredo**, Schlumberger

Operators in the Gulf of Thailand engage in fast-paced drilling operations, striving to produce sufficient volumes of natural gas to support the needs of Asia's growing economies. As an example, an operator plans to drill about 500 gas wells over the next three years. The key technical challenge is that nearly half of these wells will penetrate reservoirs with bottomhole circulating temperatures above 175 C (350 F). That, as it turns out, is the operational limit of most of the existing commercial HP/HT rotary steerable systems (RSS) and of Schlumberger's MWD tools.

When downhole electronics, seals and sensors are exposed to high temperatures, tool failures increase as their life expectancy plummets, causing increased nonproductive time (NPT) for operators. Reliability begins to suffer when temperatures exceed 150 C (302 F). Components designed to last about 1,000 hours at 150 C survive less than 100 hours at 175 C. Therefore, when temperatures reach 175 C, drillers in the Gulf of Thailand and other HP/HT regimes typically halt operations, pull the MWD and/or RSS tools out of the hole and continue drilling blind. They rely on conventional stabilized or packed bottomhole assemblies (BHAs) without any real-time measurements or directional control. After each hole section, they must pull out of hole again and run a separate gyroscopic survey to confirm well positioning.

This common approach takes longer than drilling under normal conditions. Additional trips incur NPT. Without downhole measurements to steer the borehole, risks and costs associated with well control and collision increase. It is possible, in some cases, to miss the target completely, resulting in lost production or potentially a dry well.

The following case study with recent advancements in MWD and RSS technology demonstrates how operators in the Gulf of Thailand—and elsewhere— are enabled to continue drilling safely, efficiently and confidently, even under very high temperatures and pressures.

Gulf of Thailand case study

One E&P company in the Gulf of Thailand plans to drill up to 75 exploration and development wells per year for the next three years in temperatures above 175 C. To reduce the cost of well construction and the uncertainty of inaccurate wellbore placement while drilling blindly, the operator decided to field-test a new HP/HT MWD tool. The top objective for its first test well was to reach the target reservoir in a single run.

The new tool is a collar-mounted MWD tool designed to operate reliably and continuously—not merely to "survive"—in circulating temperatures as high as 200 C (400 F) and pressures up to 30,000 psi. It provides directional and inclination surveys, annular and internal pressures, azimuthal gamma ray, and shock and vibration MWD. Existing high-temperature electronics systems typically harness ceramic-encapsulated chips mounted on plastic boards, which begin to deteriorate and crack once temperatures rise above 175 C. By completely removing the plastic elements from the BHA, the new proprietary microchip modules that comprise the MWD and RSS electronics are designed for purpose rather than merely surviving at higher temperatures, operating normally up to 200 C.

By deploying the new HP/HT MWD tool in the Gulf of Thailand, the operator's first well successfully drilled the reservoir section in one run, even though the temperature reached 186 C (367 F). No additional trips were required for maintenance or a gyroscopic survey. Afterward, the tool was serviced locally to ensure it was still in good condition. Then it was deployed in four more wells without further maintenance, performing for a total of 256 hours. Maximum recorded temperatures in those wells ranged from 183 C to 193 C (361 F to 380 F).

During 2013, the operator used the new HP/HT MWD tool in 10 wells, encountering a maximum temperature of 193 C. Every well section was drilled in one run, saving 12 to 24 hours per well compared with previous wells. Given the operator's HP/HT drilling plans, reducing drilling time by even half a day per well would save 25 to 37 days per year, saving about $3.5 million per year, substantially reducing rig costs and bringing gas production online sooner.

The combination of MWD and RSS services rated at 200 C now provides E&P companies reliable directional control under HP/HT conditions.

Latin America case study

An operator in Latin America was developing offshore reservoirs in abrasive rock with compressive strength around 25,000 psi, circulating temperatures above 150 C and pressures of more than 15,000 psi. Wells had low ROPs, and downhole tools suffered high failure rates. Drilling a typical 8½-in. section required multiple runs and took 30 to 35 days.

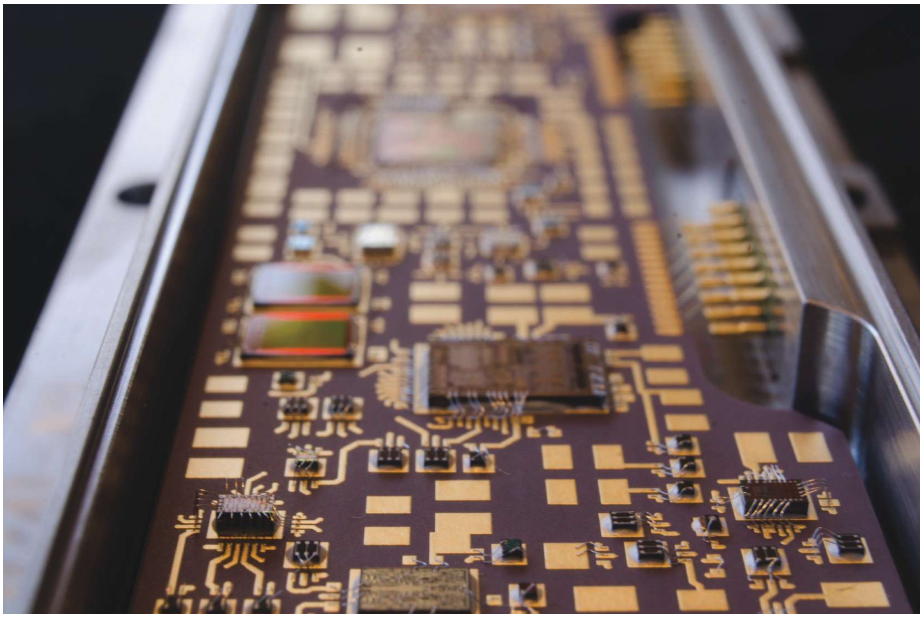
Using a conventional directional BHA with either motors or RSS rated up to 150 C, the operator started drilling another deviated well with an expected bottomhole temperature of more than 170 C (338 F). When the tool reached its technical limit, drillers replaced the existing drive system with a conventional stabilized BHA and continued drilling blind. Without much directional control, the trajectory began deviating from the plan due to the well inclination and hard formation. Without altering the path, the wellbore might have missed the target objective altogether.

At that time the new HP/HT RSS had been introduced in the region, and a decision was made to use it to correct the well trajectory and finish drilling the 8½-in. tangent. The HP/HT RSS uses push-the-bit technology and the same ceramic electronics as the HP/HT MWD tool, and its bias unit replaces a large elastomer seal with a metal-to-metal seal. Without the use of plastic components within the electronics, the HP/HT RSS operates reliably and continuously at temperatures up to 200 C and pressures up to 30,000 psi. What's more, the entire BHA runs on downhole turbine power instead of batteries, eliminating time limits on runs due to previous power constraints and HSE concerns of hazardous materials. It also decreases the environmental footprint by eliminating waste.

By deploying the new HP/HT RSS, drillers successfully corrected the well trajectory from 77 degrees to 57 degrees, completing two consecutive runs with a single tool in the same hole. They recorded a maximum bottomhole temperature of 173 C (344 F) and pressure of 16,000 psi. In addition, the RSS achieved an average ROP of 3.84 m/hr (12.6 ft/hr), which was 16% faster than the previous record for the field. The well was finished in 18 days rather than the planned 27 days. Reducing the drilling cycle by nine full operating days saved the company $1.35 million in rig costs alone.

Integrated solution

In 2012 the industry spent an estimated $21 billion for HP/HT operations, often in very complex wells and areas with high geological uncertainties where real-time measurements and directional services can determine the difference between success and failure. For the first time, a unique new HP/HT MWD service and HP/HT RSS provide operators with a fully integrated HP/HT logging and drilling solution, permitting operators to reach further and deeper into harsh HP/HT conditions in search for more oil and gas without compromise. Instead of tweaking legacy technologies to survive longer in HP/HT environments, the new HP/HT BHA was engineered specifically to thrive under extreme conditions. Currently, HP/HT RSS and MWD systems/BHA are used in four different places around the world, enabling operators to reach hot and deep challenging wells in HP/HT environments. E&P



Rated up to 200 C and 30,000 psi, the HP/HT BHA is specifically designed to improve reliability in wells with extreme heat and pressure. Using a proprietary design with a ceramic electronics board, ceramic-encapsulated microchips and metal-to-metal seals in the bias unit, the HP/HT BHA eliminates all plastic components to improve performance in extreme HP/HT environments. (Source: Schlumberger)

Challenges with deep deviated wells in shale oil

The industry is pushing hard in its bid to increase the average time between failures, with the advantages of CR becoming increasingly apparent in specific circumstances.

L.J. Guillotte Jr., MRP Energy Services

For the past several years shale exploration has driven America toward energy independence but not without challenges. The cost of drilling and completing horizontal wells continues to drive industry experts and engineers to seek more economical ways to exploit these reservoirs.

New drilling technology allows the wells to be drilled much faster. Well pad drilling and zipper fracks are gaining popularity with many producers as hydraulic fracturing drives the cost of shale oil production.

While most producers put an emphasis on exploration, many also are now focused on artificial lift methods. This is due to the decline curves of wells before artificial lift systems are required. With these decline curves becoming more prevalent in the Eagle Ford, Permian, Bakken and other shale plays, the number of wells produced using artificial lift are growing at an exponential rate.

Background

Today the largest amount of production is said to come from electrical submersible pumps (ESPs). However, the largest number of wells are completed using reciprocating rod lift (RRL) or sucker rod pumps (SRPs).

Engineers are challenged with optimizing production over the life of the well and frequently conduct a front-end load engineering study to predict the life of the well's performance. Having this modeling in place along with a comprehensive understanding of the long-term effects of different completions and artificial lift methods can drive down the overall cost to produce a well and drive up the production, positively impacting a company's return on investment.

Today's shale oil production presents many new challenges as the industry drills faster and uses frack sand in hydraulic fracturing. Many forms of artificial lift are not designed to handle solids produced from the wellbore, albeit injected during fracturing. In heavy oil produced in Canada, Venezuela, Colombia and California, progressive cavity pumps (PCP) are the most commonly used form of artificial lift. Fundamentally this is an auger-based design with a rotor and stator designed to produce solids and high-viscosity oil. Producers are trying different forms of artificial lift to optimize production.

Because the industry is now more efficient in shale oil, it has deep deviated wells producing side-loading conditions both in the vertical and horizontal sections of the well along with sand slugging sometimes associated with well kicking post-flowback.

The industry is seeing the meantime between failures (MTBF) increasing due to well deviations. One common problem in deep deviated wells is side-loading conditions, where rod and tubing wear are experiencing side loads in excess of 150 psi, resulting in premature failure either in parted rods or holes in the tubing string. A common failure in conventional sucker rodstrings is due to the mechanical makeup of conventional sucker rods. Mechanical failures have been reduced due to the implementation of best practices, but operators now have side-loading conditions coupled with sand slugging. Most producers are challenged in seeking ways to increase their MTBF.

Front-end load engineering study

One process many producers are practicing is a front-end load engineering study, where the life of the well is analyzed as it relates to the capex and opex invested over the course of the well's productive life using products and equipment that maximize productivity at each phase of its life, beginning with the initial completion until post-artificial lift.

There have been technological advances made by the producer and service companies over the last 25 years still being used today that are conducive to producing shale oil, such as ESPs, RRL and gas lift, among others. There remains a keen focus on refining technologies such as the linear pumpjack and advancements in elastomers used in PCPs or high-temperature wear-resistance coatings used in production tubing and drillpipe.

Since SRP remains the most common method for shale oil in deep deviated wells (with more than 350,000

wells using SRPs in the U.S. alone), the industry is focused on increasing the MTBF caused by side-loading, misalignment of pumpjack and/or the pumpjack walking and bottomhole pump failure due to producing solids and gas migration.

Additionally, operators are experiencing difficulties when trying to set conventional tubing anchors or packers. These, among others, are common problems associated with deep deviated wells.

CR

Coiled rod (CR) has been around since the early 1970s, originally designed for SRP wells along the Rockies due to the fault lines. Later adapted by PCP in the early 1980s and the most common method used with PCPs today, CR is becoming a hot topic among producers as a viable method used with SRP wells.

Challenges such as corrosion remain with this technology. However, in wells where corrosion is not an issue, CR can reduce side loads and friction significantly.

Of course, one of the major challenges for most producers is having service equipment available on the ground when a well goes down. It is highly specialized, similar to coiled tubing but on a smaller scale. It is clear from speaking with several of the majors and independents who have expressed growing interest in CR that the industry is moving in that direction.

CR disperses the side-loading effect that is typical of a conventional sucker rod coupling, usually 4 in. in length, bearing the entire load over the entire length of deviation. Inhibitors, lubricants and surfactants are commonly used to reduce paraffin and/or scale buildup, which typically occur in or around the rod and tubing couplings.

Some of the benefits of using CR are reduced friction and paraffin, resulting in increased production since there are no couplings. Additionally, the rodstring can be rotated on a regular basis so that the contact area is exposed to the chemical treatment process. CR is not the solution to all deviated wells, such as wells with corrosion (although there have been advancements made to coat the rodstring using polymers and nanocoatings to address this), but CR can contribute to reducing MTBF.

Tubing anchors and stuffing boxes

Other advancements such as the quarter-turn tubing anchors and self-aligning stuffing boxes are making progress. Both of these technologies are interesting as they gain successes with their install base, particularly due to side loading and misalignment of the pumpjack units.

The ¼-turn tension tubing anchor catcher is a nice option to the packer. Many operators are removing the elements of the packer to handle gas migration and solids. Setting a multiple-turn packer or tubing anchor can be challenging when set at 3,048 m (10,000 ft) with side loads in excess of 150 lb. In some cases even the most experienced workover superintendents find it challenging when setting these tools in deep deviated wells.

