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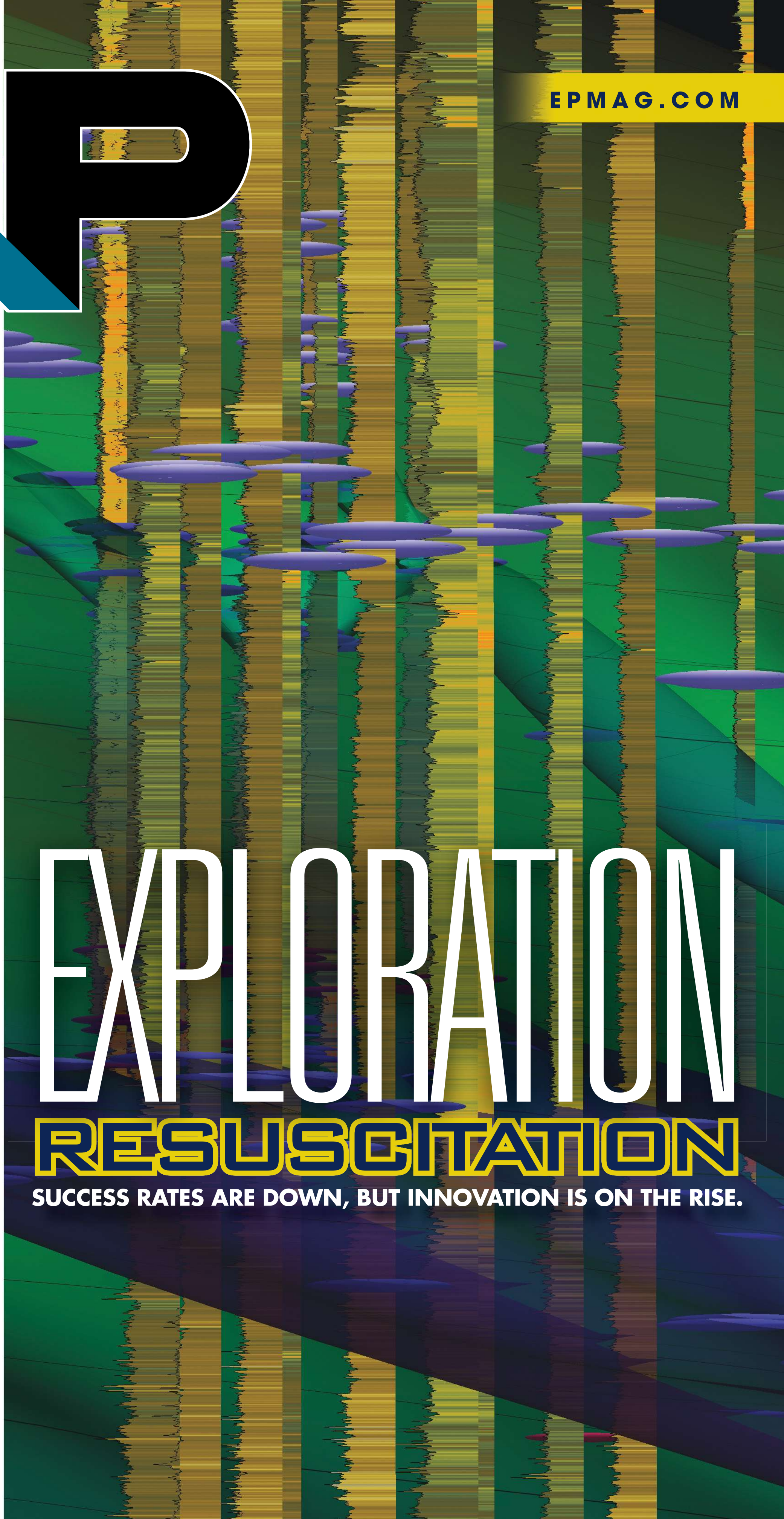

EXPLORATION & PRODUCTION
WORLDWIDE COVERAGE
OCTOBER 2015
VOLUME 88 ISSUE 10
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DEPARTMENTS AND COMMENTARY

COMING NEXT MONTH The November issue of ***E&P*** will examine the continuing importance of getting the most out of mature fields. Other features will include presalt and subsalt exploration, land rig advances, unconventional completion optimization, and subsea processing, and the Marcellus Shale and the Caspian Sea regions will be highlighted. As always, as you're waiting for your next copy of ***E&P***, be sure to visit ***EPMag.com*** for the latest news, industry updates and unique industry analysis.

ABOUT THE COVER Exploration success has been dropping, but new developments in technology might change that paradigm. Left, despite the scandal rocking Petrobras, Brazil is moving forward with its presalt development plans. (Cover image courtesy of DrillingInfo; cover design by Felicia Hammons)

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First oil flows at Otakikpo offshore Nigeria

The Otakikpo-002 well produced from only the first of four planned production strings and flowed oil at various choke sizes for more than 24 hours at a peak rate of 5,703 bbl/d of oil on a 36/64-in. choke, Lekoil said.

Norway sees dip in drilling permit applications

Plunging crude prices have led to a sharp decline in investments by oil firms on Norway's continental shelf this year, leading to higher unemployment and concerns that the country's most important industry will continue to contract, Reuters reported.

GeoPark strikes oil onshore Colombia

The Jacana Field is located southwest of the Tigana oil field, following the same fault trend, and appears to be a combination structural-stratigraphic trap.

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OE 2015: Industry moves toward deeper frontier

By Mark Thomas, Editor-in-Chief

Today's challenge is figuring out how to go deeper and longer but cheaper, a company executive said at SPE Offshore Europe 2015.

WTI, Brent forecasts revised downward

By Mike Madere, Hart Energy

Report: Large production-growth regions in 2015 are not expected to repeat their performance in 2016.

Apache advances in Egypt despite tough market conditions

By Velda Addison, Associate Online Editor

Apache Corp. said it has an exploration success rate of 78% in Egypt.

OE 2015: North Sea must stop over-engineering, CEO says

By Mark Thomas, Editor-in-Chief

Speaking during SPE Offshore Europe 2015 in Aberdeen, Scotland, Proserv CEO David Lamont said the North Sea has many years of profitable life ahead of it if the industry quickly adopts more collaborative and efficient business practices.

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Music to my ears

A couple of months ago I lamented the lack of industry leaders willing to speak their minds.

For those who can't recall, I said that when times are tough we look to the movers and shakers in our industry to give us insight, inspiration and some good old-fashioned straight-talking. We all know what they're thinking—but it seldom gets uttered.

Imagine my delight, therefore, when attending SPE Offshore Europe in Aberdeen, Scotland, to hear several VIPs get up and shoot straight from the lip. Perhaps it was the crisp Aberdeenshire air and the long-known willingness of many a Scotsman to tell people some home truths.

One of those speaking his mind publicly was Robin Allan, Premier Oil's director of the North Sea region and exploration. Earlier I sat through a presentation by BP's Bernard Looney, who espoused the importance of sitting, talking and learning from partners and contractors to better implement efficiencies and cost savings.

Allan, however, had his own views on the success or otherwise of implementing that kind of culture. He called on the majors to improve the way they deal with the smaller players in the U.K. "The view from a smaller company is the way that the majors approach commercial problems and difficulties in tackling all these undeveloped discoveries [is inappropriate]. If you are a BP or a Shell or an Exxon [employee], you don't get promoted by being nice to an EnQuest or a Premier; you get promoted for sticking one over on them. That's what they want to see.

"The majors want to see aggressive commercial behavior where they win and someone else loses," he added. "That works very well for them as companies globally, but that is not a model that can help sustain the basin."

David Lamont, Proserv's CEO, also joined in, saying, "Despite talk in recent years of the urgent need to act and collaborate, even before the oil price crash, the industry as a whole still has a long way to go. Everyone knows what needs to be done, but the inertia in the industry is of great concern."

Effort to collaborate in the industry, while being undertaken by some companies, still is the exception, he explained. A return to $100 per barrel oil prices is unlikely. In the event prices do rebound, the industry cannot return to the old way of doing things, with past practices proving wasteful in today's market.

Samir Brikho, CEO of Amec Foster Wheeler and a former Offshore Europe chairman, decided to join in too, saying, "The industry has been quite lazy in changing because oil prices have been helping us a lot. At a time like this, you need to take a look at how you can take out the fat. Once we have done this, we will never go back; this will become the new norm."

There were several other examples I also could have used here. The plain speaking was a refreshing change and music to the ears of all those looking for constructive and honest views at industry events rather than sanitized "PR-speak." Long may it continue. E&P

Back to the future?

Today’s tough times call for new attitudes about mature fields.

Rob Hull, Halliburton

In the oil and gas industry, change is continuous and cyclical. The current cycle is characterized by depressed prices, lower rig counts, companies right-sizing and an even heavier emphasis than usual on ensuring every dollar is invested as wisely as possible. To the inexperienced, this might appear to be a time of reassessment, retrenchment and retreat. Seasoned professionals, however, can view this as the perfect time to increase interest, insight and initiative in existing assets to boost productivity and profitability. Mature fields can offer the best way to achieve this goal.

Immense potential

When asked why he robbed banks, famous American safecracker Willie Sutton is said to have replied, “Because that’s where the money is.” This may or may not be an apocryphal tale, but there is no doubt that mature fields contain the most energy reserves. Approximately 70% of worldwide oil and gas production already comes from mature fields, yet the average worldwide recovery factor for oil is only 35%. A mere 1% recovery increase could produce an additional two-year supply, which is definitely needed.

The International Energy Agency forecasts that energy demand will increase by 37% over the next 20 years. Because of disorder in so many important producing areas of the world coupled with changing climate goals and increasing environmental restrictions, supply might not be able to keep pace. Improved recovery from mature fields cannot only help meet this demand, but it can do so at far less cost than finding and developing energy from new fields.

Good dollars and sense

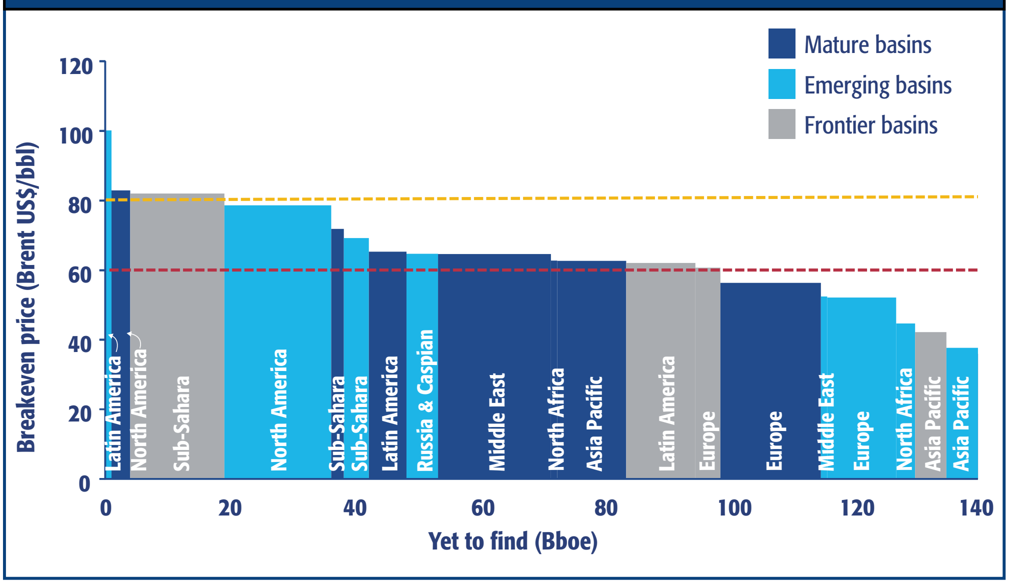
When considering the cost of barrels of oil equivalent, it is much more cost-effective to continue production from mature fields than to bring new discoveries into production. In North America, production from new wells costs virtually twice as much as production from existing fields. In Europe, the Middle East, South America, Australia and other parts of the world—while not precisely the same—the cost differences all trend in a similar direction and are all dramatic. New fields are simply a much more expensive proposition.

Mature basins have less cost sensitivity to discovering hydrocarbons than frontier basins, and it is easier to maximize ultimate oil recovery with proven reserves.

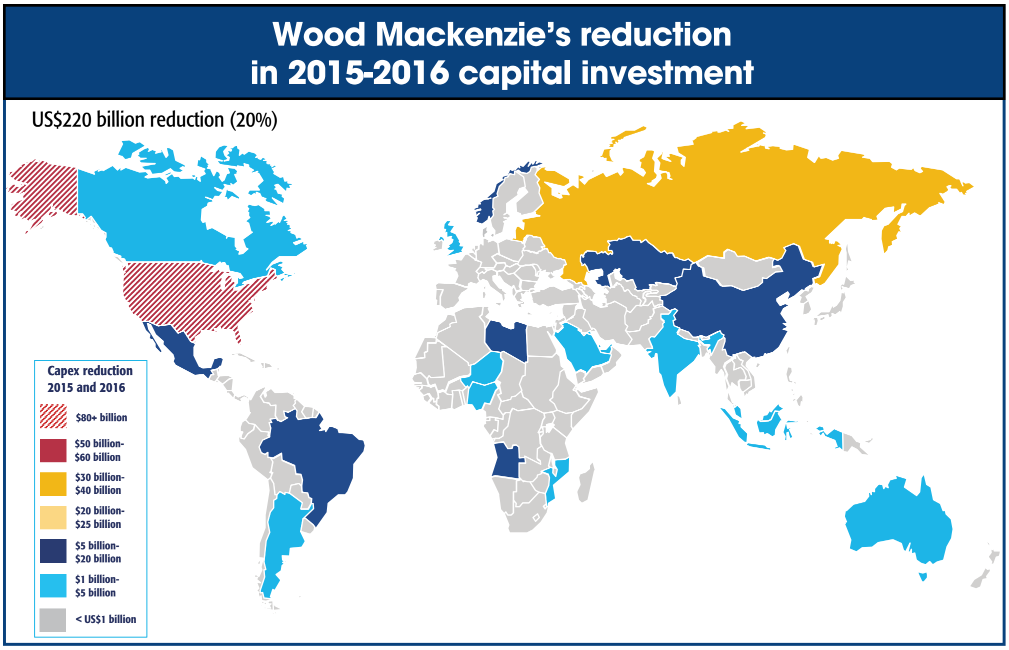
Holding back new thinking

Present-day oil and gas professionals tend to have outdated ideas of mature fields, often considering them as secure revenue streams that only require ongoing routine maintenance. This kind of thinking is not only ill-advised but also prevents available hydrocarbons from being produced and ignores possible revenue

Breakeven prices for yet-to-find oil prospects by basin maturity



A comparison of costs to produce from basin types is shown. (Source: Wood Mackenzie Exploration Service)



Spending was cut across all major oil sectors from fourth-quarter 2014 to second-quarter 2015. (Source: Wood Mackenzie Exploration Service)

that could help producers increase productivity and profitability in these tough economic times.

Reservoirs seldom remain static; they change over time. The current state of a mature field could be vastly different than when first developed. Current advanced technologies can be used to help find new pay zones in older fields. Additionally, reentry capabilities are both decreasing costs and increasing recovery. These advancements in new production and recovery methods can be applied to older fields to help remediate productivity shortfalls.

Finding incremental barrels, maximizing recovery

To maximize productivity from mature fields, operators should consider three approaches: immediate impact interventions, where the goal is to rapidly remediate underperforming wells and produce oil immediately; optimized reservoir management, which focuses on maximizing secondary and tertiary flooding techniques while looking for any pattern optimization; and discovery of new pay zones, which is where the application of new technology is required for detecting and accessing incremental reserves. All three present challenges but also have potential for significant benefits.

Tough times call for new approaches.

Immediate impact interventions

To immediately begin producing, operators must deal with challenges of conformance, cleanout, stimulation and overall process improvements. Fortunately, multiple technologies exist that can improve well production and rapidly increase performance on individual existing wells to achieve more barrels of oil equivalent such as refracturing the reservoir, cleanouts with coiled tubing, Pulsonix acoustic stimulation service to help ensure optimal fluid delivery and an array of conformance chemicals and mechanical shutoffs.

When the proper immediate impact interventions are applied in insightful ways, production can improve; recovery can increase; and opex, downtime and lost production can all be reduced.

Optimized reservoir management

Employing management solutions to access and optimize additional reserves can achieve more barrels of oil equivalent over time. Artificial lift can be employed by means of electric submersible pumps that stroke longer, pull harder, self-adjust when necessary, help dewater and continuously monitor performance. Infill wells can be geosteered to better locate sweet spots and improve contact, and adjustments to sweep efficiency can enhance overall hydrocarbon mobility. When these kinds of production optimization processes are engaged and contact is maximized, enhanced recovery is highly probable.

Finding new pay zones

In the U.S., most mature fields were actually first drilled in the 1950s and 1960s. Logs for these wells were printed on paper and, after initial interpretation, were often archived in boxes and left to disintegrate. However, drilling technology has since advanced exponentially, enhancing the ability to view farther into the reservoir. With current data, new insight can be gained into fieldwide reservoir fluids contact and the different phases. This can help narrow the scope of the reservoir, thereby enabling rediscovery of increased production potential.

New drilling and completions can be targeted for initially undetected pay zones or untapped structures not connected to the main frame. Advanced logging techniques can help find zones that were missed by conventional tools of earlier decades. Once these bypassed or new zones are targeted, drilling and completion plans can be determined to more economically reach them, resulting in more available reserves and increased shareholder value.

Justifying increased spending

While many experts are forecasting a small drop in expenditures for mature fields in 2015, the long-term trend is one of increasing investment to sustain necessary production levels. Since 2011, mature field drilling capex has increased globally, driven by buoyant oil prices and the cost of inflation.

Mature field intervention opex spending during that same period has been driven by rising costs and the increasing importance of mature fields for supplying growing global demand. Globally, the market is split approximately 70:30 in favor of drilling capex spending, and this is likely to remain the case for the foreseeable future.

Much to offer

Globally, mature fields offer a vast opportunity to help meet global energy demands and stabilize financial markets across the energy industry. The Asia-Pacific region has approximately 43% of reserves in mature fields, with the large gas concentrations in Australia's Northwest Shelf being key to that total. Latin America has 24% of its onstream reserves currently considered mature. In Mexico, Pemex is investing heavily in managing the decline of its core assets. Nearly 80% of the Middle East and Northern Africa region's reserves are considered to be mature.

In North America, virtually all of the onshore conventional reserves in the lower 48 states are mature, and spending also is increasing as mature reserves are added, largely in the Gulf of Mexico. Northwest Europe is a mature region, with relatively few new fields projected to come onstream in the near future.

In Russia and Central Asia, 80% of the total onstream reserves are considered mature. With relatively low recovery rates in many fields, significant investment is likely to be made to improve return. Sub-Saharan Africa is a largely nonmature region as a whole; however, West Africa and especially Nigeria contain large concentrations of mature plays.

In total, approximately 70% of the world's reserves are in mature fields. As more advances are made to recover these reserves, these fields become increasingly important for meeting the world's unrelenting requirement for energy. E&P

North Sea is in fight for survival

U.K. players large and small are up for the battle to extend the life of this world-class basin for decades, but how effectively it is responding to the 'lower-for-longer' oil price slump is debatable.

Mark Thomas, Editor-in-Chief

This debate was in the spotlight throughout the recent Society of Petroleum Engineers Offshore Europe event in Aberdeen, Scotland. Although virtually all those speaking agreed that the region is on the right track, the pace of change is more contentious.

According to Bernard Looney, COO of production at BP, times are undeniably tough, with thousands (65,000 according to industry lobby group Oil & Gas UK, he pointed out) having lost their jobs.

But the long-term outlook is brighter, he said during a presentation. "First and foremost, we are in a growth industry, and that is not going to change any time soon. All the forecasts suggest demand for energy will continue to rise. At BP we believe demand will be a full one-third higher by 2035 than it is today. Much of this is driven by population growth—1.6 billion extra people will need energy in this time period—as well as by increasing prosperity, especially in emerging economies.

"Second, despite the environment, the industry here in the North Sea continues to invest billions of dollars to bring new oil to the marketplace," he continued. "Third, here we have a highly skilled, highly experienced and highly engaged workforce right on our doorstep—the envy of many an oil capital throughout the world. And fourth, the North Sea has extensive infrastructure in place, not to mention resources with some 15 Bbbl to 20 Bbbl of oil potentially yet to be produced."

Admitting that the industry needs to drill more exploration wells and push reservoir recovery factors above the mid-forties, Looney said the region still offers rewards. "Last autumn we announced the Vorlich discovery, and earlier this year GDF Suez announced the Dalziel discovery," he said.

Challenges

At the same time, the industry also must be realistic. "There are some real challenges," Looney said. "This is a mature basin with declining production. There are reliability and production efficiency challenges, not to

The U.K. sector continues to see significant new projects unveiled despite the industry downturn, including most recently Maersk Oil's Culzean gas condensate field, an HP/HT reservoir in the central North Sea that was the largest new field discovered in the past decade. The development will see $4.5 billion invested by the field partners. (Source: Maersk Oil).

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Bernard Looney,
COO of production at BP
(Source: BP)

mention high costs. And of course, we have the backdrop of a 50% drop in the oil price. So given all that, is the North Sea worth fighting for? The answer is unequivocally, absolutely it is."

Looney said BP has been going back to basics, making its equipment more reliable, eliminating defects and improving production efficiency. The company's plan is paying off. In 2011 its plant reliability worldwide was 85%; now it is 94%. "With that improvement we are finally beginning to see a major turnaround in our North Sea operating efficiency."

One example Looney flagged "from the frontline" came from Egypt. "One of the team [members] realized that by slowing down supply boats traveling to rigs—running them at 90% of full speed—we would only burn 70% of the fuel. And if we kept the boat outside the 500-m [1,640-ft] zone where possible (on a comfort dynamic-positioning mode), we would consume 80% less fuel. [These are] small things, but they all add up."

The company also is learning from smaller independents and its contractors. "We recently sold a set of assets to a small independent. They do some things very differently from us, and they do them very well," he explained. "One operation cost us close to $1 million, and they did it for half of that. The question for our team was why? So we started a formal learning exercise with them, and it has been fantastic. We're learning a huge amount and applying it to our operations, and they're picking up some things from us as well, helping to make both our businesses better.

"A similarly impressive example is the independents who revolutionized the U.S. onshore sector and have continued to do so in the face of falling oil prices," he added. "One company stated this summer that they estimate for every dollar they spend on their Bakken wells in 2015, they are getting approximately 80% more reserves than they did in 2014. That is a pretty phenomenal result. And the question we should all be asking is what can the North Sea learn from that experience?"

Contractor feedback

Contractors also "hold a mirror up to us as operators," Looney said. This year the company sat down with many of its contractors, including Wood Group and Cape. "At our request they provided us with lists of where we could save money if we changed the way we work. These ideas range from decommissioning plans to scaffolding management and from streamlining contracting norms to reviewing man-marking ratios.

"These are suggestions that will generate and sustain millions and millions of dollars in savings," he added.

BP has been slimming its portfolio for some time, even prior to the price drop. In the U.K. it has divested fewer strategic assets, allowing it to concentrate capital and effort in the central North Sea and the West of Shetland region. Recently, the British government approved Maersk Oil's Culzean Field development, where BP is a partner along with JX Nippon. This project represents $750 million of investment for BP alone and follows on from the $1 billion it is investing in its Eastern Trough Area Project (ETAP) fields announced this summer. The latter will increase recovery from ETAP and extend its life beyond 2030.

One well on the company's Mungo Field saw a fivefold increase in production through an innovative horizontal completion of a new reservoir section, Looney said. "Across the field network we're investing in well stimulation and intervention work, retrofitting new gas-lift capability and [undergoing] a huge two-year subsea pipeline upgrade project as well as drilling new wells."

Looney's end point was that BP's North Sea projects have to compete worldwide in this period of "lower for longer." "The low oil price drives demand up. Demand this year will be about double what it has been averaging the last 10 years. Production in the U.S. Lower 48 will likely show a decrease next year, which would be the first time since 2008. So the market is beginning to work. But at BP we are in the 'lower-for-longer' camp."

High operating costs

Robin Allan, director of North Sea and exploration for independent Premier Oil, was blunter in expressing his opinion about operating costs on the U.K. Continental Shelf, saying they are still too high to make the region economically viable. He also is less of a believer in the amount of collaboration taking place.

Speaking in a separate session from Looney, Allan told delegates it was easier to do business in Vietnam than in the U.K. "I'm not that optimistic. I think most of the


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cost savings we have seen have come from cutting out work that was not absolutely necessary, from reduced fuel costs and from renegotiating such contracts as we were able to renew. I don't think the cost of this basin has reduced to the point where it is economically viable going forward," he said.

However, costs in the company's businesses in Asia are "incredibly much lower on every aspect compared to here," he said. "And it is not just about the weather or the sea state in the North Sea. It has way too high a cost base. Unless the collaborative work goes to a whole new level, I don't see a particularly optimistic future for the U.K. North Sea."

Premier is in the middle of two large developments in the region, Solan and Catcher, and the company is committed to continuing those and looking for others, he said. "But it is not a competitive basin for most of the companies that have a desire to work internationally as we do. There are plenty of other places where the cost of doing things is much less."

Project over-engineering

During Offshore Europe 2015, Proserv CEO David Lamont called for the North Sea sector to stop over-engineering its projects in order to bring costs down.

Lamont said the region had many years of profitable life ahead of it if the industry quickly adopts more collaborative and efficient business practices. But it has some way to go yet. "Everyone knows what needs to be done, but the inertia in the industry is of great concern. The time is now to put a stop to this and make dynamic changes to the way we act and behave. Changing our approach to how we think and do business will see the industry thrive rather than simply survive," he said.

"While we are seeing real efforts and actions to collaborate, it is still the exception rather than the rule," he continued. "Too many people in the industry are still holding their breath for a return to the 'good old days of $100 oil,' which simply won't happen. Even if it does, the practices of the recent past are too wasteful in any case." E&P

Land contractors hunker down

Rig pricing is under pressure as operators delay drilling until 2016.

Richard Mason, Hart Energy

It all changed in July. Falling commodity prices upended the apple cart of hope for land contractors that had grown comfortable with anticipation of a modest improvement in demand for drilling services. Sentiment quickly soured among service providers as demand for oilfield services subsequently evaporated. And land rig pricing, which had dropped to levels that contractors argued were cash cost-neutral at the end of June, began weakening again.

Land drillers are once again stacking out rigs that roll off contract, letting valuable crews go and hunkering down for survival mode in a downturn that is proving unexpectedly sticky. Multiyear contracts have become multiwell contracts but mostly have devolved to well-to-well or pad-to-pad contracts as operators seek only to meet drilling obligations to hold acreage or focus on the very best reservoir rock.

In the Permian Basin, some contractors began promoting a return to footage contracts. Footage contracts bundle services and expand margin but entail greater financial risk. The contracts had largely disappeared from the market during the high-demand era that characterized the industry after the 2010 recovery.

- **Day rates for U.S. land rigs have renewed their slide lower**
- **The benchmark Tier I 1,500-hp AC-VFD unit is down 30% from peak**
- **Demand for drilling services is trending lower**

As for rig pricing, it's not hard nowadays to find a benchmark Tier I 1,500-hp AC-VFD unit capable of pad drilling for less than \$19,000 per day, or more than 30% below peak pricing last year. Considering those rigs make up more than half of the 820 rigs currently turning to the right, it's a sobering commentary on the state of the land drilling market, which this time last year was moving to add more than 190 newbuild pad-capable rigs to satisfy demand in expanding horizontal tight formation development programs.

Average rig rates peaked for all rig classes about this same time last year at just less than \$21,000 per day. At the end of second-quarter 2015, average rates for all rig classes had fallen to \$17,200 per day, according to Hart Energy telephone surveys. That figure is even more significant when considering the majority of rigs that had stacked out in the current downturn were lower priced conventional mechanical units and older electric DE-SCR drive rigs. In other words, although operators were high-grading rigs when possible, overall rig pricing was dropping to levels last seen in the 2009 market collapse.

Indeed, at the end of second-quarter 2015, the only markets where rates for the benchmark 1,500-hp AC-VFD unit averaged above \$20,000 included Louisiana's Haynesville Shale with its deep HP/HT drilling and the emerging SCOOP/STACK play in the Anadarko Basin. Rates averaged \$20,000 in the Marcellus and Utica shales, although rig count was trending lower for both plays in August.

Elsewhere, spot market rig rates for the benchmark Tier I 1,500-hp AC-VFD unit were less than \$19,000 and, in some low demand markets, flirting with \$18,000 as the industry grappled with utilization in the low 40-percentile range.

Lower commodity prices have wiped out operator intentions for activity expansion in 2015 as most adopt a wait-and-see attitude while many plan to avoid expansion until WTI prices move back into the mid-\$50 range on a sustainable basis.

Indeed, several publicly held oil and gas operators are still outspending cash flow in 2015 with hedges expiring and a futures market that seriously discourages further hedging. Many publicly held operators have not yet come to terms with the prospect of living within cash flow, and that will have a near-term detrimental impact on demand for drilling services.

Meanwhile, a sobering backlog of 4,000 drilled-but-uncompleted wells awaits completion before operators see the need to drill additional wells, while pundits have pushed the forecast for recovery out to second-half 2016. It's hunker-down time for land drillers. E&P

Data management grows up

Solutions have been available for decades, and companies are finally starting to embrace them.

RHONDA DUEY
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Recently Katalyst Data Management announced that it has acquired the Perth-based oil and gas data management division of SpectrumData Pty. Ltd., a leading provider of data management, tape transcription and scanning services for the geoscience industry in the Asia-Pacific region. This is not an earth-shattering announcement, just a move to broaden Katalyst's global footprint.

But in a conversation with Katalyst President and CEO Steve Darnell, I learned a few things about the data management business that I didn't know. And I think the biggest thing is how much more the oil and gas industry is trusting third-party companies to store and manage their data.

Ever since the concept of the cloud arose, the industry has been struggling with the pros and cons. Yes, it's nice to have access to data 24/7 without investing in IT infrastructure. But companies spend millions of dollars on proprietary subsurface datasets and don't want that information compromised. Companies like Katalyst are offering an alternative.

Katalyst offers the hosting service as well as the "heavy lifting," which is the actual process of preparing data and information to be loaded in a digital form from reading tapes, scanning documents, metadata indexing and quality control. The data are prepared to be loaded and organized so that any company using the service can access them quickly and easily at any time.

The company also offers a service called SeismicZone, which allows oil companies to license their own proprietary data. "If a company acquires data in the Denver-Julesburg Basin and then decides they're no longer core to its business, it can put those data to market via the SeismicZone online portal and sell a license just like a geophysical contractor sells a license," he said. "Our goal is to provide significant additional value for data we store for our customers. We want data to be active."

Katalyst offers hosting services as well as data scanning. (Source: Katalyst)

Having written about this industry for 20 years, I've seen a lot of these solutions come and go. Darnell said that the industry's mindset had to change. Kelman, the forerunner of Katalyst, started offering these types of services in the mid-'90s and had some success in Calgary in Alberta, Canada, he said. "But to try to take that and expand it, there was some pushback," he said.

Initially there were several issues that made hosted data management unpalatable to oil companies. One was cost. "Costs have come down," Darnell said. "There's been a transition away from licensing technology to accessing technology." He added that iGlass, the data hosting service, is similar to a Google search. "You can go in, you can see the data and you can access them, but you don't have to have everything behind your firewall," he said.

"I think the mindset has changed, and cost has been a big factor," he continued.

Darnell added that the shale boom has created an appetite for legacy data, and this has made information management and data mining so integral to a company's success that large oil companies are now creating career paths for data management professionals.

Darnell said the ultimate goal is to be able to store and manage all types of subsurface data that a company might have. "We are [developing] and will continue to develop our platform," he said. E&P

Lastest GoM lease sale shows lack of quality prospects

Some U.S. senators are lining up against offshore drilling at a time when new prospects are needed.

SCOTT WEEDEN

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Read more commentary at
EPmag.com

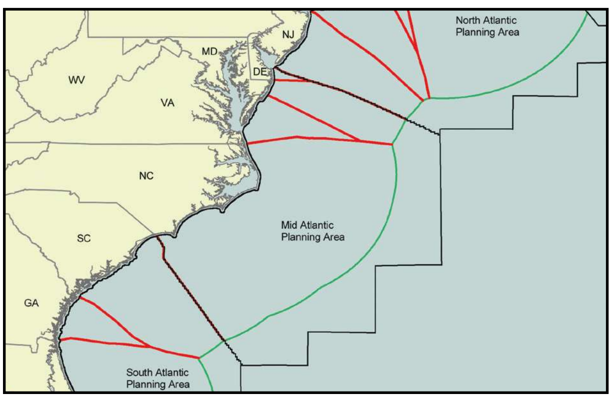
Even though the U.S. Bureau of Ocean Energy Management (BOEM) blamed the lack of interest for the most recent Western Gulf of Mexico (GoM) lease sale on current crude oil market conditions, that doesn't come close to telling the whole story about the worst lease sale with the fewest participants and lowest bids since 1983.

For 33 blocks out of 4,000 blocks offered—a measly 0.8% of 1%—only $22.7 million in high bids were uncovered. Of the 33 high bids, BHP Billiton Petroleum (Deepwater) Inc. had 26 bids.

According to the Aug. 19 BOEM press release, "Lease Sale 246 builds on the first seven sales held under the Obama Administration's Outer Continental Shelf Oil and Gas Leasing Program for 2012 to 2017." If it built on the earlier sales, it didn't build much. The only two places where the federal government is holding lease sales are the western GoM and the central GoM.

It makes one wonder what kind of results there would have been in a down market if the sale had been in the eastern GoM, Baltimore Canyon or off the Carolina coast. The western GoM has never drawn an overwhelming amount of interest, and having yet another western Gulf sale won't change that.

The federal government puts a lot of spin on Gulf lease sales, but the pickings are getting slimmer as the same blocks get offered over and over again. If the government wants to increase interest and boost revenues, it would behoove BOEM to open new areas.



Opening the East Coast offshore to exploration would generate considerable industry interest. (Source: BOEM)

Given the opposition to offshore drilling in Congress, though, opening new areas is easier said than done. Following the federal government's approval for Royal Dutch Shell to drill offshore Alaska, 12 U.S. senators—all of whom oppose offshore drilling—in a letter asked the Securities and Exchange Commission (SEC) to "conduct a full review of the disclosures of companies currently drilling or planning to drill for oil offshore in the Gulf of Mexico and the Atlantic, Pacific and Arctic Oceans and take necessary action to protect investors and maintain the integrity of the market."

The senators include Ben Cardin (D-Md.), Sheldon Whitehouse (D-R.I.), Dick Durbin (D-Ill.), Jeff Merkley (D-Ore.), Elizabeth Warren (D-Mass.), Barbara Boxer (D-Calif.), Bob Menendez (D-N.J.), Patrick Leahy (D-Vt.), Richard Blumenthal (D-Conn.), Brian Schatz (D-Hawaii), Bernie Sanders (D-Vt.) and Cory Booker (D-N.J.).

Except for the senators from Illinois and California, not a single other state produces oil, gas or coal to any great degree. But those other states sure do consume oil, gas and coal. "Maintaining the integrity of the market" must mean that those states aren't willing to contribute to U.S. energy supply.

"America has never been more energy secure with an abundance of domestic oil. There is no need to expand drilling into waters less able to recover from a spill," according to the senators' press release.

But that's a very short-term view. Energy-consuming states also need to be looking at their long-term need. E&P

Scott

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Waste not, want not

The spirit of innovation continues to drive the industry's search for new ways to do more with methane emissions.

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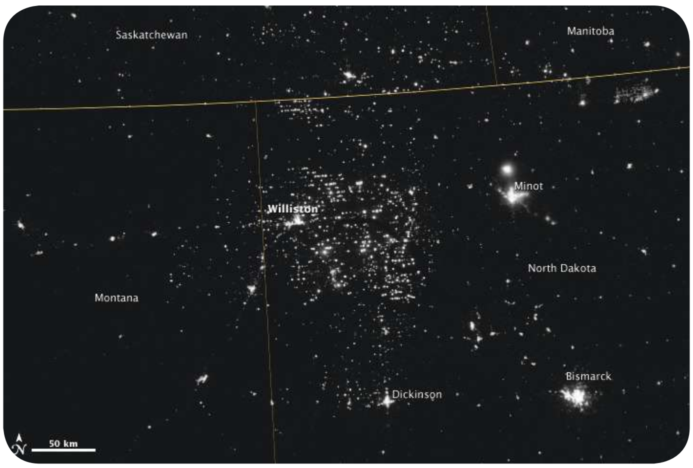
Read more commentary at
EPmag.com

It was the satellite image that launched millions of furrowed brows skyward. Scattered across the image's inky expanse of sparsely populated northwestern North Dakota were the bright blips that indicated the prolific oil and gas operations underway in the Bakken Shale. The nighttime image, captured on Nov. 12, 2012, by a NASA satellite, showed the white specks of light associated with drilling equipment, temporary housing and gas flaring.

In the close to three years since the image was snapped, the industry's response to those flares and unseen vapor emissions has been swift. There is an increased focus and interest in the technologies that repurpose emissions. More operators are using field gas to keep the generators and engines running on their fields.

In August the U.S. Environmental Protection Agency (EPA) proposed new standards to cut greenhouse gas emissions and smog-forming pollutants from oil and gas facilities. The proposed standards expand on the rules enacted in 2012 and are expected to reduce the equivalent of 7.7 million mt to 9 million mt of CO_2 in 2025 at new and modified facilities, according to the EPA.



The bright lights of North Dakota's Bakken Shale, as seen from space, were captured in 2012. (Source: NASA)

To accomplish this reduction, the proposed standards would require oil and gas processing and transmission facilities to find and repair methane leaks; capture methane and smog-forming volatile organic compounds from hydraulically fractured oil wells; and limit emissions from pumps, compressors and other equipment.

Jack Gerard, president and CEO of the American Petroleum Institute, responded to the proposal, saying in a press release that the rules were unnecessary.

"The oil and gas industry is leading the charge in reducing methane," he said in the release. "Even as oil and natural gas production has surged, methane emissions from hydraulically fractured natural gas wells have fallen nearly 79% since 2005, and CO_2 emissions are down to 27-year lows. This is due to industry leadership and significant investments in new technologies."

In the same way that companies squeezed additional value from produced water, new technologies are being developed that can maximize the value of methane emissions. One example is a turnkey solution for converting natural gas flares into synthetic crude oil or transportation fuels.

The FLARE BUSTER developed by Black & Veatch and Emerging Fuels Technology Inc. uses a proprietary Fischer-Tropsch reactor/catalyst system to convert wellhead gas into room-temperature, pumpable synthetic crude oil that can be combined with crude oil or turned into transportation fuel blendstocks, according to a press release.

"Waste not, want not" is a lesson that the oil and gas industry has learned the hard way at multiple points in its history. Thankfully, today's advancements in technology are making it a little less painful. E&P

Jennifer

Battle for North Sea heats up

Fairfield changes tack, but don't ring the death knell yet.

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Read more commentary at
EPmag.com

How quickly things change. Little more than a year after it took full control of the Dunlin cluster of fields in the U.K. North Sea with the aim of squeezing as much as possible out of it, Fairfield Energy has changed tack sharply and started the job of decommissioning the fields.

Fairfield was set up more than a decade ago with the remit of breathing new life into old North Sea fields that were no longer deemed viable by major operators.

The company, which boasted shareholders including former BP boss Lord John Browne of Riverstone, was supposed to ride to the rescue of the U.K. Continental Shelf.

Ian Sharp, Fairfield's COO, said when the deal for Dunlin was done last year that the move was a "positive and logical progression for Fairfield Energy and demonstrates our commitment to the North Sea."

Fast forward a year and with the oil price halved from more than $100/bbl to less than $50/bbl and a huge leap in contractor rates in the region to contend with, Fairfield is turning from a swashbuckling producer to a decommissioning specialist.

It has put its old fields up for sale and launched the take-down program for Dunlin because of the "asset's life cycle, the depressed oil price and challenging operational conditions in the North Sea."

Production from all Dunlin cluster fields was shut down in mid-June 2015, although the Dunlin Alpha platform will remain fully manned and operational. The platform will continue to export third-party oil into the Brent system pipeline.

The phased decommissioning process is anticipated to take a number of years, with high offshore activity levels maintained throughout.

The closure of the fields is all the more disappointing because Fairfield has done a great deal of work on the Dunlin, Dunlin Southwest, Merlin and Osprey fields since acquiring them from Shell and its partners in April 2008. The deployment of new technology and the introduction of operational and efficiency improvements had resulted in a significant extension of its life cycle.

But in the face of events conspiring against it, Fairfield has taken what may seem like a pragmatic approach. And it isn't the only one. Maersk Oil recently announced that it is closing its Janice Field in the North Sea.

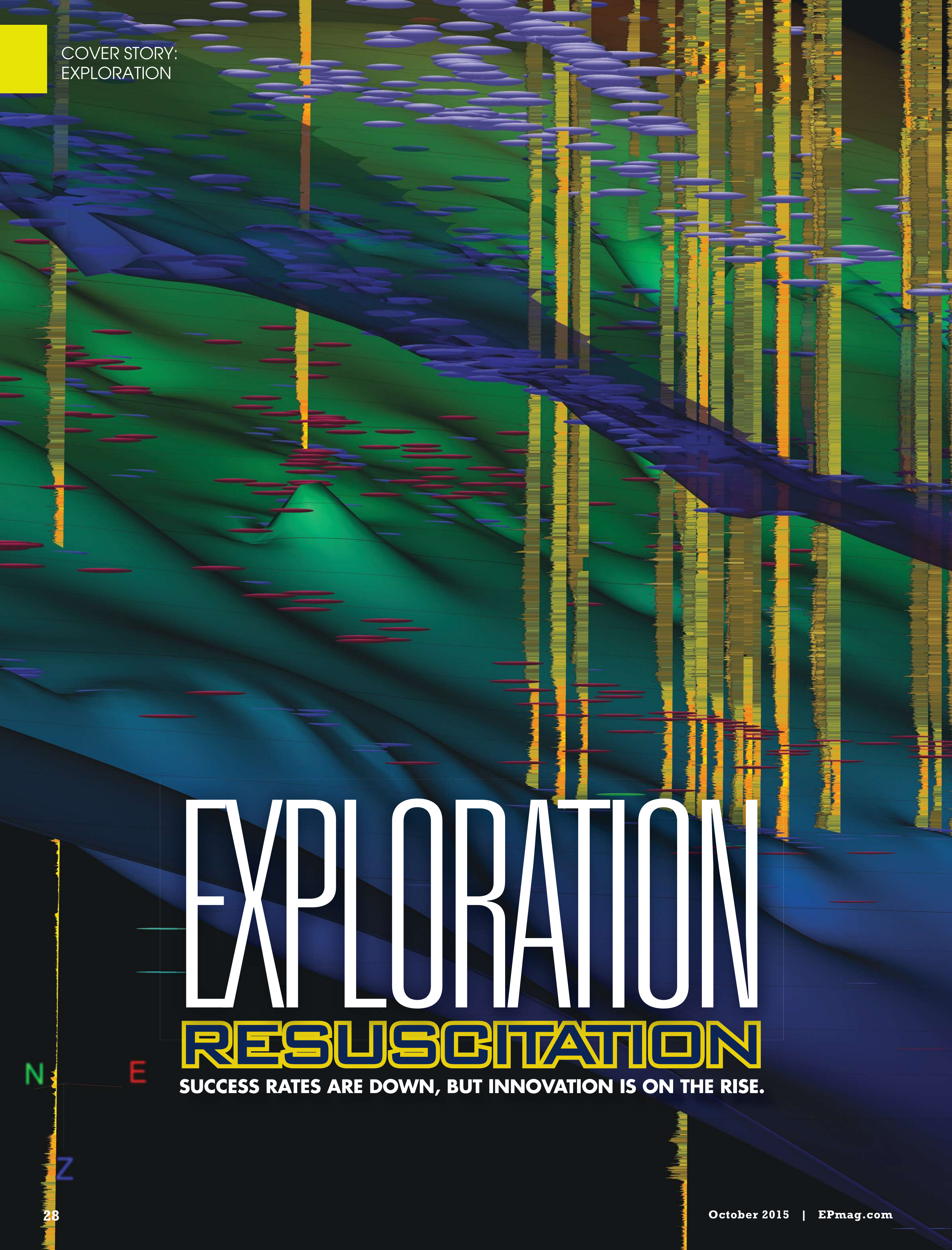
This isn't the beginning of the end, however, according to those who are battling to extend the life of aging fields.

