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ON THE COVER

A whole new reality. Companies such as Oceaneering International, are using next-generation training techniques to get their employees ready before they get into the field and have to deal with real life equipment and situations. **Find out more in our cover story on page 28.** *Image rendered by Luis Parada Pereira from Abyssal, courtesy of Oceaneering International, Inc.*

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Elena Valova Senior Reservoir Engineer

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Departments & Columns

Can cost efficiency and safety be complementary?

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Online Exclusive

Training in 3D

Audrey Leon visits with Subsea Solutions to find out how the company uses 3D printed models for education and training purposes.

Photo from Subsea Solutions

What's Trending

Abandoning the Arctic

- **Shell exits Alaska**
- **US cancels Arctic lease sales**

(See more on page 14)

Photo: Harald Pettersen/Statoil

People

Rowe takes over as Cameron CEO

R. Scott Rowe has assumed the role of president and CEO of Cameron International. Rowe has served with Cameron for 13 years, most recently as president and chief operating officer. He previously served as CEO of OneSubsea, the company's joint venture with Schlumberger.

OE WEBINAR: Proving the industrial internet of things

Asset integrity is all about continuously monitoring equipment and process health. Analytics gathered through the Industrial Internet of Things (IIoT) can change work flows from reactive to proactive, head off problems before they become big issues, help eliminate unplanned downtime and improve asset performance and safety. Join Honeywell Process Solutions' Dan O'Brien and OE Automation Editor Greg Hale as they discuss how these solutions could be a game-changer.

Tune in 10:00 – 11:00 a.m. CST
Thursday, 5 November 2015.

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Voices

The cost of doing business. With the industry heading into a 'lower-for-longer' price mindset, OE asked:

Can cost efficiency and safety be complementary?

Efficient organizations are safer. Put simply, efficient organizations are capable of doing more of the right things. The industry's ability to execute planned work offshore is widely recognized as hugely inefficient. This is a key component of both recent cost escalation and potentially increasing risk – the escalating back log of maintenance of safety critical equipment being one example.

We need to better balance workload and risk. To do this we need a common understanding of operational risk and tools that enable better decision making throughout an organization.

Phil Murray, CEO, Petrotechnics

There is a misconception that finance people only care about money, while HSE people care about safety without keeping company finances in mind. What's true is that leaders of finance and HSE are equally invested in efficient spending and employee safety. Financial-efficiency should be a daily leadership function, regardless of market conditions. Safety is about assessing risk, mitigating risk and ensuring those mitigations are working properly. The question to ask is, "Can my organization successfully do those three things under slightly tighter cost restrictions?" Properly managing resources is the most important aspect of HSE leadership, so you can protect your operations, your equipment, your people and your bottom line.

Michael Dardar, CSP, director HSSE, Blackhawk Specialty Tools

General industry perception is that in many cases the cost of implementing managed pressure drilling (MPD) on a rig prohibits its very adoption. The facts, however, prove the opposite. In deepwater wells, approximately 40% of drilling hazards are pressure-related; 30% represent NPT brought on by wellbore stability issues and kicks that often result in abandoning the well. The ability of MPD to instantly alter the wellbore's annular pressure profile as a response to instant changes in mass flow balance variances significantly reduces not only event identification and response time but also the ability to preserve wellbore stability and optimize drilling while minimizing risk to personnel and assets. Using MPD as a technique ahead of conventional open-to-atmosphere drilling techniques is unquestionably better. The rapid global uptake over the last decade has reduced, if not eliminated, the risk described above, reduced the risk-to-reward ratio, and quantified risk and cost reduction.

Guy Feasey, global director of sales and marketing for Secure Drilling Services, Weatherford

Absolutely. Companies are becoming increasingly focused on finding ways to improve production efficiency without compromising safety. The competency of employees is at the core to minimizing the risk of interruptions brought about by incidents or issues flowing from operational failures or shortcomings.

The industry is increasingly looking towards electronic competence systems, which can effectively track employees' knowledge and capability. By establishing a better way of tracking competence, it will in turn raise the bar on safety performance across the workforce and secure improved production efficiency.

Kevin Short, commercial director, Atlas Knowledge Group

"Our industry professionals have always adapted quickly to challenges, whether it be price, production, reserves, conquering hostile environments, regulations and many more. The current reduction in activity level and workforce is creating an opportunity for us to respond once again. The main focus of any cost reduction effort is our people. While smaller, the workforce pool should be more experienced and possess greater skill sets than ever before. The industry must use this opportunity to develop great leadership. It is well understood that good leaders work smarter and safer."

William "Bill" Bethea, principal/vice president – Engineering, Offshore Technical Compliance

Considering the current market situation there is a risk that cost efficiency and safety may not be complimentary elements, particularly if the objective is just to continue doing the exact same operations, but with reduced costs. Nevertheless, the drive for cost savings gives decision makers the chance to look at using new technologies that may previously have been overlooked to enable them to become more efficient.

A good example is coiled tubing drilling. This drilling intervention method has reduced human interaction compared to conventional jointed pipe drilling and therefore provides a safer and more reliable operation. Drilling with coiled tubing also saves rig-up time and reduces operating times, resulting in cost efficiencies which consequently provide greater value to the operator. In this way, the effectiveness and efficiency of new technologies can be optimized to reduce not only costs but the safety risks, too.

Toni Miszewski, managing director, AnTech

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Undercurrents

The blessing is not a curse

For many years, tiny Israel was thought to have no oil and gas resources like that of its neighbors in the region. They called it a blessing, according to Dr. Yuval Steinitz, Minister of Natural Infrastructure, Energy and Water Resources, who recently spoke at Rice University's Baker Institute in Houston, because the country focused instead on creating a high-tech economy. But, in the last decade Israel soon found some of the largest natural gas finds in the world including Tamar (10 Tcf, 2009), and Leviathan (22 Tcf, 2010).

However, like most things in the region, it hasn't been smooth sailing. The operator behind those finds, Houston-based Noble Energy, has been through a tug-of-war with Israeli anti-trust regulators over monopoly concerns that have until now derailed and delayed Leviathan's development. Tamar was discovered in 2009 and brought into production in 2013. Things haven't moved as fast for Leviathan.

"We have made a few mistakes," Steinitz conceded. "We created some obstacles and difficulties. When I became minister of energy, my first priority was to resolve all the technical, regulatory difficulties and establish a framework from the government for oil and gas exploration and pave the way to the speedy development of Leviathan."

Just five months on the job, Steinitz has attempted to change the way Israel's regulators do business with not just Noble, but with what they hope will be more foreign operators. The event in Houston included diplomats and members of the Texas/Israeli Chamber of Commerce, who hope to "export" the US oil and gas industry to Israel.

And Steinitz noted that Israel needs Leviathan to be developed not just for the revenue stream, but for the country's energy security. Steinitz hopes are that eventually more companies will come in and help discover further natural gas, and maybe even oil, resources deep offshore. And he's hoping the new regulatory framework, which he says should be signed by year's end, will sweeten the deal for foreign companies.

"We want to attract other companies, and welcome companies to continue to explore our waters," he said. "There is still a lot of gas waiting to be explored in our waters, another 100 Tcf. In addition, the chances of discovering oil fields is high probable. We hope to move forward."

What remains to be seen is how the framework's terms, once finally approved by Israel, can convince potential investors that may be wary of working in the country following the setbacks Noble and its partners have endured regarding Leviathan's development.

Find more of our Mediterranean and North African coverage beginning on page 50 of this issue. **OE**

AtComedia
Atlantic Communications Media

AtComedia
1635 W. Alabama
Houston, Texas 77006-4101, USA
Tel: +1-713-529-1616 | Fax: +1-713-529-0936
email: info@atcomedia.com

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OE

PUBLISHING & MARKETING
Chairman
Shaun Wymes
swymes@atcomedia.com
President/Publisher
Brion Palmer
bpalmer@atcomedia.com
Associate Publisher
Neil Levett
neil@aladitd.co.uk

EDITORIAL
Managing Editor
Audrey Leon
aleon@atcomedia.com
European Editor
Elaine Maslin
emaslin@atcomedia.com
Web Editor
Melissa Sustaita
msustaita@atcomedia.com
Contributors
John Bradbury, Greg Hale, Audrey Raj, Heather Saucier
Editorial Assistant
Jerry Lee
Editorial Intern
Elia Barnett

ART AND PRODUCTION
Bonnie James
Verzell James

CONFERENCES & EVENTS
Events Coordinator
Jennifer Granda
jgranda@atcomedia.com
Exhibition/Sponsorship Sales
Gisset Capriles
gcapriles@atcomedia.com

PRINT
Quad Graphics, West Allis, Wisconsin, USA

EDITORIAL ADVISORS
John Chiang, *Houston Offshore Engineering*
Susan Cunningham, *Noble Energy*
Marshall DeLuca, *Wison Floating Systems*
Edward Heerema, *Allseas Marine Contractors*
Kevin Lacy, *Talisman Energy*
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South African ports play a leading role in stimulating the Blue Economy in Sub-Saharan Africa.

With 3 900 kilometres of coastline, 330ha of coastal land, eight ports and three coastal provinces at its disposal, South Africa is geographically well-placed to leverage the opportunities arising in the oil and gas sector.

In the spotlight: The Port of Saldanha Bay

South Africa's deepest natural port, the Port of Saldanha Bay, is strategically located in close proximity to West Africa's offshore oil and gas fields, the continental shelf that supports these commodities and has the marine industrial backup needed to exploit the opportunities in the up- and midstream sector. The Port of Saldanha accommodates vessels with a draught of up to 19 metres and has been identified as a key and strategic port to be developed into a dedicated oil and gas hub and services complex.

A significant increase in the number and frequency of requests for purpose-built facilities from large rig operators has necessitated that the Port of Saldanha be established to international standards in order to increase its competitiveness in relation to services such as rig repairs, bunker fuel supply and pipe storage.

Africa's challenges inspire new development and growth

Africa currently produces more than 10 million barrels of crude oil per day – approximately a tenth of global production – the compounded annual growth rate of oil production in West Africa being estimated at 5.8%, Southern Africa at 6% and Central Africa at 7.7%. This growth, however, may not be achieved if the region is not equipped with ports that can serve as dedicated oil and gas hubs and offshore supply to support services centres which meet the growing infrastructure-intensive needs of current and future oil and gas exploration on the seas of the continent.

Given the current production of around five million barrels of oil per day in West Africa alone, the South African Oil & Gas Alliance (SAOGA) estimates that the drilling infrastructure already in place would need to be serviced and maintained over the next 30 to 40 years, meaning that the demand for the facility is definitely sustainable in the medium to long term.

Recent developments in Africa, particularly in the oil and gas sector, have seen maritime activity increase, with Durban growing in activity as a result of the significant finds in East Africa. To support this growth, many up- and midstream service and equipment providers have clustered their offices in Cape Town, a traditional port of call.

Operation Phakisa: Bringing the vision to life

The South African government has established a collaborative forum, Operation Phakisa (a seSotho word meaning 'hurry up') comprising of the National Ports Authority, together with the Department of Trade and Industry and Department of Public Enterprises, to enable the implementation of the Saldanha Bay Industrial Development Zone (IDZ) and fast-track priority developmental projects that drive economic development.

To improve infrastructure and services to support the oil and gas industry that directly impact the cost performance of the industry, the private sector has demonstrated its support of the project by investing approximately R250 million (approx. USD $20 million) towards establishing fabrication-related infrastructure in the Port of Saldanha Bay. This investment will assist in positioning the Port of Saldanha as one of the strategic catalysts in unlocking South Africa's untapped ocean economy potential, aptly known as the blue economy and estimated to have a potential total GDP contribution of R177 billion and the capability to create thousands of jobs, skills creation and new business opportunities.

Creating an import and export investor's paradise

Over the next five years, investments in port infrastructure for the oil and gas industry are expected to exceed 10 billion rands (US$1 billion). Foreign investors looking to use South Africa as a base for expanding African operations will benefit from reduced secondary and dividend taxes offered by the Saldanha free port facility.

The Industrial Development Zone, which is set to be located adjacent to the main port, will have a variety of back-of-port activities offering investors the benefit of being located in a customs control area (CCA), or a free port facility, which means that no Value Added Tax (VAT) will be payable on goods, services, land, buildings or infrastructure items imported and exported at the CCA.

The IDZ will have dedicated quayside access to enable seamless and efficient turnaround of vessels in and out of the facility. The complex will also offer a world-class, one-stop shop for regulatory services such as permit applications and approvals, immigration administration and business support. In addition, companies operating within the IDZ will also have access to financial and non-financial support for employment and training activities for both skilled and semi-skilled staff on site.

South Africa is set to position itself as an integral player in the oil and gas sector!

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Global E&P Briefs

A Fleeing the Arctic

Shell is ceasing further exploration offshore Alaska after the company found oil and gas indications that were not 'sufficient to warrant further exploration' at the Burger prospect, in the Chukchi Sea, 150mi from Barrow, Alaska.

Once Shell announced its decision, the US Department of the Interior decided to cancel two planed Arctic offshore lease sales scheduled for 2016 and 2017. "In light of Shell's announcement, the amount of acreage already under lease and current market conditions, it does not make sense to prepare for lease sales in the Arctic in the next year and a half," said Secretary of the Interior Sally Jewell.

B Bill could ban West coast drilling

US Senators have introduced the West Coast Ocean Protection Act, legislation to permanently prohibit offshore drilling on the outer continental shelf of California, Oregon and Washington.

The West Coast Ocean Protection Act includes clear language stating that "the Secretary of the Interior shall not issue a lease for the exploration, development, or production of oil or natural gas in any area of the outer Continental Shelf off the coast of the State of California, Oregon or Washington."

C BG buys blocks off Eastern Canada

BG Group has acquired three non-operated positions offshore Newfoundland from Repsol. The blocks are located in the Atlantic Ocean, approximately 200km from St. John's, Newfoundland. BG Group is a 10% partner with Statoil (operator) and Chevron in blocks EL1125 and Block EL1126, and a 25% partner with Statoil (operator) on block EL1123.

D Eni in Mexico development

Italy's Eni won,a production sharing contract to appraise, develop, and exploit the oil fields of Amoca, Miztón e Tecoalli, in the Area 1 in the Bay of Campeche, offshore Mexico, following the country's phase two of Round One held on 30 September.

The Amoca, Mitzon and Teocalli fields are in shallow water, 20-40m, and are close to shore. According to the official estimates by the local authorities, the combined oil volumes in place for the three fields are approximately 800 MMbo and 480 Bcf of gas.

E Horn Mountain Deep targets 2017

Initial production from the Horn Mountain Deep well is expected by 1H 2017 and will be tied back to existing facilities, says Freeport-McMoRan. This well, combined with two follow on development wells at Horn Mountain Deep, may be capable of producing an aggregate of 30,000 boe/d. The well was drilled to 16,925ft, where it encountered about 142ft net of middle Miocene oil pay as indicated by logging while drilling logs. In addition, these results indicate the presence of sand sections deeper than known pay sections in the field.

F Noble hits Humpback pay

Noble Energy's 53/02-01 Humpback exploration well has recorded oil and gas shows, according to partner Falklands Oil and Gas (FOGL). The 53/02-01 well was drilled to 4718m and intermediate wireline logs indicating the possibility of hydrocarbon bearing sandstones between 4642-4704m. The well is now being deepened to evaluate additional targets, says FOGL.

More wireline logs will be run when the well reaches total depth.

G Brazil's 13th bidding round flops

Brazil's 13th Bidding Round resulted in 37 out of the 266 blocks sold, bringing in about US$89 million.

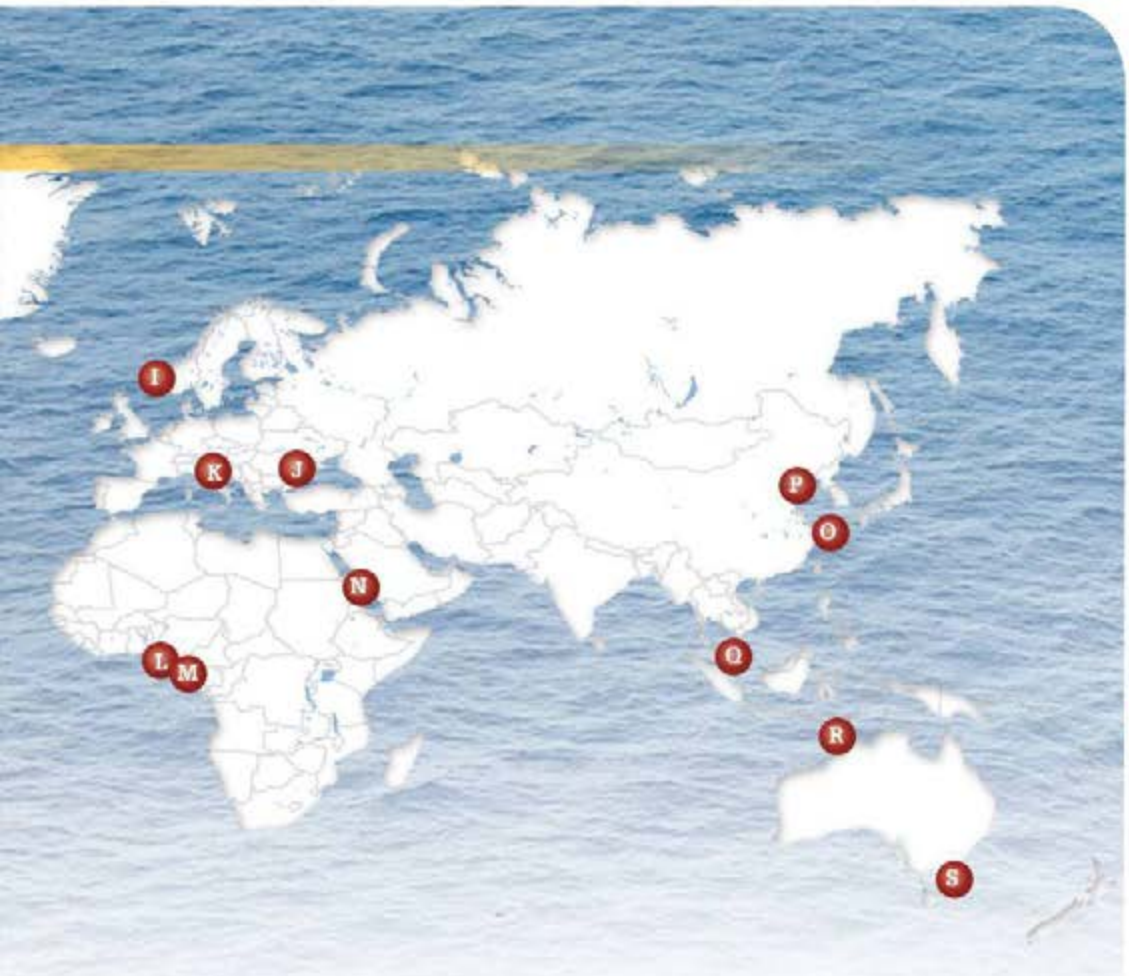
A total of 17 international companies were sold blocks, however, the biggest sale, at $16.7 million, went to Brazil's Queiroz Galvão for block SSEAL-M-351.

It was expected for foreign companies to bid in deepwater areas, but they stayed away, said Magda Chambriard, ANP general director. State-owned oil company Petrobras was absent from the round.

H Petrobras hits at Libra, Carcará

Petrobras announced a further hydrocarbon discovery at the giant pre-salt Libra field in the Santos basin, offshore Brazil. The Brazilian national said that well 3-BRSA-1310-RJS, in the central portion of the block, identified the presence of hydrocarbons in a low-porosity reservoir. This is the fourth well drilled in the Libra area since exploratory drilling began last August.

Petrobras announced it discovered high-quality (31°API) light oil potential at the third well in the Carcará pre-salt discovery area offshore São Paulo. Well 3-SPS-104DA or



Carcará Noroeste, is located in block BM-S-8 in the Santos basin, 226km from the coast of São Paulo.

The carbonate reservoirs, at a depth of 5870m below the salt layer, have excellent characteristics. A significant oil column of 318m was found and there has been no oil/water contact for this accumulation, Petrobras said.

I Gullfaks wet compression project started

Production started at Statoil's Gullfaks subsea wet compression project, in block 34/10 in the northern part of the Norwegian North Sea. The project will help increase recovery from the Gullfaks South Brent reservoir by 22 MMboe and extend plateau production by around two years. The current recovery rate is around 59%, but Statoil has been striving to increase that to 62% through extended reach wells, new completion and sand control technology and water alternating gas injection.

"The recovery rate from the Gullfaks South Brent reservoir may be increased from 62% to 74% by applying this solution in combination with other measures," says Kjetil Hove, senior vice president for the operations west cluster.

J Black Sea activity rises

Russia's Lukoil discovered natural gas pay at its deepwater Lira field in the Black Sea, offshore Romania.

The Lira-1X exploration well is located about 170km from the coast, and encountered a productive interval 46m thick after hitting a depth of 2700m.

Seismic data shows the field can reach up to 39sq km, and reserves can exceed 30 Bcm, which Lukoil expects to confirm during evaluation drilling.

In addition, the Bulgarian Ministry of Energy awarded Shell a permit for deepwater exploration in blocks 1-14 Silistar in the Black Sea.

Shell's proposed working program includes 2D and 3D seismic studies, and measures for the protection of the environment, human health and cultural values.

K Eni in Italy gas find

Eni encountered gas at the Guendalina sidetrack well offshore Italy. The well, located at the Guendalina gas field in the Adriatic Sea, reached its target depth of 3276m measured depth.

Wireline logging confirmed that all the target levels are gas bearing and encountered slightly higher to prognosis in an up-dip position with good reservoir characteristics and with an additional deeper gas level. The well is now being completed as a producer.

L Bonga Phase 3 starts production

Shell started production from the Bonga Phase 3 project offshore Nigeria, with expected peak production to hit about 50,000 boe/d.

Bonga Phase 3 is an expansion of the Bonga Main development, in OML 118. The Bonga field is located approximately 120km off the coast of Nigeria in the Gulf of Guinea.

Production will be transported through existing pipelines to the Bonga floating production storage and offloading (FPSO) facility, which has the capacity to produce more than 200,000 bbl and 150 MMcf/d of gas, Shell said.

M Noble's Cheetah disappoints

Noble Energy will plug and abandon its Cheetah exploration well, drilled to 13,320ft total depth, after finding both crude oil and natural gas shows in multiple non-commercial reservoir sands.

Cheetah, a four-way structure located offshore Cameroon, was thought to contain unrisked gross mean resources of more than 100 MMboe.

Noble said that results from the well are being integrated into its geologic modeling for the remaining prospectivity in the Tilapia license.

N OPEC production declines

Oil production from the Organization of the Petroleum Exporting Countries (OPEC) totaled 31.2 MMb/d in September, down 60,000 b/d from August as Saudi Arabia further reined in supply, according to a Platts survey of OPEC and oil industry officials and analysts.

Saudi Arabia was the only member country to reduce supply last month. Small increases totaling 80,000 b/d came from Angola, Iran, Libya, Nigeria and the United

Arab Emirates (UAE).

Saudi supply fell back to 10.26 MMb/d in September from 10.4 MMb/d in August, the survey estimated.