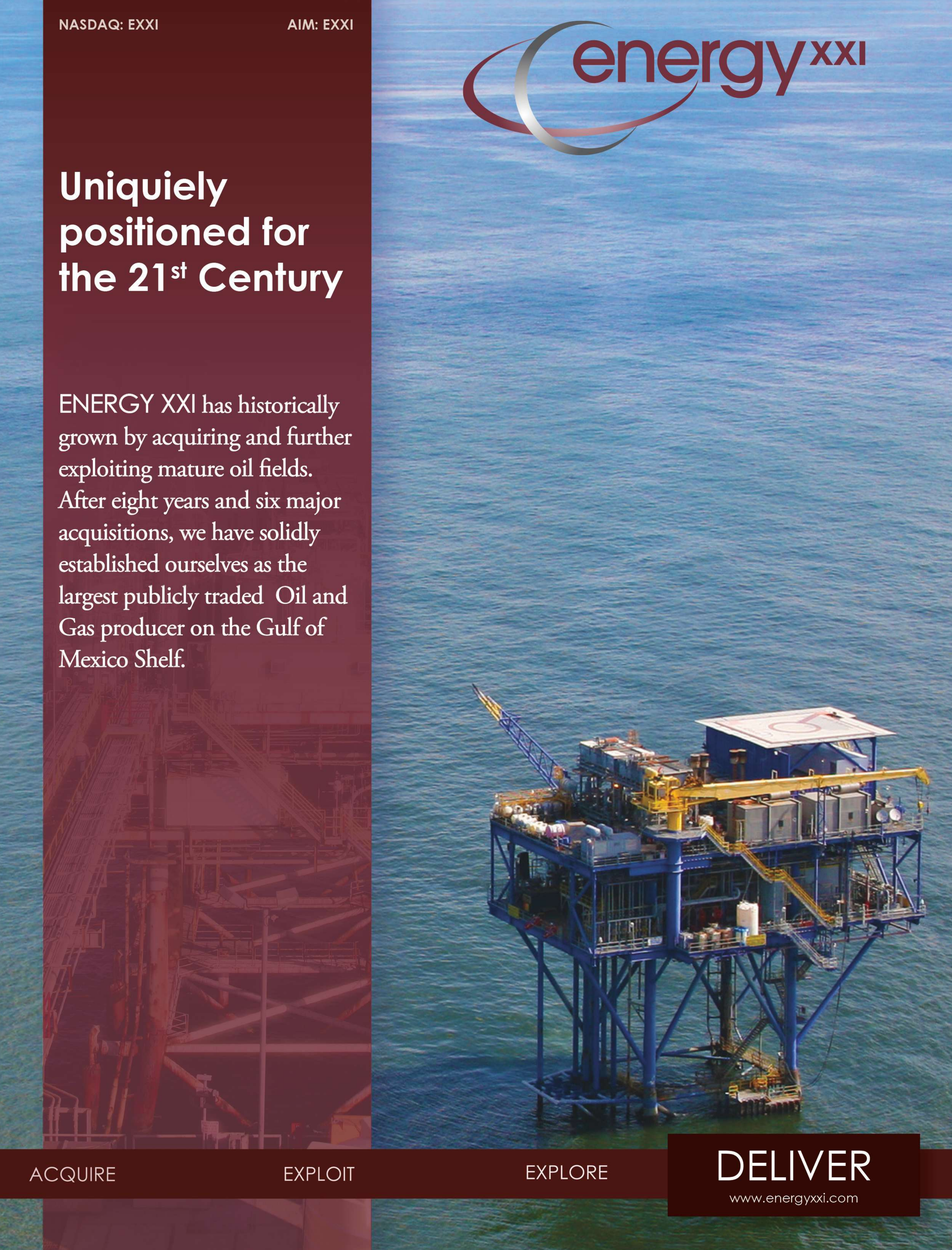
This is where a ¼-turn tension tubing anchor could save a company time and money. Another form of anchor gaining traction is the hydraulic anchor—although not a "catcher," it can provide operators a solution when the tubing cannot be turned at all.

SRPs are the most common method for shale oil in deep deviated wells, so the industry is addressing challenges such as the MTBF caused by side-loading and misalignment of the pumpjack.

One common problem often mentioned is misalignment or walking of the pumpjack. This is where the pivot stroker-style stuffing box can provide a nice option to the conventional stuffing box. The top of the box pivots up to 1.5 degrees to help eliminate misalignment caused by the polished rod or pumping unit.

These are just a few of the technologies available on the market today to address problems associated with deep deviated wells. These technologies are not a "one fix all" but rather solutions to specific problems with deep deviated wells. CR, tubing anchor catchers and self-aligning stuffing boxes incorporate old and new technologies that assist with these wells and positively increase the MTBF.

To get the most out of each artificial lift system, each well should be engineered individually based on its own characteristics. E&P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Using stranded gas to energize artificial lift

Industry interest in natural gas power options for the production phase of assets is growing.

David Dickert, Aggreko

In their push to optimize field operations, oil and gas operators continually look for new ways to boost long-term production from their wells while keeping costs down and minimizing any impact to the environment. Infield power generation is one area that is garnering increased attention in this regard.

While diesel fuel has reliably powered oilfield equipment, natural gas-powered engines and generators are growing in acceptance as a viable and cost-effective alternative to diesel—particularly when a reliable supply of natural gas is available.

Among the benefits natural gas generator systems provide over conventional diesel systems is their economic advantage in the long term. While natural gas units carry larger upfront capital expenses, they have been shown to cost 40% to 45% less to operate than diesel units, primarily due to fuel savings. These units generally exhibit longer run times between service intervals compared to their diesel counterparts, thus maximizing field uptime. Natural gas units also use field-proven "lean burn" technology to meet emissions guidelines at both federal and state levels.

Much of the focus of natural gas-powered rental equipment has been on drilling and hydraulic fracturing operations. However, there is growing interest in expanding this power option for the production phase of an asset. Artificial lift systems that use electrical motors, for example, are a long-term production application that can benefit from natural gas power.

Addressing deployment challenges

For operators to take full advantage of the benefits of natural gas power generation in the field, they must first be aware of the challenges in deploying this option on a large scale. They must then develop a power supply strategy in partnership with a third-party supplier that is flexible and scalable to address these challenges and meet the needs of each stage of field development.

Temporary power solutions can address these deployment challenges as well as other challenges that are preventing widespread adoption of natural gas power generation, which currently include the following.

Being able to deploy an alternative fuel power plant as quickly and as large as a diesel plant. Ensuring efficient and seamless installation of alternative fuel power is addressed by partnering with a temporary power provider capable of supplying all components in an integrated package. Such a package includes modules to condition the field gas by removing water and acid gases like hydrogen sulfide (H_2S), electrical infrastructure including the generators and cabling to connect to the drilling rig or artificial lift system, and accommodations to hook up an alternative fuel source such as liquid propane or LNG in the event that the main gas supply is disrupted.

Having the capability and knowledge to use field gas with varying Btu content. When handling varying Btu-content field gas, some upfront processing is usually required to remove higher Btu components (ethanes, propanes and butanes) and water from the methane. The power provider should have the in-house expertise and technology to reliably separate these components from the methane stream, allowing the operator to capture the higher Btu components rather than flare them off.

Being assured of consistent power generation in the face of changing gas supply volumes. Achieving consistent power generation when the gas supply varies is addressed by a system that is flexible with regards to fuel source. Gas from the wellhead or from the pipeline is often the most cost-effective and reliable source as it avoids the need to ship in fuel in the form of LNG or CNG. In fields that are forced to flare gas because they do not have adequate capacity or infrastructure in place to handle excess gas production, it makes sense to divert this gas for power generation. Not only does this option minimize field emissions, it also allows the operator to capitalize on a fuel source that would otherwise be lost.

In remote or rapidly developing field locations, dual-fuel options such as the use of liquid propane-powered engines are available. This option is particularly attractive in the early days of field production before a steady

A stranded gas temporary power application is seen operating in West Texas. (Source: Aggreko)

source of field gas is available. Production can initially be powered by liquid propane, which is eventually switched out for natural gas once the infrastructure is in place to reliably access gas from nearby pipelines.

Maintaining reliability and ensuring adequate real-time monitoring in the field. Reliability is addressed by monitoring various field parameters, including flow rates into the generator and electrical output to the rig or production equipment. This information is relayed in real time from remote field operations to a central office, providing operations personnel with constant access to the working condition of the generator. The system also includes alarm functionality to immediately notify personnel of a problem with gas supply or generator function in the field. A repair team can then be sent directly to that location to address the problem and get power generation running at its optimal output.

Realizing results

In a remote part of West Texas, an operator had limited access to electric grid power, which curtailed expansion plans and presented challenges in maintaining production from existing wells. As a result of limited grid electricity, more than 16 of the operator's wells were underdeveloped or shut in.

The operator needed a temporary power solution, but fuel options including diesel, LPG, LNG and CNG were considered uneconomic. Field gas was readily available, although it was in the form of wet sour gas containing greater than 300 ppm of H_2S. A permanent solution to cleaning this gas also was considered cost-prohibitive, and with a utility upgrade still six months away, the operator needed an alternative power solution for its immediate needs.

The operator consulted with a power supplier to develop a scalable and easily deployable temporary power management solution. Technical specialists worked with the operator's field operations team to engineer a cost-efficient strategy to scrub the toxic sour gas out of the stranded field gas supply and turn it into a viable fuel source to power a temporary natural gas generation station. The temporary station was designed to work in parallel with the utility grid, providing the incremental power required to run gas-lift equipment and other production operations.

The temporary power solution was able to reduce the H_2S levels in the supply gas to 0 ppm by passing through a tower equipped with SulfaBate pelletized H_2S scavenger. The solution also included multiple gas-liquid separators to reduce the liquids content of the gas prior to introducing it to the generators and a temporary flare to purge test gas. The dry, desoured gas then entered two 1-MW natural gas generators, which provided parallel and base load with the utility grid at 12.4 kv.

This solution was able to power a fully operational well site less than one week after startup and generated a payback greater than 10:1. With the additional electricity supply afforded by the temporary power system, eight wells were able to convert from rod pump to electrical submersible pump as the lift method. This conversion increased the operational capacity of the field crew, which immediately began drilling new wells to continue toward the goal of 100% operation of available production.

Regardless of its size, any natural gas power generation system should address a number of issues in the field. First, the system must be capable of running efficiently on natural gas of varying Btu content and from different sources. The system should be able to deal with intermittent supplies of natural gas and automatically switch to another fuel option if necessary without causing any delays or interruptions in field production. And ultimately, the power system must run reliably for long periods with minimal requirements for maintenance or downtime. E&P

Acknowledgment

This paper was presented at the SPE 2014 Artificial Lift Conference North America held in Houston Oct. 6-8, 2014.

Preparing for its future

New offshore drilling company is set to make its market splashdown in 2016 with new rigs and new approach.

Jennifer Presley, Senior Editor, Offshore

Fortune favors the bold, or so the saying goes. Launching a new company in a highly competitive market like offshore drilling would certainly attract Fortuna's interest, but being prepared is what will help carry any startup to the bank. Preparation enables new companies to stay ahead of and stand apart from the competition. Experience teaches that preparation also will carry a company far. Preparation and experience are two ways Cayman Island-based Blue Ocean Drilling is setting itself apart from the pack. A deep understanding of its clients—the operator—is another.

"The focus for us has been to look at what operators want," said Tony Beebe, executive vice president of operations for the company. "They want a rig that drills efficiently and reliably and is crewed by well-trained personnel. Those are the fundamental basics. We hope to do those as well as or better than anybody else in the market. It is a tall order."

As a startup offshore drilling company, Blue Ocean has made great strides in the year or so that it has been in business. By essentially starting with a fresh, clean sheet of paper, the company has focused on selecting its rig and equipment designs necessary to operate. The company is focused on key markets where it sees long-term growth potential based on the age of the fleet as well as fleet growth to meet the production goals set by the nation or projects. Being new brings with it advantages and disadvantages, Beebe noted.

"We don't have the legacy of utilizing old systems on new rigs, but you also have to create everything from scratch," he said. "Realistically, it comes down to the people you hire, the systems you build and what you can do as a team. Doing the fundamentals really well is the foundation of our operational excellence."

Building the foundation

In early 2014 the company contracted with China's Shanghai Waigaoqiao Shipbuilding for the construction of two Gusto MSC CJ46-X100-D design deepwater jackup rigs. The high-spec units operate in water depths up to 114 m (375 ft) and perform drilling operations at depths up to 9.1 km (30,000 ft) with an accommodation capacity of up to 120 crew members. The X-Y cantilever design (21 m by 12 m or 70 ft by 40 ft) provides a larger drilling envelope at max loads, according to the company. In addition to offering offline stand building for increased operational efficiency, the rigs are equipped with a 7,500-psi mud system with three 2,200-hp mud pumps. The first two rigs are expected to be delivered by the shipyard in second-quarter 2016 and fourth-quarter 2016.

"To remove risks for our end clients, we were very careful in picking out the rig by selecting an established, proven design," said Beebe. "We also were careful in selecting equipment and what yard we went with to build our rigs. Those three lay the foundation in removing risk for our operators."

In October 2014 the company announced that it has in place option agreements in third-quarter 2014 and first-quarter 2015 for the construction of up to four Gusto MSC CJ50-X120-E design deepwater jackup rigs. This design of high-spec jackup rig offers operation depths of up to 122 m (400 ft) and can drill to depths up to 10.6 km (35,000 ft). It also offers offline stand building and dual mud systems for increased operational efficiency.

Dr. Yuanhui Sun, CEO, chairman and president of the company, noted that to the basic design of the CJ50 the company made additional investments for improvements to meet industry requirements down the road.

"For example, we increased the accommodations from 120 to 150 people, increased the hydraulic horsepower and topdrive capabilities and enhanced the mud cleaning capacities of the rig," he said. "These modifications will help with operational efficiencies and help our market capability to compete for jobs in the future. Basically, with similar design rigs we offer differences that will really put us closer to customers picking our rig over competitor rigs."

Maximizing productivity

According to Beebe, productivity on a rig is driven by what is happening on the rotary table or the wellbore, with a lot of activity that can be driven offline. As part of its design and selection process, the company looked not only at offshore processes but land too.

MARCELLUS–UTICA MIDSTREAM
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January 27-29, 2015
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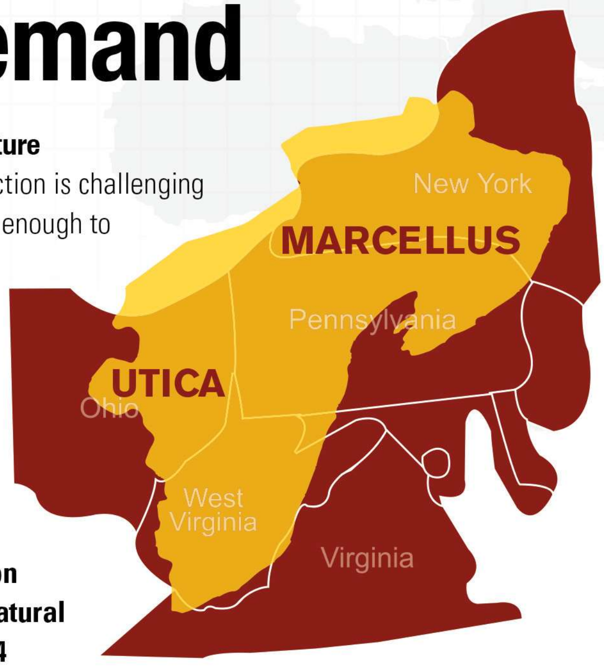
Extending the Reach: Meeting Global Demand

Reversing Course - Retooling Appalachia's Pipeline Infrastructure
An unprecedented surge in Marcellus and Utica natural gas production is challenging Appalachia's midstream community to add takeaway capacity fast enough to keep up with ever-increasing activity. After decades of building pipelines to carry gas into the Northeast, midstream operators are now investing billions on bidirectional flow capacity. According to the EIA, **by 2017 nearly one-third of the natural gas pipeline capacity (8.3 Bcf/d) into the Northeast could be bidirectional.**



Midstream operators are also working to build **35 Bcf/d of new pipeline capacity in the region. Sunoco's planned $2.5 billion 350-mile pipeline will quadruple the volume of Marcellus natural gas** moving through the Philadelphia area. And at approximately **$4 billion, ETP's 800-mile Rover Pipeline will transport 3.25 Bcf/d of natural gas** to markets in the Midwest, Great Lakes and Gulf Coast regions.

These projects are reshaping Appalachia's midstream infrastructure. How can your company get in on the action? Attend the 2015 **Marcellus-Utica Midstream** conference and exhibition to hear directly from top executives involved with these multi-billion dollar projects.

Sources: E&P magazine, The Philadelphia Inquirer and the U.S. EIA

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MARCELLUS-UTICA MIDSTREAM CONFERENCE & EXHIBITION

AGENDA

Tuesday, January 27

5:00 pm Opening Reception
Save yourself time and pick up your **Marcellus-Utica Midstream** badge early! Use this opportunity to participate in the Opening Reception, which includes a complimentary, fully catered buffet and complimentary drinks.

