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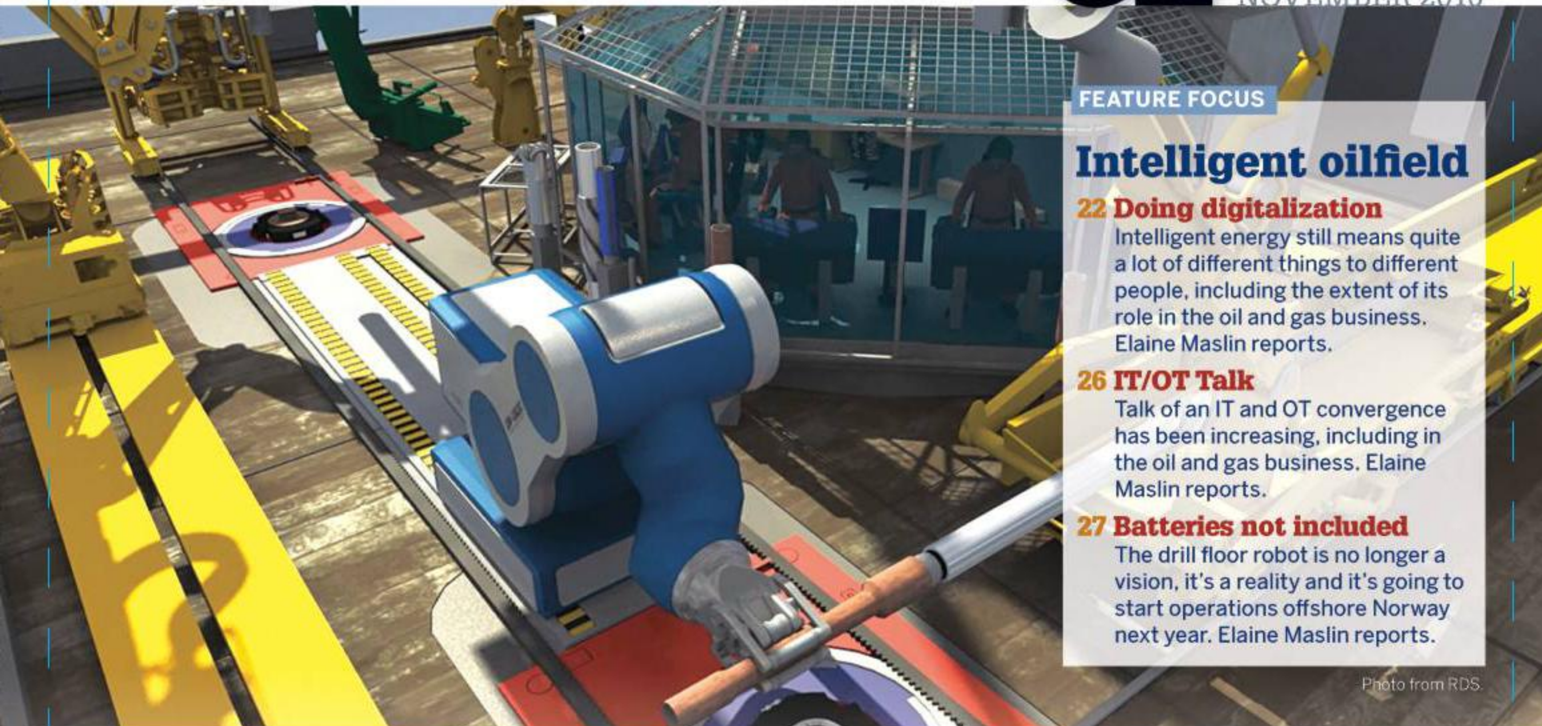

FEATURE FOCUS

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Photo from RDS.

Features

ON THE COVER

Get smart. This month's cover is an illustration representing how the oil and gas industry is embracing a new high-tech future. The cover photo features Maersk Drilling's new Highlander jackup drilling rig on location. See more on page 22.

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Departments & Columns

ATCOmedia
Atlantic Communications Media

AtComedia
1635 W. Alabama
Houston, Texas 77006-4101, USA
Tel: +1-713-529-1616 | Fax: +1-713-523-2339
email: info@atcomedia.com

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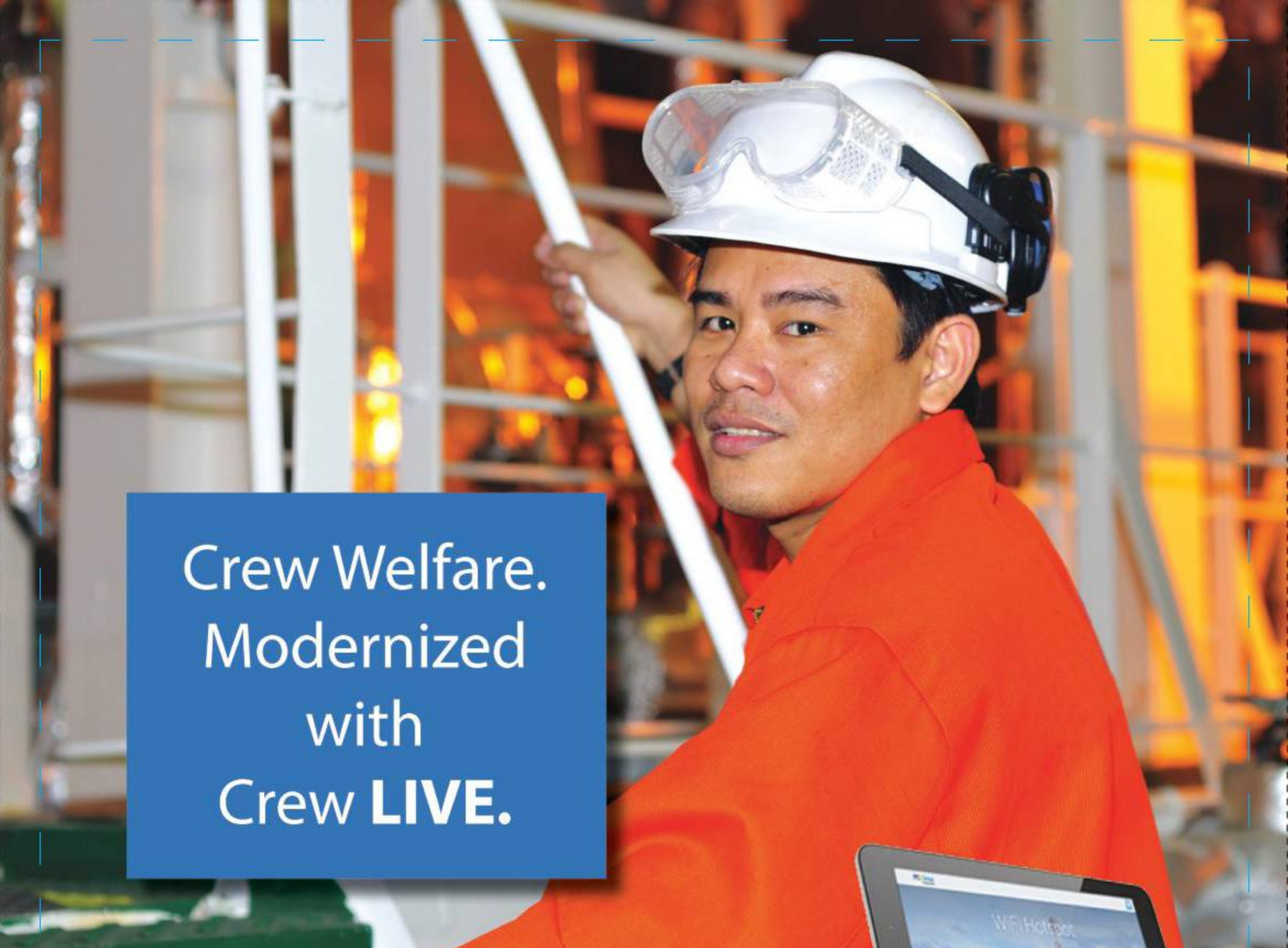
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Photo from SBM Offshore.

A pinch of pre-salt

After a thoroughly no good, very bad, couple of years for Brazil, the country is on the path to reform, and the first part starts with the country's coveted pre-salt. Audrey Leon reports on what the opening means for the country and its state-owned oil company.

What's Trending

Making deals

- Kashagan exports first batch of oil
- Petrobras relaunches Libra FPSO bid
- Pemex seeks shallow water farmout

Image from North Caspian Operating Co.

People

Image from Sevan Marine.

Sevan's Lieungh to step down

Carl Lieungh will exit his role as Sevan Marine's CEO, effective 1 January 2017. Current CFO, Reese McNeel will take his place, and carry out both functions in parallel, Sevan said in October. Lieungh, who has served as CEO since 2011, will continue to advise the board until yearend 2017.

Undercurrents

Thar she blows

When the oil price was high, many oilfield services firms paid little attention to the opportunities in the offshore renewables industry. The payback just didn't offer the same margins they could make in oil and gas.

Now that contracts are thin on the ground in the oil business, is it too late for offshore contractors to take a slice of the offshore renewables market?

In some ways the industry has missed the boat, quite literally. The offshore renewables sector developed to a degree that bespoke vessels have been built to service the industry, from installation vessels – interestingly, now over supplied due to a building spree in the early 2010s – to crew supply boats and specialist service vessels (*see Ulstein's X-Bow, X-Stern on page 36*).

It's perhaps not too late, however, says Alan Duncan, senior associate, BVG Associates. Speaking at a National Subsea Research Initiative event in Aberdeen early October, he pointed to some of the opportunities.

While the industry is nascent in the US, it's well established in northern Europe, despite ever present uncertainties about government support. The UK is No. 1 in the world for activity, he says, with 1-1.5GW installed capacity expected to be added per year through 2020. Other key areas for expansion include Germany, the Netherlands and, after 2020, France, the latter being "a new kid on the block" to offshore wind growth.

But, as build out continues, so will the requirement for operations and maintenance (O&M) work, he says, which could be about 40% of the market by value. "(Approximately) 7700 (offshore) turbines will be installed by 2025, each operating for 25+ years," he says.

While there's less cash to be made in O&M, compared to capex installation projects (57% of the value), O&M could offer a steady, stable, long-term work stream.

What's more, while project management methodologies have been developed in the offshore renewables industry, and a nearshore O&M philosophy is in place, there's less of a strategy formed for the future, larger, further from shore sites in deeper waters. "The distance to O&M ports is increasing year-on-year," he says. "Average water depth is less than 30m at the moment. It will be going to 60-70m, which will be a challenge. Oil and gas has experience in manning assets offshore. The offshore wind industry doesn't have a long-term vision of the O&M supply chain. There is a lack of track record of long-term service agreements."

While O&M offers the greatest opportunity, there are other areas where offshore industry expertise could play a role in offshore renewables, Duncan says: project management; array cables; substation structures; turbine foundations; secondary steel work; cable installation; and installation support services. There's also an opportunity for new technologies, such as innovative repair technologies, cable repair, condition-based monitoring and inspection technologies, and ways to increase the access time to offshore turbines.

But, firms will also have to focus on cost reduction. There's an aim to reduce costs in offshore wind so that it can survive without subsidy after 2023. Costs have been coming down and as turbines get larger (8MW turbines are being built and 9-10MW might not be far off), this will help reduce costs. But, O&M costs will also be expected to come down, he says. This could be through condition monitoring systems, automation, improving marine logistics and the C-word: collaboration. It could also mean different contracting scenarios.

To date, a lot of the service operations have been done under warranty, supported by the original equipment manufacturer (OEM). As warranties end, there's potential for new service business structures – i.e. moving from service contracts with an OEM to contracts with the wind farm operator or asset owner based on turbine operation availability. While service operations vessels like those contracted to Siemens are starting to play a role, Duncan asks if offshore accommodation units with daughter ships could be another approach. OE

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PUBLISHING & MARKETING

Chairman/Publisher
Shaun Wymes
swymes@atcomedia.com

EDITORIAL

Editor/Associate Publisher
Audrey Leon
aleon@atcomedia.com

European Editor
Elaine Maslin
emaslin@atcomedia.com

Asia Pacific Editor
Audrey Raj
araj@atcomedia.com

Web Editor
Melissa Sustaita
msustaita@atcomedia.com

Contributors
Emma Gordon
Prof. Alex Kemp
John Sheehan

Editorial Assistant
Jerry Lee

ART AND PRODUCTION

Bonnie James
Verzell James

CONFERENCES & EVENTS

Events Manager
Jennifer Granda
jgranda@atcomedia.com

Exhibition/Sponsorship Sales
Patrick Wymes
pwymes@atcomedia.com

PRINT

Quad Graphics, West Allis, Wisconsin, USA

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A Mexico's shallow water heats up

Mexico's National Hydrocarbons Commission (CNH) approved Italian oil major Eni's plans to drill the Amoca 2 well in the shallow waters of the Gulf of Mexico. Drilling is expected to start 1 December and end in March 2017. The Amoca 2 well is in 27m (88.6ft) water depth, 2.1km away from the original Amoca 1 well, near the Bay of Campeche, CNH said.

Elsewhere, Pemex applied to Mexico's Energy Ministry, SENER, for a joint venture (JV) for two shallow water fields in the Gulf of Mexico in mid-October. The JV will cover Pemex's Ayin and Batsil fields, off Campeche, with an estimated proven, probable, and possible 3P resources of about 281 MMboe; and 46 MMboe in proven reserves.

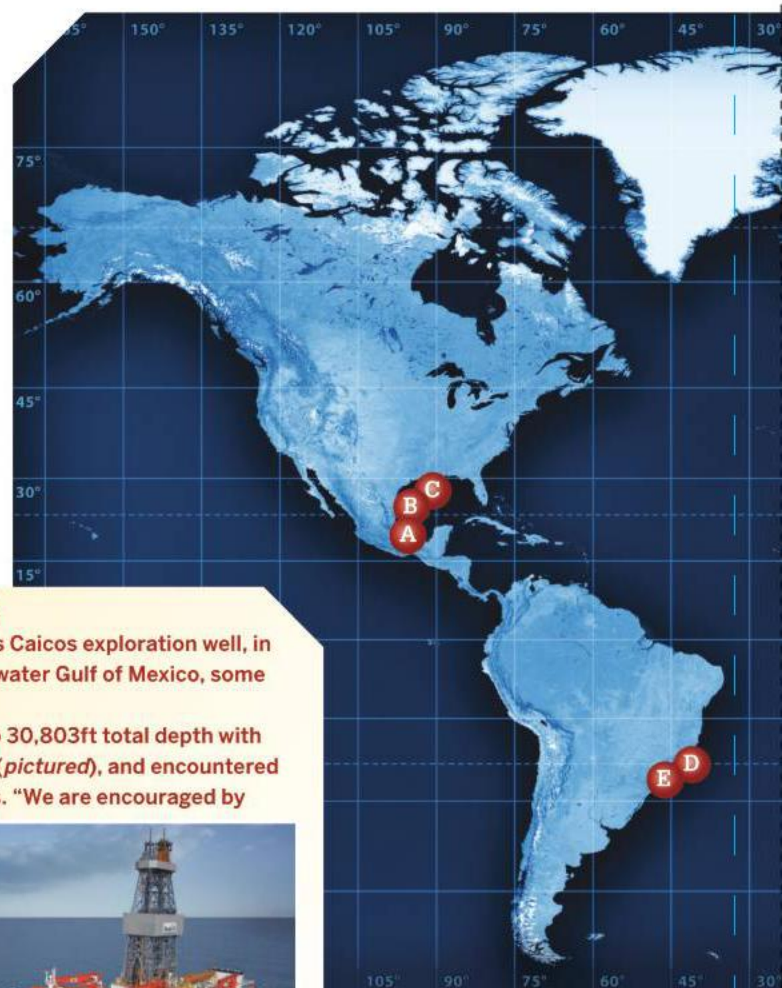
Pemex also said that its second joint venture partner could be announced as soon as March 2017.

B Mexican seismic roundup

France's CGG will use ultramodern images help to assess exploration blocks in Mexico's upcoming licensing round, in the Perdido fold belt. The reprocessing project, Encontrado, is a merge of nine existing surveys, acquired with different orientations, straddling the US-Mexico border.

The majority of the data is wide azimuth, but the project also includes some narrow-azimuth surveys. The volume of over 38,000sq km, of which 35,000sq km in Mexican waters, covers some of the most prospective areas in the Gulf of Mexico, including Great White and Trion discoveries.

Acquisition of Searcher Seismic's Buscador nearshore 2D seismic survey and TGS's Gigante have been completed offshore Mexico. Buscador comprises 11,200km of long-offset 2D data specifically targeting the nearshore areas covering rounds 2, 3 and 4. The data is currently being processed by DownUnder GeoSolutions, with fast track data available from December, and final data deliverable next year. TGS completed its 186,000km Gigante seismic survey, which began in June 2015 with five seismic vessels contracted to acquire a dense, modern, long offset regional 2D seismic grid.



C BHP hits at Caicos

BHP Billiton discovered oil at its Caicos exploration well, in Green Canyon 654, in the deepwater Gulf of Mexico, some 100mi south of Louisiana.

The Caicos well was drilled to 30,803ft total depth with Seadrill's *West Auriga* drillship (*pictured*), and encountered oil in multiple Miocene horizons. "We are encouraged by the Caicos results and are moving to further appraise the area," said Steve Pastor, president operations, petroleum, BHP Billiton. "The next step will be drilling the Wildling well in November."

D CGG starts Santos Basin shoot

CGG started the Santos VII (Saturno) broadband 3D multi-client survey in the pre-salt area of the deepwater Santos Basin, offshore Brazil.

Santos VII will cover over 13,900sq km, including the highly prospective Saturno prospect, a major pre-salt opportunity with no 3D seismic coverage to date.

The BroadSeis dataset will be acquired in two phases between September 2016 and June 2017 and processed in CGG's Rio de Janeiro subsurface imaging center.

Santos VII is the third phase of CGG's Santos Basin Trilogy, a project designed to support the evaluation process for Brazil's next pre-salt licensing round.

E Karoon targets Brazil stake

Karoon Gas Austalia entered talks with Brazil's Petrobras add stake in the Baúna and Tartaruga Verde fields, offshore Brazil. Karoon hopes to take 100% operated interest in Baúna, inside BM-S-40, in the shallow waters of the post-salt Santos Basin, which is currently producing about 45,000 b/d. Karoon also hopes to take a 50% non-operate interest in Tartaruga, in BM-C-36, in the deep waters of the Campos Basin, Petrobras will remain operator.

F Greater Stella remains on track

Aberdeen-headquartered Ithaca Energy is edging closer towards first oil from the Greater Stella Area Development in the UK North Sea. First oil, from the *FPF-1* floating production unit, is scheduled for November, as planned. As *OE* went to press, Technip was in the process of concluding the remaining subsea commissioning works. Stella is in Blocks 29/10a and 30/6a under license 011. Ithaca's partners are Dyas (25.34% interest) and Petrofac (20%), with Ithaca holding the remaining 54.66%.

G Goliat resumes production

Production resumed at the Goliat field in late September, in the Norwegian Barents Sea, after production halted on 26 August. Production was halted due to a gas detection in an unwanted area, Eni says, during a planned venting of gas, as part of a maintenance operation. This led to an automatic power shutdown to eliminate ignition sources. During the shut down, non-essential crew was evacuated as per procedure due to limited power supply.

The 180 MMbo field, the first producing oil field in the Barents Sea and the northernmost producing oilfield, achieved first production in March this year.

H Statoil makes Njord discovery

Statoil has made a discovery at the Njord North Flank in the Norwegian Sea. Drilled using the semisubmersible *Songa Delta* to 4105m below sea level, the NF-2 exploration well, 6407/7-9-S, encountered 102m of oil-bearing reservoir in Middle and Lower Jurassic sandstones of the Ile and 157m of a gross gas condensate-bearing column in Lower Jurassic sandstones in the Tilje formation.

A side-track well, 6407/7-9A (NF-3), was also drilled and encountered a 195m gas-bearing column in the Tilje Formation and a 140m gas-bearing column in the Lower Jurassic sandstones in the Åre Formation.

Both wells are 6km north of the Njord production facility, in PL 107 C.

A preliminary estimate of the size of the NF-2 discovery is 1.3-18.9 MMboe for NF-2 and 0.6-9.4 MMboe for sidetrack NF-3, Statoil's partner Faroe Petroleum says.

J BP, Egypt further Nooros development

BP and Egypt's minister of petroleum signed three amendments for concessions offshore Egypt in late September, that will allow for the economic development of the giant Nooros project in the Nile Delta offshore concession.

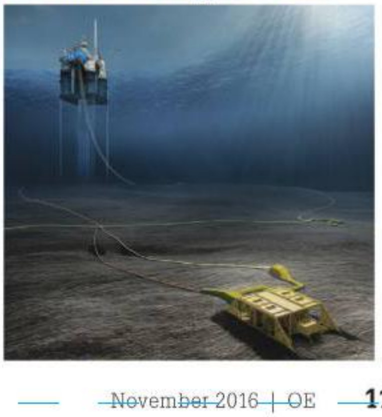
The amendments were signed for the Temsah, Ras El Barr and Nile Delta Offshore concessions.

The amendments were a critical milestone to enable the fast-track development of the Nooros field, says BP, which holds 50% interest in Temsah and Ras El Barr, and a 25% interest in the Nile Delta Offshore Concession. The remaining working

I Dvalin plan submitted

DEA submitted a development and operation plan for the Dvalin field (previously named Zidane, in PL435, in the Norwegian Sea, to the Norwegian Ministry of Petroleum and Energy. The Dvalin license plans to produce a total volume of approximately 18.2 Bcm of natural gas from two reservoirs. The development cost is estimated to US$1.23 billion (€1.1 billion), with planned production start in 2020.

Dvalin, which is 15km northwest of Heidrun and 290km from Nyhamna, will be developed with a four well subsea template, which is connected to the Heidrun platform. At Heidrun, the gas will be partly processed in a new module, before the gas is transported in a new export pipeline to Polarled, going to the Nyhamna onshore gas terminal. At Nyhamna, the gas will be processed and transported to the European market.



Global E&P Briefs

interest is held by Eni through its subsidiary IEOC.

K Eni closer to East Hub start-up

Eni's *Armada Olombendo* floating production, storage and offloading (FPSO) vessel will soon sail away from Singapore to the East Hub Development, offshore Angola, following its naming ceremony in mid-October.

First oil from East Hub is planned by 1H 2017, Eni says. East Hub encompasses nine subsea wells, of which five are producers and four are water injectors, in 450-550m water depth. The hydrocarbons which are produced from these wells will be transported via a pipeline system to the FPSO to be treated and stored prior to export.

Eni is the operator of Block 15/06 with a 36.84% stake. The other partners in the joint venture are Sonangol Pesquisa e Produção (36.84%) and SSI Fifteen (26.32%).

L Mozambique seismic awarded

CGG has been awarded an extensive multi-client program by the Instituto Nacional de Petroleo (INP) to acquire seismic data offshore Mozambique. The program includes a 2D survey of over 6550km in the offshore Rovuma basin, including blocks R5-A, R5-B and R5-C, and a large 3D survey over the Beira High in the Zambezi Delta. The 3D survey is expected to cover up to 40,000sq km, subject to pre-commitment. It will cover blocks Z5-C and Z5-D and surrounding open acreage in this deltaic area which is believed to be prospective.

M Hibiscus adds Malaysia acreage

Hibiscus signed a US$25 million deal with Shell to acquire operatorship and 50% stake in four fields in the 2011 North Sabah Enhanced Oil Recovery production sharing contract (PSC), offshore Sabah, Malaysia.