Primeline spuds exploration well

Primeline Energy Holdings has spudded LS23-1-1, the first of two exploration wells. Located in block 33/07 in the East China Sea, the well is 24km from the LS36-1 gas field platform.

Total depth of the well is designed to be 2688m, with several target zones in Palaeocene sediments.

Drilling is scheduled to take approximately 30 days, including logging, using China Oilfield Services Ltd.'s HYSY941 jackup rig.

Resources discovered in this drilling campaign can use or share the LS36-1 gas field production infrastructure to speed up development and optimize future development costs and economics.

ROC spuds second Bohai Bay well

ROC Oil commenced drilling the QK12-3-1D well located in block 09/05, covering an area of 335sq km in the prolific Bohai Bay basin, offshore China. The well is approximately 10km southeast of Tanggu, the largest port in China.

Drilling operations will test the oil potential of a 3-way dip closed structure matured by 3D seismic data. This is the second of two planned exploration wells and will be drilled to 3600m.

Lundin spuds Malaysian well

Lundin Petroleum resumes exploration offshore Malaysia and spuds the Mengkuang-1 exploration well, in license PM307.

Lundin says the well will target hydrocarbons in Miocene-aged sands 75km to the northwest of the Bertam field.

Mengkuang-1 will take about 30 days to drill to a total depth of approximately 1300m below mean sea level using Seadrill's West Prospero jackup rig.

MEO exits three Aussie permits

MEO Australia is cutting three permits from its Australian exploration portfolio in the next six months due to high risks and minimal potential. MEO is exiting the NT/P69 permit in the Heron area, after assessments of the discovery concluded that it was too small to be a potential gas supply source for the Tassie Shoal projects.

The company is also withdrawing from two Western Australian permits: 62.5% stake in the WA-360-P permit, and 50% stake in the WA-361-P permit. According to MEO, the remaining prospectivity in these permits is considered too high risk for its exploration strategy, when compared to its other assets.

Bass Strait Oil receives extension

Australia's National Offshore Titles Authority (NOPTA) granted Bass Strait Oil a 12-month suspension and extension for the work program and permit term or its 100% owned and operated VIC/P68 permit offshore Australia. The Vic/P68 exploration permit, which covers 1074sq km lies to the west of Vic/41, in the northeast part of the Gippsland Basin. It covers parts of the Central Deep, Northern Terrace and Northern Platform, with water depths increasing from 50-150m towards the southeast. The permit is currently in Year 3 of the six-year term. The Year 3 work program, which entails acquiring 225sq km of 3D seismic, now expires 3 November 2016.

Contract Briefs

Statoil awards Johan Sverdrup work

Statoil has awarded contracts for two Johan Sverdrup jackets to Kvaerner Verdal and Dragados Offshore.

Kvaerner Verdal's contract is worth approximately US$122.8 million and covers engineering, fabrication and construction of the steel jacket for the Johan Sverdrup processing platform. Weighing 17,700-tonne, the jacket will be constructed at the yard in Verdal and installed on the Johan Sverdrup field in the summer of 2018.

Dragados Offshore's contract covers engineering, fabrication and construction of the steel jacket for the Johan Sverdrup utility and accommodation platform. Weighing 7600-tonne, the jacket will be constructed at the yard in Cadiz. Field installation is scheduled for the summer of 2018.

SBM wins Browse FEED

Technip has awarded SBM Offshore a front-end engineering and design (FEED) contract for three, large-scale turret mooring systems associated with the proposed Browse FLNG development offshore Australia. The three, large-scale turrets are expected to be designs similar to and slightly larger in size than the Shell Prelude FLNG turret that SBM Offshore was awarded in 2011.

Saipem racks up $680 million in contracts

Saipem has won new engineering and construction contracts cumulatively worth approximately US$680 million. Included are contracts awarded by Saudi Aramco and Eni.

The contract with Saudi Aramco is an EPCI job for offshore structures that include an observation platform, wellhead production deck module, auxiliary platforms, 20in internally cladded flowline and composite power cable. The structures will be installed offshore Saudi Arabia.

The Eni Angola contract is another EPCI job for block 15/06 - East Hub Development Project. The scope of works includes the provision of five flexible risers and 20km of rigid flowlines, as well as installing SURF facilities which include umbilical sections, rigid spools, well jumpers and 14 PLETs to be fabricated in Angola. The project will be completed by yearend 2016.

Technip wins Stones contract

Shell has awarded Technip a contract for the development of subsea infrastructure for the Stones project. Included in the service are two subsea production tie-backs to the floating production, storage and offloading (FPSO) vessel.

The contract covers engineering of the required second pipeline end terminations (PLETs); fabrication of the PLETs and piles; and installation of the subsea production system, inclusive of associated project management, engineering and stalk fabrication.

DOF Subsea secures Husky contract

DOF Subsea won an IMR contract with Husky Energy in support of their operations offshore Eastern Canada. The DOF Subsea team based in St. John's will supply IMR services over a period of 10 years firm, with options for an additional 10 years. The work scope includes an IMR vessel and two work class ROV systems and personnel. ▪

Malampaya fuels the Philippines

Audrey Raj explains how an old deepwater field such as Malampaya continues to power the Philippines and benefit its economy.

The Malampaya natural gas field continues to power a third of homes and businesses in the Philippines, thanks to its new offshore structure, the depletion compression platform (DCP), which recently came online in early October after its installation was completed in September. Located adjacent to the existing Malampaya shallow water platform 50km from Palawan in western Philippines, the DCP is the first offshore platform to be designed and built in the country.

Spearheaded by the Department of Energy (DOE), the Malampaya deepwater gas-to-power project is a joint undertaking of the Filipino national government and its private sector.

Shell Philippines Exploration operates Malampaya under service contract 38 (SC38) with 45% interest. Its joint venture partners are Chevron Malampaya (45%) and the Philippine National Oil Co. Exploration Corp. (PNOC-EC) (10%). Since it began operations in 2001, the Malampaya offshore gas field has become one of the main sources of energy for the Philippines.

It has produced cleaner burning natural gas for three power plants in Batangas, which have a combined generating capacity of 2700 MW.

However, pressure in the gas reservoir deep beneath the seabed dropped over time, potentially reducing the supply of electricity to millions of people.

To address the problem, Shell designed the DCP, which will boost the pressure to help keep gas flowing out of the reservoir at current levels for about another decade.

Malampaya overview

Discovered in 1992, the Malampaya story spans over a decade when Shell first discovered a natural gas reserve in the Camago-Malampaya reservoir.

Following the spudding of five wells, some 2.7 Tcf of natural gas and 85 MMbbl of condensate located in approximately 3000m below sea level were identified.

After comprehensive studies in 1995 showed that the area presented an opportunity for commercial gas development, in 2001 the Malampaya deepwater gas-to-power was inaugurated.

Along with the original field development of 1998, additional two stages – Malampaya Phase 2 (MP2) and Malampaya Phase 3 (MP3) – were formulated to sustain gas production to power Luzon, the most populous Filipino island.

While MP2 saw the drilling of two new wells in 2013, MP3 was the design, fabrication and installation of the second Malampaya offshore platform, the DCP.

In early 2015, the Malampaya Phase 3 depletion compression platform was towed from its fabrication site in Subic Bay, Philippines.
Photos from Shell.

Malampaya currently produces 380 MMscf/d of natural gas and 15,000 b/d of condensate. The natural gas extracted from these wells is transported through flowlines to an offshore shallow water production platform for initial processing.

Condensate is stored at the base of the platform, while the dried gas is transported via a 504km underwater pipeline to the onshore processing gas plant in Batangas.

Two onshore pipelines transport the fuel to three gas fired power stations, namely, Santa Rita (1000 MW), San Lorenzo (500 MW) and Ilijan (1200 MW).

Economic benefits

Historically, the Philippines has been an economy that relies heavily on imported fossil fuel, and the Malampaya deepwater gas-to-power project has helped to reduce that dependency by 30%.

While Malampaya has signaled the birth of a natural gas industry for the Filipinos, it has also been instrument in contributing billions of pesos in government revenue share and significant local employment opportunities.

For example, in 2013 alone the DOE together with the Malampaya joint venture partners turned over a total of US$1.1 billion dollars' worth of revenues to the national government.

Since, the Philippines is not as mature as its Southeast Asian neighbors, such as Indonesia and Malaysia, the country's oil and gas professionals lack local employment opportunities, too.

In addition to providing some 1200 local jobs, the construction of DCP has also generated more businesses for homegrown companies supporting the project.

Workers tapped for the construction have attended mandatory training to elevate their competencies as well.

So far, the Malampaya Health Safety and Environment Training Center has upgraded the skills and technical knowledge of more than 6000 Filipino workers to international standards recognized by the Offshore Petroleum Industry Training Organization.

The country now has a competitive edge in pitching for future oil and gas projects, as this latest installation phase of the DCP demonstrates technical capability of the Filipino workforce.

Furthermore, to inspire the youth into oil and gas engineering, in 2014, Shell opened the fabrication yard at the Keppel Subic shipyard where DCP was being constructed to would-be engineers.

About 30 engineering students from Ateneo De Manila University, De La Salle University, University of the Philippines–Diliman and University of Santo Toma witnessed the DCP slowly coming to completion.

Self-installing DCP

A team of more than 1400 Filipino workers took about two years to build the DCP, which was constructed at the Keppel Shipyard in Subic, Zambales, within 11.8 million safe man-hours.

Keppel was responsible for the fabrication of the entire DCP, including the integration of the topside modules and the fabrication of the link bridge connecting the DCP to the shallow water platform.

Fluor Philippines, which was involved in MP3's front-end engineering design (FEED), also provided engineering, procurement and construction (EPC) support services.

Engineering and consulting firm, Arup, was appointed by Fluor as a subcontractor to complete the substructure detailed design and provide procurement support on substructure related matters.

Following the completion of the engineering design in early 2014, Shell appointed Arup to provide engineering support services for the fabrication and installation of the 13,000-ton self-installing substructure.

For Shell, the self-installing technology of the platform was a first of its kind, as it enabled the platform to be installed without the need for large specialized installation vessels.

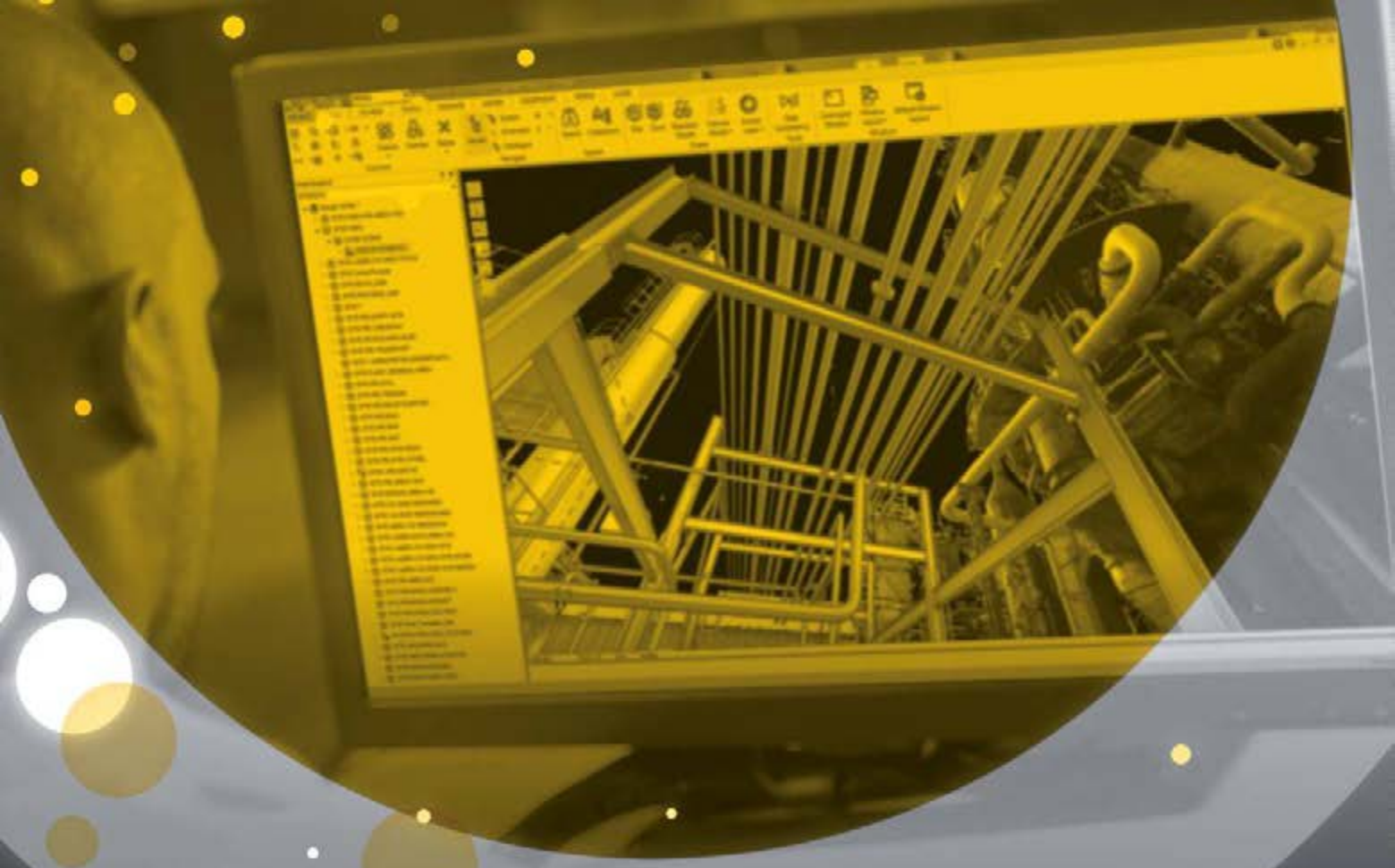
The platform was built to float and was towed from Subic to the Malampaya location, offshore Palawan. The inbuilt jacking system enabled the 80m legs to be jacked down and lifted the platform from the water into its final position.

According to Arup, the complex soil conditions at the installation location required a novel seabed removal and rock replacement solution to ensure stability of the gravity based foundations.

The DCP was installed within the installation tolerance of 1m from the set out point ensuring the interconnecting bridges to the existing platform could be installed without any modification.

As the Malampaya field is located in an earthquake and typhoon prone region, the DCP and the bridge were constructed to withstand strong tremors as well. OE

The depletion compression platform was installed alongside the existing Malampaya platform in the West Philippine Sea.



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Thinning the herd

For the offshore floating rig market, the downturn presented the perfect storm: too many rigs, not enough demand, and with some 200 newbuilds set to enter the market over the next decade. Audrey Leon reports.

The Maersk Developer, operating the Hadrian-5 well for ExxonMobil about 200mi offshore in the KC-919 area of the Gulf of Mexico, on 6 July 2011. Photo from Robert Seale/Maersk Drilling.

To say that 2015 has been a bad year for some rig owners would be an understatement. The segment has too many rigs and not enough demand.

Many analysts expect the declines to continue into 2016. Tom Kellock, an analyst for IHS, told ***OE***: "With limited contracting opportunities and more newbuilds joining the fleet, utilization will fall further – unless the rate of attrition accelerates very rapidly."

Analysts at Rystad Energy reported in June that the offshore drilling industry is on the verge of "the largest ever retirement cycle in history," with as many as 88 units needing to be taken out between 2015 and 2017. At the time of the report, Rystad Energy said it expected 49 units to be taken out in 2015, a record level not seen since the 1985 oil crisis. Rig owners have to retire an additional 36 units in 2016 to balance the floater demand, the firm said, with demand expected to pick up again in 2017.

Joachim Bjørni, an analyst for Rystad Energy, told ***OE*** that the firm expects the downturn to continue and reach bottom in 2016. And many rig providers seem to agree that things will not improve any time soon.

Exploration

On the exploration side, Wood Mackenzie's Andrew Latham says things aren't likely to improve there either for some time. "In exploration, we're almost certainly going to see 30% lower spend over the industry this year, no different in the drilling segment," he says. "That cut back would be steeper still if there weren't contracts from 2013 and 2014 that rolled into this year. You've lost more than 30% of your demand. And you've also got more units. Yes, there have been some taken out, but new ones keep arriving. Construction program has not stopped abruptly."

Certainly, day rates have a role to play in operators choosing to limit drilling activity to more mature, low risk wells. Despite that trend, the number of discoveries has been decent this year.

"It looks like there's about 5 billion boe new resource from new discoveries in the 1H 2105," Latham says. "Experience says this will grow by another third or so, just through better disclosure, better appraisal, etc., but 5 billion for half a year, isn't bad."

Latham says, in a typical year, the industry finds approximately 15-20 billion boe in a full year, and he believes the industry is on track to reach at least 15 billion boe by year's end.

"Now, what makes that an impressive achievement, is because so far we're seeing fewer wells," he says.

Latham notes we're seeing fewer wells mostly due to budget cuts, but also due to a new focus on low risk wells. "The industry is spending less and it's not renewing rig contracts as quickly as they would have done a year or two ago," he says.

"Of course, if you drill lower-risk wells, and measure your risk accurately, lo and behold, you get a higher success rate."

Latham says the Macondo accident and the push for safety in the aftermath has attributed to rig demand in recent years.

"If you go back to pre-Macondo (2009), operators typically took 50 days of rig time per deepwater exploration well," he says. "Last year, it was more like 80 days." Latham attributes this to a number of factors such as water depth, the objective and target depths, which are deeper. But, he also says the industry is taking a more cautious approach to deepwater wells, with more testing of the BOPs (blowout preventers), for example. Drilling more low risk wells could reverse the previous high demand for rigs, he says.

"Higher risk frontier wells require more days than a lower risk well in a more mature, established play," he says. "You spend less time moving on location, and the depth is shallower. Where the geology is better known, you can drill a much plainer, vanilla wells.

"In a frontier setting, you have to have all sorts of contingencies and plans for all sorts of unlikely but possible hazards in the subsurface," he says.

Rystad analyst Bjørni expressed similar sentiment. "Operators have been communicating that they are focusing on exploration close to existing infrastructure, this will give cheap barrels to develop and increased probability of success."

Quick stats

OE's at-a-glance guide to offshore hydrocarbon reserves and key offshore infrastructure globally is updated monthly using data from leading energy analysts Infield Systems (www.infield.com).

New discoveries announced

Depth range	2012	2013	2014	2015
Shallow (<500m)	71	74	73	34
Deep (500-1500m)	23	19	29	14
Ultradeep (>1500m)	37	35	13	9
Total	131	128	115	**57**
Start of 2015 date comparison	135	125	90	-
	-4	3	25	**57**

Note: Operators do not announce discovery dates at the time of discovery, so totals for previous years continue to change.

Reserves in the Golden Triangle

by water depth 2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	9	30.75	333.28
Deep	12	941.00	2195.00
Ultradeep	40	10,923.75	12,450.00
United States			
Shallow	14	86.30	234
Deep	19	722.27	818.48
Ultradeep	26	2791.50	3420.00
West Africa			
Shallow	110	3736.20	15,898.22
Deep	37	4622.50	5540.00
Ultradeep	13	1635.00	2160.00
Total	270	**25,458.52**	**42,715.70**
(last month)	(277)	(25,749.27)	(43,190.98)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	889	38,242.09	511,028.44
(last month)	(892)	(38,248.29)	(513,122.34)
Deep	119	7198.58	71,043.91
(last month)	(120)	(7555.58)	(71,735.91)
Ultradeep	82	15,378.25	30,997.00
(last month)	(81)	(15,333.25)	(30,957.00)
Total	1,090	60,818.92	**613,069.35**

Pipelines

(operational and 2015 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,594	(41,973)
Planned/ possible	24,193	(24,542)
	65,787	(66,515)
8-16in.		
Operational/ installed	81,651	(82,709)
Planned/ possible	49,002	(49,411)
	130,653	(132,120)
>16in.		
Operational/ installed	92,607	(92,622)
Planned/ possible	38,461	(43,131)
	131,068	(136,753)

Production systems worldwide

(operational and 2015 onwards)

Floaters		(last month)
Operational	285	(273)
Under development	41	(49)
Planned/possible	347	(312)
	673	(634)
Fixed platforms		
Operational	9302	(9529)
Under development	117	(85)
Planned/possible	1407	(1380)
	10,826	(10,994)
Subsea wells		
Operational	4783	(4813)
Under development	271	(436)
Planned/possible	6631	(6442)
	11,685	(11,691)

Global offshore reserves (mmboe) onstream by water depth

	2013	2014	2015	2016	2017	2018	2019
Shallow	22,856	14,528.45	37,823.29	24,420.96	19,433.05	19,959.89	25,506.62
(last month)	(22,856.00)	(14,528.45)	(38,972.67)	(23,670.89)	(20,214.31)	(20,345.01)	(25,506.62)
Deep	481	4469.26	4340.71	2237.76	2252.09	4,534.73	6417.57
(last month)	(481.00)	(4469.26)	(4340.71)	(2291.58)	(2230.92)	(4921.92)	(6417.57)
Ultradeep	2917.00	2342.81	1966.63	3049.17	3287.44	5221.54	7318.54
(last month)	(2917.00)	(2342.81)	(1929.58)	(3034.17)	(3287.44)	(5221.54)	(7318.54)
Total	26,253.26	21,340.52	44,130.63	29,707.89	24,972.58	29,716.16	39,242.73

14 October 2015

Dealing with lowered demand

With demand for rigs down, and many companies seeking to reduce day rates for currently contracted rigs, there has been a push toward cold stacking or just scrapping rigs entirely.

Cyprus-headquartered Ocean Rig announced in October that if no future work is found for two of its fifth generation ultra-deepwater semisubmersible rigs – the *Eirik Raude* and *Leiv Eiriksson* – built in 2002 and 2001, respectively, they could be scrapped.

"The market continues to remain challenging due to the massive spending cuts initiated by the oil companies," said George Economou, Chairman and CEO, Ocean Rig. "In this environment, cash preservation and liquidity remain our number one priority and we will adjust our available capacity to the new market conditions. For rigs that we cannot secure long-term employment that are coming up for their five-year SPS we will cold stack the units and in the case of the semisubmersible rigs seriously consider all our options including disposal or scrapping."

Simmons & Co.'s Ian Macpherson said of Ocean Rig's news at the time, "[the fleet status update] serves as a reminder of just how bleak the demand situation is right now for the offshore drillers, indicating that its two [fifth generation] harsh environment semis are likely to be scrapped, one of its [sixth generation] drillships is likely to be cold stacked, and another [sixth generation] drillship could (we infer) also be heading to cold stack as well following an untimely contract cancellation."

Bermuda-headquartered Seadrill – which operates one of the largest floater fleet, consisting of 69 rigs comprising drillships, jackups, semisubmersibles and tender rigs – shares a similar outlook on the rig market.

"The outlook for activity beyond 2015 is difficult to judge, but most oil companies are not looking towards adding rig capacity at this point," the company said in May. "It is likely that capacity utilization will drift lower as the year progresses and a significant number of ultra-deepwater rigs are likely to be stacked by the end of 2015."

For companies that have either declared bankruptcy or are still swirling around it, 2016 will not be pretty.