Wednesday, January 28

7:30 am Registration, Breakfast & Networking
Start your day off right with a hot and cold breakfast before you take a seat for an exciting and informative day of presentations.

8:30 am Welcome & Opening Remarks
- **Paul Hart**, *Editor-in-Chief, Midstream Business*, ***Hart Energy***

8:35 am Opening Keynote: Appalachia's Continuing Growth
EnLink Midstream has an expanding presence in the Utica and Marcellus plays through its Ohio River Valley operations. Its CEO provides insights on what this major midstream player sees ahead for the region.

Moderator: Paul Hart, *Editor-in-Chief, Midstream Business*, ***Hart Energy***

- **Barry Davis**, *CEO*, ***EnLink Midstream Partners LP***

9:00 am Pipeline Spotlight: Rich Gas – Dry Gas
This Marcellus midstream operator has expansion plans in place to serve the specific transportation and storage needs of the play's operators.

Moderator: Theresa Ward, *Group Managing Editor, Midstream Business*, ***Hart Energy***

- **Edmund Knolle,** *Vice President, Business Development*, ***Crestwood Midstream Partners***

9:25 am Equity Panel: Financing The Marcellus-Utica Buildout
These world-class plays demand enormous capital for full development. Here's a look at the capital Appalachian operators need to complete the infrastructure necessary to serve the growing unconventional plays, how they are going to access it, and how Appalachia opportunities fit into broader energy and financial markets.

Moderator: John Harpole, *Senior Advisor, Midstream*, ***Hart Energy***

- **Ron McGlade**, *Vice President, Midstream Infrastructure, Business Development & Marketing*, ***Tenaska***
- **Sunil Sibal**, *Director & Senior MLP/Energy Infrastructure Analyst*, ***Global Hunter Securities***

10:15 am Networking Break
Word of mouth – many people believe this is the most credible form of advertising. Take time to mingle with the outstanding exhibitors.

10:45 am Processing Panel: Continuing Improvements In Gas Processing Technology
The abundant gas liquids produced from the Northeast plays has created challenges and opportunities for gas processors. These panelists discuss what they see ahead.

Moderator: Frank Nieto, *Senior Editor, Midstream Business*, ***Hart Energy***

- **John Wilkinson**, *President and CEO*, ***Ortloff Engineers***
- **Mark Sutton**, *President and CEO*, ***Gas Processors Association***
- **Loren Pieper**, *Vice President, Processing Technology*, ***Valerus***

11:45 am Spotlight: To Market, To Market—Where Will The Production Go?
The Marcellus and Utica form a big part of the broad gas megatrend under way in North America. The operator of the nation's largest natural gas network reviews the market for the region's growing gas and gas liquids production—and its own organic growth plans to connect producer and consumer.

Moderator: Deon Daugherty, *Associate Editor, Midstream Business*, ***Hart Energy***

- **Karen Kabin**, *Vice President of Business Development*, ***Kinder Morgan Energy Partners, L.P.***

12:15 pm Networking Luncheon

1:30 pm Operator Spotlight: The Marcellus Evolution
MarkWest serves as the dominant gas processor and fractionator in the Marcellus and has a growing role in the Utica as well. Its COO looks at how this midstream major is changing to meet regional producers' needs.

Moderator: John Harpole, *Senior Advisor, Midstream*, ***Hart Energy***

- **John Mollenkopf**, *COO*, ***MarkWest Energy Partners***

1:55 pm Spotlight: Completing The Buildout
The rugged country atop much of the Marcellus and Utica creates special environmental and right-of-way challenges for pipeline and gas plant projects. This presentation looks at how to get the work done.

Moderator: Theresa Ward, *Group Managing Editor, Midstream Business*, ***Hart Energy***

- **Russ Krauss**, *Vice President, Marketing & Research*, ***Resource Environmental Solutions***

2:20 pm Roundtable: The Utilities' Viewpoint
The abundant gas production coming out of Appalachia comes at the same time as new emissions standards alter assumptions about use of alternatives, such as coal and fuel oil.

Moderator: Paul Hart, *Editor-in-Chief, Midstream Business*, ***Hart Energy***

- **Mark James**, *Vice President, Economic & Business Development*, ***American Electric Power***





- **Mark Eisenhower**, *Vice President, Strategic Planning & Development,* ***Chesapeake Utilities Corp.***

3:00 pm **Networking Break**
The more visible you are, the more successful you can be! Stretch your legs and visit the exhibit hall for a chance to visit with other delegates.

3:30 pm **Panel: So Near And Yet So Far**
Marcellus and Utica natural gas lies nearby in historically underserved New England. But distance is far from the only consideration operators must consider when adding pipeline capacity to this major market. And exports to foreign lands also figure prominently in operator plans.

Moderator: John Harpole, *Senior Advisor, Midstream,* ***Hart Energy***

- **Brian McKerlie**, *Vice President, Business Development,* ***Spectra Energy***
- **Don Raikes**, *Vice President*, ***Dominion Transmission Inc.***

4:15 pm **Closing Spotlight: Sailing Ahead**
The Mariner pipelines are entering service, providing crucial outlets for produced ethane and other gas liquids. The new Allegheny Access system is moving much-needed refined products into the Marcellus-Utica region.

Moderator: Deon Daugherty, *Associate Editor, Midstream Business,* ***Hart Energy***

- **Hank Alexander**, *Vice President, Business Development,* ***Sunoco Logistics***

4:45 pm **Networking Reception**
Hit the exhibit floor with your business cards to make connections with the key personnel you came to meet.

Thursday, January 29

7:30 am **Registration, Breakfast and Networking**
Jumpstart your day with a complimentary, fully catered breakfast in the exhibit hall. Use this time to meet with exhibitors and other industry

8:30 am **Welcome & Opening Remarks**

- **Paul Hart**, *Editor-in-Chief, Midstream Business,* ***Hart Energy***

8:35 am **Keynote Address: Meeting The Pipeline Challenge**
North America enjoys an outstanding gas transmission network. But the industry faces major challenges as it repurposes existing systems and adds new capacity, thanks to the growing unconventional plays.

Moderator: Paul Hart, *Editor-in-Chief, Midstream Business,* ***Hart Energy***

- **Richard Hoffmann**, *Executive Director,* ***INGAA Foundation***

9:00 am **Resource Spotlight: Running Room In The Marcellus**
The geologist among the first to recognize the Marcellus' potential as a major hydrocarbon producer sees extensive remaining potential in the play.

Moderator: Frank Nieto, *Senior Editor, Midstream Business,* ***Hart Energy***

- **Terry Engelder, PhD**, *Professor of Geoscience,* ***Pennsylvania State University***

9:25 am **Special Address: How Fracking Changed Our World**
The Marcellus and Utica plays, as big as they are, are only part of the unconventional boom that has altered the course of the energy industry. A noted author and close observer of the oil and gas business provides his personal glimpse of what he sees happening in Appalachia.

Moderator: John Harpole, *Senior Advisor, Midstream,* ***Hart Energy***

- **Russell Gold**, *Senior Energy Reporter, The Wall Street Journal, and Author of The Boom: How Fracking Ignited the American Energy Revolution and Changed the World*

9:50 am **Spotlight: Adding Links To The Value Chain**
Two of the region's biggest midstream operators plan to join forces, creating growth opportunities as they expand their service offerings to producers.

Moderator: Paul Hart, *Editor-in-Chief, Midstream Business,* ***Hart Energy***

- **Jim Scheel**, *Senior Vice President for Northeast Gathering & Processing,* ***Williams***

10:15 am **Networking Brunch**
One of the most important reasons to attend a conference is the networking. Visit the exhibit floor and connect with current customers and meet with new prospects, too!

10:45 am **Regulatory Spotlight: Regulatory & Policy Update**
With the congressional elections just completed and a presidential election next year, the industry's regulatory environment is in flux. A look at the potential impacts on midstream sector of the industry.

Moderator: Frank Nieto, *Senior Editor, Midstream Business,* ***Hart Energy***

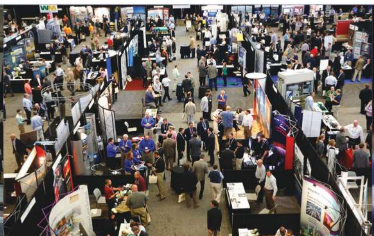
- **John Kneiss**, *Director, Governmental Affairs,* ***Stratas Advisors***

11:10 am **Panel: Oil & Gas In The Buckeye State**
The Utica continues to grow in economic and political importance, changing Ohio from a follower to a leader in the energy industry.

Moderator: John Harpole, *Senior Advisor, Midstream,* ***Hart Energy***

- **Craig O. Pierson**, *President,* ***Marathon Pipe Line LLC***
- **Scott Williams,** *Executive Vice President and Chief Commercial Officer,* ***Blue Racer Midstream***

12:00 pm **Conference Adjourns**

MARCELLUS–UTICA MIDSTREAM

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SPEAKERS

Barry Davis
CEO
EnLink Midstream Partners LP

John Mollenkopf
COO
MarkWest Energy Partners

Hank Alexander
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Blue Racer Midstream

Karen Kabin
Vice President, Business Development
Kinder Morgan Energy Partners, L.P.

Richard Hoffman
Executive Director
INGAA Foundation

Conference Topics:

- Providing pipeline access to New England
- Meeting processing needs in the Marcellus
- Regulatory hurdles and challenges
- The growth of the Utica

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Construction of Blue Ocean Drilling's jackup units is underway at China's Shanghai Waigaoqiao Shipbuilding yard. (Source: Blue Ocean Drilling)

"Offshore has been a leader in pipehandling, racking pipe and building stands offline," Beebe said. "But there are areas that have not been as well thought out or planned for jackup wells offshore as they have on land.

"We looked at doing a lot of those things so that the productivity on the well—for example, the time you're doing well construction—is maximized. It's the little things in the design—how we ran piping, how we put hoses in place, how we set up our test assemblies, how we laid our equipment for logistics—that were done to focus on efficiency in the wellbore."

Another area the company focused on was the cleaning of the wellbore, and it applied a land-based approach to its offshore operations.

"Most wells that a jackup drills are deviated, and some are horizontal like a land rig. When you're drilling horizontal or deviated, the amount of mud pumped and the flow rates change. Your ability to clean the hole drives a lot of your drilling rates and performance, so we looked at the areas involved in drilling that horizontal well section and made adjustments in the rig design.

"The dual mud systems of the CJ50 offer the ability to build a mud system offline and be prepared to switch from one mud system to another," said Beebe. "A lot of wells use three different mud systems. So there are two switches and—depending on the rig and conditions—it can sometimes take 24 hours to switch mud systems. On our rigs, it should be 30 minutes. We did a lot of those things to help reduce the time on the well, help improve drilling performance and help keep the mud in the condition the operators want."

In addition to flow rates, the group looked at other areas like hook loads where they could add value to constructing the well and then build those into the design and selection of equipment, Beebe added.

"We focused on activities in the well and on the surface," he said.

Adapting to innovation

It is no secret that the industry is slow to adopt new technology, but there has been a gradual shift over the years as systems are proven reliable—for example, digital controls. This shift has delivered with it a wealth of new data flowing into the dog house, requiring additional training to learn the nuances of drilling by joystick.

"The industry has used digital controls for a while, and within those controls there's considerably more communication. There's a lot more data analysis and data available off the systems," Beebe said. "Those are the fundamentals, and that's taken place over the last 15 years, but it got a lot of momentum in the last 10. The digital technology, the communication and the data have led to improved decision-making and enhanced automation."

Adapting to innovations like automation takes time, and for Blue Ocean Drilling the clock is ticking with just little over a year to go before its first jackup leaves the yard. E&P

Developing the Caspian Sea

Jackups, operators address challenges of world's largest enclosed body of saltwater.

Tom O'Gallagher, Eurasia Drilling Co.

The Caspian Sea, bordered by Kazakhstan, Russia, Azerbaijan, Iran and Turkmenistan, is the largest enclosed body of saltwater in the world, with a 1.2% salinity level. The depth varies from 5 m (16 ft) at the Caspian shelf to 1,025 m (3,363 ft) at its deepest point in the southern part, averaging 196 m (643 ft). Sea levels depend upon the inflow from two rivers, the Volga and the Ural. Evaporation is the only form of sea level regulation, and water levels average 30 m (98 ft) below sea level. In winter almost one-third of the northern Caspian freezes, and in summer the Iranian sector sees water surface temperatures of about 30 C (86 F).

The Caspian Sea is used for oil and gas extraction, tourism, and fishing, although strict environmental regulations have been implemented to protect locals who depend on its resources and native species, such as sturgeon, for their livelihoods. Hence, all oil and gas activities must adhere to delivering zero discharge during drilling and production operations.

Operating in the Caspian

Eurasia Drilling Co.'s (EDC's) offshore division, known as BKE Shelf, has its origins in Lukoil Shelf Ltd., which was founded in 1999. EDC entered the offshore drilling market in 2006 with the purchase of Lukoil's Astra jackup, located in the Caspian Sea.

EDC's BKE Shelf division has grown to be the largest independent offshore operator in Russia and currently has four jackups operating in the Caspian Sea. The Astra is currently drilling in Russian waters; the Saturn and Neptune jackups are drilling in Turkmen waters; and the latest addition is the Mercury jackup, which is en route from the shipyard in Astrakhan, Russia, to Turkmen waters. The Mercury is expected to be commissioned in January.

EDC also provides drilling services on Lukoil's ice-resistant offshore platform LSP-1 on the Korchagina Field, located in the Russian sector of the Caspian Sea. The contract for Lukoil's LSP-1 platform in the Korchagina oil and gas condensate field is a "life-of-drilling" contract. Since the start of drilling on this ice-resistant platform, more than 19 wells have been constructed, and many of these are extended-reach wells, with the longest being more than 8,400 m (27,560 ft).

The Mercury makes the journey through the Volga-Caspian Channel on its way to the Caspian Sea in December. Ice has already begun to form, adding to the logistical challenges. (Source: Eurasia Drilling Co.)

Astra jackup

The Astra jackup is a Baker Marine Services BMC-150-H design capable of drilling to 4,875 m (16,000 ft) in water depths up to 38 m (120 ft). It has been deployed extensively for drilling in Russian and Kazakh waters and has been the workhorse for many operations such as the eight fields discovered by Lukoil. To date, Astra has drilled more than 40 new wells in the Caspian Sea.

The distribution of these wells by sector is as follows:

- In the Russian sector, more than 20 exploration and appraisal wells were drilled for Lukoil in the Khvalynskaya, Shirotnaya, Rakushechnaya, Diagonalnaya, Sarmatskaya and West-Sarmatskaya fields plus an exploration well for the KNK Consortium (Rosneft/Lukoil) in the Ukatnaya Field;
- Astra drilled 11 directional development wells and also performed a workover for Dragon Oil in the LAM Field in the Turkmenistan sector; and
- Astra also has been deployed in the Kazakhstan sector, drilling more than 10 exploration and appraisal wells across the following fields: the Tub-Karagan Field for KMT and Rosneft; the Kurmangazy Field for KMG and Lukoil; the Auezov, Khazar and Tulpar

fields for CMOC, KMG, Shell and Oman Pearls Co.; the Atash Field (KMG and Lukoil JV); and N-Block for N-Operating Co.

One of the important properties of Astra is its ability to drill in a variety of water depths. The maximum water depth in which Astra has worked is 33 m (108 ft), while the minimum is 5.2 m (17 ft, Kazakh sector). The deepest well drilled by Astra was 4,875 m (15,995 ft).