The deal comprises four producing oil fields and associated infrastructure that includes St. Joseph, South Furious, SF30, and Barton oilfields.

The PSC also contains pipeline infrastructure and the Labuan Crude Oil Terminal. Total oil production (on a 100% PSC basis) averaged approximately 18,000 b/d in 2015. The acquisition is expected to complete in 2017.

N Searcher expands PNG survey

Searcher Seismic started the acquisition of the 11,000km Hahonua 2D seismic survey offshore Papua New Guinea. In addition, Searcher and Gardline have initiated a multi-beam and coring survey; the Davaria geochemical survey, covering the entire Gulf of Papua to identify and analyze hydrocarbon seeps.

"Papua New Guinea continues to be an area of high interest for our clients and these two new projects, when combined with our existing coverage, will provide a unique and comprehensive exploration tool for the entire offshore Gulf of Papua," says

Contracts

Aibel awarded Dvalin job

Aibel has been awarded the modification assignment to ready the Heidrun platform to receive the production from the Dvalin field (formerly Zidane).

The award entails that Aibel will build two new modules to be installed on the Heidrun platform in the Norwegian Sea. These will be a 4000-ton module for gas treatment (M40) and a 400-ton injection system (H25). H25 is to be installed in 2018, while M40 is to be installed in 2019. In addition to building the modules, Aibel will clear the area on Heidrun and manage integration on the platform.

The project will be managed from Aibel's Oslo office, where planning and engineering work has commenced. The actual construction work will be carried out at the company's yard in Haugesund.

Sea Trucks gets Nigerian work

Sea Trucks was awarded a contract by an international oil major to West African Ventures, Sea Trucks' principle Nigerian business, for the provision of an accommodation vessel to a deepwater field, offshore Nigeria.

The scope of work covers accommodation support services for 250 passengers, as well as to provide marine logistics support for the execution of the turnaround maintenance work scopes during the turnaround project.

Jascon 30, one of the group's DP3 accommodation construction vessels, has been nominated for the scope. *Jascon 30* is equipped with a 270-tonne heave compensated main crane. The vessel features accommodation for 296 persons, a heave compensated gangway and 700sq m of unobstructed deck space. The accommodation capacity of *Jascon 30* will be increased with a portable accommodation block, which will be installed on the deck. Offshore activities are scheduled to commence in October 2016 for a duration of three months firm, with options to extend.

Lamprell delivers rig and awarded contract

Rig builder and engineering firm Lamprell delivered its latest newbuild jackup and won a new contract.

A US$90 million contract award, from Jacktel, part of Master Marine, is for the upgrade of the mobile operating unit *Haven* as an accommodation service vessel for use on Statoil's Johan Sverdrup field, offshore Norway.

The scope of works includes procurement, construction and installation of extended legs and new suction caissons. Lamprell will fabricate the new leg sections and suction caissons in its Hamriyah yard in the United Arab Emirates.

After transportation of the constructed rig components to Norway, Lamprell will assemble and install them on the Haven in collaboration with local Norwegian construction service provider, Coast Centre Base. The work is due to complete in Q2 2018.

Meanwhile, Lamprell has delivered the Shelf Chaopraya jackup drilling rig and its delivery to Shelf Drilling. The Shelf Chaopraya was designed according to the LeTourneau Super 116E (Enhanced) Class design and features high specification offshore drilling technology, as well as accommodation for up to 160 people. ▪

Rachel Masters, global sales manager, Searcher Seismic.

Kashagan ships oil

The first batch of export crude oil has been shipped from the giant Kashagan oil field, in the north Caspian Sea.

Production is expected to gradually increase up to a first level of 180,000 b/d, with a target level of 370,000 b/d to be achieved by the end of next year, says Eni.

Over the past year, the North Caspian Operating Co. (NCOC) has been rebuilding the pipeline infrastructure, comprising two, 95km pipelines.

"Following the successful pipelines replacement, the field has been recently reopened," says Eni, which is part of the NCOC consortium, alongside Total, ExxonMobil, Shell, Inpex, China National Petroleum Corp. and state-owned firm KazMunayGas.

The present project is seen as the first experimental phase of the mega-field's development, with future phases still being planned.

BP bets on Ironbark

BP intends to acquire a majority stake in two exploration permits containing the potentially massive Ironbark gas prospect on Australia's North West Shelf from Cue Energy Resources.

The move will see BP acquire 80% interest in permits WA-409-P and WA-359P in the Carnarvon basin, offshore Western Australia, which the Ironbark prospect straddles.

According to Cue, Ironbark is a giant Mungaroo formation prospect covering up to 400sq km with a best technical estimate of 15 Tcf of prospective recoverable gas resource, based on an internal technical assessment.

Cue says Ironbark, drilling on which is slated for 1H 2018, is in "moderate" water depths, under 50km from the North Rankin platform and near to the Pluto and Wheatstone LNG infrastructure, says Cue, making its prospects for commercialization positive.

Under its deal with Cue, BP is to fund 100% of the work program required under the permit for the first three years of the license renewal. BP also has an option through to May 2017 to acquire 42.5% equity in WA-359-P, which, if exercised, would see BP fund 50% of the cost of drilling a well in that permit. Cue says BP will also assist it in securing a partner or partners on an exploration well in WA-359-P, scheduled for 1H 2018.

Ups and downs for Great Australian Bight

Karoon Gas Australia has been awarded a three-year commitment to explore the Great Australian Bight, in which the company will focus on acquiring seismic surveys, offshore South Australia. Karoon was awarded exploration permit EPP46, covering 17,793sq km, in what the company describes as Australia's most active and prospective frontier oil exploration province, the Ceduna sub-basin.

While Karoon is betting on the Great Australian Bight, supermajor BP has decided to drop its deepwater drilling plans, saying that it will not be able to compete or capital investment with other upstream opportunities in BP's global portfolio.

BP's proposed Great Australian Bight plan originally consisted of drilling four exploration wells. Drilling on the first two wells, using a newbuild semisubmersible mobile offshore drilling unit in 1150-2250m water depth, was originally due to start in Q4 this year.

However, drilling plans have faced a series of hurdles with Australia's National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA), which had asked BP for further assessment.

A Maria template close to installation.
Photo from Wintershall/Thor Oliversen.

Ave Maria

Germany's Wintershall weighed several concepts for its Maria field development, which sits in a mature area off Norway. Elaine Maslin reports on how the firm drew upon multiple neighbors to select the right solution.

There's a joke about how many engineers it takes to change a lightbulb. A similar refrain could be used for the Maria field offshore Norway. In this case, the question would be "how many host facilities does it take to develop a subsea tieback?" The answer is four, five if you count a subsea template.

However, far from being a joke, this project – German-operator Wintershall's first development on the Norwegian Continental Shelf (NCS) – is a neat solution and an example of how things can be done in a mature basin in the future.

The project, currently under development, will see the Maria field brought online through the use of facilities – from gas lift to oil export – on the Kristin, Heidrun, Åsgard B, and Åsgard C production units, as well as a connection to the Tyrihans subsea template.

"To our knowledge, this is a fairly unique concept," says Hugo Dijkgraaf, Maria project director, Wintershall, at ONS, in Stavanger, Norway, back in August. "It uses each host's capacity to use what they do best."

"We think the Maria project is a smart solution in a mature area," says Dennis Dickhausen, Maria subsea manager, Wintershall, who also spoke at ONS. "We think this way of developing is a win-win. For existing hosts, which face a decline in production, Maria will extend production and there will be more players to share the costs. For us it is good because we can get down capex and costs."

To tieback or not to tieback

The Maria field is in 300m water depth, 200km offshore Trondheim, Norway, in blocks 6407/1 and 6406/3 on the Halten Terrace in the Norwegian Sea. It was discovered in 2010, followed by an appraisal well in 2012, confirming about 180 MMboe recoverable resources, most of which is oil.

As at the end of August this year, the development project, one of only two plans for development and operation submitted last year in Norway, was about 35% into execution and on time and budget. Two templates have been installed with two of three pipelines installation and modifications on the host platforms ongoing. First oil is due in 2018.

One of the Maria templates before it was installed offshore.
Photo from Vestbase/Ture Haugen.

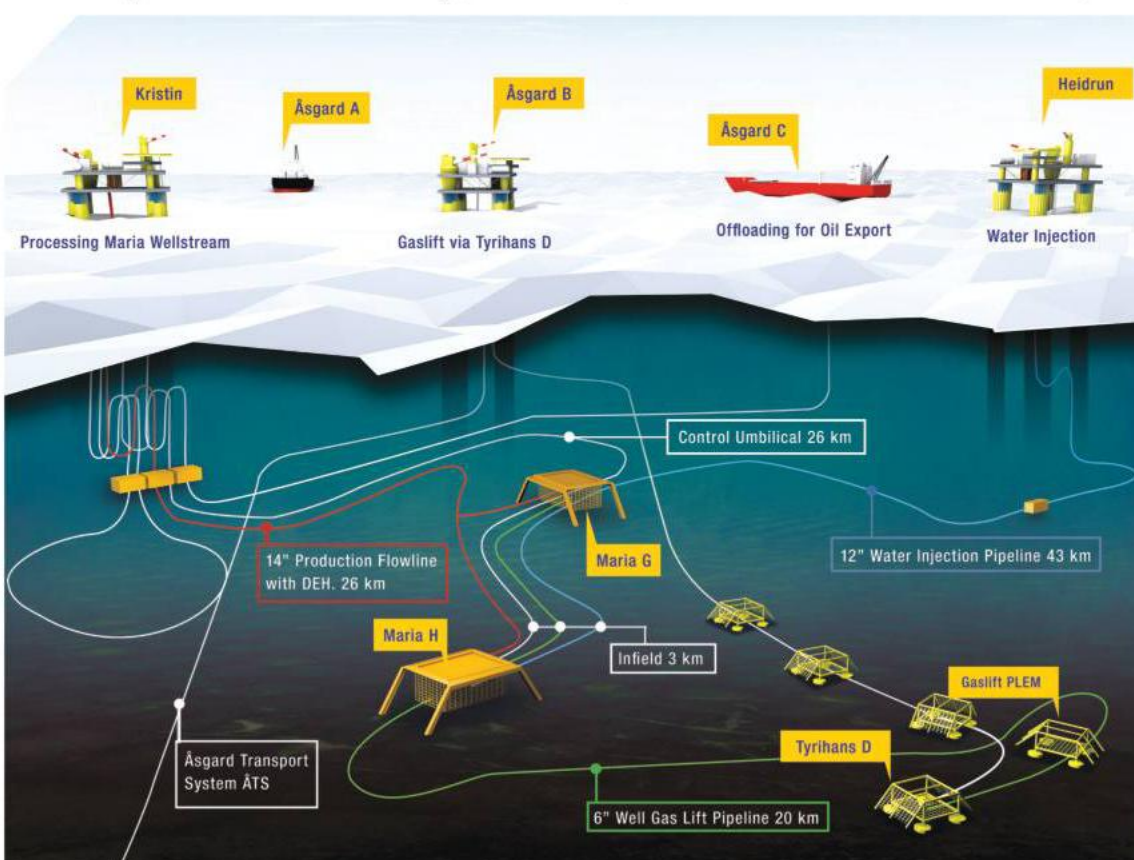
The development's complexity is due to the mature area in which the field is located. "When we started, we saw we didn't have a clean sheet of paper," Dickhausen says. "There was quite a lot of infrastructure (nearby), which we needed to assess. There are several floating installations and seafloor infrastructure."

It was a big process, with hundreds of combinations of ideas, he says. "It's a prolific area with many platforms and export lines in a 50km radius," Dijkgraaf says. The number of concepts were narrowed down to five, including a traditional tieback, a standalone development with a floating production, storage and offloading (FPSO) unit, together with Statoil, taking in the Trestakk field, and a tieback to Åsgard. None were that simple, however.

"We found out that the tieback projects we had were not able to take the Maria fluids and provide all the services, because of flow assurance concerns, and issues on brownfield modifications, with space restrictions," Dijkgraaf says. "We screened out tiebacks and worked hard on the FPSO and found a good technical solution, but the economics were marginal and not robust enough, and today [in the current oil price environment] we are happy we made that decision."

A standalone facility would have required a lot of new, project specific equipment, a complete vessel, and up to three crews, resulting in a lot of capex and opex. Even when Trestakk was included in the concept, to share costs, there were too few synergies, Dijkgraaf says. "They had more gas than us and needed a big gas plant, so it (the vessel concept) grew and grew.

"In the end, we needed to make a decision and we decided to screen out the FPSO concepts, which had become too expensive compared to a tieback. But, it wasn't easy because none of the hosts we looked at could provide all we needed or were too far away and we had to deal with flow assurance issues. So,



Sharing facilities – the Maria field layout.
Image from Wintershall/Paints Multimedia.

A Maria template close to installation with the *Normand Oceanic*.
Image from Wintershall/Rolf Skjong.

Subsea 7 is the main pipeline and subsea construction contractor, supplying the three pipelines linking Maria to the surrounding infrastructure, including the 26km, DEH production flowline, 46km-long plastic-lined water injection pipeline from Heidrun, and the 22km pipeline to supply gas lift.

While it sounds like a complex project, Wintershall believes 50% of capex was reduced by going forward with this concept. "We think it is a way forward and could be used by other players in the industry when you have discoveries in mature areas," Dickhausen says. Indeed, Wintershall has said a similar system is under consideration for its Skarfjell development in the Norwegian North Sea.

One issue could be availability of gas for gas lift and water for pressure support from the different hosts. But, Dickhausen doesn't think this is a big risk. "It carries more complexity, but you can rank (the risk) down because we can live without water injection, for months, without negative effects," he says.

we had to go back to the drawing board and find another solution."

Despite the apparent challenges, the firm and its partners, Petoro and Centrica, decided to move forward with a subsea tieback development.

"We agreed to mature a creative tieback concept involving several of those host installations topside and subsea," Dijkgraaf says. It was a commercially demanding decision, with agreements having to be made with four host licenses. While Statoil operated all of them, each is treated as a separate business unit and also had different third parties involved. Such negotiations are notoriously tricky and have put stop to or slowed to a near halt many a project on the UK Continental Shelf. But, offshore Norway, under the Petroleum Act, firms are compelled to provide opportunities for tie-ins if they have availability.

Solutions

The solution is a two-template development with oil piped to the Kristin semisubmersible production platform (online since 2005), 23km away, via a 26km-long pipeline. The pipeline has a direct electric heating (DEH) system to avoid hydrate formation.

The two templates are standard NCS templates supplied by FMC Technologies, under a subsea production systems contract, which includes manifolds and riser bases, and installed by Subsea 7. Each template has four slots, with three wells planned on each template, comprising two producers and one injector. The Xmas trees are also standard and Wintershall says that it's secured a cost-effective workover landing string system. It has a five-year contract with Expro for a complete workover riser system, including surface test tree and subsea landing string systems. The wells are controlled from Kristin.

For pressure support, water is supplied from Heidrun, a floating tension leg platform with a concrete hull (online since 1995), 43km away. A new pipeline has been installed for this. On Heidrun, a sulphate removal plant was due to be installed this summer, to treat the injection water.

Gas lift will also be used in the wells to aid the flow of the well stream. Gas from the Åsgard B semisubmersible gas and condensate processing platform (onstream since 2000) will be used, via an existing pipeline, which goes to the Tyrihans field (a subsea tieback to Kristin and Åsgard producing since 2009), then a new 22km-long pipeline back up to Maria.

Production fluids will go to the Åsgard C condensate storage and offloading vessel, from where they will be offloaded by shuttle tanker. Gas will go to Kristin and exported to Kårstø.

"For gas lift, that needs to be running and processing needs to be running," Dickhausen says. "We have studied a lot and expected uptime of these systems and we came to the conclusion we expect good uptime. There is a risk but we think it is controllable."

That the host facilities will support Maria through its life is also a question. But, Dickhausen says that they are not coming to the end of their life anytime soon. "Kristin and Åsgard are planned to run for a long time still," he says. "It's more about sharing the costs. Closer to the end I'm sure we will need to evaluate how long we need to keep going until limited by operational costs but then again there could be other discoveries. There are still exploration opportunities around."

While significant savings have been made, Wintershall is still working on ways to reduce costs further, such as looking at how to reduce costs on rock dumping.

Production well drilling, with horizontal wells, using the *Deepsea Stavanger* semisubmersible drilling rig will start next year. The *Deepsea Stavanger* dual derrick sixth generation unit will drill six wells, three on each template, on the Maria field starting from April 2017. Start-up is planned for 2018, three years from after the plan for development and operation was submitted. OE


Early Engagement
Umbilical design • Thermal analysis • Engineering studies
R&D • FEED / Concept select support
Qualification and Testing
Material testing • Component level testing
Fluid compatability • Full ISO/API testing • Blue Sky development
Umbilical manufacture
SIT testing • Flying lead supply • Hardware design & supply
Project specific umbilical manufacture • Packing and storage solutions
Offshore commissioning and support
Commissioning services • Supervisory/support services for installation
Aftersales support • Integrity studies

ANALYSIS

Capturing the (CO_2) energy

Norway's government has agreed to a new round of funding into carbon capture and storage technologies. Elaine Maslin reports.

Research and testing is set to continue at Technology Centre Mongstad. Photos from Gassnova/Helge Hansen.

Last month, Norway took a step forward in its ambitions to advance carbon capture and storage (CCS) technologies.

The country's government, which has a US$50/tonne tax on CO_2 emissions from industrial sources, agreed to \$43.5 million (NOK 360 million) in funding for the continued planning of a full-scale CCS demonstration facility in Norway.

Continued support is also expected to be pledged for the country's Technology Centre Mongstad (TCM) – which has been a focus of CCS technology development, but on which a current support agreement ends in August 2017 – and CLIMIT, a body for CCS research and development.

Norway has been injecting and storing CO_2 in offshore formations at the Sleipner field for 20 years, due to above market specification CO_2 levels in the gas in one of the Sleipner project's reservoirs. At Sleipner, the CO_2 from the produced natural gas is sequestered at the platform and then reinjected. One single chromium-steel well (which prevents CO_2 corrosion) has been used for this task. Meanwhile, CO_2 from the Snøhvit field, a subsea tieback in the Barents Sea, is also extracted and reinjected. On this project, onstream since 2007, CO_2 is sequestered onshore, then piped back offshore for injection.

Norway now wants to extract CO_2 from large onshore industrial plants, such as cement factories, energy from waste schemes, etc., which otherwise struggle to reduce their emissions, and then transport the CO_2 offshore for storage.

So far, a number of concept studies for demonstrator projects have been drawn up, but, it is not likely that a full-scale project, which would aim to store 1 million tonne per year of CO_2 over 25 years, will go into front-end engineering and design (FEED) until 2018, with an investment decision not before 2019, a statement from the government said in September.

While the work at Sleipner and Snohvit gives confidence that CO_2 can be reinjected (high grade steel wells built to handle CO_2 content are one enabler), taking gas from onshore industrial facilities and storing it offers challenges that the likes of semi-state-owned oil firm Statoil and the Norwegian state enterprise for CCS, Gassnova, are seeking to address.

However, a report from Gassnova earlier this year, summarizing feasibility studies for three projects, was positive about the chances of success. Projects were put forward by

Norcem, a cement factory, Yara Norge, an ammonia plant, and the Waste-to-Energy Agency in Oslo. Gassnova has separately assessed the feasibility of ship transport of CO_2 from locations for capture to storage sites (it's thought that at least initially this would be more cost-effective than building pipelines). Meanwhile, Statoil completed feasibility studies at three different sites on the Norwegian Continental Shelf. The best solution was the Smeaheia area, east of the Troll field, which could be fed CO_2 via ca.50km-long pipeline from a nearby onshore site, Gassnova says.

Other countries are also pursing industrial CCS projects. In the Netherlands, a project to extract CO_2 from a biomass-based power plant at Rotterdam port to a site 6km offshore is being assessed. This project is in the define stage with a potential startup in 2019-2020, according to CCS Network, an EU body.

Stop start

Another project, one of two hoping for a share of government support in the UK, was Shell's Peterhead power station project, in northeast Scotland. This would have seen CO_2 sequestered then piped offshore to Nexen's Goldeneye field. However, last year the funding was very suddenly pulled and the project left high and dry. A similar project in Yorkshire, England, called White Rose, suffered the same fate.

Another UK project, operated by Norwegian-owned Sargas Power, is seeking to extract CO_2 from a newbuild natural gas power station, the Don Valley Project (previously "Hatfield Project"), and pipe it offshore for storage. This project has had more success in terms of funding. While it didn't succeed in a UK bid for funding, it received cash from the EU. However, by 2019, the UK will no longer be a member country. Sargas took over the project in 2014.

Despite the knock backs for Peterhead and Don Valley, another project was launched – as *OE* was going to press. The UK's Energy Technologies Institute (ETI) is to invest US$793,380 in a nine-month project to develop an outline gas powered power plant with CCS scheme, with a "template" gas power plant design, to identify potential sites and build a "credible" cost base. Construction group SNC-Lavalin, infrastructure services firm AECOM and the University of Sheffield are to work on the project.

Government support appears more forthcoming in Norway. "CCS is one of the government's five prioritized areas for enhanced national climate action," says Minister of Petroleum and Energy Tord Lien. "In order to reach the government's ambition to realize a full-scale demonstration project for the capture, transport and storage of CO_2, we have to work systematically to establish a thorough decision basis."