Already this year two notable groups have declared bankruptcy: US-based Hercules Offshore and Brazil-based Schahin Group, which filed for bankruptcy in April. Schahin Group, which operates several vessels for embattled Brazilian oil company Petrobras – including the *Schahin Cerrado* drillship that drilled the giant Libra prospect offshore Brazil – blamed its situation on a tight national and international credit market, making it too difficult to find financing.

The downturn isn't the only thing hastening the need to jettison dead weight from the global fleet, impending newbuilds are another concern. Bloomberg reported in December 2014 that more than 200 new rigs were due to be delivered in the next six years. And many companies have answered the call to rebalance.

Global rig provider Transocean, with a sizeable fleet of 63 floaters, led the pack in rig scrapping this year, opting to drop 20 of its oldest floaters, with 12 newbuilds due to enter its fleet over the next decade. According to Transocean's latest fleet status report, the company has stacked 15 rigs and idled 13.

According to data from several firms (Infield, Rystad, and IHS), the area with the lowest utilization are the US GoM and Southeast Asia. Kellock says: "these [regions] are somewhat penalized because both are areas where rig owners cold stack un-needed rigs."

Houston-based Ensco, which operates a fleet of 75 rigs, has cold stacked two semisubmersibles (*ENSCO 8500* and *8501*) in

The Maersk Integrator, the third of four newbuild jackups to be added to Maersk Drilling's fleet from 2015-2016, in Amøyfjorden, Norway.
Photo from Maersk Drilling.

the GoM and one jackup, ENSCO 56, cold stacked in Malaysia. This year, the company received a cancellation notice from US oil major ConocoPhillips for the *ENSCO DS-9* drillship, which was to start a three-year contract in the GoM. Additionally seven Ensco rigs, a mix of semisubs, drillships and jackups have been held for sale. One newbuild, the *ENSCO DS-10* drillship, will be deferred by 18 months.

Arguably having one of the worst years is Hercules Offshore. The company announced a 40% reduction in its workforce, sold four rigs, delayed delivery of newbuilds, and in June, declared bankruptcy. In late July, the company reported a US$89 million loss in its 2Q 2015 results. With much of its jackups based in the hard-hit GoM, Hercules has cold stacked nine rigs as of July 2015, and sold six more jackups that had previously been cold stacked in the region since 2009.

Some of the currently cold stacked jackups in Hercules' fleet are over 30 years old. For example, the Hercules 120 jackup was built in 1958, and redesigned in 1974 for offshore drilling operations. The Hercules 200 was built in 1979. The Hercules 253, the last on the list, was built in 1982.

Some bright spots

Noble Corp. is one player who has managed to keep its utilization levels high. As of its July fleet status report, only one floater, the *Noble Homer Ferrington* semisubmersible, out of its fleet of 32, has been cold stacked. The *Noble Homer Ferrington*, a Friede & Goldman 9500 Pacesetter, was delivered in 1985. Another semisub, *Noble Jim Thompson*, was retired.

In August, Maersk Drilling, which operates 22 rigs, reported a profit of US$218 million in 2Q 2015, which it attributed to strong operational performance, fleet growth and general cost savings. At the end of 2Q 2015, Maersk Drilling's forward contract coverage was 83% for the rest of 2015, 61% for 2016 and 32% for 2017. The total revenue backlog by the end 2Q 2015 amounted to $5.3 billion.

Three Maersk rigs were idle during the period. And in July, the company announced it would decommission the Maersk Endurer jackup and recycle the rig in China. Built in 1984, it was one of the oldest in Maersk Drilling's fleet. Earlier in the year, the company announced it would eliminate 90

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	111	90	21	81%
Jackup	403	291	112	72%
Semisub	156	113	43	72%
Tenders	30	19	11	63%
Total	700	513	187	73%

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	30	27	3	90%
Jackup	58	37	21	63%
Semisub	15	13	2	86%
Tenders	N/A	N/A	N/A	N/A
Total	103	77	26	74%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	8	4	4	50%
Jackup	96	62	34	64%
Semisub	28	13	15	46%
Tenders	18	12	6	66%
Total	150	91	59	60%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	26	21	5	80%
Jackup	8	5	3	62%
Semisub	19	17	2	89%
Tenders	2	1	1	50%
Total	55	44	11	80%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	37	31	6	83%
Semisub	25	21	4	84%
Tenders	N/A	N/A	N/A	N/A
Total	62	52	10	83%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	95	85	10	89%
Semisub	2	1	1	50%
Tenders	N/A	N/A	N/A	N/A
Total	97	86	11	88%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	18	17	1	94%
Jackup	17	14	3	82%
Semisub	7	5	2	71%
Tenders	9	6	3	66%
Total	51	42	9	82%

Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	3	1	2	33%
Jackup	22	13	9	59%
Semisub	11	7	4	63%
Tenders	N/A	N/A	N/A	N/A
Total	36	21	15	58%

Source: InfieldRigs
14 October 2015

One of two fifth generation semisubmersible drilling rigs that could be scrapped if no other contracts come along.
Photo from Ocean Rig.

positions from its head office in Copenhagen, Denmark. In January, Maersk Drilling took delivery of its third, of four, ultra-harsh environment jackup, XLE-3, from the Keppel FELS shipyard in Singapore. A fourth is due to be delivered from Daewoo Shipbuilding and Marine Engineering (DSME) shipyard in South Korea in 2016. The four jackup rigs represent a total investment of $2.6 billion.

Seadrill currently has 15 rigs under construction comprised of four drillships, three semisubmersibles, and eight jackups. According to the company's 1Q 2015 report, Seadrill's order backlog as of May was $8.9 billion, comprised of $7.2 billion for the floater fleet and $1.7 billion for the jackup fleet.

"During [1Q], the market has seen very little new fixture activity and the new contracts that have materialized are at significantly lower day rates," Seadrill remarked in its most recently quarterly report. "Customer conversations have focused on renegotiation of existing contracts, often in exchange for additional duration."

And, Seadrill isn't the only company seeing this trend in renegotiations. Hercules Offshore received a reprieve from Saudi Aramco in June. The operator rescinded its termination notice for the Hercules 261 jackup. The two companies reinstated the five-year contract for the jackup that will run through November 2019.

Perth-based explorer Pura Vida Energy announced in early August that its exploration partner in the Mazagan permit offshore Morocco, Freeport-McMoRan planned to take advantage of the current depressed market. "Rates for deepwater drillships have fallen sharply since the *Atwood Achiever* was contracted and the operator has canceled the second slot under the rig share agreement in order to contract another vessel to take advantage of the current weakness in market conditions for rigs with the aim to reduce the cost of the second well."

The ultra-deepwater drillship *Atwood Achiever* had a contracted day rate of $667,000 on its original fixed contract, which was supposed to end in November 2017.

With most of its rigs facing a day rate change due to cost escalation provisions within contracts, Atwood Oceanics has opted to delay the delivery of one ultra-deepwater drillships the *Atwood Admiral*, under construction in South Korea, until March 2016. In its fleet status report, the company noted it could choose to delay a second, the *Atwood Archer*, to June 2017, if necessary. **OE**

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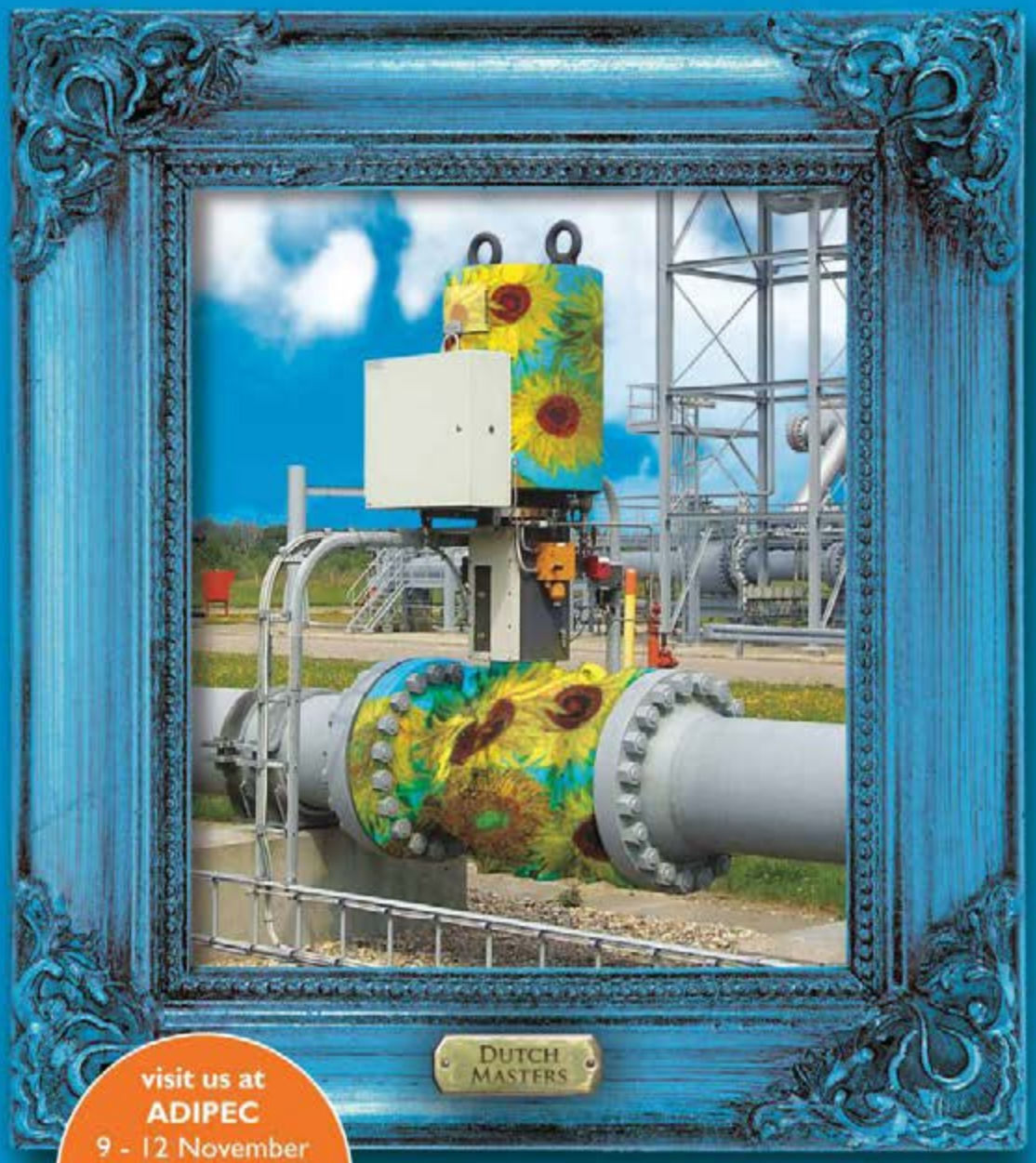

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Lessons learned

Learning from incidents is easier said than done. Edward Smith and Richard Roels, of DNV GL, give guidance on how to maximize learning from incidents, accidents and other events.

Following a major incident, it is common to hear those involved talk about "learning lessons" in a way that implies this is an automatic or natural process. In fact, evidence suggests that it can be challenging for major hazard industries to learn effectively from incidents.

Responding that "we have learnt from this incident" is an open phrase that could mean different things to different people:

a. That the team of investigators has understood how and why an incident occurred.

b. That several people in an organization now know how to prevent it happening again.

c. That an organization has implemented a set of changes (for example in equipment and personnel behaviors), which will prevent this event happening again.

d. That an organization has implemented a set of changes, which will prevent this event, and similar events, happening again and even learnt about its processes for Learning from Incidents (LFI) as a result of an incident investigation.

These points represent a range of learning potential; however, a change must happen before it can be claimed that learning has occurred. Implementing changes and taking preventative action would be expected to reduce risk further than simply carrying out an investigation.

The Energy Institute (EI) published "Guidance on investigating human and organizational factors aspects of incidents and accidents" in 2008. While most companies have now implemented processes for identifying why an incident happened, the next challenge is to learn from, and change after, an incident. The EI is currently updating the original guidance to cover the whole LFI process, from reporting and finding out about incidents through to effective learning and changing practices.

Key LFI stages

The LFI process consists of several stages including reporting, investigation, producing recommendations and actions, and broadening learning.

Photos from DNV GL.

While many incidents will be formally reported, not all are and details of others will be gathered informally. Research has indicated that many incidents per actual accident need to be reported to drive organizational learning.

Incident investigation is considered to cover both the fact finding and analysis stages, recognizing that iterations between these stages will be required to eventually reach a conclusion of what happened and why. Some organizations may struggle to provide competent investigation personnel, especially to cover specialist topics such as Human and Organizational Factors (HOF).

Carrying out recommendations and actions is a common area of weakness, even investigations carried out by experienced investigators can make recommendations that are never implemented.

Improving the processes around managing recommendations and the resulting actions will help implement the local learning associated with a specific event and lay the foundations for broader learning. There are clearly difficult challenges in reaching a wider group of people, beyond those immediately affected, and helping them to learn from an incident.

Previous research into LFI has identified that along each of the stages there are blockers to learning, e.g.:

- Fear of being blamed, professionally embarrassed or incriminating others by reporting.
- Lack of awareness about what should be reported or included in an investigation.
- Complexity of reporting systems and recommendations.
- Insufficient resources allocated to investigation.
- Recommendations not accepted by line management
- Insufficient checks that recommendations will effectively reduce risk.
- Legal constraints.

However, each set of blockers also has a set of enablers, which have been identified to overcome the challenges, e.g.:

- User-centered reporting processes.
- Feedback at end of LFI process to demonstrate that reports lead to effective changes.
- Senior management commitment to provision of competent investigators.
- Consultation while developing recommendations
- Check recommendations are risk proportionate and will not inadvertently increase risk.
- Turning lessons into good practice guidance, which does not carry liability risks.
- Develop indicators for following up on implemented actions.

The final step in implementing LFI is evaluation, i.e. has effective learning taken place. Monitoring measures with tangible outcomes, such as number of recommendations overdue, is relatively straightforward. However, corporate and personnel attitudes are harder to measure and more can be done in this area to establish good practices.

The potential blockers show the number of challenges to implementing an LFI process. By updating the EI guidance to include the whole process, the good practice enablers mentioned will allow organizations to build a structure, which will improve LFI. Reducing the blockers to learning and increasing the learning potential will ultimately improve risk management. OE

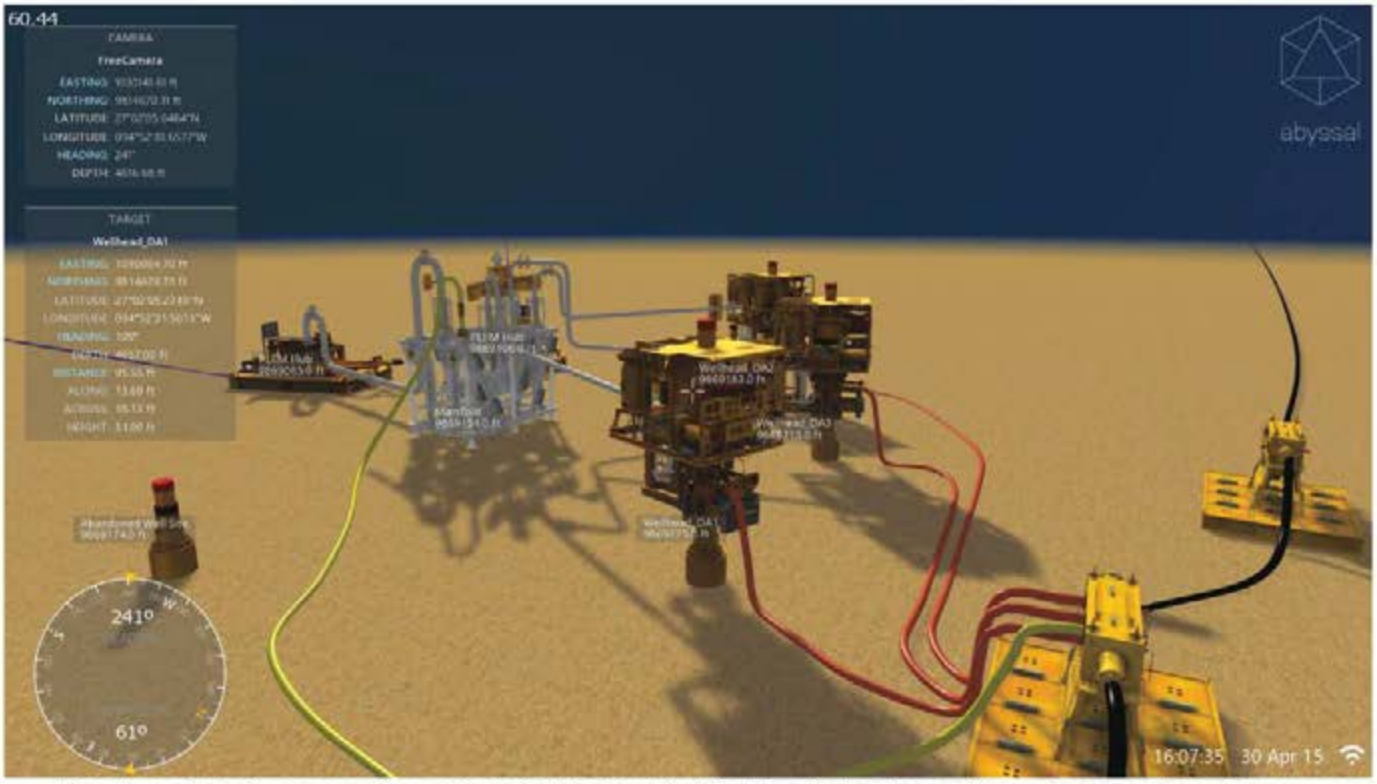
This paper was originally presented at Hazards 25, 13-15 May 2015, Edinburgh, UK

***Dr Edward Smith** is a Senior Principal Consultant at DNV GL. He has a PhD on how maintenance management affects the reliability and safety of major hazard systems. He joined DNV in 1989 where his main activities have involved safety risk assessment, safety management systems and human factors. He has also worked in aviation (especially Air Traffic Management), offshore, dangerous goods transport, rail and onshore process industries.*

Richard Roels is a Senior Consultant at DNV GL. He is a Chartered Occupational Psychologist specialising in the management of major accident risk in the oil and gas and transportation industries. His work covers aspects relating safety management and human factors, including inspection activities on behalf of regulators, conducting safety reviews and inquiries following serious incidents, as well as undertaking other specialist studies.

FURTHER **READING**

Lloyd's Register's Mark Tipping outlines the considerations which need to be taken into account to assure the future of FLNG by reducing new build risks and costs. http://www.oedigital.com/component/k2/item/10663-assuring-the-future-of-flng



The subsea field view as seen demonstrates the high level tactical view that can be used for subsea operations. This ensures a more complete picture for the ROV operator and subsea engineer and provides for effective field management in low visibility conditions. The use of survey positioning gear subsea allows the equipment to be positioned with centimeter level accuracy.
Images from Oceaneering.

Taking augmented reality **subsea**

Mark Stevens and Bob Moschetta, of Oceaneering, discuss the benefits of using augmented reality for subsea training.

Augmented and virtual reality environments are beneficial for offshore operations or any remote environment. The overall risk is reduced and job execution is improved. Specifically, safety is enhanced as the entire subsea environment can come to life and the job can be performed in the virtual environment. Thus, work instructions, procedures and processes which are intended for the actual job can be viewed and tested. This helps ensure problems that affect the equipment, the people and the execution of the job can be corrected ahead of time.

This increased visualization of how the job is supposed to occur provides the opportunity for the continuous improvement cycle to be used as equipment, process or work instructions can be modified based upon the virtual testing of executing the job, thereby reducing the risk and improving efficiency.

Situational awareness

Augmented reality takes into account additional sensor data,

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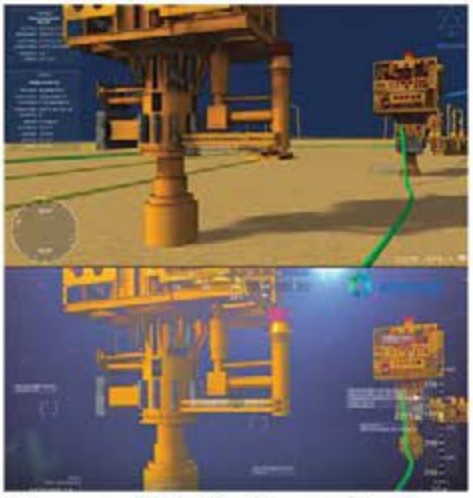
which enhances situational awareness. An example would be loading 3D models into a live video display. If the offshore visibility decreases due to fog or muddy water, the 3D models overlaid into the video would provide additional inputs to ensure the job can be completed effectively. Training employees on utilizing the augmented reality tools ensures that they are using all available means to complete the project.

Augmented training can ensure that personnel are aware of the potential hazards presented by the environment, equipment and procedures that will be utilized for jobs. This allows for hazards and inefficiencies to be identified and resolved, thus reducing the likelihood of managing the change, incurring delays and increased risk at the job site. Recommended changes can be communicated to the project managers and engineers to ensure the proposed changes to equipment and processes are adequate for the particular job.



The augmented reality view combines the real-time video with the 3D model, which allows operations to occur in real time. This view demonstrates the overlay capability whereas the 3D model is overlaid into the real-time video which provides the augmented reality capability. The bottom view is the real-time video with the model rendered into the ROV operator's screen.

Training

Performance enhancements for training can be provided by augmented reality due to the increased realism provided by the latest augmented systems. The repeatability of the training scenarios and the utilization of an effective physics engine to replicate the real-world environmental factors (i.e., gravity, wind, and temperature effects) should ensure flawless execution of the actual job. An example of a physics engine would allow a trainee to simulate how an ROV would work as he/she is heading towards an object and the engine was cut off. The physics engine would show the ROV slowing down instead of an instant stop.

Skills and capabilities can be captured and replayed utilizing an augmented reality platform by capturing the user input via all of the control systems. This can be combined with other sensor data such as the position of equipment which can be reviewed with new technicians to demonstrate the most effective process to complete a mission or job. The capturing of the user input would allow an organization to set up a baseline mission profile that can be replayed back to a new user so that their inputs and controls are adjusted to meet or excel the baseline recording.

Equipment

The use of haptic controls and touch sensors should allow for remote operational missions to be achieved while not on-site. Haptic tools recreate the feel of actually touching objects even though the operator is remote. These controls provide realistic feedback to give the user, which creates the feeling they are present in close proximity to the system. Using the robotic optical cameras and controls from the remote system allows the operators to explore and identify hazardous conditions, such as a subsea equipment failure, which has the potential for a subsea release of oil or gas.

Additionally, the utilization of wearable augmented headsets should see an increase in usage in the commercial market. Various products over the next two years will be hitting the market on the consumer side (i.e. Oculus, Sony, and Microsoft) and these should accelerate the usage of the tools and how they can be used in the workplace.

Oceaneering's experience

Oceaneering utilizes ROV simulators throughout our worldwide training centers. The use of the simulators ensures that the ROV pilots are familiar with the processes and controls for each upcoming mission and also allows for advanced testing of new ROV tooling that was developed for the specific job. Portable simulators are utilized offshore for recurrent training, thus ROV operators can assess, practice and review any changes to the mission. Moreover, potential hazards can be identified and corrected.