Saturn jackup

The Saturn jackup was purchased from Transocean in 2011. Previously known as Trident 20, it was built in a shipyard in Azerbaijan and started its maiden well in 2000. Since then this rig has drilled more than 35 new wells and performed 14 workovers. Thirty of the wells and all of the workovers were for Petronas in the Magtymguly, Diyarbekir, Mashrykov and Garagyol fields in Turkmen waters. It also has drilled two exploration wells for Japan Azerbaijan Oil Co. in the Azerbaijan sector of the Caspian Sea and two exploration wells in the Kazakhstan sector—one drilled for AGIP KCO in the Kalamkas Block and one well for CMOC in the Pearls Block. Saturn currently continues to drill wells for Petronas in Turkmen waters.

The Mercury was completed by Lamprell in the Astrakhan shipyard at the end of October 2014. (Source: Eurasia Drilling Co.)

Newbuilds

BKE Shelf was recently awarded a three-year development drilling contract by Dragon Oil for its Cheleken development in Turkmen waters. EDC will service this contract with two newbuild jackups. These rigs are LeTourneau S116E design, built by Lamprell. They are built in modular form in Sharjah and shipped through the Volga-Don canal system for final assembly in Astrakhan, Russia. The rigs are capable of drilling to 9,144 m (30,000 ft) in up to 107 m (350 ft) of water. The first newbuild jackup, Neptune, was deployed in February 2014. Starting 2015, Neptune is also contracted to drill for several clients in the Russian waters.

EDC's newest addition to the Caspian, the Mercury, has just been completed and will join the Neptune in January 2015. The Mercury jackup is a LeTourneau Super 116E rig design, equipped with three Lewco W-2214 7,500-psi working pressure 2,200-hp mud pumps and Lewco LDW-1500-AC 3,000-hp drawworks. The rotary table has a 1,257-mm maximum opening.

The Mercury is built to operate efficiently even in storm conditions. It is able to withstand 16.8-m (55-ft) tall waves at 13.7 seconds and winds up to 100 knots. Normal operating conditions for the Mercury comprise 12.2-m (40-ft) tall waves at 11.7 seconds with winds at 100 knots as well. The Mercury storage capacities consist of 335 cu. m (11,830 cf) fuel oil, 652 cu. m (23,025 cf) liquid mud and 154 cu. m (5,438 cf) liquid brine/oil.

Getting the Mercury to the Caspian Sea is a journey of 180 km (112 miles) through the Volga-Caspian Channel from the Astrakhan shipyard where it was built. The journey is a race against time to allow the Mercury to be deployed in the Caspian before it freezes. Other difficulties include access to the limited standby boats in the Caspian Sea to complete the tow. The Mercury had to wait on boats that were first used to tow out a production platform from Astrakhan to the Russian sector before Mercury could be moved.

When Mercury starts up in January, EDC will own and operate four of the five jackups operating in the Caspian Sea. The fifth jackup is the Iran Khazar owned by NIOC and is operating in the Turkmen waters for Dragon Oil.

There are two additional jackup rigs planned to start operations in the Caspian Sea. The first of these is a newbuild named Caspian Driller, owned by Momentum Engineering, which was due for delivery in 2012 but is now late with an unknown start date. It is contracted to Dragon Oil for work in Turkmen waters.

The second is the Prime Exerter, owned by Ezion Holdings. This 33-year-old rig was dismantled in Holland so it could be shipped into the Caspian Sea through the Volga-Don canal system. It is being reassembled in Baku, Azerbaijan, and is contracted for work with Petronas in Turkmen waters. Delivery was due at the end of 2013; a revised delivery date is unknown.

EDC believes the Caspian Sea activity requires seven or eight jackups due to the large number of exploration licenses yet to be drilled. And if this leads to more discoveries, there will be a significant amount of development drilling required to put these fields online. E&P

Momentum builds in China's emerging shale gas sector

This huge country has had to look, learn—and invest—in resources outside its own borders just as much as it has at home to find the key to unlock the subsurface riches that it undoubtedly possesses.

Mark Thomas, Editor-in-Chief

Chinese companies are estimated to have invested more than $8 billion in U.S. shale plays for various reasons, including a combination of financial returns, investment diversification and technology. Investing also has given them a bird's eye view of U.S. regulatory and managerial practices in the shale gas sector.

But the investment and learning are also going the other way, with several U.S. and European majors playing a crucial role in prying open China's fledgling shale gas market.

Although current progress remains relatively slow, with the deep and complex shales in China's basins (compared to the U.S.) and the scarcity of water proving tough nuts to crack, China has a government that is 100% behind the industry's efforts to recreate the American shale gale within its own borders. This is hardly surprising when estimates by outside authorities such as the U.S. Energy Information Administration put the country's technically recoverable resources at a size two-thirds larger than those in the U.S. at 31.6 Tcm (1,116 Tcf), making it the world's largest.

Energy policy

In June 2014, President Xi Jinping outlined China's energy policy with the following five-part strategy:

- Promote revolution in energy consumption;
- Promote revolution in energy supply;
- Promote revolution in energy technology;
- Promote revolution in energy governance; and
- Strengthen international cooperation.

These will continue to shape China's shale gas development as already evidenced by the money sunk so far by China's state-owned giants into its domestic shale exploration and development activity. It had already invested close to an estimated $2.5 billion and drilled 322 wells as of June 2014, according to official China reports. The number of wells is now around the 400 mark, with most of that activity involving China National Petroleum Corp. (PetroChina) and China Petroleum & Chemical Corp. (Sinopec). This activity has resulted in a national production forecast of 1.6 Bcm (56.5 Bcf) of shale gas for 2014.

However, alongside the estimated $65.5 billion spent by U.S. companies three years ago (a long time in the fast-moving unconventionals business) to drill more than 10,000 shale oil and gas wells in North America, according to the American Petroleum Institute, China's domestic efforts up to the present day still pale in comparison.

The year 2014 has, however, seen a more realistic attitude begin to emerge in China compared to the aggressive early growth goals given in the central government's last "Shale Gas Five-Year Plan" issued in March 2012. That included ambitious goals such as an annual production target of 6.5 Bcm (229.5 Bcf) of shale gas by 2015 and 60 Bcm to 100 Bcm (2.1 Tcf to 3.5 Tcf) in 2020.

With last year's annual figure at 1.6 Bcm of shale gas, the likelihood is that the country's 2020 shale gas production target will be cut to a more achievable—but still challenging—30 Bcm (1.1 Tcf). The 2015 figure of 6.5 Bcm is perhaps more achievable based on the latest forecasts.

Picking up the pace

Even with more realistic targets being put in place, the pressure remains on the state companies involved to pick up their pace of activity to meet the central government's dictates.

One of the latest moves saw PetroChina and Sinochem link up to tap shale gas from five blocks in the southwest of China. The two firms, together with State Development and Investment Corp. (SDIC) and local state enterprise Chongqing Institute of Geology and Mineral Resources, jointly set up Chongqing Shale Gas Exploration and Development Co. Ltd., with a total registered capital of 6 billion yuan ($974.96 million).

With the aim for the new entity to start production in 2017, a total of up to 26.05 billion yuan ($4.2 billion) has been earmarked to be invested in exploiting the five blocks, which cover a total of 15,600 sq km (6,023 sq miles). Although not yet formally confirmed, Chongqing Shale Gas E&D is expected to drill an initial 16 exploration and appraisal wells with up to 360 production wells to follow if the block potential is realized. The municipal government puts Chongqing's exploitable shale gas reserves at 2 Tcm (70.6 Tcf). PetroChina holds a 40% interest in the new company, with Sinochem holding 20%, SDIC 39% and a local Chongqing company 1%.

CNPC-Shell partnership

PetroChina also is continuing to ramp up its ongoing activities with Shell, building on the strong success of their Changbei tight gas project in northern China to target further tight gas and new shale gas prospects.

Shell operates Changbei in Shaanxi province under a production-sharing contract (PSC) with PetroChina, with the field producing since 2007 and currently flowing 3.3 Bcm (116.5 Bcf) per year, mostly to supply gas to northeast China (including Beijing). PetroChina itself sees Changbei as a model cooperation project, with the state oil company's top management going on record recently to say in a press statement, "Our upstream business should learn from Changbei."

Much of that learning is being applied to the shale gas potential of the Fushun-Yongchuan Block in Sichuan province. The block covers an area of about 3,500 sq km (1,350 sq miles), for which Shell and PetroChina signed in March 2012 the first-ever shale gas PSC in China. This milestone deal for the Shell-CNPC partnership was approved by the government in 2013, with an ambitious drilling program underway.

Target of 2.6 Bcm

PetroChina is already saying that it is on course to surpass a 2.6 Bcm (91.8 Bcf) target for shale gas production in 2015 from its fields in Sichuan.

"Based on the production of our test wells, we are very confident to achieve or even beat our estimates for 2015," said Xie Jun, deputy general manager of PetroChina subsidiary Southwest Oil & Gasfield Co., in a recent Bloomberg report. This was a "very conservative" estimate, he added. PetroChina aims to produce 5 Bcm (176.6 Bcf) itself by 2017 and 12 Bcm (423.8 Bcf) by the end of the decade, said Xie, with large-scale commercial production from Fushun expected to get underway during the first half of 2015.

The state-owned enterprise has nine shale gas exploration rights in Sichuan and Chongqing, with four underway or close to commercial production. It also has previously signed agreements with other companies such as ConocoPhillips in late 2012, with whom it is still studying the potential development of unconventional energy resources in the Qijiang shale gas block in the Sichuan Basin. It has other cooperation agreements in place with Chevron, Exxon Mobil and Hess.

China's hopes up until now have largely rested on Sinopec, which operates the country's largest shale gas-producing project in Fuling. This flagship project already produces 3.2 MMcm/d (113 MMcf/d) of gas, with Sinopec now projecting a 5 Bcm total annual figure for 2015 after wells drilled over the last 18 months performed better than anticipated. The company is predicting the block could reach 10 Bcm (353.1 Bcf) of production per year in 2017.

Sichuan shale spend of $2.1 billion

In August PetroChina's president, Wang Dongjin, admitted that PetroChina was about "a year and a half behind Sinopec in shale gas exploration because we concentrated our resources on the Longwangmiao natural gas project in Sichuan," according to Bloomberg.

The geographical structures in PetroChina's fields in southern Sichuan are more difficult to drill than the

China Shale Gas Projects Involving IOCs (As At End 2014)

Start Date	IOC	NOC	Project Location	Work Commitment & Status
Oct 2007	Newfield Exploration	PetroChina	Weiyuan Field in the Sichuan Basin	No details
July 2010	Hess Corp.	Sinopec	Shengli Oil Field in east China	No details
April 2011	Chevron	Sinopec	Qiannan Basin	Seismic; 2 exploratory wells, both were unsuccessful
Mar 2012	Total	Sinopec	Anhui Province	No details
Mar 2012	Shell	CNPC	Fushun-Yongchuan Block	Work program under the PSC
Jun 2012	Shell	Sinopec	Hunan, Hubei and Jiangxi	Seismic; 2-3 wells
Dec 2012	ConocoPhillips	Sinopec	Qijiang, Sichuan Basin	Seismic; 2 wells
Feb 2013	ConocoPhillips	CNPC	Neijiang-Dazu, Sichuan Basin	No details
Mar 2013	Eni	CNPC	Rongchang Block, Sichuan Basin	No details

Fuling project, with the gas reservoirs smaller, according to Xie.

PetroChina's plans for the whole of 2014 and the first half of 2015 are to invest 13 billion yuan ($2.1 billion) on Sichuan shale gas E&P. Drilling cost per well in the region is put at about 65 million yuan ($10.5 million) at present, which should come down following large-scale drilling and better understanding of the geology, according to Zhou Zhibin, deputy general manager at Southwest Oil & Gasfield.

The company has about 3.9 Tcm (137.7 Tcf) of shale gas reserves in Sichuan and Chongqing, of which 1.5 Bcm (53 Bcf) lies at depths of less than 4,000 m (13,124 ft). It will concentrate on exploring for the reserves in these areas in the short term, said Xie, according to Bloomberg.

"We have completed most of the drilling work, and the drilling of additional wells will continue into 2015," Shell China spokesman Shi Jiangtao told Bloomberg. "We see that the Sichuan geology is challenging, and we are approaching this at the appropriate pace. We continue to evaluate and should know more toward the end of 2014 or first-quarter 2015, when we will decide how to move forward with each of the projects."

Shell spent about $1 billion in 2013 in the Sichuan Basin, focused on exploration and appraisal drilling and geological studies.

For PetroChina, shale gas output in the area will be complimented by considerable conventional gas reserves. The Longwangmiao site in southeast Sichuan has the capacity to produce as much as 11 Bcm (388.5 Bcf) of gas annually.

Ramping up capabilities

Having a supply chain in place that can handle future activity will be crucial, as it was in the U.S. According to a wide-ranging study commissioned by the U.S. Energy Association and produced by Columbia University's Center on Global Energy Policy entitled "Meeting China's Shale Gas Goals," China is making substantial progress on this front.

The study, which was released in September and saw several dozen interviews conducted with individuals from across the full E&P sector, government and universities in China, highlighted among many other things that 3,000 fracturing vehicles have been put into field operation, according to the country's National Energy Administration (NEA).

"Equipment that includes openhole packers, frac[k] plugs and other downhole fracturing tools have been developed, with some now being exported to the North American market. NEA says that China has gained experiences in horizontal drilling, well completion and large-volume fracturing technologies," it stated in the study.

However, it continued, "Shale gas drilling costs have been high. One expert we spoke with estimated that drilling time at Chinese sites averages 250 days, as compared to 10 to 20 days at many U.S. shale plays. According to one estimate, Sinopec and CNPC's short-term losses from shale gas drilling through the end of 2013 are close to $1 billion."

An oil worker inspects one of the wells on a gas field in the remote Xinjiang Uygur Autonomous Region. (Source: PetroChina)

Commitment to innovation

Overall, the study's findings indicate that China's road toward its own shale gale could be a long one, and among the many important factors it flagged was that of "innovation."

In one of its concluding remarks it stated, "Growth in China's shale gas sector will require innovation, as technologies and approaches developed in the U.S. context are applied in China. Some of these innovations may be relatively straightforward, such as transport equipment redesigned for mountainous conditions. Others may be more challenging, such as new hydraulic fracturing techniques to respond to China's unique geology.

"Foreign partners can help contribute to innovation if given incentives and allowed to do so. The extent to which China creates conditions in which innovations and innovators can thrive will be central to the growth of the Chinese shale gas sector." E&P

Advancing science through collaboration

Industry cooperative pushes pressure prediction, life-of-field seismic in its latest projects.

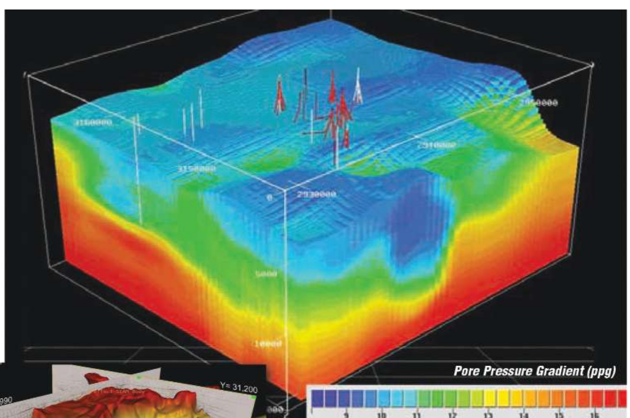
Rhonda Duey, Executive Editor

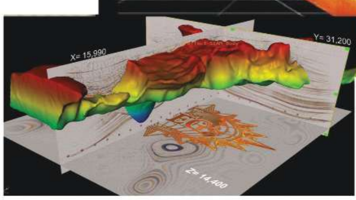
In a highly competitive industry like oil and gas, secrets are often held close to the vest. This might give one company an advantage over another. But it doesn't do much for technology advancement.