There is some urgency, according to Tip Meckel, research scientist at the Bureau of Economic Geology, Jackson School of Geosciences, at the University of Texas-Austin. Speaking at a workshop on offshore CO_2 storage in May this year*, he said

In-Depth

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	2013	2014	2015	2016
Shallow (<500m)	76	74	57	20
Deep (500-1500m)	19	31	20	9
Ultradeep (>1500m)	34	13	13	6
Total	129	118	90	35
Start of 2016	127	114	72	-
date comparison	2	4	18	35

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	34.50	333.28
Deep	11	941.00	1595.00
Ultradeep	38	10,415.50	12,173.00
United States			
Shallow	10	70.60	155.00
Deep	15	684.00	805.00
Ultradeep	19	2402.00	2318.00
West Africa			
Shallow	107	3710.20	13,791.56
Deep	31	3392.50	5000.00
Ultradeep	10	1335.00	1000.00
Total	241	22,950.80	36,837.56
(last month)	(245)	(23,672.16)	(37,151.13)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	864	33,124.84	404,049.86
(last month)	(864)	32,780.73)	(405,753.29)
Deep	118	6,647.16	67,177.14
(last month)	(120)	(6600.52)	(68,856.21)
Ultradeep	73	15,062.40	41,288.00
(last month)	(76)	(15,823.40)	(42,288.00)
Total	1055	54,834.40	512,515.00

Pipelines

(operational and 2015 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	42,126	(41,076)
Planned/ possible	24,738	(24,024)
	66,864	(65,100)
8-16in.		
Operational/ installed	83,417	(81,443)
Planned/ possible	49,666	(49,499)
	133,083	(130,942)
>16in.		
Operational/ installed	93,956	(94,052)
Planned/ possible	43,625	(42,994)
	137,581	(137,047)

Production systems worldwide

(operational and 2015 onwards)

Floaters		(last month)
Operational	273	(271)
Construction/ Conversion	47	(49)
Planned/possible	323	(301)
	643	(621)
Fixed platforms		
Operational	9258	(9145)
Construction/ Conversion	101	(87)
Planned/possible	1384	(1361)
	10,743	(10,593)
Subsea wells		
Operational	4843	(4859)
Develop	437	(393)
Planned/possible	6512	(6423)
	11,792	(11,675)

Global offshore reserves (mmboe) onstream by water depth

	2014	2015	2016	2017	2018	2019	2020
Shallow	14,543.34	21,245.45	30,282.16	24,000.35	10,927.69	21,437.97	17,709.65
(last month)	(14,540.52)	(21,144.93)	(30,213.12)	(23,864.57)	(11,071.13)	(21,376.71)	(17,771.98)
Deep	4477.34	976.73	2039.73	5106.94	2751.57	4342.14	4250.39
(last month)	(4477.34)	(976.73)	(4847.45)	(2833.28)	(2585.84)	(4317.83)	(4155.73)
Ultradeep	2342.81	2023.18	3145.58	2481.25	3333.11	4144.56	9237.36
(last month)	(2342.81)	(1922.92)	(3145.58)	(2481.25)	(3457.52)	(4144.56)	(10,050.25)
Total	21,363.49	24,245.35	35,467.47	31,588.54	17,012.36	29,924.67	31,197.40

6 Oct 2016

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	99	66	33	66%
Jackup	399	229	170	57%
Semisub	121	71	50	58%
Tenders	31	20	11	64%
Total	650	386	264	59%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	30	25	5	83%
Jackup	25	4	21	16%
Semisub	13	7	6	53%
Tenders	N/A	N/A	N/A	N/A
Total	68	36	32	52%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	11	3	8	27%
Jackup	118	65	53	55%
Semisub	32	15	17	46%
Tenders	22	13	9	59%
Total	183	96	87	52%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	24	18	6	75%
Jackup	49	28	21	57%
Semisub	23	17	6	73%
Tenders	2	2	0	100%
Total	98	65	33	66%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	49	32	17	65%
Semisub	38	24	14	63%
Tenders	N/A	N/A	N/A	N/A
Total	88	56	32	63%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	3	1	2	33%
Jackup	116	84	32	72%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	123	88	35	71%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	18	14	4	77%
Jackup	20	8	12	40%
Semisub	5	3	2	60%
Tenders	7	5	2	71%
Total	50	30	20	60%

Eastern Europe

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	2	1	1	50%
Semisub	N/A	N/A	N/A	N/A
Tenders	N/A	N/A	N/A	N/A
Total	2	1	1	50%

Source: InfieldRigs 10 October 2016

This data focuses on the marketed rig fleet and excludes assets that are under construction, retired, destroyed, deemed non-competitive or cold stacked.

that for CCS to make an impact, some 6 Gigatonne of storage is needed by 2050, which would be equivalent to 6000 Sleipner projects. Offshore shelves, he added, are the largest gigatonne-scale storage sites for CCS.

Norway says it will support concept studies on up to three CCS projects. The concept studies will go on until autumn 2017. Continuation of the project to a FEED phase will be considered in the budget for 2018, with a potential investment decision in summer 2019.

Net benefits

While storage is the main goal, CO_2 injection could also play a bigger role in increasing oil recovery rates, says Pål Helge Nøkleby, business development manager, Aker Solutions. This way, it could also be a bridge to CCS solutions.

Speaking at ONS in Stavanger earlier this year, Nøkleby says a 5-9% increase in recovery could be gained from CO_2 injection. Nøkleby says 10-11 million tonne of CO_2 could help extract some 52 MMboe. But, it's not yet been exploited due to the space CO_2 processing equipment would take up, he says, as well as the cost of shutting in facilities to integrate these facilities.

Aker Solutions has been looking at the potential for subsea CO_2 separation and injection technologies. Recent breakthroughs such as the Asgard subsea gas compression project already offer some of the technology required, by adapting it for CO_2 service. Aker Solutions has also developed a subsea membrane separator for subsea CO_2 separation for enhanced oil recovery (EOR) backflow and sour gas fields. These would be in retrievable modules and would enable 97% of the CO_2 content in a well stream to be separated.

For storage or injection of CO_2 from onshore sites, CO_2 could be supplied by ships via subsea buoy system or even European trunklines, he says.

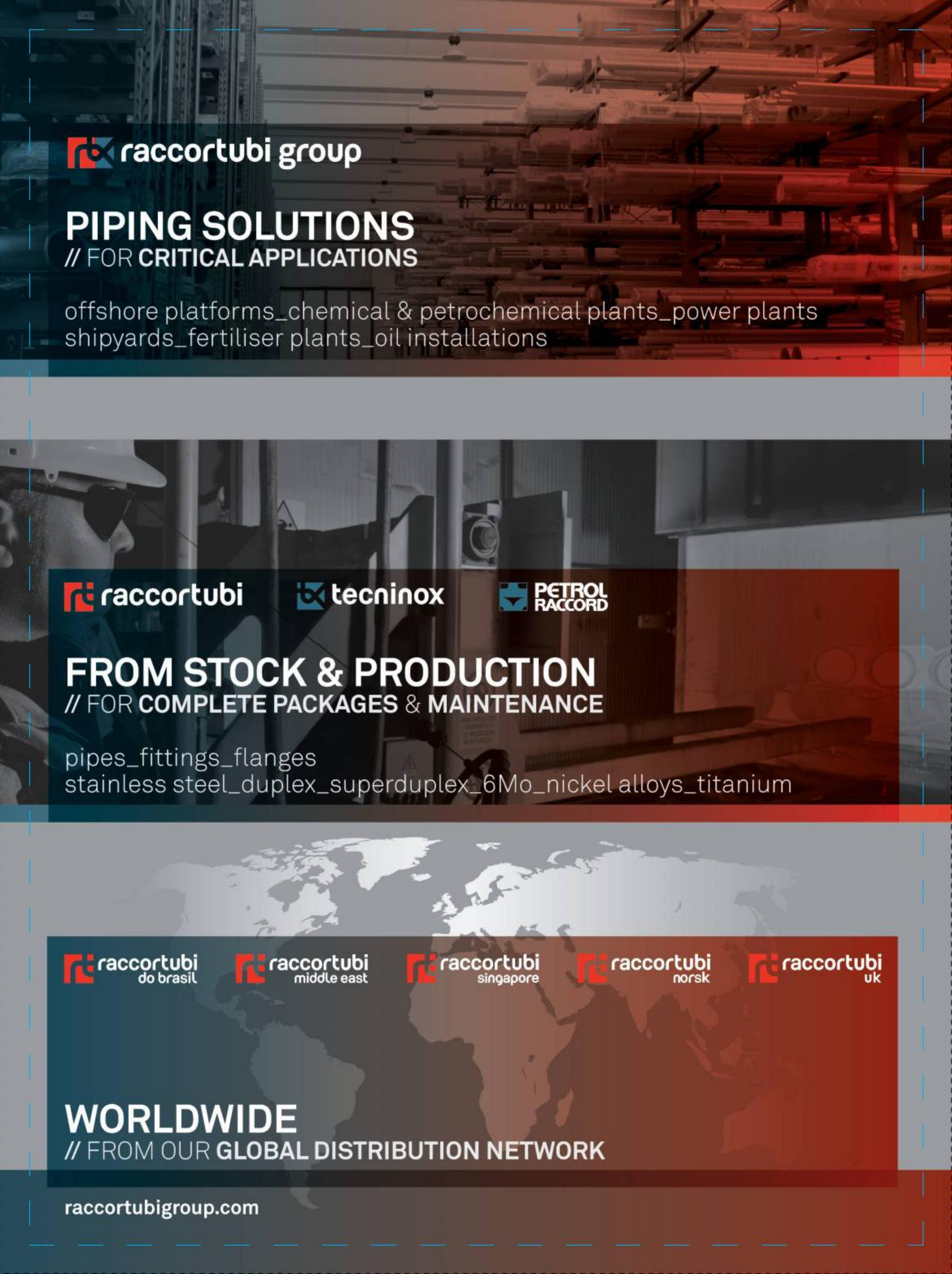
"Small subsea processing units could serve small compartments in bigger reservoirs in parallel to conventional production," Nøkleby says. "They can be used for late-life injection or permanent storage. Retrievable modules can be moved. EOR [as such] can be considered a step towards CCS."

Norwegian firm Reinertsen has also developed a solution. Torkild Reinertsen, the firm's president, says it has bought the rights and the IP for a membrane palladium technology on which it has been working with research firm Sintef. The technology comprises some 100, 2m-long pipes covered in palladium and contained in a pressure vessel. They're used as a membrane through which hydrogen is extracted and CO_2 captured.

The firm has had promising test results, Reinertsen told ONS. It has an agreement with Statoil to test the technology on a methanol plant outside Trondheim. A mobile test unit was taken to the test plant late August to start testing. Potentially, the technology could be used to produce large amounts of hydrogen from offshore gas, initially onshore, but when the technology has become more compact, also offshore.

"It will be a real game-changer," he says. The firm is setting up a subsidiary for these works and hopes to have factory building units next year. OE

**IEAGHG, International Workshop on Offshore Geologic CO_2 Storage, 2016/TR2, May 2016.*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PIPING SOLUTIONS
// FOR CRITICAL APPLICATIONS
offshore platforms_chemical & petrochemical plants_power plants
shipyards_fertiliser plants_oil installations
raccortubi
tecninox
PETROL RACCORD
FROM STOCK & PRODUCTION
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pipes_fittings_flanges
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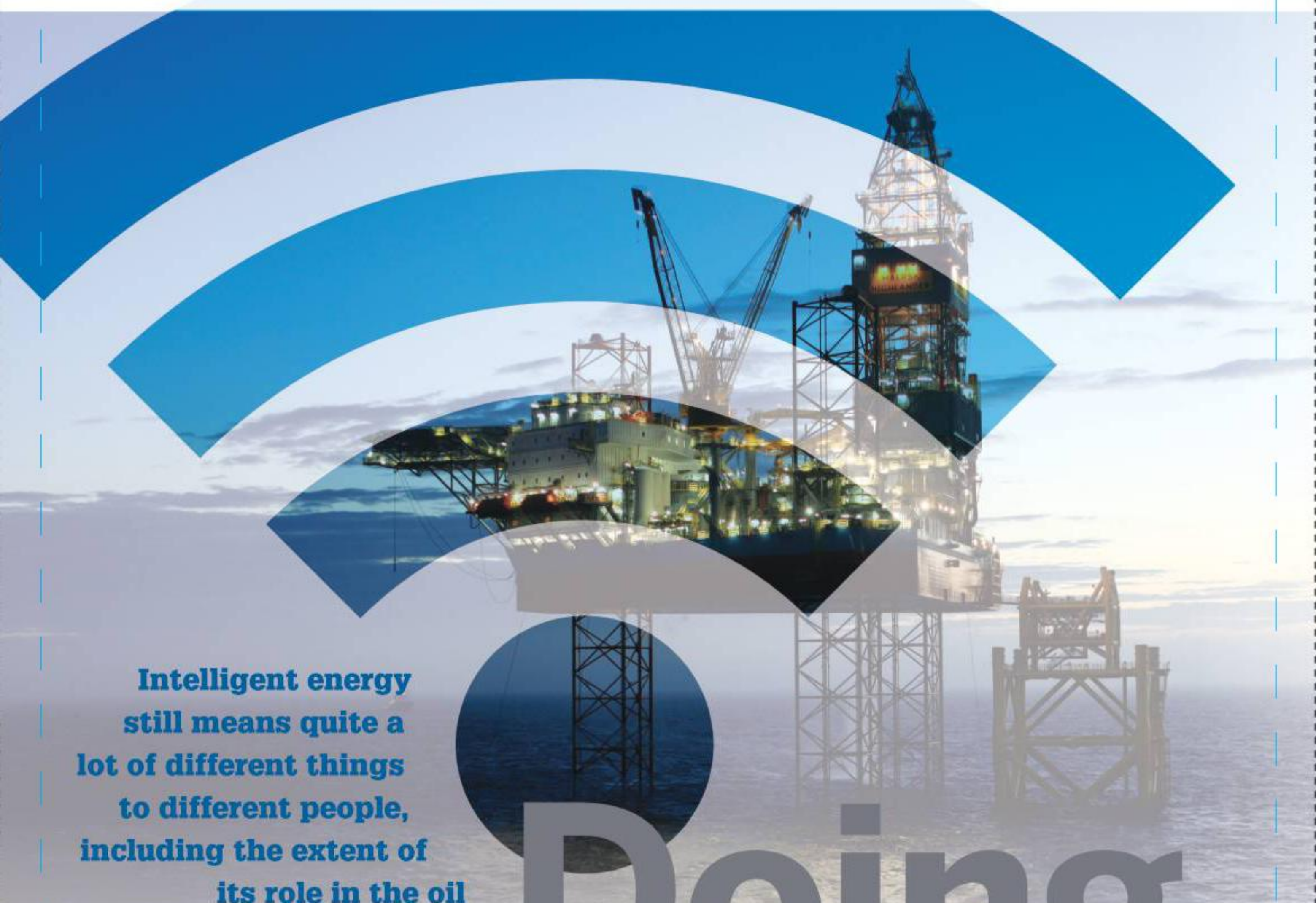


Intelligent energy still means quite a lot of different things to different people, including the extent of its role in the oil and gas business. Elaine Maslin reports.

Doing digitalization

"A traditional response is no-longer enough in today's downturn," a senior executive told the SPE Intelligent Energy conference in Aberdeen this summer.

BP, for one, is looking to transform itself into a digitalized business, while others see having a suite of smart oilfield technologies as the way to maintain their competitive edge in a US$40/bbl world.

It could be a painful journey (*See 'IT/OT talk' on page 26*) and will not come overnight, but it will help drag the industry into the 21st century, cloud computing and all.

Greg Hickey, process engineer, upstream technology, BP, and former technology development manager on BP's Field of the Future program, says a fundamental change is underway.

"It is not just a downturn, it is a new business climate," he says. "Companies will have to change. There's a lot of oil around that can be produced at $40-60/bbl and it is not going to go away. We need to be competitive.

"As a company, we are driving down cost in all aspects of our operations and in general our operations are leaner. We have fewer people than two years ago and an ongoing focus on standardizing the way we do things, and elimination of

The Maersk Highlander drilling rig on location.
OE graphic. Photo from Maersk Drilling.

non-value adding things. But, we know this traditional response is not enough. Doing more in the same way only takes us so far.

"We realize at BP we need to set out on a journey to modernize the upstream business. We need to focus on our margins and we recognize part of that is to digitize the upstream business. We need to pursue a manufacturing ethos, such as Toyota. We are responding with smarter ways of working and a new generation of business solutions to support this environment."

Mark Edgerton, manager of reservoirs, Chevron UK, agrees. "As an industry and as a basin [UK North Sea] we are struggling to remain an attractive place to put capital. It is here that I feel intelligent energy has a role to play, it provides us with a way to change."

"We want to change our inward arrogant attitude. We want to learn from industry and the outside world."

— Johan Atema, Shell

Beyond the future

BP launched its Field of the Future program 15 years ago. It centered on connectivity and collaboration between on- and offshore operations, fiber optic communications and advanced collaborative environments, and real-time data monitoring centers.

"Now, our CEO [Bob Dudley] says digitalization of the business is fundamental to the way we need to operate in this new business climate," Hickey says, just like how the pharmaceuticals, aerospace and mining industries have already done, with some great success stories.

So, why hasn't the oil and gas industry done this before? "We didn't have the platforms to allow inter-operation," Hickey says. "We didn't have the databases to support it. There was no cloud infrastructure to allow the software as a service model to become a more normal way of working.

"We could collect data in real time and put it in a historian and analyze it, but we couldn't really find the patterns in it once it was there," Hickey adds. Back in 1990, most of the data in the control system was in silos offshore, he says. McKinsey has said that only 1% of the data from an average 13,000 sensors offshore is used in decision making.

"Development of smart oilfield tools didn't keep pace with the complexity of availability of large amounts of data being created," says Mike Hauser, project manager, CiSoft Solutions, at the University of Southern California. "A lot has changed in the last decade. Many building blocks (for the digital oilfield) have been created and are becoming more commonplace."

Hickey adds: "Today, we can bring [data from] 50,000 sensors onshore every few seconds and have industrial strength platforms to work with, like GE's Predix, to process the data and run productivity analytics."

Hickey admits that when BP implemented the Field of the Future, "[the company was] in a glass box," meaning that BP had wanted to keep the technology to itself. However, now it wants to change the model.

"We don't want to own digital technology and we want to move fast," he says. "We are committed to cloud computing. We are not a company that wants to own cloud solutions. We are removing the shackles to create opportunities. We want others to help. GE delivered better capability than we can ourselves, so we can reap the benefit."

Sharing data

Shell shares a similar attitude. "We want to change our inward arrogant attitude. We want to learn from industry and the outside world," says Johan Atema, vice president manage producing assets, Shell, at the same event.

Shell has been using its data in a more explicit way inside its own business, setting targets, benchmarking unit costs, recovery from wells, etc., and making this information available across the business to help drive improved performance. Benchmarking and improvement plans are something the firm's often more marginal downstream business is shocked that its upstream counterpart hasn't done before, Atema says. Upstream hasn't had the same need to improve as downstream has had, until recently.

Painting was one area were costs were saved. It was costing >£1000/sq m via a contractor. This was higher than in Norway. "We went back to our contractor and said 'this isn't competitive,'" Atema says. Their response was it was because of Shell's permit to work systems, etc. "We had to look in the mirror. Now we are more competitive than


In the spotlight at SPE Intelligent Energy: Judson Jacobs, senior director, Energy, IHS; Johan Atema, VP Manage Producing Assets, Shell; David Boyle, UK operations manager, ConocoPhillips; Mark Edgerton, manager of reservoirs, Chevron UK; and Greg Hickey, process engineer, Upstream Technology, BP.
Photo from Reed Exhibitions.

Johan Atema, VP Manage Producing Assets, Shell. Photo from Reed Exhibitions.

Norway. It's about transparency of data."

Shell, like BP in its Field of the Future program, has also set up collaborative onshore/offshore environments. The most critical equipment is put in a tool, sweet spots of the operating envelope are monitored and automatic alarm functions, advice based on operating history, etc., used. This has been tested on the Draugen facility, offshore Norway, with the result being 95% availability, including turn arounds, Atema says, pointing out that this has all been done with existing technology and data infrastructure. "With good working practices and mindset you can achieve good uptime," he says.

Elsewhere, intelligent energy is done differently, due to the different nature of the business. Atema says onshore Oman, where there are thousands of wells and outdated infrastructure, the approach has been to give instrumentation wireless connectivity and then use a smart mobile worker, equipped with a GoPro, a tablet device, and an iPhone, etc. They can issue a permit to work remotely, using day to day technology.

Tool kits

For Chevron's Edgerton, intelligent energy is a tool kit, for condition-based monitoring. "Installing this equipment (e.g. sensors) costs money, but Chevron sees it as a good investment," he told SPE Intelligent Energy. "All rotating equipment operating from Aberdeen has it installed and the signals go to Houston to an integrated team. But also to the vendor." Subject matter experts in Aberdeen are also involved.

"Each of those groups can intervene to prevent a failure or to improve performance," he says. "We are getting better reliability. But, as we continue to get data, we can build a history of performance to take it to another level, be more predictive about when we are going to fail and schedule maintenance as a result." Some $9 million in equipment failures has been cut thanks to the work in condition monitoring, he says.

"The next step is real-time optimization as conditions change," he adds. "Changes are often small, 1% in a certain piece of equipment. But it adds up, 1% change every day over the course of a year can be $3 million in extra revenue. Again, as we build the business plan, we build understanding [of how] to optimize going forward."

However, these technologies can be used on a broader level. Data from offshore technicians can optimize plans and resources, awareness around which work teams are the most efficient can also be built and knowledge shared, like at Shell.

By doing all this, and having an integrated operations center, production efficiency has increased 4%, and some $51 million value added has been achieved in the last 18 months, Edgerton says.

Centralizing

For others, it's more structural.

David Boyle, operations manager for ConocoPhillips in the UK, outlined how the business had changed its structure, which had been an asset-based portfolio run in silos. The firm wanted to improve functional strength in key disciplines, such as asset integrity and production engineering, and create an integrated operations model, with multi-discipline teams created in support of offshore operations, standardizing where it made sense, creating more time for planners to look into data and make decisions about when and how work is best done, instead of spending time managing data.

On a practical level, this has meant a 30% reduction in staff, but increased capacity to support work, because people can work more efficiently, Boyle says.

As an example, the changes have helped increase so-called "tool time" from two hours in a 12-hour shift in 2014, to 5.9 hours in 2015, and 6.5 hours as of September this year. Boyle thinks eight will be about the best that can be achieved (tool time is the number of hours actually on the job, as compared to preparing, finding equipment and/or materials, or arranging permits to work). Reliability has seen a 50% improvement, thanks to some of this work, he says.

Maintenance has also been re-examined. Now, instead of an annual shutdown for maintenance, it will be done every three years on some UK facilities, as it is on the Ekofisk platform in Norway. Meanwhile, what had been an increasing backlog of maintenance work has been reduced.

Internet of things

Perhaps not all firms have the same vision as BP, but they're all headed in a similar direction. "Now we truly have the capability to run the Industrial Internet of Things, to ingest and analyze [data], often in real time, to optimize the way we operate from reservoir to export, and soon we will be able to integrate all this together," Hickey says.

The alternative? While companies like BP are not going out of business any time soon, Hickey offers a warning against complacency. "If you look at the top 15 companies 20 years ago, most are not in the top 15 now and many have disappeared altogether. We have to be aware of that."

Furthermore, the world is increasingly full of so-called "digital natives" who will have expectations on how the businesses they join operate. The analog oil firm will not be first on their list. **OE**

IT/OT Talk

Talk of an IT and OT convergence has been increasing, including in the oil and gas business. Elaine Maslin reports.

"The first thing people need to realize is there's an ugly job to do and [they need to] roll up sleeves," says Duncan Irving, principal consultant, Oil & Gas, EMEA and APAC, Teradata.

He's talking about how to deal with the mass (mess, even) of data the oil and gas industry generates daily. Traditionally, the industry has had IT as a corporate function, including analytics, with operations using different systems, depending on the business unit or asset, he says. In operations, data is sourced and held in the function that uses it as part of a so-called "point solution." So, while data analytics are used on a corporate level, "out in the field, there's less of an analytics culture," he says.

"OT [operations technology] starts in a particular business unit and every business unit is doing their own thing," Jane McConnell, industry consultant, oil and gas, Teradata, told *OE* at SPE Intelligent Energy in Aberdeen. While point solutions are created for particular problems, "they're not doing something that's transformative," Irving says.

Because of point solutions, all oil industry data is in totally different systems, McConnell says, and totally disconnected.

"Vendors tend to perpetuate the situation by locking the data into their own systems," she says. "If someone wants to add something extra into the workflow and puts it in Excel, it locks it up. It can be replaced by software, which fits in the point solution, but this perpetuates the situation where point solutions are in all these places. So, you end up with no real control of how data moves. All this data sits in different silos. There is no control group in charge of a lot of these systems.

"Oil data can also be quite hard [i.e. compare sensor data to subsurface data], making it hard to handle. Then, you'll have people who understand business intelligence tools, but who don't know the data and people who know the data but spend all day buying applications," she says.

However, the Internet of Things (IOT) is giving a glimmer of hope that this can be changed. "IT-OT is coming to fore," she says. "It is people in the IT department opening their eyes and seeing all these systems they didn't know existed before. But, there's still a cultural difference between the two groups."