The use of augmented training helps to ensure the operator's situational awareness is such that the loss of visibility that may occur on the actual job should not impede the mission and objectives. This is possible as the augmented visuals provided in the operator display will provide a clear picture of the situation to allow the mission to continue.

This is similar to the aviation community where the pilot's heads up display (HUD) is augmented with the runway position in zero visibility and the pilot is comfortable completing the landing due to confidence provided by his/her training. Augmented reality training in the aviation world is so effective that the first time an airline co-pilot operates the controls of a commercial aircraft, it is typically with customers onboard. The Pilot-in-Command or senior pilot then provides monitoring of the co-pilot's activities and this demonstrates the cost savings as well because a dedicated aircraft isn't required. **OE**

***Mark Stevens**, Director of Oceaneering Communications Solutions (OCS), is an information technology industry veteran with extensive experience in the global oilfield communications segment. He has been with Oceaneering for more than 15 years and is responsible for growing OCS's global technology business both organically and through strategic acquisitions that further extend the company's hardware and software development expertise and resources.*

***Bob Moschetta** is the Sr. Vice President of Health Safety Environmental-Training-Quality at Oceaneering International, Inc. He is experienced in integrating industry best practices, HSE management principles, quality improvement processes, and regulatory standards. Bob is a Certified Safety Professional with a master's degree in safety management from West Virginia University.*

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Investigating the deep

Heather Saucier speaks with Mark Randolph and Susan Gourvenec, professors at the University of Western Australia's Centre for Offshore Foundation Systems, about deepwater geotechnical challenges, such as complex carbonates found off the coast of Australia, and new developments for effectively exploiting deepwater oil and gas.

As offshore exploration moves into deeper waters and into frontier basins that are carbonate in nature, challenges in geotechnical engineering have inspired a handful of advancements that, in some ways, are revolutionizing the offshore industry.

Many are taking place at the University of Western Australia's Centre for Offshore Foundation Systems (COFS), which maintains the highest concentration of geotechnical researchers in the world, not to mention a carbonate-based "backyard" highly conducive to researching soil sampling, geohazards, anchoring systems, and welcoming the world's first floating liquefied natural gas (FLNG) facility.

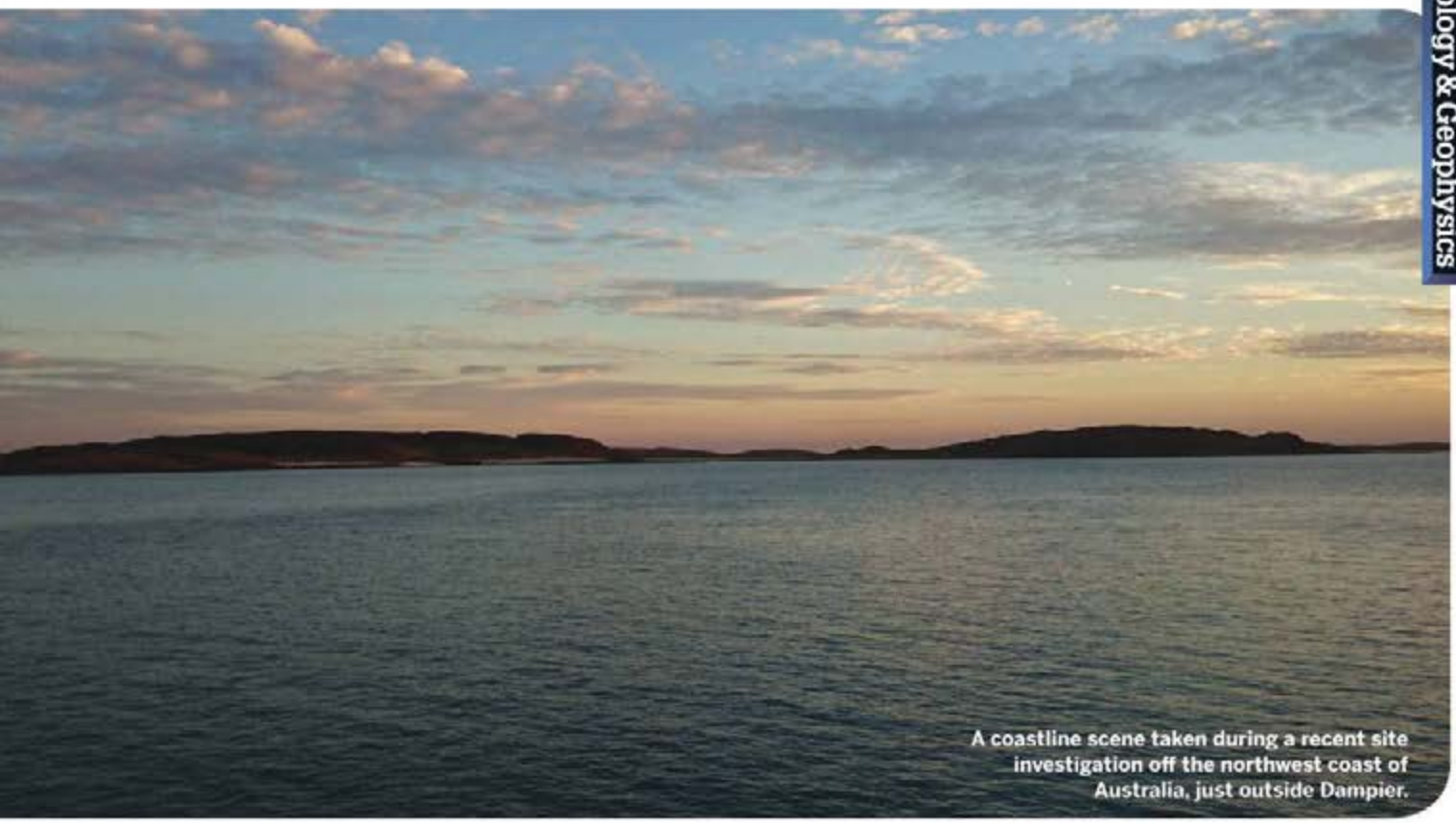
"We have got 60-70 research staff and students, partly because of the problematic seabed soils off the coast of Australia, and we need a concerted effort to understand them," said Mark Randolph, a geotechnical engineer and professor and founding director of COFS, which is funded by the government and industry. "In many ways, we are on the leading edge of research."

Seabed drill being recovered (at night). The upper A-frame and the circular carousels of drill rods, etc., are visible.
Photos taken by Chris Atwell, Seafloor Drill Superintendent, from the Fugro-McClelland office in Houston.

Unlike areas such as the Gulf of Mexico and the North Sea, which have established deepwater drilling programs, areas off the coast of Australia, India and China must deal with the complex carbonates that comprise their seabeds to effectively exploit oil and gas.

"Carbonates vary in nature and strength as you go down vertically through the seabed," Randolph explained. "If you move laterally by 1km, you might find completely different stratigraphy."

"Australia is just now looking over its continental shelf," said Susan Gourvenec, a professor of geomechanics at COFS and



A coastline scene taken during a recent site investigation off the northwest coast of Australia, just outside Dampier.

co-author, with Randolph, of *Offshore Geotechnical Engineering*, a book that initially started out as a student's guide.

She added that Australia's first truly deepwater offshore project, the Gorgon gas project, extends 1100m deep in one field.

Soil sampling

As the industry moves off the continental shelf, it becomes more difficult to investigate the seabed. "It's not just a matter of taking scoop samples," Randolph said. "Quantitative measurements of soil strength must be made."

Mark Randolph

In the last decade, "enormous" developments in seabed robotic drilling systems have been made, Randolph said. Today, small and modular systems can be lowered into the water column and opened like a moonlander on the seabed. They are connected to remotely operated vehicles (ROVs) with umbilical cords, and all operations take place on the seafloor.

"Clever robotics drill through the layers of the seabed down to about 40-50m," Randolph explained. "It's a revolutionary way to take samples. You end up with a higher quality sample for less than the traditional cost of a vessel."

A joint industry project led by COFS kicked off earlier this year with Benthic Geotech, Fugro, Shell, Total and Woodside. All are working to advance site investigation by delivering new sensors, tools, and engineering design methods that will improve intelligent and efficient geotechnical seabed surveys.

One goal is further advancing seabed penetrometers, including the T-bar and piezo ball devices, developed by Randolph and colleagues in the 1990s to measure soil strength. This new phase of research includes additional penetrometer devices, such as the hemiball and toroid, which will provide more detailed measurements of soil response through seabed interactions that are more directly relevant to engineering design.

"We still take samples and test them in a lab, but there has been an increasing amount of sophistication in testing offshore, and penetrometers are good examples of that," Randolph said. "The more you can do offshore in situ, the more confidence you have in the numbers you get."

Geohazards

As geotechnical engineers strive to better understand the makeup of the seafloor, understanding geohazards is crucial. "Geohazards have seen a significant increase in attention by the industry as it moves into deeper waters," Randolph said.

Seabed slides, caused by continental shelf breaks, can inflict severe damage to fixed platforms, pipelines, submarine cables and other seafloor installations.

"Most deep waters are riddled with historical, or relic, slides," Randolph said, adding that slides can be tens and even hundreds of kilometers long. "We must be able to accurately assess the risks of new slides to protect subsea infrastructure."

Assessment of risk from seabed slides involves not only estimating the probability of a new slide being generated, but modeling the likely runout path of the resulting debris flow and determining whether or not it will impact subsea infrastructure.

Anchoring systems

Now that floating production storage and offloading (FPSO) vessels are replacing many fixed platforms, innovative anchoring systems are being developed to better secure FPSOs and simultaneously reduce production costs. The dynamically embedded plate anchor (DEPLA), developed by COFS Associate Professor Conleth O'Loughlin and Mark Richardson, a former PhD student at COFS, is one of the cutting-edge developments.

The DEPLA is a rocket-shaped anchor

A view of Fugro's seabed drill being lowered into the water from the vessel.

that relies on its weight and kinetic energy from free-fall to penetrate to a target depth in the seabed. Once it is embedded, its shaft is removed, leaving the anchor's flukes vertically embedded initially, but then rotating under the action of the mooring line load to serve as a plate anchor.

Also relatively new is the OMNI-Max anchor, which is a gravity-based, dynamically penetrating anchor capable of being loaded in any direction around its axis. Developed by Delmar, the anchor penetrates more deeply into the soil under extreme loading and uplift angle conditions, according to the company's website.

"It's a clever design," Randolph said, commenting on its minimal size yet great holding capacity. "It can be installed to a moderate depth, and when it is pulled it further penetrates the seabed floor and becomes stronger."

The first FLNG

The need for effective anchors couldn't be more obvious than on the developing FLNG project in Australia's Prelude field, 200km off the continent's northwest coast. "This is a revolutionary technology developed by Shell," said Neil Gilmour, the company's vice president of Integrated Gas Development. "It has the potential to change the way we produce natural gas."

Susan Gourvenec

Rather that send natural gas to a processing facility through large and costly pipelines, the FLNG will liquefy the natural gas on the vessel so that it can be offloaded directly onto tankers for export, Randolph explained.

"The FLNG vessel itself is a gigantic tanker, nearly half a kilometer long. The loads on each mooring are high – extremely high," he said, adding that each corner will be anchored by four lines that are attached to vertically driven piles 50-60m in the seabed.

Projects like the FLNG are necessary to reduce the cost of producing gas from deep waters, Randolph explained. "The export pipelines are colossally more expensive and hard to engineer. Especially in shallow waters, you must deal with the waves and the currents. The cost to stabilize a pipeline becomes enormous. The big driver is to avoid these large export pipelines – which are typically more than 1m in diameter – by liquefying the gas offshore."

Making the seabed your friend

In the wake of such technical advancements, Gourvenec reminds of another possibility to make offshore geotechnical engineering more effective: making the seabed your friend.

"A lot of offshore operations can actually improve the strength of the soil with the loads they place on the seabed," she said.

For example, when a subsea mat is set down on the seabed, the load of the foundation and structure it supports applies a load to the seabed, Gourvenec explained. This causes water in the soil voids beneath the foundation to drain away. As the water drains, the voids reduce in volume and the soil beneath the foundation becomes denser and stronger. The same holds true of lateral loads applied to a foundation, derived from thermal expansion of the attached pipelines.

"If these increases in seabed strength can be 'banked,' then efficiencies in foundation design can be realized," Gourvenec said. "Since operational loading – rather than environmental loading – causes the lateral loading of subsea infrastructure, the operational processes are known – unlike unpredictable and uninterruptable environmental loading – and can be included into design processes."

Ramping up research

Randolph recognizes that the industry is experiencing a downturn. However, he insists that now is an ideal time to develop more economical ways to exploit deepwater fields in challenging environments. Ironically, it also is a time when funds for research are often cut.

"The industry is down at the moment, but there are still new fields to be developed in next 10-20 years," he said. "It's harder to get research funding, and companies need to cut costs by using less expensive technology. But, the way to develop smaller gear requires research." OE

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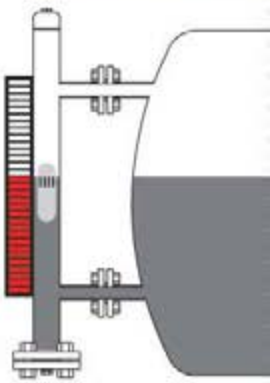
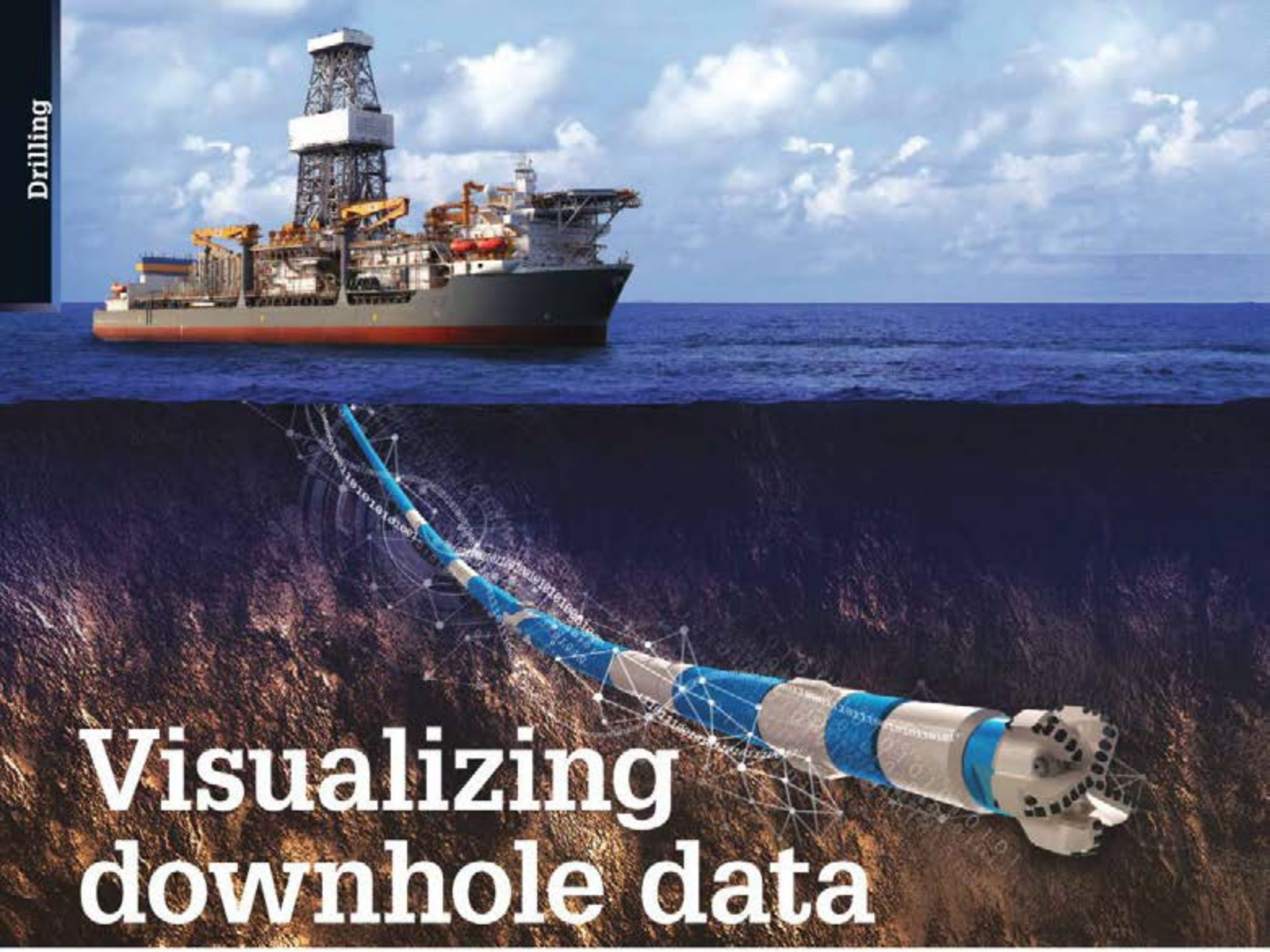




Visualizing downhole data

Melanie Luthi, Sanna Zainoune, and Stephen Forrester, of NOV, discuss how streaming downhole data on a job in the Norwegian North Sea helped improve both the drilling process and decision making.

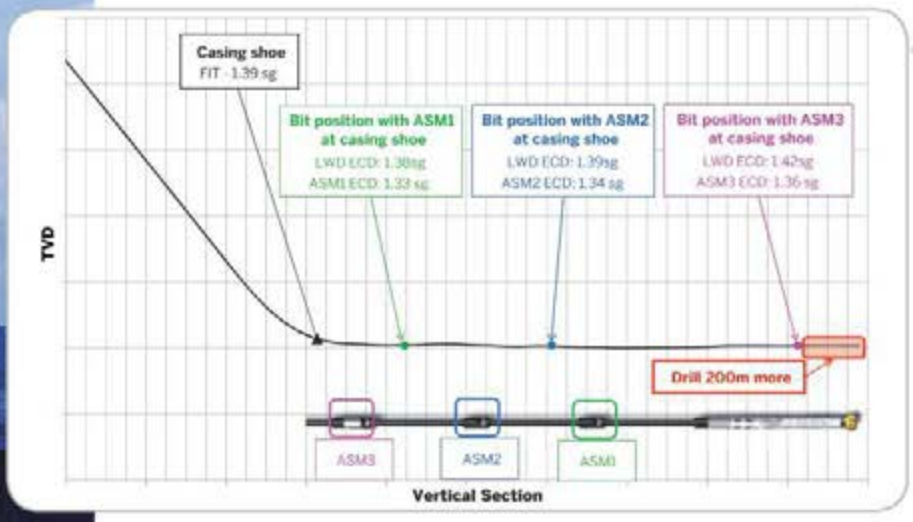
When tasked with a job that included complex reservoirs and conditions, NOV opted to utilize its eVolve Optimization Service, developed within NOV Wellbore Technologies. The system equips existing rigs and rig crews with an advanced toolkit that improves performance, enables real-time decision making, and enhances analytics capabilities. The premier tier of the eVolve service, AUTOMATE, enhances wellbore quality and makes drilling more efficient while reducing well delivery times and improving safety.

Total E&P Norge is developing a Norwegian North Sea field that consists of an oil reservoir and several deeper, structurally complex, high-pressure gas and condensate reservoirs. Wells drilled in this operation have restricted pressure windows, necessitating a more complete understanding of the environment. NOV was tasked with providing Total E&P Norge with the downhole data to analyze the wellbore, which would improve decision making for more efficient and safer operations.

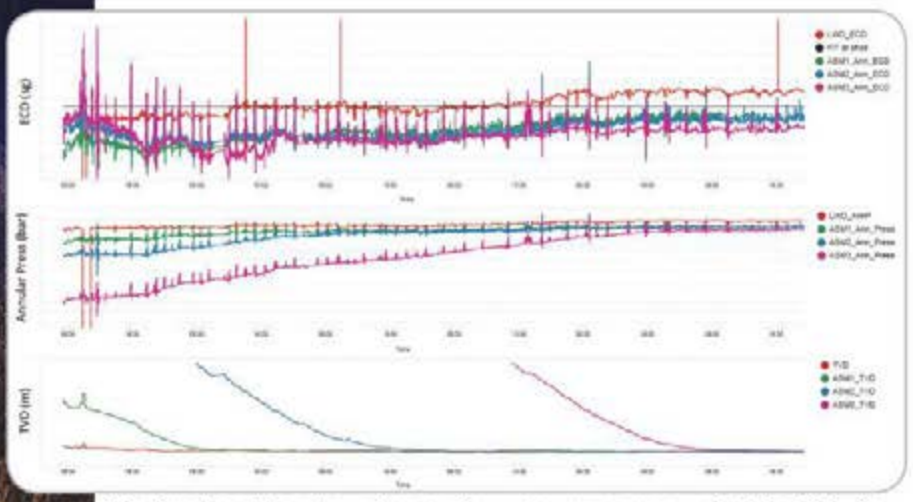
Based on the specific parameters of Total E&P Norge's project, NOV incorporated the BlackStream along-string measurement (ASM) tools to meet the stated objectives. BlackStream ASM tools acquire temperature, annular pressure, rotation, and three-axis vibration data at high frequencies. When coupled with the IntelliServ high-speed Wired Drill Pipe telemetry network, the BlackStream ASM tools provided streaming visualization of the downhole data to enable substantially reduced nonproductive time, improved wellbore integrity, and sustained safety.

This project has the dual intent of providing significant and immediate value to the operator while developing lessons-learned for future operational implementation and continued engineering developments. We improved both access to wellbore pressure information and the support required to incorporate this new and additional information into performance improvements across multiple phases of the drilling operation. These phases included, but were not limited to, the following scenarios:

- A relatively long drain with a restricted pressure window was successfully drilled using the BlackStream ASM tools as part of the AUTOMATE tier of the eVolve service. Operators have conventionally relied on annular pressure measurements at the bit and hydraulics models to estimate the equivalent fluid density at the casing shoe. By using the BlackStream ASM tools, an extended dataset was collected in real time, providing a detailed picture of the pressure and equivalent circulating density (ECD) distribution both in the open- and cased hole. This real-time data enabled timely and precise optimization of drilling parameters, fluid properties, and section length, resulting in the oil producer



This trajectory profile highlights how the ECD measurements along the string provided by NOV's BlackStream ASM tool helped in monitoring wellbore conditions, not only at the bit, but also in critical parts such as the casing shoe.



The time-based log shows the annular pressure, as measured at the bit by the LWD tool, and also by three BlackStream ASM tools placed along the string. If only using the LWD tool, the client would have to rely on modeled hydraulics calculations to estimate the ECD at the casing shoe. Using the BlackStream ASM tools the ECD is measured along the wellbore and at the casing shoe, eliminating uncertainties and allowing the client to make an informed decision. Images from NOV.

well's drain being extended by approximately 656ft (200m) measured depth. Total E&P Norge's use of this new method to acquire data along the drillstring gave them the confidence to safely drill ahead.