> "We must respond on an urgent basis to make sure that we do not lose more of these assets."
> —David Lamont, Proserv

"It's not too late for the North Sea, but you wouldn't want too many Dunlins," said David Lamont, CEO of Proserv, during the Offshore Europe Conference Sept. 8. "I'm really optimistic about the North Sea for a number of reasons," he continued. "I would even go as far as to say that the lower oil price is good for the North Sea because it is making change compelling rather than something that could take a long time to introduce.

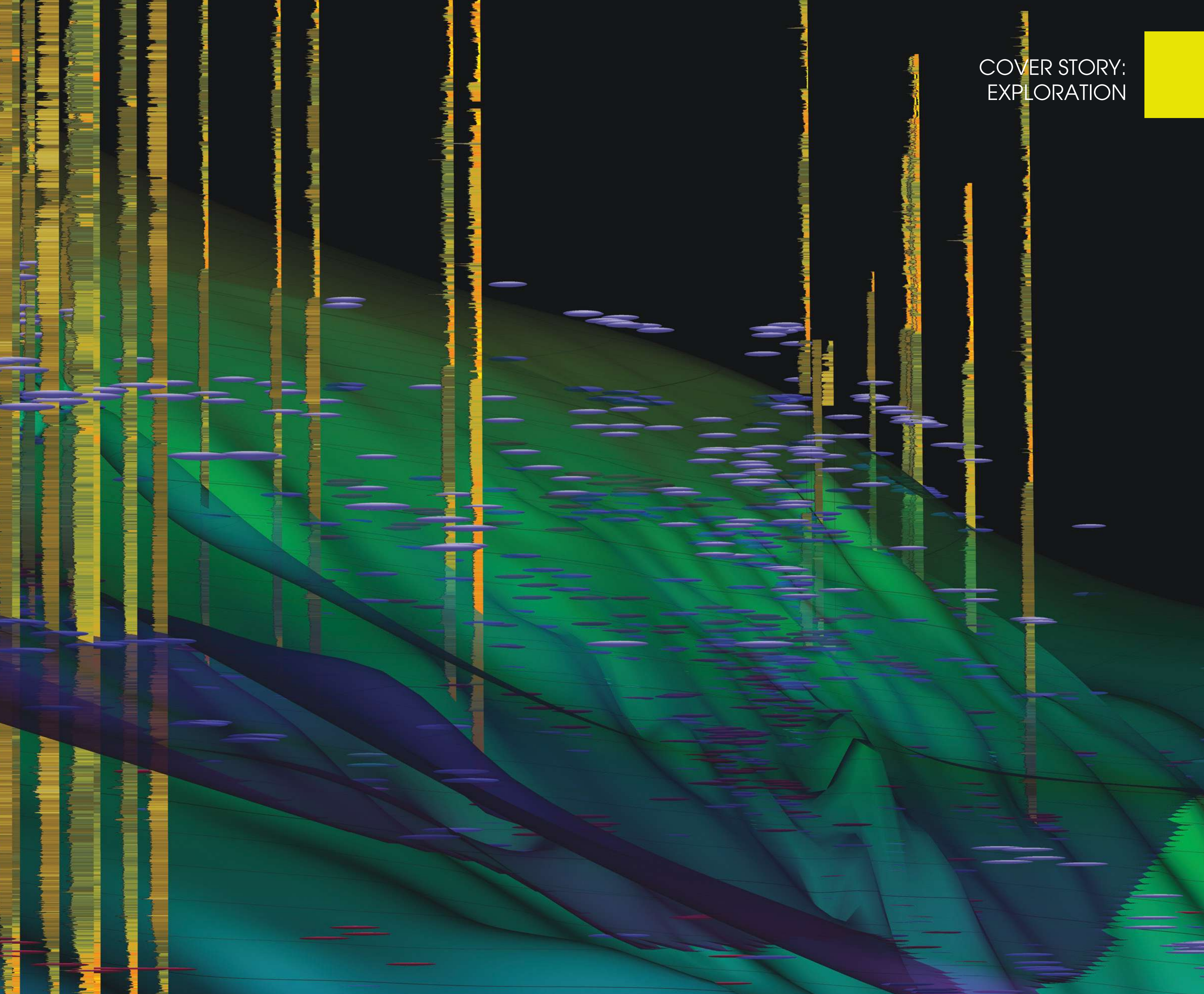
"There will be those cases, but with more intervention early we can extend the life of assets," he added. "That will snowball in a more positive way because we can be putting more production through the old assets. The big fear of the industry is that we're not responding fast enough to save some of these assets. We must respond on an urgent basis to make sure that we do not lose more of these assets."

We shall watch and wait. E&P



EXPLORATION RESUSCITATION

SUCCESS RATES ARE DOWN, BUT INNOVATION IS ON THE RISE.



A recent study on exploration success rates indicates that big discoveries, particularly of oil, are few and far between. In recent years, companies, particularly the majors, have become enamored of frontier exploration. But their enthusiasm has not resulted in big finds.

But in the special section that follows, companies that will be exhibiting at the Society of Exploration Geophysicists annual meeting describe new technologies that promise to reverse this trend. From acquisition to processing to interpretation to potential fields, service companies continue to lead the way in innovation.

Advances in seismic imaging have not always been sufficient to target high-quality reservoirs.

Is the easy oil really gone?

Discoveries continue to be made, but the industry's track record is showing signs of weakness.

Rhonda Duey, Executive Editor

Just reading the headlines, it seems that the oil and gas industry continues to find enough hydrocarbons to power the world for centuries.

Recent highlights include:

- Statoil, which announced its eighth discovery in Block 2 offshore Tanzania in March;
- Kosmos Energy, with a significant find offshore Mauritania;
- W&T Offshore, announcing a discovery at Ewing Banks Block 910 in the Gulf of Mexico (GoM);
- Pemex, reporting major oil and gas discoveries in the shallow-water GoM with estimated reserves of 350 MMbbl;
- Exxon Mobil, with its Liza-1 discovery offshore Guyana; and
- Eni, which discovered a "supergiant" gas field offshore Egypt.

These are just the offshore discoveries. Onshore, both conventional and unconventional reservoirs continue to be discovered or developed.

But a recent report by Richmond Energy Partners, "The State of Exploration," indicates that all is not rosy on the exploration front. The study, released in April

2015, examined the exploration success in 2014, a year in which oil prices were robust until the November downturn. It was not a pretty picture.

Declining performance

It's not that the industry stopped exploring. It's just that the results were often disappointing.

In the executive summary, several conclusions were drawn:

- Discovered volumes and average commercial success rates in 2014 were at a seven-year low;
- 2014 was a record high for frontier drilling, but the success rate remained less than 10%;
- With the cost structure prevailing before the oil price downturn, more than 50% of the discovered fields were uneconomic at $60/bbl oil;
- Some exploration strategies have been more successful than others, and these vary greatly even amongst companies with the best track records. "[Having] focus and discipline is the most reliable route to sustained performance," the summary noted. "This old mantra may have been forgotten in the heady days of $100-plus per barrel oil prices;" and
- Conventional exploration continues to be relevant since low-cost-to-produce discoveries can still be made. "Lower oil prices herald an era of more focused exploration, albeit on an opportunity set tempered by the lack of frontier success in recent years," the summary noted.

Keith Myers, a managing partner at Richmond Energy Partners, explained that this study has been conducted for several years. It reviews exploration performance over a five-year period.

"What's become apparent is how poor the performance was in 2014, and that's even before the oil price crashed," Myers said. "Exploration was already facing headwinds."

The summary noted that commercial volumes discovered in 2014 were the lowest in five years, a 42% drop from 2013 and more than a 60% drop from the peak discovery year of 2012.

Geographically, only nine of the 131 basins drilled resulted in more than 500 MMbbl of gross oil discoveries.

"The presalt Santos play remains by far the most significant oil play to have emerged this century, and the presalt of the Kwanza Basin is the only other [greater than 1 Bbbl] oil province discovered since 2008," the summary noted.

The study examined four companies that were the most successful in terms of volume: Lundin, Tullow, Talisman and Cobalt. The differences in their strategies were notable. Cobalt, for instance, has a presalt and subsalt focus and is very much play-focused on deepwater. "These are expensive wells," Myers said. "In the case of the [GoM], it was expensive to access acreage as well. They spent nearly $1 billion on leases."

Talisman has taken more of a geological focus, including foreland basins in Colombia and fold belts in Kurdistan. Lundin has focused on overlooked plays in proven mature basins, while Tullow has pursued the most diverse strategy both geographically and in terms of play maturity.

Gas discoveries have not been the issue. It's oil discoveries that are scarce; hence, the study focused on successful oil finders. Myers said that the gas discoveries flattered the boe number, so statistics on a boe basis look more positive than the numbers for oil discoveries alone.

"There were a record number of frontier wells drilled in 2014," he said. "But the success rate of these wells hasn't significantly improved in terms of yielding new commercial plays, particularly for oil. The plays that have emerged have been relatively modest in scale; very few of them have been more than 1 Bbbl in size."

Can technology help?

Exploration technology has made enormous strides over the past couple of decades, but sometimes it's still not enough to help these numbers along. "The main

Operators are anticipating a move toward lower risk exploration targets. (Source: Inova)

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Reward awaits those willing to explore during downturn

Cookie-cutter model leads to marginal price economics.

Emily Moser, Oil and Gas Investor

It might be hard to imagine, but a lot of opportunity still exists during a downturn, according to Jim Manatt, chairman and CEO of Thrust Energy Inc.

"In our lifetime—I think I've said this before but I mean it this time—you're not going to buy leases for less than you can get them right now," Manatt said during the Summer NAPE business conference Aug. 19.

For Manatt, reward awaits those who are willing to re-emphasize exploration and be the industry's next trailblazer.

"I know that I'm with the 150 most pathologically optimistic people in the industry right now—we're all here at Summer NAPE," he said. "I'm sure you see your glass as half full, and it's going to get fuller." The glass, he added, would begin to fill up if companies broke out of the cookie-cutter model the industry has found itself in.

Ten years ago, the model was shale deals. Today, the trend has shifted toward "cash flow-neutral" deals, Manatt said. Oil and gas companies in the U.S. have been focusing primarily on "farming operations," or exploration with minimal risk. The desire for exploration seems to have dried up.

And with the cookie-cutter model comes marginal price economics. "No management seems willing to entertain any risk for future or new reserves," he said. "The flip is you get to pay the price for the proven acreage and your position on marginal returns."

However, the reward for being the first company to explore in an area can be exponential, as was evident in the early shale deals. Yet not many companies seem to be willing to take that gamble, according to Manatt.

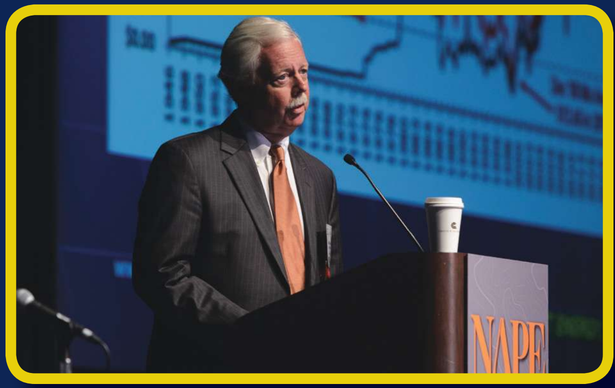
"You're either replacing your reserves or you're going out of business, and a lot of us are just slowly going out of business right now," he said.

For Manatt, there's no time like now for change.

"It's time to take maybe 10% to 15% of the operating budgets and allocate them to big-return potentials, and with that comes some risks," he said.

Manatt acknowledged that the remaining exploration opportunities in the U.S. might be challenging because of the mature oil and gas environment. What's left is a lot more difficult to get at than what has already been found, he said.

Developing new technology will open up what would have been a bypassed opportunity. Technology will drive future development, just as it did in the early days of shale, he said.



Jim Manatt addresses the crowd during the Summer NAPE Business Conference. (Source: NAPE)

An example would be the marriage of hydraulic fracturing and horizontal drilling, which was pioneered by George Mitchell. Mitchell's willingness to accept risk enabled his company, Mitchell Energy & Development Corp., to access natural gas deposits in the Barnett Shale in North Texas in the 1980s and 1990s.

"You have to solve a problem. George solved a big one," Manatt said. "He spent 20 years and untold millions of dollars knowing that there was a way to get the gas that he knew was in the Barnett."

After all that time, money and disappointment, Mitchell was finally rewarded. In 2002, he sold his company to Devon Energy Corp. for $3.1 billion.

Manatt has strived to follow a similar path as Mitchell.

At Thrust Energy, which he founded in 1995, Manatt said the goal is to "recognize what hasn't been seen before in the subsurface ahead of the competition." This will create economic value for the company and its shareholders.

Headquartered in Roswell, N.M., Thrust develops and leases within a 458,000-acre liquids-rich shale project in the Permian Basin of New Mexico. The company recently found a ground-floor working-interest partner for the project. Manatt said he could not reveal the partner just yet.

"I will tell you that I've been on the street for five years trying to sell my deal, and I've had 150 people slam the door in my face, most of them politely," he said. "But things are changing." ■

technical reasons for failure of the frontier wells are reservoir [presence and quality] and charge access [migration]," the summary noted. "3-D seismic technology is not changing the performance of frontier drilling. For example, since the 2007 Jubilee discovery, of the 67 frontier wells that targeted analogous deepwater Upper Cretaceous prospects at a cost of [$6.85 billion], there have been just two commercial discoveries—one oil at Pitu in Brazil and one gas at Mzia in Tanzania." Exxon Mobil's Liza discovery in Guyana has recently added a third.

Added Myers, "The issue is that often when oil is being found, it's not in commercial-quality reservoirs. Especially in the plays that have a stratigraphic component, it's essential to have 3-D seismic. But it has not led to an improvement in frontier success rates from a commercial perspective because of the difficulty in mapping effective traps and good-quality reservoirs."

So what's the problem? Myers said that questions abound. Is the industry not finding the emerging oil plays because they're not there to be found? Do explorers have the right tools? Are companies drilling in the wrong places?

"We have opinions, but we don't have the answer," he said. "It's certainly not from lack of effort. The industry has been trying very hard and throwing a lot of money at it. But it hasn't cracked the code."

However, with lower oil prices come lower costs for technology. In a recent presentation, Dr. Nick Cooper, executive director and CEO for Ophir Energy, noted that the current exploration market offers "a compelling opportunity."

"The risk profile of the geology has not changed, but the cost of assessing the subsurface risk has fallen dramatically," he said. "It is well documented that rates for both seismic vessels and drilling rigs have fallen, but perhaps the most important change is that licences for prime acreage can now be acquired without having to undertake firm drilling commitments.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A change in strategy

In many cases, high-risk wells were drilled for reasons other than an expectation of a huge discovery, such as the aforementioned commitments made in bid rounds or acreage acquisitions. There also was an increased appetite for frontier drilling after the 2009 downturn.

"The larger companies all tend to move together, and they decided that frontier was the thing," Myers said. "So they all increased their level of frontier drilling."

Given the current downturn, companies are expected to return to a more conservative approach. Richmond Energy partners expects a 40% drop in exploration drilling in 2015 and a change in focus toward near-field, faster-to-develop discoveries.

"Exploration is still relevant if you can make low-cost-to-develop discoveries that are economic at $50/bbl oil," Myers said. "Conventional exploration still has a place in oil company strategy. But there has to be more focus than there has been, and inevitably that means fewer wells."

The summary noted that at a benchmark price of $70/bbl, a large number of discoveries made between 2008 and 2014 become unviable at current capex and opex levels. "The assessment shows that standalone oil fields of [100 MMbbl] in shallow water may only just be economic at current prices and costs, and standalone deepwater discoveries need to be [greater than 250 MMbbl] in size," it stated.

The future of frontier exploration

With a more sober approach, it's likely that this dismal trend can be reversed. The Exxon Mobil discovery is a good case in point. The discovery well, based about 193 km (120 miles) offshore Guyana, encountered more than 90 m (295 ft) of high-quality oil-bearing sandstones. The Stabroek Block upon which the well was drilled covers an area of 26,800 sq km (10,348 sq miles). Currently Exxon Mobil and its partners, Hess Guyana Exploration Ltd. and CNOOC Nexen Petrolum Guyana, are analyzing the data to determine the full resource potential.

"This could lead to excitement in Suriname and Guyana," Myers said. "Liza will be sure to stimulate activity as long as the border dispute doesn't hinder things too much. Nothing is ever simple politically, unfortunately."

Other areas that hold potential are the Mexican GoM and Atlantic Canada, he added. But with continued depressed oil prices, a quick bounce-back in exploration is unlikely.

"It would require a material success somewhere in a new play opening up to see a big step-up in exploration," he said. "But reduced activity might not be a bad thing. The industry was drilling a lot of very expensive dry holes, which was not helping the overall situation.

"We've got to get these high-risk exploration wells in plays that don't seem to be working out of the system, and then the industry can move on again." E&P

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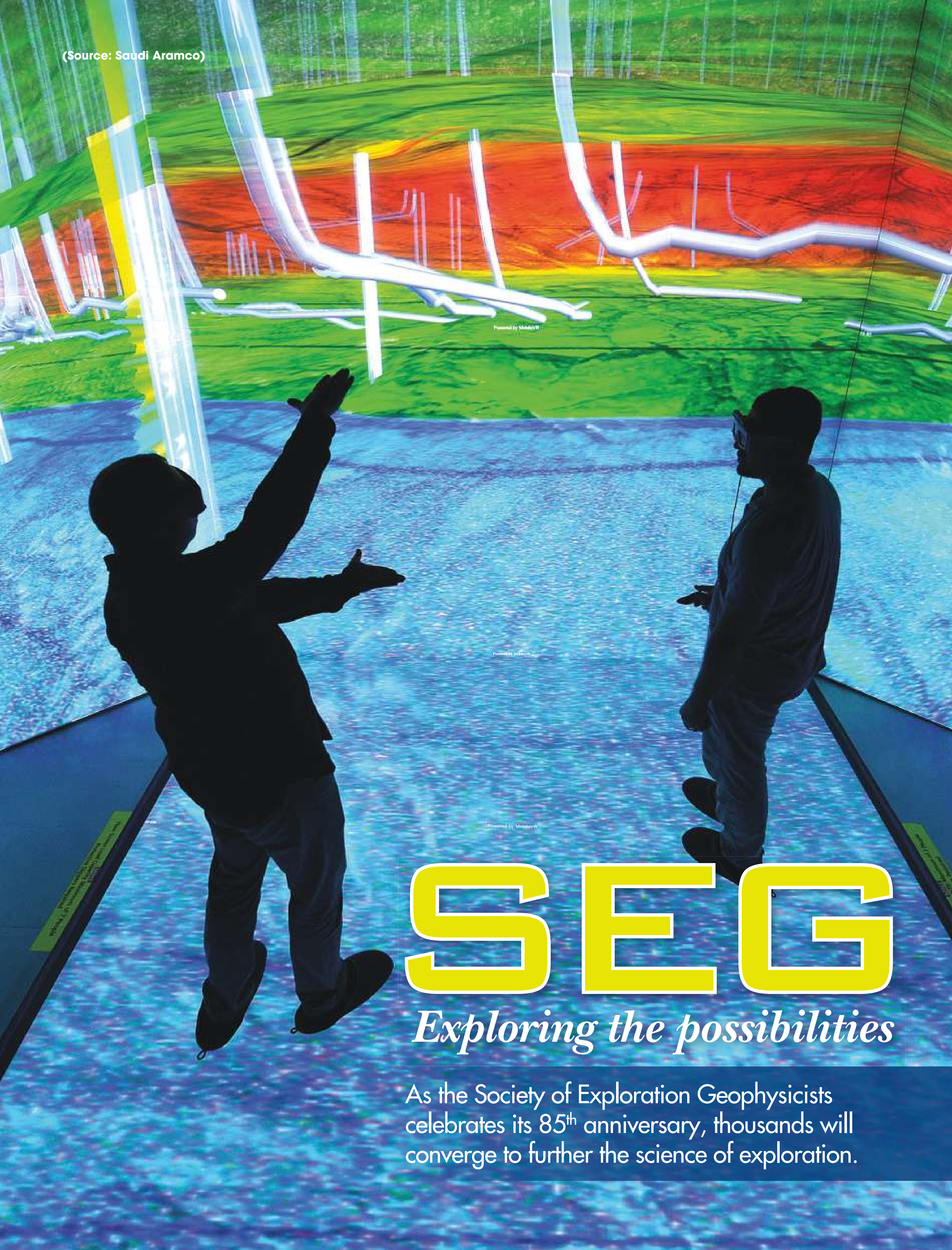
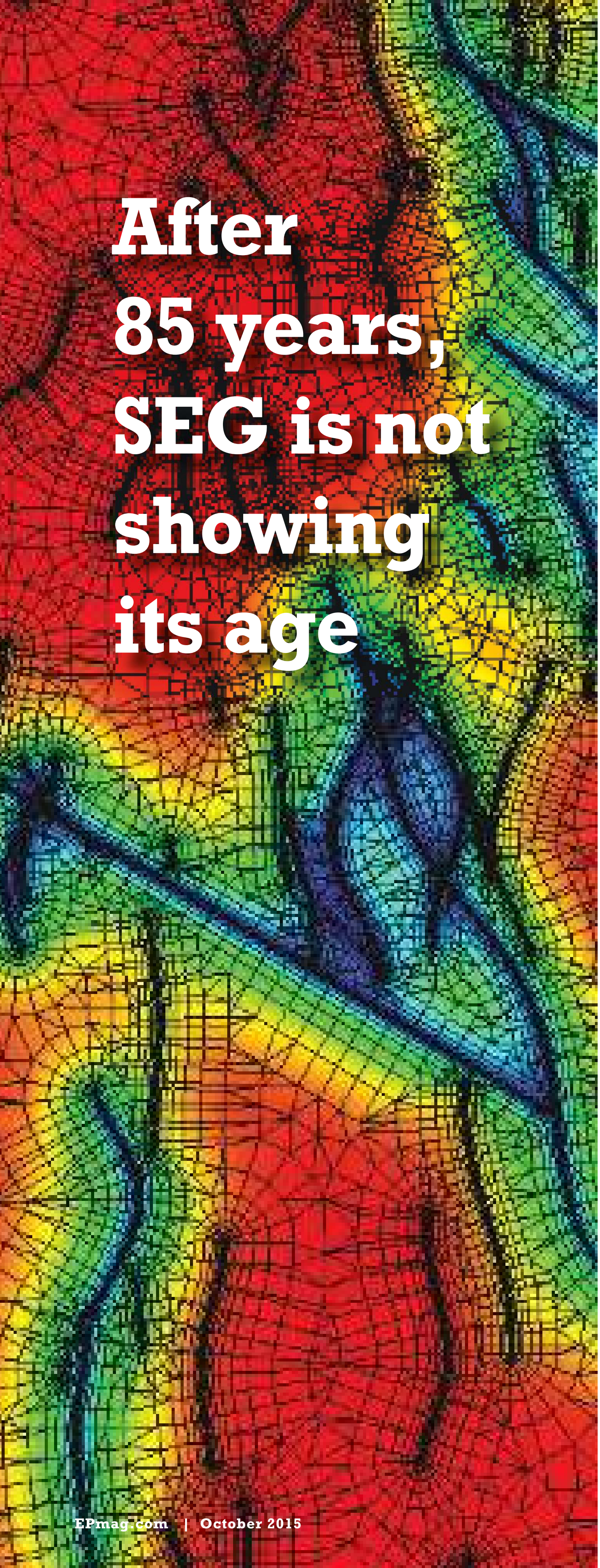


(Source: Saudi Aramco)

SEG

Exploring the possibilities

As the Society of Exploration Geophysicists celebrates its 85th anniversary, thousands will converge to further the science of exploration.



After 85 years, SEG is not showing its age

Annual convention continues to showcase top exploration technologies.

Rhonda Duey, Executive Editor

It all started in Houston on March 11, 1930. According to an article in *The Leading Edge* published during the Society of Exploration Geophysicists' (SEG's) 75th anniversary 10 years ago, events in the 1920s that proved up seismological and gravitational exploration methods seem to have spurred the desire to form a society that specialized in exploration geophysics.

"During that decade, exploration methods based on seismology and gravitation were confirmed in the field, the first well logs were recorded, the first contracting company was started (and several others were about to be created) and, most importantly, the practitioners of these then-arcane techniques were finding lots of oil," wrote then-editor Dean Clark. "Thus, by early 1930 all of the elements were in place to support a professional society dedicated to the new discipline."

Since that time SEG has gone on to be a highly respected global society dedicated to the study of geophysics, not just for exploration purposes but also to solve worldwide issues such as tsunami preparedness, earthquake preparedness, habitat management, landslide preparedness, volcano preparedness, pollution mitigation and water management. In addition, the society has previewed some of the exciting developments taking place in exploration geophysics, most recently including full waveform inversion, wide-azimuth seismic, broadband seismic and more.

This year's program includes a week of short courses, events and technical presentations as well as the exhibit, which will showcase almost 400 companies and their wares. Despite the downturn, the event, which takes place in New Orleans and comes a little more than 10 years after the devastation of Hurricane Katrina, is expected to be quite successful. "Wisdom dictates that in trying times lie the best opportunities," wrote Julius Doruelo, SEG annual meeting steering committee general chair, in his opening letter to attendees. "There is no better example of that than New Orleans—it is ironic that the 2015 event will be held in the very city whose recent history serves to remind everyone not to lose sight of brighter days in the future." E&P

Recent enhancements to Halliburton's DecisionSpace unconventionals offers asset teams a geoscience, reservoir and engineering solution. (Source: Halliburton)

A big job in tough times

SEG's incoming president promises a strong, stable society.

Rhonda Duey, Executive Editor

When John Bradford, a professor of geophysics at Boise State University, agreed to run for president of the Society of Exploration Geophysicists (SEG), he had no idea that by the time the gavel was passed to him the industry would be facing a severe downturn.

"I do have some ideas for the society," Bradford said, "but I have to say that the list of priorities has changed from when I agreed to run."

Priority number one, he said, is to keep the society running and keep it sustainable. Bradford said the society went through the budget planning process in May and budgeted for a significant reduction in revenues. "Our major contributors are oil companies, and most of our members work in the oil industry," he said. "So when they're hit, that has a hit on our budget as well."

But it's not all doom and gloom. The hope is that, through careful planning, SEG won't have to eliminate any major programs. Bradford also said that the annual meeting in October will give the organization an opportunity to gauge the health of the industry to better plan for 2016.

Already SEG is making concessions for the members who have lost their jobs due to the downturn. Its career center enables members to post their resumes, view current job postings, get advice about networking and career building and get tips from members on how to make the most out of their education and career. Unemployed members also can take advantage of discounts on products and programs.

"We have a dues waiver program for members who have been laid off," Bradford said. "And unemployed members can get a 50% discount in their registration for the annual meeting."

New technology

While the mood in the industry is tense, it hasn't stopped innovation from occurring, and SEG will continue to be a showcase for the latest technological advances. Bradford said that one of his areas of interest is the use of passive seismic sources to image the subsurface. "We're doing that both in the oil industry and in other areas of applied geophysics, like near-surface geophysics, where we're looking at groundwater problems or engineering problems," he said, adding that passive sources can be things like cars driving past or nearby trains. A related area of interest, he said, is microseismic, where the source effort is typically hydraulic fracturing. "We can use that information to characterize the subsurface," he said.

John Bradford

Another area of interest to Bradford is full waveform inversion (FWI) and the advances that have recently taken place. "The methodology of FWI allows us to make full use of all of the information that's available in a seismic signal," he said. "That has been slowly developing over a period of time. It's getting to a point of maturation at this stage where it's quite useful, and what we can get out of it is pretty exciting."

Plans for the future

Despite the downturn, Bradford has ambitious plans for the organization. SEG recently hired a new executive director, and Bradford said it's time to do some strategic planning.

"Going through a formal strategic planning exercise and getting that in place so that we have a clear direction for the society for the next five to 10 years is probably the No. 1 objective that I have," he said.

A secondary objective is to grow SEG's near-surface technical session, which was formed last year. "Getting that group well established and on firm footing for the future is a goal I have," he said.

Third, Bradford sees a dearth of women in applied geophysics teaching positions. "I'm a geophysics professor in an applied geophysics group, and we have no women faculty in our group," he said. "While there is a disparity in many science, engineering and mathematics disciplines, applied geophysics is one of the disciplines with the lowest percentage of female professors.

SEG offers several resources for members who have been laid off as well as employed members and students. (Source: SEG)

"We have a women's networking committee, a group that was formed within SEG to promote women's issues in both industry and academia. One of the things I would really like to do is establish a program to help encourage and support women faculty members in applied geophysics."

Each SEG president has brought his or her own set of objectives to the office, and this has paid off over the years in a stronger society better able to weather downturns. Bradford said that one of the efforts was to globalize the society's membership. This resulted in rapid growth up to about 2010, and membership is now stabilized.

Stability also has been enabled by not relying on a single event for the bulk of the revenue. "I'd say probably what has had the most impact on our stability and ability to weather the downturn is the diversification of our revenue portfolio," he said. "Our primary activity, and what supports most of the SEG programs, is our annual meeting. But we run, both individually and with other organizations, other large meetings around the world, and those help make us less dependent on one single event to have a broader range of sources that we can draw from."

He added that SEG recently added a second building to its campus in Tulsa, Okla., which is expected to provide a "sustainable and stable source of income" in the future.

Hand-in-hand with the downturn, of course, is the "crew change." But Bradford doesn't see it as a major threat to SEG. Many retirees maintain their active memberships, and the society also offers a program for them to get a membership at a reduced rate. Student membership has grown substantially over the years, and one of Bradford's goals is to get them to convert to professional membership once they enter the workforce.

"We try to attract and maintain these young professionals so that we have the younger generation as a stable and long-term part of our membership," he said.

In all, Bradford's message is that SEG is not looking inward trying to survive but is offering its members the continued benefits of a professional society. "We're feeling the pain that our members are feeling," he said. "We're doing what we can to remain stable and continue offering services, and we have programs that are available to assist our recently unemployed members as best we can." E&P

Louisiana subsurface, Mississippi Delta are centers of attention

SEG's Applied Science presentation will cover delta sedimentation, evolution and coastal restoration.

Ariana Benavidez, Associate Editor

There is "a wide range of really interesting problems" to study along the Louisiana coast, including the Mississippi Delta, according to Torbjörn E. Törnqvist, this year's SEG Applied Sciences Education Program speaker. The popular program, which targets high school students, is scheduled for Wednesday, Oct. 21, at the Ernest N. Morial Convention Center.

In his one-hour presentation, "Why does the Louisiana subsurface matter," Törnqvist will discuss how studying the Mississippi Delta subsurface can teach geologists how this coast functions and how it may be changing in the future. In addition, one of the main topics currently being discussed in Louisiana is coastal restoration, such as big river diversions, he said. He will discuss what can be done to restore the coast "because it has degraded a lot, especially in the past century," he said.

"It's really essential that we include all the knowledge we have about how sedimentation in the delta actually works and how it has worked in the past—that will give us the best benchmark for what we can expect in the future," Törnqvist said.

> "The Mississippi Delta has a very special place in geology." —Torbjörn E. Törnqvist

Törnqvist is the Vokes geology professor in the Department of Earth and Environmental Sciences at Tulane University. From 2006 to 2013, he was director of the National Institute for Climatic Change Research Coastal Center, a U.S. Department of Energy funding agency supporting basic research to reduce the uncertainty about the future of coastal ecosystems nationwide resulting from climate and sea-level change.

Most of his current research focuses on the Mississippi Delta. One issue in this area is delta evolution. "A better understanding of delta evolution can help us predict how the Mississippi Delta will look in the future," he said. This also is a favorable region in which to study past rates of sea-level change, something Törnqvist works on extensively.

Torbjörn E. Törnqvist

Originally from the Netherlands, where he received his education, Törnqvist came to the U.S. to study the Mississippi Delta. "The Mississippi Delta has a very special place in geology. It's kind of the most common textbook example of what a delta looks like," he said. "Pretty much every geologist around the world will be at least familiar with it, and many will have actually read something slightly more detailed about the delta. So for me, it was kind of an obvious choice to focus some of my own work [on this delta]."

Törnqvist said a good amount of groundwork has been done on this area, "and it's something we can build on." The oil and gas industry has conducted many studies on the Mississippi Delta and Louisiana coast to understand how delta sedimentation works, he continued. "There are many different reasons why doing geology [in the Louisiana subsurface] is beneficial. There is a lot going on in the subsurface of Louisiana, and it affects everyone who lives here," he said.

The Applied Sciences Education Program has limited seating, and reservations are required for students and teachers. Students and teachers should contact the SEG business office via email at *jcole@seg.org* or via phone at 918-497-5574. The first 200 students and teachers to register for the program will be invited to participate in a special extended program, which includes a guided tour of the convention geophysical exhibits and activities related to geology and geophysics. Annual meeting delegates do not need to register to attend the lecture. E&P

From concept to commercialization: towed-streamer EM

Technology can provide an increase in data density and acquisition efficiency, resulting in cost-effective, accurate mapping of subsurface resistivity.

Joshua May, PGS EM

What is the meaning of efficiency? One interpretation is simply to achieve more for a lower outlay; this theme has been synonymous with PGS' towed-streamer electromagnetic (EM) technology from concept to commercialization.

Acquisition efficiency

Three-dimensional towed-streamer EM acquisition rates of up to 250 sq km (96 sq miles) per day have been achieved in the Barents Sea, with average daily production in 2014 on a large 3-D EM project on the order of 120 sq km (46 sq miles) per day with 1-km (.62-mile) line spacing. To ensure maximum efficiency when acquiring data, the system was designed to be deployed from the same vessel as a GeoStreamer. This enables the acquisition of both dual-sensor broadband seismic and high-density towed-streamer EM data simultaneously.

Data density

To accurately invert controlled-source EM (CSEM) data, it is essential to have a high-density dataset to commence the inversion process, especially to achieve high-resolution, accurate models of the subsurface resistivity. PGS seeks to ensure efficient acquisition of high-density EM data by employing a shot cycle every 120 seconds and recording 72 individual offsets in the EM streamer. This EM shot cycle equates to one shot every 250 m (820 ft) when acquiring data at 4 knots. By combining the 72 receiver offsets with the 250-m shot spacing, PGS achieves high data density on both the source and receiver sides.

The improvement in overall subsurface understanding, risk mitigation and inversion resolution gained from simultaneously acquiring high-density towed-streamer EM with GeoStreamer broadband seismic is demonstrated in Figure 1. PGS used a single seismically interpreted horizon to guide a 2.5-D inversion. The results are clear: The higher the data density, the more accurate the recovery of the subsurface resistivity, especially at depth.

Broadband seismic, EM data integration

To improve the resolution of the EM data, seismic horizons (or other geophysical data) can be used to guide the inversion (Figure 1). While guided inversion can improve the resolution, unconstrained inversion remains a high-value product, especially when interpreted in conjunction with GeoStreamer data. Seismically guided anisotropic 2.5-D inversion of towed-streamer EM data can improve the lateral and vertical resolution of resistivity anomalies, adding further value to the complementary seismic and EM data through integration of the two.

PGS is developing an integrated workflow that uses seismic, well log and towed-streamer EM data to estimate total hydrocarbon volume in place. Work is ongoing on this project, and PGS anticipates publishing a detailed paper soon.

When acquired, interpreted and integrated with seismic, maximum value can be extracted from towed-streamer CSEM data. This makes it a cost-effective method to de-risk frontier areas, improve well location decisions, provide drilling hazard identification and monitor changes in gas saturation. The key differentiators of towed-streamer EM are acquisition efficiency and the increase provided in data density, resulting in cost-effective and accurate mapping of subsurface resistivity. E&P

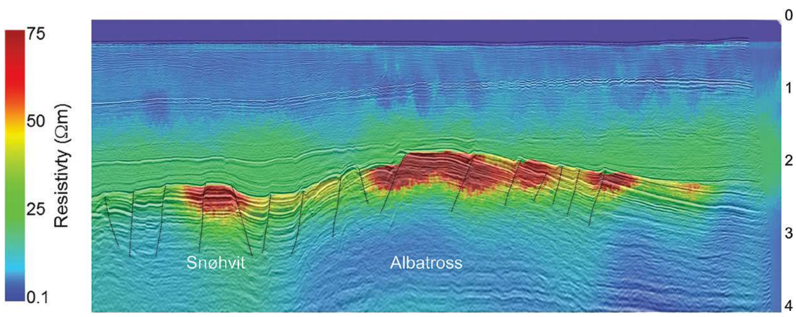
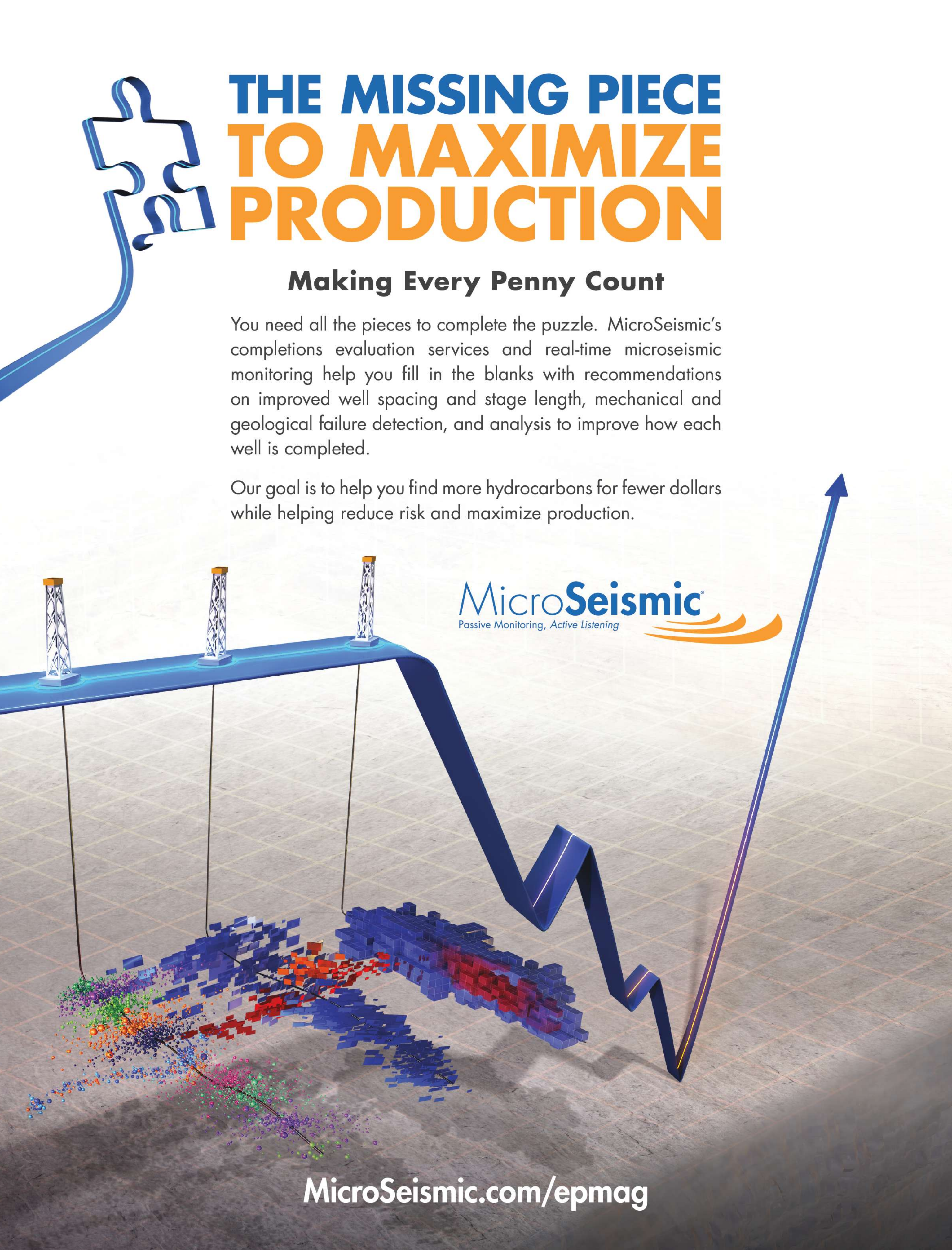


FIGURE 1. Seismically guided 2.5-D inversion results show accurate subsurface resistivity, especially at depth. (Source: PGS EM)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Revealing exploration opportunities in the GoM

Newly acquired seismic data offshore Mexico offer improved understanding of basin architecture and evolution.

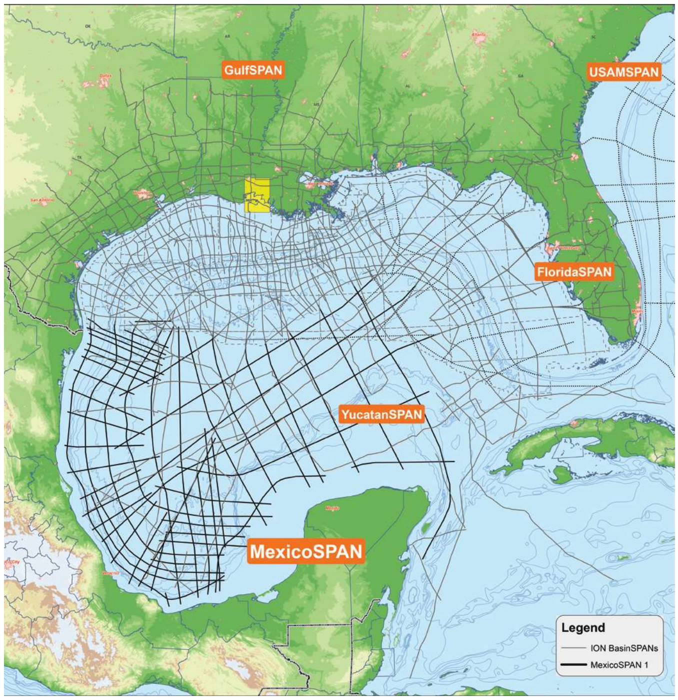
Contributed by **ION**

To help E&P companies identify new exploration opportunities in the deepwater Gulf of Mexico (GoM), ION is providing a deep-imaged regional set of 23,000 km (14,292 miles) of 2-D seismic data in Mexican federal waters. This new acquisition program, MéxicoSPAN, along with ION's existing YucatánSPAN, GulfSPAN and FloridaSPAN programs, is designed to allow explorationists to fully integrate seismic, well and outcrop information onshore East Texas, Louisiana or Florida, in the ultradeep waters of the central GoM and in the proven and potential hydrocarbon provinces offshore Mexico.