Analytics can be done. The onshore fracking industry, being newer, with a new set of processes – well spacing for example, which hadn't been such a focus before – and a much more agricultural setup, has been able to start with a blank sheet of paper, Irving says.

Illustration from iStock.

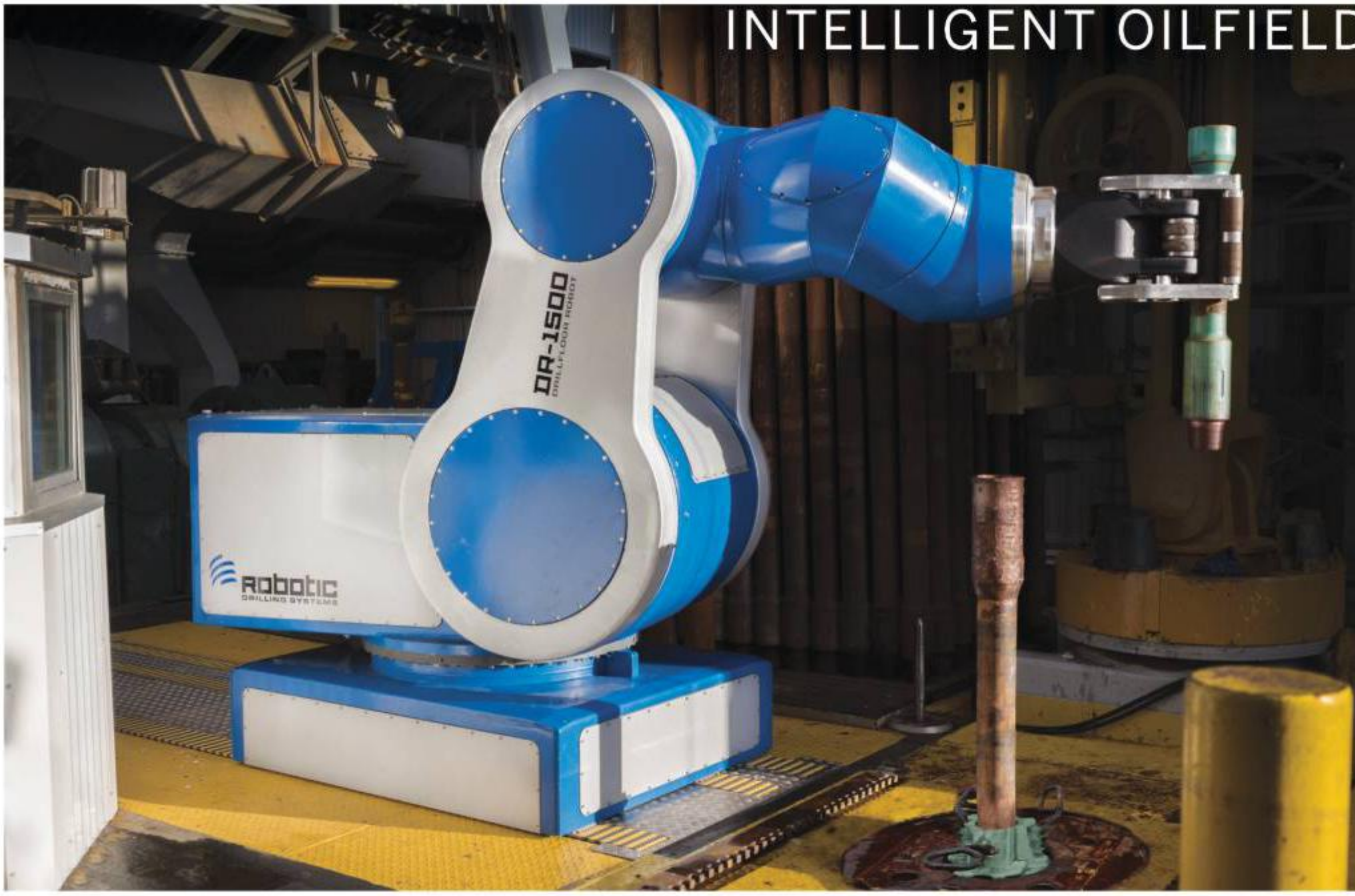
In refining, where it is also easier to link data from the refinery to cost or value of that activity – as part of a process more like manufacturing, operators use one system to know what's going in one end and coming out the other, and what's going on in the chain, so they can see where they are being suboptimal.

"Shell wants to know what is going through every pipe at any one time, with an integrated thread to tankers and trading desks, so they can see where their tankers are and save money, time deliveries, etc.," Irving says. Even so, there are not that many refiners beyond Shell, BP, Exxon and Chevron that are that good at it, he says.

Cindy Crow is industry principal, oil and gas, at US-based OSIsoft, which provides the PI System, based around the PI Server, an information management system. The PI Server collects real-time data from sensors across an operation, no matter the vendor, and brings them onshore for access. From there, through the PI System, they can be monitored, visualized, and analyzed.

While such a system currently enables high frequency vibration monitoring and the potential to de-man facilities, what's changing is an IT and OT convergence, where OT and IT information can be used together to optimize operations, Crow told *OE* at ONS in Stavanger this summer.

To put it another way, the data collected can be pushed out to other tools, such as predictive analytics or productivity platforms, and then used to look at similar processes or vendor equipment across the entire business. Third party vendors could also access the data, without compromising safety, as they're not getting direct access to the data or system. **OE**



The world's first drill floor robot installed at the Ullrigg Drilling and Well Centre. Photo from RDS.

Batteries not included

The drill floor robot is no longer a vision, it's a reality and it's going to start operations offshore Norway next year. Elaine Maslin reports.

"The robotic drill floor is not a vision. It's here, it's now and it's working." This is a bold statement, but one that, after some US$45 million investment over 11 years, Kenneth Mikalsen, chief technology officer, Robotic Drilling Systems (RDS), is now able to make.

The firm has made what it calls the first drill floor robot – an automated handling tool able to perform multiple functions – which is set to be deployed on a rig offshore Norway in early 2017.

It's not any old rig either. It's Odfjell's *Deepsea Atlantic*, which is currently working for Statoil on the huge Johan Sverdrup field – Norway's largest ongoing industrial project. Odfjell also has a 38% stake in RDS, alongside other stakeholders including Statoil, Westcon and venture capital firms.

The firm has also assembled a full robotic drilling system, using a suite of four drilling robots, including a roughneck and pipe handler. Earlier this year, the full system was demonstrated working together at the firm's Sandnes, Norway, base. Next year, a full set is due to be deployed at the Ullrig Drilling and Well Centre, operated by Norwegian research organization Iris, in Stavanger (Ullrig has had one drill floor robot since late last year).

RDS also has an order for a pipe handler from Nabors, giving the fledging commercial company a $4.5 million backlog.

Lars Raunholt, RDS' founder (when the company was called Seabed Rig) and now vice president of business development, will be glad the previously autonomous seafloor drilling unit-focused firm took a change of direction.

The full robotic drill floor system during workshop testing. Photo from RDS.

"Ten years ago, 20-25% of oil yet to be found was in the Arctic," he told SPE Intelligent Energy in Aberdeen early September. "Shell was one of the companies active in the Arctic and was looking for new technology. What a difference 10 years makes. The ice is melting, Arctic exploration has gone with the oil price and we don't do business with Russia [an Arctic player] because of the sanctions. We decided to focus on automation and robotization on conventional rigs."

Thanks to that shift, RDS now has technology it hopes will advance drill floor automation. "We think the technology we have brought forward is an enabler for automation and digitalization of drilling operations," he says. "[Using these robots] you can operate twice as fast as you can today, depending on what you are doing."

Raunholt says 40 operational days a year could be saved using these robots, through faster, more precise and consistent handling, especially around tripping, but also bottomhole assembly, and casing running, as well as increasing safety by removing staff from the drill floor. "There is less maintenance, and in principle no maintenance for at least 10 years, as well as easy installation," he adds.

RDS has designed and built four different drilling robots in total, including the drill floor robot, a robotic pipe handler, an electric roughneck, and a multi-size elevator. They are all able to work on their own or together.

Mikalsen says that the units have been designed to be robust, using standard known components (from the likes of Siemens, Nabtesco [gears], Igus [cables], and others). On each, the entire control system is within the robot, and they're all-electric, so a control cabin or hydraulic power unit isn't required. "You just hook up with power and communication," Mikalsen says, speaking at ONS in Stavanger late August. "When the first drill floor robot was sold to Ullrig, it was shipped already tested and loaded with the programs it needed. It just had to have its position calibrated and then the programs run."

There're no sensors or cables on the outside and they are slightly over pressured on the inside to enable EX-approval (based on the EU ATEX equipment in hazardous environment safety directives) and make them easy to flush down.

Key innovations in these tools, Raunholt says, includes making them all-electric and running them on a dynamic robotic control system. "The usual control systems used in manufacturing are used to do repetitive tasks," he says. "The drill floor robots will be tasked with much more varied tasks." RDS worked with Boston, Massachusetts-based robotic software firm Energid on the controls systems for this reason.

Seven axis solution

The drill floor robot is also unique – automated pipe handlers and roughnecks are types of equipment that already exist, the drill floor robot is new, and can be used to do manual operations that are done today, Raunholt says.

The seven-axis drill floor robot (which Raunholt says has the world's strongest electric manipulator handling arm) selects tools, such as grippers, spinners, clamping tools and other handling tools, automatically, with an inductive interface supplying power and communications to make the tools smart, i.e. for measurement or filming for inspection. It has 1500kg capacity, at 3m outreach. It runs on an average 13kW power, using seven electric motors with total 100kW installed power.

The pipe handler has 9° of freedom, with a 3500kg capacity lower boom able to move between horizontal and vertical. It can also change its own handling tools, such as a gripper or spinner-gripper, which can spin pipe directly into or out of the stick up, with the roughneck then only having to do the make and break operation.

The roughneck has 270kNm capacity, which means manual tongues aren't needed, and a triple torque grip wrench with 120° total rotation per grip. The elevator has 350-tonne capacity, but could be bigger, and can perform remote controlled change of inserts and tilt 90°.

"All the robotics are force sensitive," Mikalsen says, saving exerting undue pressure on the pipe threads and reducing torque required for handling. Each machine knows where it is in relation to other machines it would be working with, so they won't collide. The pipe handling robot can pick up pipe from horizontal, and you can drill while picking up pipe and building stands, he says. The drill floor robot and pipe handler can also spin, so the roughneck doesn't have to, "adding up to an effective system," Mikalsen says. "It means actions are repeatable but also with speed."

Because it's an electric system, energy is more easily saved through the control system and a "digital twin" can be created for monitoring and testing. The human machine interface has been reduced to a standard computer with two screens and a graphics card, he says.

Using these robots will save at least one month during a one-year operations window, Mikalsen says by "saving time during handling with drill floor pipe handling, casing handling, etc."

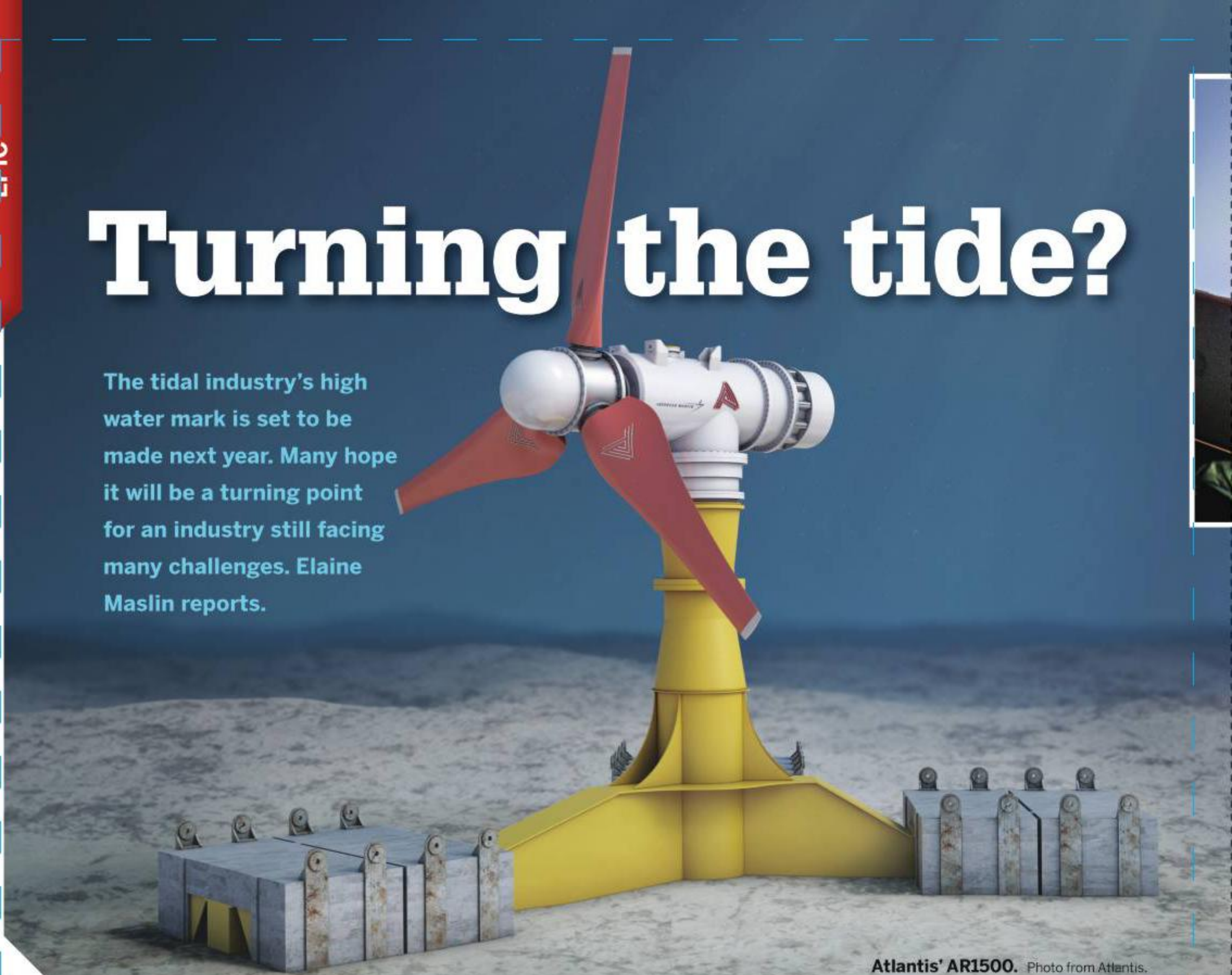
Estimates from the company suggested that savings for a typical sixth generation rig could be 30-40 days per year, which could repay the cost of the $10-15 million equipment in a year, according to a research note from Nordea, earlier this year. "We think this is a company that will continue to gain attention as we progress and expect an increasing number of contractors to consider their technology," Nordea said.

Raunholt agrees, saying that while today's market is bad, a market for robotics still remains. Statoil, Shell and ConocoPhillips have been supporting RDS for a number of years, and now Eni and Total are also involved. The firm has also had grants from the Norwegian government. "There is also no other company within the electric drilling robot niche," he adds.

The first offshore deployment on the *Deepsea Atlantic* will occur in Q2 2017. The drill floor robot will join existing machinery on the rig and will be positioned between the main and auxiliary drill centers, serving each.

In December, a pipe handler is due to be delivered to Nabors Industries, who will use it onshore, outside Europe. This unit has horizontal to vertical handling capability so it can pick up pipe from a horizontal position and serve it to the drill string, reducing manual tasks and increasing operational time.

Future developments could see further integration with drilling control systems. **OE**



Turning the tide?

The tidal industry's high water mark is set to be made next year. Many hope it will be a turning point for an industry still facing many challenges. Elaine Maslin reports.

Atlantis' AR1500. Photo from Atlantis.

By the time you read this, the first turbines in what will form the world's largest tidal energy array will have been installed. It's no small achievement and a lot is riding on its success – not least investor interest.

The marine energy industry – wave and tidal – has had its challenges in the past year to 18 months, from key wave energy players going bust to current uncertainty in terms of government support and access to the grid.

But, it's also had its successes, notably in the tidal sector. Alongside the first, three-turbine phase of the MeyGen tidal energy project being built out, Edinburgh-based Nova Innovation launched the first tidal array to supply electricity to the power distribution network, and Orkney-based Scotrenewables, a floating turbine device developer, has just installed its SR2000 ready for testing at the European Marine Energy Centre (EMEC) in Orkney.

MeyGen's owner, Atlantis Resources, is near financial close on phase 1b of the MeyGen project, with phase 1c expected soon after. The full project will see up to 86 turbines installed. As Atlantis Resources gears up to execute that work, as well as another project at the Sound of Islay, it expects to see costs drop as it industrializes processes, and as investor confidence increases. But, turbine manufacturing capacity is a challenge.

Richard Parkinson, of James Fisher Marine Services. Photo from Tim Winterburn / HIE

This will see an unprecedented 6-12 months of growth for the firm, according to Atlantis Resources CEO Tim Cornelius. The next phases of the MeyGen project will be a "great opportunity to build supply chain. From new boats to kit to unprecedented supply for turbines," he told Scottish Renewables' Marine Conference, Exhibition & Dinner in Inverness in mid-September.

While previous years have been described as being the most significant in the industry, next year may very well be that year – at least Cornelius thinks so and he appears to be

David Collier, project lead engineer on MeyGen. Photo from Tim Winterburn / HIE

in the driver's seat.

Great expectations

There are big expectations around marine energy in Scotland. Lorne Crerar, chairman of Highlands and Islands Enterprise (HIE), a public development agency, says 1700 people are employed in the sector across the UK, and that number is expected to rise by 20,000 in the next decade.

EMEC, which has been a key testing site for many emerging wave and tidal technologies will see its 26th and 27th devices installed this year and it is looking to expand and add hydrogen production facilities to help capture more of the energy it could produce.

While two wave energy firms (Aquamarine Power and Pelamis, both based in Edinburgh) failed in the recent past, Wave Energy Scotland, a publicly funded organization, was created to continue wave energy development. It has now been running over 18 months and recently closed a third stage competitive tender for developers. Some £2.25 million (US$2.75 million) for eight separate projects was allocated. In addition, four companies have been selected for a second stage of power take off systems development with £6.25 million ($7.64 million) funding awarded.

Nascent nacelles

But, many point to the industry's still nascent stage of development, compared to that of wind, which had an incremental growth curve.

Ronnie Quinn, general manager of the Scotland portfolio at The Crown Estate, which is currently being devolved to the Scottish parliament, says early targets for marine energy were missed.

"There had been an aim for 100MW by 2020," he told the Marine Conference. "If that had been on target, the first (arrays) should have been developed in 2014. The pace of development in Pentland or Orkney has not been in line with expectations and on the way we have seen the loss of flagship companies [Pelamis and Aquamarine Power]."

Offshore wind is a good example of how marine energy can evolve – and the time scale it could take, Quinn says. At the end of 2002, the two-turbine Blyth turbine was completed offshore northeast England supplying 4MW, he says. Then, in 2004, Robin Rigg, Scotland's first offshore wind farm, was built, achieving 90MW capacity. Now the Beatrice wind farm is being developed, with offshore construction starting next year. The 588MW farm, also off Scotland, is due be operational in 2019.

Cornelius says the only reason the MeyGen project has survived is thanks to support from the supply chain – "people working together." As has been happening in offshore wind, contractors are becoming investors in projects. Global Energy Group at Nigg, in the Scottish Highlands and Belgium's DEME Group have invested in MeyGen and also work on it.

Reducing cost

Reducing cost is a big concern for the industry. Cornelius says now is a good time to make the most of reduced rates caused by the low oil price, however.

While turbines could be supplied at half the cost out of Asia, the firm wants to keep production in Europe. But this will be a challenge. "There are currently not enough turbine suppliers for our needs. We are hopefully placing orders for 50 turbines in the next short while. But, we don't have capacity. It is a challenge to produce maybe eight systems a year," Cornelius says.

On Meygen, costs could be saved by refining the technique used to drill the onshore to offshore boreholes for running the power export cables, Cornelius says. Costs will also come down due to the larger project size.

David Collier, project lead engineer on MeyGen, says it's clear some of the costs currently being encountered are a function of this being a pre-commercial project, including building turbines on an individual basis. "Most of the supply chain had never heard about marine energy, it took a long time to warm them up and we were still in a world where they didn't know what we wanted them to do and, in fairness, we weren't sure what we wanted them to do. We were designing and building everything from scratch. There are a lot of learnings we don't have to pay for again."

Indeed, for the contractors, it has been a learning curve. Richard

Ronnie Quinn, general manager of the Scotland portfolio at the Crown Estate. Photo from Tim Winterburn / HIE

Atlantis' CEO Tim Cornelius. Photo from Tim Winterburn / HIE

Antritz's turbines at AtlantisResources' official MeyGen launch event in September. Photo from Atlantis.

Parkinson, of James Fisher Marine Services (JFMS), has spent nine years working in renewables, but had spent 25 years in the subsea and offshore sector before that.

"Tidal is the most challenging," he told the Marine Conference. JFMS has been working on Meygen, alongside about 60% of other marine energy projects on the go. "The big challenge at MeyGen is the sheer aggressiveness of the site, especially in flood tides, and the small windows we have got to operate in," he says. "We are working with DP (dynamic positioning) vessels and pushing them to the limit." Timing is crucial in these environments, he says.

Unsurprisingly, similar conditions have been experienced at other sites. JFMS worked on the Sabella tidal turbine project, in the Fromveur Strait, offshore France, this summer. While not as bad as Meygen, it was an aggressive site. Previous installation work had resulted in damaged cables, Parkinson says. JFMS was brought in to take the devices out, reinstall cables and then reinstall devices. Cables were also damaged on Tidal Energy Ltd.'s project offshore Wales.

"A lot of developers overlooked challenges in installation, and a lot are not here anymore, and I think that's why," he says.

"Going forward, we are very aware that conventional techniques won't work. We need to think of this as a new industry."

Parkinson points to offshore wind and how specialist vessels have been developed. James Fisher Group bought Mojo Maritime, including its *Hi Flo 4*, twin-hull DP offshore construction vessel, last year. JFMS is also developing a high performance remotely operated vehicle (ROV) to work in 5 knots with IKM. "It means we can work through a spring tide," Parkinson says. "At the moment, if the ROV goes down for five minutes, the pilot will freak out. Cable stability, wet mate connectors, subsea drills for piling are also being worked on," he says.

Plodding policy

But, it's not all about the technology or how it's installed and maintained. Jenny Hogan, director of policy, Scottish Renewables, says projects are in jeopardy without a viable route to a viable market.

"Projects going in the water over coming months urgently need clarity on support," she told the conference, including a minimum price for contracts for difference, a funding mechanism to bridge the cost of producing energy using renewable energy, compared to the market price.

Access to the grid (into which developers would supply their electricity) is also a challenge, Quinn says. It was designed for power to be generated close to large population centers, not off remote Scottish islands. The National Grid, which controls power distribution, isn't likely to invest speculatively or quickly, he says, creating a chicken and egg situation.

A move to make project consenting easier, by streamlining the process, has also been held up by a recent court decision, Quinn says.

And, then there's Brexit. Marine energy firms, including Atlantis have had significant support from the European Union (EU). While he disagrees with Britain's departure from the EU, Cornelius says that it's had a positive impact in so far as it has made everyone very focused about funding. The downside has been a weaker pound, limiting buying power. There's also general uncertainty. "There's a lot of water to travel under this bridge," he says.