- When total losses were encountered while drilling, the BlackStream ASM tools were used to monitor annular pressure trends. The information provided by the tools helped in estimating the relative height of the annulus fluid column. The flow-off information enabled continuous monitoring of the well, even while waiting on cement. The AUTOMATE tier of the eVolve service generated better information concerning wellbore conditions and stability, ultimately providing value for the client.
- After Total E&P Norge encountered losses, a cement plug was pumped and the BlackStream ASM tools were run as part of the cement stinger. After an injection test was performed at a low flow rate, our BlackStream ASM tools were used to monitor annular pressure trends. This data, provided in real time with high accuracy, helped confirm that the losses were efficiently sealed off. The AUTOMATE tier of the eVolve service provided the data necessary to bring clarity to the total wellbore environment, and the real-time information describing the hole condition enabled the client to resume drilling operations without further delays.
- When a packoff occurred, the annular pressure measurements provided by the BlackStream ASM tools helped Total E&P Norge understand where the string was stuck. A sudden annular pressure increase at the BlackStream ASM tool closer to the bit was not seen by the other tool placed in upper part of the drillstring. The difference between the two readings proved that the packoff was being seen in between the two sensors. The ability to identify the packoff location from this information helped find the optimal location to cut the pipe without having to run a wireline freepoint indication tool. The AUTOMATE tier of the eVolve service provided real-time information that described the hole condition, enabling the operator to safely manage a critical situation.

Acquiring data from distributed sensors along the drillstring in real time reduces lost time, increases performance, and enables real-time decision making. An improved understanding of ECD and equivalent static density distribution and fluid behavior along the wellbore is a vital component of the decision making process.

As the industry seeks to advance wellbore technologies through new developments in automation and optimization, NOV has successfully implemented the AUTOMATE tier of the eVolve service.

The value derived from this operation in the Norwegian North Sea is just one example of enabling clients to more efficiently and effectively address challenges and meet objectives. Moreover, NOV's commitment to ongoing development of software applications and processes for implementation in future projects ensures that the company will continue to learn how to better serve and add value to worldwide client operations. **OE**

Sanna Zainoune *is a senior dynamic drilling solutions engineer. In the industry since 2005, she joined NOV this spring. Her role is to provide technical support to operational projects in the North Sea. She holds a master's in process engineering from Engineering School of Grenoble, France.*

Melanie Luthi *is business development support manager focused on the eVolve Optimization Service. Luthi holds a bachelor's in both mechanical engineering and business administration from the University of Kansas.*

Stephen Forrester, *a marketing and technical communications writer with NOV, worked as a contributing editor on this article.*

Minimal facilities for maximum margins

As the oil price continues to fall, more focus is falling on lower cost platform solutions for marginal fields. John Bradbury reports on a marginal field development consortium project.

The SIFT concept. Images from ABT Oil & Gas.

ABT Oil & Gas (ABTOG), a joint venture between RMRI risk consultancy and Enegi Oil, has already travelled quite a distance in its journey towards low cost production solutions and its goal of transforming marginal field development.

ABTOG has identified a number of characteristics it believes are critical to marginal field developments – re-deployability, independence from infrastructure, storage capacity, lower operational costs (OPEX) delivered through normally unattended operations, and a higher certainty of cost and delivery schedule.

"Given that a major contributor to offshore OPEX is personnel-related, we analyzed, which areas can be reduced or eliminated entirely, which can result in huge savings through normally unattended operations," explains Simon Bygrave at ABTOG. "In conjunction with this, we have brought together existing capital expenditure (CAPEX) efficient techniques to provide substantially more economic offshore solutions. We began with production buoy technology, with varying conditions in mind, and more recently have developed our NU-SIFT platform (normally unattended self-installing fixed tower), which is designed for North Sea conditions."

Based on existing cell-spar technology, the NU-SIFT is a re-deployable production facility with storage capability and platform-based wells, minimizing the need for subsea equipment. The NU-SIFT can be installed without the need for heavy lift vessels and is fixed to the seabed using a range of options depending on the conditions, including a micropile template or suction anchors which reduce decommissioning costs.

The current NU-SIFT design can operate in up to 120m water depth, accommodate a jackup for development well drilling, which further reduces cost, and handle up to 5500-tonne of topsides The concept features three cylindrical legs, which also provide storage capacity along with an additional, central storage cell.

While this could be suitable for a central North Sea location, Jonathan White, business development director for Apollo Engineering in Aberdeen, says the platform's application is not limited to this location.

Bygrave says the firm's analysis of a marginal field project in the North Sea demonstrates that the NU-SIFT could reduce development costs by up to 60%.

Previously ABTOG worked with Antrim Energy to create a floating solution for the North Sea Fyne field. Although this project has stalled due to the oil price fall, work completed for the field's Field Development Plan has advanced the NU-SIFT design.

Undeterred, ABTOG formed a collaboration with a number of offshore specialists who are working together to execute projects by combining their expertise. Bygrave explains: "The Marginal Field Delivery Consortium is dedicated to developing hydrocarbon resources around the world, which cannot be economically recovered using conventional methods."

He says consortium members offer the technology and services required to deliver marginal oil and gas projects, from project identification and concept selection, through to operation and decommissioning. Apollo Offshore Engineering was one of the first companies to join the consortium in May this year.

White says: "We believe that there is still significant potential in the North Sea, and beyond, for innovative production solutions that will allow operators to extract reserves efficiently and effectively. This is exactly the type of approach and technology our industry presently needs for continued investment to unlock marginal reserves."

Apollo is focusing on the structural design of the NU-SIFT: "Marginal fields will need a range of solutions to exploit these reserves depending on the field characteristics. The NU-SIFT is just one of the production solutions the consortium offers," White says.

Apollo is working with ABTOG to design the structure to accommodate storage requirements, reducing subsea costs, whilst also ensuring NU-SIFT is simple

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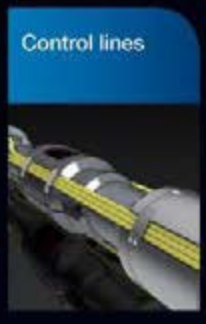

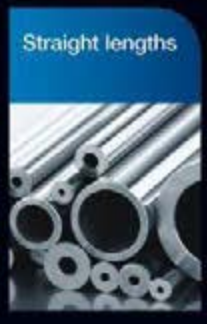

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to install and re-deployable with minimal cost from project to project – a key requirement for smaller marginal fields.

Bygrave says: "Our solutions combine two aspects, the normally unattended topsides and the structure, which, for the NU-SIFT, also houses the storage. Having developed a number of production solutions appropriate for different conditions we describe ourselves as structure neutral, in that we can combine the normally unattended topsides with any of the structures we offer depending on field characteristics."

ARUP's ACE concept.

ABTOG is working with two other consortium members to develop the normally unattended capability, which is crucial to lowering OPEX. Processing specialist Frames is designing process equipment to ensure that monitoring, reliability and maintenance schedules allow normally unattended operations, while Kongsberg Maritime's Integrated Control and Safety Systems (ICSS) will be used to manage the operations from onshore.

With the consortium's emphasis on fit for purpose design – and no "gold-plating" – it is key that the designs achieve the levels of reliability and safety required. Although there are normally unattended installations operating on gas fields in the southern North Sea, we are yet to see a fully functioning normally unattended oil production facility, Bygrave points out, although Premier Oil is close to starting production from its fixed jacket Solan facility, west of Shetland, which it intends will be normally unattended. Statoil is also considering an unmanned wellhead platform on Oseberg as an alternative to subsea wells.

"Although we have demonstrated that we can combine proven technology to significantly reduce the overall capex, it is the cumulative effect of annual OPEX reductions that has the greatest impact on project NPVs (net present value)," Bygrave continues. "This further enables the release of marginal resources, which might otherwise be lost."

He adds: "By leading the evolution of offshore production we can help secure the marginal resources not only in the UK Continental Shelf, where the cost pressures are critical, but worldwide. As basins mature we see a huge and growing market for the expertise and technologies the consortium offers."

Fabrication

Construction of a NU-SIFT facility could take 18-24 months, Bygrave suggests. "We would love to build this in a European or UK facility and where possible we will try to use local fabricators," he says. "We have had discussions with a number of yards in the UK, Europe and Asia, but no decisions have been made."

Consideration has also been given to harnessing expertise gained in building tubular frames for offshore wind farms. "This is of a size and scale that it could definitely be manufactured in a European sphere," White says.

A NU-SIFT could be in operation as early as 2018, Bygrave suggests, depending on progress with project negotiations. Nevertheless, Bygrave reports ABTOG is having "detailed" discussions with operators about several marginal field opportunities. He adds: "The fall in the oil price over the last year has increased the number of fields, which require low cost solutions, such as ours, if they are to be developed. We have seen a significant increase in interest from operators and licence holders keen to transform the value of their assets. Crucially, by extending the life of mature fields the consortium can help operators to defer decommissioning and associated expense.

Simon Bygrave

"We are very proud of what we are doing with the consortium members," Bygrave says. "It is a great example of companies genuinely coming together and collaborating to achieve the goal of maximising economic recovery. In addition to the production solutions, a major aspect of delivering marginal field projects is having the right capabilities and taking the right approach to maximize efficiency. The key goal of our consortium is to deliver marginal field projects on time and within budget. That requires careful project management and specialists working together with a coordinated approach and dedication to cost reduction."

Bygrave says the consortium continues to advance its production solutions as opportunities present themselves and more ideas come to the fore. "With Arup joining the consortium in July, we are very pleased to combine our normally unattended topside capability with their award winning Arup Concept Elevator (ACE) platform as further option to the NU-SIFT."

Outside the consortium, work is underway to implement the collaboration called for in Sir Ian Wood's Maximising Economic Report published in 2014, through the Technology Leadership Board. This group which involves the Oil and Gas Authority, Oil & Gas UK, Industry Technology Facilitator, as well as operator and supply chain representatives. One of its working groups, is focusing on Small Pools, led by EnQuest on oil, and Centrica on gas fields.

As announced during Offshore Europe, the next step will be "Hackathons," which will aim to identify a range of ways to reduce marginal field development costs.

Previously Shell and NAM introduced their SWEEP concept - Smart Well Engineering Exploration and Production - to identify and exploit smaller gas fields in the southern North Sea, starting with the UK Carrack field. The concept, aimed at deposits of 1 Bcm or less, and too small for their own minimal facility platforms or even mono-tower wellhead protection structures or extended reach drilling, involved using standardized subsea trees and pipelines to connect deposits together to host platforms.

Also, unmanned production buoys has a proposed a floating solution for redeveloping the UK Angus and Fife fields, which involves submerging processing equipment below the water line (OE: May 2014). OE

Tablet-based software for Ex inspections and maintenance

Data collection, such as registration of equipment is done directly on the tablet. Photos from SafeEx.

René Larsen, of Inspection and maintenance software specialists SafeEx, discusses how Ex inspection software was deployed on a gas compression jackup rig destined for the Cantarell field offshore Mexico.

Before any rig or offshore production facility is put into production, International Electrotechnical Commission (IEC) regulations require that first initial detailed Ex inspections are carried out. On average, a jackup rig contains up to 1500 individual pieces of Ex equipment, making such a task daunting.

Initially, SafeEx started as an interim management company supplying engineers and technical personnel for the oil and gas industry. The people behind SafeEx were performing Ex inspections manually and realized the challenges caused by this traditional method.

For example, information was collected with a pen and paper and subsequently entered into a computer, which is a time-consuming method. It also means a high risk of errors, if the report is not given to the right personnel or in time to fix any crucial issues. Likewise, the safety inspection personnel must physically bring various documents required to conduct Ex inspections such as Ex register, drawings, certificates, checklists, etc.

Moreover, the traditional method does not provide any proof of the inspector's presence by the equipment, which offers the possibility for neglect.

Therefore, in 2008 SafeEx launched its first version of the SafeEx Software, which in 2015 was launched in a second-generation tablet-based version. SafeEx is DNV GL-verified and the software is among others used at BW Offshore, Seadrill, Petronas, Dong Energy and by Mexico's TRESE.

One advantage of the system is that it can be fully integrated into the facility's ERP system and then used to maintain the Ex inspection data, negating a need to install or implement a separate additional inspection system.

How it works

With the SafeEx software, the inspection procedures are converted to electronic tasks on layout drawings, which the inspection personnel conduct guided by a handheld tablet. Each piece of equipment has an RFID chip approved for Ex zone 1 installed, which enables the software in the handheld device to create an electronic time-stamp and full electronic audit trail.

Certificates, drawings and other important attachments are accessible on the

Scanning the RFID chip initiates the inspection and creates an electronic time-stamp.

Each equipment is fitted with an RFID chip, approved for Ex zone 1.

tablet and regularly synchronized. Photos are taken with the tablet giving instant capture of equipment defects or non-conformities as inspection and maintenance work is executed. Even registering new equipment or the repositioning of existing equipment is easily done directly on the layout drawing.

Each RFID chip has a unique ID connected to the customer's Ex register, thus enabling the software to recognize the specific piece of equipment in the system when scanned – and displaying the checklists, values and documents linked to the specific piece. Information entered under inspection is synchronized with the web system, where it is instantly visible to those, who need to diagnose any issues and determine follow-on actions. The checklists in the software by SafeEx are in accordance with the IEC 60079-17.

Implementation offshore Mexico

Earlier this year, the firm won a contract with Mexican engineering firm TRESE to supply the SafeEx software system on a gas compression jackup rig. The rig has just left the yard in China, heading for the Cantarell field in the Mexican sector of the Gulf of Mexico.

The gas compression jackup, supported by four 122m tall cylindrical legs, unit is based on CIMC's Taisun 200B design and is scheduled to be in production by year's end. The unit is capable of operating in up to 55m water depth.

"With SafeEx's software we found a modern and efficient work tool, which not only reduces the use of man-hours, but also increases safety by providing a full overview of the condition of the onboard equipment," says Ricardo Silva of TRESE.

Since 30 July, SafeEx's mother company Offshore & Marine Contacts has had a team on board the unit in order to make the system ready for use. Furthermore, the software is being translated into Spanish. Some 1000 pieces of equipment had to be Ex inspected on the jackup.

Once fully integrated into the unit's ERP-system, the system will be used to conduct further inspections and planned maintenance, such as fire and gas checks, dropped objects and various frequent checks. **OE**

***René Larsen** started his career as a shipbuilder at Orskov Yard in Frederikshavn, Denmark. In 2002, he got an education as a chief engineer and went on to being a sales and project manager for Aalborg Industries, a marine boiler company. In 2008, after 21 years in the marine industry, where he gained both administrative and offshore practical experience, René Larsen started an interim management company: Offshore & Marine Contacts. Seeing the need for technology to conduct inspections and maintenance, SafeEx was shortly after created.*

The future of flow

NEL's flow measurement facility.
Photos from NEL.

NEL's Emmelyn Graham discusses multiphase flow measurement – where is it going and what is needed.

Accurately measuring a complex mixture of oil, water and gas in the field has remained a major challenge. Traditionally, separators were used to separate out individual component streams to allow subsequent single phase metering.

However, there are many disadvantages to using separators, including their excessive cost and infrastructure needs. To overcome these issues, multiphase flow meters were developed in the early 1990s, to support more economical development of marginal, deeper and more complex fields.

The first generation of multiphase flow meters failed to meet the required performance criteria to allow their uptake. However, several decades on, and following successive technological advances, industry has now gained greater confidence in their use and, more importantly, recognizes the vital role these meters will play moving forward.

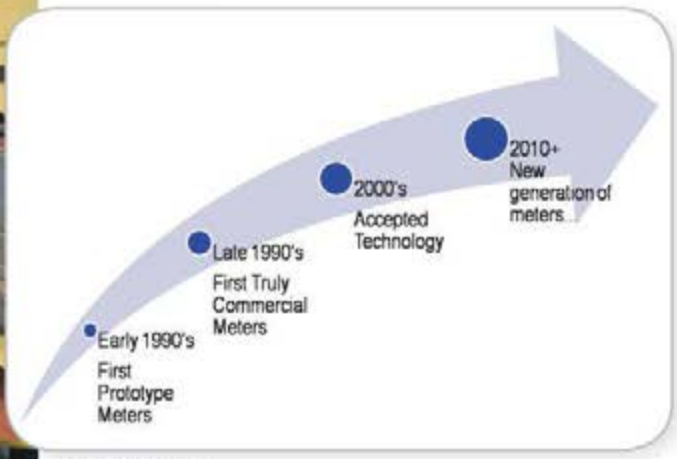
Multiphase meters offer reduced capital and operational expenditure; increased capability to monitor individual wells in real-time; less dependence on high-maintenance separators; and minimal loss of production through well test shutdowns. Overall they have become more accepted by industry for allocation and well/reservoir monitoring.

These types of flow meters will play a major role in the colossal shift to subsea production in deeper waters. Confidence in the technology has significantly improved with some new field developments no longer relying on separators. However, the sole reliance on multiphase and wet-gas meters for subsea applications brings unique challenges that need to be better understood and addressed.

Despite the huge advances in meter development there is still considerable scope for improvement in terms of accuracy and reliability. Materials and sensors need to be more robust to cope with the harsher environments subsea, including surviving sand-entrained flows. They have to be more compact and lighter to allow their effective deployment in deep water environments. Greater consideration also has to be given to the power and communication bandwidth which can in itself restrict their use subsea.

Further development

Different sensing methods have been used in multiphase flow technology, ranging from differential pressure devices, gamma densitometers, capacitance, microwave and ultrasonic sensors. However, many commercial meters have now adopted a similar strategy as most include a blind-tee or a similar mixing element, a Venturi, a densitometer and/or capacitance measurement. Cross-correlation of sensor data can also be used to determine flow velocity. While



Progress chart.

this industry homogenisation to a single design is a practical solution to meet current flowmetering requirements, the future of multiphase flow metering will be driven by the industry's need to develop cheap, light-weight, flexible production systems that efficiently and safely exploit increasingly difficult fields.

Subsea development

The reliability of multiphase meters installed in subsea locations is a key goal for oil and gas operators, especially in times of reduced oil profits, as the cost of repairing or replacing failed subsea equipment is excessive. The drive to develop deeper subsea wells increases the cost exponentially.

The trend for deeper water wells, longer subsea tie-backs and increased distance to processing facilities means that subsea equipment must be robust and able to cope with extreme conditions. Equipment must be reliable for efficient operation and easily maintained; it is also extremely important to identify any potential flow assurance issues.

Flow assurance issues can have a major impact on the reliability of subsea multiphase flow meters including the formation of hydrates, waxes, scaling, slugging, chemical deposits, erosion and corrosion. Failure to quickly identify and mitigate these problems can cause serious damage to equipment, affect measurements, and have catastrophic consequences in terms of safety, production and reduced revenue. In some cases multiphase meters can be used to identify certain flow assurance issues to allow early mitigation.

Oilfield evolution

Another challenge for flow metering technologies today is that the majority of the world's remaining oil reserves are classed as heavy oils, yet most of the multiphase meters on the market have been designed to operate with relatively low viscosity oils. To date very few multiphase meter technologies have been validated for heavy oil applications, nor have they been assessed for use when emulsions are present. Both these areas are expected to come under increased focus in the medium-term.

New developments

The development of four-phase meters (to include sand monitoring) will assist in detecting and mitigating the major flow assurance issue of erosion in subsea infrastructures. This is an increasing problem for industry due to the higher sand content from deeper waters, more complex field development and the dependence on long piping tie-backs and increased distance to processing facilities.

Many multiphase meters use radioactive sources to determine fluid densities. However, the unknown degradation of the radioactive source over the lifetime of the meter, together with safety and environmental implications, has seen a push for alternative operating technologies.

Potential game-changing, tomography-based visualization systems are currently under development to support the critical need of identifying flow assurance issues as early as possible. This includes detecting slugs, which can have a catastrophic effect on plant and equipment due to the induced pressure fluctuations.

New clamp-on technologies have emerged onto the market over recent years. In particular these allow retrofitting to existing flow lines and the ability for temporary assignment. The early first generation of ROV-retrievable clamp-on subsea multiphase have been developed and tested. The focus is to now have these deployed and tested in the field.

Downhole measurement technologies are a big must for industry to better control and optimise the well and reservoir. The ability to monitor and react closer to the source presents major advantages and a step change in optimization and recovery. Although some multiphase meters have been developed and integrated into Xmas trees at the wellhead, much innovation and research is still needed in this area to achieve the required level of accuracy and robustness.

Another new area of focus over recent years has been around virtual flow metering. This is software that combines distributed measurements to calculate the flow rate. For example, the pressure drop across a choke, wellhead temperature and the downhole pressure could be used as inputs to derive flow rate. Furthermore, these systems can potentially be easily integrated into existing infrastructure so eliminating the need for additional hardware. Both well and pipework flow simulation software are also being integrated with these systems to allow real-time modelling and optimization of production. Multiphase flow meters can be used to tune virtual metering systems. Ultimately, utilizing virtual metering can provide an effective back-up in the event of multiphase metering dysfunction.

Since their introduction many years ago multiphase flow metering techniques have continuously evolved to meet industry needs. Their use is expected to increase due to the cost reductions and diverse applications they provide, including supporting reservoir engineering, sand management, leak detection, process optimization, condition monitoring, fiscal/allocation reporting and integrated production management. However, in the eyes of industry, multiphase technology is still cost-prohibitive to allow them to be deployed on a well by well basis. **OE**

Emmelyn Graham *is a flow measurement consultant with over eight years' experience at NEL, specializing in wet-gas and multiphase flow metering. Graham has been involved in producing new equations for the correction of gas flows with entrained liquid for Venturi tubes, which has been included in a new ISO wet-gas technical report. In addition, she has used her experience to provide training on flow measurement globally. She is currently the UK representative within EURAMET (European Association of National Metrology Institutes) for the Technical Committee of Fluid Flow and is working on a large European collaboration with operators and equipment suppliers to advance multiphase flow metrology and reduce measurement uncertainty. She has a PhD in science and engineering from Edinburgh University.*

Going deep, but still some way to go

ROV technology developers gave an update on their progress at the Subsea UK ROV Conference. Elaine Maslin reports on some progress, as well as where one operator thinks ROV and AUV technology could improve.

After a string of boom years, like most in the industry, the remotely operated vehicle (ROVs) sector is looking forward to a slow 12-18 months.

Longer term, demand will pick up and how and what ROVs are used for and look like is evolving.

Traditionally mostly used for drilling support, demand is shifting towards deep and ultra-deepwater marine construction support demand and longer term inspection and maintenance focused deployments.

The result is a developer market striving to provide ever higher capability systems, Oceaneering's Nexxus, Forum's XLX-Evo and the UHD-III to name a few, Kieran O'Brien, analyst at Infield Systems, told the Subsea UK ROV Conference in Aberdeen late September, with retirement rates on older units likely to increase.

But, it isn't all just about higher capability. What role new types of subsea robotics can play in the subsea fields of the future, remains under the microscope. For some, a step change is needed in the market to offer new solutions for new environments and subsea technologies.

James Jamieson, technology manager at Subsea 7, says throughout the development of ROV systems, there has been gradual improvements and then step changes, driven by technical requirements in the market, such as the original step from using divers to ROVs.