In response to the necessity for increased collaboration, the Society of Exploration Geophysicists launched the SEAM project a few years ago to provide a cooperative research environment to help solve some of those thorny problems that no single company is likely to overcome. "It's set up to provide challenges to the industry through actual seismic and other geophysical data," said William Abriel, a geophysical adviser for Chevron and vice chair for SEAM. "The concept is to see where the industry wants to make progress and to provide a safe place since people who, if trying to do this on their own, would find it difficult, time-consuming or expensive."

Already SEAM has completed several projects. The first project was a subsalt modeling project over a 60-block area of the deepwater Gulf of Mexico. The model has been constructed in a form that enables extension to other complex environments.

Phase II involved three different models: unconventionals, near surface, and foothills overthrust. Abriel said the first model has been built and distributed, while the second two models are still under simulation. The full project is expected to be finished by year-end 2015.





Pore pressure prediction and hazard avoidance are the themes of one of the most recent SEAM projects. (Source: SEAM)

Next up

Two new projects are now underway, both of which promise to help the industry better understand difficult problems. The first is a project funded by a Research Partnership to Secure Energy for America alliance called pressure prediction. "It's for the deepwater Gulf of Mexico," Abriel said. "The concept is to understand the approaches to working with pressure prediction and the different mechanisms for pressure. The geophysical simulations will help us to appreciate how to predict pressure using different techniques."

Some of these mechanisms include the compaction disequilibrium mechanism, the centroid mechanism, and chemical changes that generate pressure such as smectite-illite transformations and hydrocarbon cracking, he said.

The plan is to reengineer the salt model from Phase I, although Abriel said this will be up to the participants. He added that it's difficult to resolve pressure effects just with geophysical data. "That's one of the advantages of having known answers like the model information," he said. "It helps so much to measure what the impact of geophysics is on those pressure measurements."

The second project will look at life-of-field seismic, targeting not the exploratory practices but the production and development activities in the oil and gas industry. Abriel explained that no "case history" exists that would allow people to test their theories about reservoir dynamics. "In real life, you don't actually know what's going on between any two wells," he said. "There is no benchmark."

The goal is to provide that benchmark. Participants will provide input into which types of reservoirs should be studied, and these will be put into context in "a box of exciting geology" with a structural and stratigraphic framework.

Once the reservoirs are ensconced in their geology boxes, production scenarios can be tried—depletion, water injection, well trajectories, gas cap expansion. This will enable operators to study potential effects of different scenarios on different types of reservoirs.

The idea, Abriel said, is to combine forward geological modeling with reservoir simulation. These two models typically occupy different scales. Seismic simulation will attempt to bridge that gap and also bring in geomechanics.

"The point is, we'll control it because we're building it from our imaginations using concepts that we already know," he said. "It won't look like it's from Jupiter. It will look like Earth reservoirs that we understand."

Another aspect of this project will involve integration of data from seismic, gravity, electromagnetics and wells. All of these data can be generated synthetically. This will enable users to enter this "nondynamic cube" to first do exploratory work and find the reservoirs. They can do the structural and stratigraphic mapping, place wells, build their reservoir characterization model and then build the forward model to compare the reservoir behavior to the reservoir simulation.

"If we could predict reservoirs perfectly, we would do this once and then walk away," he said. "There would be no production management. Given that there's a gap between what took place and what you guessed, you need to close that gap."

Abriel added that anyone who wants to illustrate life-of-field activities would be interested in this model. "What a fabulous teaching and training tool!" he said. "It's a dataset where you already know the right answer, so that's of some value."

It also will offer the opportunity to introduce uncertainties into the dataset in a controlled manner. These might be a wellbore being misplaced by a few meters, seismic data with tide effects that weren't taken into account properly or an invasion problem with the well logs.

"These are all uncertainties that you can introduce," he said. "And the degree to which you can understand, estimate, capture and describe uncertainties with these data becomes another one of the deliverables."

Ultimately, Abriel sees oilfield management in the future consisting of building what is understood of a model and then altering it as companies learn more about their fields. "That level of software integration will enhance our ability to manage reservoirs significantly," he said. E&P

Unlocking the future of E&P data communications

The technology explosion has redefined the digital oil field.

Dan Steele, FreeWave Technologies

The oil and gas industry is changing. Not only are remote sites continuing to proliferate, but the demands of 21st century technology and access requirements are expanding at an unprecedented pace. It is no longer acceptable to have lags in data communication. The industry faces challenges moving forward, including remote monitoring of wellheads and storage tanks, dealing with 24-hour production demands and managing high costs in both time and money to manage far-flung sites.

Traditionally, companies were tasked with seeking multiple solutions to address these challenges—ad-hoc communication networks or combinations of networks to try to suit applications. But as wireless broadband has grown in popularity and the machine-to-machine (M2M) industry has evolved, today's technology offers comprehensive solutions that suit almost any communication need in the field, both local and remote.

In today's digital oil field the name of the game is speed and reliability. Across the entire utility industry, not just oil and gas, production needs have ramped up exponentially each year, forcing companies to scramble to find the best possible solutions to meet those needs. To successfully meet the increase in demand as well as address the host of accompanying challenges, companies need high-bandwidth two-way connectivity that:

- Enables remote and local M2M monitoring and control of wellheads and pipelines;
- Securely connects them to the operations center; and
- Empowers maintenance team members to connect with video, voice and data communications in real time.

Fortunately for the industry, advanced technology has kept pace.

High-speed problem-solving

The only way to successfully run oil and gas operations is to ensure that each element and moving piece is functioning as smoothly as possible. When faced with aging infrastructure at remote locations, sending a repair team is costly in both time and money. What if the team doesn't have the necessary pieces for a repair? It's a wasted trip, and it railroads the operation, halting production and eroding efficiency. With today's technology, two-way high-speed communication effectively eliminates these problems. Real-time video and data feeds allow dispatchers to monitor the wellhead site, providing them with the necessary information to make decisions quickly and communicate with repair crews in real time, cutting out the unnecessary lag between the breakdown and the repair.

Broadband connections in the field are a crucial tool for any organization. Providing access to high-speed Wi-Fi access points and 3G/4G cellular backhaul allows field personnel to access information in remote sites, a capability that previously was limited to fully wired sites. Wi-Fi at the wellhead gives workers the ability to log into the system and troubleshoot onsite, no matter how remote. And imagine how much of a difference that makes for maintenance crews that can perform diagnostics from the cab of a pickup truck during a snow storm or other inclement weather.

Security and surveillance

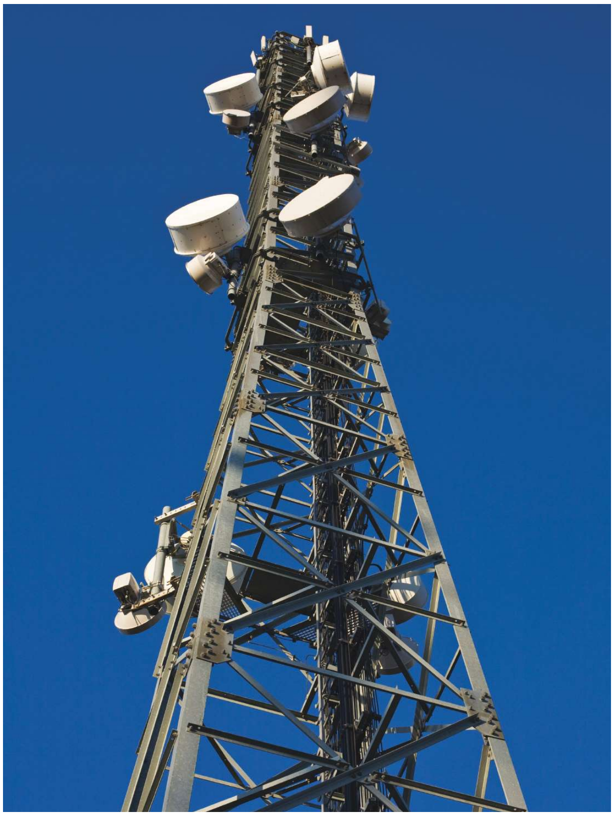
One major challenge associated with far-flung sites is the ability to establish security and surveillance without the benefit of onsite personnel. With millions of dollars sunk into wellheads, it makes sense to protect those investments. Transmitting high-quality video in real-time over a broadband network is an invaluable commodity. Driven by the demand for video and other bandwidth-intensive applications, some of today's newer wireless communication solutions transmit information up to 200 mbps, providing enough bandwidth to enable video surveillance for improved site security.

In addition to high bandwidth, field solutions are incorporating end-to-end Internet protocol (IP) connectivity, which allows all different kinds of traffic to be sent over a single link. To ensure that there is no interruption in connectivity, new technologies are equipped with mesh networking capabilities that operate on a "best path" system, meaning that if one path breaks down, the network automatically reroutes itself to the next best option bypassing the breakage and maintaining an uninterrupted flow of the video or data stream. For organizations with numerous locations, being able to rely on communications networks to provide uninterrupted feeds and updates means that asset tracking and trespasser alerts can happen instantly—protective measures that are invaluable both financially and psychologically.

The future of wireless broadband

Because different kinds of communication networks require different frequency bands, wireless broadband solutions must be able to meet these needs. Some providers offer the ability to leverage multiple radio modules per unit with high over-the-air data rates, high bandwidth and secure communications. Furthermore, the ability to support a 3G/4G modem in the field provides companies with flexibility on multiple levels: connectivity for mobile devices like phones, tablets and laptops; acceleration of network deployments; and, when wired networks go down, a wireless broadband solution that can use its drop-in network capabilities to serve as temporary communications until the damaged systems are up and running again.

The evolution of wireless broadband in the field is not without its opposition. Some critics hold strong to the belief that wired systems are more dependable and carry less risk than wireless solutions. In the past these were valid concerns. But wireless systems have been developed to the point that today across the industrial spectrum wireless is accepted and incorporated as seamlessly as wired systems. For adopters, huge benefits await, including determining how resources can be leveraged in the most valuable way, achieving greater operational efficiencies, increasing productivity, and improving production quality and innovation within organizations. Additionally, because these wireless solutions require no retrenching or rewiring and do not require digging for repairs, the environmental impact is greatly diminished. For an industry under constant scrutiny for its exploratory practices, valid or not, taking steps to mitigate these concerns and criticisms is not simply a token gesture; it is a strong step toward educating the public about companies' abilities to adapt to new technologies and advancements in a way that virtually has no downsides.



Technological advances have made wireless communications a viable alternative to wired options in remote locations. (Source: FreeWave Technologies)

From wellheads to headquarters

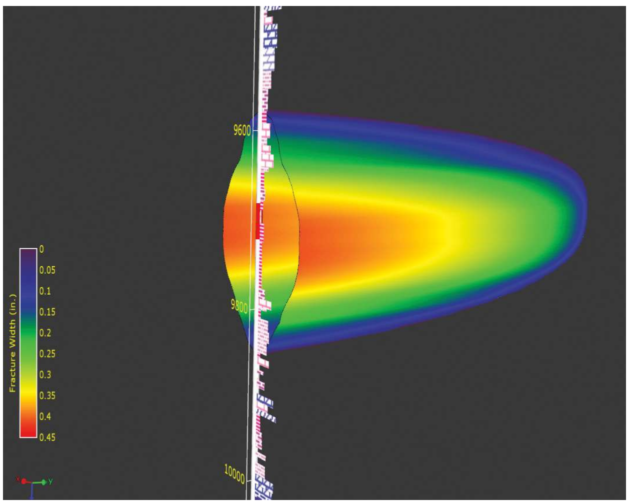
The growth of wireless broadband technology in the field has come with another set of perks: a wide array of remote monitoring capabilities. Today's "smart" wireless routers allow asset-intensive organizations to pull information and data from geographically dispersed sites back to headquarters. This increased level of corporate control is the next generation of remote monitoring. For many organizations, wellhead sites to office or headquarters communications are trending toward an IT-centric umbrella. The digital oil field is rife with opportunities to leverage the ability to connect remotely to corporate networks. Where previous communication models relied on intermittent transmitting and monitoring, the capabilities enabled by today's gateways, in the form of smart routers, allow for headquarters to track assets in real time no matter how hard-to-reach or remote a site may be.

A brave new wireless world

The oil fields of today are a far cry from the fields of the past. As with any industry based on innovation, execution, precision and speed, stagnation is a death knell. Each year technological advances offer better and more efficient means of achieving the same end. The wireless solutions available are ideal for solving the myriad challenges facing the industry. Keeping up with the demand of a 24-hour production cycle, monitoring remote sites in far-flung areas with little to no onsite personnel and managing the cost of both the time and money required for crews to go onsite are all very real problems. Now there are very real solutions. E&P

Software drives faster, better models for hydraulic fracturing

PowerLog Frac from CGG is a tool to petrophysically analyze well log data and directly feed results into fracture simulation software. Completions engineers can use the resulting models to design better hydraulic fracturing projects and improve well projects. The intuitive petrophysics-based software generates formatted rock and fluid properties to allow engineers to run multiple frack scenarios with better accuracy, according to a press release. By eliminating manual calculations and spreadsheets, these scenarios can be run in hours rather than days. Because of the time traditionally needed to acquire input data for the models, frack design and analysis are currently applied in only a very small percentage of hydraulic fracturing. With PowerLog Frac's time savings, fracture simulation can be implemented as part of a standard completion process. The tool was created by CGG GeoSoftware in collaboration with Baker Hughes Inc. as part of a joint software development agreement. Baker Hughes will use PowerLog Frac in its pressure pumping operations to generate scenarios immediately and drive its fracture simulation design software, the release said. *cgg.com*



Rock and fluid properties generated with PowerLog Frac resulted in a solid fracture simulation model for the target zone in the Upper Wolfcamp Shale. (Source: CGG)

Roller cone bit provides reliability for extended operations

Tercel Oilfield Products has released its new premium series roller cone drillbits. The bearing roller cone bit line has precision-machined bearing races that are designed to provide better fit and finish for extended operations even with higher revolutions per minute and heavy weight on bit. The bearings are machined for reliability and consistency, according to a company product announcement. The seal system is engineered to provide optimal configuration and an extreme pressure synthetic lubricant to extend the bearing life. Tungsten carbide hard facing is applied to all surfaces of the steel tooth cutting structures and on the shirttail tip and leading edge on all tungsten carbide insert (TCI) and steel tooth premium bits to provide more protection in challenging formations. Flat top TCIs are pressed into the gauge surface of each steel tooth cone for additional security. *terceloilfield.com*

Data improve drilling targets, reduce formation uncertainty

Baker Hughes launched its SeismicTrak seismic-while-drilling service, which delivers precise measurements for reducing formation uncertainty and enables operators to hit reservoir targets with greater accuracy, according to a product announcement. The SeismicTrak service provides real-time seismic and waveform data that allow operators to adjust the well trajectory to avoid potential drilling hazards. The service can detect pressure changes, potential exiting of the reservoir and other downhole uncertainties while drilling, which allows it to inform operators of approaching formation changes just below the bit. Operators can then quickly change their well trajectory, adjust their mud weight or set casing to mitigate hazards. In highly deviated, horizontal or extended-reach wells, the SeismicTrak service can access boreholes that may be difficult for wireline, reducing the need for additional openhole time or the use of risky deployment methods. The service collects real-time checkshot data and full wireline-quality vertical seismic profile data in memory for processing after drilling to increase subsurface understanding. The service provides time/depth measurement technology with a drift of less than one millisecond over 10 days. Baker Hughes borehole seismic experts process, interpret and integrate all the provided data into a complete well plan. *bakerhughes.com*