Until earlier this year, ION had the energy industry's only regional 2-D seismic data throughout the southern GoM—YucatánSPAN. With this new acquisition, explorationists can improve their understanding of the basin architecture and evolution as well as high-grade areas for hydrocarbon prospectivity, which might result in the identification of additional leads or prospects while reducing overall exploration risk.

The regional extent of the program is designed to provide full, seamless coverage of the prolific E&P areas of the western GoM as well as the exploration frontier areas within the ultradeep waters between Florida and the Yucatan peninsula. These data can be used to correlate well information from the data-rich areas offshore the U.S. into frontier exploration areas offshore Mexico. They also can be used to help correlate zones of production in carbonate plays in the southern GoM into frontier areas of the U.S. such as offshore Florida.

The new data were processed using ION's processing technologies and leveraging experience in seismic processing, depth imaging and acquisition in Mexican and U.S. waters. These data could provide the basis for this license round as well as future rounds. Underwriters of the program already have received fast-track migrated products to assist in their evaluation of the open acreage in the Perdido Fold Belt and the southern Bay of Campeche salt basin as well as lines connecting the northern and southern ends of the GoM for a basinwide understanding. The final processed data will be completed in early 2016 along with interpretation products such as regional horizon surfaces (time and depth) and gravity modeling.



This map illustrates the locations of ION's multiclient data available for the GOM, including its latest program, MéxicoSPAN. (Source: ION)

With Phase I complete and 3-D data soon becoming available from Mexico's Comisión Nacional de Hidrocarburos and wide-azimuth seismic contractors, additional acquisition phases can enhance the program with the precise amount of 2-D data necessary to better identify the size and location of major prospective structures. This combination of regional 2-D and local 3-D data can enable geoscientists to more efficiently evaluate risk through a broader understanding of the basin's evolution, architecture and hydrocarbon potential. E&P

Advances in seismic technology offshore Mexico

Multiclient survey in Campeche Basin is designed to address imaging challenges.

Contributed by **Schlumberger**

Back in 1930, the founders of SEG would have known many of the basic principles required for accurate subsurface imaging, but limitations in acquisition, processing and interpretation systems forced major compromises. Over the years, recording hardware and computer technology have evolved to overcome many of these compromises, enabling more accurate sampling of seismic wavefields and resulting in increasingly reliable earth models.

Applying modern seismic technology, Schlumberger is acquiring long-offset wide-azimuth 3-D data over an area of about 80,000 sq km (31,250 sq miles) in the Campeche Basin using eight WesternGeco vessels divided into two fleets. Each fleet is deploying four seismic sources and recording data with up to 28 streamers, each of which is 9 km (5.623 miles) long. The two fleets have covered as much as 150 sq km (60 sq miles) per day.

The multiclient survey—designed to address imaging challenges including near-salt and subsalt structures, complex faulted structures and deep-thrusted structures—is being acquired using Q-Marine Solid streamers with a nonfluid-fill technology. Until recently, most streamers contained hydrocarbon fluids to provide buoyancy; however, in the event of damage such as shark bites, which are quite common, this can lead to leakage. By comparison, solid streamers are more environmentally friendly, have higher resistance to physical damage and are recognized as delivering good low-frequency signal-to-noise ratio. The Q-Marine point-receiver marine seismic system leverages advances in electronics and fiber-optic networks to provide high channel-count recording. Data are sampled at 3.13-m (10.25-ft) intervals along each streamer, enabling finely sampled recording of both signal and noise in the seismic wavefield. Shell geophysicists documented the potential of the single-sensor method in the late 1980s, but limitations in hardware and processing capabilities at the time prevented full realization of its benefits. Adequate sampling of streamer noise allows targeted signal-processing techniques to suppress it while preserving the integrity of the seismic signal. This effective noise removal allows acquisition of high-quality seismic data even in poor weather or when towing streamers through strong currents.

Amazon Warrior **is the world's first vessel designed from the bottom up for seismic operations. (Source: Schlumberger)**

One of the vessels acquiring the new dataset is *Amazon Warrior*, the world's first vessel designed from the bottom up to deliver optimum performance during seismic operations. Until now, seismic companies have identified various types of existing hull designs they considered suitable for their operations and converted the top decks to accommodate and deploy the specialized equipment. A feature common to all of these hull designs is that they were originally optimized for another purpose, which in most cases was to enable economic transit from one seaport to another at high cruising speeds. Efficient acquisition of high-quality marine seismic data not only requires deployment of large spreads of specialized in-sea equipment but also cost-effectiveness at the normal production speed of 5 knots, which on average represents about 80% of a vessel's time at sea. Amazon-class vessels are designed with a hull, propulsion system and all the other components required to optimally meet the seismic requirements while also maximizing HSE performance and operational efficiency. *Amazon Warrior* currently is towing 14 streamers at 100-m (328-ft) separation and recording 40,320 seismic traces per shot. By comparison, surveys in the 1980s typically recorded just 96 to 120 traces per shot. E&P

Integrated subsurface modeling can help lower cost per boe in unconventionals

Workflow tools can help increase production while decreasing cost per barrel.

Contributed by **Halliburton**

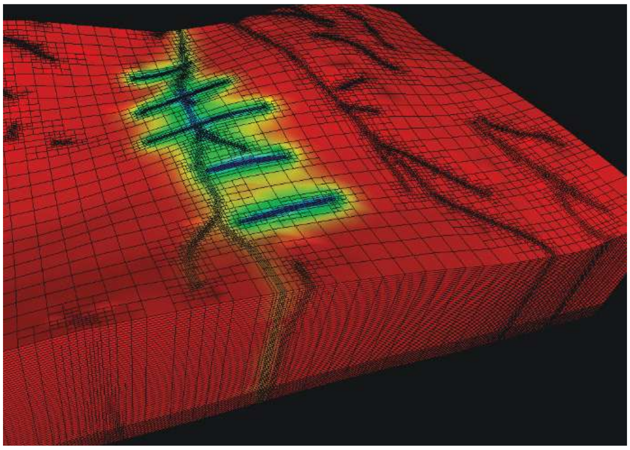
Given the price of oil, many operators in unconventional resource plays find themselves at or near the economic breakeven point. In such uncertain times, it's critical to reduce the operational cost per boe. This can be achieved by either lowering the numerator (cost) or by boosting the denominator (production) or, better yet, by doing both.

Traditional factory approaches to drilling and hydraulic fracturing have focused primarily on the cost side of the equation, whittling expenses by applying essentially the same formula to every lateral as rapidly as possible. Until the oil price crash, this might have appeared sufficient. Today it's a formula for failure. The industry now knows that unconventional reservoirs exhibit extreme variations, both laterally and vertically. Every shale is complex and unique.

To ensure smarter, faster decisions about where and how to drill and where and how to fracture, operators must integrate all available data, information and knowledge in a single, continuously updated subsurface model. Unfortunately, tools designed for conventional reservoirs need significant modification to accurately capture, model and simulate the heterogeneities and natural fractures present in shales. New technology is essential.

Commercializing proven and new technologies

Two years ago Halliburton began deploying a wide range of geoscience and engineering tools on a common software and data platform to deliver the new CYPHER Seismic-to-Stimulation Service for unconventional reservoirs. The platform provides advanced functionality for integrated geophysical, geological, petrophysical, geomechanical and engineering interpretations. With these tools, joint client and service company teams have built more comprehensive models, applied multivariate statistical analyses to identify sweet spots, modeled complicated fracture networks and accurately simulated induced fractures. The tools also enable teams to run flow simulations, perform history matching and efficiently evaluate completion designs.



Patent-pending unstructured gridding automatically creates higher resolution grid cells surrounding natural and induced fractures, with coarser cells elsewhere. (Source: Halliburton)

The company is commercializing its DecisionSpace Unconventionals software. Recent enhancements seek to offer asset teams a complete end-to-end geoscience, reservoir and engineering solution for the full E&P life cycle. DecisionSpace Unconventionals provides a common multidiscipline subsurface model, updated continuously with new data before, during and after each well is drilled to help with improved decision-making and increased team collaboration.

Key technologies include patent-pending unstructured gridding, which automatically creates higher resolution grid cells surrounding natural and induced fractures, with coarser cells elsewhere. This can improve the usability of flow models, history matching and performance predictions. A new fracture productivity tool will provide a simplified interface to the reservoir simulator, enabling users to enter data easily, build sophisticated models and quickly see the impact of various drilling and completion scenarios over the life of the reservoir.

Improving both sides of the equation

Used in several major North American shale plays to date, these integrated workflow tools have helped to both decrease the numerator and increase the denominator of the cost per boe ratio.

For example, in a step-out development just outside the core productive area of the Barnett Shale, an operator had completed only three successful wells out of 11. Production was poor and highly inconsistent from well to well (according to URTeC paper 1920572). To avoid abandoning the asset, the company shot 3-D seismic, brought in the new seismic-to-stimulation reservoir technologies, acquired additional formation data and developed a comprehensive earth model, which revealed tremendous vertical heterogeneity. The multidiscipline asset team identified a more promising target interval, determined how to land and geosteer laterals more accurately, created a complex fracture model from borehole image and microseismic data, ran flow simulations, and revised and optimized its previous completion strategy.

As a result, IP improved by more than 50%, well-to-well performance became far more consistent, and average post-project well costs shrank initially by nearly 5% and subsequently by an additional 22% despite new data acquisition and higher proppant volumes. E&P

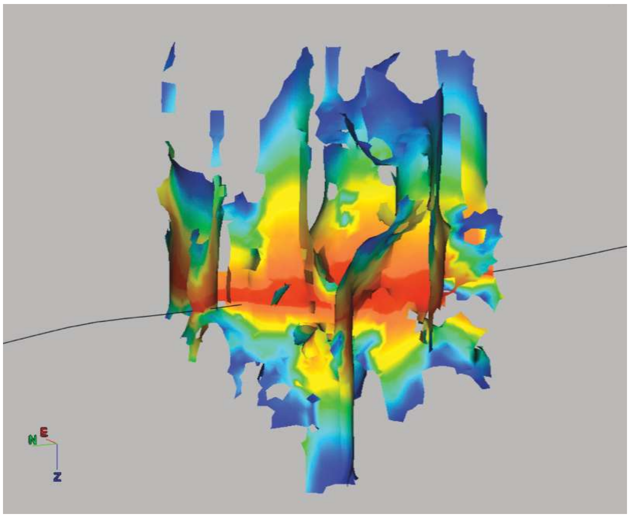
Ambient seismic provides new understanding of unconventional production potential

Identify areas or volumes that are acoustically active due to natural fractures, hydraulic stimulation or production-related activity.

Contributed by **Global Geophysical**

Global Geophysical has developed an approach for understanding unconventional production potential using ambient seismic recordings captured over days, weeks or months. Using proprietary processing techniques, ambient seismic reveals the extent and density of natural fractures; the size, orientation and shape of induced fractures; the volume of rock activated during stimulation; and the volume of rock active during production.

Ambient seismic can be collected during the acquisition of traditional 3-D seismic surveys and as a "monitoring" service for fracture stimulation, injection and production. The data can be recorded with a surface array or with a buried array. The detectability of the radiated seismic energy depends on the signal-to-noise ratio of the trace data after filtering has been applied to suppress the various types of noise. For good focusing, the surface wave noise must be removed. Trace processing for noise removal reveals and concentrates the real seismic energy. The optimum surface array design is a uniform hexagonal distribution



Ambient seismic monitoring images fracture propagation, revealing the progression of fractures opened during the fracking process. A tomographic fracture image shows activation time with early-in-stage activation times represented by warmer colors and late-in-stage activation times represented by cooler colors. (Source: Global Geophysical)

of geophones covering the required aperture. This design samples noise at multiple azimuths so that surface noise is suppressed and not passed into the image.

Steps for computing the image volumes include data acquisition, velocity model building, trace processing for noise suppression, imaging and fracture image computation. Ambient seismic recordings have extreme value for the prediction of frack treatment performance before the actual treatment, focusing the seismic emissions during the frack treatment for estimating the volume of rock that is stimulated, mapping the time sequential activation of the fractures during treatment and measuring the active producing volume over time during production.

Increasingly, it is understood that the concentrated seismic energy revealed in trace processing is the result of long-duration signals (LDSs) rather than the microearthquakes (MEQs) that are recorded by other microseismic methods. LDSs are continuous seismic waveforms originating in the reservoir that last for seconds or minutes and that are episodic and pulsating in nature. It has been found that LDSs contribute most of the signal to natural fracture images. Traditional MEQ techniques fail to capture a significant amount, and sometimes the majority, of seismic energy. Recent experience by Global Geophysical and others also shows that natural fracture networks play a significant role in the effectiveness of hydraulic stimulation and in the long-term producibility of unconventional wells.

The fracture imaging method for this type of acquisition and data can be best described as a one-way travel time prestack depth migration. To image the ambient seismic signals, the time of investigation and the spatial volume for investigation must be chosen. Streaming the ambient signal through the depth-imaging algorithm images the depth volume for the entire time window of interest. The resulting volume contains the fracture surfaces that are extracted to compute volumetric fracture images. The integration of a large number of volumes from a significant period of recorded time combines all of the impulses at a single location to build up the signal and suppress the noise. The finished product is then an accurate representation of the acoustically active areas and volumes and can be used to understand fracture patterns, intensity and location as well as fracture propagation timing.

One of the most powerful applications of this technology is the ability to understand the potential effectiveness of fracture stimulation. Ambient seismic data collected before the frack job are used to image the natural seismicity from the reservoir, revealing acoustically active natural fractures. Mapping where natural fractures intersect a new or planned well helps predict the influence of the natural fractures on drilling and stimulation. Ambient seismic collected during stimulation allows for the characterization of induced fractures and of the overall impact of stimulation on the reservoir and on nearby wells. Finally, ambient seismic data captured while wells are in production helps define the active producing volume around the wellbore at that time in the well's production history. Monitoring production volumes periodically over time allows for identification of missed pay, refracturing candidates and planning for infill drilling. E&P

Vibratory downhole and marine sources can be monitored remotely

Marine vibratory sources can project variable frequency energy into the water for days in programmed sweeps.

Contributed by **GPUSA Inc.**

Imagine powerful land-based seismic sources that can be controlled and monitored remotely from a desk. Envision small yet powerful marine vibratory sources that can project variable frequency energy into the water for days in precisely programmed sweeps that are consistent and repeatable. GPUSA Inc. has integrated factory automation technology, programmable logic, touchscreen control and variable frequency drives with downhole and marine vibratory sources.

Marine vibrator

Airguns are small, powerful, reliable and have been a staple in the marine seismic industry for 40 years. For more than a decade, the oil and gas industry has been searching for an alternative to the airgun, with a marine vibrator replacement being seen as the "holy grail." But designing a high-power, low-frequency marine vibrator with a reasonable size, weight and cost is challenging. To be practical, a marine vibrator must have dimensions much smaller than the wavelength of the sound that it produces. For example, at 100 Hz the acoustic wavelength is about 15 m (50 ft), but an acceptable size for a marine vibrator is probably .91 m (3 ft) or less. Achieving high power at low frequencies from a small transducer requires very large volume displacements. The "in the box" solution is to use a magnetostrictive material with very high displacement. However, even a .91-m stack of Terfenol-D, which has the highest magnetostriction of any alloy, provides only about 1/16 in. of displacement. Despite this, several companies have developed innovative transducer designs that leverage these small displacements into larger ones. GPUSA's approach uses small, powerful motors capable of producing displacements up to 100 times larger than equivalently sized magnetostrictive actuators.

Downhole vibrator

Most in the industry would agree that using a downhole source is like trying to use a squirt gun to put out a forest fire; it just doesn't have enough power to do the job. Times have changed. GPUSA's downhole vibrator 2.5-in.-diameter tool that can be held in one hand. It also includes a built-in accelerometer tested to withstand a gravity force of 5,000 to track the vibrator's output for real-time quality control and deconvolution post-processing with the received signals. No clamps are necessary, and all the bells and whistles needed to synchronize with the rest of the seismic equipment are accessible via water-tight connectors without opening the front panel. E&P

Seeing geology before interpreting it

System combines computational approaches with cognitive capabilities in interpretation.

Contributed by **GeoTeric**

In the oil and gas industry billions are spent on acquiring and processing the best-quality seismic data possible to make informed decisions when drilling wells and producing oil and gas. With the vast quantities of data generated, it is easy for interpreters to get into a "cognitive overload" situation, leading to confusion rather than understanding and wasting both time and money.

Computers are able to provide rapid high-resolution objective and fully volumetric results. However, interpretation of these results involves matching what is seen with what a geological feature is known to look like. This is a complex challenge that no computer can carry out as efficiently or as effectively as the human brain, which is why making full use of human cognition is vital in next-generation interpretation systems.

Developed to better harness cognitive capabilities, GeoTeric's Cognitive Interpretation system combines the power of computational approaches with an appreciation of the importance of the human element in interpretation. The system allows users to see the geology in their seismic data before interpreting.

Cognitive interpretation combines compute power with humans' ability to detect patterns.

"We have developed Cognitive Interpretation to allow geologists and geophysicists to use their cognitive capabilities as effectively as possible and therefore generate the most accurate and detailed seismic interpretation possible," said Jonathan Henderson, managing director for GeoTeric. "It adds considerable value to both conventional interpretation and QI [quantitative interpretation] workflows, ultimately helping clients reduce time and cost and improve decision making." E&P

The seismic wow factor—a precursor to unlocking offshore Mexico

With new data comes new understanding.

Brad Torry, TGS

Volatile hydrocarbon prices are driving major changes in the industry. Companies are establishing new economic baselines and new criteria for evaluating exploration, exploitation and development opportunities. With risk reduction paramount to overall investment return, access to new data and information is more important than ever. In the exploration world, this means looking to analogues as the basis for forming new prospects and play fairways.

Nowhere has this become more prevalent than offshore Mexico. Having undergone an energy reform, Mexico offers new exploration and development opportunities in a basin with well-known analogues, the U.S. Gulf of Mexico (GoM). On an aerial comparative, the U.S. GoM covers an estimated 695,000 sq km (268,341 sq miles) vs. the Mexican GoM, which covers an estimated 825,000 sq km (318,534 sq miles). Compare this to drilling activity and densities in the respective areas. In waters less than 100-m (328-ft) deep, there are an estimated 14,478 wells in the U.S. vs. 474 on the Mexican side. In waters deeper than 100 m, the numbers become more staggering, with 4,204 exploration wells in the U.S. and only 117 in Mexico. The opportunity here is immense.

In terms of active petroleum systems, the GoM (U.S. and Mexico) is considered one sedimentary basin from source to sink. Although differences do exist, such as the Chicxulub impact crater and disproportionate carbonate reservoirs, it is the similarities (analogues) that should drive early drilling and exploration opportunities. Early activity is expected as a natural extension of conventional salt basin exploration to Mexico (offshore southern Mexico in the southeastern basins and Campeche-Sigsbee Isthmus salt basin and offshore northern Mexico in the Perdido and Salina del Bravo basins). This new activity will benefit from the seismic wow factor established by two decades of advancements in acquisition and imaging for salt and subsalt formations. On the acquisition end, the ability to select made-for-purpose acquisition configurations (narrow-azimuth, wide-azimuth and full-azimuth) presents significant gains vs. early U.S. GoM exploration. On the imaging front, faster information delivery cycle times are being achieved through significant investment and advancements in hardware and compute capacity. These strides, coupled with advanced applications such as various prestack data-conditioning options, improved velocity analysis and assorted migration applications, are contributing to superior interpretations. Combining the advancements in acquisition and imaging will lead to improved de-risking and optimized prospect and play fairway definition.

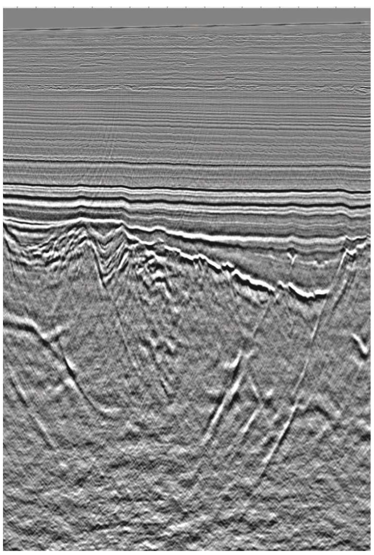


FIGURE 1. A new image from TGS Panfilo 3-D displays the seismic wow factor. (Source: TGS)

So with all this new technology, what is most exciting? As with most emerging sedimentary basins, new data and information lead to new interpretation and understanding. This is the seismic wow factor. Much of offshore Mexico is located in nonsalt provinces, which is equivalent to the abyssal plain region of the U.S. GoM, primarily the Lund and Henderson protraction areas south of the Sigsbee salt edge. Although no drilling has occurred in this region, the data in Figure 1 provide unprecedented views of what is to come. New images of what is believed to be thickening (2,000 m to 3,000 m [6,562 ft to 9,843 ft]) of Jurassic-aged sediments will lead to new interpretations and hydrocarbon assessments. Of additional note in Figure 1 is what is now classified as intra-crustal features between basement and oceanic crust. Although limited studies have been conducted on the seismic reflectivity in this zone, new images (shown in the figure) provide insight to basin forming and evolution aspects. This insight will lead to new interpretations of basin-forming events, the nature and timing of sediment deposition related to the opening of the GoM, and these events' impacts on the petroleum systems. Additionally, these new images present the need for greater understanding beneath the salt, an area which historically has been challenging to image.

The geoscience community must identify new sources of hydrocarbon accumulations to supply the long-term demands of society. The seismic wow factor means with new data comes new understanding. These new data will challenge conventional thinking and lead to new and far-reaching opportunities. When the initiative to acquire new seismic data in new unexplored regions is taken, the wow factor is gained.

Happy hunting. E&P

New microseismic technique predicts propped volumes, reservoir performance

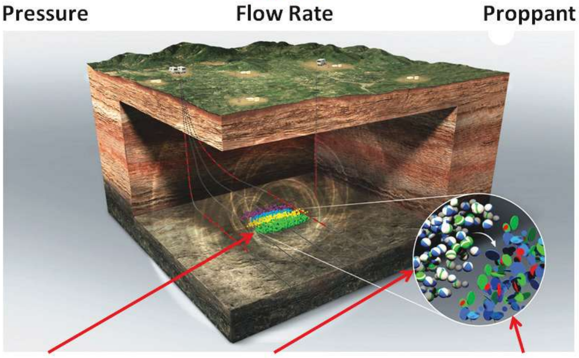
A technique for developing a DFN model is at the forefront of advanced geomechanical analysis.

Contributed by **ESG**

Integral to any hydraulic fracturing project is having the insight into how fracturing strategies are affecting the rock. Microseismic monitoring is an essential tool that detects the very small seismic events that occur during hydraulic fracturing and provides an image of how a program is developing. Basic microseismic monitoring can provide insight into stage half-lengths, the overlap between stages and out-of-zone fracturing/growth. To get the most out of a microseismic program and observe a frack in more detail, advanced analysis should be applied. ESG's advanced technique can construct and visualize the discrete fracture network (DFN).

Advanced analysis takes microseismic events beyond just locations and magnitudes. Using seismic moment tensor inversion (SMTI), the source mechanism of the events (whether the event rupture was an opening, closing, slipping or shear movement) and orientations of the individual ruptures are determined. With this information, a robust DFN can be identified. DFN models show the interconnected pathways that are formed in the rock as a result of hydraulic fracturing, through which fluids and proppant may flow. Knowing where these pathways have been created is vital to any hydraulic fracturing program.

A few microseismic vendors have proposed that DFNs can be constructed by connecting the hypocenters of



SMTI-based DFN provides an optimized representation of the reservoir. (Source: ESG)

the microseismic events and obtaining the orientations and fracture lengths based on this network. However, through ESG's technique, these events can now be assigned fracture orientations using SMTI, and the length of these fractures can be determined by the frequency content of the waveforms generated by the event. By combining both the orientation and length of the fractures using high-quality events, the company's technique can create a more data-driven DFN. The user can then extend those known orientations and lengths to non-SMTI events, forming an even more detailed model. "A robust DFN model is essential for accurately determining where your proppant and fluid are being distributed," said Dr. Ted Urbancic, CTO at ESG.

To generate this robust DFN, SMTI events are visualized as penny-shaped cracks oriented in a 3-D space sized according to the individual rupture lengths. Using ESG's methodology, the orientations of the DFN are first estimated through SMTI and then are extended to non-SMTI events through an optimization algorithm.

ESG's technique was used on a large-scale multiwell hydraulic fracturing project in the Horn River Basin in Northeast British Columbia. The Horn River Basin is a shale gas play that is made up of three members (in order of increasing depth): the Muskwa, Otter Park and Evie. The pad comprised 10 horizontal wells and was completed using a zipper frack technique. Three of ESG's geophone arrays were deployed in the vertical sections of nearby wells and collected data for 76 stages. More than 90,000 events were located over these stages, ranging in magnitudes (M) from above -3 M to 1 M, providing a good basis for examining questions on the progression of hydraulic fracturing in the reservoir. The DFN provided the user with a basis for refining geomechanical models, allowing it to better predict propped volumes and reservoir performance over time. E&P

The growing influence of reservoir modeling

New technologies work together to enhance the effectiveness of reservoir modeling and uncertainty quantification across the prospect life cycle.

Contributed by **Emerson Process Management**

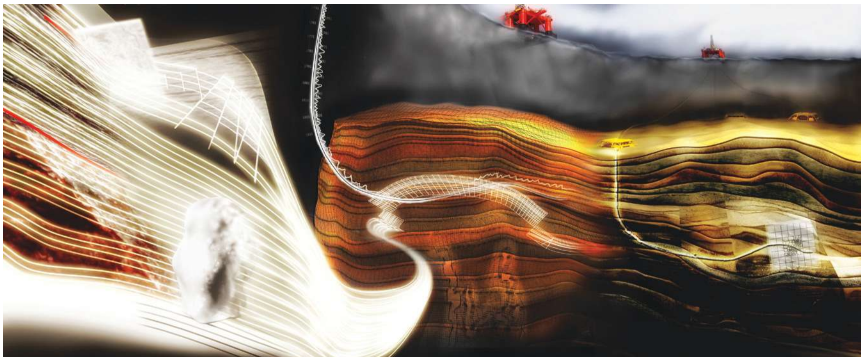
The decline in oil and gas prices and operators' growing needs to generate maximum returns from their assets have ensured that reservoir modeling remains a powerful and highly important decision-making tool.

Three-dimensional reservoir modeling is the standard platform for mapping, understanding and predicting reservoir behavior, providing operators with the crucial information they need on where to drill, what production strategies to adopt and how to maximize oil and gas recovery.

The latest technology developments within Emerson's reservoir modeling software Roxar RMS, for example, can enhance the effectiveness of reservoir modeling and uncertainty quantification across the prospect life cycle.

Roxar RMS 2013.1, launched in June, includes tightly integrated structural modeling tools that enable users to quantify uncertainty more effectively. Uncertainty management decision-making is enhanced through a closer integration between structural modeling and 3-D gridding tools as well as horizon uncertainty modeling tools that allow users to incorporate realistic uncertainties into the horizon model.

Another recent technological development from Emerson, known as model-driven interpretation, allows users to build models directly from the geophysical data. In this way, users can set and collect uncertainty information associated with an interpretation, easily and reversibly test geologic hypotheses and add more detail to the model as and when required.



Roxar RMS 2013.1 includes tightly integrated structural modeling tools that enable users to quantify uncertainty more effectively. (Source: Emerson Process Management)

These technical innovations are leading to the consistent treatment of uncertainties and ensuring that modeling and uncertainty management remain at the center of the reservoir management workflow—modeling complex fields, increasing recovery rates and accelerating time to first oil.

An open and flexible platform for workflow integration and data sharing is another key element of successful reservoir management. Such a workflow improves data management, enables operators to integrate their own IP and specific applications and ensures maximum scalability.

This is being achieved at Emerson through a multirealization "big loop" workflow within Roxar RMS where the modeling process is highly automated and flexible enough to incorporate new data, concepts or applications as soon as they become available and at any time.

The workflow generates multiple and consistent models that capture uncertainties at all levels and that have the ability to incorporate new data such as newly drilled wells or velocity models.

This, in turn, is used by the simulation model for field development planning, well placement and as input to economic analysis.

Finally, Emerson's future development strategy will embrace a host of innovations over the coming months, strengthening Roxar RMS' interoperability, performance and usability.

The growth in cloud computing-based collaboration and information management, for example, has the potential to usher in a revolution in how reservoir models are handled, interpreted and shared. Cloud computing-based developments within Roxar RMS seek to enable users to collaborate in real time, access data at the same time and extend reservoir modeling further across organizations.

In July 2015, Emerson acquired Norwegian company Yggdrasil, a provider of flow assurance and production optimization software. The incorporation of Yggdrasil's METTE production optimization solution within Roxar RMS can help operators align their modeling, uncertainty quantification and simulation data with production; optimize their field development and production plans; and increase oil and gas recovery in challenging environments.

Advances to the Roxar Tempest reservoir engineering suite seek to allow more accurate and realistic production scenarios, the testing of multiple realizations and improved uncertainty quantification on volumes and cumulative production. E&P

From cuttings to completions: automated wellsite mineralogy comes of age

Analyzer generates quantitative geological datasets.

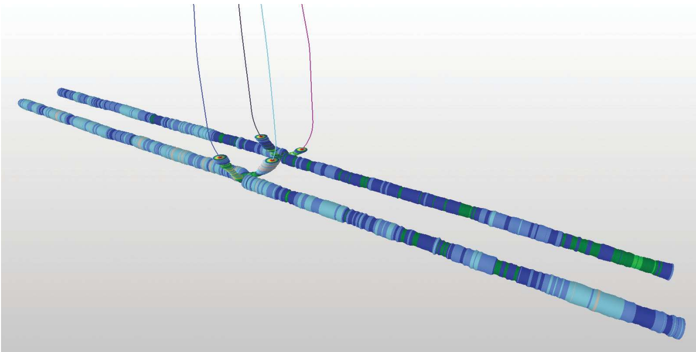
Contributed by **CGG**

To supplement the engineering data and geophysical wireline logging data collected from boreholes, drill cuttings are an often overlooked but abundant source of geological data. Sometimes the cuttings are logged manually at the well site to provide qualitative information for reservoir characterization, but their full value has never been realized.

RoqSCAN is a new-generation analyzer of portable, quantitative and automated rock properties. Developed by CGG Robertson and Carl Zeiss Microscopy Ltd., the analyzer is ruggedized and fully portable, which means it can be deployed at well sites for near real-time analysis to inform on-the-fly drilling and completion decisions. RoqSCAN delivers quantitative mineralogical and textural data from drill cuttings or core pieces using nondestructive scanning electron microscopy and energy-dispersive spectroscopy techniques with a high micron resolution. Robertson has developed an extensive proprietary mineral library to translate these scans into quantitative mineral maps. The textural data include automatic detection and classification of porosity, pore size distribution, and pore aspect ratio.

This technology advancement avoids exposure to costly wireline or LWD data acquisition and lost-in-hole scenarios and requires no additional rig-time costs.

RoqSCAN has experienced success both in the field and in the laboratory, driven partly by the shale boom in



RoqSCAN lateral well mineralogical and textural rock typing looks at four lateral wells drilled off the same pad into the Lower Eagle Ford Formation, demonstrating the heterogeneity in the reservoir from well to well. (Source: JewelSuite and the BHI/CGG Shale Science Alliance)

the U.S. and increasing demand from unconventional play operators for improved reservoir characterization along the lateral well to optimize completions. The analyzer is a surface-based means to generate quantitative geological datasets where cuttings samples are often the only source of data available. Only a small proportion of horizontal wells are logged, so operators often make completion decisions without any knowledge of the local subsurface heterogeneity in their shale play.

Wellsite geosteering services have used RoqSCAN mineralogical zonation schemes to identify the location of the drillbit in the formation. With a quantitative measurement of key rock texture parameters such as pore size distribution, pore aspect ratio, rock chemistry and mineralogy, a better understanding of the mechanical properties of the formation can be obtained. This has led to RoqSCAN being used to design completion programs for wells based on the actual geological and mechanical properties of the formation. For seismic reservoir characterization projects where elastic attributes from seismic inversion are used to screen plays for potential production hot spots, RoqSCAN can provide hard geological data to calibrate rock physics models and constrain the inversion to achieve a more accurate and quantitative geomodel.

Case studies published within North American shale plays demonstrate how shale well economics can be improved in terms of optimized production and cost reduction by achieving better stage and perforation cluster placement (honoring the reservoir heterogeneity), the elimination of noneffective stages, and more effective deployment of frack fluids and proppants.

CGG is in the early days of automated mineralogy supporting drilling and completion decisions, and work continues on improving the service. Two areas for development include petrophysical inversion of RoqSCAN measurements to directly generate elastic (i.e., seismic-style) rock properties and reducing the uncertainty in the depth lag associated with cuttings recovery from horizontal wells. A quality-control system using MWD gamma ray, RoqSCAN pseudo gamma ray and mineral attributes has been developed to align cuttings samples to the correct borehole depth interval.

RoqSCAN is offered in the field through Baker Hughes. E&P

Controlled sound-field sampling

Using more than two sources in dense in-line overlapping shot mode can enhance geophysical data quality.

Contributed by **Polarcus**

To reduce exploration costs, E&P companies have sought, and seismic companies have delivered, improvements in 3-D acquisition productivity. However, image resolution, most notably in the crossline direction, previously has been compromised. An approach being posited by Polarcus can eliminate cost-quality compromise and provide E&P companies with a solution that addresses both productivity and quality.

In terms of seismic spatial sampling for 3-D imaging, the subsurface imaging grid is a function of the relative spatial geometry between sources and receivers on the surface. For towed streamer acquisition, a subsurface line is sampled midway between the surface position of each source and each streamer. Therefore, sets of subsurface

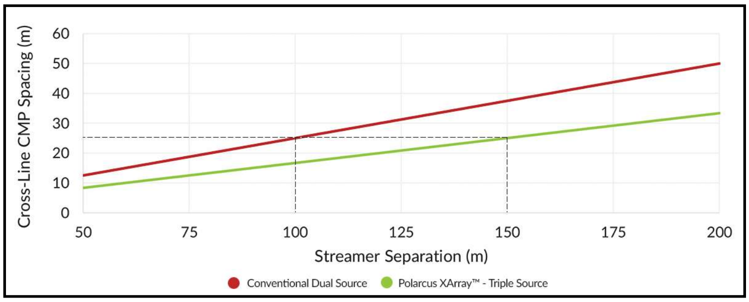


FIGURE 1. CMP-line separation is compared to subsurface swath width in the graph. (Source: Polarcus)

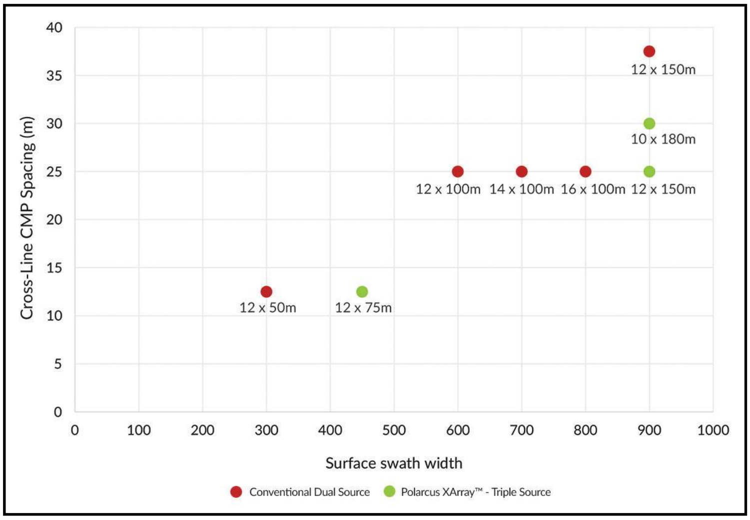


FIGURE 2. The chart compares dual-source acquisition with Polarcus XArray controlled sound-field sampling. (Source: Polarcus)

lines are acquired on each pass of a multisource and multistreamer survey vessel.

Traditionally, 3-D towed streamer surveys have used two source arrays fired at alternate shot-point locations. For any streamer configuration, the subsurface line sampling is then one-fourth of the streamer separation. Using this technique, the spacing between subsurface lines is controlled by the streamer separation. For example, 100-m (328-ft) separation produces 25-m (82-ft) subsurface line spacing, and 50-m (164-ft) streamer spacing produces 12.5-m (41-ft) subsurface line spacing.

Within the last few years, large footprint surveys have increased in areas where quick acquisition turnaround is essential to meet regulatory requirements. This is driven by environmental concerns, climatic limitations or to meet license work commitments. This demand from E&P companies has led to seismic contractors offering more streamers and larger separations. Over the past decade, the trend in the number of streamers has progressed from 10 to 16 or more. Simultaneously, streamer separation has increased from 100 m to 200 m (656 ft). As streamer separation increases, so does the cross-line sampling interval from 25 m for 100-m separations, to 50 m for 200-m separations. This can lead to lower resolution imaging in areas of complex structural geology and aliasing of multiples and other types of coherent noise.

Multisource acquisition

Polarcus is revisiting the concept of using multiple sources to increase the crossline sampling from towed streamer spreads. For example, using three source arrays produces subsurface line spacings that are one-sixth of the streamer separation compared to one-fourth for dual sources. Figure 1 shows the relationship between crossline sampling vs. streamer separation for dual- and triple-source configurations.

From the data, it is evident that the increased crossline sampling from triple-source configurations is significant and grows as streamer separations increase.

Figure 2 shows that the 25-m crossline sampling produced by dual sources and 100-m streamer separations can be achieved with 150-m streamer separations and triple sources, increasing efficiency by 50% for 12-streamer spreads. The efficiency benefit for a 12-m by 150-m streamer spread with triple sources holds even when compared to a 16-m by 100-m streamer spread with dual sources.

When the triple-source geometry is coupled with de-blending of overlapping records from dense inline shooting, the bin fold can be maintained at near the same levels as dual sources while providing 50% more surface shots and subsurface source-to-receiver ray paths.

Polarcus can extend the multisource overlap shooting concepts to acquire very dense crossline sampling with conventional streamers. In a recent test, the company demonstrated a 6.25-m (20.5-ft) crossline sampling using a five-source configuration. This type of acquisition is not necessarily aimed at increased operational productivity but more to specific projects where complex structures in the near surface need to be resolved to allow accurate imaging of the underlying hydrocarbon deposits.

By leveraging modern-day acquisition technologies of source and receiver/recording systems and advanced data processing, Polarcus has demonstrated that using more than two sources in dense in-line overlapping shot mode can enhance geophysical data quality while maintaining the high productivity of large streamer spreads. E&P

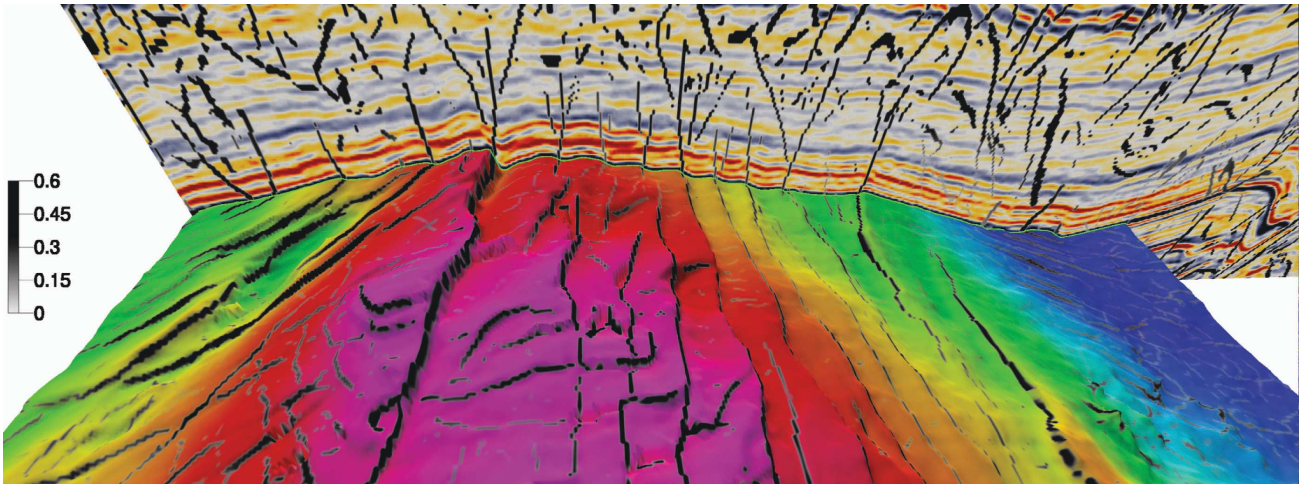


FIGURE 1. dGB's new thinned fault likelihood attribute is based on algorithms developed at CSM. (Source: dGB Earth Sciences)

Platform can improve seismic interpretation

Software provides solutions for data visualization and attribute analysis.

Contributed by **dGB Earth Sciences**

dGB Earth Sciences is releasing OpendTect Version 6.0 and OpendTect Pro, a seismic interpretation platform for professionals that acts as a commercial layer on top of the free OpendTect software. The software will be launched during the 2015 SEG Annual Conference and Exhibition in New Orleans.

OpendTect serves open-source, academic and commercial users and seeks to provide solutions for data visualization and attribute analysis. In addition, the software has been used as a platform to run workflows supported by commercial plug-ins and can now be used as a seismic interpretation system.

OpendTect Pro seeks to provide improved conventional seismic interpretation workflows in addition to workflows available via the company's commercial plug-ins. The software offers additional functionality, including Schlumberger's PetrelDirect for data interaction with Petrel; PDF-3-D, which enables the grabbing and sharing of interactive 3-D PDF files; a new basemap utility with mapping functionality that improves OpendTect's user interaction; a ray tracer for amplitude-vs.-offset analysis; and the Thalweg tracker, a 3-D horizon/body tracker for seismic facies analysis.

In addition, the software will see a redesign of its seismic interpretation workflows within the open-source software for improvements to usability. This includes a new 3-D horizon tracker, improved 2-D seismic interpretation workflows, improved fault interpretation workflows, an overhaul of existing 2-D viewers, increased speeds for data handling and RGB+RGBA color blending in volumes. OpendTect 6.0 is sponsored and steered by BG Group.