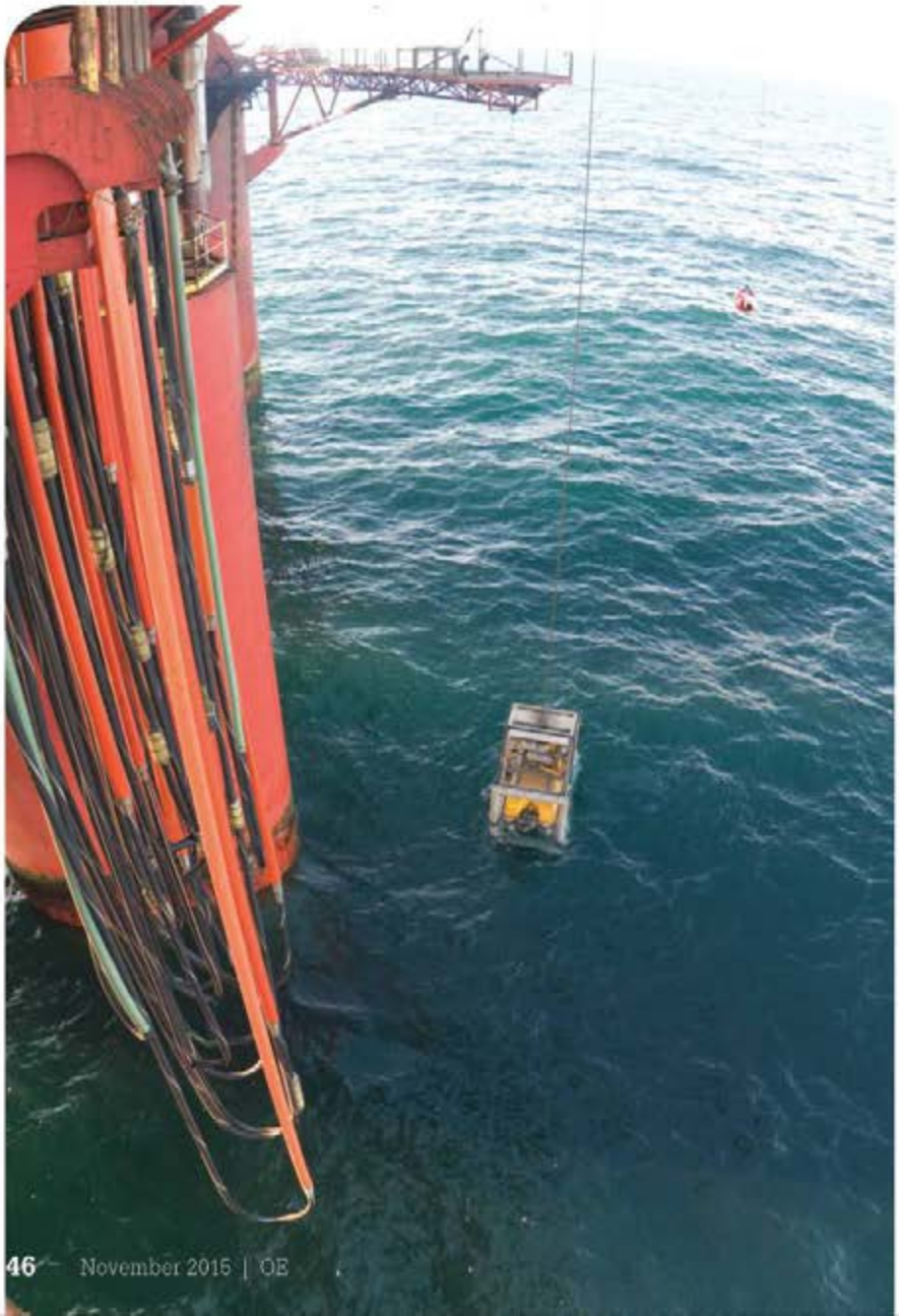
Today, work class ROVs are pretty mature, he says, thanks to gradual improvements over the years.

"Nothing has really changed much in the last few years apart from them getting more reliable," he says.

"Things are stabilizing. They are expected to work consistently. If they break down you can fix them quickly. There's always a challenge to make things better. Today's challenge is to lower cost and to have 100% reliability."

Subsea 7 is looking to initiate another step change with its AIV, an autonomous vehicle with lower costs because it would not rely on a support vessel.

The use of such a vehicle would be for planned and unplanned condition monitoring, wide area inspection around



Platform-based ROV being deployed.
Photo from iStock.

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Subsea 7's AIV.
Photo from Subsea 7.

a vessel, potentially with multiple units operating and the vessel moving away, or a unit being hosted on the sea bed.

Subsea 7's goal is for it to be able to navigate around the sea bed without obvious external references, using simple robust mission planning and advanced navigation, through which it can locate itself, and to be able to hover and inspect things, safely. Further, it would also be expected to perform tasks involving physical interaction with the subsea infrastructure.

Challenges for such a unit include launch and recovery, from a ship, via a basket deployment system, or from a subsea docking station, for which it would need to be reliable enough to be on the sea bed for months at a time, no longer reliant on weather or a vessel. How to automate it so that it can self-diagnose and inform an operator what needs changing is also on Subsea 7's hit list.

Jamieson says that Subsea 7's development program for the AIV is taking in four steps – making the unit first "see", then "sense", then "touch" and finally "do". For the navigation systems, Subsea 7 has been working with SeeByte.

"We are at one (see) and (sense)," Jamieson says. "Touch is difficult, but it is next. The challenge at the moment is that we gather a vast amount of data."

Another challenge will be getting such technology adopted. Efforts to create a similar system have been made in the past and have yet to be deployed.

But, despite the move towards making the system "touch and do", this is not a system to replace the ROV, just as the ROV didn't ultimately remove the diver from the subsea workspace. It will be a new tool to compliment what is available and offer a new solution to life of field inspection and maintenance work from the likes of floating production systems.

Peter MacInnes, vice president, sales and marketing, FMC Schilling Robotics, offered a "what if" scenario for the ROV industry, posing systems that could be more productive, more consistent, make better use of data and are easier to repair, using examples of where such technologies are in use already.

Despite uptime being around 98%, according to ROV operators, oil firms' view is that it's more like 20-80%, due to time lost around running multiple trips to the surface to change out tooling or acquire additional consumables.

"The ROV should be able to remain on sea floor with a tooling package," he says, by using sea water instead of hydraulic oil, and integrating this into the manipulator arm, removing any potential oil leakage to the environment and the need to write leak reports. "On the surface, the user just selects what he wants and the ROV selects the tool. This is a common in modern day machining, the operator just instructs and the machine does it," MacInnes says.

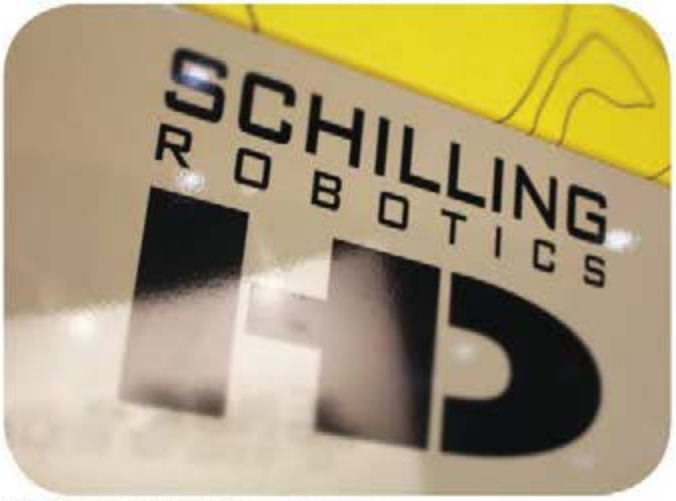
An operation like connecting a hot stab could take eight, 15, or 25 minutes or even an hour, depending on the operator, due to the skill involved and training largely only being on the job. "Imagine a world where all three can do it in eight minutes by using automation simplifying how the task is done," he says. "In the real world, we have collision avoidance systems and automated parking on cars."

Currently, data generated during a job is stored on a CD-ROM or hard drive and then never looked at again unless there is an incident. "Imagine a world where ROV data is compiled and synchronized with the video data you capture, all of which is readily available and when you play it back you can select which elements of the data you want to see in the video," he says. "The existence proof is agriculture. Today's tractors have a tremendous amount of automation, automated crop reporting, automated navigation, automated steering and analysis of soil real time to determine where and how much fertilizer should be added." Finally, real-time diagnostics and plug and play repair systems, connected to onshore or tools like iPads, could lower repair times. He cites real-time condition monitoring in today's offshore wind turbines as how others are already doing this.

But, while ROVs have become well-established and ROV manufacturers are striving to offer ever more clever systems, there are still those yet to be fully converted.

Richard Stark, Apache North Sea project services manager, said ROV work on the Forties field, one of the large most iconic fields in the basin, has been limited to infield pipeline work and cathodic protection systems, and tying in Apache's first subsea tie-back, Bacchus in 2013.

It is not for lack of subsea infrastructure – Forties has 17 infield pipelines, three subsea wells, and 11 subsea



Schilling Robotics close up. OE staff photo.

Eye on the industry

OE spoke with Scott McIntyre, Project Manager, Technip UK, to find out his thoughts on the oil and gas business and his advice for young professionals.

OE: How did you get into oil and gas? What did you aspire to do when you were younger?

I studied BA Hons Law and Management at Robert Gordon's University, Aberdeen, and as part of the third year we had to complete an industry placement.

I was lucky enough to secure a position with Subsea 7 as associate proposals engineer within the tendering department. I enjoyed the challenging, fast-paced environment and decided to look for work in the industry when I graduated.

When I was younger I had aspirations of studying sports science or sports coaching.

OE: What upcoming projects are you excited to begin and why?

We have recently completed a brownfield construction project for a major operator which involved a range of fabrication and installation activities. Following this, I am now working within Technip' in the UK's Life of Field business stream.

Technip is involved in a wide variety of activities ranging from asset integrity to traditional IRM activities and decommissioning to full brownfield construction. I am looking forward to playing a key role in the delivery of these.

OE: What technologies are you keeping an eye on?

I am always challenging myself and my team to work smarter and more efficiently, this includes sourcing effective tools and following leaner processes where appropriate. This practice is even more important in the current climate.

Scott McIntyre

The majority of the supply chain really embraces this approach now, and is actively marketing tools and technologies which can support companies like Technip going forward. This is of key importance to the industry, particularly for the future development of the decommissioning market.

OE: What advice do you have for students considering a career in oil and gas?

A career in the oil and gas industry can be very varied, challenging and will certainly more than meet anyone's personal goals and objectives. The oil and gas sector is a global business with fantastic opportunities. The industry really will take you as far as you wish to go.

OE: With respect to the downturn, are you still hopeful about the future of the offshore industry, and that of the UK, in particular?

Everyone within the industry understands that the global oil and gas market can be volatile in nature at times. I am hopeful that, through standardization and cost savings, the UK offshore industry will recover resulting in a stronger position. OE

structures. But, Apache has mostly used divers for the work it needs doing.

However, since its purchase of the Beryl fields in 2012, from ExxonMobil, the firm has had more exposure to ROVs. The Beryls, which has two hubs, Beryl A and Beryl B, have significantly more infrastructure, with 62 pipelines, 45 subsea wells (of different types and vintages), 47 subsea structures, and the 250km-long SAGE pipeline. Apache also has two semisubmersibles drilling at the Beryls, both with ROVs, as well as use of the *Well Enhancer*, which also has an ROV.

Apache recently carried out its first platform-based ROV survey of its jackets, caissons and risers, flying in a VideoRay ROV for some of it, which look up little space and could be flown in at short notice, saving space and costs, Stark says.

In another move new to Apache, the firm used an AUV to inspect the SAGE pipeline. But, the choice to use ROVs and or AUVs is still not clear cut, Stark says. While they see a lot of work needing to be done on the old Beryls subsea infrastructure, "it's not necessarily designed for ROV intervention," he says. This leads to using divers, "especially on wells where a lot of work is needed to convert non-ROV capable equipment to ROV capable equipment."

He says while platform based ROVs are "definitely the way to go", the footprint required to host larger ROV systems makes them difficult to accommodate on older facilities like Forties. The AUV inspection worked, but they would have liked better definition, speed and fewer wave height restrictions for deployment, added Stark.

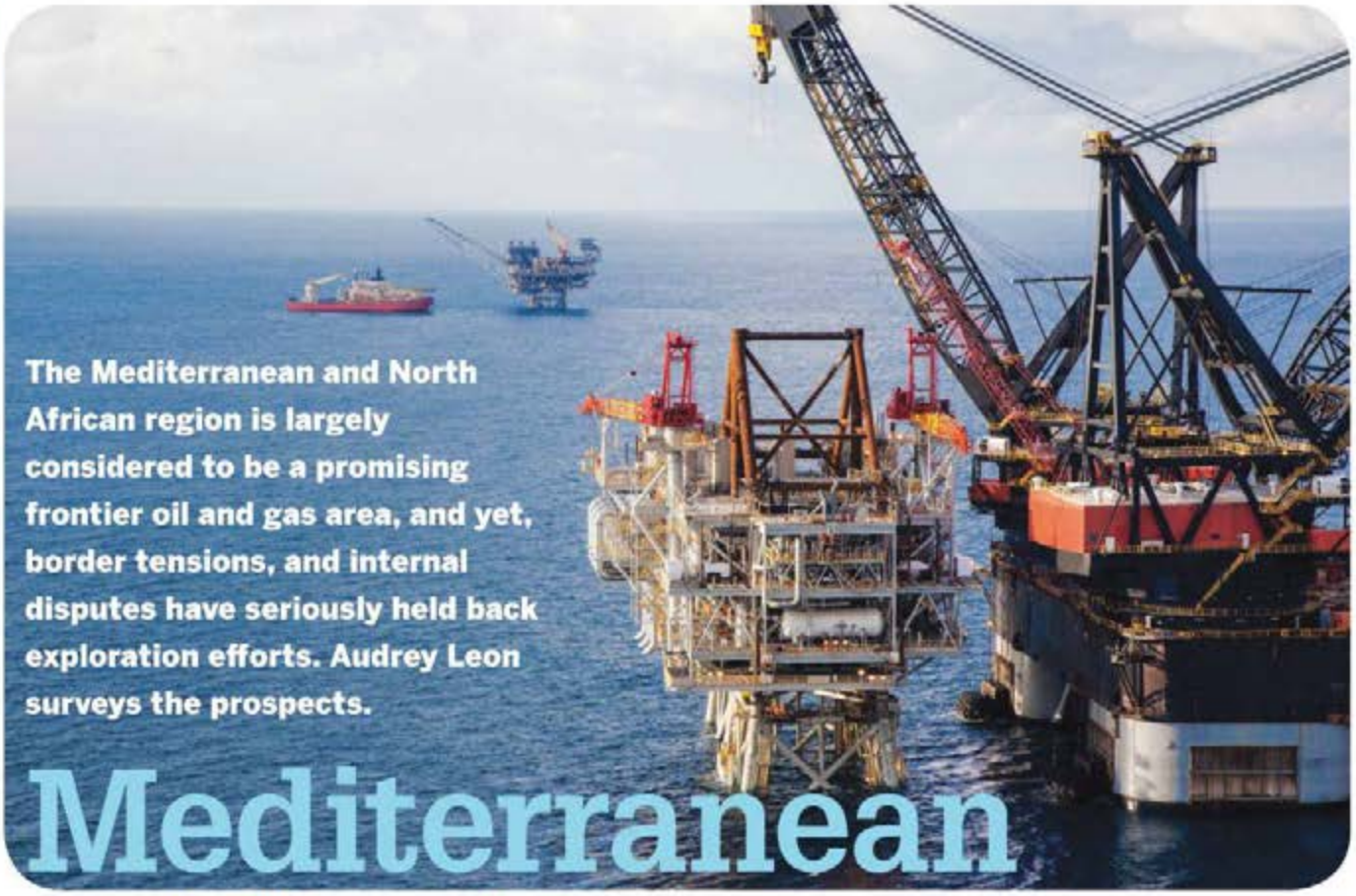
ROVs have come a long way and are entering a new age, but for some this work horse and AUVs still have some way to go to prove their worth. OE

FURTHER READING

ROVs: down but not out
http://www.oedigital.com/regions/arctic/item/10643-rovs-down-but-not-out

An ROV sea change
http://www.oedigital.com/drilling/drilling-hardware/item/10499-sea-change

Sparking a ROVolution
http://www.oedigital.com/drilling/drilling-hardware/item/10500-sparking-a-rovolution



The Mediterranean and North African region is largely considered to be a promising frontier oil and gas area, and yet, border tensions, and internal disputes have seriously held back exploration efforts. Audrey Leon surveys the prospects.

Mediterranean gridlock

The Tamar field offshore Israel.
Photo from Delek Group.

The Mediterranean is renowned for its beauty, but several factors – unrelated to oil prices are hurting the area's chances for oil and gas success.

When asked what country seemed most promising in the Mediterranean/ North African sector, Sarah Haggas, Director – Middle East, for IHS Energy said, "A few years ago I would have said Lebanon," but in terms of the Mediterranean, she says, everything is on hiatus.

Lebanon

According to the US Energy Information Administration (EIA), the ongoing dispute between Lebanon and Israel over their shared maritime boundary could affect Lebanon's ability to proceed with its offshore development plans. The area in dispute covers over 300sq mi, and the EIA says this portion may contain potentially significant hydrocarbon resources given its location near the center of the Levant Basin. The US Geological Survey estimates from 2010 placed the potential mean recoverable resources in the Levant Basin at 1.7 billion bo and 122 Tcf of natural gas.

Noble and Delek's discoveries off Israel. Map from Delek Group.

Since 2013, Lebanon has been hoping to offer 10 offshore blocks, but the round has faced many delays. And the last time it was even mentioned by the country's petroleum ministry was August 2014. Both Haggas and the EIA contend that delays have been faced due to politics. The EIA attributing the delay to issues surrounding the demarcation of the southern boundary of Lebanese territorial waters.

Haggas said that the biggest factor could be due to Lebanon's government. Since 2014, Lebanon has lacked a president. Currently, its Prime Minister Tammam Salam, who has served in that role since February 2014, has also served as acting president since May 2014. Because of this, Haggas says, the country hasn't been able to formally legislate their own petroleum law. "There's lots of potential due to various seismic surveys, but no legislation that allows it," she says. "They are working on it, but there is no fixed deadline at the moment."

Flare test at the Tamar field offshore Israel. Photo from Delek Group.

Other factors affecting Lebanon's proposed bid round from 2013, include a border dispute with its neighbors Syria and Israel, the latter which is home to many large discoveries in the Levant basin. Complicating matters, Haggas says, while Lebanon does not have diplomatic relations with Israel, it does have them with Syria. However, Lebanon has not ratified international offshore boundaries with either country. And until that happens, nothing in that area can truly be defined, especially not in the short-term, she says.

"The countries have not focused on exploration in those border zones," she says. "You'll have problems that will be contended by that neighbor."

Israel

Disputes are fairly common in the region, whether they be among neighbors or with foreign oil and gas operators inside a country. Most recently, Israel took on US Independent Noble Energy and its local Israeli partners when it thought the companies had a monopoly over the country's resources.

And indeed, Noble and its partners Delek and Avner Oil had discovered some sizeable natural gas finds offshore Israel. First came Noa in 1999, then the 1 Tcf Mari-B in 2000, and the 10 Tcf Tamar field in 2009, which was touted as the largest deepwater natural gas discovery in the world at the time. But, the largest was yet to come, the 19 Tcf Leviathan discovery, in December 2010. Since its discovery, Leviathan is now estimated to contain up to 22 Tcf of gross reserves.

All seemed to be going well, until Noble and its partners submitted a US$6.8 billion development plan in September 2014 for Leviathan, which sits 130km from Israel's coast in around 1600m of water. Noble intended to have the field up and producing by 2017, and then 2018, but faced more delays from the Israeli government and the Israel Antitrust Authority, which decreed that it would not approve the development plan, even though a key component, the divestiture of the smaller Tanin and Karish gas fields had been previously reached. Israel now wanted Noble and its partners Delek Group, to sell interest in the producing Tamar field in order to maintain interest in Leviathan, due to monopoly concerns. What would transpire would be a long fight between the US operator and Israel's government, which is only now coming to some sort of resolution.

In August, Noble Energy told ***OE***: "On August 13, Prime Minister Benjamin Netanyahu and Minister of Energy Dr. Yuval Steinitz announced that the government of Israel finalized the regulatory framework, which provides a path forward for the development of Leviathan, Karish, Tanin and the further development of Tamar, and for the citizens of Israel to realize the benefits of the country's vast offshore resources.

"The framework presented on August 13 acknowledges the importance of moving forward with Israel's discovered oil and natural gas resources without delay, establishes a foundation for competition, and ensures that Israel's citizens pay a fair price for natural gas. The framework also promises a stable investment climate that will enable the continued exploration and production of Israel's offshore resources. Noble Energy welcomes the clarity this framework will bring."

Of course, the issues around Noble and Israel have been closely watched by the oil and gas industry, and have left many wondering if working in the Eastern Mediterranean country is worth it.

"Many international oil companies are reluctant to come work [in Israel]," Haggas says. "Because, it may precludethem from working elsewhere (in the region)." Additionally, Israel has not generally held formal licensing rounds in the past, Haggas says, but it is planning to launch a new offshore licensing round in its EEZ in the future. There has been no proposed date as yet.

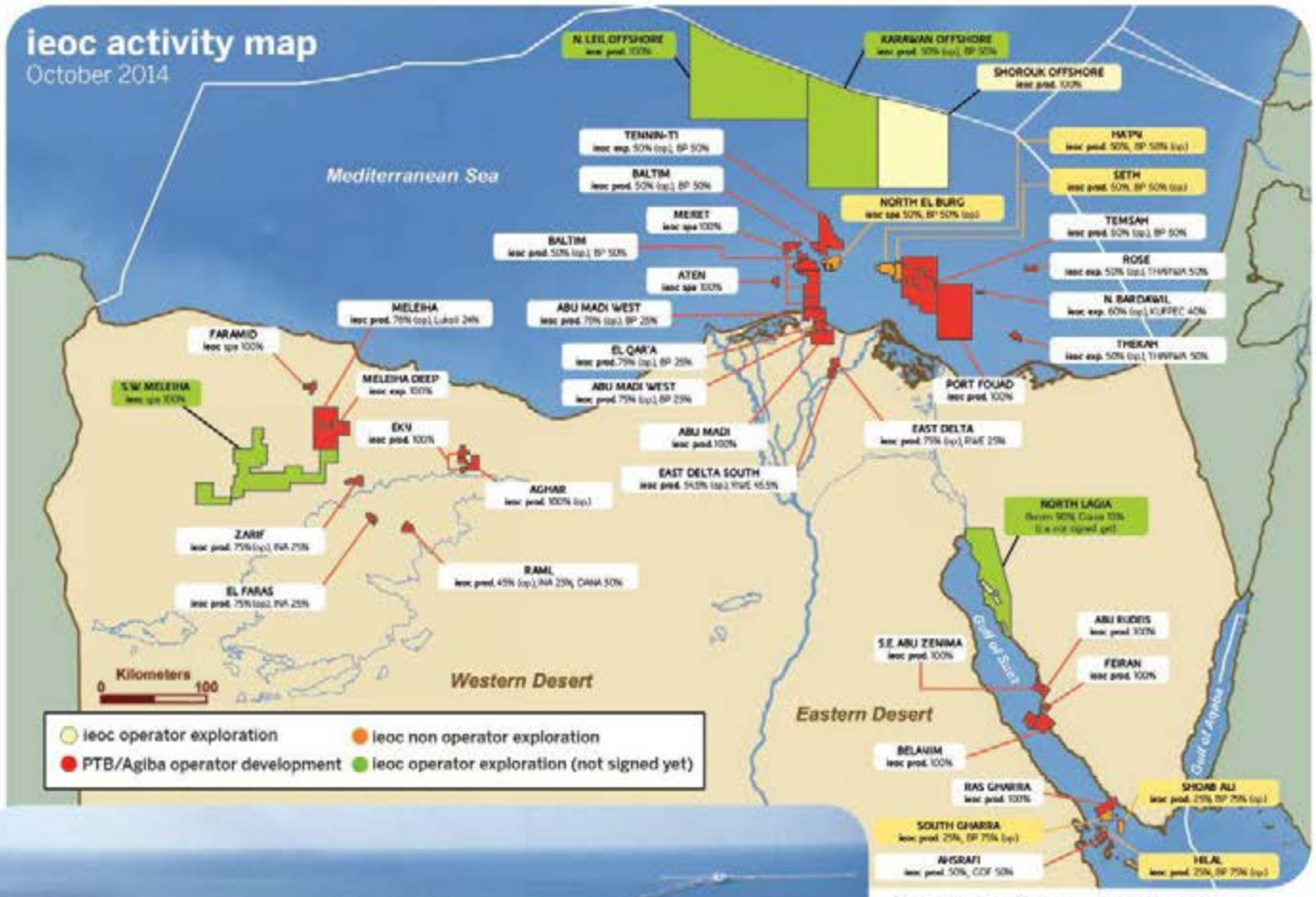
Egypt

From not so friendly to somewhat friendly climates, Egypt has presented itself as a country to watch in the region.