Andrew Scott, CEO Scotrenewables.
Photo from Tim Winterburn / HIE

Diversifying

Perhaps because of its challenges, in finding routes to market, companies are working with other users of the sea. Albatern, a wave energy developer, for example, is working with a fish farm of the island of Muck, providing power, and EMEC is working to convert the excess power it can't export into hydrogen to power vehicles and potentially even ferries. At MeyGen, the grid connection will incorporate an onshore wind farm, which will help smooth out the power supply from the, while predictable and regular, changing tidal energy output.

Investor confidence

Meanwhile MeyGen's progress is anticipated to help improve the investment market, showing that there's a viable product in which to invest. "We are at the cusp of transition from research and development to commercialization," Cornelius says. While that commercialization "means getting boring," it also means bringing low price debt into the market.

"[That's more of an] amazing achievement compared to anything technical we have done," Cornelius says. "The predictable nature of our generation is just what pension funds want to see." This will help make phase 1c completely self-funded, he adds.

A happy ending

"The potential is still there, it hasn't gone away," Quinn says. "The resources are there and the skills are there, but we need to heed the challenges." OE

Developing US offshore wind

Installation at the Block Island Wind Farm offshore Rhode Island.
Photo from Deepwater Wind.

By Darryl François, BOEM

Offshore wind turbines have been successfully deployed in several European nations since 1991. Over the past five years, the US offshore wind industry has achieved major milestones. The US Bureau of Ocean Energy Management (BOEM) has awarded 11 commercial leases for offshore wind development covering more than a million acres that could support a total capacity of 14.6GW.

According to an analysis conducted by the National Renewable Energy Laboratory (NREL), the US offshore wind resource is robust, abundant, and regionally diverse, allowing for offshore wind development that can be located near congested load centers with some of the highest electricity rates.

However, realizing the potential of US offshore wind energy will require addressing key challenges including: reducing the costs and technical risks associated with domestic offshore wind development, supporting stewardship of US waters by providing regulatory certainty and understanding and mitigating environmental risks of offshore wind development, and increasing understanding of the benefits and costs of offshore wind energy.

National offshore wind strategy

To facilitate the responsible development of US offshore wind energy, the US Department of Energy (DOE), through its Wind Power Program, and the US Department of the Interior (DOI), through BOEM, jointly drafted an updated offshore wind national strategy.

This strategy identifies the gaps that need to be addressed in order to facilitate the deployment of offshore wind and provides a set of actions that DOE and DOI will undertake to address these gaps and help the nation realize the benefits of offshore wind development.

US offshore regulations – Transparency and certainty

BOEM has made great strides in granting access to the Outer Continental Shelf (OCS) for renewable energy development and is committed to incorporating the lessons learned to identify and improve the program where appropriate.

BOEM has received suggestions for specific changes to its regulatory process that could make developing offshore wind more efficient. The recommendations include:

- Reducing the burden of regulatory requirements for meteorological buoys by, under certain conditions, BOEM reconsidering its requirements associated with buoy deployment.
- Changing decommissioning financial assurance requirements by potentially providing for flexibility to offer decommissioning financial assurance later in the operations term, which could help ensure that decommissioning requirements are met in a manner that does not disadvantage offshore wind developers relative to other forms of new power generation.
- Ensuring effective and timely plan reviews by ensuring that the process is more transparent, predictable, and expeditious to reduce scheduling uncertainty and financial risk.
- Enhancing coordination around lease area identification by making adjustments to BOEM's typical Task Force establishment process in order to ensure that planning and leasing efforts are better informed.

Feedback from developers also suggests that it is not practical to submit a construction and operations plan that includes all project specifics, and that

US wave and tidal projects

The US Department of Energy (DOE) selected 10 organizations in late August 2016 to receive more than US$20 million in funding for new research, development, and demonstration projects that advance and monitor marine and hydrokinetic (MHK) energy systems. Three demonstration projects will integrate next-generation MHK hardware and software technologies into system designs. Their effectiveness will be tested during full-scale, open-water deployments over one year:

- **Dresser-Rand was selected to integrate a 1MW air-turbine power system into the OceanEnergy oscillating water column wave energy device, doubling the power output of the previous design. DOE says the device's performance will be demonstrated and validated during a year-long deployment offshore Oregon.**
- **Maine-headquartered Ocean Renewable Power Co. will enhance the performance of its tidal turbine system by integrating several advanced component technologies. The device's novel floating design will move the turbine near the surface to capture higher flow velocities and will help reduce the cost of installation and on-water operations, ultimately lowering the cost of energy. The device will be deployed in the Western Passage off the coast of Maine.**
- **Seattle-based Oscilla Power will integrate cost-reducing technology advancements into its Triton wave energy converter. Oscilla's unique device design features tethered connections between a surface float and an underwater heave plate. The device will be tested at the US Navy's Wave Energy Test Site in Hawaii. — *OE Staff***

a degree of flexibility would allow developers to make certain project-design decisions—such as which turbine to use—at a more commercially advantageous time later in the project-development process. This could potentially be accomplished by implementing the "design envelope" environmental review approach that is employed in certain European nations. With this approach, the environmental review is conducted by resource area, to include the greatest potential impact from a range of design options and parameters.

BOEM will consider these and other recommendations through a transparent, informed process, and make updates to its renewable energy program where appropriate.

Technology changes and US design standards

The global offshore wind industry has experienced an incredible acceleration of technological innovation over the past few years. Offshore wind turbines are increasingly cost-effective and more reliable as a result of being scaled up in size (megawatt power ratings). Furthermore, the industry is exploring new innovative techniques to open more areas for development by aggressively developing floating turbine technology. As a result, it is more vital than ever to establish US design standards that are in line with today's technologies.

While physical site conditions along the US coastline bear some similarities to those in the established European market, there are key differences requiring additional scientific and engineering assessments. Currently, there is a significant lack of data describing meteorological, oceanographic, and geologic conditions at potential project sites, particularly for US-specific conditions.

Recognizing this knowledge gap, BOEM has partnered with the Bureau of Safety and Environmental Enforcement (BSEE) to select and fund appropriate renewable energy research in operational safety and pollution prevention related to offshore renewable energy development through the Technology Assessment Program. And, as part of the National Offshore Wind Strategy, DOI and DOE are partnering to facilitate the development of offshore standards for the US that build on knowledge gained from offshore wind experience around the world.

Offshore wind in the US is gaining momentum and the outlook is promising. We've executed the first right-of-way grant in federal waters for renewable energy transmission in support of the Block Island Wind Farm offshore Rhode Island, which will be operational later this year.

With 11 leases on the OCS now in the hands of developers and another two lease sales anticipated within a year's time, there has never been a more exciting time for offshore wind in the US. BOEM is committed to working with its diverse stakeholders to ensure that the process is as transparent as possible as we continue to lease the OCS for environmentally responsible renewable energy development activities. **OE**

FURTHER **READING**

For more information, please read the 2016 National Offshore Wind Strategy and visit our website at boem.gov.

***Darryl François**, of the US Bureau of Ocean Energy Management, is responsible for managing the regulatory framework that governs the development of renewable energy projects on public lands of the US outer continental shelf. His responsibilities include policy development and management oversight of the review of technical and engineering design aspects of project plans and offshore survey activities and compliance with terms and conditions related to safe project deployment and operations. He received a BS in physics from Bradley University and a MS in geophysics from Pennsylvania State University.*

Going forward in reverse

Elaine Maslin reports on a new breed of service and operations vessels entering the market, which can go ahead and aft just as happily as they entered.

"It can go backwards at 12 knots," is not a claim you hear often about an offshore vessel. And yet, it might be something we soon hear more.

It's the speed achieved during sea trials by Ulstein's latest SX175 design, *Windea La Cour*, an 88m-long service operation vessel (SOV) for offshore wind farms. It's the first Ulstein vessel to sport both the firm's unique X-Bow design, but also an X-Stern.

Its ability to go "backwards" is no mistake. The design makes it suited to working close to offshore wind farm structures, whichever way it is headed and the weather is coming from.

The vessel's genesis comes partly from Ulstein's work for the offshore sector, for which it initially had the idea to have platform supply vessels with an X-Bow and X-Stern. But, it's also been very much influenced by detailed work designing a dedicated SOV for the wind industry and a sign of Ulstein's philosophy that more offshore wind farm work could be done by monohull vessels, including foundation installation.

"We feel that for installation work, especially for the foundations, the most effective tool is a floating platform and this is actually already been proven by Seaway Heavy Lifting, which has successfully installed many turbine foundations and transition pieces from their floating vessels," says Edwin van Leeuwen, product director, Ulstein Design & Solutions. "It makes installation faster as it is less restricted by jacking operations. Then, it can make sense to install the nacelle and turbine blades from a jackup, as it has more precision high up."

In fact, Ulstein's SOV development stems back to work conducted on the

Windlifter design monohull DP (dynamic positioning) installation vessel. At the time, the market wasn't ready for such a concept, but the idea sparked an interest with UK firm SeaEnergy and later on resulted in work in developing a dedicated SOV, which then triggered Siemens, a big player in the wind market.

Ulstein's ideas exceeded Siemens' initial concept requirements. "That was the first time so much effort was put into a dedicated offshore wind SOV design together with a client," says Nick Wessels, marketing and sales manager, Ulstein Design & Solutions. "We had changed their mindset and it opened up the possibilities."

The first of two SX175 units being built, the *Windea La Cour*, was delivered on 23 June 2016. The vessel then sailed out for its first service campaign on 1 September to work on the massive, 150-turbine Gemini offshore wind park, which is being built 85km off the Netherlands, on contract to Siemens. The second vessel, due in 2017, will work on the Sandbank and Dan Tysk wind farms, also for Siemens.

Windea La Cour has accommodations for 60 people in single cabins, with 40 dedicated to technicians, a motion-compensated gangway system and a 10-person daughter craft for transferal to wind turbines.

"The X-Stern also allows us to have the gangway on the starboard instead of the center line and allows better outreach. You can have either the stern or bow heading into the weather. We also found the motion pitch behavior was improved by doing this," van Leeuwen says.

It's not Ulstein's first SOV, however. An X-bow designed vessel, the *Siem Moxie*, was delivered to Siem Offshore Contractors in 2014, with a string of new features, including propulsion and hull system choice, a new type of crane and cable-lay support capability.

But, Ulstein has also been eyeing the offshore wind installation market, as they have a large background in developing offshore heavy lift installation vessels. The firm came up with the already mentioned Windlifter design, a vessel to carry multiple entire turbine top sections – complete with nacelle and blades – for installation in one piece. More recently, Ulstein started working on jackup designs including a heavy lift jackup able to lift 1500-1800-tonne, both jacked up and while afloat.

Ulstein's van Leeuwen says the firm is looking at a completely new design, together with a client, for installing wind turbine foundations, which may or may not be a jackup.

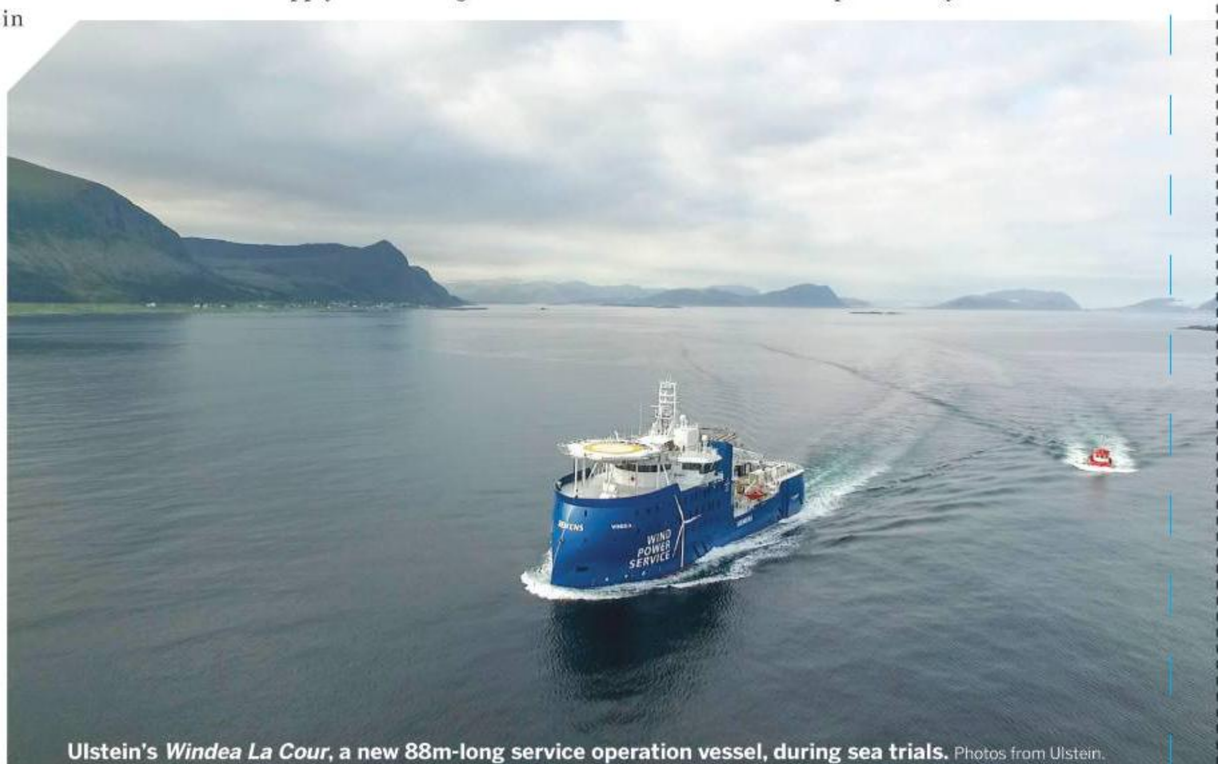
"Given the trend in the industry for even bigger wind turbines, larger installation units will be required or different installation methodologies," van Leeuwen says.

Beside specialized vessel designs, Ulstein is also very active in the design and supply of handling tools via its subsidiary Ulstein Equipment. In 2011-12, they developed the industry's largest pile gripper frames (PGF), used at two different jackups and with one back in use again today on a third jackup. The foldable PGF design from Ulstein allows the installation of monopiles and transition pieces from a jackup vessel to be performed in a single jackup cycle, hence reducing the number of jackup cycles and the risk involved in these operations. Ulstein is of course considering if the system can be used on a DP vessel as well, for which it has to be motion compensated.

To complete the portfolio of offshore wind installation handling tools, Ulstein delivers pile upending tools and recently designed and built a complete new flange lifting tool for transition piece lifting. Being a complete mechanical system, securing and releasing from a transition piece is just a matter of using a simple mechanism. The simpler, the better is the general opinion at Ulstein Equipment.

A new concept is also emerging – Ulstein Colibri, a system that can be added on to existing cranes as a retrofit, to compensate crane motions to keep the load on the hook stationary. "It's not heave compensation, but motion compensation," Wessels says. Instead of compensating the entire crane, this system only compensates the movement of the crane tip, so it only has to deal with the load hanging off it. A prototype is being developed as we speak.

With the offshore wind industry further developing, Ulstein launched a new cable-lay vessel idea, as it thinks there will be a need for cable-lay capacity. They came up with something new for the market – a unit with the biggest capacity for a single length cable in one vessel. But *OE* will have to look at that another day. **OE**



Ulstein's *Windea La Cour*, a new 88m-long service operation vessel, during sea trials. Photos from Ulstein.


The SeaTwirl wind turbine.

National Instruments' Charlotte Nicolaou shows how software systems are helping to create installation tools as well as helping to design offshore wind systems in the renewables sector.

Houlder's pile gripper arms.

Photos from National Instruments.

Soft engineering

A software environment, LabVIEW, created by Austin, Texas-based National Instruments (NI) is helping to ease the challenges faced by companies working in the offshore renewables space.

In the renewables sector, LabVIEW has been used to help control pile driving and to create control systems for new, floating offshore wind turbines.

When building new turbines, monopiles of up to 700-ton in weight, 75m-long and with a diameter of 7m need to be hammered into the seabed to act as the foundations for the turbines. Embedding these monopiles vertically into the seabed can be tricky, due to strong currents and ocean tides pulling the piles at different angles. If done incorrectly, they need to be fully removed and re-driven, which incurs significant costs.

Marine engineering firm Houlder developed a solution to this problem which consists of two, 70-ton hydraulic gripper arms that are used to hold a monopile in place while it is hammered into the seabed. With Houlder's gripper arms mounted on the offshore vessel, any risk of uneven foundations is vastly reduced as they ensure the piles are vertical at all times.

A system of this magnitude requires a highly precise and robust control system. Houlder's developers wrote the gripper arm software entirely in LabVIEW. This software sets the position of the gripper arms, translates that to the hydraulic cylinder length required and adjusts the hardware accordingly. It can implement safety limits, such as a minimum closing of the arms to avoid crushing the monopiles. It also monitors extensive analogue and digital I/O, allows for real-time control of the gripper arms using a joystick, has safety features to shut down the system if a fault is detected, and displays important information to the engineers via a user interface. This software is installed on an embedded device with a deterministic operating system allowing for fast and reliable responses from the software.

Houlder, which has used the system since 2013, has added a second, larger set of gripper arms to help with the construction of the Rampion wind farm, off southern England, which is due to be completed in 2018.

While the traditional wind farms Houlder works with require hammering foundations into the seabed, two companies from Sweden, SeaTwirl and software developers WireFlow, teamed up to produce innovative floating wind turbine designs. The SeaTwirl wind turbine is one that is simple to install and can be deployed further from shore, where it is too deep to install standard turbines but where there are much stronger winds.

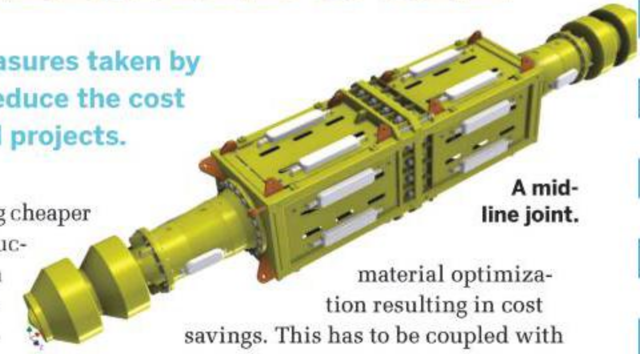
A huge difference in this design is that the entire body of the SeaTwirl turbine rotates to generate electricity, which means it can produce power no matter what direction the wind is blowing. It doesn't need a yaw or pitch control system to get the blades in the correct position. Research shows that vertical axis turbines have a higher structural limit than their horizontal axis counterparts meaning they can be larger and therefore more cost-effective. The SeaTwirl turbines are still in the prototyping stage and their latest device is a 30kW turbine situated off the west coast of Sweden.

Despite being simpler in a lot of respects, this turbine design still needs a powerful control system and for that, SeaTwirl and WireFlow used LabVIEW as it was the fastest to program, high performance option they considered. Their software monitors the turbine and wind speed, controls the rotational speed to keep the power generation at optimal efficiency, logs important data and securely sends information back to the monitoring station, 70km away in Gothenburg. It also contains a number of fail-safes to protect the system in an emergency. As the system is still in development, all data is available for authorized engineers to access remotely. SeaTwirl plans to continue creating larger and more efficient wind turbines, with the help of LabVIEW. OE

Charlotte Nicolaou *works as a marketing engineer looking after NI's software products. In particular, she's interested in data management for big analog data applications. She has a PhD in biophysics from the University of Sheffield.*

Cutting umbilical costs

Ian Probyn outlines measures taken by Technip Umbilicals to reduce the cost of long-length umbilical projects.



A mid-line joint.

Despite the low oil price, a number of long-length tieback projects have been sanctioned over the last few months.

To safely control and supply power and chemicals to the remote trees and manifolds, an umbilical system is installed along the length of the tieback to a host vessel or platform. As the cost of the umbilical system is largely driven by material content, the overall system cost is approximately proportional to length. The trend for greater tieback lengths and the strong cost focus of the industry has brought the umbilical business into the spotlight of cost reductions.

Technip Umbilicals is addressing this challenge through a focused research and development (R&D) program to optimize the materials used within the umbilical structure, developing technologies to ease and save installation cost, and leveraging manufacturing asset capabilities to maximize efficiencies without compromising performance, quality or reliability.

This cannot be achieved by simply reducing requirements or using cheaper materials. Only through a structured engineering study can changes be justified and ensure the product remains reliable and fit for purpose.

Component savings

Hydraulic fluids and chemicals are transported through the umbilical in steel tubes or thermoplastic hoses. Typically, the bore size and pressure of the tube is set by the flow requirements and the umbilical manufacturer must calculate the wall thickness, based upon the requirements of the main umbilical design standard ISO13628 and clients' specifications.

Technip Umbilicals has developed a suite of integrated design software tools that enable designers to rapidly optimize the tube wall thickness, based on material type, project environment, manufacturing and client requirements. However, working with clients to review their internal specifications has enabled conservatisms to be identified and justify material optimization resulting in cost savings. This has to be coupled with the ability to demonstrate the robustness of the product through the whole life cycle including installation and dynamic fatigue. Installability is proven through the use of validated analysis tools that predicts the behavior of the structure and confirms suitability without compromising the long-term reliability.

The latest developments in thermoplastic hose technology have seen temperature, pressure and water depths increase, enabling hoses to be used in more traditional steel tube applications allowing the inherent cost advantage of thermoplastic over steel tube to be exploited. Although the R&D focus has been to push the operating pressures higher beyond the previous ceiling limits, the knowledge gained can also be applied to lower pressure hose designs. Cost savings can be realized through

more efficient material use, allowing savings of up to 20% over previous equivalent designs.

Manufacturing

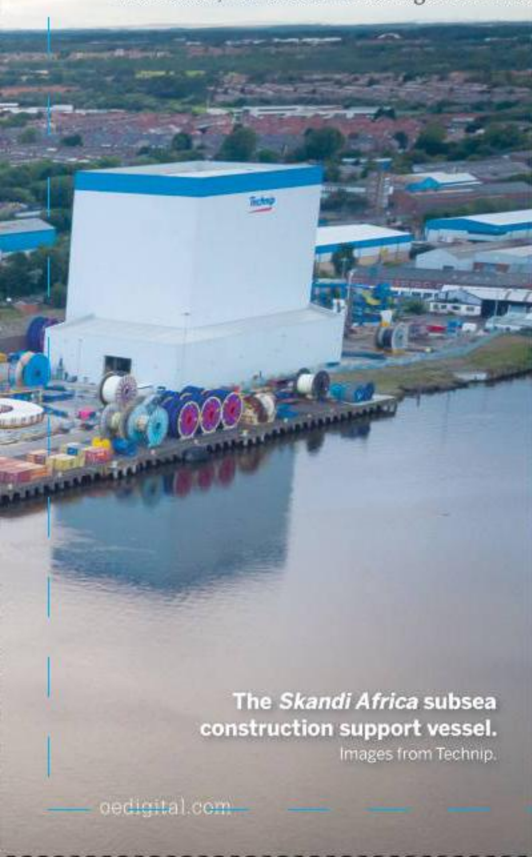
The capability and capacity of the lay-up machine used to bring the functional components together into the umbilical bundle can significantly affect the final cost. Large capacity machines, which can be operated with high proficiency, enable the assembly process to be both high quality and efficient with minimal downtime to reload components, bobbins, and perform tie-in welds and cable splices. Experience in positioning components and smart use of filler materials can deliver the required project performance requirements, while also easing the manufacturing process and reducing assembly time.