During SEG 2015, the company also will introduce the Faults & Fractures OpendTect plug-in. The technology offers new fault attributes and edge-preserving smoothing filters as well as tools for extracting fault planes and unfaulting seismic volumes.

Figure 1 shows the new thinned fault likelihood attribute, which is based on algorithms developed at the Colorado School of Mines (CSM).

dGB is implementing a new 3-D HorizonCube algorithm also based on CSM algorithms. Instead of tracking the dip field as with the current HorizonCube tracker, the new algorithm provides a constrained inversion of the dip field with any errors globally minimized. Constraints are in the form of user-picked positions on multiple seismic events. In addition, faults—automatic and/or interpreted—can optionally be included to constrain the solution. E&P

Shot-point data management tool collects, organizes field data

Software allows users to manage projects from surveying to shooting.

Contributed by **Dyno Nobel**

Dyno Nobel developed the ShotPoint Logix software system for shot-point data acquisition in geophysical exploration.

The software is designed to collect and organize field data to produce accurate analysis and reporting. In geophysical exploration, gathering accurate shotpoint information from survey crews, drilling crews and shooting crews can be a problem. Data collection needs to be simplified so recording crews can produce accurate, reliable reports and analysis.

Shotpoint Logix seeks to streamline the acquisition of data into an easy-to-import and -export program, allowing users to manage projects from surveying to shooting.

The software allows survey crews to automatically import survey information through cloud capabilities. Drilling crews can then upload this information to Dyno Nobel's GeoShot Tagger, a handheld computer that can be used to associate shotpoint locations from preloaded data with GPS coordinates.

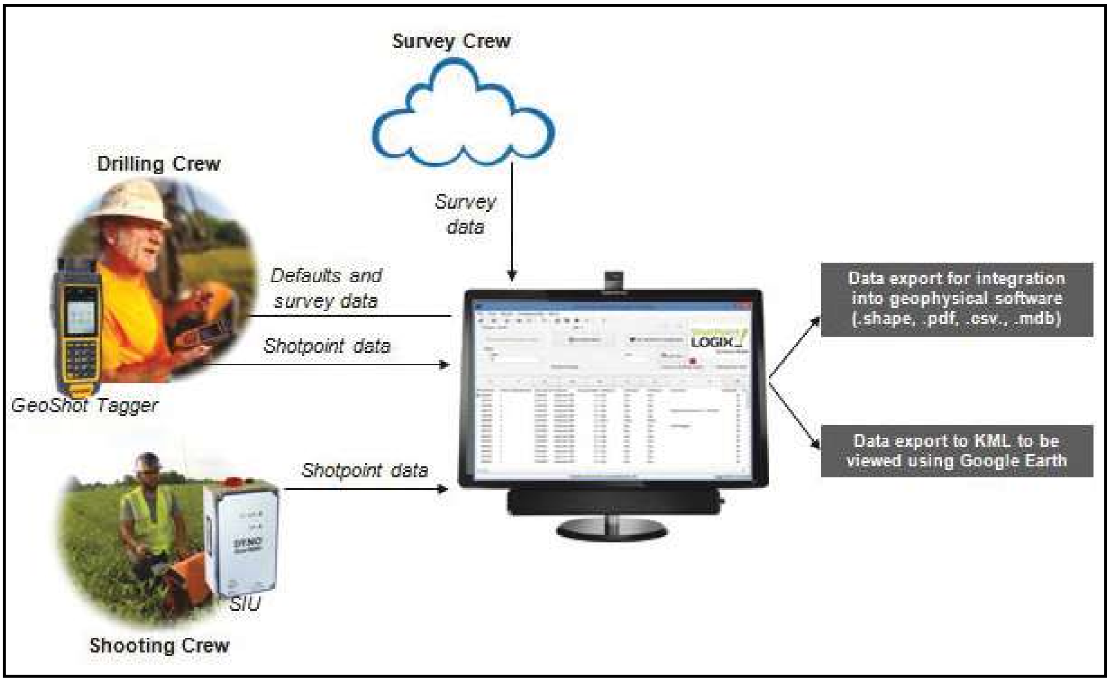
The Tagger can enable drilling crews to automatically capture field data such as identification of a driller, the actual drill location, the date and time stamp, and the shotpoint number. To ensure reliability, the Tagger also tests detonator communication. After this information is recorded, the drilling crew can upload it to ShotPoint Logix, where it is aggregated and sorted for analytical purposes.

Once the drilling and loading are complete, shooting crews can use the seismic interface unit to test and fire the detonators, collecting additional shotpoint data for analysis. These data can then be imported to ShotPoint Logix.

The software can track the life of products and practices for improved quality control. Other features the software offers include:

- Plotting shotpoints on Google Earth for visual data management;
- Showing unloaded, loaded and fired holes;
- Creating drilling, summary and custom reports;
- Providing multiple filtering options; and
- Exporting data in multiple formats that are compatible with other seismic software.

The software is compatible with the company's electronic initiation system, GeoShot, and its electric initiation system, ElectricSuper Seismic. E&P



ShotPoint Logix is a user-friendly software that tracks the life of a crew's products and practices, resulting in better quality control. (Source: Dyno Nobel)

Latest advance in microseismic technology: auto moment tensor inversion

Using a cross-correlation technique, process determines the station-by-station relative amplitude and phase of each event.

Peter M. Duncan, MicroSeismic Inc.

The industry is notoriously cyclical. As the price of oil fluctuates, so does the level of E&P activity that is the industry's calling and passion. One fact remains constant throughout good times and bad: The oil and gas industry is driven by technical innovation. When prices are high, the industry innovates new ways to find resources previously out of reach. When prices are low, the industry develops new ways to reduce the cost of producing the resources it has in hand.

In recent years, the prodigious development of technology for microseismic monitoring of hydraulic fracturing is one example of a technical innovation driven by high commodity prices and the resulting push to produce hydrocarbons from previously inaccessible shales. Early realizations of microseismic monitoring technology provided estimates of the source location of the sounds recorded during the fracturing process. These microseismic events were interpreted to be the result of rock breaking during hydraulic stimulation. Mapping the event locations provided an estimate of the size and shape of the treated rock volume and a visual record of how fractures evolved. As this technology matured, it became clear that an adequate deployment of geophones also could estimate the nature of the rock break (i.e., the event's focal mechanism). The focal mechanism describes the size and orientation of the break and the direction of slip.

The event's moment tensor is the mathematical representation of the source mechanism. The established process for estimating the moment tensor of an event presents several challenges. First, an adequate sampling of the event wavefront is required to map the phase and amplitude distribution of the signal over a significant fraction of the focal sphere surrounding the event. Second, the event first-arrival P-wave amplitude must be hand-picked to determine the phase and amplitude spatial distribution, which is a time-consuming and error-prone process. Also, the process of solving for all of the components of the moment tensor can be unstable and nonunique.

Most estimates of focal mechanisms are overly simplified because they evaluate only the focal mechanism of the largest events, limiting the solution to double-couple (shear only) mechanisms and limiting the number of distinct mechanism types to a small number (usually three or less). Even using this simplified method, the effort required for the process of estimating focal mechanisms makes real-time delivery of the analysis challenging. Yet the need for such real-time analysis is becoming increasingly important in today's environment.

Recently, MicroSeismic Inc. developed a method for analyzing focal mechanisms in real time using an automatic moment tensor inversion to quickly calculate event moment tensors. This automated process uses a cross-correlation technique to determine the station-by-station relative amplitude and phase of each event in comparison to an estimate of the source function derived from a linear inversion of the data. This replaces the laborious method of manually hand-picking P-wave arrival amplitudes and allows for a unique focal mechanism estimate for every recorded event. This provides a more accurate representation of the discrete fracture network geometry and a more robust event catalog. An uncertainty in the estimates also is available, allowing for spurious solutions to be rejected. The result is a more complete and accurate event catalog delivered in real time, enabling important completion decisions to be made while they are still relevant.

Such real-time results enable optimal completion of each stage, more complete refracturing jobs along the entire wellbore, detection of geohazards before they cause wasteful pumping or even failure of the completion and targeted treatment of fractures of interest. The ability of automatic moment tensor inversion to provide microseismic data in real time can improve these real-time decision-making capabilities. E&P

A 20-year history of vibrator technology innovation

Vibrator vehicle design allows broadband frequency generation and smaller footprint for accessing difficult or environmentally sensitive areas.

Dennis Pavel, INOVA Geophysical

The 85th anniversary of SEG's Annual Meeting provides an opportunity to reflect on the technological progression of onshore seismic acquisition equipment. While great strides have been made in improving acquisition systems and sensors to meet more demanding imaging requirements, great progress also has been made in the area of vibrator source technology.

In 1995, Input-Output acquired vibrator technology from Western Geophysical. Six years later, the company purchased the Pelton line of source controllers. These acquisitions extended Input-Output's portfolio beyond seismic systems to include a complete line of source products. Input-Output later changed its name to ION Geophysical and in 2010, together with BGP Inc., formed INOVA Geophysical in a joint venture focused on land seismic equipment.

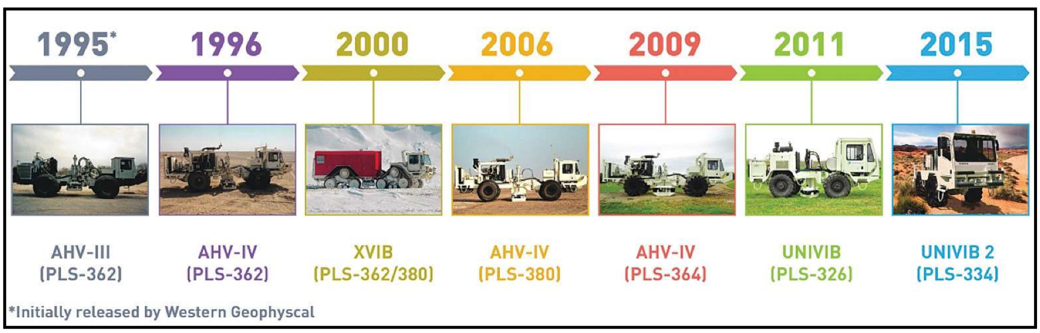
Through INOVA's history of vibrator vehicles, the articulated hydrostatic vehicle (AHV) series of large-scale vehicles has had the greatest longevity. First introduced in 1989 and in production at the time of purchase from Western Geophysical, the AHV-III 362 model offered 61,000 lb of peak force and a frequency range of 5 Hz to 250 Hz. In a similar weight class, the AHV-IV 362 model vibrator followed in 1996 with frame and baseplate improvements as well as a patented mass structure design to prolong mechanical life and enable long-term field reliability. Demand for greater peak force to image greater depths over long offsets and to allow greater energy penetration on less-than-ideal surface conditions prompted the advancement of the AHV-IV 380 heavy vibrator in 2006, which offers up to 80,000 lb of peak force.

More recently, increased interest in broadband recording resulted in the AHV-IV 364 Commander vibrator. With a peak force of 61,800 lb and a frequency limit of 1 Hz to 250 Hz with maximum peak force from 5.18 Hz, the 364 unit was the first in a series of INOVA vehicles specifically designed for broadband frequency generation. The 364 large-scale vibrator included mechanical, supply pressure and servo valve system improvements designed for better low- and high-frequency performance.

Broadband requirements, coupled with the need for a smaller footprint to access difficult or environmentally sensitive areas, propelled the recent development of UNIVIB. This small-class vehicle provides flexible hold-down weight variable from 18,000 lb to 26,000 lb and a wide frequency range from 1 Hz to 400 Hz, dictated by ground conditions and source controller settings, including drive level, peak force and hold-down weight. A second version, UNIVIB 2 is under development with the gross vehicle weight range shifted upward from the first UNIVIB, encompassing 24,500 lb to 36,000 lb.

These source vehicles are part of INOVA's CLARITY Broadband Solution, which includes broadband digital sensors, high-performance cable and cableless acquisition systems, and advanced source controllers.

Source control has been an integral part of INOVA's vibroseis technology. Beginning with the acquisition of the Pelton Co., the Vib Pro source controller experienced success due to its ability to control amplitude, phase and distortion. Launched earlier this year and developed in partnership with Seismic Source Inc., the Vib Pro HD (high definition) is the latest source controller from INOVA and offers a modern digital platform. E&P



A timeline shows the progression of INOVA's vibroseis vehicle line. (Source: INOVA Geophysical)

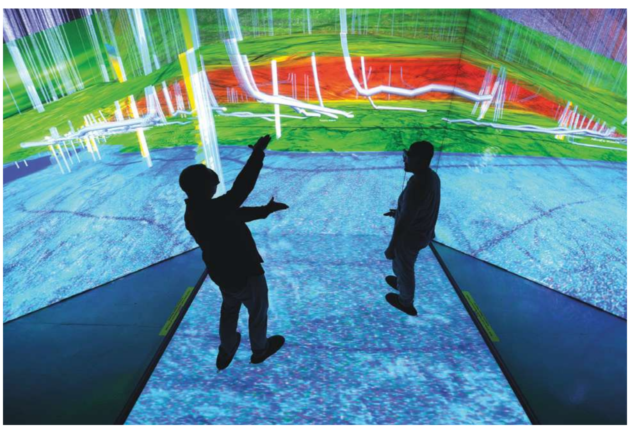
Bringing geophysics closer to the reservoir

New technologies integrate geophysics with principles of geomechanics, geology and reservoir stimulation.

Contributed by **Saudi Aramco**

Saudi Aramco will share advances in the geophysical value chain, presenting nearly 20 technical papers during the 85th Annual Society of Exploration Geophysicists (SEG) International Exposition and Annual Meeting in New Orleans. This year's contributions represent developments from all of Saudi Aramco's worldwide upstream research centers, including those in Dhahran, Saudi Arabia; Beijing; Delft, the Netherlands; and Houston.

For decades, Saudi Aramco researchers have been making substantial contributions to geophysics. Taking a multidisciplinary research approach to developing technical solutions for upstream challenges, the company has expanded its global R&D network as it aims to increase the discovery of oil and gas reserves while improving recovery rates. Saudi Aramco's upstream geophysical research is founded on three major initiatives: bringing geophysics closer to the reservoir to improve data fidelity and resolution; introducing automation into the seismic value chain to speed acquisition, reduce costs and improve processing and interpretation turnaround time; and multiphysics. These high-impact R&D initiatives have become topics of industry discussion and have opened new frontiers in geophysics research.



Saudi Aramco scientists integrate wellbore and seismic data using immersive virtual reality technology. (Source: Saudi Aramco)

"We are seeing more integration of geomechanics, geology, geophysics and reservoir simulation," said Tim Keho, senior geophysical consultant and head of the geophysics team at Saudi Aramco's Houston research facility.

Addressing the challenges of seismic monitoring on land is a common theme in many of Saudi Aramco's SEG papers. Keho said poor image quality and poor repeatability caused by near-surface variations are primary challenges limiting wider application of seismic monitoring on land.

Three of the monitoring papers examine double time-difference inversion, 4-D image warping and interferometry redatuming technologies, all of which are designed to reduce the impact of time-lapse seismic noise. "Virtual source redatuming improves image quality and repeatability by relocation of surface sources below the complex near surface to locations coincident with buried receivers," Keho said. Moreover, a new concept for reservoir characterization and monitoring will be discussed in the paper "Bring geophysics closer to the reservoir: a new paradigm in reservoir characterization and monitoring," presented by Andrey Bakulin.

Other technical papers address efficiency in imaging and inversion and introduce new technologies such as super-resolution stacking using concepts from compressive sensing and techniques to improve imaging methodologies such as reverse time migration with a new idea called de-primary to reduce depth-imaging artifacts.

Several papers will highlight research in low-rank methods to incorporate data interpolation and de-noising within imaging algorithms and exploring multiscale concepts to improve the speed of finite element modeling. The nonseismic research group within Saudi Aramco's geophysics technology team recently introduced electromagnetic (EM) methods for onshore waterfront monitoring and tested new sensor technologies. In-house EM, gravity and seismic modeling codes comprise the engine for deployment of advanced joint-inversion algorithms critical for integrating nonseismic with conventional seismic data. E&P

Enabling geoscientists to do more while spending less

Modeling tool allows 3-D geoscience mapping with increased accuracy of reservoir interpretation.

Contributed by **LMKR**

As focus moves from exploration to production optimization, asset teams turn their attention to maximizing recoveries while reducing cycle time and driving down production costs. Getting the most out of data across multiple domains, finding improved methods to interpret and integrate geological and seismic data critical to maximizing reservoir understanding, and finding new ways of mapping and visualizing assets are critical to achieving this. What was once considered high-science technology for the "specialist" is now a daily requirement for use by all members of the asset team.

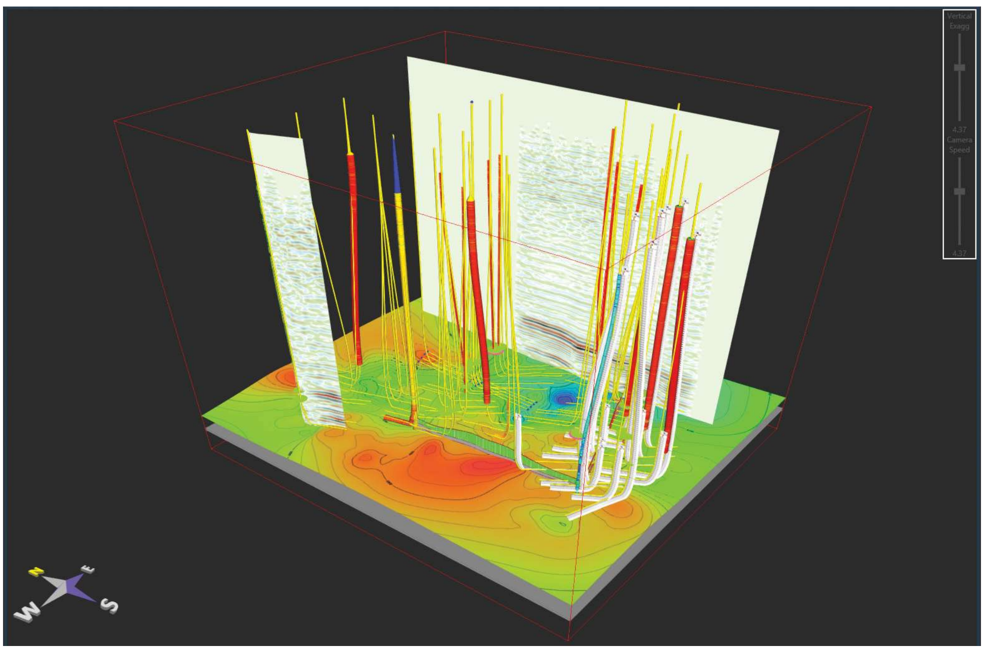
GeoGraphix 2015 seeks to address these challenges. Over the last 31 years it has evolved from a DOS-based mapping tool to a fully functional integrated 3-D geoscience system. The tool can reduce the cycle time of prospecting to production through integration between domains in addition to increasing the accuracy of reservoir interpretation through 3-D geomodeling to bring domains together in time or depth. As such, the tool enables viewing a cohesive 3-D scene for improved decision-making.

The tool includes multiple modeling tool selection and simultaneous application, Quick-Pick mode enabling correlation within multiwell cross sections and 3-D earth model updates, and views of vertical sections at any point in the 3-D geomodel.

Users can create velocity models using average or interval methods that accommodate lateral variation in velocities. These models can then be used to create static depth volumes or to perform dynamic depth conversion using interwell depth point integration.

The tool's field-planning capabilities include hazard avoidance for existing vertical wells, the display of field plans in Google Earth or Bing, the updating of target points on maps to see changes in an integrated 3-D view and productivity enhancers for field development.

The 3-D view displays smartSECTION/FrameBuilder interpretations, including geomodeled 3-D surfaces and well-to-well cross sections and fence diagrams for a geologic view. The tool also provides a geophysical view, with depth-converted seismic horizons and fault displays. Users can plan and view wells with seismic backdrops, PRIZM log templates for correlating, displays of zone attributes, the ability to modify formation tops, and production bubble maps and pie charts. E&P



Using geological and seismic interpretation, users find sweet spots in one integrated 3-D scene. (Source: LMKR)

Data center provides remote 3-D visualization for upstream oil and gas

Infrastructure addresses the need for secure, remote 3-D access to G&G applications and data for geographically dispersed teams.

Contributed by **NetApp**

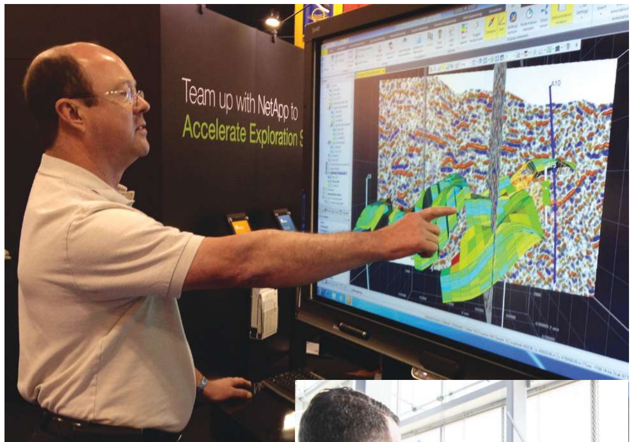
For many, the idea of working remotely simply means working away from one's desk or office. For individuals in the oil and gas industry, working remotely can mean being onsite to study the earth's subsurface in a remote corner of the world. However, technology is enabling access to critical data such as remote 3-D visualization images, which allows a mobile workforce to view the latest subsurface images—wherever they may be. Technology is allowing more efficient and cost-effective workflows in the oil and gas industry.

Imagine sitting at a desk in Houston and being able to access geological data from India that can accurately predict hydrocarbon deposits while maintaining compliance with international laws. This type of a mobile upstream workforce is changing the industry. The challenge is that an upstream IT environment is significantly different from a traditional IT environment. The upstream environment can require hundreds of different applications with a complex mix of integrated operations needs that can include both sequential and random data access, extremely large file sizes and regulatory requirements.

Moving data to visualization workstations outside of a data center is a difficult process as network connections lack the necessary bandwidth for real-time operations and workflows span organizational boundaries. Until now, remote visualization solutions have been complicated to deploy and manage and have not provided the quality or responsiveness that users expect.

NetApp, along with Cisco, Citrix and NVIDIA, developed the FlexPod Datacenter with Citrix XenDesktop and NVIDIA GRID. This infrastructure addresses the need for secure remote 3-D access to geology and geophysics (G&G) applications and data for geographically dispersed cross-disciplinary teams to improve collaboration and accelerate decision-making. Its key components include:

- FlexPod, a data center solution from NetApp and Cisco that scales to support growing workload demands without impacting performance;



A geoscientist interacts with a 3-D model of the subsurface at a remote location while the application runs in the corporate data center. (Source: NetApp)

Remote 3-D visualization allows a mobile workforce to view the latest subsurface images on any client device without local data copies. (Source: NetApp)

- Citrix XenDesktop, which can deliver applications and desktops as secure mobile services to improve mobility and provide greater security for intellectual property with centralized control. XenDesktop with HDX 3D Pro can deliver a native, touch-enabled experience that is optimized for the type of device as well as the network; and
- NVIDIA GRID technology, for offloading graphics processing from the CPU to the GPU in virtualized environments. NVIDIA GRID vGPU allows multiple users to access the graphics processing power of a single GPU to share GPU resources and broaden the reach of visualization.

FlexPod Datacenter with Citrix XenDesktop and NVIDIA GRID has been tested with G&G applications and datasets from companies such as Schlumberger, Halliburton Landmark and Paradigm to ensure that the solution will work seamlessly with the necessary applications. E&P

Seamless data integration from land to transition zone and beyond

A recently developed cablefree system enables safer, easier and faster surveys in shallow marine environments.

James Blattman, FairfieldNodal

Seismic acquisition in swamps, marshes and shallow-water transition zones poses a particularly vexing challenge for contractors tied to conventional cabled recording systems. Traditional crews spend an inordinate amount of time troubleshooting leakage issues caused by inevitably damaged cables and, at water depths of 60-plus m (197-plus ft), contractors are limited in their ability to conduct surveys at all. These marine challenges waste time and impede productivity at the very least; at worst, they put workers at much greater risk with every maintenance issue that requires attention.

Understandably, seismic contractors and oil companies alike for quite some time have been on the hunt for a low-cost shallow marine system that not only improves a crew's operational performance but also allows crews to work more safely. Using the technology of its Z700 nodal acquisition system, FairfieldNodal developed the Z100 nodal acquisition system, which is designed to meet the challenges of seismic acquisition in transition zones and shallow water.

Recent field trials in the Gulf of Mexico proved that the Z100 system provides the same advantages of the Z700 and Z3000 marine nodes, yet the Z100 nodes' reduced size and lighter weight allow smaller boats to handle them without the need for a sophisticated node-handling system. The Z100 autonomous node systems operate with near 0% technical downtime and no troubleshooting required. Production rates are increased while HSE exposure for companies and crew members is reduced.

Weighing 26 lb, the Z100 node is lightweight and man-portable and can acquire multicomponent/4-C data from onshore out to a water depth of 300 m (984 ft). Because the Z100 nodal system shares the same data management system as FairfieldNodal's ZLand system, seismic contractors can operate a single crew with a combination of ZLand nodes and Z100 nodes to overcome water obstacles such as lakes and rivers found in traditional land surveys.

Each Z100 node contains a highly accurate chip-scale atomic clock to provide acquisition-corrected timing of plus or minus 0.1 ms when deployed for 30 days. Typically, crews deploy the Z100 nodes by boat via a rope system or place them in the water individually with an anchor and float assembly for easy retrieval. Dual-tilt sensors and an internal digital compass make it possible to correctly reorient the data received from each of the three orthogonal omnidirectional velocity sensors. The Z100 nodes' circular shape and specific gravity allow excellent vector fidelity and coupling along the seafloor compared to rectangular or box-shaped nodes. E&P

The ZMarine family of nodes, the Z100, Z700 and the Z3000, are shown. (Source: FairfieldNodal)

The Z100 nodes were ready for deployment on the FairfieldNodal *European Supporter* in June. (Source: FairfieldNodal)

Hydraulic pipe recovery system reduces impact of stuck-pipe issues

A full-strength sub is positioned in the drillstring, which lands a jetting dart to sever the internal API pin connection.

Mike Churchill, Churchill Drilling Tools

Stuck pipe has traditionally been a challenge for the oil and gas industry, but during recent years it has become clear operators are even more determined to reduce the impacts associated with stuck-pipe issues.

Even with the best planning and practice, certain wells have a significant probability that some of the string will not come back out of the hole. While losing a bottomhole assembly is never ideal, far worse can be the time wasted trying to get it free and redrilling afterward. Churchill Drilling Tools decided to take a fresh look at the problem in 2014.

The results of collaboration with drilling crews in the North Sea and the Gulf of Mexico (GoM) and extensive R&D work resulted in the HyPR HoleSaver, the first hydraulic pipe-recovery system.

In March 2015 the system was first deployed by a supermajor to optimize stuck-pipe contingency in zones highly vulnerable to differential sticking. Since then, the tool has been selected by two other major operators and is being considered for deployment in a wide range of upcoming wells, in particular in the GoM.

The tool consists of a full-strength sub positioned in the drillstring, which can be severed in a couple of hours. A jetting dart is launched and lands inside the sub, jetting the internal API pin connection.

Before the concept reached the drawing board, a number of questions were considered. Could significant time savings be delivered from the point at which the decision is made to sever the string until sidetracking or fishing commences? With its expertise in dart-activated tools, Churchill decided to see whether applying those principles in a new approach could significantly cut wait times. If a new system were to help, what would its traits be?

Need for new method

A major delay in severance is often due to the mobilization of specialist equipment or personnel. This is exacerbated in remote locations or when moving restricted equipment such as explosives or hazardous chemicals. Ideally, any new method should be self-operated or at least allow cutting and retrieval operations to begin while third-party services are mobilized.

As strings become more sophisticated, each additional element has the potential to upset others. The sub must have full structural integrity and be totally benign as far as other tools are concerned (Figure 1). This means being wider in internal diameter (ID) than any lower component and having fully compliant and tapered lead-ins to ensure all activating devices and flow have an unrestricted path through the tool.

The weakest point in every joint is normally the pin, but if that area was targeted with enough energy, then perhaps it could be sufficiently weakened so that parting could be achieved with just a small loading. Calculations confirmed that removing half the pin ID would put most connections in this breakable range. The logical solution for Churchill was to use a dart to focus energy from the mud pumps precisely on to the weak point.

R&D leads to proven performance

Establishing the feasibility of making deep cuts into connections using only hydraulics was the first objective. Initial testing confirmed the first few millimeters of steel could be claimed within 10 minutes. Tests were, however, short-lived as these highlighted the major design challenge for the system.

Depending on gap size, the energy dissipated and produced by the jets at 1,325 l/min (350 gal/min) is approximately 250 hydraulic horsepower. The dart assembly has to

FIGURE 1. Full-strength (both in tension and compression) rotary API connections are put into the string, and there are no special weak points. Tool dormancy also is completely benign, with large IDs and fully compliant and tapered lead-ins. (Source: Churchill Drilling Tools)

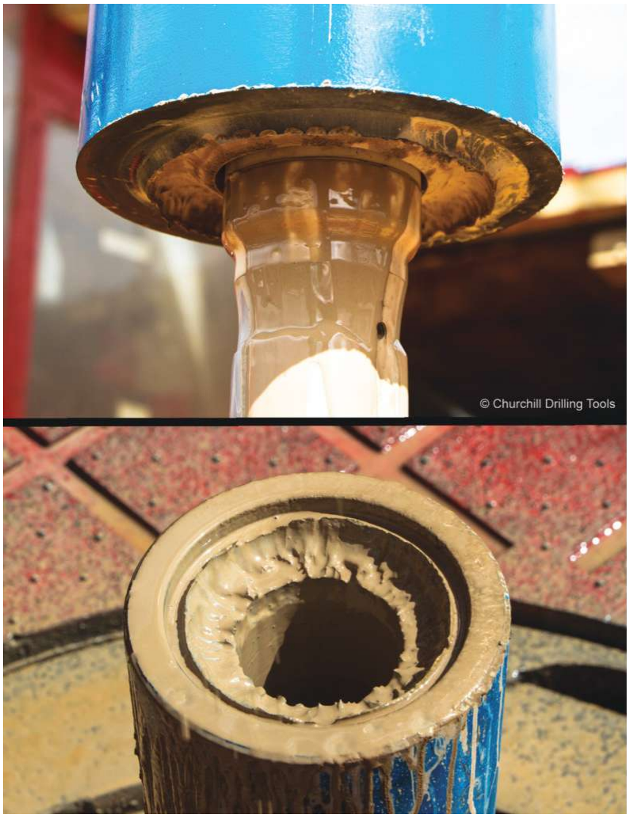


FIGURE 2. Above: The image shows a top sub with the pin cut and mud draining from the dart jet. The dart is unaffected despite the 4½-in. IF pin being completely severed. The process took just 112 minutes. Bottom: Clearly visible are the remains of the pin left inside the bottom sub, which retains a completely undamaged and fishable box. (Source: Churchill Drilling Tools)

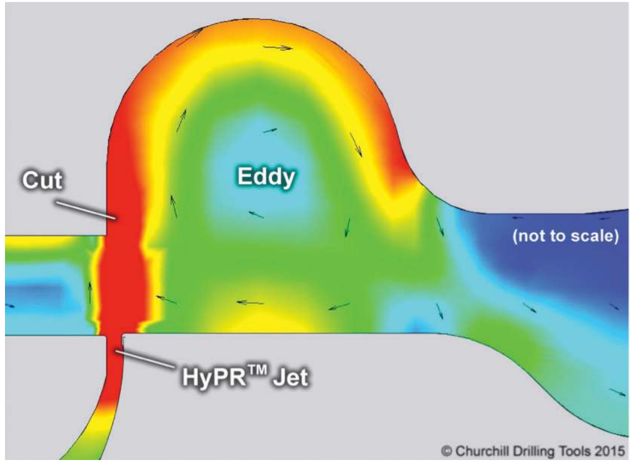


FIGURE 3. A high-velocity jet is produced from the dart by deflecting the flow through a tight ceramic nozzle at the pin's weak spot. The pin weakens rapidly, and what was a full-strength API connection is now easily parted with a small loading from above. (Source: Churchill Drilling Tools)

sustain very high loads as it deflects the flow at right angles and accelerates it up to 91.5 m/sec (300 ft/sec) through the nozzle. The jet and resulting eddies generate harmonic effects, amplifying the stresses on vulnerable areas in the assembly. Initial designs were not able to survive more than 10 minutes of flow.

In a secondary version, the seat was relocated from the tail to the nose of the dart. While this would add complexity in terms of the need for bypass channels around the seat area, it would greatly increase the stability by effectively removing an unsupported cantilever oscillating in the wake of the jet.

Priority was given to maximizing the safety factors in the fixings to remove the possibility of structural failure. By having seating below the jet, the dart can be left behind after cutting as it is no longer held in the top half of the sub (Figure 2). This enables the recovered pipe to be clear after cutting for cementing a sidetrack plug immediately.

As the darts became stronger and longer tests became possible, patterns of washing began to emerge both on the target pin area and on the dart itself. There was a dramatic wearing just below the pin in the target area. However, a smaller secondary eddy also appeared further down the wake as well as a short eddy zone just in advance of the jet. While immaterial to the cut, this wear geometry had implications for the integrity of the dart.

High-velocity zones

It was clear the high-velocity zones on the steel dart were not being totally defended by their tungsten carbide coatings. The deflection, jet and eddy areas on the dart were all showing signs of washing in the coatings. The materials in these zones were therefore replaced with solid ceramic assemblies.

Once the system was working, attention switched to establishing the performance envelope. Variables such as mud type, particle size, jet size, flow rate and connection size all impact the load on the dart and the speed of the cut. The test program was performed on a full land-rig setup with twin 5,000-psi 12-in.-stroke triplex pumps and was designed to model a full range of scenarios from slimhole to deepwater.

The performance envelope is first bounded by the circulating system power and pressure capability; second by the particle size, which limits the tightness of the jet and therefore jetting velocity; and third by the power limits of the dart in terms of physical integrity (Figure 3). The data showed it was not necessary to push close to the limits of the envelope because the cutting is very fast, even at lower flow rates.

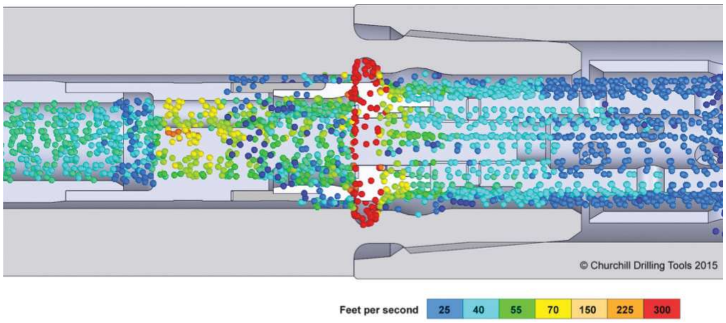


FIGURE 4. This is a fluid velocity profile as the pin is jetted away. Velocities above 30.5 m/sec (100 ft/sec) cause wear, and the red zones illustrate rapid wear at more than 91.5 m/sec (300 ft/sec). A secondary eddy cutting also can be seen below the first cut. There was a strong correlation between finite element modeling and the live rig test results. (Source: Churchill Drilling Tools)

The tool's dart is designed for free fall and/or pumping into place with a pressure increase confirming landing. As expected, the tests showed the user would see falling pressure within a few minutes of landing as the ID of the pin started to wash. Once the initial cut is made, pressure falls become less indicative as to the progression of the cut, and there is not a specific pressure indication for the pin approaching its yield point (Figure 4). Applying a small amount of "pull" during cutting will part the pipe when the time comes, and the positive result will be self-evident.

From weakness to strength

It took less than 12 months for progression from the identification of a major problem for the drilling industry to a potential solution and ultimately the creation of the tool. The HyPR HoleSaver is now being deployed to provide stuck-pipe insurance. While no operator wants to get stuck, it's reassuring to know a rapid solution is at hand should it be needed. E&P

Flexible fire protection for offshore applications

Rubber's ability to withstand extreme temperatures and weather conditions makes it a reliable option for offshore fire protection.

Doug Marti, Trelleborg

Deepwater drilling and production have been revolutionized by increasingly advanced technology in recent years, making high-performance and dependable solutions even more important. This is because, in the harsh environments presented by the offshore world, the requirement for equipment to operate safely and effectively while providing peace of mind is becoming more challenging. Fire protection is a critical part of onboard safety, and reducing the risk of fire hazards is a vital and challenging part of designing and engineering offshore oil and gas installations. Corrosion-free rubber-based solutions can be the key to ensuring that people, structures and equipment are protected.

Going above and beyond

Though technology has advanced to better address the changing environment, customers still require superior, cost-effective solutions with an increased focus on longer life. Customers once required products that could last 20 years, but now it's often up to 40 years.

For optimum fire safety, choosing the most suitable material is imperative. Rubber-based material is, not surprisingly, becoming a more popular choice within the offshore industry due to its flexibility and durability.

Compared to alternative materials such as steel, ceramic wool or fiberglass, rubber can withstand more extreme temperatures, weather conditions and vessel movements and offers an exceptionally high durability. It is a diverse material that can damp, seal and protect, and most of all, it has an extremely long lifetime.

FireNut, a rubber-based nut and bolt fire protection, is subjected to extensive fire testing. (Source: Trelleborg)

Safety first

In increasingly challenging environments, it's no surprise that onboard safety is a key priority for the offshore oil and gas industry. Ensuring this safety is paramount and is becoming more difficult.

Critical to delivering onboard safety are advanced fire protection systems, whether referring to the platform's surface protection, an onboard deluge system or coating for the pipes and flanges, for example. The performance of these is essential for the safety of personnel, asset protection and preventing event escalation.

In the offshore oil and gas sector where the risk of rapid fire spread is great, firestop solutions need to provide full assurance to the onboard team that they will not fail to protect against fire. If damage is caused, costly shutdowns and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Elastopipe, a rubber-based fire deluge system, is installed on an offshore platform. (Source: Trelleborg)

repairs would be required. In the worst-case scenario, the platform may fail altogether.

The harsh offshore weather environment causes metal products and components to be susceptible to rust and corrosion, which can be detrimental to the performance and function of the platform. Additionally, ceramic wool and similar materials used for fire protection will become less effective when wet. This simply isn't an option as demands offshore become greater.

Passive fire protection

Firestop solutions are available in a series of materials and products to protect personnel, equipment, critical components and structures and to assist emergency response activity by buying time to gain control of the fire and evacuate the area. With proven engineering and manufacturing techniques for protection of all kinds of fires, from simple cellulose to hydrocarbon and jet fire, the rubber materials consist of layers and meet corrosion, thermal, fire and mechanical protection requirements, protecting structures from exceeding temperature limits.

Rubber has the unique capability of being able to withstand weather conditions and vessel movements and to provide ease of inspection and fire protection over the life of a project.

It is key that any fire protection specified for use on an offshore facility provides the required fire protection throughout the fire exposure period. In addition, integrity means that protected areas between modules and decks will prevent the spread of flames and hot fumes throughout the fire exposure period.

For some projects there can be the requirement for a protected surface area temperature not to exceed a certain level throughout the fire exposure period. For these types of requirements, insulation materials are used in conjunction with firestop protection. The critical temperature on the surface of a component is project-specific information, with typical values falling in a maximum range of 200-plus C to 400-plus C (392-plus F to 752-plus F). Similarly, in accordance with the U.K. Health and Safety Executive, the generation of smoke and toxic fumes must remain low.

Firestop applications

The platform laydown deck areas are susceptible to regular impact and abrasion due to containers being loaded onto the platform in addition to the harsh offshore elements. A flexible decking material capable of withstanding these conditions is an ideal solution. Rubber provides the corrosion protection in addition to environmental and impact protection, all while maintaining the required fire protection rating.

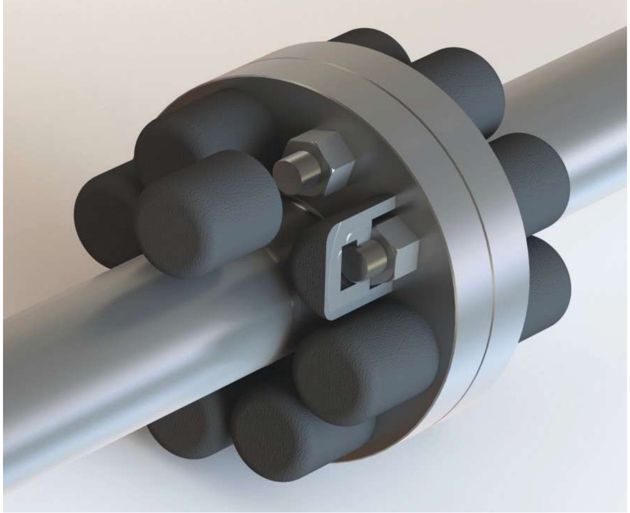
By avoiding hot work onboard, fire hazards and shutdown requirements can be reduced. Surface protection designs that can be installed using other techniques should be prioritized. Surface tiling should feature insulation to isolate fire temperatures from areas below and should also ensure a nonslip surface for worker safety. Sophisticated coating designs can withstand blasts of up to 30.5 psi and jet/hydrocarbon fires for more than two hours.

The flexibility of a rubber-based tile means that it can take up movement in any direction, reducing the likelihood of cracking. As it is regularly exposed to the sun, it should ensure UV and ozone protection so that it does not damage over time.

Other areas of the topside that should be considered for fire resistance are nuts and bolts used in flanges—one of the weakest areas of any platform. Typical fire protection, which covers the complete flange, will not allow easy inspection of the units. By protecting only the nuts, regular inspection can be performed, reducing installation time and overall weight. Using molded rubber-based material on just the flange nuts protects the stud bolts from elongating and the flange from breaking the seal during a fire.

Installing effective and reliable Firestop systems onboard can increase the safety of offshore oil and gas installations. In the harsh offshore and onshore oil and gas industry, operators need the assurance of a material that delivers proven performance without fail.

It is the responsibility of the manufacturer to ensure that it can provide high-performance and reliable solutions, now more than ever. Similarly, operators should look to work with manufacturers that can provide solutions that will guarantee performance and importantly, safety. Operators should have access to the latest and most innovative solutions that will significantly improve onboard safety and provide peace of mind to all those on board. E&P



A cutaway illustrates how the FireNut protects nuts and bolts from fire. (Source: Trelleborg)

The cost of bacterial disinfection

Monitoring and testing bacterial disinfection treatments are key to managing costs.

Mark Patton, Hydrozonix

Bacterial disinfection is a basic objective in the management of produced water. Disinfection is accomplished with the use of oxidizing or nonoxidizing biocides. Because of the relatively slow-acting nature of nonoxidizing biocides, determining the optimum dose and performing real-time monitoring can be difficult. These monitoring difficulties, when combined with the toxic nature of nonoxidizing biocides, have swayed the industry toward using mostly oxidizing biocides. Oxidizers like ozone and chlorine dioxide (ClO_2), among others, are commonly used.