Late last year, the country began repayments to oil and gas companies that were owed billions of dollars, including supermajor BP and UK-based BG Group. The debt was due to the Arab Spring uprising that disrupted production in the region. In October 2014, Egypt had paid some $1.4 billion out to foreign companies. And now, according to Mohamed Zine, regional director, Africa, IHS, the country owes just $3 billion.

Despite the debt, Zine says, Egypt still remains one of the most attractive countries in North Africa for several reasons: Low cost operating environment with established infrastructure; competitive production sharing contract terms (35% cost oil and 80/20 profit share); gas price flexibility and import pragmatism, which is keeping companies on board, despite the payment delays; plus, bid-rounds organized on a regular basis (three bid-round per year organized by the three national companies: EGPC, EGAS and Ganope). However, the number of bid-rounds was less than usual during the last four years due to the unrest in the country, Zine adds.

At the end of August, Italian operator Eni hit a jackpot offshore Egypt with its Zohr deepwater natural gas discovery, which it has called the largest gas field in the Mediterranean, and possible the world. Eni says the field could hold up to 30 Tcf of lean gas in place over some 100sq km.



Top: Map of Eni's prospects in Egypt. Bottom: Egyptian LNG (ELNG) terminal at Idku
Photos from Eni and BG Group, respectively.

When the find was announced, Simmons & Co. analyst David Kistler said Eni's new discovery could be potentially negative news for Noble Energy because it provides more competition for Israeli gas in the region. "In addition, the Egyptian authorities are likely motivated to develop the field as quickly as possible in light of natural gas shortages in the country," he said in Simmons morning note. "This could remove a key customer for Leviathan gas while placing more gas competition into the international market."

However, Zine disagrees that this new discovery could disrupt Israel's burgeoning natural gas business.

"I don't think that this discovery will have a big impact on Israel's gas market," Zine says. "Egypt needs more big discoveries to have a significant impact on regional gas market.

"Israel needs to secure its gas supply in the future for strategical and political reasons and Egypt has a fast growing domestic demand."

Zine says the search for new resources is a major concern for Egypt, as it consumed more than 1.7 Tcf of gas last year (the amount destined to the domestic market). Before the Arab Spring occurred in 2011, Egypt was once an exporter of gas, but now it is an importer, Zine says, having to run its LNG liquefaction plants under capacity.

The analyst believes gas produced from Zohr will eventually end up on the local market, and possibly as LNG exports to Europe, with some exported to Jordan and possibly Syria and Lebanon in the future through the Arab Gas pipeline.

"The country has been facing energy deficits for a number of years now, as a result of growing demand and decreasing production, and most of the gas originally slated for exports has been diverted to supply the local market," Zine says. "The Zohr discovery was a relief for the country as it has started long-term LNG import plans." Zine says Egypt has signed contracts with Algeria, Qatar and Russia to meet its needs.

But indeed, the future looks bright for Egypt, which by far has the most activity. In October, the country awarded four offshore blocks to BP, Eni, Edison and Total, with a total investment of $306 million and a signing bonus of $10.5 million to drill eight wells, and conduct 3D seismic survey, according to Egypt Oil & Gas.

EGAS' chairman said at the time that the offers made during the 2015 international exploration Mediterranean bid round represented a good turnout in light of the challenges posed by declining crude oil prices worldwide in the current period. **OE**

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(check one box only)

- ☐ 01 Executive & Senior Mgmt (CEO,CFO, COO,Chairman, President, Owner, VP, Director, Managing Dir., etc)
- ☐ 02 Engineering or Engineering Mgmt.
- ☐ 03 Operations Management
- ☐ 04 Geology, Geophysics, Exploration
- ☐ 05 Operations (All other operations personnel, Dept. Heads, Supv., Coord. and Mgrs.)
- ☐ 99 Other *(please specify)*

2. Which of the following best describes your company's primary business activity?
(check one box only)

- ☐ 21 Integrated Oil/Gas Company
- ☐ 22 Independent Oil & Gas Company
- ☐ 23 National/State Oil Company
- ☐ 24 Drilling, Drilling Contractor
- ☐ 25 EPC (Engineering, Procurement., Construction), Main Contractor
- ☐ 26 Subcontractor
- ☐ 27 Engineering Company
- ☐ 28 Consultant
- ☐ 29 Seismic Company
- ☐ 30 Pipeline/Installation Contractor
- ☐ 31 Ship/Fabrication Yard
- ☐ 32 Marine Support Services
- ☐ 33 Service, Supply, Equipment Manufacturing
- ☐ 34 Finance, Insurance
- ☐ 35 Government,Research, Education, Industry Association
- ☐ 99 Other *(please specify)*

3. Do you recommend or approve the purchase of equipment or services?
(check all that apply)

- ☐ 700 Specify
- ☐ 701 Recommend
- ☐ 702 Approve
- ☐ 703 Purchase

4. Which of the following best describes your personal area of activity?
(check all that apply)

- ☐ 101 Exploration survey
- ☐ 102 Drilling
- ☐ 103 Sub-sea production, construction (including pipelines)
- ☐ 104 Topsides, jacket design, fabrication, hook-up and commissioning
- ☐ 105 Inspection, repair, maintenance
- ☐ 106 Production, process control instrumentation, power generation, etc
- ☐ 107 Support services, supply boats, transport, support ships, etc
- ☐ 108 Equipment supply
- ☐ 109 Safety prevention and protection
- ☐ 110 Production
- ☐ 111 Reservoir
- ☐ 99 Other *(please specify)*

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S31OS1

Surveying Mediterranean prospects

Jerry Lee reports on all the exploration and production activity currently ongoing in the Mediterranean and North Africa.

While much of the Mediterranean and North Africa's offshore is largely dormant due to geopolitical issues, there is still plenty of exploration activity ongoing in the region. ***OE*** takes a look at exploration efforts in Tunisia, Croatia, Libya, Italy, Albania, Cyprus, and Egypt.

Croatia

Earlier this year, Croatia awarded its first licenses for the exploration and exploitation of hydrocarbons in the Adriatic Sea. Five companies were awarded 10 licenses covering 10 exploration blocks in the Adriatic.

The awards were preceded by Croatia's first offshore bid round on 3 November 2014, which offered 29 blocks in the eastern Adriatic Sea covering a total of 36,822sq km. Bids were received from six companies for 15 exploration areas.

The Marathon Oil and OMV consortium was granted a license for seven exploration blocks: North Adriatic 8, Central Adriatic 10, Central Adriatic 11, Central Adriatic 22, Central Adriatic 23, South Adriatic 27 and South Adriatic 28.

In addition, INA (Industrija nafte d.d.) was granted a license for South Adriatic 25 and South Adriatic 26, while an ENI and MEDOILGAS consortium was granted a license for Central Adriatic 9.

The majority of the blocks offered fall within the Dinaric basin, however the most northerly blocks offered span part of the Po basin, whilst the western parts of the shallow and medium water blocks enter the Northern Apennine basin.

Offshore Croatia is underexplored with known plays including the Pliocene gas plays of the northern and central Adriatic, and Pre-Tertiary oil plays of the southern Adriatic, according to Deloitte Petroleum Services.

The estimated value of investment plans in the exploration activities for which the companies were competing amounts to US$592.6 million (HRK 4 billion).

Libya

Exploration offshore Libya has proved fruitful for Eni with two new gas and condensate discovery made offshore Libya in Area D.

The first discovery was made through the B1-16/4 well in the Bahr Essalam South exploration prospect, 82km from the coast and 22km from the Bahr Essalam producing field. The well encountered gas and condensates in the Metlaoui Formation of Eocene age. During the production test the well produced 29 MMscf/d and above 600 b/d of condensate. In a producing configuration the well is estimated to deliver over 50 MMscf/d and 1000 b/d of condensate.

The second discovery was made through the Bouri North A1-1/1 exploration well, 140km from the coast and 20km north of the Bouri production field.

The well also encountered gas and condensate in the Metlaoui Formation of Eocene age. During the production test, the well flowed at 1340 boe/d. In production configuration, the well is estimated to deliver in excess of 3000 boe/d.

The *Maersk Discoverer* drilling in Egypt's East Mediterranean Sea.
Photos from BP.

Tunisia

Development activities for the Zarat field offshore Tunisia has seen progress with the submission of an updated plan of development by PA Resources to Tunisian authorities.

The updated plan, developed by PA and partner, state oil company, L'Entreprise Tunisienne d'Activités Pétrolières (ETAP) will see a two phase development, with the first phase comprising four production wells and production facilities to process and export 20,000 b/d and 100 MMscf/d gas. Phase two would see a further four development wells and expanded facilities to increase capacity to 40,000 b/d and 200 MMscf/d.

Following acceptance of the Zarat plan of development, the project will enter a front-end engineering design phase with project sanction during 2017. First oil would be expected in 2020.

The Zarat field is a large, shallow water, gas condensate and oil field containing estimated recoverable reserves of 147 MMboe, according to PA.

Albania

Following offshore oil discoveries made in Albania by Petromanas and Shell, the country began seeking bids for seven offshore and onshore blocks in mid-May. Offshore offering included the Ionian 5, located in the Ionian Sea and the Rodoni blocks, located in the Adriatic Sea.

In June, however, the bids for the offshore blocks were delayed indefinitely.

"The deadline for the handover of the applications for the sea blocks, due to the consolidation of the seismic data, will be postponed for another deadline," said Damian Gjiknuri, Albanian Minister of Energy and Industry.

According to Reuters, part of the Ionian 5 block offered in the bid round overlaps with an area where Greece is searching for oil. Due to the territorial disputes between Albania and Greece over their territorial waters, the bidding process may be delayed till the dispute is resolved.

Italy

Italy has the fifth largest proved reserves of crude oil in Europe with 560 MMbbl as of 1 January 2014, and it is sitting on the sixth largest gas reserves in continental Europe (at 2.1 Tcf), according to the US Energy Information Administration. However, no exploration wells have been drilled in Italy's offshore since 2008, but this may be set to change as Italy now seems eager to open up and exploit the country's own resources.

Rockhopper Exploration has taken a step forward in its plans to develop an offshore Italy oil field with the approval of its environmental impact assessment, for the Ombrina Mare field, by Italy's Minister for the Environment and countersigned by the Ministry of Cultural Heritage.

Italy's Ministry of Economic Development will now have to complete the process to award the Ombrina Mare production concession.

Rockhopper plans to drill and test an appraisal well to extend existing resource estimates and to optimize plans for the development of the asset prior to project sanction.

"We are delighted to report progress on the Ombrina Mare project. While additional approvals are still required before we move into the production concession, we consider this to be a significant milestone towards unlocking the project," said Sam Moody, Rockhopper's CEO.

In addition to Rockhopper, Global Petroleum says it is seeing progress on its bid to gain blocks in the Adriatic Sea. Global's permit applications in Italy cover four contiguous blocks in the southern Adriatic offshore Puglia, adjoining the median line with Albanian waters. The applications are currently progressing towards approval of the environmental impact assessment (EIA) documentation.

Cyprus

Noble Energy's Aphrodite reservoir in the Eastern Mediterranean has been deemed commercial, according its partner the Delek Group. Located in block 12 offshore Cyprus, Aphrodite has estimated gross mean resources of 5 Tcf of natural gas, with multiple high-quality pays in Miocene sand intervals.

The partners intend to submit a proposed outline for Aphrodite's to the government of Cyprus, Delek said.

Egypt

Egypt has increased its offshore activities starting the year off by signing six agreements, out of 20 new petroleum

expected, for exploration in the Gulf of Suez and the Western Desert.

Following the summer months three offshore blocks were awarded from the delayed 2014 exploration bid round. Emirati Pacific Oil was awarded the offshore Block 2 (South East Ras El Ush) in the northwest of the Suez Gulf. Block 2 covers 68sq km in up to 75m water depth and includes the West Ashrafi field which has already tested for commercial oil and gas.

Furthermore, Magawish Petroleum won Block 4 (North Magawish), a site in the north zone of the southern Gulf of Suez covering 194sq km, and Egyptian Trident Petroleum won Block 6 (North West Sea Bird), north-west of the Gulf of Suez covering 191sq km.

Also, last month, Egypt's state gas company EGAS announced the result of the 2015 international exploration Mediterranean bid round, with blocks awarded to BP, Eni, Edison and Total.

In total, four blocks were awarded, with a total investment of U$306 million and a signing bonus of $10.5 million to drill eight wells, and conduct 3D seismic survey, according to Egypt Oil & Gas.

In an official statement, EGAS chairman Khalid Abd Al-Badie said Block 4 North Ras El Esh was awarded to BP and Eni affiliate International Egyptian Oil Company (IEOC).

In addition, IEOC, BP, and Total were awarded Block 7, in the North El Hammad area. Italy's Edison was awarded Block 12, Northeast Hapi, and BP was awarded Block 12, North El Tabia.

Last month also saw two new exploration licenses in the Mediterranean Sea awarded to Eni. The two blocks, North El Hammad and North Ras El Esh which cover areas of 1389sq km and 1927sq km respectively, are in the shallow waters of the Mediterranean Sea, facing the Nile Delta and located southwest of the Temsah area and west of the Baltim area.

Eni and BP also had earlier success offshore Egypt this year.

BP started the year by signing an agreement to develop the $12 billion West Nile Delta (WND) gas fields, then made a 5 Tcf gas discovery at its North Damietta offshore concession in the East Nile Delta.

The discovery was made at the Atoll-1 deepwater exploration well located about 80km north of Damietta city, 15km north of Salamat and only 45km to the northwest of Temsah offshore facilities.

Following the discovery, BP increases its WND stake as their Partner DEA farmed down. The WND fields will develop 5 Tcf of gas resources and 55 MMbbl of condensates, with production set at reaching up to 1.2 Bcf/d.

Eni began the year signing two concession agreements to explore Blocks 8 and 9 located near the boundary of Cypriot's waters. North Leil is located in Block 9, which covers 5105sq km and is in 2100-2800m water depth. Karawan is located in Block 8, which covers 4565sq km and is in water depths ranging from 2000-2500m.

The agreements were followed later by two recent discoveries. A potential 15 Bcf of gas in place with upside, plus associated condensates, was discovered at the Nooros exploration prospect in the Abu Madi West license, in the Nile Delta, offshore Egypt. The discovery will be put into production and tied-in to the existing Abu Madi gas treatment plant, located 25km southeast.

The Nooros discovery was then trumped by the discovery of the deepwater Zohr field, which could hold up to 30 Tcf of lean gas in place (or 5.5 billion boe) over some 100sq km, and could become one of the world's largest natural gas finds. The discovery well, Zohr 1X NFW, is in 4757ft (1450m) water depth, was drilled in the Shorouk Block (Block 9), deep offshore and close to Cypriot waters, which was awarded to Eni in 2014.

These discoveries followed Eni's signing of a new $2 billion deal for exploration and development activities offshore Egypt. **OE**

Two operators on the Ramadan production platform bridge, located in the Gulf of Suez off the coast of Egypt.

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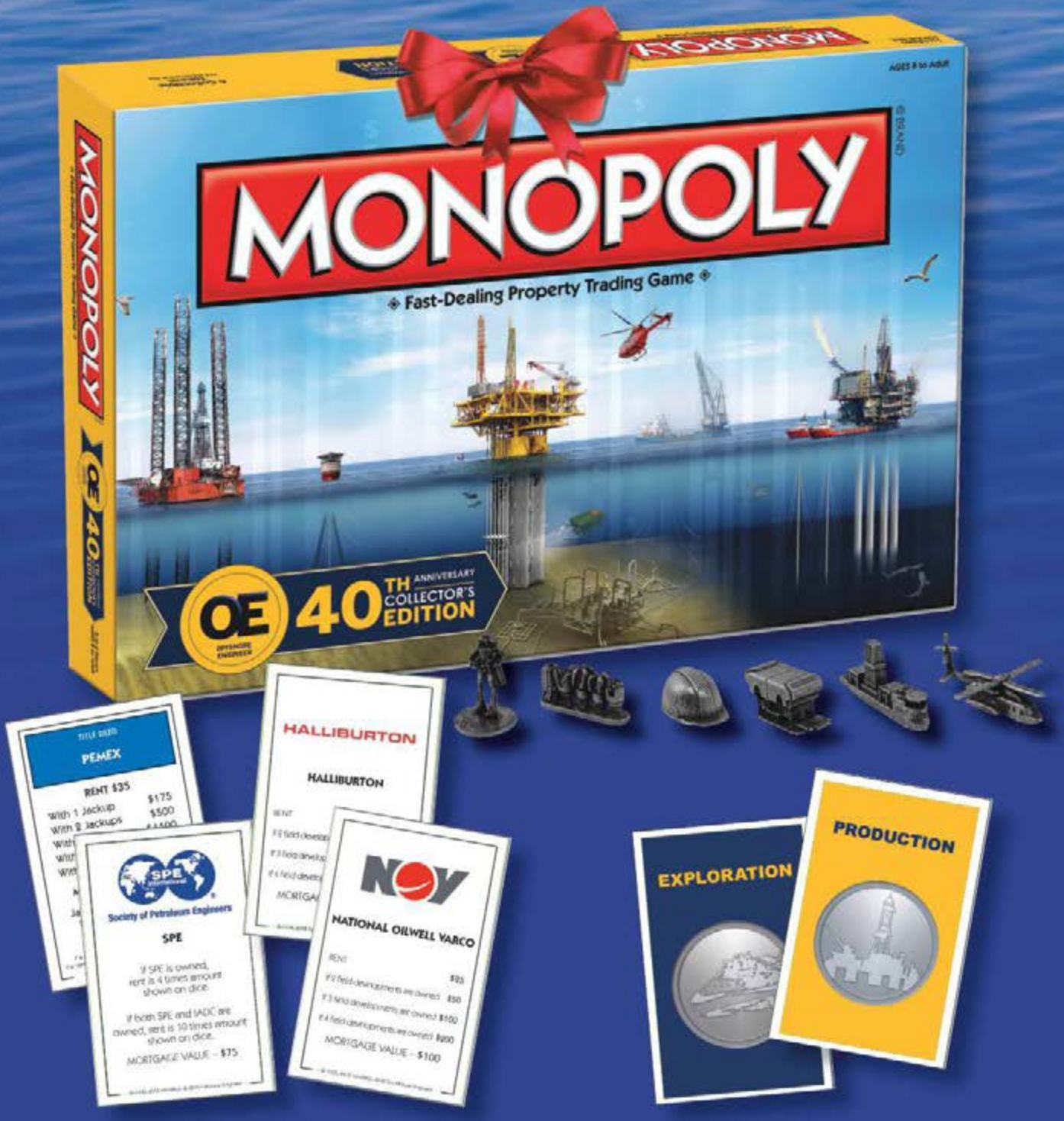

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Understanding pore pressure

Automated managed pressure drilling is the future of conventional drilling. Photos from Weatherford.

Gregory Hale discusses how managed pressure drilling helps to eliminate the guess work.

Realizing the potential benefits automation brings, numerous drilling giants are integrating managed pressure drilling (MPD) into drilling rigs, which not only saves time and money, but also enhances the safety capabilities of their rigs.

"The drilling industry is behind other industries, but the technology is shifting towards automation," said Sayamik Ameen, MPD engineer at Weatherford.

Using MPD enables drilling with a better understanding of pore pressure (PP), which is one of the most critical parameters in well planning along with geomechanical analyses of wellbore stability.

Several empirical methods aim to estimate the pore pressure using seismic and logging-while-drilling data, and drilling parameters. Experts have studied the uncertainty in pore pressure estimates using these methods because of noise and fluctuations in the received data as well as the under-compaction effect in over-pressured formations. It is common practice to calibrate these methods with data from the repeat formation tester (RFT) or drill stem test (DST). MPD, on the other hand, enables precise measurement of the PP with dynamic pore pressure testing (DPPT), which reduces the nonproductive time inherent in RFT and DST without compromising safety.

Old vs new

"During conventional drilling, we predict pore pressure values using the available common correlations in the industry," Ameen said. "When a driller experiences a kick, he controls it. With MPD however, the automated control system provides early kick and loss detection, hence eliminating the uncertainty in providing pore pressure values along the wellbore."