Tools, algorithms enhance completion decisions

Sigma Cubed Inc. has developed a new generation of 3-D earth modeling and anisotropic velocity analysis tools, enhanced processing, and higher revolution-event location algorithms to help operators extract more from their data and have more confidence in their microseismic events for more reliable completion decisions, a product announcement said. Starting with the survey design phase through processing of perforation shots and microseismic event location, the new unified anisotropic velocity modeling workflow enables geoscientists to update models in near-real time for efficient and reliable interpretation. This improved event location correlates better to ground truth, providing the geoengineer with higher confidence in the microseismic response to pumping curves, geologic features, completion strategies and reservoir characterization. Additionally, new autodetection and autolocation algorithms deliver microseismic mapped events in half the time for a significant reduction in project turnaround time and improved real-time decisions. Even without 3-D seismic data, operators can perform rapid 2-D well trajectory imaging and 3-D borehole seismic imaging and then integrate the results with 3-D structural data. This integrated workflow collapses the most significant sources of uncertainty in microseismic mapping. *sigmacubed.com*

Rigless ESP conveyance system maximizes uptime

AccessESP has released its next-generation rigless electronic submersible pump (ESP) conveyance system, Access375. The fourth-generation single-section permanent magnet motor is one-fifth the length and weight of a conventional induction motor. The one-piece design removes the need for tandem and triple motors; by reducing system complexity, installation is simpler and more reliable, according to a product announcement. The robust mechanical design is based on the adoption of components and techniques proven in the last 20 years in the MWD/LWD and the completions industries. Access375 is qualified for challenging, offshore and remote location applications. This technology builds on the benefits of AccessESP's previous generation of rigless ESP conveyance systems. Benefits include fullbore access to the reservoir; compatibility with major ESP providers' equipment; and live well ESP installation and removal using conventional slickline, coiled tubing or a wireline tractor. This results in maximized production uptime with reduced costs, time and complexity of ESP intervention, the announcement said. *accessesp.com*

Cell makes testing drilling fluids safer, simpler

Fann Instrument Co. introduced the HPHT Safe Cell, an HP/HT test cell for use in drilling fluids testing to reduce the chance of accidental opening. The cap can be removed from the current industry standard cell while under pressure; the Safe Cell's two-piece threaded cap design prevents removal under pressure. This

The HPHT Safe Cell keeps operators from opening the cell while it is under pressure. (Source: Fann Instrument Co.)

increases safety. The product uses the CellTell Positive Pressure indicator to show pressure status, warning users when the cell is pressurized. The Safe Cell's screw-in end cap allows the cell to be opened and closed by hand without requiring screws. No cell clamp is required as the cap cannot be removed while under pressure. The simple design saves assembly and disassembly time. Safe Cell is now available in four versions, including a double-ended cell. Variations of the single- and double-ended versions use ceramic discs instead of screens. *fann.com*

Differential pressure/pressure transmitter works with limited power supply

Yokogawa Electric Corp. has developed a new low-power version of the DPharp EJA-E series differential pressure/pressure transmitter. It outputs 1- to 5-V DC and HART signals and has been designed to meet the specific requirements of upstream applications, a product release said. Differential pressure/pressure transmitters are used in the industry to measure the pressure; flow rate; and level of liquid, gas and steam. As E&P activity grows in places with poor infrastructure, devices must be able to function on a limited power supply. Due to a redesign of its power circuitry, the low-power DPharp EJA-E series transmitter consumes just 27 milliwatts of power. The transmitter is built to be highly accurate and stable, with a reference accuracy of ±0.055% and the ability to remain within ±0.1% of the upper range limit for seven years. *yokogawa.com/us* E&P

The new low-power DPharp EJA-E series transmitter is designed to be highly accurate and stable while also being energy-efficient. (Source: Yokogawa Electric Corp.)

From scarcity to abundance

Canada's E&P sector holds offshore and onshore opportunities but faces challenges from nearby competition.

Velda Addison, Associate Online Editor

As one of the world's top oil and gas producers, Canada has gained prominence for being a reliable source of hydrocarbon resources that have maintained investors' attention for decades.

Emerging opportunities, including shale plays like the Montney and Duvernay—still considered to be frontier—as well as acreage offshore the country's east coast that could lead to even more supplies. But just like other countries blessed with abundant natural resources, oil and gas developments in Canada, where oil production led by the oil sands is predicted to grow by an annual average of 175 Mbbl/d until 2030, still face obstacles.

For starters, falling oil prices have further squeezed the budgets of E&P companies, which have become more focused in spending, strategically cutting loose assets that are not in sync with their missions. Regulatory and environmental pressures remain. In addition, the globalization of the industry has heightened competition as Canada's E&P sector moves from scarcity to abundance, according to Barry Munro, EY's oil and gas leader for Canada. With an evolving energy environment, he said that the implications of cost matter, organizations must think globally and innovation is key.

"There is a pretty prolific resource, and I believe the fiscal terms are attractive to source capital. There are some who believe that offshore Canada looks oiler than offshore the northeastern part of the U.S.," Munro told *E&P*. So "it would appear that the geology is right and they have the right level of players and the infrastructure and policy support. But the challenge from the scarcity world to abundance world is that there are competing alternatives for capital for the E&P companies who would have to drive the exploration forward."

These companies are looking for places with the strongest opportunities, and Canada remains attractive for some companies, including Exxon Mobil. The company operates one of the country's largest offshore fields—Hibernia—with a massive 52-well development, called Hebron, underway just 32 km (20 miles) southeast of the Hibernia project. Estimated to produce more than 700 MMbbl of recoverable oil, the heavy oil field is located offshore Newfoundland and Labrador in the Jeanne d'Arc Basin.

Offshore opportunity

Nearly 35 years after its discovery in 1980, the $14 billion Hebron oilfield development is progressing in about 91 m (300 ft) of water, with first oil expected by year-end 2017. Hebron, just like Hibernia, will produce through a gravity-based structure (GBS) and an integrated topsides deck.

"We knew we would be facing challenging environmental conditions in designing Hebron because of the arctic environment of our offshore field, the Grand Banks. At this location we are faced with icebergs, significant waves, seismic activity and fog," Geoff Parker, senior project manager for Hebron, told *E&P* in an emailed statement. "We've designed the platform to address these conditions. One example is that we carried out wave model testing to determine global wave loads and local impact loads on the GBS."

The GBS, constructed by Kiewit-Kvaerner Contractors with 130 Mcm (4.6 MMcf) of reinforced concrete, was towed from dry dock to the deepwater construction site at Bull Arm in July 2014.

"Following that, a flotilla was assembled around the GBS. After the flotilla was established, the GBS contractor commenced a concrete slip forming operation at the deepwater site, which concluded in November," Parker said. "This raised the GBS height another 44 meters [144 ft] to approximately 71 meters [233 ft]. Next year we will take it up to its full height of approximately 120 meters [394 ft]."

Parker added that mechanical outfitting, another key activity at the deepwater site, is expected to continue for the next year or so until the GBS is ready for mating with the topsides. The topsides will be sized for an oil production rate of 150 Mbbl/d, and the standalone concrete GBS will be designed to store about 1.2 MMbbl of crude oil.

The development—operated by ExxonMobil Canada Properties with 36% interest and partners Chevron Canada Ltd., Suncor Energy, Statoil Canada and Nalcor Energy Oil and Gas—has come a long way, considering its history. Test results at the Hebron asset in the 1980s showed uneconomic rates of oil in the Ben Nevis reservoir and gas/condensate in the A Marker and Lower Hibernia reservoirs, according to Hebron's field development plan. Good news came with the second phase of delineation drilling in 1999, when more than 1 Bbbl of stock tank original oil in place was encountered while testing the Ben Nevis reservoir on the "Hebron horst" fault block.

"The Hebron asset currently contains three discovered fields: the Hebron Field, the West Ben Nevis Field and the Ben Nevis Field," Parker said. "The Ben Nevis reservoir within the Hebron Field is the core of the Hebron project and is anticipated to produce approximately 80% of the Hebron project's crude oil."

Unlike the Hibernia development, which produces light crude, Hebron's crude is heavier and more viscous at 20°API, Parker noted.

"The Hebron project will extend the life of the offshore oil and gas industry in Newfoundland and Labrador," he added after noting, however, that the size and complexity of the project have posed challenges in finding sufficient skilled individuals within a small labor pool. This has led to the development of training programs. "It represents an important next step in the development of a sustainable offshore oil and gas industry in Newfoundland and Labrador."

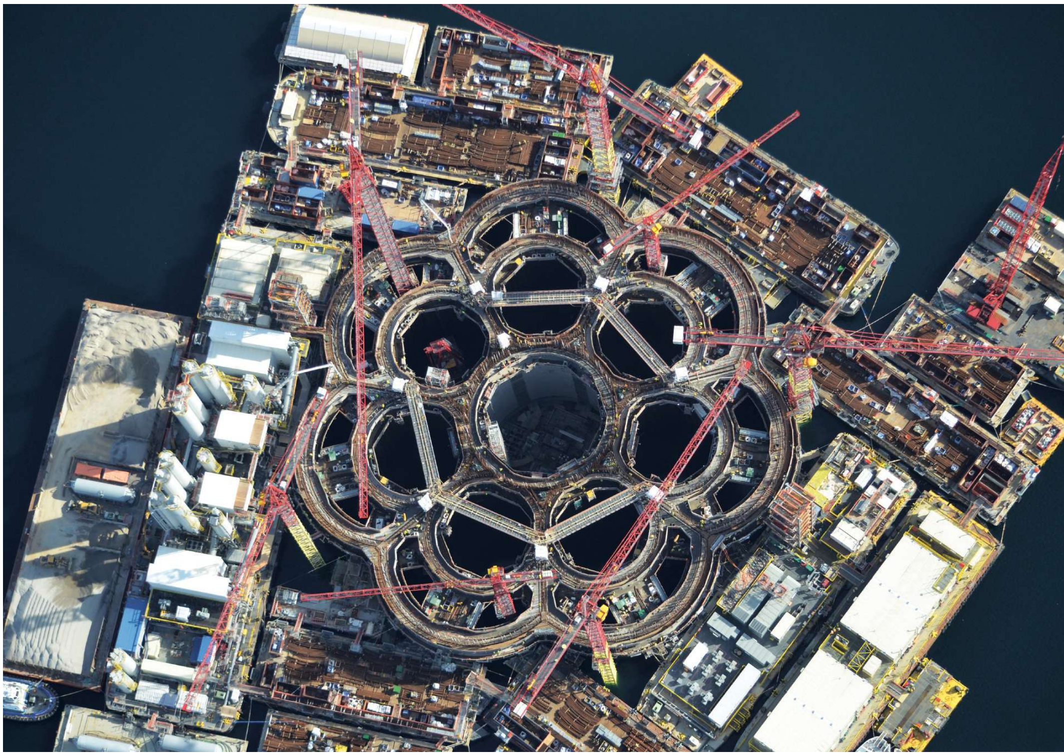
While hopes are high for Atlantic Canada's ability to raise oil volumes, Canada is already witnessing a surge in natural gas production, prompting companies to pursue LNG exports despite competition—nearby and afar—being ahead in development.

"From a Canadian perspective, our biggest customer has become our biggest competitor," Munro said. "We have a Canadian natural gas industry that was built around supplying natural gas to the U.S., and that customer has gone away."

LNG competition

Last year around this time, Munro said global buyers of LNG would have looked to the U.S. with skepticism given the uncertainty concerning whether there would be sufficient political support to accelerate export LNG development in the U.S. This, in turn, would drive prospective buyers to Canada, where there weren't as many question marks around LNG export regulations.

"Fast-forward to today—I think that there has been a market shift in what appears to be political support for LNG exports out of the U.S., and all of them are at stages of development that are farther along than any of the Canadian projects," Munro said. "Now there is this intense competition for customers. … People do realize that the demand for LNG isn't infinite. Now you have direct Canadian-U.S. competition for export LNG."



Constructed at the Bull Arm fabrication site in Newfoundland, the GBS for the ExxonMobil Canada-operated Hebron Field will tower 120 m (394 ft). (Source: ExxonMobil Canada Properties)

About 18 LNG projects have been proposed for Canada's east and west coasts, with British Columbia's Pacific coast having multiple proposals clustered at the ports of Kitimat and Prince Rupert. As of mid-November, none had reached the sanctioning phase. The proposed projects, if all are built, amount to 130 million tonnes per annum that could grow to more than 300 million tonnes per annum at full-phase buildout, said Jeff Fetterly, principal for oilfield services analysis with Calgary-based Peters & Co. Ltd.

Asia presents the most opportunity for Canada's LNG export industry, Jeff Fetterly of Peters & Co. said at the North American LNG Exports conference. (Source: Hart Energy)

"Asia is clearly the market opportunity for most of Canadian energy exports," Fetterly said, speaking at Hart Energy's North American LNG Exports Conference. "When you look at the Asia-Pacific basins specifically, supply is at a deficit to demand, and as a result there is an opportunity here for North American LNG, and specifically Canadian LNG."

However, he said, there is more liquefaction capacity under construction now than regasification capacity. "So the race is on" among potential LNG suppliers, Fetterly said, later adding that Canada is competitive but probably at a "modest deficit" compared to projects proposed for the U.S. coast.

Fetterly noted that one emerging piece in Canada's LNG development that appears to be under the radar is floating LNG, which six proposed projects plan to utilize. He called this move advantageous from several perspectives, including from capital cost and scalability standpoints. However, the vertically integrated model typical of Canadian LNG projects means significant upstream costs. "We estimate that somewhere between two-thirds and three-quarters of the total capital cost of a project is going to be associated with developing the upstream resource. In the case of the Petronas and Shell projects, they both have sizable resources that have been accumulated in the Montney region," Fetterly said. "But the average well cost in those regions is north of $8 million if you include associated infrastructure."

He estimated that more than 6,000 wells would have to be drilled for the Petronas LNG project over the span of 25 years to generate sufficient gas supply to meet the project's needs. Yet active drilling programs in Canada where existing production is about 450 MMcm/d (15 Bcf/d) are among the country's strong points.

Significant gas resource potential exists in the Montney and Horn River plays, and at least one large LNG operation could have a significant impact on the pace of development, he said. At the time, gas production in the region was around 105 MMcm/d (3.5 Bcf/d) with about 5,000 wells drilled since 2000. "The impact from a services/upstream development standpoint is pretty staggering on what could ultimately happen. The risk obviously from an inflation standpoint is there as well," Fetterly added. Pipeline costs are among the downsides, considering one pipeline could cost $7 billion or more to build. "The capital cost to build a pipeline from the Montney, both on the British Columbia side and the Alberta side, to the coast is significant for topography, capital and time," he said.

Compared to the U.S., however, Canada's west coast is far closer to the Asian market than the U.S. Gulf Coast, Munro said. He also pointed out that Canada's projects are all greenfield projects that require intense amounts of regulatory and First Nations support to proceed with buildout. "In the U.S. they are building off of brownfield assets. The question is whether the plant construction costs in the U.S. by repurposing existing facilities offset the shipping cost disadvantage that U.S. projects would have," Munro said. "We're witnessing an intense level of competition in that regard.