Residual oxidants

Monitoring is critical for an effective bacterial disinfection program. Without proper monitoring there are no guarantees bacteria are effectively being killed. Oxidation reduction measurements and testing for residual oxidant are useful but only give a probability of disinfection. The other concern with residual oxidant measurements is that real-time methods can be affected by interference in produced water, meaning uncertainty can exist about the accuracy of these residual measurements. Nonetheless, residual oxidant monitoring has become the most common way to monitor disinfection.

Residual oxidant reacts with other additives used in fracturing, creating other concerns. Residual oxidation reacts with friction reducers (FR) and gels, effectively reducing the latter's ability to perform. Friction reduction will decrease with increasing residual oxidation, and gel viscosity and break times can be affected. Relying on residual oxidation as a verification of bacterial reduction performance is directly accepting some level of incompatibility.

An adversarial relationship exists between residual oxidation for disinfection and compatibility with other frack additives. Unfortunately, the effects of residual oxidation on compatibility have been widely ignored and underappreciated. In many applications, gel formulas are adjusted or stabilizers are added to improve gel compatibility, which in actuality merely treats the symptoms without addressing the root cause. FR concentrations also are normally adjusted, which again only treats the symptom without addressing the cause. It is not uncommon for more FR to be used than is necessary, masking the effect of incompatibility.

Water treatment technology	Number of wells	FR concentration, % in mass
Biocide	22	0.0123
ClO_2	9	0.0146
Ozone	27	0.0042

TABLE 1. A comparison is shown of FR concentrations found in Permian Basin wells over a one-year period. (Source: Hydrozonix)

Oxidant	Oxidation potential, V	Half-life @ 20 C (104 F)
Hydroxl radicals	2.8	< 1 second
Ozone	2.3	20 minutes
Hydrogen peroxide	1.8	Hours
ClO_2	1.5	93 minutes
Chlorine	1.4	140 minutes

TABLE 2. By focusing on rapid disinfection, improving mixing and mass transfer and selecting an oxidant with a shorter half-life (in red), an effective bacterial disinfection program is created that doesn't sacrifice compatibility. (Source: Hydrozonix)

Using pump pressure to dictate dosage

A yearlong case study in the Permian Basin was completed using FR concentration directly as reported from FracFocus. The data shown in Table 1 are from the same operator in the Permian Basin using the same completion method on all wells.

Disinfectants were an oxidizing biocide, ClO_2 and ozone. Instrumental in these results was the operator's commitment to adjust FR concentration based on pump pressures. This prevented overdosing. Ozone, which uses less residual oxidation, showed decreases in friction reduction ranging from 30% to 50%.

There has to be a commitment to allow pump pressure to dictate FR dose rate. This will allow an operator to enjoy the cost benefits of lower FR use while exposing the effects of incompatibility from residual oxidation.

Incompatibility arises when there is too much residual oxidation present when the fluid reaches the blender. How each oxidizing biocide affects compatibility is a result of its oxidative strength, half-life and residual concentration (Table 2). Stronger oxidants tend to work faster, and improving mixing and mass transfer will help consume oxidation and will speed up the disinfection process. The most effective approach to bacterial disinfection is to focus on rapid disinfection, improve mixing and mass transfer and select an oxidant that has a shorter half-life. This combination provides an effective bacterial disinfection program without sacrificing compatibility.

Monitoring, testing are key

In municipal water markets, residual oxidation is key. Long transit times and keeping water disinfected during transport and storage before use require strong residual disinfection. Unfortunately, this concept does not transfer to frack water reuse. The idea of needing residual disinfection to ensure there are no downhole impacts ignores the fact that additives are introduced that react with oxidizers. The chance that residual oxidation will find bacteria before FR or gels, which will be at significantly higher concentrations, is unlikely.

The goal becomes to disinfect before the blender and have enough residual disinfection to maintain disinfection in the working tanks. An effective, quantitative real-time testing program can ensure that adequate disinfection has been achieved without excessive residual. Monitoring working tanks is critical.

In many cases, residual oxidation testing is used exclusively. There are accuracy concerns testing produced water. A test program should include a real-time bacteria quantification method.

It is difficult to test for FR in real time as a result of proprietary formulas and the lack of test methods. A field device can be used to test friction factor before and after treatment. Reductions in friction reduction after treatment will indicate an incompatibility.

Fluids can be evaluated for compatibility and FR overdosing. Eliminating overdosing is important to evaluate compatibility. Testing FR at different dose rates will allow optimization of the effective dose rate. When too much FR is used, some of it can be oxidized without a significant change in friction. When the dose rate is reduced to an optimum rate, changes in concentration will have a noticeable effect on friction reduction.

This baseline test will establish a starting point to begin evaluation. With a baseline, treated water can be compared to untreated water with the appropriate FR concentration. Figure 1 shows friction reduction between a baseline of untreated water and 0.5 gpt (gallons of FR per 1,000 gallons of water), treated water with FR and treated water without FR using ClO_2. This displays a compatibility concern. It would require a decrease in ClO_2 concentration and then further evaluation of disinfection to determine if optimum disinfection can be achieved while preventing a compatibility problem.

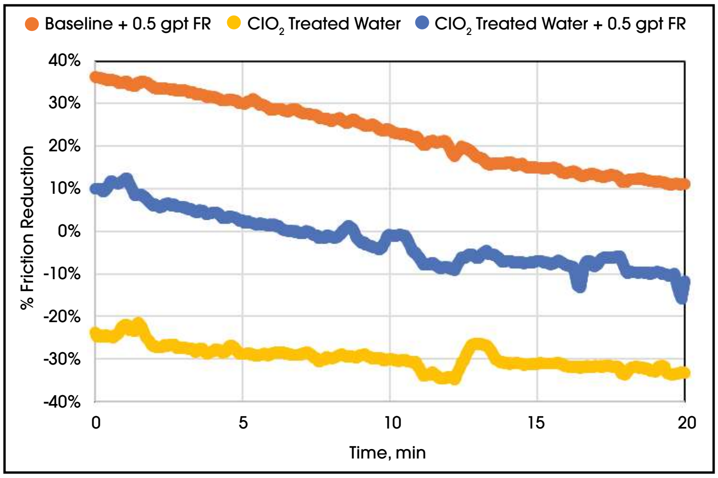


FIGURE 1. The friction reduction between a baseline of untreated water and two different types of treated water is displayed. (Source: Hydrozonix)

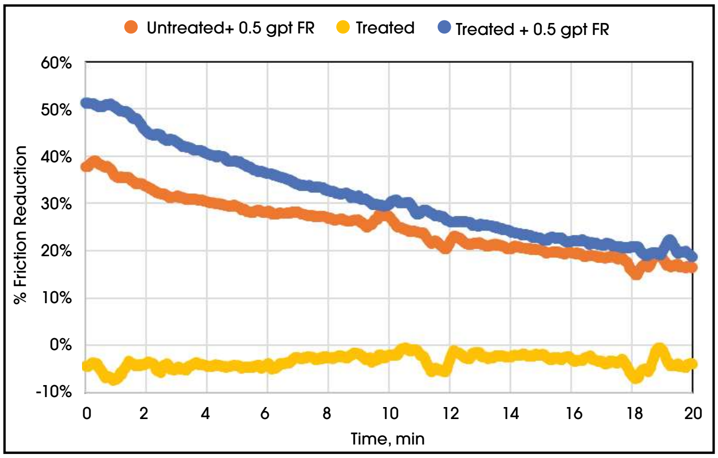


FIGURE 2. The selection of ozone as the treatment technology shows an improvement in friction reduction. (Source: Hydrozonix)

In this last example, ozone and friction reduction were monitored (Figure 2). A baseline was established, and treated water was compared with and without FR. There is an actual improvement in friction reduction. This is not unusual as a result of the mass transfer and formation of microbubbles that aid in friction reduction.

Performing these tests in the field can avoid compatibility issues in addition to helping validate the current FR dose rate. Money can be saved by avoiding compatibility issues through overdosing. Reductions greater than 50% are not uncommon and can result in significant savings. E&P

MPD automation manages narrow drilling windows with reduced footprint

Choke control system with a proportional valve replaces multiple directional valves of different sizes, resulting in a simpler and more robust design.

Blaine Dow and **Paul Thow,**
M-I SWACO, a Schlumberger company

The oil and gas industry has made great strides in developing effective techniques to drill longer wells into geologically complex formations, but it also has met challenges in the form of fluid losses and wellbore instability. Efforts to overcome these challenges gave rise to the development of managed-pressure drilling (MPD) techniques in which constant bottomhole pressure (BHP) is maintained by applying backpressure to the annulus of the well to compensate for dynamic pressure losses.

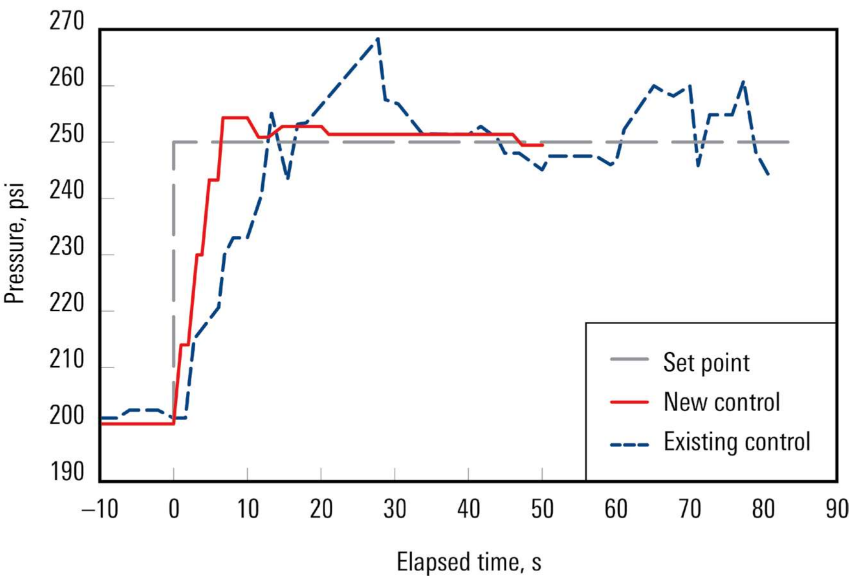
The MPD control system is used to maintain the BHP within a drilling window bordered by the reservoir's pore pressure and its fracture initiation pressure. Existing automated annular pressure-control systems use a pseudo real-time hydraulics model to determine the appropriate backpressure and then open or close a choke to restrict flow from the well and maintain that backpressure. A dedicated backpressure pump may be used to provide additional fluid volume and an extra degree of precision, but it also adds more equipment, power requirements and transportation costs to the project.

The pressure window maintained by a control system is dictated by timeliness or how quickly the system responds to disturbances; accuracy, or how far the BHP is from the target pressure; and precision, or the amount of variation in BHP. A trade-off often exists between these factors. For example, increasing the speed of the system tends to increase pressure overshoot. Finding the right balance between responsiveness and precision depends on the operator's skill at tuning the control system.

Advancing choke control

To address the industry need for more precise MPD control from a smaller and less equipment-intensive system, M-I SWACO, a Schlumberger company, embarked on a multiyear project to deliver more streamlined choke control with @balance Control Services. One component of this new system comprises a proportional valve that adjusts flow based on an electrical input signal. This valve replaces multiple directional valves of different sizes to provide speed control, resulting in a simpler and more robust design.

The other design change focused on the control loop, which was modified to output a speed and direction signal. Conventional systems provide single-loop control using a single error term derived from the difference between the measured surface backpressure and the desired set point pressure. To indicate both the direction and duration of the movement of the choke, conventional systems require a system operator to manually set proportional and integral gains.



This graph shows the comparison of response to a set-point step change between existing and new control sources. (Source: Schlumberger)

These parameters interact with each other, presenting choke tuning challenges and introducing the risk of overshooting the set-point pressure.

The @balance Control Services system operates in two modes: e-balance Control System for efficiency-focused wells where simplicity is key and i-balance Control System for difficult wells where intelligence is demanded of the control system. The control loop compensates for the error in the pressure, the speed of the choke and the rate of change in the pressure error.

Being able to rapidly change both the speed and direction of the choke allows a less complex control algorithm. The loop also provides the ability to adjust the speed of the choke in proportion to the rate of change of the pressure correction, which allows a more robust control algorithm and less tendency for overshoot.

Multitiered testing

The new MPD control system underwent a rigorous three-year testing period, beginning with short flowloop testing that helped verify system modifications as these were implemented and established an initial expectation of performance.

Another series of tests analyzed the system's ability to control step changes in pressure set point at fixed flow rate and its ability to track pressure set-point changes resulting from simulated connections. The new controller demonstrated precise and crisp response to changes in set point, as the graph shows. The controller reached the set point in less than half the time of the existing system with minimal overshoot (less than 5 psi) and quickly stabilized. Field trials were initiated following this round of testing.

M-I SWACO crew members review a connection on the operator interface. (Source: Schlumberger)

Proving field potential

A trial of the new control system was conducted by a North Sea operator drilling an exploration well with a predicted narrow mud-weight window (0.92 parts per gallon [ppg]/0.11 specific gravity [sp gr]) and with large uncertainties regarding pore pressure prediction. The operator decided to drill with a statically underbalanced drilling fluid and use MPD to keep the well overbalanced at all times. This required displacing the well between lighter underbalanced drilling fluids while drilling and a heavier overbalanced drilling fluid to maintain control while tripping.

The new system underwent acceptance testing prior to field deployment. The test well was 2,010 m (6,594 ft) measured depth and 1,535 m (4,947 ft) true vertical depth with a 15.1-ppg (1.81-sp gr) oil-based mud. The system was evaluated under both normal and contingency field operations per the operator's specifications.

During 10 simulated connections, the system maintained downhole pressure within the operator's specified upper and lower boundaries (plus or minus 36 psi). The elapsed time from the start of ramp-down to the end of ramp-up varied from four minutes to seven minutes. Two simulations tested system performance without the use of a backpressure pump. The results did not differ significantly compared to simulations when the backpressure pump was present. For contingency event simulations, the system maintained BHP within the operator-specified window of plus or minus 72 psi.

Satisfied with these results, the operator deployed the control system in its North Sea well. To verify that the correct mud weight was used to maintain static overbalance, dynamic pore pressure fingerprinting was performed prior to each displacement. The control system provided accurate control of the pressure steps at each stage.

Once the proper mud weight was confirmed, a mud rollover schedule was created using the VIRTUAL HYDRAULICS software suite to model equivalent circulating density and equivalent static density throughout the drilling and tripping process. The control system used this schedule, along with the integrated real-time hydraulics model, to automatically adjust surface backpressure and maintain constant BHP as the drilling fluid was displaced down the drillstring and up the annulus. The system successfully completed six displacements between drilling fluids and maintained BHP within a window of plus or minus 0.11 ppg (plus or minus 87 psi).

The control system also was used by an onshore U.S. operator that encountered wellbore instability problems while drilling the intermediate hole sections of wells. While the operator previously used MPD to mitigate wellbore instability problems, the remote nature of this location and limited rig space raised concerns about equipment footprint and system complexity.

The @balance Control Services allowed the removal of the backpressure pump from the MPD system, eliminating approximately 61 m (200 ft) of pipe work, suction lines to the rig's mud pits, a trip tank and pressure-relief lines. Pump removal also saved more than 31.4 sq m (338 sq ft) of space and reduced electrical power consumption from 480 v per 250 amps to 480 v per 10 amps.

Removing the auxiliary pump called for the MPD crew to trap pressure on connections. This required the control system to quickly close the choke to ensure that the appropriate pressure was obtained without overshooting the desired pressure. The control system maintained BHP to within plus or minus 0.27 ppg (106 psi) during connections, allowing the MPD crew to achieve the desired level of pressure control.

Building on early successes

Since the early field trials, the @balance Control Services system has demonstrated a response time to changing downhole conditions that is two to three times faster and as much as a threefold improvement in accuracy and precision. The system has been deployed on other wells without a backpressure pump, and Schlumberger plans to offer the backpressure pump as only an optional component on future deployments. By reducing the complexity of the field equipment, the system affords further benefits, including the option to reduce crew size. E&P

References

SPE/IADC paper 173126, titled, "Breakthrough advance in MPD automation: A new system manages narrower drilling window with reduced equipment and crew," was originally presented during the SPE/IADC Drilling Conference and Exhibition in London March 17 to 19, 2015.

Impact of CSEM on return of exploration investment

Technique has an effect on exploration capital efficiency.

Daniel Zweidler, DZA Inc. and Mack Institute, Wharton School at UPenn;
and **Daniel Baltar** and **Neville Barker**, EMGS

The primary role of exploration organizations is to deliver commercial contingent resources that allow produced reserves to be replaced, that enable growth promises and that allow shareholder value to be met. The quality of exploration investment decisions is tightly linked to an understanding of the inherent uncertainty in the geological interpretation and associated volume and value evaluation.

During the exploration process, there are known uncertainties and unknown uncertainties. The known uncertainties are those that can be assessed, such as the probability of finding a certain volumetric range of hydrocarbons in a prospect, inferred primarily from seismic information. The unknown uncertainties represent opportunities (or risks) that have not yet been identified due to the absence of data, such as alternative play models. In this case the lack of evidence does not necessarily mean new opportunities don't exist; they just cannot be seen yet.

Successful exploration companies must therefore carefully consider the type of information required in making their decisions and how the information will be utilized to minimize both types of uncertainty. The potential impact of new information has to be balanced against both its cost and the ease with which it can be embedded into existing decision-making.

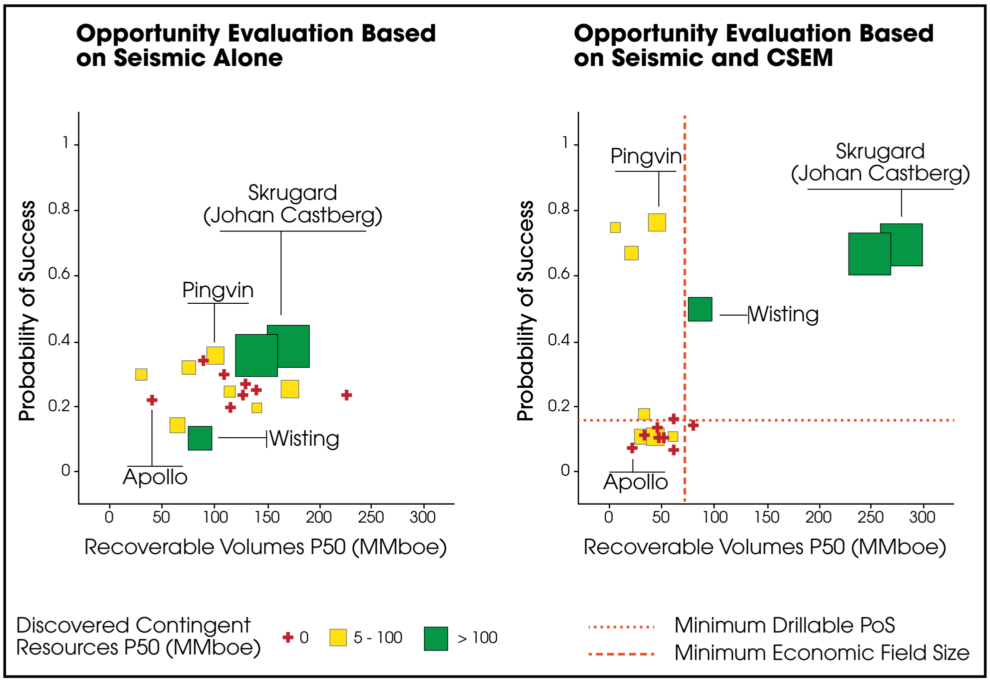


FIGURE 1. Eighteen Barents Sea prospect evaluations are compared to well outcomes. At left, reasonable PoS and P50 volume predictions made from publicly available seismic and geological information are shown. At right, updated predictions are demonstrated, with these predictions taking the seismically focused evaluation as *a priori* and updating with 3-D CSEM information. (Source: EMGS)

CSEM technology

Seismic methods provide information about the acoustic impedance contrasts between geological layers, allowing structural definition of geological features and depositional systems analysis; lateral changes in acoustic impedance and amplitude-vs.-offset effects provide constraints on lithology and fluid presence. Yet interpreters are still left with large uncertainties in hydrocarbon presence and, if present, the volumes within undrilled prospects.

In contrast, controlled-source electromagnetic (CSEM) technology provides information on subsurface resistivity. In sedimentary basins, resistivity is primarily

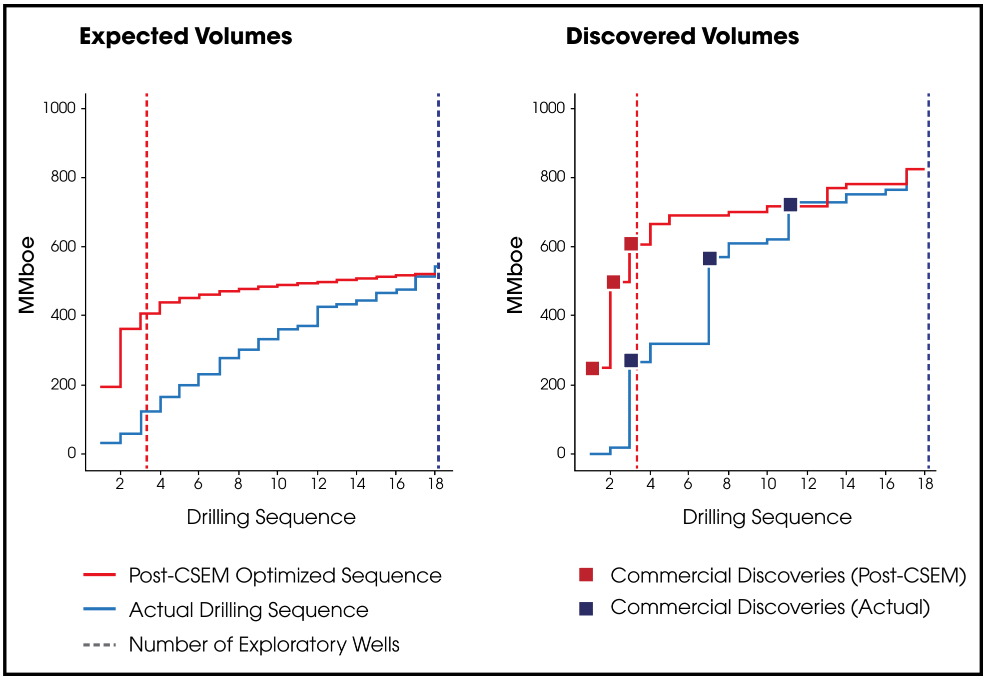


FIGURE 2. The impact of CSEM on drilling sequence and number of exploratory wells is optimized based on decreasing expected hydrocarbon volumes (left). At right is the impact of an optimized drilling sequence on actual commercial discoveries with a success rate of three out of three for the post-CSEM sequence and a success rate of three out of 18 for the actual drilling sequence. (Source: EMGS)

driven by the quantity of brine in the sediment. CSEM information also provides constraint on the area and anomalous transverse resistance (net thickness times resistivity contrast) of buried resistive layers.

CSEM-derived resistivity can therefore help explorers understand the fluid distribution and the size of the resistive bodies (net rock volume) in a basin—two of the largest uncertainties in the opportunity evaluation workflow.

Growing maturity

CSEM technology has undergone rapid evolution over the past 15 years. During this process, it has faced and is now overcoming adoption hurdles of a similar nature to those faced by geochemistry in the late '70s and seismic direct hydrocarbon indicators in the '90s.

While some acquisition systems reached maturity in the early 2000s, the algorithms to process the data into a broadly interpretable form naturally lagged behind. Even today, the core "processing" technology (3-D anisotropic inversion) is of a variable quality within the industry.

CSEM-derived resistivity images are not seismic volumes. They are sensitive to different earth properties with different levels of uncertainty. To the uninitiated, weaknesses in the information may be more obvious than strengths: Those fuzzy blobs will put off more than one geologist until they are taught how to interpret with, rather than against, the data uncertainties.

Like many new technologies, CSEM has been developed and promoted by domain experts with a limited understanding of end users and of how decisions are to be made with the information. This has led to a focus on data integration approaches suited to low-uncertainty environments. To the authors' knowledge, any potential CSEM value propositions remain immature.

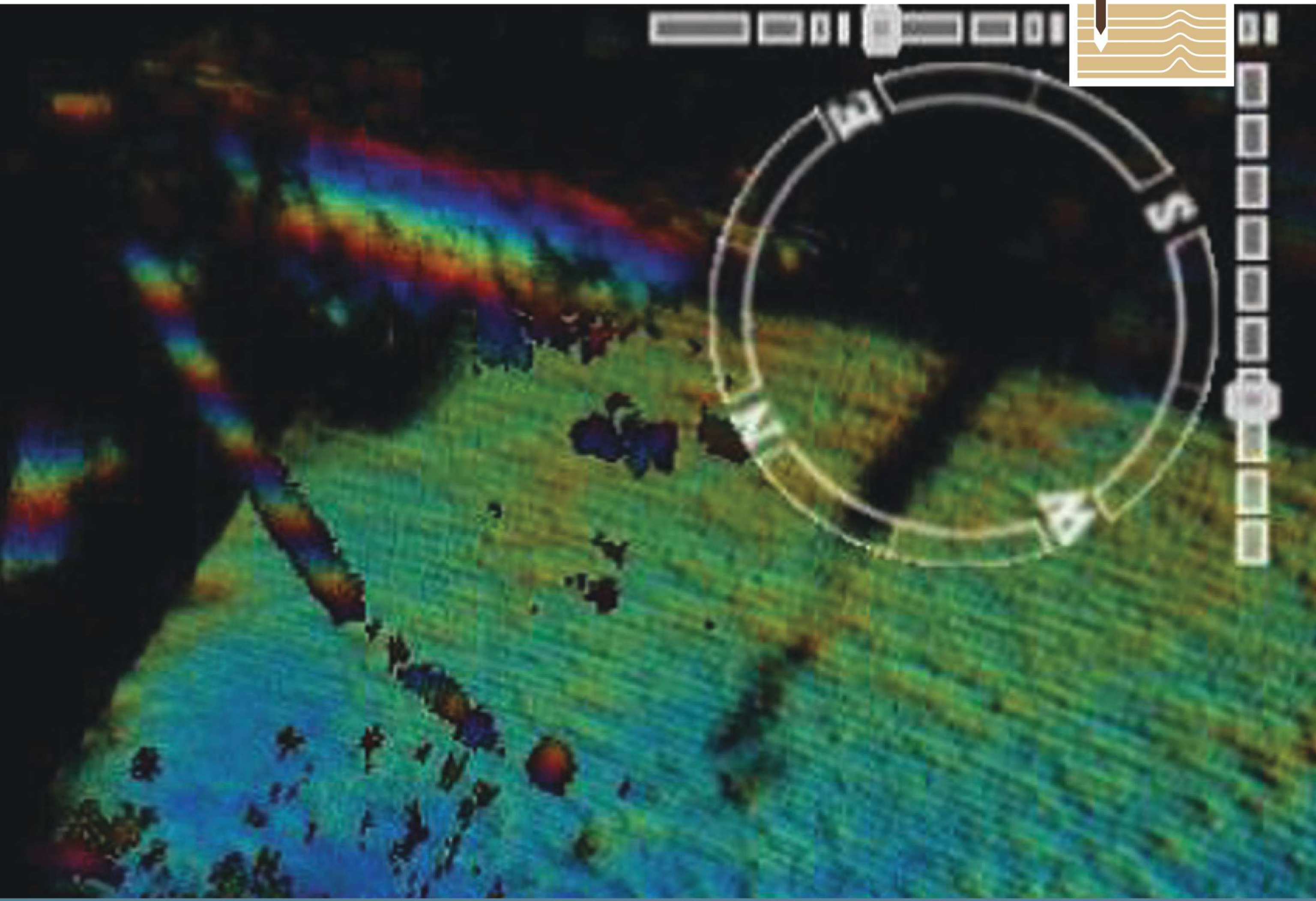
In the last few years, more experts of high-uncertainty-environment interpretation (explorers) have become engaged with the technology; corresponding progress in the reliable embedding of CSEM information in exploration is now working its way through to the literature.

Impact on exploration investment decisions

The authors had access to a CSEM dataset from the Norwegian sector of the Barents Sea that includes 18 wells drilled in the period from 1988 to 2015, with half drilled from 2013 to 2014 and only one drilled prior to 2007.

A reasonable quantitative prospect evaluation of the portfolio (Figure 1), based solely on geological and seismic information, leads to prospects ranging from 10% to 38% probability of success (PoS) with a P50 recoverable hydrocarbon range of 30 MMboe to 226 MMboe without any clear clustering.

The same portfolio integrating CSEM information using the method outlined by Baltar and Barker, 2015, has a range from 6% to 77% probability of success and volumes between 5 MMboe and 280 MMboe. Most importantly, however, the portfolio now shows clear polarization and clustering.



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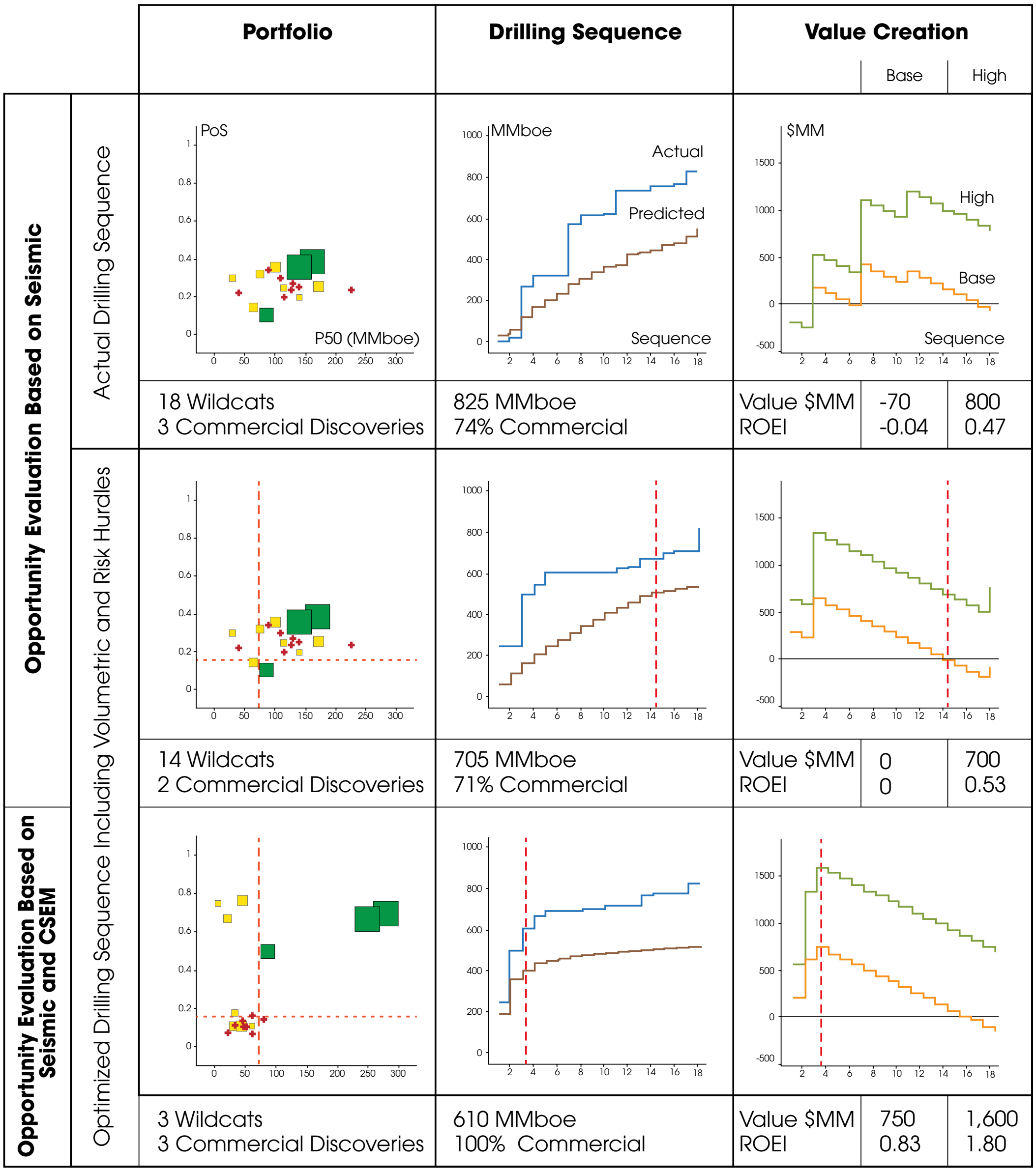

FIGURE 3. This figure summarizes the impact of CSEM-enabled investment decisions. The original drilling sequence of 18 exploratory wells delivered three commercial discoveries, with a negative ROEI based on $60 boe. A drilling sequence based on volumes and risks updated with CSEM information would have delivered three exploratory wells for three commercial discoveries for an ROEI of 0.83. (Source: EMGS)

One could argue that this comparison is unfair as the original sequence could never be optimized in this fashion due to license timing and well commitments. To address this, the return on exploration investment (ROEI, defined as the net present value divided by the exploration and appraisal investments) has been calculated for three alternative drilling sequences (actual, optimized without CSEM and optimized with CSEM). Using simple but valid cost and value assumptions based on the authors' experience in the field, value creation (and erosion) curves were generated from these drilling sequences at two oil price scenarios ($60/bbl and $80/bbl). From these curves and the number of wildcats in each scenario, under a base price assumption, only the portfolio including CSEM and an optimized drilling sequence will have a positive return; all others will ultimately erode value (Figure 3).

Turning the clock back and redefining the drilling sequence based on this new CSEM-integrated interpretation (Figure 2) shows that, in this case, the first three wells to be drilled would be commercial discoveries and any subsequent wells (which should not be drilled based on risk and volumetric hurdles) would be dry or technical discoveries—the drilling of three instead of 18 wells with the same overall commercial success.

CSEM-derived resistivity applied in large surveys wherever uncertainty is large enough is a valuable tool that allows a significant reduction in both known uncertainties (volume ranges and chance of success) and unknown uncertainties (new lead generation and basin geology insight).

The biggest challenge now lies with oil companies that must adapt their exploration workflows and train their people to harness this potential. E&P

References available.

FTG surveys can be acquired by aircraft or vessel, reducing environmental footprint. (Source: ARKeX)

FTG could be E&P game-changer

Doubts, low prices are still stumbling blocks to broad industry acceptance.

Jim White, ARKeX

It's often best to make "informed" decisions when resolving challenges. The information necessary to assist the process, although available through numerous channels, sometimes is uselessly bypassed or avoided for unknown or indefensible reasons. Often, it is not until long after the process or challenge has subsided that a historical perspective brings to light the fact that, had all available information been utilized, a more fruitful outcome could have been accomplished.

A similar review of an exploration strategy is required as the industry adjusts to continue effective exploration under a reduced budget.

Potential field methods and remote sensing technology have been widely used in the E&P process for decades, and the use of such data continues successfully today. Electromagnetic, magnetic and conventional gravity data, along with hyperspectral imagery and radiometric methods, are some of the most commonly used techniques. However, a more advanced gravity mapping process has gained significance over the past decade and has provided an enhanced subsurface picture for oil and gas exploration: gravity gradiometry. This high-resolution broadband mapping technique was initially developed by Lockheed Martin for military use and has since been declassified and made commercially available for hydrocarbon and mineral exploration. The data can be rapidly acquired with aircraft or vessels. The resolution attainable places the technique into direct and useful relevance to the design, processing and interpretation of the seismic survey.

ARKeX has been acquiring broadband gravity using full-tensor gravity gradiometry (FTG) instrumentation in combination with a scalar gravity sensor for more than a decade now, but the adoption challenge remains a large hurdle. Specific to the challenge is how to get oil and gas companies to recognize the comprehensive benefit of a broadband gravity measurement and commit budget to it at the optimal point in their exploration process. Technically, a multisensing approach that provides information on the rock's density and velocity properties makes perfect sense (who would want one's medical practitioner to run just a single test for a medical diagnosis?). In terms of risk, companies like ARKeX need to demonstrate that there is a clear and quantifiable value proposition available to those prepared to challenge a paradigm and that this delivers a distinct benefit that outweighs the cost and risk of making such a change.

ARKeX depends on an effective coaching process, relying on previously successful surveys to demonstrate the quality of the data to qualify its assertions that alter-


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ing the timing and scale of broadband gravity surveys will enhance the effectiveness and efficiency of the whole exploration process. As exploration moves into its new budgetary cycle, the development of efficient practice seems to be imperative. So how is it done?

Timing

Timing is ably demonstrated by case studies in the East African Rift, where the cost and logistical load associated with seismic acquisition and drilling drives a strong incentive to get those surveys right the first time. Operators have exploited the well-publicized attributes of broadband gravity surveys—including a low cost, low environmental impact and rapid and accurate results—to the extent that gravity data acquired using FTG instrumentation are becoming accepted as a valid work commitment associated with exploration licensing rounds. Similar opportunities are now available in West Africa and the Caribbean.

Scale

How is the question of scale addressed? Fundamentally, large-scale imaging offers two benefits. Clearly, operational costs are diluted as benefits of scale become available. More importantly, though, and on a key technical point, spectral continuity at long wavelength allows proper defendable quantitative interpretation of a deep structure without the ambiguity associated with edge effects and survey merges. In asking for the adoption of comprehensive surveys, explorationists are being asked to take a leap that involves prominent invoices associated with acquiring data that may be outside a licensed area. Geology, and more importantly its response to remote sensing technologies, does not stop at license block boundaries. Ideally, a case study is needed that illustrates this aspect of the value proposition; the majority of surveys to date are not large enough to provide a positive example, but several are in preparation.

One such case will be the environmentally sensitive U.S. East Coast, where hard work resulted in an award of the first geological and geophysical license in more than 30 years to probe this area. ARKeX spent a considerable amount of time in preparation and presentation to the Bureau of Ocean Energy Management (BOEM) and then applied for one of the nine geophysical permits to explore off the east coast ahead of the planned Outer Continental Shelf lease sale in 2021. In July 2015 ARKeX was awarded the permit to commence a multiclient FTG program specific to the offshore areas of the exploration-friendly states of Virginia, North Carolina and South Carolina. Here, scale is a necessary attribute as the broadband gravity data will be instrumental in defining both the licensing strategy and the seismic campaigns that will follow.

Unfortunately, industry funding is slow in coming as a result of a few key influences. One is the apprehension from the E&P sector that the seismic permits (for proposed multiclient programs) will still not be granted due to issues with the National Marine Fisheries Service and its incidental harassment authorizations. This will be mitigated with the realization that a responsibly designed "right first time" seismic program will minimize disturbance to the environment, cost to the exploration companies and inefficiency for the seismic companies. It should be noted that the broadband gravity won't replace seismic data. It can, however, be complementary and beneficial when coordinated with seismic programs, so any notion that by awarding ARKeX its permit, BOEM can put the others aside is erroneous.

> The timing and scale of broadband gravity surveys will enhance the effectiveness and efficiency of the whole exploration process.

Another potential impediment is the obvious curtailing of capex by E&P companies for discretionary expenditure on exploration programs that won't deliver value for a few years out, and this represents another instance of the timing paradigm. Offshore exploration, particularly 2-D seismic, has a proportionally smaller incentive to optimize the efficiency of a line plan when compared with its onshore counterpart. If the viewpoint of proportionality is abandoned and consideration is instead given to the absolute savings associated with avoiding sub-optimally positioned seismic lines, whether onshore or offshore, a real efficiency gain can be demonstrated. Clearly the efficient and properly designed survey also will be the one with the smallest environmental footprint.

In conclusion, ARKeX continues to work hard to provide asset teams with the collateral they need to procure, acquire, process and incorporate broadband gravity data into their E&P processes. Numerous successes over the years and around the world are a testament to the technical and commercial benefits of such technology. E&P

How mesh networks can drive profits for the oil industry

Kinetic mesh networks support automation and real-time monitoring on job sites, improving production efficiency and preventing costly downtime.

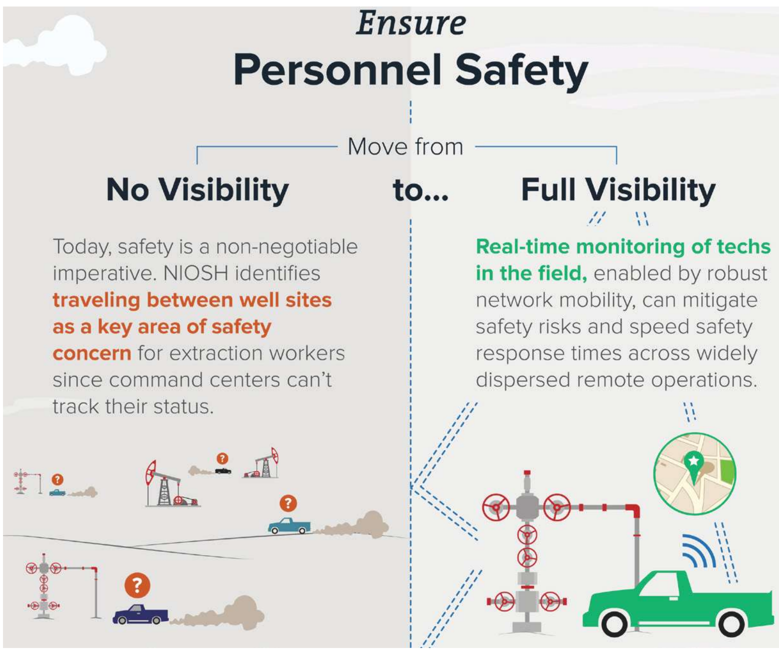
Josh Parker, Rajant Corp.

While sagging oil prices are making headlines right now, a lack of production efficiency may be the underlying issue for profitability in the oil and gas industry. Ironically, improving production efficiency may offer a way to combat declining oil prices.

A 2014 report from McKinsey and Co. stated, "With the substantial production volumes of offshore production platforms, even small improvements in production efficiency will have a meaningful financial impact as additional throughput translates directly into more revenue. In the low-volume regimes of current unconventional mature assets—oil sands, for example—carefully targeted automation steps can cut costs and, more importantly, can also improve the reliability of production equipment, leading to higher revenues that can extend an asset's economic life."

The report concluded that improving production efficiency by 10% can yield a $220 million to $260 million bottomline impact on a single brownfield asset. But to benefit, oil and gas companies have some catching up to do. Based on an analysis of North Sea offshore platforms, McKinsey found that average production efficiency dropped in the past decade, while the performance gap between industry leaders and other companies widened, from 22% in 2000 to around 40% in 2012.

So if automation can drive production efficiency, why is the industry lagging behind? There are certainly challenges associated with improving production efficiency in oil and gas, regardless of location. And historically, the industry has struggled to keep pace with certain advanced technologies such as automation.



Kinetic mesh networks tied to sensors on equipment deliver data back to the operations center, thereby reducing the need for personnel to visit each equipment location to capture needed information. (Source: Rajant Corp.)

Given the drop in oil prices, it can no longer afford to fall behind. For oil and gas in particular, getting it right is critical on several fronts. Hundreds of thousands of dollars, as well as employees' lives, are at stake.

Keeping a watchful eye

Monitoring and automating job sites both show great potential for driving efficiency improvements, which are not only beneficial from a profit standpoint but also create a safer work environment. Real-time monitoring can protect employees from equipment failure and catastrophic events.