A common requirement of long-length tieback umbilicals is to incorporate a large central tube, typically 2-4in bore, known as a LBCT, to carry monoethylene glycol or methanol for flow assurance of the hydrocarbons. The inclusion of a LBCT can add complexity and cost to the umbilical because of the additional bending stiffness and complexity of tube welding required. Current 2D X-ray inspection can be ambiguous, and coupled with very stringent internal pass criteria, previous projects have suffered from high rejection rates, leading to the weld being cut-out and redone.

However, forensic investigation via microscopic material inspection and finite element structural analysis found a high proportion of the welds removed from the tube string would have been acceptable in service. Hence, a revised criterion was developed, which reflected a more realistic acceptance level, and was thoroughly justified via structural and fatigue testing of sample welds made with built-in flaws to prove suitability. The new acceptance criteria would have significantly reduced the unnecessary removal of sound welds and prevented the additional cost and time taken to replace them.

There could also be an impact from developments in the non-destructive testing technology used to assess the integrity of welds during production. A move from 2D radiographic inspection to 3D tomographic inspection developed in a recent R&D collaboration provides the basis for a quantitative inspection regime. The tomographic technology coupled with real-time finite element analysis of the welds has the potential to remove the ambiguity in interpreting conventional 2D images, while providing a clear service based acceptance criteria for any weld.

The Maria development umbilical.



The *Skandi Africa* subsea construction support vessel.

Images from Technip.

Termination

The umbilical termination assembly (UTA) hardware used to terminate the ends of the umbilical and enable connection to subsea equipment can influence the installation process and cost. Based on a standard modular design the hardware can be customized to fit the varying number and type of functional components. External size extremities are governed by the lay equipment to allow the hardware to pass through the installation caterpillars.

A useful adaption of the traditional UTA, which has been successfully deployed on a number of projects, is a midline joint that allows lengths of umbilical to be daisy chained together. Each half of the joint is fitted and tested at the factory and rapidly connected offshore. The midline joint could allow a long-length umbilical to be installed via reels rather than a carousel, opening up a greater choice of installation vessel, potentially offering a lower overall cost. Alternatively, a midline joint can be utilized to join two lengths of extra-long length umbilical together to provide flexibility with available weather windows.

Recent R&D studies have focused on the installability of the umbilical and development of a special tape layer that increases the frictional interface between the steel tube bundle and the outer sheath. While the umbilical is squeezed by the caterpillar tensioner, the tape interacts with the sheath and can effectively double the friction value. The upside is that either a greater installable water depth can be achieved, or a smaller, more cost-effective lay-spread can be utilized. Also, recent investigations into the umbilical behavior in axial compression, often experienced during installation, have allowed previously conservative limits to be raised, widening the allowable sea state at which the product can be installed.

Summary

The outlook remains strong for longer length umbilical projects and the main functional components can be optimized for material use through working with clients to reduce conservatism while remaining fit for purpose.

State-of-the-art lay-up assets enable efficient manufacturing and clever use of termination hardware can provide flexibility during offshore installation. New technologies and learnings have been deployed to ease installation and ensure the umbilical remains a reliable cost-competitive component of the subsea infrastructure. **OE**

***Ian Probyn** is global technology lead for Technip Umbilicals. Probyn graduated with a degree in automotive engineering from Loughborough University and spent his early career crashing numerous cars both physically and virtually using finite element analysis (FEA). Fifteen years ago, he entered the subsea industry, joining the R&D team at DUCO (now Technip Umbilicals). He represents the firm on the technical committee of the UMF (Umbilical Manufacturers' Federation) and is a Technip Group Expert.*

Three's company

The *Lewek Constellation* during reel exchange operations with the *RB1*.
Images from EMAS Chiyoda Subsea.

EMAS Chiyoda Subsea's John Meenaghan discusses challenges and solutions employed at three back-to-back tieback projects the company recently carried out in the US Gulf of Mexico

EMAS Chiyoda Subsea (ECS) completed the Big Bend, Dantzler and Gunflint deepwater subsea tieback developments for Noble Energy in the US Gulf of Mexico (GoM) in April 2016. The key to developing these challenging developments back-to-back was an innovative reel-lay concept featuring a portable reel delivery system, and a one-stop-shop project execution team approach.

The workscope included project management, engineering, procurement, construction and installation of eight pipeline end terminations (PLETs), five in-line tees and stalking, spooling and installing of over 160mi (258km) of 8in and 12in pipe-in-pipe (PIP) flowlines and over 56mi (100km) of umbilicals in water depths reaching 7200ft (2200m).

The offshore construction campaign began in May 2015 when ECS performed record-breaking pipelay trials for the newly launched flagship, *Lewek Constellation*. ECS laid 3.2km of 16in rigid test pipe with 28mm wall thickness and two PLETs in 7368ft (2250m) water depth. The installation required 632-ton of top tension, setting a world record for the highest tension ever experienced for rigid, reeled pipe.

Innovative reel delivery system

The fast track nature of these three developments required an innovative execution plan to bring all three developments online in under a year. Conventional reel-lay operations require reel-lay vessels to transit back and forth to the spool base to replenish the reels with the PIP and steel catenary riser (SCR) stalks. Welding, non-destructive testing and field joint coating of the stalks are critical path activities with known degrees of associated risk.

ECS utilized a portable reel concept allowing the *Lewek Constellation* to stay offshore in the project location while a dedicated barge, *RB1*, shuttled between the spool base and the pipelay location delivering

Reel exchange offshore.

loaded reels in exchange for empty reels. Reel transfers (four empty for four full) have been executed in under 24 hours on location. The result is a more efficient use of the pipelay vessel during the campaign removing reeling from the critical path and minimizing vessel transit time. This effectively decouples the *Lewek Constellation* from the spool base and takes the pipeline fabrication off the critical path by controlling welding and inspection conditions onshore in a controlled environment.

Pipelay campaigns

Between Q2 2015 and Q4 2015, the *Lewek Constellation* conducted more than 38 heavy lifts between 900- and 2250-tonne transferring rigid pipe reels for the Big Bend, Dantzler and Gunflint projects as well as lifting a topside module onto an offshore platform. In total, the *RB1* made 10 trips between the spool base and the vessel.

The Big Bend project is a single tieback with a bidirectional PIP flowline loop and insulated SCR from the Big Bend wells to the Thunder Hawk host platform facility. The pipe diameters included an 8in insulated pipe carried in a 12in outer pipe with the distinction of being the heaviest PIP system ever deployed in the world using the reeling method.

The Dantzler field, co-developed with Big Bend, consists of dual tiebacks with bidirectional PIP flowline loop, including a daisy-chain configuration connecting both Dantzler wells at Mississippi Canyon (MC) 782 and an insulated SCR to the Thunder Hawk host platform facility at a water depth of 6561ft. A bidirectional PIP flowline segment then connects the Big Bend and Dantzler fields forming a pigging loop through both systems in either direction. This co-development of flowlines is known as the Rio Grande Loop, and includes the Big Bend and Dantzler flowlines, SCRs, and hull piping up to the boarding valve.

The Gunflint field, in MC 948, consists of dual bidirectional insulated PIP flowlines and two wet-insulated SCRs along with umbilicals and subsea systems between the Gulfstar 1 spar in MC 724 and the two production wells.

Challenges

Early in the project, ECS received new soil data for the Dantzler field and it turned out to be softer than initial

The PLET handling system.

assumptions taken from the Big Bend project. This led to a determination that both Big Bend and Dantzler PLET mudmats would require wings to provide more stability to the PLETs and subsea structures on the seabed. While the *Lewek Constellation* could easily handle the weight and size of Gunflint's PLETs and in-line sled, when the wing structures were added for Big Bend and Danzler, the PLETS became among the heaviest ever installed in the world. This required ECS to replace the existing 60-ton PLET handling device (PHD) with a 100-ton PHD for deployment of the heavier PLETs. Fortunately, the *Lewek Constellation* has one of the largest moonpools in the industry. The wings extended from the structures once they were lowered to the seabed through the 8m x 19m moonpool. Also equipped with a 3000-tonne Huisman crane and dual 600-tonne A&R system with a tri-plate that enables abandonment and recovery up to 1100-tonne, the vessel is able to lower very heavy structures or pipe product to the seabed in excess of 13,000ft (4000m) of water.

Throughout the pipelay campaign, ECS also encountered extremely challenging 3-4 knot loop currents. The *Lewek Constellation* was able to hold her position in currents greater than 3 knots, plus heavy seas and strong winds while installing SCRs at Big Bend. Equipped with nine thrusters and powered with eight main and auxiliary generators controlled by a Kongsberg Maritime dynamic positioning (DP3) system, the effects of weather were minimized by the ability of the vessel to adjust during installation sequences and continue working in very high current conditions.

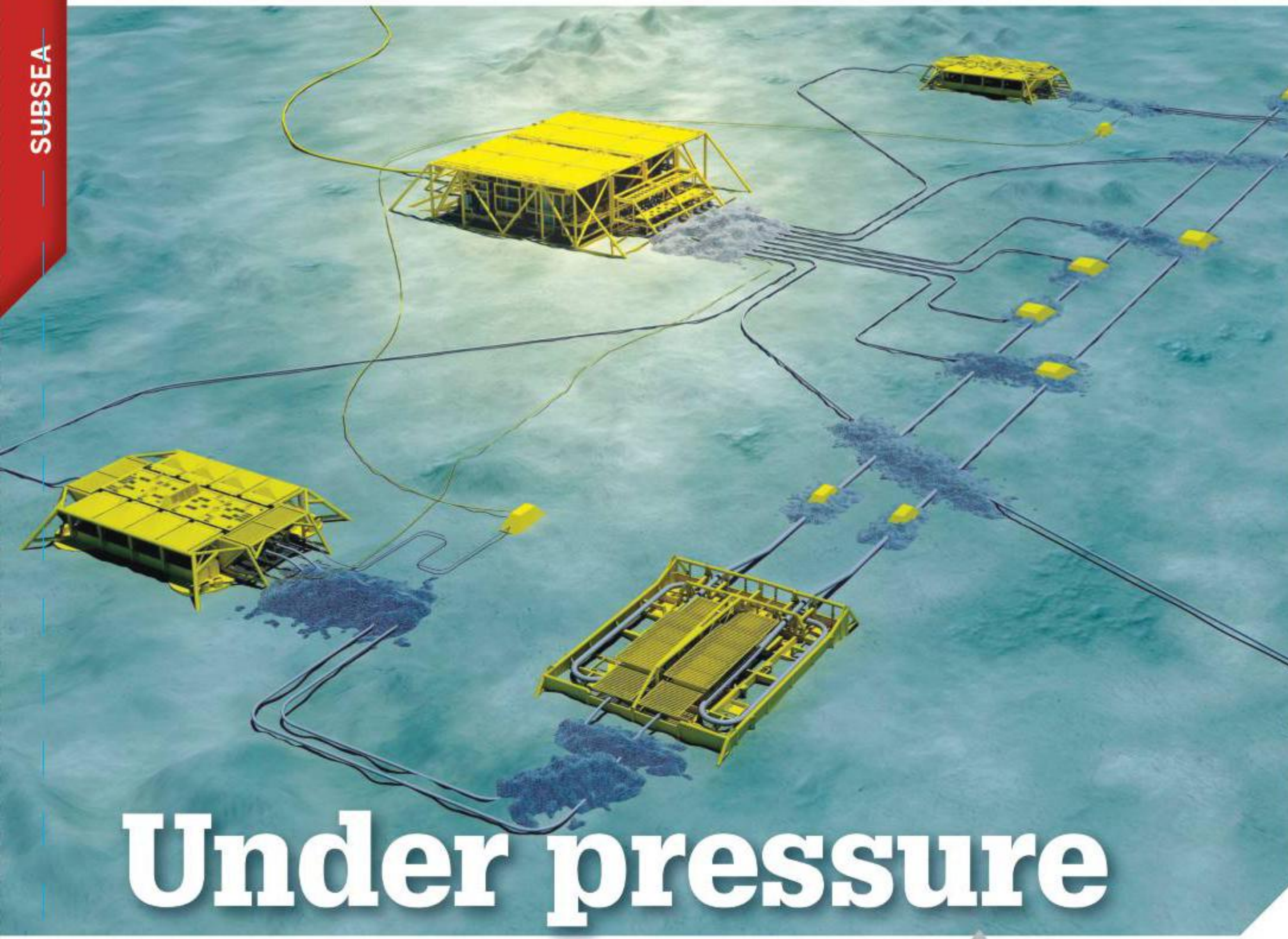
Technology and assets

Every ECS asset and facility available in the US GoM region was used over the course of the project. Subsea structure fabrication and linepipe production took place at EMAS Marine Base (EMB); offshore survey and light construction operations were carried out with *Lewek Falcon* and *Ambassador*, umbilical installation with *Lewek Connector*, rigid pipeline installation with *Lewek Constellation* supported by *RB1*, and the installation of subsea structures, flying leads and rigid jumpers with *Lewek Express*.

The one-stop-shop approach applied to these three back-to-back tiebacks in combination with the innovative reel delivery system and unique vessel design were all key elements in the successful execution of the campaign.

Noble Energy brought the Big Bend and Dantzler fields online in October 2015, with Gunflint starting production in July 2016, all three within budget and ahead of schedule. **OE**

***John Meenaghan** joined EMAS Chiyoda Subsea in 2011 as vice president Global Operations. He has over 40 years' experience in construction and installation, and is an industry pioneer in reel-lay. He is responsible for all offshore and onshore construction activities, including operational oversight and management of senior level offshore construction managers, supervisors and work forces. He was directly responsible for leading the transitional efforts from build to operations for the Lewek Constellation, the Reel Barge 1 and the two spool bases (Ingleside, Texas, and Gulen, Norway). Prior to joining the company, Meenaghan also served Santa Fe, Technip, Brown and Root, and Subsea 7 respectively over a period of 35 years.*



Under pressure

Subsea compression at Ormen Lange. How it could have looked. Image from Statoil.

Last year was a breakthrough year for subsea compression. Elaine Maslin surveys the projects that came online and discovers what became of Ormen Lange.

After some 30 years in development, subsea compression is finally proving its worth offshore Norway, at least in part.

Late September, Statoil, which installed the world's first subsea gas compression system on the Åsgard field, said the system had been "running like a Swiss clock with practically no stops or interruptions," with close to 100% system regularity, since it came onstream a year earlier.

It has already helped increase production by some 16 MMboe and is expected to boost recovery from the Mikkel and Midgard reservoirs by as much as 306 MMboe, corresponding to a medium-sized field on the Norwegian Continental Shelf (NCS) and extending the fields' life to 2032. The recovery rate from the Midgard and Mikkel reservoirs on Åsgard has been raised from 67% to 87% and from 59% to 84%, respectively.

Meanwhile, the Gullfaks wet gas compression project, which came online after the Åsgard project, on Statoil's Gullfaks field, also offshore Norway, has had a slower start, having been taken offline after a subsea cable leak was discovered in December. Both compressors installed on the project were removed (*OE*: October 2016). Statoil has said, following evaluation of the umbilical involved, it would be looking to reinstall the system by mid-2017.

A third project had also been a contender to be one of the first subsea compression projects – Ormen Lange, a 120km step out offshore Norway. However, while its operator, Shell, halted the project in 2014, citing costs and reservoir data, it continued work on a pilot project to demonstrate the feasibility of subsea compression.

OE revealed in August that the subsea power distribution system on this project had been qualified and, late August during ONS, GE Oil & Gas said that the whole system had been qualified, at Shell's test facility at Nyhamna, Norway. GE described it as the world's first subsea gas compression system with a full subsea power supply, transmission and distribution system, using GE's Blue-CTM compressor (a centrifugal compressor designed for subsea).

Ormen Lange was discovered in 1997 and has been producing since 2007, in 600-1100m water depth in the southern part of the Norwegian Sea, about 130km northwest of Kristiansund.

Clare McIntyre, Ormen Lange business opportunity manager, says that Shell is still looking at the options for the development. "[In 2014,] we took a step back. The cost was too high and it was not going to be economic," she says. "We have time and will take time. We want to find an economic solution that gives the best solution and we are still very much in a period of looking widely at different technologies." McIntyre says that despite stopping the project in 2014, Shell continued the pilot project. "The technology from the pilot is one of the concepts we could consider for the future," she says. "It is in the running, along with a number of other concepts." But, to be a contender, costs will have to come down, which could potentially be helped by Statoil's experience on Åsgard.

An aerial view of the Nyhamna facility. Photo from Shell.

While other concepts will be looked at for Ormen Lange, Shell said that it was installing two new compressors at Nyhamna to raise the output capacity at the field and McIntyre says that even a floating facility could be considered. McIntyre says that Shell also sees the value of subsea compression technology.

"We see the benefit for other fields in the future, along with subsea separation, or a Gullfaks-type of wet gas compression solution, for example," she says.

Late September, Shell said that the two new compressors at Nyhamna would increase output capacity to 70 MMcm/d, from the current ca.50 MMcm/d. Separately, Shell said it's also planning to increase capacity at the gas processing plant to 84 MMcm/d, from 70 MMcm/d, to accommodate the future output from Statoil's Aasta Hansteen development, which is expected to start production in Q4 2018.

McIntyre says a lot of the work has focused on debottlenecking Nyhamna. "We believe there is a lot more we can get out using the existing facilities," she said during ONS.

Meanwhile, in case it has a failure on Åsgard, Statoil has a complete 12 module spare train sitting on a quayside in Norway, plus process intervention equipment at the ready.

Torstein Vintersto, vice president, project management, Statoil, told ONS that the project has given the operator a new tool in its kit, complete with intervention systems, and lessons learned during the first phase of operations. Through an online system developed by Statoil, the firm is able to go in to the highly instrumented system at any time, online, to see what is happening.

"We see significant cost reduction potential through simplification, standardization and industrialization," he told ONS. That should be music to Shell's ears. **OE**

A heavy burden

More and more heavy oil is coming into production pipelines. Measuring it, in a multiphase flow, is a challenge, says NEL's David Millington.

Heavy Oil. Photos from NEL.

Cost-efficient heavy oil production is an important feature within the oil and gas industry's near- and long-term objectives.

Over two-thirds of remaining global oil reserves are estimated to be heavy oil, where the more financially attractive, conventional reserves have been progressively depleted. Extraction and processing of high viscosity oils generally comes at the price of a much greater production cost, where refining of additional by-products also becomes a factor.

Onshore regions comprising extra heavy resources, e.g. Canada and Venezuela, often resort to enhanced recovery techniques, such as steam-assisted gravity drainage (SAGD), to boost production rates and therefore maximize recovery factors.

Thermal recovery methods are less common offshore due to financial restraints. However, artificial lifting solutions, such as electric submersible pumps (ESPs), are readily coupled with viscosity-reducing diluent to economically increase hydrocarbon production offshore.

Multiphase flow

The multiphase flow meter is another technology that could support the production of heavy oil fields. Multiphase flow meters have been in use for over 20 years on new and existing oilfield installations.

They can be employed onshore, topside and subsea (often directly at the wellhead) to deliver a full three-phase measurement of the components within the production stream (gas/oil/water) and their respective flow rates.

Multiphase meters offer a number of advantages: real-time production monitoring; improved well testing capacity; and they can also act as a full replacement to the conventional test separator setup, reducing capex and opex costs. However, very few multiphase flow meters have been designed specifically for use with high viscosity oil.

Using the traditional test separator setup for heavy oil is often regarded as an impractical approach. This typically results in long oil-water residence times and contamination issues in the separator outlet streams. Multiphase flow meters not only eliminate these limitations, but also act as a monitoring tool to allow optimization of critical enhanced recovery techniques – an advantage that can directly benefit the productivity of the oil field.

The definition of heavy oil may vary depending on the source, but it generally ranges from API gravity 10 to 22 – any less than 10 and the oil is considered "extra heavy," where challenging low reservoir pressures are common and thermal recovery (e.g. SAGD) and artificial lifting techniques would be considered essential.

Flow metering is commonly used to dictate custody and fiscal asset allocation alongside providing well monitoring data. Heavy oil measurement is more complicated. First, the effect of fluid viscosity on flow meter performance, either single phase or multiphase, is widely unknown. Second, heavier oils are often forced out of the reservoir using water flooding techniques. This tends to increase the likelihood of oil-water emulsification which presents new measurement challenges in itself.


David Millington.

Effective measurement

Over the past 10 years, the effects of heavy oil on flow metering technologies have been the focus of several research projects at NEL's flow measurement facility. This research has revealed that high fluid viscosity introduces significant measurement uncertainties, when no correction factor from a baseline low viscosity calibration is applied.

Dynamic qualification is used to identify the optimum performance of the device in controlled conditions and assess the various measurement processes within the device. This includes analysis of the direct measurement, typically performed using dual-energy gamma-ray densitometry to determine component fractions and a Venturi section to approximate the bulk velocity of the flow.

This is preceded by a mathematical model, calculating the difference in velocity between each phase. It is likely the gas phase will be travelling faster than the liquid phase; this phenomenon is known as phase slip. For a heavy oil, the phase slip is generally less than a light oil, where the viscous effects of the liquid begin to overcome the buoyancy effects of the gas. Therefore, the mathematical slip model used within a multiphase flow meter should vary with respect to changes in liquid viscosity.

Testing

NEL recently conducted an experimental program investigating flows of high viscosity multiphase mixtures. The nature of the developed flow patterns and performance of a simulated multiphase flow meter was assessed. The testing was performed in NEL's multiphase flow facility using high viscosity oil (1500cP).

The pipeline equipment included a vertical perspex Venturi tube and additional straight length perspex pipe spools to allow for flow visualization. A high-speed tomography system was installed upstream of the perspex Venturi tube to enable cross-sectional imaging of the flow pattern.

This test, alongside previous heavy oil multiphase trials, has proven substantial fluid viscosity effects, where the conditions prevent gas coalescence, as well as eradicating high frequency slugging and other flow dynamics that would typically be encountered in lower viscosity conditions. Consequently, the variation in flow pattern at the meter inlet, Reynolds number effects, and phase slip influence the performance and uncertainty characteristics of the simulated meter. Further high viscosity trials with a commercial multiphase flow meter have also been conducted. These trials have provided valuable data enabling the manufacturer to establish critical correction data to adapt the multiphase meter to heavy oil multiphase flows.

Future direction

In order to move forward and progress the functionality of multiphase flow meters for use in high viscosity flows, we should expect to see more qualification testing in heavier oils.

As found by NEL's research, the flow dynamics will change for lighter and heavier oils, adversely impacting the device measurement uncertainty if unaccounted for. Further guidance on qualification testing requirements should be proposed to ensure the multiphase flow meter will be tested in suitable conditions that better reflect its baseline performance. OE

Shear compliance


Photo from iStock.

Enovate Systems' Michael O'Sullivan and Stuart Ellison examine the US Bureau of Safety and Environmental Enforcement's new well control rule and its implications for BOP casing shear rams.

In April 2016, in response to recommendations of post-Macondo investigations [1], [2], [3], [4] regarding safety and reliability during offshore drilling operations, the US Bureau of Safety and Environment Enforcement (BSEE) published its much anticipated well control rule. The rule imposes additional requirements on operators and drilling contractors in the following areas: documentary requirements; drilling operations; blowout preventer (BOP) design and system requirements; inspection, maintenance, repair and testing of BOPs.

It is generally accepted that compliance with the new requirements present technical and operational challenges for the industry. More onerous requirements are imposed in the early planning stages of operations, in particular around the level of information and verification demanded by the regulator. What has increased is the burden of proof that the drilling equipment is fit for purpose to satisfy the requirements of the well design.