"What Canadian E&P companies are learning very quickly is that that move toward globalization means they need to have a much deeper understanding of market forces and factors across multiple jurisdictions," he added.

Oil-sands development

An area where Canada soars above the competition is oil-sands development, with related production accounting for 56%, or 1.98 MMbbl/d, of the country's total oil and oil equivalent production average of 3.5 MMbbl/d in 2013, according to a November 2014 Canadian Energy Research Institute report.

Oil-sands bitumen production is forecasted to grow from its 2013 level of 1.98 MMbbl/d to more than 5 MMbbl/d by 2030, according to the report.

"The oil sands will continue to attract multiple billions of dollars' worth of capital investment and continue to

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ramp up production," Munro said. "The issue that oil sands developers have to deal with is in part sort of ensuring adequate market access—that's either a pipeline south, a pipeline west or a pipeline east."

That was among the reasons Statoil chose to delay its Corner Field development at the Kai Kos Dehseh oil sands in Alberta for at least three years. But its Leismer steam-assisted gravity drainage development continues operations.

"Costs for labor and materials have continued to rise in recent years and are working against the economics of new projects. Market access issues also play a role—including limited pipeline access, which weighs on prices for Alberta oil, squeezing margins and making it difficult for sustainable financial returns," Statoil Canada Country Manager Ståle Tungesvik said in a news release.

The world's plentiful oil supply, led by historic high production from North American shale plays thanks to horizontal drilling, hydraulic fracturing and other technologies, has left many to ponder when the economics of developing these hydrocarbon resources will cause producers, particularly in the U.S., to slow down production. West Texas Intermediate has dropped from a high of $102 in 2014 to about $67 in early December, while Brent has stumbled from about $116/bbl to about $70/bbl.

However, Munro believes in the long run big companies will continue to invest in the oil sands because it is a massive resource.

"You're dealing with a resource that has a 50-year life, so there is a view that you have to look beyond the current commodity price cycle," Munro said. "You also believe that over time technology will continue to unlock more barrels or do it more cheaply."

But innovation is not only technology, "it is also innovation around organization structure, job processes and funding models," Munro added. "People are going to feel an even greater pinch point around their margins from a cost perspective," so innovation is a necessity. E&P

Ghawar: the Arabian granddaddy

The world's largest oil field is still going strong.

Rhonda Duey, Executive Editor

When one examines Saudi Arabia's historical dominance over other oil-producing countries, it all comes down to one field—Ghawar. This massive structure is so productive that it typically gets compared to other countries, not other fields. In fact, according to the Energy Information Administration (EIA), the field has more oil reserves than all but seven countries.

The sheer size of the field—257 km (160 miles) long and 26 km (16 miles) wide by some estimates—makes it comparable to some of the large shale plays in North America. But this is a conventional oil field that, at its peak, produced 6.5 MMbbl/d, according to the EIA. Current production is still 5 MMbbl/d and 71 MMcm/d (2.5 Bcf/d), according to "Hydrocarbons Technology."

That site also noted that Ghawar accounts for an estimated 6% of the world's total daily crude output.

Humble beginnings

One must scare up some pretty distant history to harken back to a time when Saudi Arabia was not the dominant oil-producing giant that it is today. An article in the AAPG "Explorer" titled "Elephant hid in desert" did a pretty good job. The Arabian American Oil Co. (Aramco) began a series of discoveries in the 1930s and early '40s in the Eastern Al Hasa region. American geologists had begun mapping the region in the early '30s.

Geologists from California Arabian Standard Oil Co. (Socal), meanwhile, became interested in the topography near the En Nala anticline in 1935. Following their lead, Aramco geologists began examining the area, noting that the Wadi Sahaba, a seasonal river, took a sudden bend to the south. Shallow drilling confirmed the existence of the anticline.

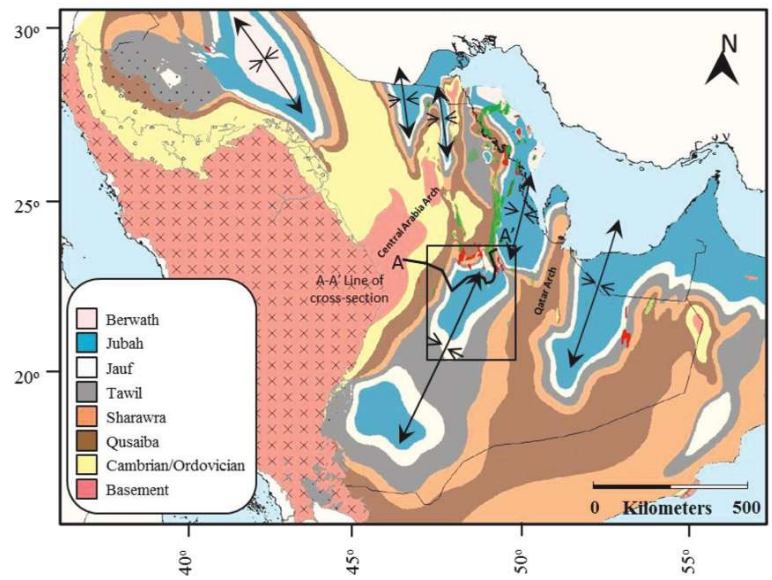
World War II intervened, but afterward explorers returned to the region, acquiring gravity and magnetic surveys to better image the anticline. They determined that the anticline contained six major structural culminations. Aramco drilled a test well in 1948 and made the first post-war discovery in the Kingdom. The well, tested from 2,038 m to 2,056 m (6,685 ft to 6,746 ft), produced gas within six minutes and oil within 11 minutes, with initial production of 15,600 bbl/d.

More wildcats would follow: Haradh No. 1 in February 1949, Uthmaniyah No. 1 in April 1951, Shedgum No. 1 in August 1952 and Hawiyah No. 1 in 1953. All discovered light crude from Upper Jurassic carbonates, now known as the Arab-D member.

By the time of the final discovery, it was becoming clear that all of these discoveries were part of the same enormous field. It was named Ghawar based on the name the Bedouin tribes used for the region.

By 1957, when the northernmost discovery was made, there were 129 wells producing 600,000 bbl/d. All but one of the original discovery wells were still producing oil as of 2011, when this AAPG article was published.

"The first detailed report about Ghawar by the Aramco geologists was presented at the [American Association of Petroleum Geologists] convention in Los Angeles in March 1958 and published in AAPG Bulletin in February 1959—a report that, amazingly,



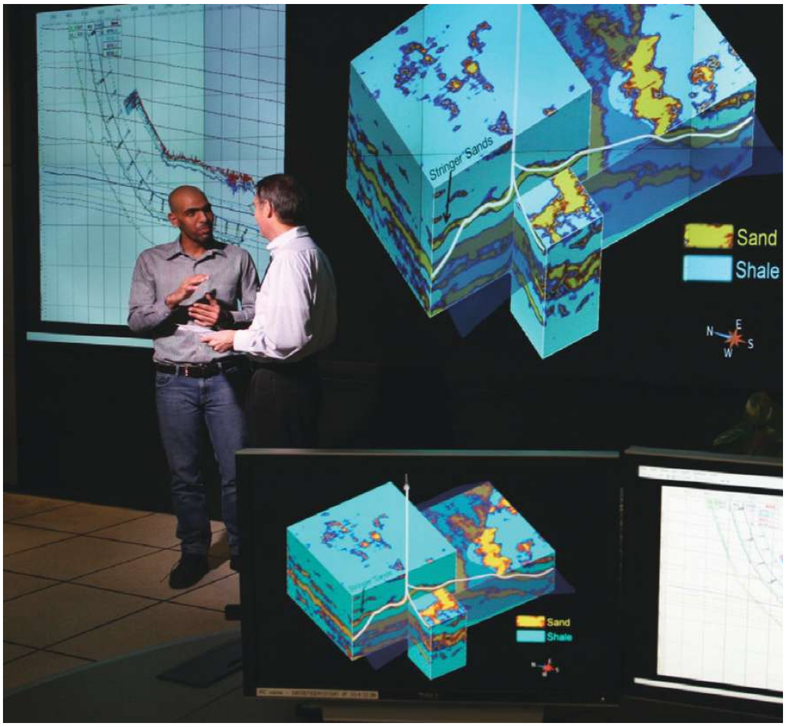
A subcrop map for the Hercynian unconformity shows the Paleozoic basins in Saudi Arabia; the Southwest Ghawar Basin is highlighted by the black rectangle. (Source: URTeC paper 1922271)

remains the cornerstone of our knowledge of this field," the authors noted.

More recent deeper drilling has uncovered vast natural gas reserves in the Permian carbonates, and the development of the southern Hawiyah and Haradh areas during the mid-1990s has improved oil production rates, according to "Hydrocarbons Technology."

The Late Carboniferous extensional uplift caused a basement horst to develop, and it is over this horst that the Ghawar anticline is draped. The asymmetrical En Nala structure has a steep western flank and "a minor component of right lateral strike-slip," the authors noted. Oil is sourced from Jurassic marlstone.

The Arab-D member is about 85 m (280 ft) thick and improves in quality in the shallower sections.



Geologists and petroleum engineers remotely direct well drilling from the Geosteering Center in Dhahran. Geosteering is part of the Haradh III project. (Source: Saudi Aramco)

Ghawar today

The Ghawar Field is located in the eastern portion of the Empty Quarter of the Arabian peninsula about 100 km (60 miles) southwest of Dhahran in the Al Hasa province in Saudi Arabia. It is operated by Saudi Aramco.

The field has long undergone secondary recovery methods. Gas injection was introduced in 1958, according to "Hydrocarbons Technology," and water injection began in 1964 to provide pressure support. Today water is pumped by pipeline from the Qurayyah Seawater Treatment Plant.

In 1995 Aramco conducted a 3-D seismic survey to examine the reservoir structure and fracture distribution to guide future development of the field. More recently the company began the Haradh III project, which relies on maximum-reservoir-contact wells and downhole interval control valves for flow control. Geosteering also has been used, and wells have been equipped with intelligent sensors for continuous monitoring.

The site noted that Ghawar had more than 3,000 injector and oil producer wells by the end of 2012. Halliburton is the prime contractor and was awarded a five-year contract in 2009 to develop as many as 185 oil production, water injection and evaluation wells. Aramco also is working on a carbon capture and storage (CCS) strategy at Ghawar to combine CCS with EOR. The project, expected to be completed at the end of 2014, would require 1.1 MMcm/d (40 MMcf/d) to be pumped from the Hawiyah and Uthmaniyah gas processing plants. It also would require an 800,000 ton/year CCS facility and a 70-km (43-mile) pipeline to transport CO_2 to the site.

Finally, the company is planning to award FEED contracts to develop three shale gas fields, one of which resides in the southern part of the Ghawar Field.

An aging giant?

Ghawar has been the world's largest oil field for decades, a distinction that brings with it the ability to control, to some extent, the world's supply of oil. But its dominance is waning as countries like the U.S. exploit their shale oil resources. And many question its ability to keep up the good work for much longer.

In an article on the "Energy and Capital" website posted in February of 2013, author Justin Williams discussed the debate on Ghawar's future. "Some experts believe [that] Ghawar has reached its peak and is in decline," Williams wrote. "Saudi Arabia will dispute that position every step of the way and assure the public that Ghawar will continue to produce at current levels for years to come. The nation claims the field most likely has 50 Bbbl left to extract."

Many sources noted the difficulty of getting reliable data, or in fact any data, from Saudi Aramco statements.

While the field may play less of a role in world politics and economies in the future, its stature as a game changer can't be denied. E&P

Fresh design creating seismic waves

It is estimated that marine seismic surveys represent about 1.5% of global E&P expenditure. Developments in source and streamer technologies combined with continuing improvements in 3-D data processing and interpretation techniques are delivering increasingly accurate and reliable information for imaging the subsurface and mapping reservoir fluid movements.

Just more than two years ago WesternGeco embarked on a project to design and build a new sustainable and efficient marine seismic platform capable of supporting all of its present and potential technologies and acquisition techniques for at least the next 10 years while also optimizing operational performance.

Unlike all previous newbuilds in the seismic industry, which were based on existing hull designs unlikely to be optimal for the requirements of 3-D surveying, the company decided to design its new vessel completely from scratch. This clean-sheet approach was applied to the operational criteria, the hull, propulsion system and all the other vessel components.

While for most newbuilds the back deck and gun deck are designed to fit a hull, the Amazon project started with the seismic elements and followed with the design of a maritime platform that would best support them.

Safety features

The design features significant safety features, including deployment systems for the sources and the 18-streamer tow points being hands-free wherever possible. A built-in offshore gangway also avoids the need for small boat at-sea transfer of personnel, while the two workboats are designed for safe, efficient replacement of streamer sections. The Amazon-class vessels—there are two—are designed to operate for at least 120 days before refueling.

Also, because seismic vessels spend about 80% of their time in production, the hull is designed to be stable and efficient at 5 knots (where a seismic vessel operates for about 90% of its life), although transit speed is estimated at 17 knots.

The vessel's scale—it's about 50% bigger than any of the owner's current fleet—also provides a large, stable platform for operations in harsh weather conditions, while the bow design reduces slamming, helping to maintain streamer control (avoiding tugging) and reducing noise in the seismic data.

The propulsion system was designed to match the hull and includes independent, ergonomically designed port and starboard engine rooms.

Arctic-class

In common with all WesternGeco vessels, the vessel uses only marine gasoil and has reduced gas emissions with no overboard discharge. It also is designed to meet DNV CLEAN Class and CLEAN Design specifications and has ICE-1A class and winterization for Arctic operations to Polar Class 7. The first Amazon-class vessel, the *Amazon Warrior*, was built in Flensburg, Germany, and began operations mid-2014. E&P

Vessel Facts	
Sector:	Seismic Survey
Owner:	WesternGeco
Name:	*Amazon Warrior*
Vessel Design:	Amazon Class
Yard Built:	Flensburger Schiffbau-Gesellschaft, Germany
First Operations:	Mid-2014
Size (length/beam):	126 m x 31 m (413 ft x 105 ft)
Gross Tonnage:	21,195
Top Speed:	17.5 knots
No. of Streamers:	18
Streamer Capacity:	More than 200 km (124 miles)
Operating/ Regional Arena:	Worldwide, including Arctic
Classification:	DNV GL
Notation:	Meets DNV CLEAN Class and CLEAN Design specifications; ICE-1A class; Winterization for Arctic operations to Polar Class 7

WesternGeco's purpose-built *Amazon Warrior* is seen at the Flensburger Schiffbau-Gesellschaft shipyard in Germany, prior to its sea trials earlier in 2014. (Source: WesternGeco)

ASIA-PACIFIC

Mubadala starts production at Thailand's Manora Field

Production commenced at Mubadala Petroleum-operated Manora oil field in the northern Gulf of Thailand, according to a press release. Production is expected to reach a peak rate of about 15,000 bbl/d of oil as production wells are completed. Up to 10 production wells and five injection wells in the main reservoir sequence are planned. The field is located within the G1/48 concession, about 80 km (50 miles) offshore in 44 m (144 ft) of water depth.