Disastrous events are a very real possibility when employees and management are not aware of what is happening in the field. In the wake of these incidents, as well as changes in transportation and worker safety, the industry is pushing the use of monitoring technology heavily.

Real-time analytics can monitor activity on a job site and help users avoid dangerous and costly scenarios such as equipment breakdowns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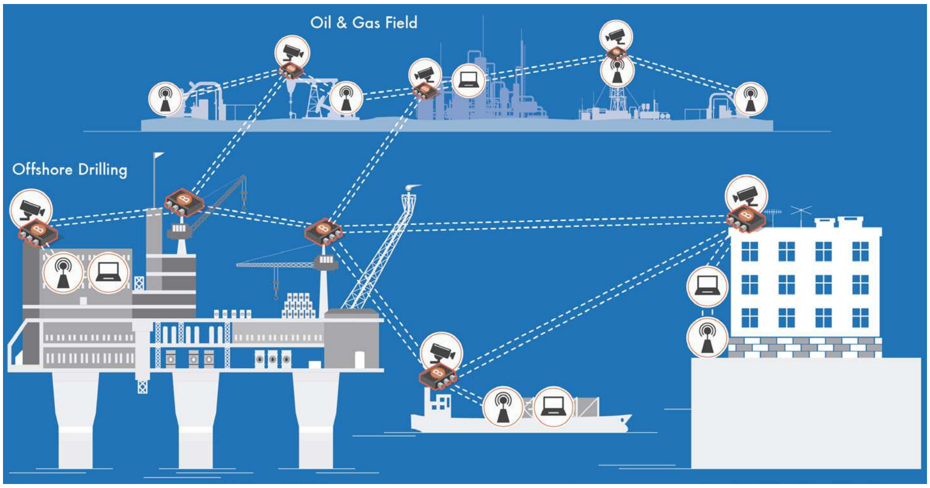
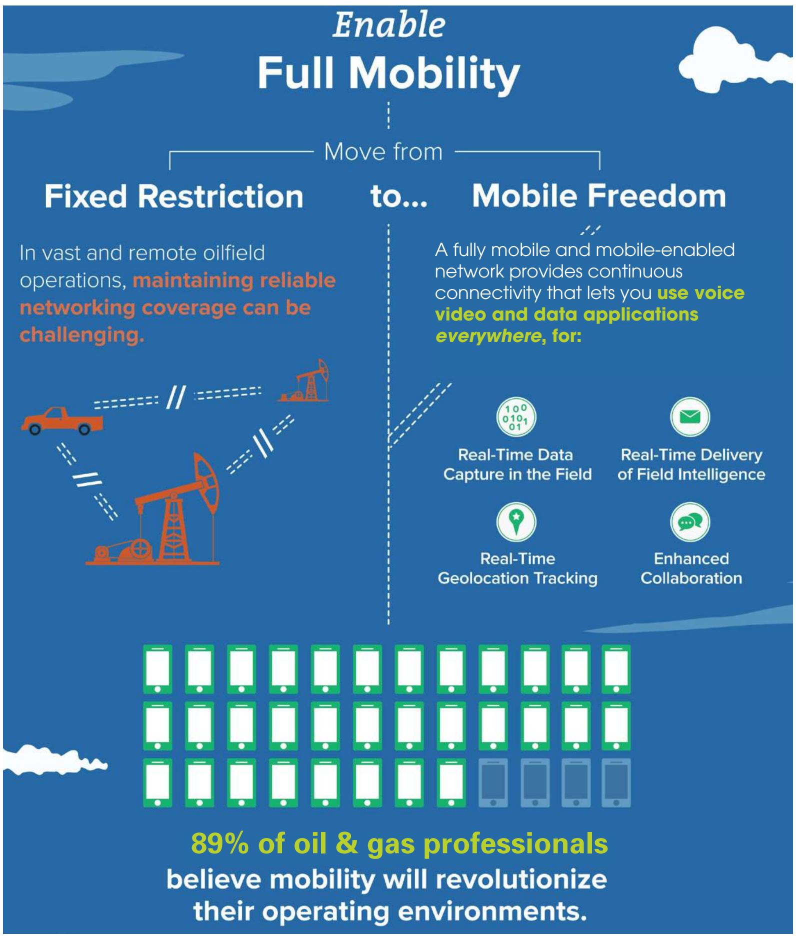


Each wireless radio or node in a kinetic mesh network is fully independent and can convey voice, video and data applications back to the network operations center, eliminating any single point of failure. (Source: Rajant Corp.)



Kinetic mesh networks are fully mobile and empower professionals to deliver service excellence without worrying about a compromised network communications infrastructure. (Source: Rajant Corp.)

and explosions. By eliminating delays in monitoring, users gain the ability to increase safety as well as efficiency because the technology gives them the ability to be proactive instead of reactive. They can solve problems before they become a liability. Risks of delayed information include the loss of equipment and lives as well as regulatory violations and hefty fines.

The oil and gas industry has been pursuing a viable real-time analytics solution for years but has struggled to get a handle on the technology. In previous models, users had to download data from multiple, sometimes hundreds, of production sites as well as download the stored files from USB drives. They then had to analyze the data and wait anywhere from days to weeks to obtain the results. Any number of incidents could occur in the meantime. For example, a $200,000 pump on the verge of failure could burn up before users were able to review data that predicted this outcome.

Fortunately, continuous technological advancements have created better monitoring solutions for the industry. Implementing a kinetic mesh network to send data across the wireless network from sensors is one option. In a mesh network, nodes use channels to create multiple delivery paths for data.

When the network needs to overcome temporary interference, the nodes will detect the quickest and most robust path of delivery to send the information. And by using intelligent path selection, nodes are able to change frequency trajectories to avoid interference and maintain connectivity. This ensures the system sends and receives the data in true real time, eliminating delays regardless of conditions. The mesh is able to "heal" itself, plus there is no single point of failure due to the nodes, so it can work around nearly any issue.

Self-sufficient equipment

Oil and gas companies can improve production efficiency in many ways by automating equipment. Maintenance is a major part of this initiative. For example, tracking equipment activity with sensors allows applications to monitor equipment conditions.

Organizations that use kinetic mesh networks can place the wireless nodes on their wellhead sites, creating a durable connection from the command center to their remote monitoring applications. These applications can carry out predictive maintenance and automated operation shutdowns, reducing the risk of equipment failure and downtime. Well-maintained equipment and decreased downtime both contribute to production efficiency improvements.

While automation has proven a challenge for the industry, some companies are overcoming it by converting existing networks into mesh networks to make them more resilient, flexible and free of a single point of failure. Automation is a major benefit of mesh and offers the industry a powerful tool for preserving revenue and lives.

One compelling example of the safety features of kinetic mesh networks is the ability to automatically shut down portions of the pipeline where the threat of a leak or explosion arises, preventing a catastrophic event.

Automation is useful in other tasks as well. In recent years high-precision drilling has been using robotics and automation with increasing frequency to change how equipment reacts to data generated by drilling activity. The drill can adjust itself to work more efficiently according to pressure and density feedback.

And if the drill is experiencing technical issues, the network can send it information—instructions of sorts—to correct technical issues, allowing the equipment to continue functioning. Automation also provides a backup; if one tool is faltering or shuts down completely, the system can cue another tool to take its place, avoiding costly downtime.

The industry has stood at a turning point with monitoring and automation for several years—from working with delayed data and reacting to trends to leveraging real-time data to control pumps from thousands of miles away. The industry has reached the point now where, sensing an increasingly urgent need for innovation, it is investing more money and development efforts into solutions like kinetic mesh networks and analytics. This trend is set to accelerate over the next few years.

Despite a slow start, the industry is steadily inching toward adopting technologies that will allow companies to improve job site efficiency and reduce costs, ultimately making the industry more profitable across the board. E&P

Underreamer control, real-time feedback exercised via MWD system

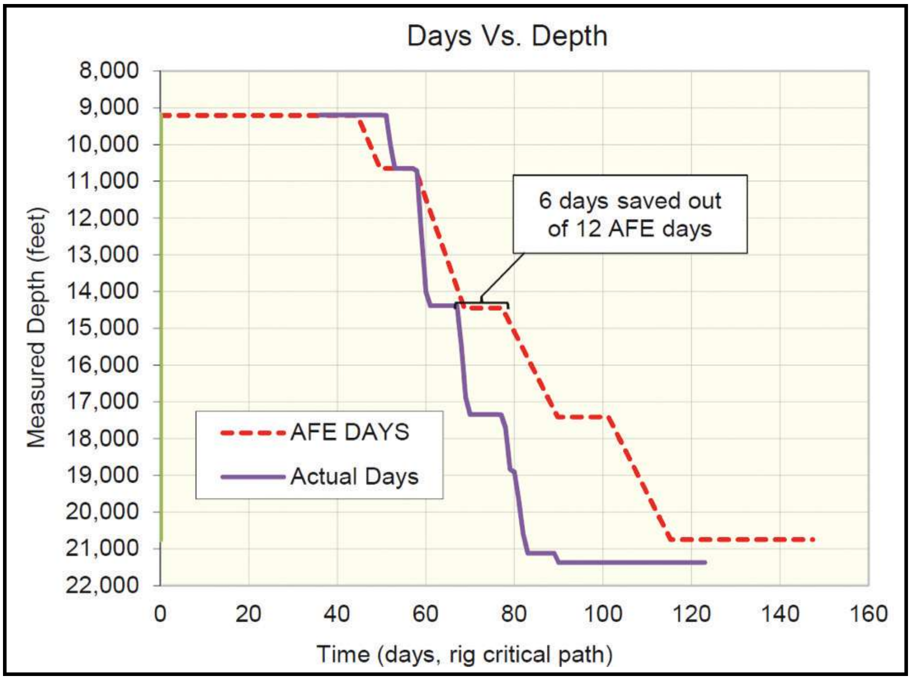
Automated drilling with on-command digital underreaming proves the value of the IoT to oilfield operations.

Sergiy Grymalyuk, Baker Hughes

With oil and gas prices at their lowest levels in years, field operators—particularly those working in challenging deepwater conditions—continually look for ways to improve well efficiency, economics and safety. On-command digital underreaming exemplifies how the Internet of Things (IoT) can raise the level of communication, operational reliability and flexibility—and with it, can provide savings in time, cost and risk—in these high-cost-per-foot operations.

Through IoT, sensors and actuators embedded in physical objects are linked through wired and wireless networks, often using the same Internet protocol that connects the Internet. The industry's first on-command digital reamer, the Baker Hughes GaugePro Echo, is powered by electrical current from the MWD system, which is generated by a mud-driven turbine or through wired pipe.

An automated drilling solution that included on-command digital underreaming helped a deepwater operator in the GoM characterize formation pressure in real time while safely maintaining circulation in the well. (Source: Baker Hughes)



An integrated drilling solution that included on-command digital underreaming enabled a well to be drilled in half the time of the AFE and eliminated the time and expense of a dedicated reaming trip. (Source: Baker Hughes)

Tool control and real-time feedback are exercised via the MWD system, which could be mud-pulse or wired-pipe technology. The blades are retracted using a hydraulically driven piston that operates independently of flow rate, fluid pressure, rpm and weight on bit.

Unconstrained by mechanical activation restrictions, the reamer can be activated and deactivated as many times as necessary. It also can provide the long-sought real-time confirmation of blade status and position, and it can send back information on oil pressure, temperature and vibration in real time for diagnostics and drilling optimization purposes.

The multiple activations reduce drilling and completion risks by enabling selective reaming of problem formations and reaming of sidetrack windows to facilitate openhole sidetracks. An additional benefit is that activation and deactivation are quick, requiring only eight minutes (via mud-pulse telemetry).

In addition to its real-time capabilities, the reamer is equipped with electronics and autonomous memory, which stores diagnostic information such as the tool mode, diameter and vibration data that can be accessed and viewed on the rig site.

The GaugePro Echo reamer can be placed multiple times anywhere within the bottomhole assembly (BHA), including very near the bit. It can drill and ream in one run, which reduces pipehandling and rig floor time along with associated HSE risks. Additionally, triple-redundancy fail-safe measures ensure that the reamer always trips out of hole, so operators can stay on schedule.

As many as three independent reamers can be placed in one BHA. This feature is especially valuable for rathole reaming. When the reamer is placed near the bit, the traditional second rathole reaming run is eliminated, wellbore conditions are improved and casing can be run faster and safer.

Compounding benefits

The first on-command digital reamer was developed jointly by Baker Hughes and an operator in 2007 as a single-size prototype controllable from the surface. The remotely operated hydraulic-electric reamer was used exclusively in the Norwegian and U.K. sectors of the North Sea. In 2012, Baker Hughes began to develop several sizes of an improved downlink-activated reamer for global offshore markets. The new reamer is the only one of its kind that can digitally confirm activation and deactivation. Thus far it has compiled a track record in the North Sea, the Gulf of Mexico (GoM) and Malaysia.

In a recent application in the GoM, a deepwater operator saved an estimated six days of total rig time—and $6 million—compared to the authorization for expenditure (AFE) plan. A well was planned with a 2.5-degree buildup rate to reach geological targets and avoid nearby wells. The operator also needed to remove the remaining pilot hole in the build section of the well so that casing could reach an optimum depth between a sand formation and a deeper slump with unknown depth spacing.

In similar hole sections in previous wells, the operator previously had to perform dedicated reaming runs to open the remaining pilot holes. Each run required a trip with a new BHA that resulted in at least 30 hours of rig time for each well, increased HSE risks and triggered hole-condition issues. Resulting tool damage, system failures and circulation loss in these wells pushed the operator to develop a 12-day AFE plan for the next well.

Combining systems, services

Combining the on-command digital reamer with an integrated rotary steerable system, MWD monitoring system and near-bit gamma service delivered precise directional control, overcame tool damage and failures and enabled the pilot hole to be efficiently reamed in the same run.

Additionally, the Baker Hughes WellLink wireline service provided web-based visualization of real-time drilling data. This service enabled office personnel to identify hazards and make even more effective drilling recommendations. The integrated solution enabled the well to be built to 3,738 ft (1,139 m) and to hit the target angle with a 2.5-degree buildup rate. The solution also did not lead to any nonproductive time or tool failures and overcame circulation loss. The pilot hole was also opened in the same run, eliminating a dedicated reaming trip.

Savings in the range of $1.5 million also were realized on two additional deepwater GoM projects. On one project, the operator wanted to eliminate as much as a rathole to maximize casing depth in an exploratory well with unknown formation pressure gradients. At the same time, the operator needed to maintain a safe overbalance by measuring formation pressures in real time.

The automated drilling solution combined on-command digital reaming with rotary steerable drilling, an LWD system that provided real-time formation pressure and mobility data, closed-loop sealing and intelligent test systems, near-bit gamma-ray LWD sensors to detect geological targets earlier while drilling, reliable neutron porosity and formation density logs at rapid sampling rates, and direct shear slowness measurements.

The integrated solution enabled the operator to characterize formation pressure gradients in real time while safely maintaining circulation on the well. Section total depth was extended, casing depth was maximized and real-time hole diameter updates were provided. The operator saved an estimated 32 hours of rig time and $1.6 million.

On another deepwater GoM well, the operator wanted to

- Build and hold a 23.34-degree angle while drilling reaming;
- Reduce rathole length without tripping; and
- Ensure reliable tool communication.

Using the on-command digital reamer eliminated the need for a dedicated rathole run and saved the operator an estimated 30 hours of rig time and $1.5 million.

In a well offshore Norway, using an automated drilling solution with the on-command digital reamer enabled an operator to drill an extremely long section 2.7 days faster than the set target despite high calculated equivalent circulating density in the 12¼-in. hole section, low drilling performance due to hard limestone stringers and unstable formations, and high torque and drag.

When objects can both sense the environment and communicate, they become tools for understanding complexity and responding to it swiftly. Automated drilling with on-command digital underreaming proves the validity of this statement—and the value of the IoT to oilfield operations. E&P

Next-generation extreme HP/HT scale, corrosion research

New research reveals differences in scale and corrosion in ultra-HP/HT environments.

Ross C. Tomson, Chao Yan, Paula Guraieb and **Mason B. Tomson,** Tomson Technologies

A key goal of the Corrosion and Scale at Extreme Temperature and Pressure project was the creation of next-generation methods and technology for use in extreme HP/HT scale and corrosion science for new offshore oil and gas production. There is a lack of data and models for corrosion and scale at extreme temperatures and pressures encountered in ultradeepwater reservoirs. The project aimed at shedding new light on these areas, thereby increasing economic security and decreasing risk in offshore production. The project was funded through the Research Partnership to Secure Energy for America and the U.S. Department of Energy.

Through this project, new methodologies for testing at temperatures and pressures ranging from normal production through extreme production conditions (up to 24,000 psi and 250 C [482 F]) were established. The project, led by Tomson Technologies, made new discoveries in inorganic scale types, developed new standards, created more accurate scale and corrosion predictive models and is poised for additional scientific discoveries through continued research.

modeling and to assess the risk of scale and corrosion. Realistic, reproducible and rapid methodologies were developed to study scale, corrosion and inhibition at HP/HT, strictly anoxic conditions (less than 1 part per billion [ppb] of oxygen) and realistic field brine compositions.

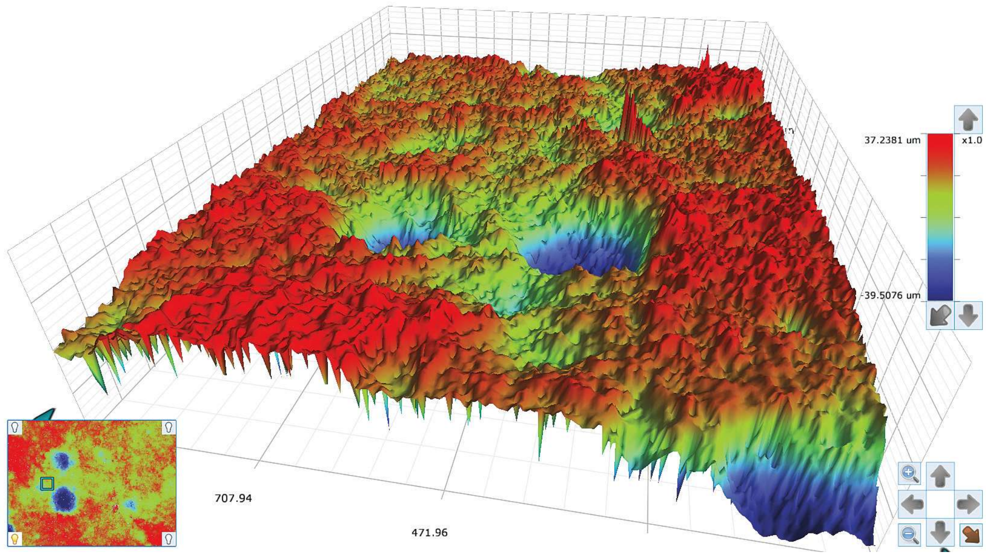
A methodology to apply vertical scanning interferometry (VSI) as a tool to automatically inspect the severity of general and pitting corrosion and deposit formation was developed. VSI requires little sample preparation, uses nondestructive white light and has vertical resolution of about 0.1 nanometers. In collaboration with Bruker, methods to use VSI for measuring both localized and uniform corrosion also were developed. The key deliverables include solubility of various scale species of interest at HP/HT, realistic brine composition and strictly anoxic conditions.

A large database for material selection was created for a wide variety of steel alloy types with experimental data from linear polarization resistance; weight loss; cyclic polarization; electrochemical impedance spectroscopy; and detailed analysis, including scanning electron microscope, X-ray diffraction, VSI and other methods. Various scale and corrosion inhibitors were evaluated for their performance and temperature stability up to extreme

Project summary

Tomson Technologies conducted the theoretical and experimental extreme HP/HT research at realistic ultradeepwater temperature, pressure and salinity conditions to validate parameters for HP/HT

An HP/HT apparatus is used to study inhibitor efficacy in field core samples. (Source: Tomson Technologies)



A VSI image shows two corrosion pits (left) on test coupon surface after exposure to 250 C field brine with CO_2. (Source: Tomson Technologies)

HP/HT conditions. Kinetics and minimum inhibitor concentration dosage for various scale species of interest under realistic field conditions were evaluated.

Developed extreme HP/HT test methodologies, equipment

To fully assess corrosion at extreme HP/HT conditions, new methods using imaging techniques such as VSI were combined with HP/HT electrochemistry probe data from autoclave experiments, inductively coupled plasma solution measurements and weight loss data. A new methodology to use VSI as a tool to rapidly and accurately analyze general and pitting corrosion was created. The project designed, built and tested both static and dynamic extreme HP/HT equipment used to study scale and corrosion up to 24,000 psi, 250 C and 300,000 mg/l total dissolved solids (TDS).

This project's advisory panel, consisting of 18 oil and gas production companies and service companies, recommended a series of alloys and brines for detailed research. The project used these fluids and alloys to further simulate realistic scale and corrosion effects in ultradeepwater production. The project experimentally obtained scale solubility measurements between the range of 100 C (212 F) to 250 C and 10,000 psi to 24,000 psi with salt concentrations that represent wells found in the ultradeepwater Gulf of Mexico.

Systems of interest such as calcium carbonate, barium sulfate, iron carbonate, iron sulfide and iron oxide scales and inhibitors with various brine compositions were studied. Until this work, scale and corrosion tendencies of these systems at extreme HP/HT conditions were unknown, and these accurate measurements helped yield more accurate prediction modeling.

New methodology: strictly anoxic testing

The current industry standard for removing dissolved oxygen from solution is to sparge. However, when studying oxidation-sensitive scale and corrosion effects, improvements were needed to reduce the dissolved oxygen content. The project designed and developed a laboratory system to produce strictly anoxic test solutions without altering the chemical makeup of the fluid. The system was able to create these solutions on the fly in real time to feed flow-through scale and corrosion experiments. Strictly anoxic conditions were used to simulate the downhole reservoir environment with extremely low dissolved oxygen concentration and were applied throughout this work. In the presence of only a few tens of mg/l of dissolved oxygen, the reaction products can be quite different from what occurs in strictly anoxic conditions, as in production wells with virtually zero dissolved oxygen.

New observation: ankerite

Siderite and magnetite are often used as model compounds in corrosion studies, but Tomson Technologies was able to demonstrate that in the presence of field brine with a distribution of divalent metal ions, the most prevalent phase to form can be ankerite. For example, ankerite formed as the corrosion product layer instead of magnetite at 200 C with simulated field brine under anoxic conditions. In addition, the dramatic effect of dissolved oxygen on siderite particle formation and appearance also was observed.

Experiments were conducted using a custom Hastelloy C-276 dynamic flow-through apparatus built during Phase I for solubility studies of various minerals including siderite, troilite and magnetite under various extreme HP/HT and TDS levels. Data collected in this research expand the solubility database of these minerals into the extreme HP/HT range, which has not previously been shown.

High-temperature scale inhibitors

The industry struggles with finding high-temperature-resistant scale inhibitors. Through this research, better candidates have been identified. Nucleation kinetics and inhibition of various scales such as siderite, iron oxides and barite under extreme HP/HT conditions were investigated. Seven commercial-scale inhibitors including polymeric inhibitors and phosphonates were tested for scale inhibition. Most of these inhibitors did not show effective inhibition for siderite at or above 100 C. However, neutral species carboxymethyl inulin was found to perform significantly better than others under these conditions. At 250 C, only sulfonated polycarboxylic acid (SPCA) showed inhibition or stabilization for iron oxides between 1 mg/l and 10 mg/l active inhibitor concentrations.

Another development seen during this project was that overdosing SPCA resulted in an iron-SPCA pseudo-scale complex, which removed inhibitor from solution and created a secondary flow assurance issue with precipitation of this pseudo-scale complex. Proper dosing is key in controlling scale under any circumstance, and this was shown to be especially true at HP/HT conditions.

Scale has major impacts on corrosion

Studying the interplay of corrosion and scale, the project found that calcite's scale tendency has a strong effect on the products and extent of corrosion on metal samples. To simulate calcite in equilibrium with the reservoir at downhole conditions, the saturation index for calcite was set to zero. Corrosion was then studied with C1018 steel coupons under these scaling tendencies. Tomson Technologies found that corrosion at 200 C was not severe (0.10 mm/year) and that the corrosion products were ankerite and siderite. Pitting corrosion was studied by VSI and showed no pitting in the test coupon. However, at a calcite saturation index of 1.15 at the same temperature (200 C), corrosion was severe, and the corrosion products were magnetite and ankerite, not siderite. E&P

In-well ESPs in deepwater—why not?

Allocating reliability to a component level will enable development of in-well ESP systems that can be deployed in deepwater developments with a high degree of confidence.

Ryan Semple, Baker Hughes

Deepwater operators have been reluctant thus far to use in-well electric submersible pumps (ESPs) because of concerns about system reliability in wells where intervention costs are extremely high. But, if early predictions about recovery factors of Lower Tertiary wells prove accurate, in-well ESPs may be necessary to achieve economically sustainable ultimate recovery in this and other deepwater and ultradeepwater basins.

Based on these predictions and intense research into ESP reliability improvement, Baker Hughes has concluded that a new, granular approach to reliability is needed, wherein required reliability is determined and validated at the component level and then rolled up to the system level. Greater confidence in overall ESP system reliability will enhance adoption of in-well ESPs to optimize ultimate recovery from deepwater and ultradeepwater assets.

Lower Tertiary's need and challenge for ESPs

The Gulf of Mexico's Paleogene play, also known as the Lower Tertiary, has been described as a potential 21st century "black gold rush" for the energy industry. The size of the prize—14 Bbbl to 40 Bbbl—is huge, but so are the challenges. Water depths are 1,524 m to 3,048 m (5,000 ft to 10,000 ft), and reservoirs run as deep as an additional 7,925 m (26,000 ft) beneath the seabed. In addition, downhole temperatures are up to 150 C (300 F), and reservoir pressures can reach 25,000 psi.

Lower Tertiary oil does not flow naturally to the surface like it does in many other reservoirs. As a result, although average recovery factors may be high initially, predictions are that the decline curve will be earlier and steeper than may have been expected.

To achieve desired recovery rates in an area where gas lifting will be extremely difficult, if not impossible, some operators have already installed ESP systems at the mud line. Placing an ESP deep in the well close to the reservoir can tremendously enhance recovery factors by significantly reducing the bottomhole pressure and allowing more production inflow. However, if a pump fails early or unpredictably, all of these benefits can be quickly offset in deepwater projects, where the cost to pull and replace a system may range from $30 million to $80 million. This is why in-well ESPs are not enjoying quick adoption in the Lower Tertiary and other global deepwater basins.

Even in shallower waters, operators need to reliably predict ESP runlife so they can more accurately evaluate their anticipated operating expenses as well as plan for intervention downtime. Unplanned downtime is always expensive, but in deepwater it can jeopardize or even destroy a project. Therefore, operators with deepwater projects that are using or contemplating using ESPs require that they be highly reliable.

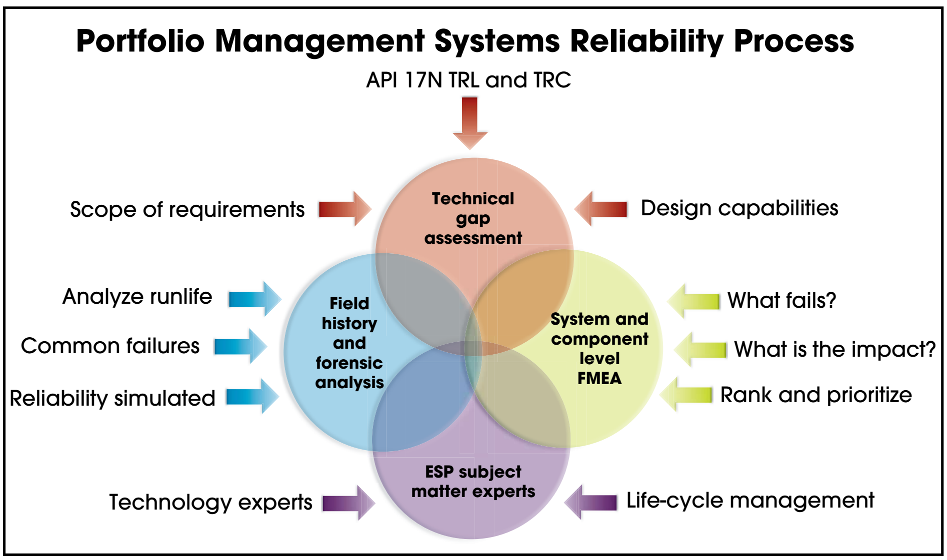


FIGURE 1. ESP component-level reliability allocation focuses on establishing what fails, modeling around it and validating improvement. (Source: Baker Hughes)

Scientific approach

In-well ESP reliability has significantly improved over previous levels. Many problematic issues have been removed by identifying shortcom-

ings and addressing them. Many ESP systems have an excellent chance of having a three- to five-year runlife. Yet the 10-year runlife that many operators desire for deepwater applications hasn't been achieved yet.

As Baker Hughes renewed its focus on research into ESP reliability improvement, it became apparent that a more scientific and comprehensive approach to determining the right areas of focus was necessary. Allocating reliability requirements at the component level had been applied successfully across numerous mission-critical systems but never for ESPs.

The process for system-reliability management (Figure 1), based on component-level reliability allocation, establishes what fails, models around it and validates improvement. The process hierarchy is as follows:

- Field data from previous systems are compiled and studied to understand how long certain components last under various operating conditions. Tasks include determining relevant failure distribution, establishing mean time to failure, analyzing failure reports and consulting with regional engineers and design authorities;
- Numerical models are built and tuned to match the historical information;
- Improvements are simulated by adjusting reliability allocation at the component level, translating the reliability up to the system level and evaluating whether the outcome meets the targeted reliability requirements; and
- Improvement targets are validated through exhaustive reliability testing at both a component and system level.

This method reduces time and expense by compressing and accelerating the testing process and enabling better control of the parameters during the accelerated reliability testing. Through simulations, the mathematical models can be tuned to match what was seen in the field and then altered to determine how systems would perform today. Through this process, it is possible to determine what needs to be done to improve component reliability and how the entire system is impacted by improving the reliability of that component.

Designing for reliability

Based on component-level reliability allocation, ESP components can be designed to include the necessary reliability as a requirement. For Baker Hughes, some examples of the ESP components that are subject to reliability assessments include O-rings, metal bellows, metal sealing elements, motor magnet wire insulation, electrical connections, thrust and radial bearings, motor oil, and materials.

At the company's artificial lift research and technology center in Claremore, Okla., component validation and verification include bench testing of all ESP components and assemblies as well as simulated condition testing in various loops, simulators and specific testing apparatus. System performance testing takes into account ESP system configuration and *in situ* simulation, including cable and umbilical lengths.

Learning from best practices

Designing for reliability is an important factor in ESP runlife, but it is only one of many factors, as Figure 2 indicates.

FIGURE 2. Complete life-cycle management for ESPs encompasses a holistic approach, which, if adhered to, can significantly extend MTTF. (Source: Baker Hughes)

For example, two North Sea operators that stress a philosophy of complete ESP life-cycle management have seen a direct positive impact on system reliability when disciplined consideration is given to best practices throughout the life cycle. For these operators, ESP technology has proven to be a robust and reliable solution. This case is demonstrated by a 7.9-year mean time to failure (MTTF) when evaluating ESP performance. Conversely, when the total ESP population in a database is considered, the degradation of runlife becomes 2.9 years MTTF as a result of diminished adherence to best practices.

Planning ahead

The intervention costs in deepwater and ultradeep water leave operators with two options for in-well ESPs:

- Make systems more reliable so intervention will be required less often. Dual completions could fit into this category; and
- Make systems easier and less expensive to intervene. This option also could include alternate deployment methods such as coiled tubing, cable and slickline.

ESP systems with high reliability are being developed through a process of allocating reliability to a component level. With this approach, operators can have a high degree of confidence as to how long a system will last and can use reliability curves to plan interventions. E&P

November 19, 2015

The Westin Houston, Memorial City
Houston, TX

7:30 am **Registration, Breakfast & Networking**

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

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

8:35 am **Opening Keynote: The GoM – A Key Part Of The Global Project Portfolio**

- **David L. Stover**, *Chairman, President and CEO*, ***Noble Energy, Inc.***

9:00 am **Panel: The Next Phase – Emerging Opportunities & Long-Term Value**

- **Brian Reinsborough**, *President and CEO*, ***Venari Resources***
- **Martijn Dekker**, *VP Appraisal and HCM, Upstream Americas Exploration*, ***Shell Exploration & Production Co.***
- **Eric Zimmermann**, *Vice President of Geology*, ***LLOG Exploration Company***

10:00 am **Networking Break**

10:30 am **Shelf Operator Spotlight: Enhancing Production Returns**

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

10:55 am **Roundtable: From R&D to JIPs & Consortiums; Competition vs. Collaboration**

- **Amol Phadke**, *Vice President of Asset Support, U.S. Offshore*, ***Statoil***
- **James Pappas, P.E.**, *President*, ***RPSEA***

11:35 am **Deepwater Operator Spotlight: A Deep Perspective**

- ***BHP Billiton Petroleum***, Speaker TBA

12:00 pm **Networking Lunch**

1:00 pm **Operator Spotlight: New Opportunity Offshore Mexico**

- **Tim Duncan**, *President and CEO*, ***Talos Energy LLC***

1:30 pm **Roundtable: Tackling The Ultra-Deepwater Challenge**

- **Roy Long**, *Ultra-Deepwater Technology Manager*, ***U.S. Dept. of Energy's National Energy Technology Laboratory***
- **David Reid**, *Deepwater Appraisal Manager*, ***Shell Upstream Americas***
- **Bret Montaruli**, *Senior Vice President, Technology*, ***ABS***

2:20 pm **Networking Break**

2:50 pm **Market Activity & Spend Trends Outlook**

- **James Hall**, *Director*, ***Infield Systems Ltd.***

3:15 pm **Roundtable: Getting To A Lower-Cost GoM**

- **Tracy Krohn**, *CEO*, ***W&T Offshore***
- **Jason Nye**, *Senior Vice President of U.S. Offshore*, ***Statoil***
- **Ronald E. Neal**, *Co-Founder and Co-Owner*, ***Houston Energy, L.P.***

4:05 pm **Closing Keynote: Lower For Longer**

- **James K. Wicklund**, *Managing Director and Senior Oilfield Services Analyst*, ***Credit Suisse***

4:30 pm **Networking Reception**

Tim Duncan
President and CEO
Talos Energy LLC

Brian Reinsborough
President and CEO
Venari Resources

Tracy Krohn
CEO
W&T Offshore

James K. Wicklund
Managing Director and
Senior Oilfield Services Analyst
Credit Suisse

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Electric ROVs closing the capability gap

With subsea operations continuing to push the boundaries to meet the market's increasingly stringent requirements, electric ROVs are narrowing the capability gap on their hydraulic cousins.

Mark Thomas, Editor-in-Chief

The significant growth in their physical size and capabilities over the past few years has resulted in electric ROVs often proving to be nimbler, greener drivers of smarter and more cost-friendly operations. This is largely due to major technical advancements across a wide scope of areas and has sparked a vibrant debate about whether they are closing the gap on their larger hydraulic cousins.

These technology advancements range from data multiplexers, fiber optics, DC propulsion, open-frame design and smaller sensors to high-voltage power transmission, auto functions, increased diagnostics, increased reliability, low-density buoyancy, smaller manipulators and discrete hydraulic power packs.

Electric ROVs such as Sub-Atlantic's Comanche light work-class unit were designed specifically to bridge the gap between observation- and work-class systems. (Source: Forum Energy Technologies).

Sub-Atlantic has manufactured cutting-edge electric observation-class ROV systems and components that have become the industry standard for hydraulic work-class ROV systems. The company has continued to build on its solid track record, recently securing a second contract with Italian oil and gas subsea services provider AALEA to deliver one of its class-leading Tomahawk observation ROV systems.

More sophisticated

"Electric ROVs have fast moved on from the days when they were basically flying cameras," said Ryan Lumsden, global product director for Sub-Atlantic. "Now they carry out a multitude of tasks due to major advancements, particularly in the assortment of manipulators, tooling and sensors they can be fitted out with.

"As a result, they have become much more sophisticated in terms of their capabilities and in more complex and challenging environments, with smaller ROVs performing tasks previously completed by larger systems."

Since its inception in 1997, Sub-Atlantic has carved out a niche for itself as a company specializing in the design and manufacture of electric ROVs, tether management systems and subsea components. In 2007 it was integrated into what has now become Forum Energy Technologies alongside the group's well-known Perry brand as part of Forum's subsea division.

The company's fleet of electric ROVs includes its Comanche, Mohican, Super Mohawk, Mohawk and Mojave vehicles, all of which benefit from its subCAN high-speed communications data network system.

Bridging the gap

The Comanche is Forum's flagship electric ROV. Considered a light work-class unit, it was designed specifically to bridge the gap between observation and work-class systems.

"One of the key considerations when designing the Comanche was ensuring it had substantial intervention capability," Lumsden said. "This was achieved by working with Schilling Robotics to develop manipulators that were compact enough to fit an observation-class ROV while retaining the capability of a work-class manipulator."

This led to a short version of the well-known Orion 7P being developed, which gave the Comanche a fully closed-loop position-controlled seven-function manipulator. This ultimately resulted in manipulative capabilities that were previously not associated with electric ROVs due to the level of accuracy and control required combined with the amount of strength and reliability needed.

"Another key consideration was hydraulic power. Although the Comanche propulsion system was natively electrical—which is what differentiates electric from hydraulic ROVs—hydraulic power was needed for the manipulators and tooling. Therefore, a compact hydraulic power unit (HPU) was developed with particular consideration given to what tools the Comanche could use to ensure the HPU was sized appropriately. This meant the Comanche could run tools such as dredge pumps, torque tools, pumping and injection systems, cutters, water jetters, and other tools, which until this time had been connected with hydraulic work class," Lumsden added.

Compact deepwater system

With a power system of 3,000 v (400 Hz) from surface to ROV, the intelligent power transmission makes the Comanche particularly suited for long tether excursions and deep live-boating operations due to reduced tether and main lift cable diameters. This, combined with a payload of up to 550 lb and a fully electric seven-thruster propulsion system configured to provide optimum thrust and lifting capability, means it is a compact system able to operate at water depths between 2,000 m and 6,000 m (6,500 ft and 20,000 ft).

In addition, its survey interfaces enable it to conduct high-spec survey work with spreads comprising dual-head multibeams, a fiber-optic gyroscope, a bathymetric system, a doppler velocity log, hydraulic boom cameras, a pipetracker, a wheeled skid, a CP with electric actuator and laser measurement equipment.

Compared to hydraulic work-class systems, the Comanche can deliver capex and opex reductions for companies because it is not only easier to operate, requires smaller crews and lower levels of maintenance, but it also needs less deck space, Lumsden said.

While acknowledging that the Comanche and electric ROVs in general can't do everything that their hydraulic counterparts can, Lumsden is quick to point out, "For ultraheavy-duty work such as construction support tasks where the ROV aids the installation of huge subsea structures, a hydraulic work class is required. However, the fact remains that the crossover with electric has increased, and the gap has narrowed."

Expanded operating envelope

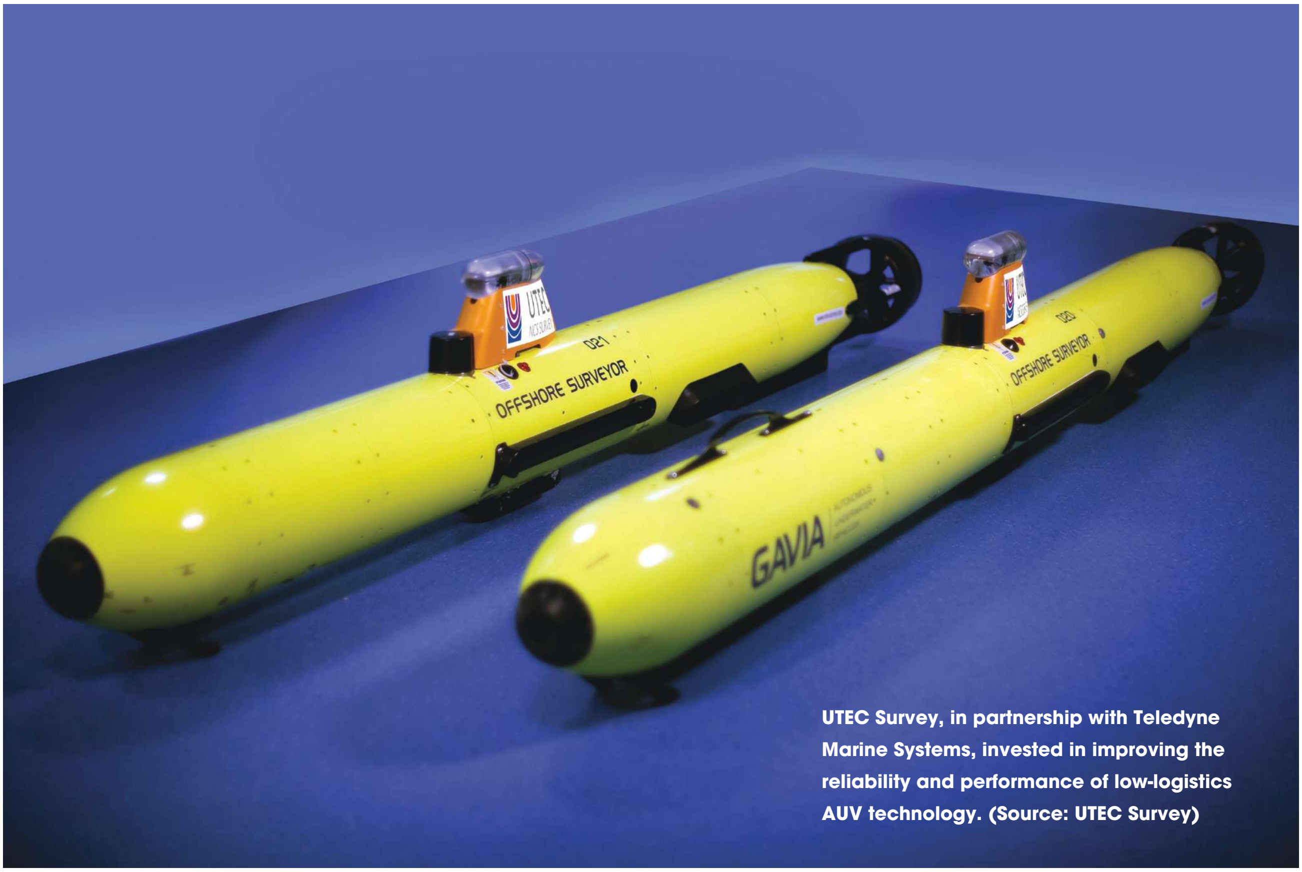
"The expanded operating envelope of electric ROVs allows them to carry out many of the tasks traditionally done by hydraulic systems," Lunsden said. "One of the major benefits of this is cost when you consider the capital purchase price is in the region of one-quarter compared with that of a hydraulic system."

The other benefit is size, he added. For example, the Comanche ROV is considerably smaller and lighter than a hydraulic system, while the vehicle's tether management system also is smaller and lighter, as is the umbilical cable and the launch and recovery system.