The general requirements for BOP systems are broadly in line with API Standard 53 [5], which is regarded as a robust standard for the design and operation of well control equipment and is recognized as such by BSEE through incorporation into the rule by reference.

Where BSEE has gone further is to demand third-party verification and regulatory approval of evidence that these requirements are satisfied. There is little or no scope for risk assessed deviations or "alternate compliance."

Implications on shearing ability

Most requirements of the rule became effective 90 days after publication. Recognizing the inability of current technology to comply with all requirements immediately, BSEE has given the industry two years to enhance shearing capability; three years to implement real-time monitoring during drilling operations; five years to deliver enhanced subsea accumulation; and seven years to introduce technology capable of centralizing pipe prior to shearing.

Enovate has carried out a detailed assessment of the implications of the rule on the shearing capability of existing casing shear ram (CSR) technology, specifically the requirement in clause §250.732(b) for the submission to a BSEE-approved verification organization (BAVO), prior to beginning any operations requiring the use of a BOP, of shearing and sealing pressure calculations for all pipe to be used in the well including corrections for maximum anticipated surface pressure (MASP).

This requirement is new. Previously, not all pipe had to be explicitly shearable and the MASP did not need to be considered when calculating shearing pressures and associated subsea accumulation volumes. BSEE is now demanding verified evidence of shearing pressures, and associated accumulation requirements, for all drill pipe bodies, tubing bodies and casing bodies.

Because of the geology of the Gulf of Mexico, wells tend to have deep total vertical depths and high bottomhole pressures (over-pressurized wells). This requires relatively heavy well architecture with 14in and 16in intermediate casing being widely used for such wells in the deepwater Gulf of Mexico.

The requirements in §250.732(b) effectively changes the design basis for CSRs, potentially making many of them

no longer fit-for-purpose for wells that are completed with heavier intermediate casing sizes. To illustrate this point Enovate has calculated the shear pressures, and associated accumulation, required to shear Q125, 14.0in x 0.82in WT casing using two common CSR configurations, i.e., 22in and 28in operators with 5000psi hydraulic control systems.

Case study

The shear pressures are determined considering two wellbore conditions, i.e., 0psi and 15,000psi wellbore pressure. In addition, for these wellbore pressures the hydraulic accumulation required at 0ft, 4000ft and 12,000ft water depth is also determined. The results are presented in the table below.

The 22in ram operator cannot cut the 14in casing under any wellbore condition as the shear pressure exceeds the available 5000psi control system pressure. The 28in operator can cut the 14in casing with 0psig and 15,000psig wellbore pressure. With 15,000psig wellbore pressure 4221psi control pressure is required. The need to supply such a relatively high pressure leaves the accumulator system with a low usable volume (typically in the range 2-5%, depending on water depth). As the table shows, although the 28in ram operator can shear 14in casing the accumulation volume required to do so becomes impractical in deepwater. To shear the 14in casing at 12,000ft water depth and with 15,000psi in the wellbore will require ca. 100, 40gal accumulator bottles.

For existing CSR technology, the calculations required by the rule will show that they will not be able to practically demonstrate the ability to shear all tubulars used to drill or complete a well that requires the use of large intermediate casing.

CSR Shear Pressure & Hydraulic Accumulation Requirements

Wellbore pressure (psig)	Water depth	22in ram operator		28in ram operator	
		Shear pressure (psi)	Accumulation (gal)	Shear pressure (psi)	Accumulation (gal)
0	0	6134	Not applicable (shear pressure required exceeds control system pressure)	3789	742
	4000				1207
	12,000				1232
15,000	0	6834		4221	1979
	4000				2438
	12,000				3864

Source: Enovate Systems.

Making existing CSR technology compliant

In light of the above, what options are available to make current CSR technology rule-compliant? At the moment potential solutions are limited to:

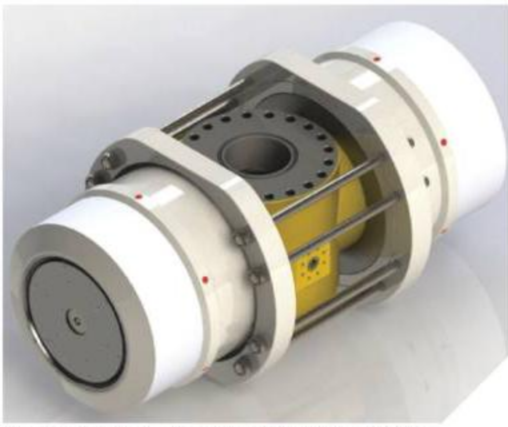
- **Introduce 10,000psi control systems** – The implications of such a change are two-fold. First, the increased pressures will require design changes to meet the increased structural loads, resulting in heavier shear rams. Second, the use of higher control system pressures means a further reduction in the available accumulation volume at depth, increasing the number of accumulator bottles required, which will in turn result in adverse impact on BOP size and weight.
- **Increase operator size** – In order to ensure that the required shear forces can be delivered using 5000psi control systems and practical accumulator volumes, it is necessary to have the ability to shear using relatively low control pressures, i.e., less than 2500psi. For current CSR technology, this means using a ram with an operator in excess of 40in. This could lead to a doubling in shear ram size and a quadrupling in weight.
- **Well design** – Another possible solution is to design wells within the BAVO verified constraints of current well control equipment. This means that wells must be designed without relying on the heavier 14in and 16in casing sizes. This approach severely limits the number of casing points that could be set in the well and with BSEE also tightening the drilling margin (a tighter drilling margin requires more casing points, not less), getting creative with well design doesn't appear workable.

The impracticality of these options mean that existing drilling equipment will be rendered obsolete in much of the Gulf of Mexico and effectively usher in a partial drilling moratorium for any well designs that require the larger intermediate casing sizes.

As more companies prepare applications for permits to drill under the new regime, it will become obvious that the operational theater has narrowed dramatically and in order to develop the oil and gas resources of the Gulf of Mexico a new approach to well control equipment is required. The industry needs something that can shear and seal the heaviest intermediate casing bodies at the highest wellbore pressures, using existing 5000psi control system and that fit within the footprint of existing BOP stacks. Fortunately, a range of technology capable of meeting these requirements is being actively developed.

Next generation rule-compliant technology

To comply with the rule's requirements, and remain within the size and weight footprint of existing shear rams, will require a step change in casing shear technology with the ability to shear large (> 13.375in), high strength (125,000psi) casing; ability to shear the largest tubulars used in well control at relatively low control pressures, i.e., less than 2500psi; ability to seal against a flowing well; capable of inherent self-centralizing of the tubular during cutting.



A schematic representation of the 18.75in En-Tegrity preventer. Photo from Enovate Systems.

Enovate has developed and qualified a shear and seal technology that meets these criteria, called En-Tegrity, which is fundamentally different to conventional ram technology because it comprises a dual gate valve with a reverse actuation method, meaning that the gates are pulled across the bore rather than pushed into it. This results in improved shearing capability and wellbore assisted closure; for the En-Tegrity, wellbore pressure increases the available shear force, unlike traditional ram technology. The En-Tegrity provides bidirectional metal-to-metal sealing. This feature facilitates improved sealing in a flowing well scenario as there are no elastomers in the bore that can be washed out.

An 18.75in preventer based on the qualified En-Tegrity technology is under development and will be market-ready in 2019. The 18.75in En-Tegrity preventer will shear Q125, 14.0in x 0.82in WT casing at shear pressures of 2000psi (0psi wellbore pressure) and 1300psi (15,000psi wellbore pressure). The ability to shear at these relatively low pressures means that the hydraulic accumulation required by En-Tegrity is ca. 50% lower at 12,000ft water depth than for a 28in operator.

In addition, a number of companies are actively developing electric actuators that are capable of delivering up to 4 million lbf. To put this figure in context, ca. 2.3 million lbf is required to shear Q125, 14.0in x 0.82in WT casing. Electric actuation is an attractive proposition because the power required to deliver this force is independent of water depth and can be delivered from the topside. In theory the size and weight that is contributed by accumulation systems can be removed completely from the BOP stack. In practice it will be necessary to have the ability to store sufficient energy subsea to deliver the required shear force in the event of loss of topside electric power. Nevertheless with electric storage technology improving all the time it is likely that a subsea electric storage system can be developed whose size and weight will be less than the equivalent subsea accumulator system. An electric actuator system could be retrofitted to existing BOP technology or incorporated into new technology such as En-Tegrity.

Conclusion

The final BSEE well control rule will have a significant impact on BOP technology. The requirement of §250.732(b)(3) to demonstrate the ability to shear and seal all tubulars to be used in the well will be difficult for current ram-type BOPs to demonstrate with 5000psi control systems. Calculations will show that current CSRs cannot shear some commonly used tubulars, such as large intermediate casing, during well completion. The requirement to account for MASP will further reduce the cutting capability of ram-type CSRs.

Enabling technologies are under development that will allow BOP systems to become rule-compliant. These include improved shear and seal technology that can deliver high shear forces at relatively low hydraulic control pressures, close and seal on a flowing well, and self-centralize the tubular during cutting. In addition, the prospect of an all-electric BOP that will render the requirement for subsea hydraulic accumulation redundant is edging closer with the development of electric actuators capable of delivering forces required to shear the largest tubulars. **OE**

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***Michael O'Sullivan** is director of technology and development at Enovate Systems. He has 23 years' experience in the subsea oil and gas industry, focused on the area of riser technology. O'Sullivan led the joint industry project that developed the current industry standards for unbonded flexible pipe (API Specification 17J and Recommended Practice 17B). He holds a first class honors mechanical engineering degree from University College Dublin, a master's degree in Aeronautics & Astronautics from MIT, and bachelor of Laws degree from the National University of Ireland, Galway. He is a chartered fellow of the Institution of Mechanical Engineers.*

***Stuart Ellison** is a principal engineer with Enovate Systems. Ellison has over 10 years' experience in the drilling and intervention sector having previously worked with FMC Technologies, Aker Solutions and Oil States. He has a proven track record for the design and qualification of well intervention technology and is the lead engineer for the development of the 18-3/4" En-Tegrity preventer concept. He is a chartered petroleum engineer and holds an MBA in oil and gas management.*

East & South Africa

LNG a-go-go

Mozambique's emerging LNG business may be picking up after a quiet period. John Sheehan reports on progress made, including Eni's Coral FLNG project.

An Anadarko employee.
Images from Anadarko.

A recent deal struck by BP to take all of the liquefied natural gas (LNG) produced by the Eni-operated Coral South floating LNG (FLNG) facility, expected to be installed offshore Mozambique, appears to signal a shot in the arm for the project.

The agreement with the Area 4 concession partners, Eni East Africa, Galp Energia, Kogas and Empresa Nacional de Hidrocarbonetos, covers the purchase of LNG for over 20 years. The deal is conditional on the final investment decision (FID) being taken for the project, which is currently expected around the turn of the year.

Made in May 2012 and outlined in 2013, the Coral discovery proved the existence of a high quality field of Eocenic age with excellent productivity, Eni said this February. It is estimated to contain around 16 Tcf of gas in place.

Mozambique's Area 4 is the world's fifth largest natural gas discovery in the last 30 years, with more than 85 Tcf estimated natural gas resources in place. It covers 10,000sq km in the Rovuma Basin, about 50km off the coastline at Palma, more than 200km from the capital Maputo, and close to the Tanzanian border.

The plan of development, the very first to be approved in the Rovuma Basin, foresees the drilling and completion of six subsea wells and the installation of subsea production systems, umbilicals, risers and flowlines and the construction and installation of a state-of-the-art FLNG facility with a capacity around 3.3 MTPA.

BP will use LNG from the contract to help meet its global supply commitments, with Mozambique ideally placed to ship LNG to China and emerging markets in southeast Asia.

Under starter's orders

The Coral South LNG sales deal signals a boost for the nascent LNG business in Mozambique, progress on which has been slow in recent months.

Giles Farrer, director in Wood Mackenzie's LNG research group, told *OE* that Coral was the project that was likely to see first movement in the country, ahead of Anadarko's Mozambique LNG plans.

"The agreement gives Eni certainty of offtake and at a reasonable price," he says. "It also gives Eni some assurances around offtake because FLNG is new technology and there is uncertainty around what utilization the facility will run at and exactly when it will be ready and how quickly it will ramp up. We understand that under the contract, BP will take what Eni is able to produce out of the facility."

Coral's FID could come soon, especially as significant cost savings have been achieved on the project. "Where previously they were talking about a 2.5 MTPA facility, they are now talking about a 3.3 MTPA facility," Farrer says. "They haven't really increased the cost estimates; despite the fact they have increased the capacity. They have achieved some pretty significant economies of scale."

Eni is understood to have already ordered a FLNG vessel from South Korea-based Samsung Heavy Industries (SHI), which is working in a consortium with France's Technip and Japan's JGC on the project.

Funding

"There are two key questions on Coral for us," Farrer adds. "The first is around finalizing the financing, because of well publicized issues Mozambique has had with regards to some of the lending it has had from the International Monetary Fund (IMF), there is increased scrutiny from a financing point of view." The IMF suspended lending to Mozambique in April because it deemed the country had violated the terms of its agreement.

"Structuring the financing deals in a way that is going to be satisfactory for the various export credit agencies and financial institutions is taking some time, although we think it is pretty close," Farrer says. Eni recently met bankers in London to discuss project financing for the field development.

Farrer says that the second issue concerns the exact makeup around participation. ExxonMobil is strongly rumored to have moved to take a position in Area 4, either on its own or in a joint venture partnership with Qatar Petroleum. It could also take a stake in Area 1. Exxon already holds three offshore exploration license blocks of its own to the south of Eni's discoveries.

"You have all that uncertainty around how that deal might be structured," Farrer says. "If you were to get a supermajor of that caliber, we would expect a company like that to look again at the engineering and look for opportunities to drive down costs further.

"We're also expecting to see cost deflation and, given the state the market is in, we're starting to see engineering, procurement and construction (EPC) contractors for land-based LNG facilities being much more aggressive in their bidding," he adds.

Farrer says that the land-based LNG EPC contractors have been tied up with a slew of work in Australia and the US in recent years, but that that it is now slowing down.

"That will be looked at as an opportunity when they look at the engineering for cost deflation to get the onshore project competitive with some of the pre-FID projects being considered in the US."

Mamba

In addition to Coral, Eni has the Mamba project on the horizon. Mamba's initial stage includes the construction of two onshore LNG trains with a combined capacity of 10 MTPA and the drilling of 16 subsea wells, with startup in 2022, for the production of 340 Bcm of gas, according to the independent development plan but coordinated with the operator of Area 1. The FID is expected in 2017.

While movement is being seen on the Eni project, Anadarko's US$20 billion, two-train 12 MTPA project in Area 1 has been stalled.

The company has experienced problems over its plans to resettle local people from the landfall area for the LNG lines in Palma, Cabo Delgado province. It has already delayed its FID on the project several times.

The onshore scope of the work includes two LNG trains, each with capacity of 6 MTPA, which is an increase of 1 MTPA over the original plan, while maintaining an estimated cost that is consistent with the co-venturers' original projections. The scope also includes two LNG storage tanks, each with capacity of 180,000cu m, condensate storage, multi-berth marine jetty and associated utilities and infrastructure.

Anadarko operates Offshore Area 1 with a 26.5% working interest. It has picked a consortium of CB&I, Chiyoda and Saipem (the CCS JV) for the initial development of the onshore LNG park. The selection of the CCS JV is subject to negotiation and entry into a definitive agreement prior to taking FID. OE

UNDER SEISMIC FOCUS

Interest in Mozambique is translating into contracts, for the seismic community at least.

Norway's Spectrum is planning a long-offset broadband 2D multi-client seismic survey after recently being awarded Tender Area 2 covering the southern Rovuma and northeastern Zambezi basins, offshore Mozambique.

French geoscience firm CGG won an extensive multi-client program from the Instituto Nacional de Petroleo (INP) to acquire seismic data offshore Mozambique.

CGG's program includes a 2D survey of over 6550km in the offshore Rovuma basin, including blocks R5-A, R5-B and R5-C, and a large 3D survey over the Beira High in the Zambezi Delta. The 3D survey is expected to cover up to 40,000sq km, subject to pre-commitment. It will cover blocks Z5-C and Z5-D and surrounding open acreage in this deltaic area which is believed to be prospective.

CGG has also won an onshore airborne gravity and magnetic survey in the Southern Mozambique Basin. The proposed multi-client seismic program in the Mozambique Zambezi region will include marine gravity and magnetic data, to aid regional interpretation.

Spectrum's survey, meanwhile, will be a variable grid with lines spaced from 10km to 20km, totaling in excess of 16,000km.

The new seismic data will image the subsurface potential in open areas of the southern Rovuma Basin and the western flanks of the Kerimbas Graben, west of the Davie Fracture Zone, revealing the prospectivity in this region for the first time, Spectrum says.

Spectrum said the survey will also aim to image the syn-rift structures and Late Cretaceous pro-delta stacked turbidite sequences in the northeast Zambezi Depression. "New 2D data will play a key role in refining our understanding of the hydrocarbon potential of the area and accelerate hydrocarbon exploration activity in what is believed to be an oil-dominated region offshore Mozambique," Spectrum says.

Thorn of Africa

A flurry of major gas discoveries in East Africa in 2012 shone a spotlight on the region. Four years later, while efforts to bring some of those resources to market via LNG developments are progressing, the exploration effort offshore appears to be in the doldrums. Elaine Maslin reports.

Activity had been tentatively returning to Somalia, but the country is not quite a ripe exploration province, yet. Somalia, which is not far from the now-proven basins to the south in Tanzania and Mozambique, had been a target for a string of majors before the early 1990s, such as BP, Chevron, Conoco, Eni, Shell, ExxonMobil, etc., according to UK-based exploration firm Soma. But, by 1991, they had all claimed force majeure due to civil war.

Things have changed, to a point. There has been greater stability in the country and the federal government has been active in re-opening the exploration play, according to Soma. There's a lot of underexplored space. Soma, whose chairman is ex-UK Prime Minister Michael Howard, says that only six offshore wells have been drilled in shallow waters along the 2300km eastern offshore basin, and none in deepwater.

Soma says that a US Geological Survey estimate puts total undiscovered resources at 16 billion bo and 260 Tcf of gas in the provinces bordering its offshore evaluation area in Somalia's offshore waters. Nearby discoveries include huge gas resources offshore Mozambique and Tanzania and heavy oil discoveries off Madagascar, according to Soma.

Soma shot 20,500km of 2D seismic over 114,000sq km, offshore Somalia, in 2014. The country's federal government also acquired 20,583km of 2D seismic from 2015-16. Soma, meanwhile, is in negotiations over 12 production sharing agreements with the Somalian government.

However, there has been little positive news from Soma since December last year and the firm has faced difficulties, not least accusations over bribery claims.

Furthermore, Somalia remains in a dispute with neighboring Kenya over their maritime border, with 100,000sq km in the Indian Ocean at dispute and recent hearings in the International Court of Justice seemingly having little effect, partly due to not being recognized by Kenya. This has led to a United Nations (UN) proposal that a moratorium is placed on oil deals in Somalia. The country is also home to 22,000 African Union personnel who are backing government forces in a fight against al-Qaida-linked group al-Shabab, which has been trying to topple the government since 2006. The UN Monitoring Group has also warned that deals on oil exploration may fuel violence and corruption in the fragile state, Bloomberg reported.

Kenya

Exploration offshore Kenya, likewise, appears to have dropped off. Houston-based Anadarko says that it has about 3.7 million acres offshore Kenya across three deepwater blocks. However, after a duster in 2013, plans for a deepwater exploration well in 2015-16 didn't materialize and the company has said very little about Kenya for some time as it focuses its efforts on monetizing Mozambique.

Current reserves
(offshore, commercial reserves only)

Country name	Reserves (mmboe)	Liquid-gas dimension
South Africa	151.22	Liquid
South Africa	371.35	Gas
Tanzania	4808.62	Gas
Mozambique	138.2	Liquid
Mozambique	7839.43	Gas

2016 production

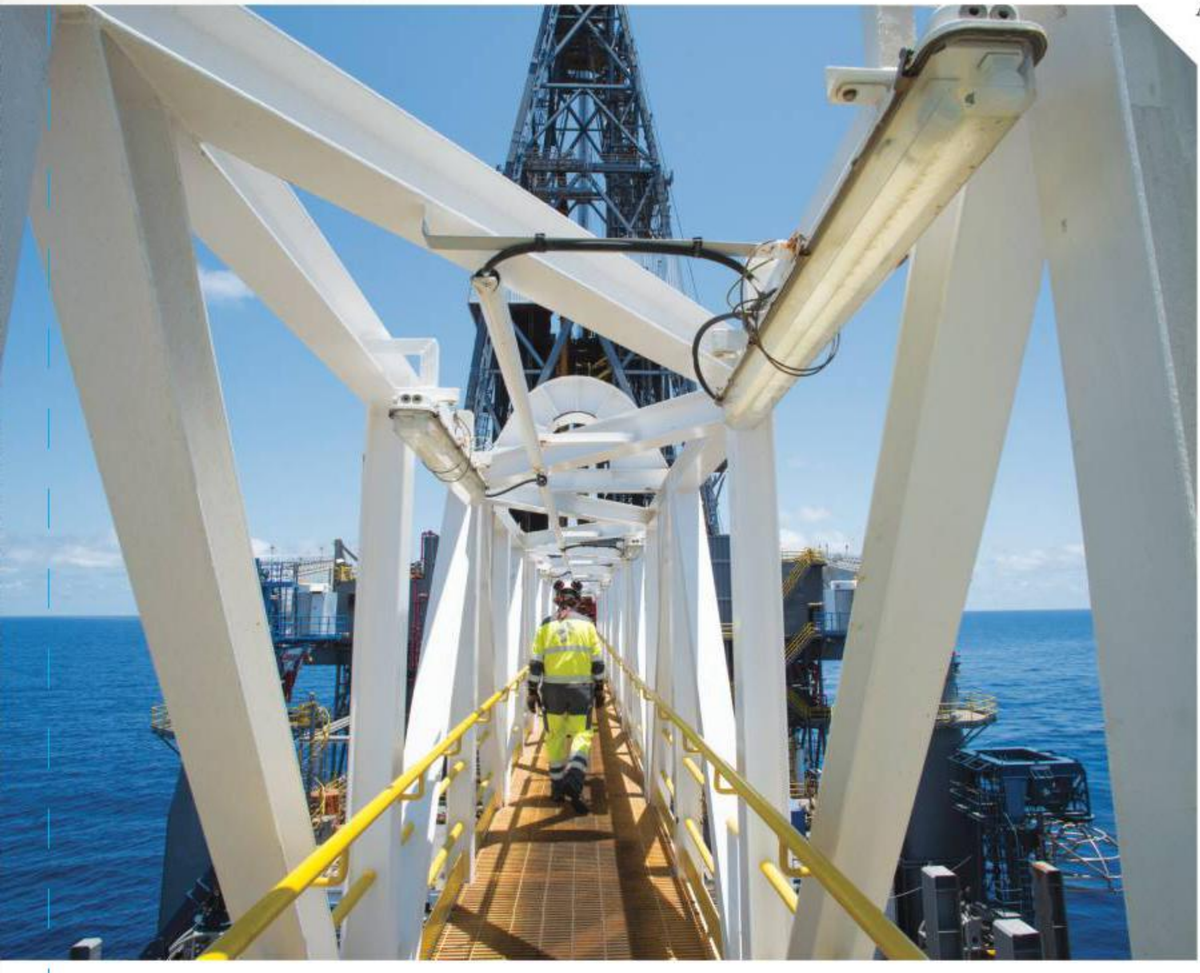
Country name	Metric (mboe/d)	2016
Mozambique	Production	0
Tanzania	Production	16.61
South Africa	Production	21.71

Source Wood Mackenzie Upstream Data Tool (UDT)
Data extracted on 5 August 2016

BG Group (now part of Shell) made a discovery on the Sunbird-1 well in 2014, but its partners, PTTEP and Pancontinental, pulled out in 2015. According to a report by the UK Department for International Development report from August 2016, BG Group confirmed that its discoveries were not yet deemed of commercial value.