CNOOC makes mid-sized discovery in South China Sea

CNOOC Ltd. has made a mid-sized discovery in Lufeng14-4 in the eastern South China Sea, the company said in a news release. The Lufeng14-4 structure is located in Lufeng Sag in the Pearl River Mouth Basin of the South China Sea with an average water depth of 145 m (476 ft). The discovery well Lufeng14-4-1 was drilled and completed at a depth of 4,098 m (13,445 ft) and encountered oil pay zones with a total thickness of about 150 m (492 ft). The oil production of the well tested around 1,320 bbl/d.

AUSTRALIA

Bauer-19 well hits oil pay in Cooper Basin

The Bauer-19 deviated development well in PPL 253 within PEL 91 has been cased and suspended as a future McKinlay and Namur oil producer after intersecting net oil pay within the Namur Sandstone as well as a 4-m (13-ft) gross interval of oil-bearing McKinlay Member, Beach Energy said in a news release. Bauer-19 was the third well in a six-well development campaign at Bauer. The well intersected the top of the Namur reservoir 4.7 m (15.4 ft) high to prognosis. The 8.7-m (28.5-ft) Namur oil column is better than the predrill prediction of 4 m.

SOUTH AMERICA

Petrobras makes first find in Colombian Caribbean

The Petrobras Orca–1 exploratory well (Tayrona Block) has revealed a natural gas accumulation in Colombian Caribbean deepwater 40 km (25 miles) off the coast of La Guajira. This is the first discovery in the history of the deepwater exploration of this region of the Caribbean. Petrobras is the operator (40%) in partnership with Ecopetrol (30%) and Repsol (30%). The natural gas accumulation was confirmed at 3,600 m (11,811 ft).

Spectrum begins deepwater project offshore Uruguay

Spectrum has commenced a 3,600-km (2,237-mile) multiclient 2-D seismic survey offshore Uruguay, a news release said. The new acquisition program will infill Spectrum's survey acquired in 2013 and cover open ultradeepwater acreage in the Oriental del Plata and Pelotas basins, anticipating the third licensing round in Uruguay expected to be held in 2015, according to the release. The data are being collected by the vessel *BGP Challenger* and will be processed in Spectrum's processing center in Houston.

NORTH AMERICA

ICA Fluor, Shell sign heavy oil deal

ICA Fluor, a joint venture between Fluor Corp. and Empresas ICA, signed a contract with Shell Canada Energy to supply modular fabrication and procurement services for 13 well pads for heavy oil extraction at Shell's Carmon Creek project under construction in northern Alberta. The project is expected to produce about 80 Mbbl/d of heavy oil from Shell's Peace River operations using steam recovery methods. The initial contract awarded to ICA Fluor is worth $264 million. ICA Fluor will fabricate the modules at the El Empalme Yard in Tampico, Tamaulipas, Mexico. The completion is scheduled for December 2017.

GULF OF MEXICO

Hess starts production from Tubular Bells Field

Production has commenced from the Tubular Bells Field located in the Mississippi Canyon area of the deepwater Gulf of Mexico, Hess said in a news release. Following a ramp-up period, Tubular Bells is expected to deliver gross production of about 50 Mboe from three producing wells by year-end 2014. The Tubular Bells Field was discovered in 2003, and the development was sanctioned in October 2011. It lies in about 1,310 m (4,300 ft) of water 217 km (135 miles) southeast of New Orleans.

Chevron produces first oil from Jack/St. Malo project

Crude oil and natural gas production has begun at the

Jack/St. Malo project in the Lower Tertiary trend in the deepwater U.S. Gulf of Mexico (GoM), Chevron Corp. said in a press release. The Jack and St. Malo fields are among the largest in the GoM. They were discovered in 2004 and 2003, respectively, and production from the first development stage is expected to ramp up over the next several years to a total daily rate of 94 Mbbl of crude oil and 595 Mcm (21 MMcf) of natural gas.

EUROPE

Statoil completes Barents Sea exploration program

Statoil has completed the extensive 2013-14 exploration program in the Barents Sea, a press release said. This represents an all-time high in exploration activity and 10% of all exploration wells drilled in the Barents Sea since its opening in 1980. The exploration program started with five wells in the vicinity of Johan Castberg to clarify the oil potential in the area to plan the development of the Johan Castberg Field. The three wells drilled in the Hoop area during the summer allowed the company to build knowledge of this huge frontier area of the Barents Sea. The last part of the exploration program was designed to increase understanding of the petroleum potential in different areas of the Barents Sea.

Centrica makes gas discovery in North Sea

Well tests at the Pegasus West discovery have led to positive results, indicating a combined sustained flow rate of more than 2.5 MMcm/d (90 MMcf/d) of gas. Centrica drilled the exploration well at Pegasus West using the Paragon 391 jackup rig as part of its strategy to build on its existing hubs. The Pegasus area is in the southern North Sea 150 km (93 miles) east of Teesside, England, close to the large Cygnus gas development, where Centrica has a significant interest. The Pegasus West well will now be suspended while the company assesses the data it has gathered and makes a decision on development.

RUSSIA CIS

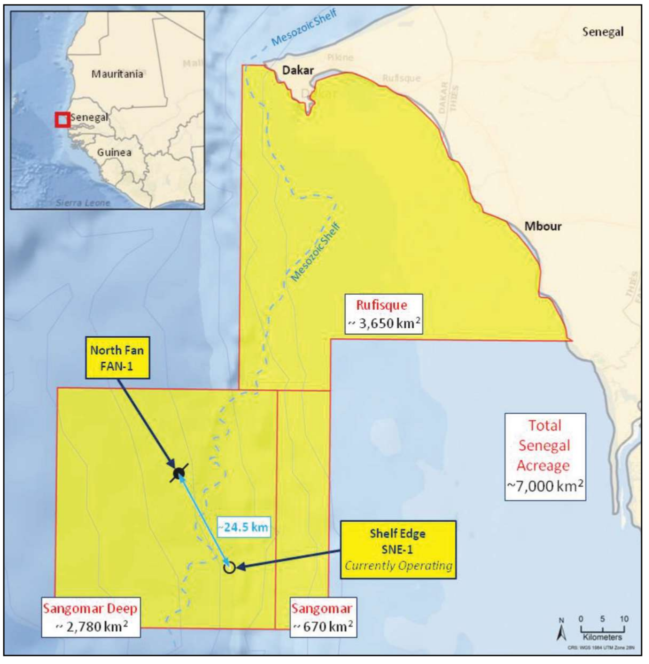
Eni signs agreements for Turkmenistan activity

Eni and Turkmenistan's State Agency for Management and Use of Hydrocarbon Resources signed an addendum to the production-sharing agreement (PSA) with respect to the onshore Nebit Dag area located in West Turkmenistan, a press release said. The addendum extends the duration of the PSA to February 2032, and a 10% stake out of the contractor share is transferred by Eni, operator of the block, to Turkmenneft. Eni will keep the remaining 90% interest stake in the PSA. This agreement will enable further E&P investments in Burun and other satellite fields of the Nebit Dag Block.

AFRICA

Cairn makes second oil discovery offshore Senegal

Cairn has made a discovery of high-quality oil in the second well in the Senegal exploration program, the company said in a press release. The SNE-1 well is located in 1,100 m (3,609 ft) water depth about 100 km (62 miles) offshore in the Sangomar Offshore Block with a target depth of about 3,000 m (9,843 ft) targeting the Shelf Edge Prospect. Intermediate logging of the SNE-1 well has confirmed hydrocarbons in the Cretaceous clastics objective, which is of similar age to oil-bearing sands found about 24 km (15 miles) away in FAN-1.



Cairn has discovered high-quality oil in the SNE-1 well. (Source: Cairn Energy)

Sidi Moussa well encounters oil

Testing operations have now concluded on the SM-1 well on the Genel-operated Sidi Moussa license offshore Morocco, according to partners Serica Energy Plc, Genel Energy and San Leon Energy. The well was drilled to a total depth of 2,825 m (9,268 ft) subsea and encountered oil in fractured and brecciated cavernous Upper Jurassic carbonates. During the course of drilling and well control operations, 26°API oil was produced to surface with the drilling fluids. A subsequent testing program confirmed the presence of oil. E&P

on the MOVE

PEOPLE

Comstock Resources Inc. tapped **LaRae L. Sanders** as vice president of land.

Lloyd's Register Energy has appointed **Siri Revelsby** senior vice president, consulting services.

Douglas Nester has become TransAtlantic Petroleum Ltd.'s vice president of Albania.

Barrick Gold Corp. made **Shaun Usmar** senior executive vice president and CFO designate. Usmar joined Barrick on Nov. 24, 2014, and will become CFO on Feb. 18, 2015. The company has appointed **Sergio Fuentes** as executive project director for Pascua-Lama.

Andrew Howell has been selected as CEO for KBC Advanced Technologies.

Manish Maheshwari (left) has become CEO-E&P for Essar Oil Ltd.

Cubility has appointed **Kai Preben Sæveland** CFO.

Norwegian Energy Co. has promoted CFO **Tommy Sundt** to CEO.

Stacy Edghill (left) has become business development lead at Petroplan's Scotland office. **Monika Pál** has become Dubai office manager.

Richard Morningstar has been named the founding director of the Atlantic Council's Global Energy Center. **Daniel Poneman** and **Carlos Pascual** have joined the board of directors.

LUX Assure made **Scott Rankin** (left) technical expert for their chemical monitoring technology CoMic.

The International Association of Drilling Contractors' board of directors elected **Ed S. Jacob III** chairman.

Christopher S. Cooper has been chosen as senior vice president and COO of the general partner of Memorial Production Partners LP.

Cartasite brought on **Tony Testolini** as chief revenue officer.

Exova has appointed **Rona Lorimer** (left) as general manager of its Salford laboratory.

Alex Harrison (left) has assumed the role of group director, energy services for London Offshore Consultants (LOC). **Adam Solomons** (right) has become managing director of LOC in Australia.

Applus RTD has named **Phillip Morrison** (left) has its new regional director for the U.S.

Alloy Metals and Tubes International has hired **Steve Martinez** (left) as warehouse operator and promoted **Denna Gatewood** (right) to director of quality assurance.

Drilling Services of America has added **Dwayne Doucet** (left) as HSE director and **Todd Whitley** (right) as senior technical adviser.

Ivanhoe Energy named **Randolph Thornton** to its board of directors.

Robert Cole has been appointed managing director for Beach Energy Ltd.

Stephen D. Pryor has retired from his role as president of ExxonMobil Chemical Co. and vice president of Exxon Mobil Corp.

William L. Transier has resigned from his position as president and CEO of Endeavour International. He will continue as chairman of the company's board.

MDU Resources Group Inc. named **Jason L. Vollmer** treasurer and director of cash and risk management to replace **Douglass A. Mahowald** who is retiring after almost 33 years with the company.

Bob Keiller, CEO of Wood Group, has been selected to join the Entrepreneurial Scotland Hall of Fame.

Kimberly C. Hosmer (right) has joined IHS Inc. as senior vice president and chief marketing officer.

Lilis Energy selected **G. Tyler Runnels** to join its board of directors.

Mark Randolph (right) was appointed to the Fugro Chair in Geotechnics at the University of Western Australia's Centre for Offshore Foundation Systems.

Trevor Bourne has joined the board of directors of Senex Energy Ltd.

Colin Beckett has been named an independent nonexecutive director on the board of Beach Energy Ltd.

Patrick McCarthy (right) has joined ProSep's board of directors as a nonexecutive director.

Marcela E. Donadio has been elected to the Marathon Oil Corp. board of directors.

E&P

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COMPANIES

Ferus Natural Gas Fuels Inc. announced the grand opening of the first merchant LNG facility in Canada. The facility, which became operational in May 2014, is located in Elmworth, Alberta. The LNG plant produces LNG fuel for engines used in drilling rigs, pressure pumping services, water heating for well fracturing, and heavy-duty highway and off-road trucks. To support the LNG supply chain, Ferus also has designed and built specialized mobile storage and dispensing equipment. The facility can currently produce up to 189,000 l/d (50,000 gal/d) of LNG and has capacity to expand up to 946,000 l/d (250,000 gal/d).

Classification society **ClassNK** is expanding its Veracruz, Mexico, office to better support the growing offshore oil industry in the Gulf of Mexico. The expansion will increase the survey capabilities and management authority of the Veracruz office.

Applus RTD has opened up an office in Pittsburgh, Pa., to provide nondestructive testing (NDT) services in the Marcellus Formation. NDT services include radiography, ultrasonic testing and digital radiography testing, and additional support in geotechnical services including seismic refraction and ground penetrating radar for pipeline design and pipeline investigation studies will be provided as well. E&P

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Planning for successful electrified fracturing

A single AC induction motor directly connected to the pump input shaft can now replace the diesel engine, transmission and associated auxiliary equipment in a hydraulic fracturing operation.

Dan Cook, Ward Leonard

Recent socioeconomic and regulatory changes are placing pressure on hydraulic fracturing apparatus to become cleaner, quieter and more efficient. This in turn is driving the development of a new breed of hydraulic fracturing platforms—the electric fracturing skid.

Conventional formation fracturing requires a fluid slurry source that can accommodate a broad range of pressures and flows during the critical stages of formation development. The current state of the art has relied upon several massive diesel engines, each mechanically coupled to multiple-piston positive displacement pumps through a multispeed transmission—an integrated system solution that has endured for the past several decades.

The success of the diesel solution is due in large part to:

- Component reliability;
- Prime mover durability;
- System flexibility; and
- Operation simplicity.

The constraints placed on the range of fluid pressures and flows necessary to successfully fracture a well require enormous total bulk pumping power capability. Additionally, the site operator must have very fine control of all of the available power. Cost-effective electric solutions that could provide the required power, precise speed and torque control in a lightweight and small footprint have been beyond the reach of technology—until now.

Advances lead to transition

With recent advances in electric motor analysis, design optimization techniques and variable frequency drive (VFD) software, it is possible to remove the diesel engine, transmission and associated auxiliary equipment from the pumping platform and replace it with a single alternating current (AC) induction motor directly connected to the pump input shaft. The electric power delivered to the AC motor is then controlled and supplied through a VFD that may be located at any convenient location onsite and connected to the motor with only a few power cables.

When using closed-loop vector control methods with an integrated high-resolution motor shaft encoder, the pump operator has the ability to apply full torque from the motor to the pump over a wide range of speeds. This translates into the ability to have full pumping pressure available with very fine control from 0% to about 40% of full flow. When exceeding 40% flow, available pressure will decrease with increases in flow. These aggregate characteristics are ideal for the critical stages of formation development.

Technical partners critical to success

Whether developing a new design skid platform from the ground up or converting existing hardware to use newer technology, the technical skills required will be vastly different from those required for "conventional" diesel fracturing. Owners and operators need to partner with leaders in the industry that will not only provide the technical support required to select the right motor, VFD and power sources but that also must have the technical ability and innovative spirit required to help the customer develop its "niche" in the market.

And given that each electric frack site will require between 25,000 hp and 60,000 hp of power vs. up to 4,000 hp for a traditional electric drilling site, it also is critical to partner with a dedicated technical motor design and manufacturing company to help plan, develop and implement a custom program that uses a range of powerful, lightweight and smaller volumetric envelope motors and drives that specifically meet the challenges this market segment presents. Traditional motor repair shops are generally not equipped to properly evaluate the applied physics and system-level tradeoffs required.

There is no doubt that this new era of electrohydraulic fracturing will be intensely competitive. Only those organizations that select the right key partners will be able to provide solutions that:

- Deliver greater mobility and portability;
- Are less expensive to transport;
- Occupy less of the total site footprint;
- Provide superior fluid power control;
- Remain quieter and cleaner than the incumbent diesel solutions; and
- Reduce recurring maintenance. E&P