"Overall, this results in a more compact system footprint, which is important when vessel or rig space is limited. It also makes it more transportable, which again is useful for mobile systems that are regularly transferred between vessels of opportunity. Furthermore, using electrics rather than hydraulics for an ROV's primary power source is more environmentally friendly," he said.

The benefits of electric ROVs have been widely recognized in Europe, where they are predominantly used, in addition to the Middle East and Far East. Lumsden believes there's less uptake in other regions such as the U.S. and Gulf of Mexico partly due to Europe having more stringent inspection, maintenance and repair regulations and also simply because no one considers looking beyond the more commonly used hydraulic work-class models.

"It's a huge oversight—a bit like cracking a nut with a sledgehammer," Lumsden said. "But as the global focus on improving cost and production efficiency across the industry continues to heighten, I anticipate attention in these provinces will start to turn to electric ROVs as a much more compelling alternative." E&P



UTEC Survey, in partnership with Teledyne Marine Systems, invested in improving the reliability and performance of low-logistics AUV technology. (Source: UTEC Survey)

Low-logistics AUV operational advancements

New AUV technologies are being put to the test offshore California and Angola.

Chris Erni and **Paul Olsgaard**, UTEC Survey

AUVs can be a cost-effective way to collect critical data needed when conducting surveys. By operating at a constant altitude above the seabed and being completely decoupled from the surface, AUVs provide a stable low-noise platform that enables the acquisition of high-quality data throughout the entire operating depth range. Additionally, when using modular and portable AUVs, the ability to operate from a vessel of opportunity provides low-cost and flexible surveys.

When compared to traditional survey methods of using vessel-mounted, towed or ROV systems, there are very clear advantages to using a low-logistics AUV, namely:

- Improved platform stability and data quality;
- Consistent resolution through the operational depth range;
- Low logistics;
- Higher productivity; and
- The ability to survey in very shallow water (as little as 2 m [6.5 ft]).

UTEC Survey is invested in developing low-logistics AUV technology to provide improved survey solutions. To achieve this goal, the company developed a collaborative relationship with Teledyne. The partnership seeks to create a framework for addressing customer needs through the development of new and improved low-logistics AUV capabilities. A key milestone occurred in March when teams from both organizations met to

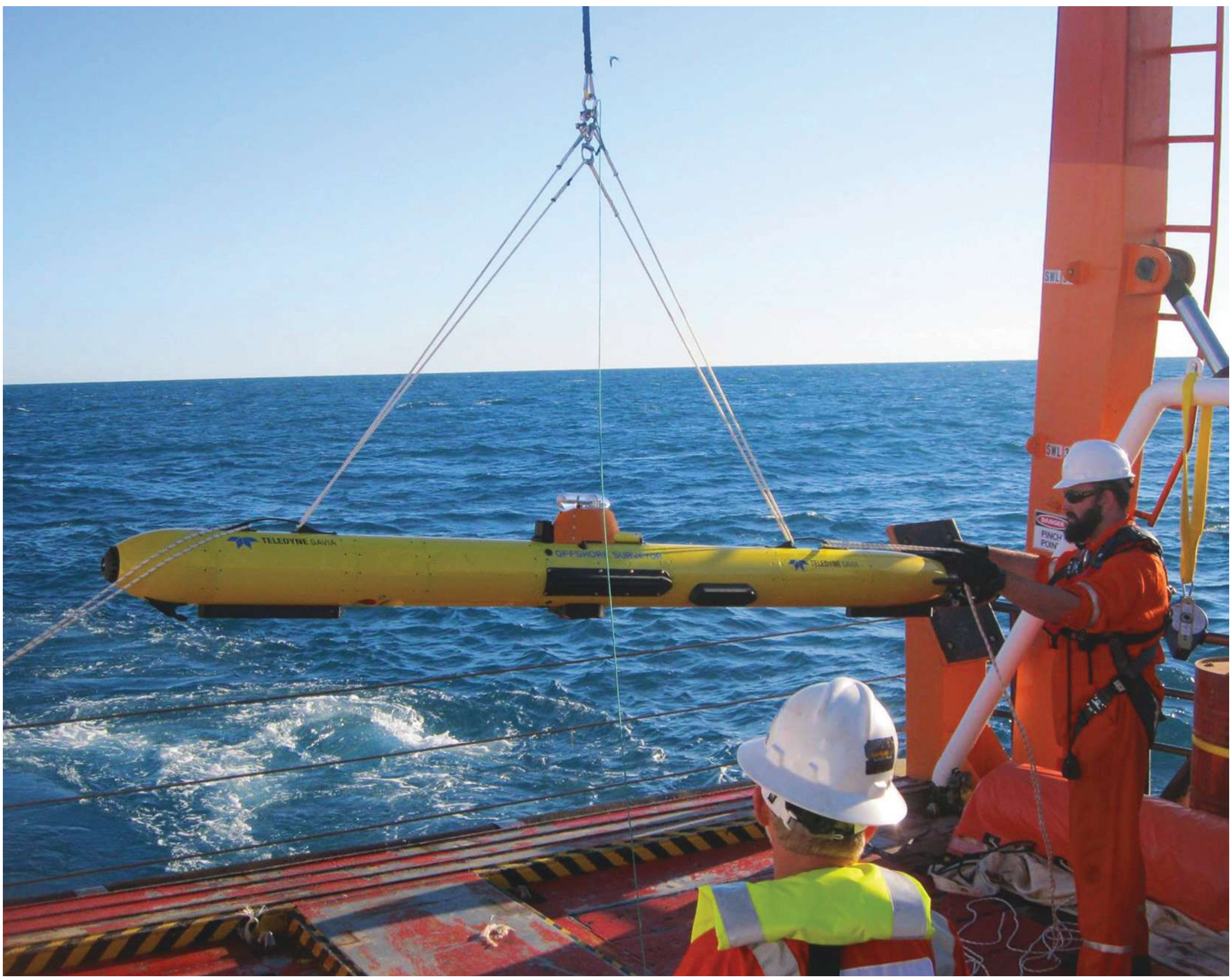
test several applications at Teledyne's Seabotix facilities in San Diego.

Successful deepwater dives

The Teledyne Gavia Offshore Surveyor is rated to 1,000-m (3,281-ft) depth. The close proximity of the continental slope to San Diego allowed UTEC Survey to prove that the technology is capable of reaching these depths and can ensure that personnel have expertise to repetitively-run missions in deepwater. During the trials, the AUV dove successfully to a depth of 897 m (2,942 ft) on three separate missions, acquiring sidescan sonar and multibeam echosounder datasets. After leaving the surface, the AUV took less than 25 minutes to reach its survey depth. In addition to the AUV, the trials utilized a variety of new technologies, including long baseline (LBL) transponders and sidescan sonars.

The Teledyne Benthos LBL transponders are deployed and calibrated in subsea arrays and can be used to enhance the AUV position solution. The derived position is integrated directly into the AUV navigation system, which can ensure accurate positioning in real time without the need for communication to the surface. Having the LBL positions integrated directly into the AUV navigation system results in the AUV being available to commence seabed survey operations with minimal delay regardless of depth. Lightweight LBL transponder nodes with acoustic burn wires allow rapid deployment and retrieval while other AUV operations are still underway.

A new model of the AUV control module, which now houses an Edgetech 2205 sidescan sonar, was used for several missions during the trials. The sidescan sonar is capable of recording low-frequency and



Testing of several applications took place at Teledyne's Seabotix facilities in San Diego. (Source: UTEC Survey)

high-frequency data simultaneously at 600 kHz and 1,600 kHz, respectively. The low-frequency transducers have a range of 100 m (328 ft) per side, while the high-frequency transducers are capable of reaching ranges up to 30 m (98 ft) per side. The range performance of the Edgetech system doubles what was being achieved with the previous sidescan sonar system and can result in a significant increase in productivity.

The new L-3 Klein Multibeam was used for several missions during the trials. The Klein UUV 3500 is an interferometer with a backscatter module that can record bathymetry at 455 kHz and backscatter at 455 kHz and 900 kHz. The effective range is 125 m (410 ft) for each side, and the technology has a superior resolution to the AUV's existing multibeam system. This more than doubles the potential daily multibeam echosounder production level for Teledyne Gavia AUVs.

A new AUV control module model with a new C-band transducer was used on missions during the trials. The new transducer design eliminates two nulls in the beam pattern to provide complete coverage and adds internal oil to provide optimum acoustic coupling. These improvements now allow uninterrupted acoustic communication between the AUV and the vessel, with constant navigation data interchange and a solid communication channel for acoustically steering the AUV via pilot mode if necessary.

Recovering an AUV following completion of a mission is one of the most challenging tasks in any AUV operation. Recovery has been improved substantially through the development of a recovery float and pneumatic line thrower (PLT). Once the AUV is on the surface, a command is remotely sent to the AUV releasing a recovery float, which is deployed from the AUV nosecone on a 10-m (33-ft) length of rope. The PLT is then used to throw a grapple over the recovery rope, allowing the AUV to be pulled back to the vessel in an easily controlled and safe fashion. The development of the new recovery float and PLT constitutes a significant improvement to the recovery process.

Case study

The UTEC AUV team recently provided support to a major installation contractor in West Africa. The Teledyne Gavia AUV performed pre-lay and as-laid surveys in support of a near-shore pipelay barge offshore Angola and Congo. Operations were completed over a three-month period from a locally chartered vessel, demonstrating the flexibility of the vehicles to be deployed from vessels of opportunity.

Pipeline route and barge anchor corridor pre-lay surveys were carried out in water depths of 3 m to 12 m (9.8 ft to 39 ft) utilizing the Gavia's multibeam echosounder and sidescan sonar survey sensors. It was subsequently redeployed to carry out post-lay surveys along the pipeline corridor to inspect for free spans and other anomalies. In addition, an anchor pre-lay survey was conducted to clear the way for barge operations alongside an existing platform. This aspect of the work scope demonstrated the versatility of the AUVs as surveys were completed inside the 500-m (1,640-ft) zone of the platform without affecting the platform operations.

This is the first time that the AUVs have been used over an extended period to support construction operations, and their use showcased the capabilities of both systems and operators. The client remobilized the vehicles in August for a further survey campaign. E&P

Quests, questions in the Cooper Basin

With a proven history of production, plenty of invested players and a bright unconventional resources outlook, the venerable basin is still alive and kicking.

Kristin Weidenbach, Oil and Gas Investor Australia

Not so long ago, people thought the Cooper Basin was dead.

Australia's largest onshore hydrocarbon resource had supplied almost 170 Bcm (6 Tcf) of natural gas to homes and businesses across a wide swath of southern and eastern Australia, but after 40 years some people thought it was on its last legs. Others had more faith, and now the believers have been proven right.

The Cooper Basin is entering a renaissance, driven by escalating domestic gas demand and the voracious appetite of three new LNG plants in Queensland.

It was New Year's Eve 1963 when the Cooper Basin was born. At 6 a.m. the Gidgealpa-2 well struck gas in the sandy wilderness of the South Australian outback. A plane bringing supplies to the isolated rig from Adelaide, 800 km (497 miles) to the south, was promptly recalled and filled with as many bottles of champagne as it could hold, and South Australia's first hydrocarbon discovery was celebrated with gusto.

"The Cooper Basin is far from decline, and we have seen strong growth in conventional 2P reserves since 2010." —Lou Dello, Santos

The discovery was made by Adelaide-based Santos in partnership with Delhi Petroleum, owned by Texas oil baron Clint Murchison. Santos owned the acreage, and Delhi provided funding, operatorship and experience to the then-fledgling Australian company. Further drilling soon confirmed a medium-size gas field at Gidgealpa, but it wasn't until the discovery of the much-larger Moomba Field in 1966 that a commercial volume of gas was assured.

By then, British oil giant Burmah Oil Co. had joined the partnership, bolstering Santos' technical expertise and providing valuable direction for construction of the gas processing plant at Moomba and the pipeline to Adelaide. It also offered commercial advice for contract

SELECT COOPER BASIN WELLS

The following well information is taken from the database of more than 400 Australian wells listed in the *Oil and Gas Investor Australia* Wells Report.

Well	Operator	Status	Product	Activity
Swan Lake-16	Santos Ltd	Completing	Gas	Cased and suspended as future producer
Emergy-1	Santos Ltd	Shut-in	Gas	Drilled, cased and suspended
Martlet North-1	Senex Energy	Shut-in	Oil	Drilled, cased and suspended
Growler-1	Senex Energy	Shut-in	Oil	Drilled, cased and suspended
Callawonga-10	Beach Energy	Drilling	Gas	Drilling ahead
Bauer-14	Beach Energy	Shut-in	Oil	Drilled, cased and suspended
Marsden-1	Strike Energy	Drilling	Gas	Drilled and completing
Klebb-3	Strike Energy	Completing	Gas	Drilled and testing

Source: Oil and Gas Investor Australia Well Report (ogiaustralia.com)

This well information is taken from the database of more than 400 Australian wells listed in the online *Oil and Gas Investor Australia* Wells Report. (Source: *Oil and Gas Investor Australia* Wells Report)

negotiations with the first industrial customers—the South Australian Gas Co. and the Electricity Trust of South Australia.

Burmah's leadership—in conjunction with Delhi's initial failure to detect hydrogen sulfide (H_2S) in the Cooper Basin gas, leading to expensive design modifications at the gas plant—resulted in Santos gaining operatorship of the Moomba plant in 1971, which it has retained since. Delhi continued as exploration and field production operator in various roles until Santos finally took over all Cooper Basin operations across Queensland and South Australia in 1992.

Still going strong

That was then; this is now.

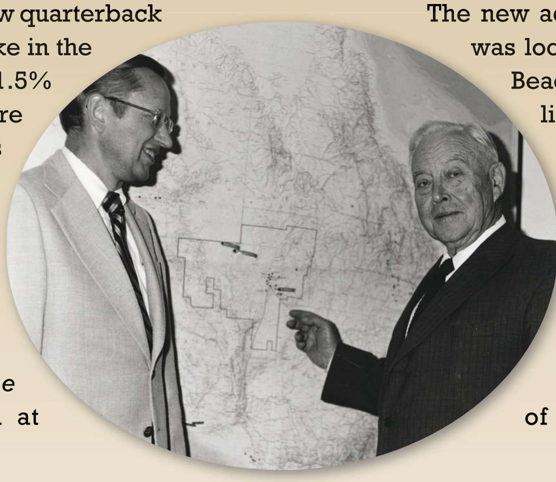
"The Cooper Basin remains a valuable producing asset for Santos," said Lou Dello, Santos' general manager for Central Australia. "The Cooper Basin is far

Changing interests in Cooper Basin

The Cooper/Eromanga Basin has seen myriad joint-venture (JV) partnerships. Santos secured the original leases and has always kept the lion's share, with Delhi Petroleum being a major shareholder since the beginning of commercial operations. However, the second generation of the Murchison family was not as passionate about the oil business as the patriarch had been.

Clint Murchison Jr. was more interested in his ownership of the Dallas Cowboys than he was in Delhi. So when the Cowboys needed a new quarterback in 1980, Delhi and its 17.2% stake in the Cooper Basin gas fields and 31.5% interest in the liquids project were sold to CSR for $514 million. This put a valuation on the entire Cooper Basin resource at that time of about $3 billion.

"Who would ever have believed a Dallas quarterback could cause such turmoil for an Australian gas producer?" *The Australian* newspaper mused at the time.



Santos' first chairman of the board, John Bonython (right), is shown with Clint Murchison Jr., who reportedly had much more interest in his ownership of the Dallas Cowboys than the ownership of Delhi Petroleum that he inherited from his father. He famously sold the company's stake in the Cooper Basin to Beach Energy when the Cowboys needed a new quarterback. (Source: Santos)

When Delhi came up for sale again in 2006, Santos assumed that it was Delhi's natural heir and announced an agreement to buy its longstanding partner. But fellow Adelaide resources company Beach Energy also wanted Delhi and engineered a secret deal to scoop Santos.

Beach had been operating its own permits in the basin since 1978, substantially increasing its holdings when portions of Santos' exploration acreage were forcibly relinquished in 1999. The South Australia government concurred with other petroleum exploration companies that Santos was unable to adequately explore the huge amount of acreage it held and wanted to stimulate competition in the basin. Beach's then-managing director, Reg Nelson, was one who didn't subscribe to the idea that the Cooper Basin was in decline.

"We seized the opportunity of the burning and long-held belief I had that the Cooper Basin was a long way from being clapped out," he reflected recently.

The new acreage Beach Energy obtained was located on the flanks of the basin. Beach considered these areas more likely to be oil-prone, with oil from the Permian source rocks migrating to Jurassic reservoirs on the fringes of the basin. Discovery of the Kenmore and Bodalla oil fields in southwest Queensland soon proved the gamble correct.

With the surprise purchase of Delhi in 2006, Beach's ownership of the Cooper Basin increased to encompass a 20.21% interest in the South Australian portion of the Cooper Basin JV (SACB JV) and 23.2% of the southwest Queensland portion (SWQ JV), both operated by Santos. For Beach, the Cooper Basin is now the engine room of the company, responsible for 99% of production and consuming 85% of capex. Santos and Origin Energy hold 66.6% and 13.19% of the SACB JV, respectively, and 60.06% and 16.74% of the SWQ JV. ■


CUDD
WELL CONTROL


30
40
Time (min)
CUDD
WELL CONTROL

from decline, and we have seen strong growth in conventional 2P reserves since 2010."

He highlighted underexplored greenfield potential in southwest Queensland, significant gas-in-place resources in greater Tindilpie, the liquids-rich northern fields in South Australia and further development opportunities at Moomba and Big Lake.

In 2014 the Cooper Basin produced 16.2 MMboe, approximately 30% of Santos' total production. Of this production, 20% came from oil, 67% from gas and the remainder from condensate and LPG.

In the current environment of constrained world oil prices, activity in these jointly held areas is focused on maximizing efficiencies and operating only the best wells across the basin's 190 gas fields and 115 oil fields, Santos CEO David Knox told shareholders at the company meeting in April. Those fields contain about 820 producing gas wells feeding into production facilities at Moomba in South Australia and Ballera in Queensland for gas sales to Sydney, Adelaide, Mount Isa and Brisbane.

Ethane is piped to the Qenos petrochemical plant in Sydney, while gas liquids, condensate and oil from the more than 400 producing oil wells are piped to wharf facilities at Port Bonython near Whyalla, South Australia, for export.

Demand for gas is expected to triple in the next few years as New South Wales sales contracts expire and LNG plants on the Queensland coast at Gladstone ramp up to full production. Santos is buying 20.2 Bcm (714 Bcf) of Cooper Basin gas from its so-called Horizon portfolio to help fuel its Gladstone LNG (GLNG) plant, while Beach Energy is selling gas to Origin Energy for its Australian Pacific LNG (APLNG) plant.

"GLNG has facilitated the development of our coalseam gas fields in Queensland, but it also has been an essential catalyst for the development of our wider east coast resources," Knox said.

"It has exposed the Cooper Basin to new markets, which has made continued development of the Cooper viable," he added. "If Santos had remained as heavily focused on the domestic market as it was just 10 years ago, those resources would not be commercially viable today. Higher gas prices lead to higher investment and ultimately production. And that is what is happening in the Cooper today."

After a long history of oil and gas success, the Cooper Basin is entering a new era as rising gas demand and new LNG plants in Queensland lead to a bright unconventionals outlook. (Source: Santos)

Oil became a resource with the Innamincka-1, the first deep oil exploration well in the Cooper Basin. (Source: Santos)

Unconventional future

After the gas discoveries of the 1960s and 1970s and the oil boom of the 1980s, it is the rise of the unconventionals that will take the Cooper Basin into the new millennium and beyond. Deep coals, tight sands and shales are all being investigated in the new wave of exploration.

Santos' super Cooper success

Dale Granger, Oil and Gas Investor Australia

Santos' remarkable recent exploration results in the Cooper Basin have yielded a 75% success rate vs. a 10-year record of 55% success across the broader Santos exploration drilling program.

Bill Ovenden, Santos' general manager of exploration and subsurface, said the company's longevity in the Cooper region was a significant factor contributing to the high rate of discovery of commercial hydrocarbons.

He said the driving force across the Santos exploration portfolio, including the key to favorable Cooper Basin outcomes, was a deep understanding of the rocks in key areas of operation underpinned by regional studies and a play-based approach to exploring.

He said big high-quality seismic datasets were the key to good regional play understanding. An additional overlay of advanced data inversion technologies, prompting new thinking and ideas, is fundamental to the future Cooper exploration harvest.

A balanced portfolio of drilling opportunities added further impetus to yields.

"Typically, our broader exploration program combines a minor measure of higher risk frontier investigation offset against a lower risk program in emerging basins with proven petroleum systems and infrastructure-led or near-field exploration in mature operations areas such as the Cooper," Ovenden said.

In the current oil price environment, the investment balance is being directed much more toward the lower risk infrastructure-led inventory.

"The Cooper near-field exploration contributes strongly to the higher exploration success rates. However, though the basin is quite mature, we are still chasing new play concepts," Ovenden continued.

"One of the recent breakthroughs has been in a real wildcat play, the deep coal. We are constantly learning new things about the Cooper, pursuing excellence and acquiring technical rationale through the drillbit." ■

In 2012, 46 years after the Moomba-1 gas discovery of 1966, the first commercial shale well in the Cooper Basin commenced production. Moomba-191 is flowing natural gas at a rate of 48 Mcm/d (1.7 MMcf/d) from the Roseneath, Epsilon and Murteree shale rock, with a composition consistent with gas produced from the Moomba/Big Lake area. Santos currently has three unconventional shale wells in production.

"Although it is still early days, Santos is encouraged by the potential of unconventional resources in Central Australia," Carl Greenstreet, Santos' general manager of unconventional resources, said.

"Across the Cooper Basin in South Australia and southwest Queensland and in the Amadeus Basin and McArthur Basin in the Northern Territory, we have 100,000 sq km [38,610 sq miles] of highly prospective acreage in unconventional gas plays."

However, with world oil prices at a six-year low, much of the unconventional resources program has been put on the shelf. Despite the great gas potential in the Cooper Basin, it is a time of belt-tightening and protecting finances until economic conditions improve.

"I do believe it will be developed; it's just going to take some time, and we're not going to rush out in this environment and spend all of our equity dollars," said Chris Jamieson, Beach Energy's group executive of external affairs.

Beach Energy is exploring tight gas acreage in the Nappamerri Trough with permits covering more than 800,000 acres stretching across the South Australia/Queensland border. Despite the disappointment of Chevron exiting the partnership in March, Beach and junior partner Icon Energy (which holds a 35.1% interest in Queensland permit ATP 855) are upbeat about the future opportunities.

"During the past three years the joint venture flowed natural gas from four wells, achieved the highest flow rate from a shale gas well [Halifax-1] in the Cooper Basin, had six petroleum discoveries in ATP 855 and has identified a significant natural gas resource within the Permian formations of the Nappamerri Trough," said Icon Energy Managing Director Ray James.

Chevron plowed $330 million into the program, which has uncovered 2C contingent gas resources of 45 Bcm (1.6 Tcf) in the Queensland permit. Beach also is exploring in South Australian permits PRL 33 and PRL 49, with 18 wells drilled across the entire trough to date.

"We've had some really good results," Jamieson said. "There's potentially a massive gas resource there. However, it's challenging. It's not low-hanging fruit.

"These formations are 3 km to 4 km [1.9 miles to 2.5 miles] down," he continued. "It's deep, it's hot and it's high-pressure. However, the coring that we've done has shown that there's a lot of gas down there. And we've flowed gas, which has been a big tick in the box.

"Now it's a matter of drilling and completing these wells efficiently and more cheaply and fracture-stimulating in a way that will generate commercial-style flow rates," he added.

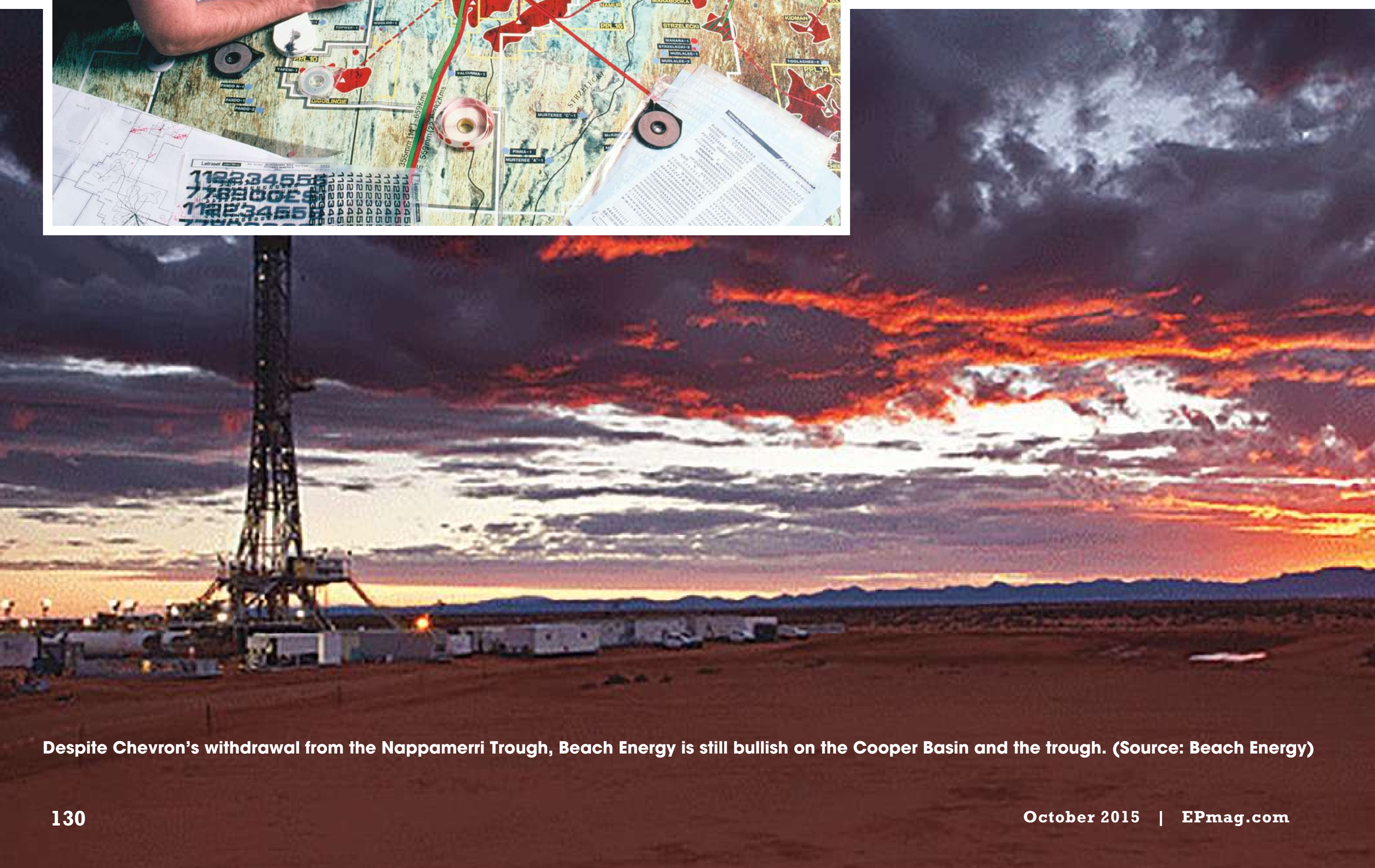
New technologies and industry developments will continue to assist the drive for unconventionals in the Cooper. Innovations in fracture stimulation such as electrical pulsing and low fluid volumes also will help unlock hydrocarbons from the deep coals of the Patchawarra Trough and the southern Cooper Basin being targeted by all of the major Cooper Basin players as well as smaller companies such as Senex Energy and Strike Energy.

Santos' Tirrawarra South-1, the first dedicated deep coal producer, is expected online in the next few months for long-term production monitoring.

Meanwhile, Beach Energy is confident of finding a new partner to join its Nappamerri Trough program once the Stage 1 data have been analyzed.

"We want to make sure we're fully across all the data and make sure that we're in the right position in terms of the next stage," Jamieson said. "We're still confident that this area will be developed at some stage; it's just a matter of when. Whether it's five years' time or whether it's 20 years' time, we're confident it will be developed." E&P

A Santos geologist draws a geological map of the Cooper Basin during the 1980s. At the time the basin was experiencing its first 'new era' as oil came onto the scene. (Source: Santos)



Despite Chevron's withdrawal from the Nappamerri Trough, Beach Energy is still bullish on the Cooper Basin and the trough. (Source: Beach Energy)

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Ropes save money, emissions

Low-environmental-impact seismic exploration is made possible by performance fibers and lightweight ropes.

Staff report

The global demand for energy continues to increase, which drives the need for exploration for future resources. Getting results responsibly, safely and cost-effectively is the governing factor that defines success; it is a demand, not a wish. The world is watching everything that oil companies do, whether they do it themselves or use the services of a third party.

Polarcus is a marine geophysical company with a pioneering environmental agenda that seeks to deliver high-end towed-streamer data acquisition and imaging services globally. Erik Godoy is the company's engineering and technical manager. With more than 20 years of experience in and around the marine exploration industry, he has seen some major changes.

"We are one of the key stakeholders in the chain of delivering oil to the consumer, and today we must comply with every global and local environmental regulation," Godoy said. "We are being tasked to go further than ever before and accept new challenges, for instance in environmentally sensitive sea areas, and at the same time meet stringent cost targets."

Seismic surveys are one of the few feasible technologies available to accurately prospect for oil and natural gas reserves offshore and have been used for decades to assess the location and size of potential oil and natural gas deposits, which can lay several miles beneath the ocean floor.

Seismic vessels tow streamers to record the geophysical information. These streamers can be up to 10 km (6 miles) long and 1.4 km (.9 miles) wide.

"Around 1995 we started to experiment with ropes instead of the heavy chain and steel cable installations we were using," Godoy said. "The goal was to reduce the towed weight so that we could increase the number of streamers to enlarge the area we could cover and improve the quality of the data."

Ropes made from standard nylon and polyester fibers, though light in comparison to steel cable, stretch under load, which would defeat the object of improving the quality of the data. There also was the risk of breakage, which could only be overcome by increasing rope diameter and weight, thus making them difficult to handle and increasing towed drag.

Godoy and his colleagues started to experiment with ropes made with Dyneema from DSM Dyneema, a super-strong fiber made from ultrahigh molecular weight polyeth-

Polarcus vessels are designed to have a low environmental footprint. (Source: Polarcus)

ylene with exceptionally low elongation properties. Ropes built from Dyneema have low diameters, which can enable seismic companies to meet their targets.

"We made mistakes in the beginning and had some failures, but we didn't give up," Godoy said. "The equipment onboard was already used for steel wire rope. There were sharp edges and damaged sheaves, and we didn't know how to splice, join or attach equipment without causing abrasion or high stress points. We also had to train the operators to work with a completely new material."

Today Dyneema is the standard fiber in ropes for seismic towing installations. Failures have been virtually eliminated, and if they do occur, they are often caused by foreign bodies in the water or by defective equipment. Towing installations can remain in the water for up to three months and are operated 24/7 by a two-shift crew system onboard specially designed seismic vessels.

Step change

The step change from steel wire to rope could not have happened without the expertise and partnership of the rope manufacturers. Suppliers such as Hampidjan, OTS and Mørenot have developed a range of high-performance ropes, rope covers and auxiliary products for seismic applications.

Today's towing installations can produce a towed drag of 60 tons to 100 tons. Another significant factor is that the equipment in the water has a value of up to $40 million, and on it hangs the successful delivery of the project. Loss of equipment or damage that causes operational downtime or, worse, a trip back to shore comes at a punishing cost.

"I cannot remember the last time we had a failure with ropes made with Dyneema that was related to the material," Godoy said. "We still have to contend with objects that get caught up in the towing installation, but we have been able to extend the standard rope replacement time from six months to 12 months or even longer. We still have a significant safety margin. We are not in this business to take unnecessary risks—the consequences are too great."

"A rope is not just a rope," added Jorn Boesten, segment manager offshore at DSM Dyneema. "In this case it is the reliable solution for seismic exploration. We have been very fortunate to have the partnership of three of the most innovative and dedicated rope manufacturers who were able to design products that use our fibers effectively. They have delivered ropes that are virtually fail-safe, and they continue to refine and adapt their product, incorporating some of our fiber innovations to meet the needs of the seismic companies."

DSM Dyneema's recently launched new products are tailored to meet the rope makers' needs. Dyneema SK99 will allow them to make lower diameter, lighter weight ropes that are still easy to handle. Dyneema XBO Technology puts rope on a par with specialty steel wire-bending performance. This will allow ropes to run through sheaves that are smaller and reduces the risks of undue wear and tear through abusive operation.

Decreasing the CO_2 footprint

Polarcus owns and operates seven ships that are among the most environmentally advanced in the world, all with Level 1 Triple-E accreditation from DNV GL. They are powered using marine gas oil (MGO) with a low sulfur content, and the engines are fitted with selective catalytic reduction systems.

Reducing drag is a major opportunity to improve fuel economy and lower emissions even further. Polarcus has a target of reducing drag by 15% by year-end 2015. At a speed of 4.5 knots to 5 knots, each ship will burn on average 40 cu. m to 50 cu. m (1,412.6 cf to 1,765.7 cf) of MGO per day. Every ton of towed drag that can be eliminated can help decrease the CO_2 footprint. Reducing the diameter of the ropes will reduce the surface area being towed through the water, lower the drag and improve fuel economy.

"To do this we need to get to a fully engineered solution to take in all aspects of the installation," Godoy said. "For that we will need to collaborate with the rope manufacturers and DSM Dyneema and bring in the material expertise and engineering capabilities of all parties. So far we have met every challenge that the oil industry and governments around the world have put before us. As leaders in our segment we want to continue to make improvements and reduce the overall impact that the work we do has on our world."

There also is a cost benefit from using lightweight ropes due to the fuel saved, which during the last 20 years has increased dramatically. Added to that is the reliability and lower maintenance that can increase returns further, which can outweight any short-term savings from lower cost materials.

As the oil industry puts pressure on its suppliers to reduce costs while acknowledging the importance of reducing the impact on the environment, investments in technology, materials science and manufacturing processes by all partners in the industry help to provide the answers to responsible discovery of the energy resources that will be needed to meet global demand in the future. E&P

Stepping out of the silo

Big Data pulls project management into the 21st century.

Brett Beaver, VisiQuate Inc.

Ironically, the energy industry has some of the most advanced technologies available for gathering valuable data and some of the most counterproductive practices of locking this information up inside departmental silos as if it were a priceless commodity. But information is different from light sweet crude. In most cases, the more it is shared, the more valuable it becomes.

That is the fundamental concept that drives a new generation of analytics solutions that take the volumes of Big Data generated by the energy industry and transform them into actionable insights that yield immediate performance improvements.

A case in point is the industry's traditional reliance on spreadsheets. When each cell is ³⁄₁₆ in. by ½ in. and there are thousands of them to every page, it's easy to miss vital data. And that is just the situation when one analyst looks at a spreadsheet. When that file never leaves the boundaries of its home department, the missed opportunities multiply even more quickly.

Here are just a few questions whose answers are hiding in those miniature cells:

- What has the company spent year-to-date? Does it need to spend more quickly or pull back?
- Are one company man's jobs more expensive than another's?
- How does a company get value from terabytes of collected data?

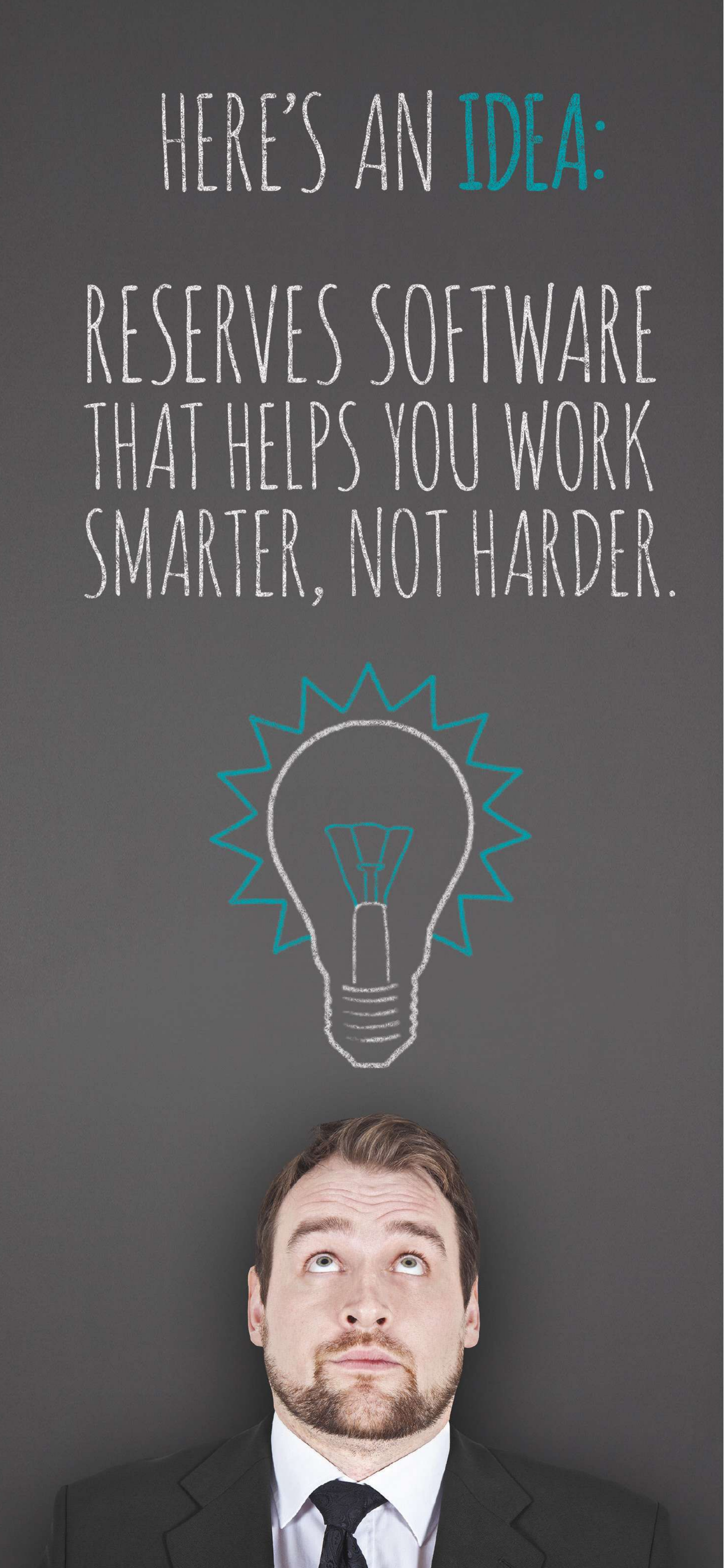
Big Data analytics provide new answers

Fortunately, fresh innovations in Big Data analytics give the energy industry two new capabilities:

- Visualizations that can make problems, opportunities, outliers, anomalies and trends jump off the screen; and
- Communication technology that supports collaboration in real time and across departments, locations and regions.

Today's analytics can enhance understanding in virtually every key area, including downtime analysis, drilling

A quick glance at the Capital Spend dashboard shows which project areas are under or over budget. (Source: VisiQuate Inc.)


HERE'S AN IDEA:
RESERVES SOFTWARE THAT HELPS YOU WORK SMARTER, NOT HARDER.

and completion performance, water inventory and treatment, and health and safety performance. Unlike older generation analytics, which delivered static reports based on lagging indicators, companies can now take advantage of streaming intelligence and predictive capabilities.

Effective collaboration from multiple locations

These data-driven analytics are valuable in their own right, but when combined with a new technology called the Celero Command Center, their impact can increase. With it, everyone can view the same information no matter where they are located. This eliminates the need for mass group emails that don't clearly communicate real events in real time.

The product lets each user create a news feed or channel that provides information related to any area of interest.

"A team leader can create a new channel and add members as easily as choosing people to add to a group email address," said J.K. Kolmansberger, VisiQuate co-founder and president. "That's just the beginning of the product's personalization capabilities. It offers a number of windows that can be combined, including a video feed of real-time incidents and a group chat window that archives every conversation. Other windows include timeline views that precisely record a series of events, production analytics by well, mapping that highlights buffer zones and nearly every other visual insight that helps users understand exactly what is happening and how to best respond to it."

Fresh innovations in Big Data analytics give the energy industry new capabilities.

With the Operations Exchange feature, users can openly communicate with other operators working in the same arena. Operators can exchange nonproprietary information that benefits all involved. This includes scheduled rig moves; well completions; heavy hauling schedules; and requests for services.

Instant ad hoc incident response teams

Another feature that seeks to add value is Situation Room. Because the product has channels that can be created by any user on an as-needed basis, it provides a way to assemble response teams for any incident, including spills, fires and accidents. The team leader selects from a collection of prebuilt widgets and places them on one screen that can be viewed on tablets, laptops and even large-screen displays at the office. These widgets can include crisis maps, weather data, live video feeds, an interactive chat window and any other information needed to respond quickly.

Events can evolve quickly, making it difficult to document the path from problem to solution. Included with the product is a timeline view that sequentially tracks all phases of the team's response in accordance with a company's document retention policy. This timeline can be reviewed at a later date to document that the response team acted in compliance with all regulations.

"Everything in this business seems to be 'rush, rush, rush.' I understand the need for speed, but you don't win a stock car race just by holding your foot to the floor and turning left," said Larry DeFluri, president of Endless Mountain Energy. "You need a great crew, a clear view of the field from your spotter and a strategy that will put you on top. That's what analytics are doing for us."

New level of precision, control

The Celero Command Center includes templates that let users create a project dashboard for nearly any type of project. These dashboards can manage the day-to-day activities of nearly any project and can publish all relevant information about the project to stakeholders across the company.

For a construction project, this could include pictures, timelines, a message board, bid documents, permits, contractor contacts, site plans and project directions. These data can all be integrated onto one high-level page, so users accessing this feed can quickly understand every phase. Just one click behind the main dashboard, a project summary page can deliver an overview of the project budget vs. actual expenses. When needed, third-party contractors can have limited access to the same information.

Because projects vary so greatly, project templates are user-configurable to feature the most important aspects of each project. Templates can be downloaded for each new project and revised by users without help from IT specialists.

There also is a timeline feature that uses large, instantly understandable visualizations to track the entire project schedule, along with project status, scheduling and budget alerts.

For most companies, trying to build a system that turns volumes of Big Data into meaningful analytics can seem like an impossible task. Fortunately, these solutions have already been developed and field-tested. E&P

Nonflammable, nontoxic shale stimulation fluid safer for environment

eCORP Stimulation Technologies LLC, a subsidiary of eCORP International LLC, developed Light Alkanes Stimulation technology, which uses low-molecular-weight alkanes. Naturally occurring, these light alkanes make up baby oil and mineral oil and are nonflammable and FDA-approved for human ingestion and exposure. They also have no adverse impacts on the environment; they are nonozone depleting and have zero global-warming potential, the company said. eCORP Stimulation is conducting further testing and experimentation of this technology in the U.S. in several basins this year. Light Alkanes Stimulation provides greater flexibility (broad range of viscosity/density), which enables this new technology to be used in varied shale formations and operating conditions. *ecorpstim.com*

Cooling water treatment provides corrosion control without aquatic toxicity

The cooling tower water is treated by new PhosZero with E-FeX technology. (Source: U.S. Water Services Inc.)