Apache drilled the Mbawa-1 well on Block L-8 in 2012, discovering gas, but later exited the license. Exploration in Blocks L-21, L-23 and L-24, operated by Eni, has been put on hold pending a resolution of the maritime border dispute with Somalia, as has Block L-22, operated by Total. Meanwhile, independents, including Ophir and Erin Energy, have been seeking partners for exploration, but with little apparent movement.

"Offshore Kenya, there have been a few surprises around the operating environment, with currents up to 3-4 knots," says Alasdair Reid, research analyst, S&E Africa Research, Upstream Oil & Gas, Wood Mackenzie.



Drillship *Discoverer Americas* was used to drill off Tanzania by Statoil. Photo from Statoil/Paul Joynson-Hicks AP.

East & South Africa

SOUTH AFRICAN EXPLORATION

"There's a lot of prospective offshore acreage in South Africa," says Alasdair Reid, research analyst, S&E Africa Research, Upstream Oil & Gas, Wood Mackenzie. "Most of the big players are in there. But, until the regulatory environment is resolved, we're not going to see much exploration activity."

Despite exploration having first started offshore South Africa in 1967*, currently, there's little offshore production, apart from the PetroSA-operated offshore Block 9 fields, located on the southern coast in the Outeniqua Basin There's also a project to develop the Ibhubesi gas field.

The main areas seen as being attractive are the Bredasdorp Basin of southern South Africa and off the west coast, near the maritime border with Namibia, in the Orange Basin.

"The key issue for South Africa is the latest petroleum bill," Reid says. "There's a lot of uncertainty around the Mineral and Petroleum Resources Development Bill and as a result there has been a slowdown in activity." It's a priority of the South African government after ratings agencies raised this uncertainty, he says, so there should be some clarity next year.

Despite the uncertainty, there's a lot of interest. CGG recently completed a multi-client airborne gravity and magnetic survey offshore South Africa, with two aircraft acquiring 78,000 line-km of offshore data across Cape Agulhas (West Bredasdorp area) and offshore Durban (Eastern Margin area), areas that were due to be offered for licensing this year. CGG says it had significant pre-funding from the oil industry for the project.

The areas are not without issues. In the Agulhas, sea conditions, currents and a narrow drilling window add to the challenges, Reid says. Total and Canadian Natural Resources International tried to drill the Brulpadda-1 exploration well in late-2014 (a well that was aimed at testing a new deepwater play), but didn't reach total depth due to mechanical issues on the rig, according to Tower Resources, which has a neighboring permit. Tower says that Total has indicated it could return in 2016-17. "It just highlights that it's not benign ocean conditions," Reid says. This will mean bigger costs too.

"As a longer-term play there's no reason why it couldn't be interesting," Reid adds, noting that South Africa also has a strong supply base, as it's often used as a base for rigs on Africa's West Coast. ▪

**According to Impact Oil & Gas.*

Tanzania

More is happening offshore Tanzania where operators are working to get proven reserves to market, through a subsea to shore LNG development, rather than seeking new resources. The exception is Shell, which seeks to take advantage of low rig rates to prove up some additional volumes on Blocks 1 and 4.

But, the country is also not without its disputes. Tanzania has a long standing dispute with the semi-autonomous state Zanzibar. The dispute is over exploration in the Zanzibar archipelago, Reid says. Shell has been caught up in this.

This isn't stopping Shell from exploring, however. The oil major has a drilling program, due to start Q4 this year, comprising two wells on Blocks 1 and 4, targeting >1 Tcf of gas, says partner Ophir Energy. Shell became operator on the blocks after taking over BG Group earlier this year.

The well on Block 1 will target Kitatange, with an estimated mean recoverable volume of 1.1 Tcf. The well on Block 4 will target Bunju with an estimated 1.4 Tcf. The wells, which have been given 40% chance of success, will fulfill outstanding exploration requirements on the licenses, according to Ophir, which estimates its 20% share of the costs is US$20 million for both wells.

Meanwhile, pre-front-end engineering and design (FEED) is progressing on an onshore LNG plant, which would take in the huge discoveries made in Blocks 1 and 4, operated by Shell, as well as Block 2, held by Statoil (operator) and ExxonMobil. FEED is expected to start following the completion of the LNG site acquisition, the geotechnical investigations and engineering studies.

Concept selection for the upstream part of the project will determine the configuration and production rates from each of the fields, Ophir says.

Last year, Statoil said it expects to make a final investment decision on its Block 2 finds in 2018, at the earliest, with first production not before 2022-23.

"Shell sees this as an LNG project that ranks well in their portfolio," says Ophir's COO Bill Higgs, in mid-September. "Shell is currently looking for ways to reduce the cost structure for the LNG project."

Statoil, as well as being operator on Block 2, also recently bought into Block 6, acquiring a 12% stake from Petrobras, according to Norwegian media reports.

"From our perspective, Tanzania is still behind Mozambique," Reid says. "They are working through the government approval process."

More broadly, there's also a question about demand for LNG. "It's important to understand the global LNG demand picture to put these East African projects in context," Reid says. "We see a window for more supply post-2024, after the current period of oversupply. These projects will have to be cost-competitive globally, but the volumes [in East Africa] are huge and well located for Asian markets."

Overall, East Africa offers a number of interesting longer term plays, Reid adds. How long, longer term is, is yet to be seen. OE

Waiting on LNG trains

It took a long time for exploration to make its impact offshore East Africa. Now it has, will there be another wait for LNG projects to look profitable? Professor Alex Kemp reflects.

The uncertainties surrounding the discovery and exploitation of oil and gas resources are generally well known. The case of East Africa is a good illustration.

Exploration in Tanzania began many years ago. For example, an unsuccessful well was drilled in Zanzibar in the mid-1950s. The Songo Songo gas field was discovered by AGIP in 1974. But, commercial exploitation from this relatively small field did not start until 2004. There was only modest exploration interest.

In recent years, the situation has been transformed through a series of major gas discoveries, generally in offshore deepwater locations. Exploration in these areas only got underway in 2006, with the first major discovery being in 2010. The Tanzanian Ministry of Energy and Minerals estimates total reserves exceeding 57 Tcf, of which 47 Tcf are offshore.

In Mozambique there is a similar history. There was very modest exploration interest after the Second World War. In 1961, the Pande onshore gas field was discovered by Gulf Oil, but it remained undeveloped for very many years with production starting only in 2004. Exploration interest similarly waned for many years. It revived somewhat in the 1990s, but with relatively unsuccessful results in onshore Rovuma basin. Serious offshore exploration did not start until the 21st century. But, spectacular successes have ensued, with several large discoveries in deep offshore waters. Currently, frequently quoted estimates of reserves are around 100 Tcf.

The present position in both countries is thus a happy one, in terms of reserves discovered. Further, there is a reasonable cross-section of large, medium and small investors. This is often regarded as a desirable feature on the grounds that differing views regarding prospectivity and investment opportunities can positively impact activity levels.

Understandably, there has been much excitement in the two countries following the large discoveries, and expectations about the possible benefits from exploitation of the gas resources have been notably aroused. Both governments have highlighted these benefits. In Tanzania, the government has toughened the contractual terms in recent model production sharing agreements by introducing an additional profits tax (resource rent tax), as well as the conventional royalty (effectively paid by the Tanzanian Petroleum Development Corp.), profit gas sharing, and corporate income tax.

Photo from iStock.

In both countries it has been generally accepted that, while some of the produced gas would be used locally as a domestic market obligation, the majority would be liquefied and exported most probably to Asia, where demand is increasing at a fast pace. But, the collapse in oil prices over the past two years has caused investors to rethink the economic aspects of these liquefied natural gas (LNG) projects.

There are two reasons for this. Long-term gas sales contracts to Japan, for example, are indexed to oil prices. The collapse in oil prices has resulted in the average Japan LNG price falling from over US$15/MMBTU in 2013 and 2014 to little more than $5/MMBTU in the early part of 2016. Asian spot LNG prices have behaved in a similar manner.

The second reason for the rethink of the economics of LNG projects from East Africa is the emergence of strong competition from other gas exporters. Australia and the US are important additions to other existing suppliers.

The net effect of the above circumstances is likely to cause some delays to field developments and LNG projects. The overall investment costs are extremely large. As elsewhere in the upstream oil and gas sector, efforts are being made to reduce costs and this will certainly continue.

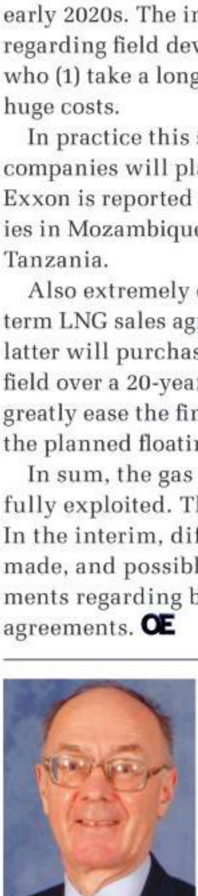
Costs of LNG schemes have come down substantially in recent years and this should continue over the next few years. In the production sharing contract terms, in Mozambique there are profit-related terms through the R-Factor profit-gas sharing mechanism. This mechanism is progressively related to profitability. The resource rent tax in Tanzania is entirely profit-related. Both mechanisms will to some extent moderate the tax take when profitability is reduced.

From the investors' viewpoint much also depends on the views taken about future gas prices. The investments will be very long-term ones, and, just as with the oil price, the gas price could well rebound by the time production occurs in the early 2020s. The investors likely to make positive decisions regarding field developments and LNG schemes will be those who (1) take a long-term view and (2) are able to finance the huge costs.

In practice this should mean that the large multinational companies will play key roles. It is encouraging to note that Exxon is reported to be interested in buying into discoveries in Mozambique while Shell has increased its stake in Tanzania.

Also extremely encouraging is the announcement of a long-term LNG sales agreement between Eni and BP, whereby the latter will purchase the entire output from the Coral South field over a 20-year period *(See page 52)*. This contract should greatly ease the financing of both the field development and the planned floating LNG plant.

In sum, the gas deposits in both countries will be successfully exploited. The big question is, when will this happen? In the interim, difficult cost reductions will have to be made, and possibly equally difficult contractual arrangements regarding both the field investments and gas sales agreements. **OE**



***Alex Kemp** is professor of petroleum economics and director of Aberdeen Centre for Research in Energy Economics and Finance at the University of Aberdeen. He has published more than 200 papers on petroleum economics and was a specialist adviser to the UK House of Commons Select Committee on Energy in 1980-1992, and in 2004, and 2009. He was awarded the OBE in 2006, for services to the oil and gas industries and wrote The Official History of North Sea Oil and Gas, published in 2011.*

East & South Africa

Big projects, big opportunities

EIC's Neil Golding outlines activity in East and South Africa.

Houston-based independent Anadarko made its first gas discovery at the Offshore Area 1 block offshore Mozambique in 2010. The discovery, along with Eni's major finds, mean that the country has the proven resources to become a major global player in the gas market. Combined, the resources could amount to 160 Tcf of recoverable gas.

Due to the significant resources, LNG plants were proposed to allow for gas to be exported to regional and global demand centers. Two projects were consequently proposed: an onshore liquefaction plant that will consist of two onshore LNG trains and have a combined capacity of 10 MTPA, and a floating LNG project to develop the Coral field, which will have a capacity of 3.4 MTPA and on which progress has been made very recently and could see gas exported by 2021.

In February 2016, the development plan for the Coral field was approved by the government, with a final investment decision (FID) expected at the time of September 2016 at the earliest. During October 2016 a supply deal was signed with BP, which agreed to offtake the total capacity of the Coral FLNG, a significant step for the project to proceed *(See page 52)*.

With such a commitment the expectation (at the time of writing) is that the FID will be made imminently and the formal award of the EPC contract will be made to the joint venture comprising of Samsung Heavy Industries, Technip and JGC. This will also mark the first major development of the country's vast offshore gas resource.

The Anadarko discoveries will move forward as two separate developments. Combined, the Golfinho/Atum and Prosperidade developments were, in 2015, expected to require a capex of US$24 billion, however, given the current climate it is expected that this figure will be reduced prior to FID being reached. The FID for these developments is expected to be made in 2017 although this has been pushed back several time from the originally expected FID date of Q4 2014. The development of Prosperidade is understood to be further advanced, the first phase of which will see the production of 2 Bcf/d of gas sent from up to 16 wells to shore via three, 22in diameter pipelines to the onshore LNG liquefaction plant.

With a limited local oil and gas related supply chain, these offshore developments, along with associated onshore developments, will offer the international supply chain plentiful opportunities in the future. OE

***Neil Golding** is head of Oil and Gas and Business Development for the EIC. He has over 16 years' experience working in the oil and gas industry in various roles.*

Solutions

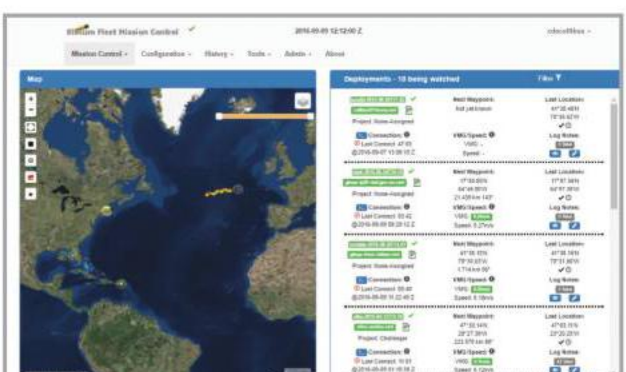
Emerson releases new multiphase flow meter

Emerson Automation Solutions has introduced the Roxar MPFM 2600 M multiphase flow meter. The Roxar MPFM 2600 M is designed to be a flexible and easily manageable wellhead measurement solution based on a field-proven technology platform. The meter is designed for customers with direct and continuous wellhead multiphase flow monitoring needs.

The Roxar MPFM 2600 M is part of the scalable Roxar multiphase product family and is designed to provide flexibility as fields mature and conditions change. The meter can be easily retrofitted in the field, delivers straightforward installation and commissioning, and has been specifically designed to meet operators' capital expenditure and varying field requirements.

The MPFM 2600 M is designed to identify and measure non-symmetrical flow in varying flow regimes, providing improved measurement uncertainty monitoring and reliability. The meter includes the advanced signal processing, field electronics and electrode geometry innovations of the third generation MPFM 2600.

www.emerson.com



Teledyne releases AUV piloting software

Teledyne Webb Research (TWR), a manufacturer of autonomous underwater vehicles (AUVs), has released their new glider piloting software, the Slocum Fleet Mission Control Software (SFMC). SFMC is a software suite used to manage multiple Teledyne Webb Research Slocum glider deployments around the world. SFMC builds on the traditional Dock Server software application and provides a revolutionary web based front end that allows for collaboration among multiple glider pilots.

The SFMC software suite offers customers some key benefits including active vehicle tracking and mission planning, consolidated data management, the ability to access piloting tools from various platforms, including tablets and smartphones, and increased security with individual login accounts and multi-level permission sets.

www.teledynemarine.com

Webtool gets hydraulic guillotine cutter

Hydraulic cutters and systems provider Allspeeds has developed a compact remotely operated vehicle (ROV) loop cutter for emergency activation of a blowout preventer (BOP). The Webtool cut loop cutter will sever the cutting loop to activate the BOP in the event other measures have failed.

During intervention, the Webtool cutter is held in position over the cut loop by an ROV. The wide mouth, open sided design of the Webtool cutter allows for easy positioning of the tool on the stainless steel, hydraulic cut loop pipe. The blade has been optimized for cutting stainless steel tube and developed so the cut loop will fully release pressure immediately after the cutter is activated.

This is Webtool's smallest hydraulic guillotine cutter, with corrosion resistant stainless steel body and cylinder, and pressure compensation on the hydraulic supply enabling use at any water depth. Useful for operation in confined spaces, the cutter weighs 7kg in water, uses 700bar maximum input pressure, and has an optional hydraulic intensifier.

www.allspeeds.co.uk

MDL develops new pipelay tensioner

Scottish back deck machinery firm Maritime Developments (MDL) has introduced a new 110-tonne, four-track pipelay tensioner to its MDL Offshore Service business.

MDL says it's the only system of its capacity readily available to take on projects worldwide. Previously, MDL has delivered three 50-tonne systems, which are currently being used in southeast Asia and in the North Sea.

The TTS-4/310 has the same safety and operational features of MDL's four-track tensioner range, including fail-safe grip system, self-centering track system and a modular, road transportable design.

The 110-tonne system joins a 50-tonne, four-track system, three-reel drive systems (RDS) and an overboarding chute, as well as a range of deck radius controlling equipment, control and power units and ancillary products in the MDL Offshore Service business.

www.maritimedevelopments.com

FES deploys DBSC off Rio

FES International delivered nine diverless bend stiffener connectors (DBSC) to the Atlanta field in the Santos Basin, offshore Brazil, operated by Queiroz Galvão Exploração e Produção (QGEP).

The DBSCs, a part of a multi-million-dollar contract between FES and QGEP, will be used on the post-salt oil field, located 185km off the coast of Rio de Janeiro.

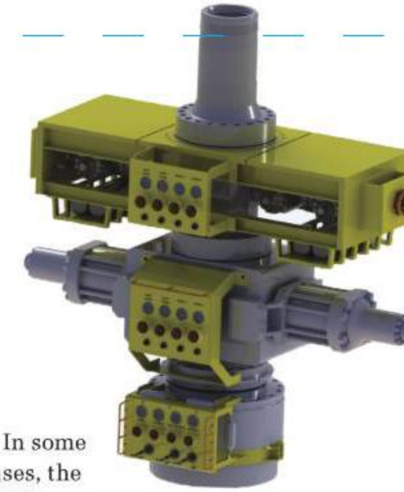
"We are seeing an increasing shift towards faster turnaround requirements from clients," said Rob Anderson, managing director, FES International. "This contract had an extremely tight schedule and it was critical to the success of the job that we were able to meet the ambitious timescales for delivery. We were able to complete the quick turnaround, which involved adapting our equipment to ensure it met the specific requirements for the project."

www.fesinternational.com

Trendsetter, Add Energy develop RWIS

Trendsetter Engineering and Add Energy have teamed up to develop the Relief Well Injection Spool (RWIS), designed to enable pumping of up to 200 bbl/min of kill mud through a single relief well utilizing multiple vessels as opposed to the conventional method of multiple relief wells.

Trendsetter says that the RWIS will provide a strategic solution that will enable drilling of both shallow and deep prolific reservoirs for regions, such as Norway, where regulatory agencies will only grants permits to drill for wells that can be killed with a single relief well.



In some cases, the RWIS may provide a tangible cost reduction in the range of US$2 million by omitting a casing string to reduce dynamic kill requirements in the event of a blowout.

The RWIS is designed to be installed on a relief well prior to intersecting the blowout well and would be positioned between the wellhead and the blowout preventer, effectively becoming a subsea injection manifold providing additional inlets for pumping kill mud. Each of these inlets is equipped with dual fail-safe barrier valves to provide the necessary means of pressure containment in the relief well.

www.trendsetterengineering.com

Spotlight

One step ahead

Daniel Sack, of EMAS Chiyoda Subsea, has spent three decades in the oil and gas industry following and participating in the next big step changes in technology – one subsea project at a time. Audrey Leon found out more.

Daniel Sack

It's not unusual to find an engineer who loves to travel. However, Daniel Sack, who took on the role of Chief Operating Officer at EMAS AMC (now EMAS Chiyoda Subsea [ECS]) in 2012, has definitely made a career of it. Sack was smitten with all the usual aspects of engineering: good pay and the ability to put theory into practice, but then, there was the travel bug.

His love affair with traveling the world led him to work for several industry leaders such as French oil major Total, Bouygues Offshore (now Saipem), Clough, Technip, and Schlumberger before settling in at ECS.

"In 1988, I went to Borneo to start my career as a reservoir engineer (with Total), but then rapidly evolved towards offshore facilities construction in West Africa and Southeast Asia (with Bouygues Offshore)," he says. While the subsea industry was evolving in the 1990s, he switched to installing conventional platforms and pipelines, and later moved to Australia in the mid-1990s, as subsea was starting to take off. He soon found himself in Houston.

"I was attracted to the sheer size and depth of the development in water depth multiple times the height of the Eiffel Tower and with a footprint on the seabed the size of Paris," he says of the subsea field. "The scale of these projects was impressive and developing them was very challenging."

Sack didn't always think he'd be an engineer. "My earliest career aspirations were to be a truck driver or an architect," he says. "You could say I was born with wanderlust. Truck drivers drove long distances from one end of Europe to the other and I always wanted to see the world.

"I was also drawn to structures, such as, bridges, buildings, infrastructure, and enjoyed building scale models of boats, airplanes, cars, etc.," he adds. "The oil and gas industry has allowed me to fulfill most of my childhood dreams on a much larger scale than I could ever have imagined."

Sack's subsea journey continued at Schlumberger in 2006, where he helped lead the development of a deepwater subsea well intervention system and later developed the early production facility group. However, by 2012, ECS approached Sack with a new opportunity.

"This was a great opportunity to start-up and build a new company using the systems, assets, people and lessons learned from top tier contractors. It was very exciting to offer clients a reliable alternative to the very large and often bureaucratic contractors," he says.

In terms of his attitudes toward technological developments, Sack says: "I've learned that it is important to anticipate needs and trends in the industry and listen to your clients. At ECS, we have invested in game-changing assets and technology, and we also work with our clients to help solve problems and save them time in the field."

He proudly cites ECS' first tieback job for Noble Energy in the Gulf of Mexico as a prime example. "We were able to execute three back-to-back tieback projects while setting a record for the highest tension ever recorded in the history of rigid reeled-lay operations," Sack says.

What else is ECS eyeing in terms of technological developments? Sack says that this past year, the group participated in a joint engineering project with a super major to advance a proprietary free standing riser solution, which he says has cost and schedule advantages while improving risk and safety exposure over the life of the field.

"We anticipate further development in the area of subsea factories, advancement in thermoplastic composite pipes, high pressure, high temperature and corrosion resistant alloy pipes and enhanced welding and coating applications, just to name a few," he says.

ECS has plenty of jobs, large and small, lined up so far, including a US$1.6 billion engineering, procurement, construction and installation project for the Hasbah field offshore Saudi Arabia in consortium with Larsen & Toubro, as well as a contract with Eni Ghana for the Offshore Cape Three Points development, slated to begin in early 2017.

"We are also working alongside our clients right now to find economic solutions for the next generation of ultra-deepwater developments," Sack says. "Many of these developments are already beyond the edge of current technology or capability, and we take pride in finding solutions to these challenges that work for our clients." OE

Editorial Index

What's next

Coming up in OE December

Abandonment & Decommissioning

OE Staff reports on the latest projects and technologies within the abandonment and decommissioning sector.

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avallance@atcomedia.com

UNITED KINGDOM SCANDINAVIA, GERMANY AND AUSTRIA
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
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

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June Jonet
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