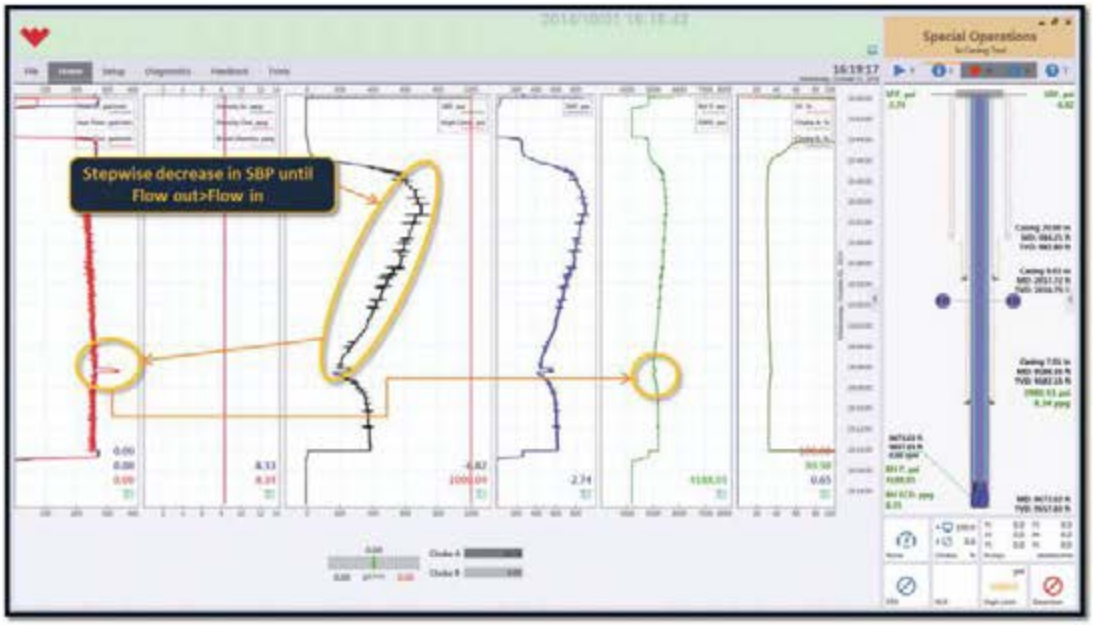
"Conventionally, we couldn't just reduce the pump rate to decrease bottomhole pressure because of the risk that an influx would emerge when measuring pore pressure while drilling. In comparison, MPD provides data and enables the control needed to precisely reduce pressure on the surface and measure pore pressure at specific depths.

MPD in real time

As mentioned, the whole idea behind MPD is to enable real-time management of the annular pressure profile and accurate monitoring of the return flow through a closed-loop circulation system.

The annular pressure profile is managed by manipulating the surface backpressure (SBP) using automated hydraulic chokes, operated by a programmable logic controller, according to Ameen's paper entitled, "Dynamic Calibration of the Empirical Pore Pressure Estimation Methods Using MPD Data," presented at OTC this year. The return flow, temperature, and mud density are measured using a Coriolis flowmeter, and the standpipe pressure (SPP) and SBP are measured using precision digital sensors.

MPD enables performing repetitive dynamic formation integrity tests (FIT)



Automated managed pressure drilling software platform.

and pore pressure tests (PPT) without the need to stop circulation. Drillers perform dynamic FIT and PPT to safely confirm the upper and lower boundaries, respectively, of the downhole pressure envelope without causing downtime.

In a dynamic FIT on an intact formation, the integrity of the entire open hole is confirmed by increasing the surface pressure until a predetermined set point while the return flow is continuously monitored, the paper describes. If there is a loss, the pressure unloads and the downhole pressure at the location where the micro-loss occurred provides the direct and precise measurement of the leak off pressure. In a dynamic PPT, the surface pressure is incrementally reduced from an initial set point until a micro-influx is observed.

Increase in accuracy

In tests, maintaining the full circulation rate enables the pressure while drilling (PWD) tool to continue reading the downhole pressure, which increases the accuracy of the pore pressure and the effectiveness of fracture pressure measurements, the paper said. Continuous measurement of the downhole pressure using PWD minimizes the uncertainties inherent in the bottomhole pressure calculations, which are caused by cutting loading and pipe rotation.

Besides direct measurement of the pore and fracture pressures through dynamic FIT and PPT, monitoring and correlation of the surface parameters provide qualitative indication of the pore pressure. Correlation of the bottoms up gas after the connections as well as monitoring of the rate of penetration and cutting analysis provide complimentary data for pore pressure interpretation.

Eliminating unplanned downtime

"The unwanted downtime that comes with conventional methodologies is not the only setback. Using the old school method requires you to increase your mud density to increase your bottomhole pressure," Ameen said. "With MPD you don't have to increase your mud density, rather, you have one density and instead manipulate the surface backpressure as needed. That way, it is under your control."

Taking advantage of actionable data gathered through MPD can ensure a more cost-effective and safe operation.

"In this industry downturn when there are limited operations, minor mistakes could cost millions of dollars and may come with an abundance of harsh scrutiny," Ameen said. "Having more certainty and obtaining more precise downhole data ensures that you conduct your job in a safer and more systematic manner. More precision means fewer mistakes." OE

Gregory Hale *is the editor and founder of Industrial Safety and Security Source (ISSSource.com) and is the contributing Automation Editor at Offshore Engineer.*

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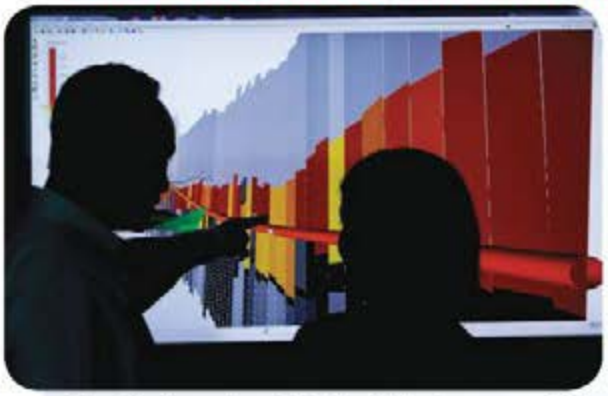
Solutions

Baker releases DeclineShift and VisiTrak



Baker Hughes released DeclineShift solution and VisiTrak LWD service at the 2015 Society of Petroleum Engineers (SPE) Annual Technical Conference and Exhibition (ATCE) in Houston. The DeclineShift solution combines detailed analysis of the asset and fit-for-purpose technology applications to improve recovery and operating costs. The process focuses on three primary areas to increase the value of an asset: optimizing hydrocarbon flow from existing wells, maximizing production revenues and increasing economically recoverable resources. Based on the operator's economic objectives, a customized solution is designed beginning with the development of an accurate asset profile and applying only the necessary technologies to enhance the asset. Then, a detailed operational plan is developed to minimize deployment time and production disruptions.

Baker Hughes recently designed and implemented a DeclineShift solution for a problematic field, where production was declining 6% monthly. The full solution included the drilling and completion of 30 new wells, 36 recompletions and 86 workovers of existing wells, and 77 new fracturing treatments, resulting in a 300% production increase and reducing monthly decline rates 43%.

VisiTrak geospatial navigation and analysis LWD service combines pre-well modeling, deep-reading LWD sensors, proprietary visualization software and reservoir navigation to improve efficiency in well construction and facilitate optimal well placement for increased hydrocarbon recovery. While drilling, extended-depth LWD readings determine the distance to, and angle of, adjacent bed boundaries to visualize complex reservoir architecture in real time, up to 100ft from the wellbore in every direction. The combination of early detection and advanced visualization allows operators to navigate to and through the reservoir's most productive zones to improve ultimate recovery.

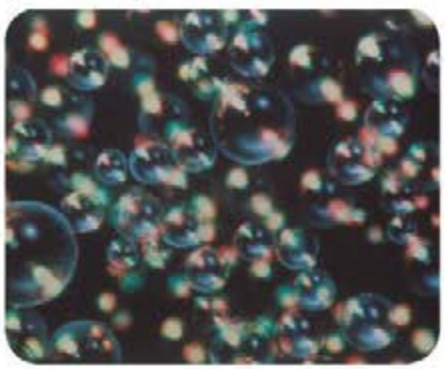
Baker Hughes recently deployed the VisiTrak LWD service offshore Brazil while drilling a 3340ft horizontal section through a series of poorly identified sand channels. Using VisiTrak, the wellbore was placed accurately in and navigated through the single productive sand channel exposing a total net sand length of 2838ft. | www.bakerhughes.com

3M Glass Bubbles development

3M Advanced Materials Division debuted its Glass Bubbles HGS4K28 product, currently under development, at SPE ATCE 2015. HGS4K28 is a high-strength, low-density additive specially designed to afford greater density reduction capabilities than other lightweight additives under similar downhole conditions.

Using HGS4K28 as a density reducing agent for completion, workover and cement slurries offers the potential for improved well integrity and well productivity when drilling in highly depleted zones and weaker formations, as it may help with problems associated with fluid loss, lost circulation and formation damage.

"With the improvement in the strength-to-density ratio, our newest addition to the Glass Bubbles portfolio is ideal for low to moderate downhole pressures," said Doug Rowen, business director of 3M Advanced Materials Division. www.3m.com



HAL introduces sonic service

Halliburton's wireline and perforating business introduced a new service at SPE ATCE 2015, the Xaminer Sonic Service.

This technology works by recording acoustic waveforms that travel from a transmitter through the formation to a receiver. As a result, operators can measure seismic properties and analyze reservoir characteristics and geomechanical properties. These acoustic applications provide information to help customers optimize completion and stimulation design and reduce drilling and completion risks.

The Xaminer Sonic tool includes 104 receivers on a 6ft array and is capable of HPHT operations. The technology can be beneficial in environments with soft rock and wells containing large boreholes, which increases signal attenuation. www.halliburton.com

Activity

Halliburton, Baker Hughes to divest more assets

The pending Halliburton and Baker Hughes mega merger will result in additional divestitures of the pair's businesses in order to gain approval for the US$34.6 billion deal. Halliburton and Baker Hughes intend to divest several of their businesses, which include: Halliburton's expandable liner hangers business; Baker Hughes' core completions business that includes packers, flow control tools, subsurface safety systems, intelligent well systems, permanent monitoring, sand control tools and sand control screens; the Baker Hughes sand control business in the Gulf of Mexico, including two pressure pumping vessels; and Baker Hughes' offshore cementing businesses in Australia, Brazil, the Gulf of Mexico, Norway, and the United Kingdom.

Halliburton is also continuing with its previously announced divestitures of its fixed cutter and roller cone drill bits, directional drilling and logging-while-drilling (LWD)/measurement-while-drilling (MWD) businesses. The combined revenue in 2013 associated with all of the businesses intended to be divested was approximately $5.2 billion. •

Shell-BG merger clears EU, faces Aussie delay

Shell and BG Group's US$70 billion merger received the unconditional merger clearance from the European Union (EU), completing two of the five preconditions for the mega merger.

"Receiving clearance from the European Commission underlines the good progress we are making on the deal. The transaction is on track for completion in early 2016," said Ben van Beurden, CEO, Shell.

However, the merger is being delayed until mid-November by the Australian Competition and Consumer Commission (ACCC) after a warning that the billion dollar takeover could increase Australian gas prices, plus limit domestic gas supplies. This follows a large number of submissions from market participants to ACCC concerned about the competition effects of the proposed acquisition.

Following anti-trust clearance from the US, EU, and Brazil, approval from China's competition authority is still outstanding.

Schlumberger calls off Eurasia acquisition

Oil services giant Schlumberger is pulling the plug on its proposed US$1.7 billion acquisition of Russian drilling contractor Eurasia Drilling to focus on other merger and acquisition opportunities, such as its recent move to acquire Cameron International for $14.8 billion, announced in late August.

The deal has been through several extensions, of which the latest expired on 30 September, and was originally set to close in 1Q 2015. It was pending confirmation from the Russian Federal Anti-Monopoly Service and the Government Commission on Monitoring Foreign Investment.

After the Schlumberger take over fell through, Eurasia announced it had received a new offer from the private sector for $10.00 per share, which spurred a special committee to negotiate the proposition.

Magma secures funding

Magma Global Ltd. (Magma), the manufacturer of m-pipe, has successfully raised US$60 million from Strategic Industrial Capital Partners (SICP) and existing investors to support its growth plans. The proceeds of the investment round will be used for the expansion of Magma's manufacturing capability and to provide additional working capital to support its rental business.

"This investment enables Magma to accelerate the expansion of our manufacturing facility, with a fourfold increase in our capability over the next two years to meet the increasing demand for m-pipe," says Martin Jones, Magma Global's CEO.

"This capital raise enables Magma to launch its rental business focused on intervention and downline applications."

3D printing JIP announced

Lloyd's Register Energy and TWI launched a new joint industry project that focuses on additive manufacturing, also known as 3D printing, and will help to develop standards and deliver safety and consistency across the energy industry.

"Challenges have existed because there has been no standardized way of proving to manufacturers and regulators that printed products are safe," says Chris Chung, head of strategic research at Lloyd's Register Energy Technology. "There have been risks associated with consistency and quality control, long term performance, data integrity, intellectual property, and in both software and hardware used in high precision manufacturing. The JIP will overcome these issues faced by manufacturers through working together."

Spotlight

Jim McFarlane Photos from International Submarine Engineering.

A treasure TROV

Jim McFarlane introduced ROVs to the North Sea industry in the 1970s and went on to pioneer AUV development. Elaine Maslin learned more from the still active industry veteran.

Jim McFarlane's history in the subsea industry is one few can match – his company introduced the first remotely operated vehicle (ROV) in to the North Sea. The industry veteran still arrives earlier than most in the office in the morning and is often flying internationally on business, despite marking his 80th birthday last year.

Complete with navy experience and technical degrees, McFarlane is one of a few who were mad enough, as he would say, to get involved in putting robotics into the sea, pioneering a new industry that we now, for the most part, take for granted – i.e. ROVs and increasingly autonomous underwater vehicles (AUVs). McFarlane played a leading role pioneering the former and has gone on to do the same with the latter.

Born in Canada in 1934, McFarlane grew up during the war years, then spent 18 years in the Canadian Armed Forces, where he rose through the ranks, before being head hunted for Hyco International Hydrodynamics, then setting up International Submarine Engineering in 1974.

During his time in the Canadian Armed Forces he was lucky enough to be put through multiple universities, gaining a bachelor's in mechanical engineering and then masters' in naval engineering, naval architecture, and marine engineering at the Massachusetts Institute of Technology (MIT).

ISE's TROV ROV – one of the first in the industry.

With his skills and expertise, including overseeing the build of submarines for Canada at Chatham Dockyards, he was headhunted to work for Hyco, based out of Vancouver, which had become a hub for underwater exploration in the 1960s. Back then, a trio of divers had decided to build a manned submersible – what became the Pisces vehicle. "That was the seminal point," McFarlane says. The vehicles became work horses for the industry, and were the start of a new technology hub on the northwest coast, and a new globally used tool. They were bought by the pioneering Sir Leonard Redshaw for Vickers Oceanics, in the UK, who helped usher in the new era of subsea robotics in the North Sea.

But, while they became established tools, the life of manned submersibles was not to be long-lived. McFarlane, who was involved in the well-known 1974 rescue of two men stranded in Vickers' Pisces III at 480m water depth offshore Ireland – a rescue heavily involving the Canadian navy – "had a flash, and started to build a tethered vehicle." He had been involved in the development of the Pisces IV and V, but saw an opportunity for something new.

After setting up ISE in 1974, aged 40, he had built a tethered ROV prototype. By 1975 it was complete and in 1976 it performed its first job monitoring rock dumping on the Piper Alpha line in the North Sea. It was the first ROV in the North Sea – in the world. These new vehicles "kicked the pants off manned submersibles," McFarlane says.

But, while McFarlane introduced ROVs to the North Sea, it wouldn't become a strong market, due to pressure to use local content by the new disbanded Offshore Supplies Office in Glasgow, over a 10-year period in the 1980s, McFarlane says. But, that didn't stop him going elsewhere, including the US Gulf of Mexico, which, having first been cool to the idea, was now keen. He also moved into newer technologies, developing AUVs, including a 40ft-long AUV with a 200mi range used in the 1990s to lay a 108mi-long monitoring cable into the arctic – autonomously, with the vehicle finding its own way back to the hole in the ice from which it was deployed – and other markets.

The business, up to 2013, had built more than 230 ROVs and AUVs and more than 400 manipulators. **OE**

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NORTH AMERICA
John Lauletta (N-Z)
Phone: +1 713-874-2220
jlauletta@atcomedia.com

Amy Vallance (A-M)
Phone: +1 281-758-5733
avallance@atcomedia.com

UNITED KINGDOM
John Steward, Alad Ltd
Phone: +44(0) 7742 570064
john@aladltd.co.uk

NORWAY/DENMARK/SWEDEN/FINLAND
Brenda Homewood, Alad Ltd
Phone: +44 01732 459683
Fax: +44 01732 455837
brenda@aladltd.co.uk

ITALY
Fabio Potesta, Media Point & Communications
Phone: +39 010 570-4948
Fax: +39 010 553-00885
info@mediapointsrl.it

NETHERLANDS/AUSTRIA/GERMANY
Arthur Schavemaker, Kenter & Co. BV
Phone: +31 547-275 005
Fax: +31 547-271 831
arthur@kenter.nl

FRANCE/SPAIN
Paul Thornhill, Alad Ltd
Phone: +44 01732 459683
paul@aladltd.co.uk

ASIA PACIFIC
Eugene Herman Tumanken
Phone: +65-8700 9570
etumanken@atcomedia.com

Fit at 30!

It was the first floating production unit in the North Sea and it's still going strong – with a deployment to its latest field, on its 12th contract, due to start next year. Elaine Maslin looks at Teekay Offshore's *Petrojarl I*.

When the Tentech 685 design *Petrojarl I* floating production, storage and offloading (FPSO) vessel floated out of NKK's yard in Japan in 1986, destined for the North Sea, few would probably have expected that nearly 30 years later it would finally be leaving the basin, and not for a scrapyard.

The move will see the *Petrojarl I* leave behind quite a North Sea heritage. The vessel is Teekay Offshore's first FPSO, back when the company, formerly Petrojarl, was spun off of PGS. The list of field names it has worked is longer than even some oilfield workers can lay claim to, with Oseberg, Troll, Lyell, Fulmar, Balder, Fife, Fergus, Flora and Angus, Hudson, Blenheim, Kyle and, most recently, Glitne, in the Norwegian sector, from which it was removed in 2013.

Working on such a string of fields, across the Norwegian and UK North Sea sectors has meant the *Petrojarl I*'s production facilities have had to deal with a host of field conditions, which Teekay Offshore proudly states shows its flexibility, as well as high production regularity, at between 96-99%.

While the vessel was built for the harsh environment of the North Sea, its next move will see it operate in warmer climates. The long-serving, turret-moored *Petrojarl I* is heading to Brazil to work on its 14th field, Atlanta, for a consortium led by Queiroz Galvão Exploração e Produção (QGEP). The field's water depth, 1535m, will be the deepest in which the vessel has worked.

The post-salt Atlanta field is a heavy crude oil field in the Santos Basin, estimated to contain about 190 MMboe recoverable with a production life in excess of 15 years.

Petrojarl I will be used as an early production system (*EPS*) on the field, some 185km offshore the Brazil coast from 1H 2016 on a five-year contract.

As part of the deal with QCEP, Teekay Offshore acquired the 215m-long *Petrojarl I* from Teekay Corp. for US$57 million and said it would spend about $175 million on upgrades at Damen Shipyard Group's Schiedam facility in the Netherlands, where it arrived at the start of this year from Norway, extending the vessel's life by 15 years.

The works consist of basic engineering, detailed and construction design and engineering, interface engineering, marine and process equipment procurement, fabrication, construction, corrosion protection/coating, transport and lifting operations, integration, mechanical completion, performance testing and commissioning activities.

The result will be marine, hull and life extension according to class, conversion of the process systems (i.e. separation train and produced water topsides) and Brazilian compliance.

To perform the work, Damen Shiprepair Rotterdam formed partnerships with Frames and Nevesbu. Frames is carrying out the design and fabrication of the new topside skids. Nevesbu is providing the marine, and topside integration engineering.

The vessel's storage capacity is 180,000 bbl, with 46,000 bbl/d production capacity, and 8-9MMscf/d gas handling. It has 10 riser slots and accommodation for 68 persons. **OE**

The *Petrojarl I* FPSO.
Photo from Teekay Offshore.

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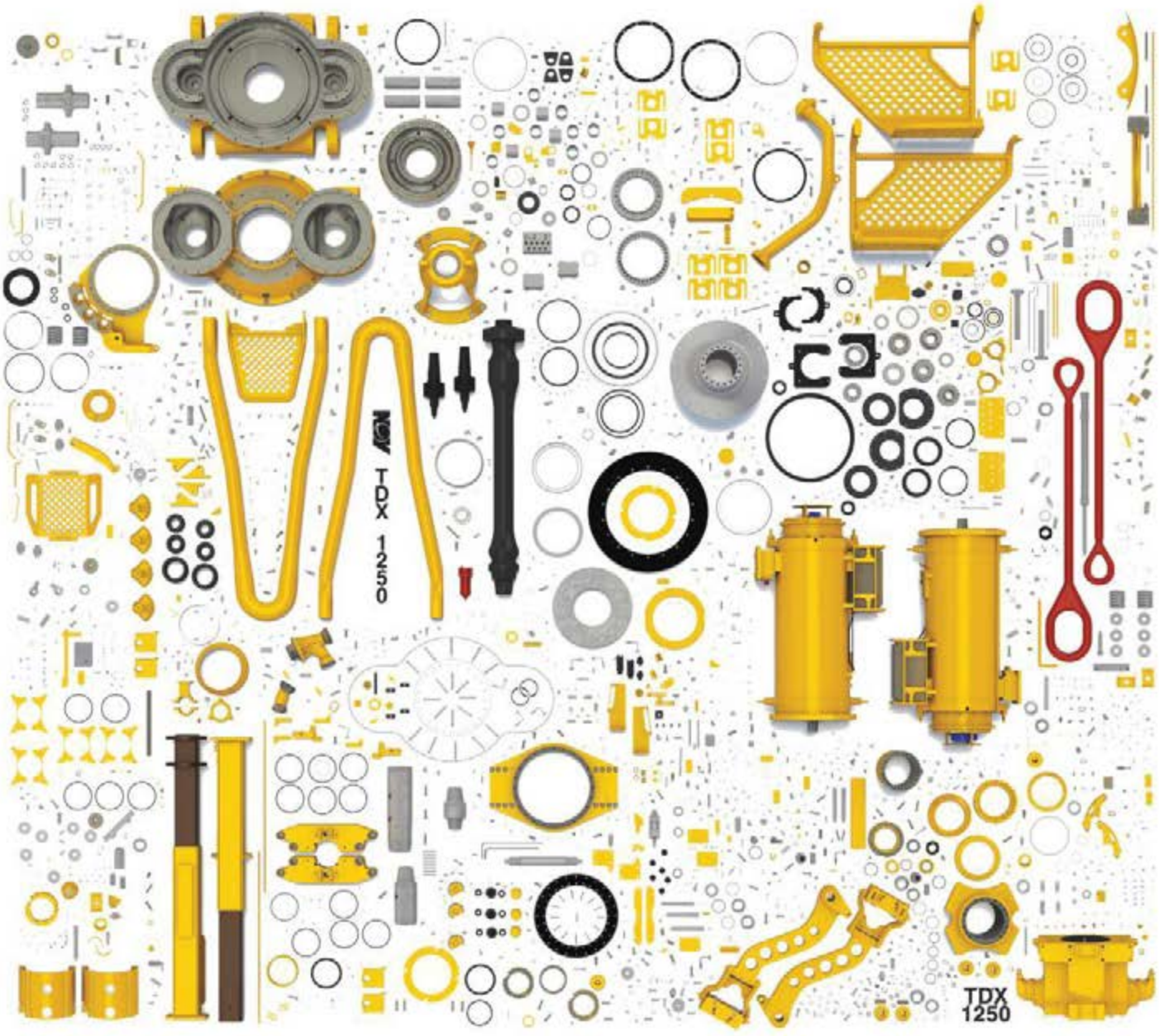

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