U.S. Water has released PhosZero with E-FeX technology, a development in sustainable chemistry for cooling water treatment, according to a product announcement. E-FeX technology is a synergistic blend of ingredients that can replace the most common uses of phosphorus in cooling water applications. The PhosZero family of cooling water treatment products is designed to provide both scale and corrosion control similar to traditional phosphorus-containing chemistries but without the discharge or aquatic toxicity concerns of older technologies. PhosZero with E-FeX technology offers protection against corrosion and scale, ensuring high heat transfer and maximum equipment efficiency, the company said. The elimination of phosphorus discharge to the environment enables regulatory compliance and can decrease costs associated with phosphorus removal from waste streams. PhosZero also can reduce the need for acid use and storage on site. *uswaterservices.com*

New technology designed to redefine EOR

Silverwell has released a new technology that is designed to meet the challenge of EOR head on, according to a press release. The Digital Intelligent Artificial Lift (DIAL) 350, the first tool developed by Silverwell, is a real-time gas injection technology that is installed directly in the production tubing with full digital, intelligent electronic control from the surface via permanent cable. DIAL 350 eliminates the need to use side-pocket mandrels, wireline retrievals or well-intervention techniques. DIAL 350 eliminates intervention costs and also provides continuous, more stable production, the company said. Six injection orifices, fitted with V0 reverse flow-check valves, each individually controlled from the surface, have a full spectrum of injection rate options. This means it is not reliant on a specific annulus pressure to maintain gas-injection rates. Pressure sensors are included in the unit configuration at the point of gas injection to provide annulus and production tubing pressure and temperature data. The actuators controlling the gas-injection points are capable of operating at pressures up to 3,600 psi, so even during modification to gas-injection rates, the well maintains continuous production. *silverwell-energy.com*

Crawler inspection robot, motion compensation system increases production

ABB has developed two new products: ABB InSight and X-Wave. ABB InSight is a crawler inspection robot that can reduce downtime, inspection costs and risks of secondary damage, the company said. Fitted with five cameras, the device is used to crawl in the air gap between

X-Wave seeks to provide cost-effective, accurate motion compensation to offshore equipment. (Source: ABB)

ABB InSight, shown with control system and screens, is a robotic crawler. (Source: ABB)

Wireless systems powered by solar energy can reduce installation and operating costs. (Source: SOR Inc.)

the stator and rotor of a motor or generator to visually inspect its status without needing to be removed. The X-Wave motion compensation system has been designed for subsea and well intervention winch systems and can continuously adapt to changing dynamics. *abb.com*

Acid tanks withstand corrosive liquids, chemicals for storage, transport

Hoover Container Solutions designed new acid tanks intended for safe transport and storage of a wide range of corrosive liquids and chemicals, the company said. Hoover's offshore acid tanks are constructed using carbon steel for the vessel, piping, valves, instruments and welds to withstand offshore conditions, with corrosion-resistant carbon steel used to construct the external frame of the tank. Linings for the interior of the tank are selected based on the materials being stored within the tank to ensure maximum corrosion protection. Each of the transportable horizontal and vertical acid tanks is equipped with a relief valve and rupture disc on the tank container as safety features. *hooversolutions.com*

SCADA system includes measurement hardware, telemetry

SENSOR Engineered Solutions offers a SCADA alternative with its remote well-monitoring system. Where SCADA systems often are provided independent of measuring and control equipment, which is then sourced from third parties, a SENSOR system allows users to interface with a single entity capable of providing a turnkey solution, the company said in a release. SENSOR, as part of the SOR Controls Group of companies, has direct access to multiple technologies for measuring pressure, temperature, level and flow. The SENSOR remote well-monitoring system has a flexible design to provide several options using off-the-shelf components. Data are collected wirelessly using communication protocols, such as HART and Modbus, into a central control panel that is SENSOR-manufactured using plug-and-play devices. *sorinc.com*

New mobile workstations run demanding applications, stay cooler longer

Lenovo has released the ThinkPad P50 and P70 workstations, the company said in a release. These ThinkPad P Series systems are designed to run demanding independent software vendor applications. The ThinkPad P50 and P70 are MIL-spec tested and come equipped with Flex performance cooling technology, which allows users to keep their systems cooler longer. *lenovo.com*

Tank monitor provides constant information

The CTS Sonic Tank Monitor system tracks liquid levels and uses local wireless technology to monitor the information, according to BJE, a division of Husky Corp. CTS uses a simple sonic range finder that constantly measures the liquid levels of tanks up to 300 in. deep. The information is relayed using a wireless radio frequency transmitter to a receiver that can be up to 36 m (120 ft) away, which eliminates the need for data cables. Information from as many as six tanks can be connected to one CTS system, and the weather-proof transmitters and internal tank transmitters can be connected directly to a power source. The system is accurate on level measurements within 1 cm, plus or minus 10%. In addition, the programmable system will sound an alarm if liquid levels reach or exceed a point that requires action. *husky.com/bje/tank-monitors-gauges/cts-sonic-tank-alarm/* E&P

Brazil emerges in first gear from 'Carwash' scandal

Brazil's reputation and undoubted potential to be one of the world's long-term offshore powerhouses has been battered and bruised almost beyond recognition, but it is starting the painful process of getting its house back into some kind of order.

Mark Thomas, Editor-in-Chief

Getting this task done will not be a short-term job because of the ongoing ramifications of Operação Lava Jato (Operation Carwash), the corruption scandal that has rocked Petrobras and the country's whole economy to their very cores.

But while Petrobras continues to wade through the scandal—while also dealing with its shrunken stock price and a massive credit crunch—business is still being done in Brazil. In addition, several of its world-class projects are still progressing to plan. It remains, after all, one of the offshore world's largest sources of recoverable oil reserves to help meet long-term energy demand, and it represents a long-term prize. As such, many companies understand they must show faith in the country's judicial system in order to eventually reap the rewards.

First things first, however. The Petrobras scandal represents bribery and corruption on a massive scale, has destabilized the government and has tipped the economy into recession. This, in turn, has stalled the country's previously powerful upward surge toward the top tier of booming economic powerhouses like China, India and Russia.

Kickbacks

The investigation into the system of kickbacks, which are linked directly to some of the main political parties (six so far), has involved the issuance of 117 indictments, the arrests of five politicians and criminal cases brought against 13 companies. The total amount of bribes is estimated to be nearly $3 billion, and that is a conservative estimate.

Oil, however, remains central to Brazil's future, and Petrobras will remain key to its successful exploitation.

It is still one of the world's largest oil companies and retains a pioneering reputation for technological innovation in the offshore sector. The scandal has not changed the engineering and technical skills that reside within the company.

Petrobras's new CEO, Aldemir Bendine, took over in February and has installed plenty of new faces in the upper ranks as part of the company's campaign to ensure the circumstances that led to systematic corruption do not happen again. He also has started the process of potentially selling assets valued at more than $50 billion, tackling a massive debt burden of more than $130 billion (the largest in the energy industry) and increasing the company's oil production.

The *Cidade de Itaguaí* FPSO vessel began producing in late July from the Iracema North area of the Lula Field in Block BM-S-11 in Brazil's Santos Basin. (Source: BG Group)

Crown jewels

That last part is where the upstream industry can start to take heart once more, especially as Bendine has expressed a clear intention not to sell off the company's "crown jewels," meaning its stakes in the country's presalt fields. But he is planning to sell off exploration assets and mature producing fields, according to a recent interview with the *New York Times*.

That will leave the door open for other majors that have long had an eye on increasing their Brazilian portfolios. The process has already started with the sale of 20% of Petrobras's stake in the deepwater Bijupirá and Salema fields, currently operated by Shell. Those fields lie in the Campos Basin with production averaging 22,000 bbl/d of light oil and 325 Mcm/d (11.5 MMcf/d) of associated gas.

Shell is considering investing billions in Brazil as part of its planned acquisition of the BG Group. The BG deal will make Shell the largest foreign investor in Brazil's deepwater fields, and it is reported to have up to $5 billion penciled in for eventual new acquisitions. Shell has long shown interest in Petrobras' producing oil fields as well as operating rights in the country's presalt basin.

Shell and BG's combined oil production in Brazil is expected to hit 550,000 bbl/d by the end of the decade from approximately 200,000 bbl/d presently. That will represent about 20% of the company's global production. BG's production in Brazil more than doubled in second-quarter 2015 to an average of 143,000 bbl/d.

Libra test

While not quite "business as usual," Brazil's offshore activity continues to tick along satisfactorily. The first oil output from a long-duration test on the giant Libra Field will flow in first-quarter 2017, according to Odebrecht Oil & Gas, which is later than the original forecast by Petrobras of the latter part of 2016. Libra is one of the world's largest oil discoveries of recent times and has Shell, Total, CNOOC Ltd. and China National Petroleum Co. as partners. Libra contains an estimated 8 Bboe to 12 Bboe of recoverable reserves.

BG also recently confirmed the start of production from the *Cidade de Itaguaí* FPSO vessel, the sixth unit to begin production across the group's discoveries in the Santos Basin. The FPSO vessel will produce from the Iracema North area of the Lula Field in Petrobras-operated Block BM-S-11.

Located approximately 240 km (149 miles) offshore, the FPSO vessel sits in about 2,220 m (7,284 ft) of water and is the second leased floater deployed on Iracema. It will help double gross production to 300,000 bbl/d of oil and 16 MMcm/d (565 MMcf/d) of gas from the area.

Subsea trees

Brazil will still represent a major slice of the global subsea tree market going forward, with the country comprising about 90% of future installations in Latin America. Its deepwater and ultradeepwater presalt and post-salt developments such as Lula, Buzios and Iracema will remain key drivers for the region.

Although the corruption scandal has seen some contracts suspended and deliveries delayed, which could in turn result in a knock-on effect in terms of the installation of subsea trees, analyst Infield Systems still expects Latin America (almost entirely Brazil) to represent the largest share of global tree installations with a 35% slice. The most capital-intensive development is expected to be Lula Central. E&P

Petrobras business plan

Petrobras will cut its spending in the period from 2015 to 2019 to its lowest level in eight years, investing $130.3 billion. That figure is 41% less than the $221 billion planned in the previous five-year plan from 2014 to 2018.

The plan prioritizes E&P projects in Brazil focused on the presalt. New production systems are estimated to total $64.4 billion, with 91% of that amount for presalt projects. In its other business areas spending will largely be limited to maintaining operations and for projects related to offloading oil and gas.

Of its total E&P investments, Petrobras said 86% will be allocated to production development, 11% to exploration and 3% to operational support. Exploration activities in Brazil will be concentrated on meeting only the minimum exploratory program for each block.

The company expects to achieve total production of oil and gas (Brazil and international) of 3.7 MMbbl/d in the year 2020 and estimates that by then the presalt will represent more than 50% of total oil output. The gas and power area has been allocated $6.3 billion, primarily for the construction of pipelines and processing units to treat gas from the presalt.

The amount of divestments from 2015 to 2016 was recently revised to $15.1 billion (of which 30% comes from the E&P area, 30% from the downstream area and 40% from the gas and power area). The plan also anticipates additional efforts in the restructuring of businesses, demobilizing of assets and additional divestments, totaling $42.6 billion from 2017 to 2018. ■

2016 MEA AWARD CATEGORIES

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

Intelligent Systems and Components: digital oilfield, smart and real-time control and monitoring systems, remote operations, automation, intelligent agents, "big data" solutions, and networks & software

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

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

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

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

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

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

Formation Evaluation: wireline logging, core analysis, cuttings analysis and well testing hardware and software

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

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

Drilling Fluids/Stimulation: chemicals, drilling mud, additives, flow enhancers and green systems

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

Hydraulic Fracturing/Completions: surface equipment, frack trees, hhp, plug-and-perf, sliding sleeves, cementing, perforating, horizontal drilling, stages, frack balls, zipper fracks and microseismic

Reaching target depth in complex presalt formation in Brazil with MPD

The BTR RCD optimized kick detection and allowed the dynamically positioned rig to rotate and maintain its position above the well.

Luiz Costa Gomes, **Renato Borges** and **Julmar Shaun Toralde**, Weatherford

The unique drilling challenges of Brazil's deep and massive presalt formations are pushing the technological envelope far beyond the capabilities of traditional methods. Buried thousands of feet beneath the salt, layered and complex carbonate reservoirs hold a wealth of resources, but conventional drilling methods are no match for them.

Narrow pore pressure windows and frequent kick-loss scenarios have propelled managed-pressure drilling (MPD) to the forefront in this high-profile sector, enabling operators to unlock the potential by reaching target depth (TD) and reducing cost and risk.

MPD, which effectively manages annular pressure in the wellbore, is increasingly being adopted in Brazil as a viable method for overcoming the limitations of standard drilling systems. MPD is now required on many rigs drilling exploratory and appraisal wells in the country's presalt formations to assess the reserve potential because thick salt layers obscure the oil and gas reservoirs below.

The MPD technique was successfully implemented on a deepwater appraisal well in a challenging presalt area, enabling the operator to drill the well to TD and confirm the presence of good-quality oil. In this case, the Weatherford advanced deepwater MPD system was integrated onto a dynamically positioned drillship to automatically adjust the downhole pressure profile and quickly detect and manage kicks in a closed-loop drilling process that delivers environmental, cost and safety benefits.

Reaction time is a key parameter in assessing the benefits of MPD over conventional drilling, especially in deepwater environments where changes in downhole pressure present the risk of a kick or fluid loss. Maintaining bottomhole pressure (BHP) is important for keeping formation fluids at bay and ensuring wellbore stability to prevent collapse.

Conventional open drilling systems manipulate mainly mud weight and flow rates to control the amount of pressure being exerted on the well itself. This is done by circulating out old mud and pumping in new mud—a procedure that can take several hours, or days in the case of a deepwater well. Adjusting the drillstring pump rate can compromise hole-cleaning. These measures contribute to nonproductive time and risk.

Closed-loop system

The Weatherford Microflux automated deepwater MPD

The deepwater MPD system hardware, installed and utilized in an offshore Brazil well, enabled the operator to safely and efficiently reach TD. (Source: Weatherford)

system overcomes these limitations with a closed-loop design that closes the well in so that backpressure can be exerted. In real time, the automated control system detects minute pressure changes and provides the capability to control an influx within volumes of 1 bbl to 2 bbl on average.

This immediate and automatic reaction time keeps the size of kicks small and reduces the risk of catastrophic well control events while enhancing drilling efficiency and reducing costs. The system, which has been deployed successfully for multiple deepwater wells globally, including presalt formations, utilizes a deepwater rotating control device (RCD), an automated MPD choke manifold, an annular isolation device, an MPD flow spool and other equipment to precisely manage the pressure profile while drilling and to maintain constant BHP.

The deepwater MPD system was deployed to drill a vertical appraisal well in approximately 1,982 m (6,500 ft) of water. The impetus for using MPD for this operation was the drilling of two offset wells that both encountered kick-loss scenarios.

The first well experienced losses up to 200 bbl/hr with no improvement even after the crew spent 15 days attempting to reverse the loss rate. The second well experienced losses of more than 50 bbl/hr with a kick-loss event occurring after the mud weight was reduced. That second well was plugged and abandoned, and a reentry operation using MPD was planned.

One critical element of the deepwater MPD riser joint is the BTR RCD, which effectively closes in the well. (Source: Weatherford)

The subsequent appraisal well was drilled using MPD to reach and assess a volcanic formation below the carbonate reservoir where kicks and losses were anticipated. Because formation pressures in deepwater wells are difficult to predict, the operator initially conducted a dynamic pore pressure test to lower the pressure of the well to gauge the kick potential. Those results, along with a dynamic formation integrity test, established the drilling window.

Well sealing

An essential element of the automated MPD control system is the deepwater below-tension-ring (BTR) RCD, which was integrated into the rig's standard open fluid-return system to close in the well. This enabled rotation while drilling to accommodate varying pressures.

A bearing assembly installed into the RCD transformed the open fluid-return system on the rig to a closed-loop circulating system, creating a pressure-tight barrier in the wellbore annulus to immediately contain and divert return fluids to prevent the influx of gas or kicks. This capability is not feasible with conventional diverter systems.

Interfacing seamlessly with the BOP system already in place, the RCD provides a safe and cost-effective means of creating a closed and pressurized system that augments well control. This feature is significant because BOPs are designed for well control emergencies and are not rated to facilitate rotation and drilling while in the closed position.

The drilling operation for the presalt well used a statically underbalanced mud weight. The automated MPD control system, including the real-time monitoring equipment and well model calculations, maintained stable BHP by applying surface backpressure. The BTR RCD, specifically designed for floating rigs with subsea BOPs, optimized kick detection and also allowed the dynamically positioned rig to rotate and maintain its position above the well.

The RCD routed return flow from the well through the automated MPD choke manifold to a Coriolis mass flowmeter, which captured critical data in real time, including mass and volume flow, mud weight, and temperature. The data are essential for facilitating a quick reaction to well control events.

By precisely managing the well pressure profile to maintain BHP, the automated deepwater MPD system offered additional downhole visibility to allow more informed drilling decisions and enable the drilling operation to continue to TD more safely. Drilling and logging operations confirmed an expressive oil column with the carbonate formation containing good-quality oil.

Deployment of the automatic deepwater MPD system enabled the operator to assess the reservoir's production potential and economic benefits, an objective that would not have been possible using conventional drilling methods. E&P

Lula already a legend

For Brazil, the Lula Field single-handedly kick-started the transformation of the province from a fairly unremarkable oil and gas backwater into a world-class offshore powerhouse.

Mark Thomas, Editor-in-Chief

Shortly after initial rumors emerged about a massive presalt discovery off Brazil's southeastern coast following the completion of the 1-BRSA-369-RJS well in October 2006 by the *Noble Paul Wolff* semisubmersible rig, there was substantial disbelief within the wider upstream industry over the early reserve estimates leaking from the excited headquarters of Petrobras and its partners Galp Energia and BG Group. Many observers simply believed that the initial size estimates being issued were for oil in place rather than total recoverable reserves.

Within a year, however, the Tupi discovery, as it was first known, was accepted as being one of the largest offshore fields ever found and Brazil's first supergiant discovery. It also was the largest find made worldwide since the Kashagan discovery in 2000 offshore Kazakhstan. A second well on the field spudded in May 2007 by the same rig firmed up the first estimates, with the 3-BRSA-496-RJS appraisal probe, drilled 9.5 km (5.9 miles) south of the original well, hitting light oil of 28°API gravity.

Reserves of 8.3 Bboe

Just before year-end 2010 and after the drilling of 11 wells in total, Petrobras, as operator of Block BMS-11 in the deepwater Santos Basin, submitted the declaration of commerciality for the oil and gas accumulations in both Tupi and also the Iracema areas to the country's National Petroleum Agency (ANP).

In that proposal the names for these accumulations were given as Lula and Cernambi, with the former named in honor of President Luiz Inácio Lula da Silva, who led the country from 2003 to 2011.

The total recoverable volumes for Lula were put at 6.5 Bboe of 28°API gravity oil with Cernambi put at 1.8 Bboe of 30°API gravity oil. These estimates were reached after the drilling of the follow-up wells and the performing of an extended well test on Lula in May 2009.

Pictured are the topsides processing modules onboard SBM Offshore's leased *Cidade de Paraty* FPSO vessel, which is producing for Petrobras on the Lula Northeast Field. (Source: Petrobras)

To put Lula's significance in perspective, overnight the field essentially added 50% to Brazil's previously known total recoverable reserves of approximately 14 Bbbl, hence the initial doubt over the first estimates that emerged about the size of the find.

Lula sits approximately 250 km (155 miles) offshore the southern coast of Rio de Janeiro in a water depth of 2,140 m (7,021 ft). Petrobras holds 65% of the concession, while BG has 25% and Galp 10%. The field's presalt reservoir contains sweet crude sitting under a layer of salt in places up to 2,000 m (6,562 ft) thick.

Energy demand

Lula, of course, is now merely part of Brazil's burgeoning presalt bonanza, with the region expected to play a significant role in meeting future global energy demand over the course of the next several decades.

The wider presalt area measures some 800 km (497 miles) in length and 200 km (124 miles) in width, stretching from offshore the state of Espirito Santo to the state of Santa Catarina. Other key discoveries in the area have included Jupiter, Carioca, Caramba, Pirambu, Caxareu, Parati, Bem-Te-Vi, Guara and Iara.

The field's development is a massive undertaking, involving what will eventually be a fleet of floating production platforms, mainly FPSO vessels (up to nine) and multiple billions of dollars of investment. Initially, pilot production began via the *Cidade de São Vicente* FPSO vessel, followed by the first definitive production system, *Cidade de Angra Dos Reis,* on Oct. 28, 2010. This has since been followed by the deliveries of the *Cidade de Paraty, Cidade de São Vicente, Cidade de Mangaratiba* and *Cidade de Itaguai* FPSO vessels, with the C*idade de Marica* and *Cidade de Saquarema* to follow later this year and in 2016, respectively.

Future phases

Future phases will see Lula Alto start producing early in 2016 as well as Lula Central by mid-year, while in 2017 Lula South and Lula Far South are expected to flow. Petrobras's latest business plan states that in 2018 the Lula North section will start producing, while in approximately 2020 the Lula West section is expected to be brought onstream.

The field's gas is exported by the 216-km (134-mile) Lula-Mexilhão Gas Pipeline, which connects the *Cidade Angra Dos Reis* facility to the Mexilhão platform.

Lula has been a game-changer as much for its technological innovation as for its sheer size. This was recognized earlier this year at the Offshore Technology Conference (OTC) in Houston, which highlighted the harsh oceanographic conditions in the presalt area as well as the achievement of production in a location far from shore and with no existing production infrastructure. Development also took place in ultradeep water and below the large salt layer in a high-pressure reservoir.

The OTC Awards Committee gave Petrobras the coveted Distinguished Achievement Award for Companies for its work in the presalt, where it "successfully implemented ultradeepwater solutions and set new water-depth records."

OTC's statement said, "Petrobras increased its efforts in technology development to exploit this hard-to-access resource in waters up to 2,200 m [7,218 ft]. By the end of 2014, Petrobras was producing more than 700,000 bbl/d of oil in the presalt layer of the Campos and Santos basins. The oil and gas production in this challenging environment demanded the development of different riser systems, which were successfully applied and are now available for the industry. Additionally, Petrobras achieved a significant reduction in the drilling and completion time for wells."

Reservoir challenges

Some of the biggest challenges were the heterogeneous carbonate reservoir and seismic imaging complexity, the thick salt layers and very deep reservoirs, and the presence of contaminants (CO_2 and H_2S) in the reservoirs.

One of the biggest lessons learned from the presalt, according to Petrobras, is the reservoir's production behavior. When the company started to define the pilot project, its main concern was that the presalt microbialite carbonate reservoirs could behave like most carbonate reservoirs, exhibiting a high initial rate followed by a sharp decline caused by the critical heterogeneities like sealing faults or facies degradation between wells.

In the Lula extended well test and the pilot production phase, despite the heterogeneities, there was good pressure communication across the reservoir, both laterally and vertically. This characteristic supported the main decisions regarding its development.

Other achievements so far have seen the company use steel catenary risers with lined pipes installed using the reel lay method, with the carbon-steel rigid risers supported by buoy supporting risers. The company also has on record the deepest use of flexible risers (in a depth of 2,140 m [7,021 ft]) and another water-depth record 2,103 m (6,900 ft) for drilling a subsea well using the pressurized mud cap drilling technique, which helps avoid loss of circulation downhole.

Work still goes on, of course. In its efforts to increase the recovery factory, Petrobras is continually increasing the alternating injection of water and gas while also planning to reduce the size but increase the efficiency of its produced CO_2 separation systems.

Lula is set to remain a game-changer for Brazil for decades to come. Earlier this year Petrobras's presalt production topped 800,000 bbl/d just eight years after its discovery. This milestone is particularly significant when one considers that it took the company 31 years to achieve 500,000 bbl/d in 1984. That last figure was achieved via more than 4,100 producing wells, whereas in the presalt the company has achieved its current level with just 411 producers. The presalt now accounts for around 25% of Petrobras' production in Brazil and by 2018 is expected to make up around half of the company's total output. E&P

Seventh-generation UDW drillships delayed for better market

Delivery of the *Ocean Rig Crete* and *Ocean Rig Amorgos*, the two newest vessels in the seventh generation of ultradeepwater drillships built by Samsung Heavy Industries for Ocean Rig UDW Inc., will have to wait until market conditions improve.

On April 27, 2015, Ocean Rig reached an agreement with Samsung to postpone the delivery of the rigs to first-quarter 2018 and first-quarter 2019, respectively. Both rigs were originally scheduled for delivery in 2017. The total project costs for the construction of each drillship were increased by $15 million, according to first-quarter 2015 results, which were released May 11.

In the second-quarter 2015 results released Aug. 6, George Economou, chairman and CEO of Ocean Rig, said, "We still believe in the long-term market recovery and in the solid fundamentals of our industry, but currently the market remains challenging. We are in the midst of a significant downturn in offshore drilling. The recent volatility in the price of oil and increased availability of drilling units do not allow a short-term market improvement."

Although the company has 93% and 69% of its calendar days under contract in 2015 and 2016, respectively, adding more drillships to the company's fleet at this time would put additional strain on its resources. The seventh-generation rigs would require higher day rates to cover the cost of capex and opex.

These rigs are based on an advanced Saipem 10000 design with dual derricks and BOPs to ensure optimal operating efficiency. The rigs are designed to operate in 3,658-m (12,001-ft) water depths and drill to 12,195 m (40,010 ft).

The derrick is an NOV Dual Dynamic Bottle Neck with a main static hook load of 1,270 metric tons (mt) and an auxiliary static hook load of 907 mt. The main drawworks are rated at 10,500 hp, while the auxiliary drawworks are rated to 7,500 hp. Both the main and auxiliary systems use TDX-1250 top drives, each with 2,680 hp.

There are six 7,500-psi NOV mud pumps and six 2,100-gal/min shale shakers. The BOP system includes seven NOV 18¾-in. 15,000-psi ram preventers and two 18¾-in. annular preventers. The choke manifold is rated to 15,000 psi working pressure, and the mud-gas separator has a gas-handling capacity of 566,337 cm/d (20 MMcf/d).

Each rig has accommodations for 240 people. The dynamic positioning system (DP Class 3) has proven station-keeping abilities under extreme conditions in harsh environments. There are six 6,705-hp thrusters. Each vessel has a riser tensioner with a capacity of 2,000 short tons. E&P

Vessel Facts	
Sector:	Ultradeepwater Drilling
Owner:	Ocean Rig UDW Inc.
Names:	*Ocean Rig Crete* and *Ocean Rig Amorgos*
Vessel Design:	Enhanced Saipem 10000
Yard Built:	Samsung Heavy Industries
First Operations:	2018 and 2019, respectively
Size (Length/Beam):	230 m (755 ft)/42 m (138 ft)
Max. Water Depth:	3,658 m (12,000 ft)
Max. Drilling Depth:	12,195 m (40,000 ft)
Transit Speed:	12 knots
BOP Stack:	Seven ram BOPs, 18¾-in., 15,000 psi; two annular BOPs, 18¾-in., 10,000 psi
Static Hook Load (Main/Auxiliary):	1,270 metric tons/907 metric tons
Classification:	ABS A1E DPS3

The *Ocean Rig Crete* and *Ocean Rig Amorgos* will be the most advanced of Ocean Rig UDW's ultradeepwater drillships when delivered in 2018 and 2019, respectively. (Source: Ocean Rig UDW Inc.)

AFRICA

Eni discovers supergiant gas field offshore Egypt

Eni has discovered the largest known gas field in the Mediterranean off the Egyptian coast, Reuters reported. The Italian major said the offshore Zohr Field could hold 849 Bcm (30 Tcf) of gas, covering an area of about 100 sq km (39 sq miles). "Zohr is the largest gas discovery ever made in Egypt and in the Mediterranean Sea and could become one of the world's largest natural gas finds," Eni said in a press release, adding that it has full concession rights to the area. The find is expected to have a major impact on the region's economy and could potentially offer Europe new supply options, allowing it to lessen its dependence on Russian gas imports. The discovery was located at a depth of 1,450 m (4,757 ft). Eni plans to fast-track development of the site using existing infrastructure.

Cobalt plans to sell stake in Angolan blocks in $1.75 billion deal

Sonangol and Cobalt International Energy Inc. have signed a sale and purchase agreement for Sonangol to acquire Cobalt's 40% participating interest in blocks 21/09 and 20/11 offshore Angola for $1.75 billion with an effective date of Jan. 1, 2015, according to a press release. This transaction is subject to customary Angolan government approvals, which are expected prior to year-end. The two companies aim to attain the final investment decision for the Cameia development in Block 21/09 by year-end 2015 to deliver first oil from Cameia in 2018. Notwithstanding Cobalt's continuing as operator for an interim period, all costs going forward will be borne by Sonangol.

ASIA

Ocean Floor completes gas hydrate survey in Japan

Ocean Floor Geophysics Ltd. (OFG), in cooperation with Fukada Salvage and Marine Works Co. Ltd., has completed another high-resolution controlled-source electromagnetics (CSEM) survey of near-surface gas hydrates in Japanese waters, according to a news release. For the survey, OFG used the Scripps Institution of Oceanography Vulcan system. The survey comprised more than 670 line km (416 line miles) of high-resolution data collected from the Fukada vessel *Shin Nichi Maru*. A 3-D inversion of the CSEM data for an area of interest for this year's survey has been completed. The contract for the 3-D inversion of the data for the entire 2015 survey area also has been awarded to OFG and will be completed in November.

AUSTRALIA

Buru makes oil find in Western Australia

Buru Energy's Praslin 1 well in Western Australia's Ungani oil field has hit oil, the company said. Wireline logs indicate a gross oil-bearing interval of about 23 m (75 ft) at the top of the Ungani Dolomite section in the well. The log response of the interval is similar to that seen over the interpreted highly productive zone at the Ungani oil field, but reservoir characteristics need to be confirmed by a production testing program, the company said. The company said it will plug the well and bring in a testing crew to run production testing. Buru Energy and Mitsubishi Corp. each have a 50% interest in the well.

Buru Energy and Mitsubishi Corp. each have a 50% interest in the Praslin 1 well in Western Australia's Ungani oil field. (Source: Buru Energy)

EUROPE

Subsea 7 awarded contract offshore U.K.

Subsea 7 SA has been awarded a subsea, umbilical, riser and flowline contract by Maersk Oil with a value in excess of $150 million for the Culzean development, the company said. The ultra-HP/HT field, one of the largest gas discoveries offshore the U.K., is located in

Block 22/25 of the central North Sea at a water depth of about 90 m (295 ft). The contract scope includes project management, engineering, procurement, construction and installation of a 22-in.-diameter 52-km (32-mile) gas export pipeline connected to the Central Area Transmission System and a 3.6-km (2-mile) pipe-in-pipe (10-in. outer pipe and 6-in. inner pipe) providing insulation for the transportation of the condensate to the infield floating, storage and offloading facility (FSO). The pipe-in-pipe will be laid with a 4-in. piggy-back line that will transport fuel gas to the FSO unit. Subsea 7 also will provide subsea structures, tie-ins to the Culzean platform facilities and precommissioning expertise. Offshore operations are scheduled to commence in 2017.

Maersk wants to shut oil installation in U.K. North Sea

Maersk Oil plans on seeking regulatory permission to shut its Janice installation, which produces about 7,000 bbl/d from three U.K. North Sea oil fields, as the Danish firm reviews its operations due to falling oil prices, Reuters reported. Maersk Oil said it would approach Britain's Oil and Gas Authority for approval to stop production in either second-quarter 2016 or third-quarter 2016. As part of the regulatory procedure, Maersk Oil may submit proposals to tie one or some of the fields back to other installations to produce again. "In terms of what happens to the fields, that will be covered by our proposals in the plan that we submit to the U.K. Oil & Gas Authority," a statement from the company noted. "Permission to cease production would then lead to a decommissioning program for the Janice FPU [floating production unit], and this would be submitted to the regulatory authorities."

MIDDLE EAST

McDermott lands its largest Middle East contract

McDermott International Inc. has been awarded a lump sum contract by Saudi Aramco for brownfield work in various fields offshore Saudi Arabia, according to a press release. Work on the contract is expected to be executed through second-quarter 2018. The award follows the June 2015 signing of a second long-term agreement between McDermott and Saudi Aramco for engineering, procurement, construction and installation (EPCI) opportunities. The package of various EPCI projects that make up the lump sum award represent the largest single award for McDermott's Middle East area operations in company history. Revenue from the fixed-price award is included in McDermott's third-quarter 2015 backlog.

Iran expects South Pars production to start in October

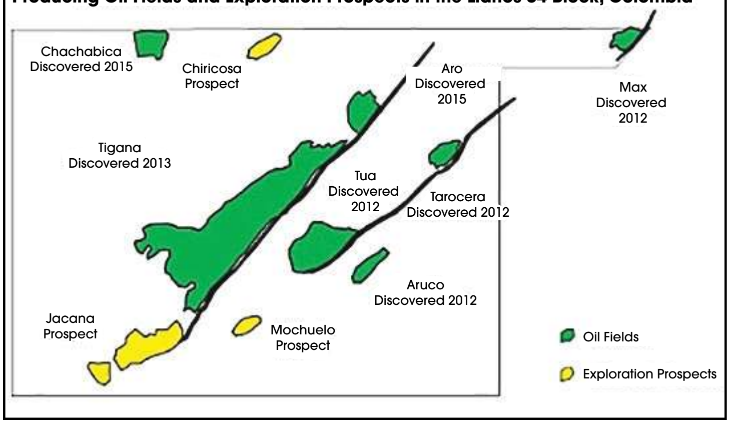
Iran plans to bring online two new gas operations in October after the OPEC member completes development of another section of the world's largest gas field, its oil minister said, according to a Reuters report. Iran and Qatar share the field, which Iran calls South Pars and Qatar calls the North Field. The field, located in the Persian Gulf, accounts for nearly all of Qatar's gas production and about 35% of Iran's. Development phases 15 and 16 of the South Pars Field are close to starting production and will be inaugurated by President Hassan Rouhani in October, Iranian Oil Minister Bijan Zangeneh said at a news conference, according to Shana, the oil ministry news agency. Production capacity from the two phases is expected to reach 48 MMcm (1.7 Bcf) within a month, Shana said. The phases also will produce 75,000 bbl/d of gas condensate.

SOUTH AMERICA

GeoPark strikes light oil in Colombia

GeoPark Ltd. has made an oil discovery on the Llanos 34 block in Colombia, the company said. GeoPark drilled and completed the Chachalaca 1 exploratory well to a total depth of 3,740 m (12,270 ft). A test conducted with an electric submersible pump in the Mirador Formation at about 3,538 m (11,606 ft) resulted in a production rate of about 1,100 bbl/d of oil of 30°API. The water cut was about 6%. Further production history is required to determine stabilized flow rates of the well and the extent of the field. GeoPark is drilling the Jacana 1 exploration well and the Tilo 2 appraisal well, both in the Llanos 34 block. Testing of these wells was scheduled to be conducted in September. GeoPark, the operator, has a 45% working interest in the Llanos 34 block. E&P

Producing Oil Fields and Exploration Prospects in the Llanos 34 Block, Colombia



Geopark is drilling the Jacana 1 exploration well and the Tilo 2 appraisal well, both in the Llanos 34 block in Colombia. (Source: GeoPark)

PEOPLE

Juniper Systems' President and CEO **Rob Campbell** stepped down after 14 years to accept a position as president of Campbell Scientific Inc., Juniper Systems' parent company. **DeVon Labrum** (left) has taken Campbell's place as Juniper Systems' new CEO.

Managing Director and CEO of Santos **David Knox** will step down once his successor has been appointed.

Bjarte Bruheim stepped down as CEO of Electromagnetic Geoservices ASA. Until a permanent CEO is in place, **Stig Eide Sivertsen** serves as the interim CEO.

Bristow Group appointed **Don Miller** CFO.

Altaaqa Global appointed **Julian Ford** chief commercial officer.

Jan Schott of Goodrich Petroleum Corp. resigned in September as senior vice president and CFO. **Robert C. Turnham Jr.**, the company's president and COO, assumed the role of interim CFO while the company searches for a new CFO.

Barrick Gold Corp.'s **Kelvin Dushnisky** was promoted to president. **Richard Williams** was selected as the company's COO, and **Basie Maree** was named CTO.

Denbury Resources Inc. named **Chris Kendall** COO.

LINN Energy LLC and LinnCo LLC selected **David B. Rottino** as executive vice president and CFO.

Schramm Inc. appointed **Thomas (Tom) G. Strauss** CFO. Strauss replaces Senior Vice President and CFO **John Bellis**, who retired Oct. 1 after more than 30 years with the company.

Wood Group Mustang appointed **Elaine Lisenbe** (left) CFO and **Valencia Amenson** (right) as vice president of human resources.

Frank's International N.V. named **Alex Cestero** as senior vice president, general counsel and secretary.

Solomon Associates' **Steve McCoskey** assumed the role of vice president of Middle East operations.

Greene's Energy Group LLC named **Michael "Mike" Hayes** vice president and general manager of pressure testing and services and the engineering group.

EthosEnergy appointed **Kevin Taylor** as its president of power solutions.

qedi named **Naveen Adusumilli** as the company's general manager for the Middle East.

Henkels & McCoy Inc. promoted **Bob Kearns** to senior director of the project management office. The company also promoted **Richard Hill** (left) to vice president of major pipelines.

Greene's Energy Group LLC named **Brian Cooper** as its key account manager focusing on the Permian Basin region.

STIRLING Group appointed **Alan McIntyre** to head up its emergency response and crisis management consultancy services in the U.K.

GulfStar Group selected **Roshan Gummattira** to lead its technology practice.

Tap Oil Ltd. appointed **Michele Ryan** as the company secretary and general counsel.

Wenche Agerup was elected to Statoil's board of directors.

Schramm Inc. appointed **Sean Roach**, its current vice president of drilling systems and services, to lead the company's new expanded office in Houston.

Robbert Booij was appointed as ABN AMRO's country executive for the U.K. and general manager of ABN AMRO Bank N.V., U.K. branch.

Unit Corp. elected **Carla S. Mashinski** as the independent director of the company's board of directors.

The OMV Supervisory Board appointed **Johann Pleininger** (left) as the executive board member responsible for upstream. He succeeds **Jaap Huijskes**, who resigned.

Peak Oil & Gas Ltd. appointed **Peter Armitage** as an independent non-executive director.

Ceona's **John Smith**, chairman of the company's board, stepped down due to ill health, the company reported in August.

Noted offshore technical pioneer **Edward E. Horton III** passed away at age 87 in August in Houston.

COMPANIES

NEOS GeoSolutions Inc. acquired ION Geophysical Corp.'s Denver land seismic data processing operation.

ClassNK opened a new exclusive survey office in Brunei. Operations began Aug. 17.

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NEAH GES launched its U.K.-based Maritime Division (GES Maritime) in August.

qedi, a completions, commissioning and technology provider, opened an office in Abu Dhabi, United Arab Emirates.

FEI will provide imaging equipment, software and support for digital rock research to the University of Wyoming. The Wyoming Legislature's state matching program will contribute an amount equal to the equipment and support provided by FEI, for a total of $24 million. The investment will create the new Center of Innovation for Flow in Porous Media.

Indian Register of Shipping (IRClass) opened offices in Abu Dhabi, United Arab Emirates. Abu Dhabi is the second office location for IRClass in the country following Dubai.

IMI Critical Engineering has opened its new IMI CCI service center in Aberdeen, Scotland. The facility offers machining, repair, testing and field service support as well as demonstration units and boardroom presentation areas for customers. E&P

ADVERTISER INDEX

Integration: the new business as usual

Data play a key role in a strong balance sheet.

Aaron Gatt Floridia, Schlumberger Reservoir Characterization Group

With plummeting crude oil prices and highly unstable market conditions, upstream industry projects worldwide will likely face continuing challenges for the foreseeable future. Achieving a strong return on investment in any play remains problematic unless operators significantly reduce both the cost and risk of oil and gas development projects.

Project economics are sensitive to a multitude of factors, including recoverable reserve volumes; the mix of fluids present; reservoir quality and heterogeneity; drilling efficiency; completion design; and the wellhead equipment, production and processing facilities involved.

For example, the infrastructure required to develop and produce natural gas is highly sensitive to the precise composition of the effluent. Failing to detect the presence of hydrogen sulfide (H_2S) gas or underestimating its concentration can put human health and safety at risk and cost tens of millions of dollars in damage resulting from corrosion and equipment failure. Overestimating the H_2S concentration also can be expensive thanks to over-engineered treatment systems.

Accurate measurements

Cost and risk cannot be effectively managed by relying on generalizations or uninformed estimates—accurate measurements are the necessary basis for achieving economic success. There is a growing appreciation of this relationship in unconventional plays, where the failure to unravel vertical and lateral variations in mechanical rock properties and reservoir character from well to well or even along a single long lateral can undermine a drilling campaign or stimulation operation.

Historically, it has been a challenge to obtain sufficient geoscience and engineering data to properly understand shale reservoirs, which have turned out to be more complex than anyone imagined. Going forward, it will be essential to not only acquire more data but to integrate diverse measurements across the reservoir life cycle to minimize risks, uncertainties and associated costs. No single measurement, no matter how sophisticated, can ever be definitive.

Typically, isolated measurements are taken by multiple contractors or various segments of an oilfield services company at different depths and different points in time—some prior to drilling, some in real time while drilling, others by wireline and still others during flow-testing or laboratory analysis. Each disconnection between the measurements, tools and service providers is yet another opportunity for vital information to fall through the cracks.

To help oil and gas companies meet this challenge, oilfield services providers must begin integrating previously segmented drilling, formation evaluation, reservoir characterization, testing, and completion and production data and services. Collaboration across these silos and the integration of measurements at every scale, from core to seismic survey, across the E&P life cycle must become routine—in effect, the new "business as usual."

A U.S. operator engaged Schlumberger to design an integrated hydraulic fracture treatment strategy for a vertical pilot well and new horizontal laterals in the Wolfbone Formation—an interval of stacked, heterogeneous conventional and unconventional reservoirs in the Permian Basin.

Technical experts integrated measurements from four advanced wireline tools. All reservoir data were fed into the Mangrove engineered stimulation design in the Petrel E&P software platform to optimize treatment stages, perforation placement and job execution by using the HiWAY flow-channel fracturing technique.

Despite a 30% reduction in proppant and 6% less fluid per stage than conventional stimulation, initial oil production ranked among the Wolfbone play's top 20%. The operator identified cost savings of $734,900 per well. On the basis of the new integrated measurements and models, the company drilled and completed its first horizontal well in a new, deeper target interval. Initial production was 60% higher than that of offset laterals, and the 10-month cumulative production was 39% higher. Post-project analysis of the integrated drilling, completion and production data enabled the operator to further improve plans for subsequent operations. E&P


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