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The Abandonment & Decommissioning issue

page 22

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FEATURE FOCUS

The Abandonment & Decomissioning issue

Photo by Jan Berghuis/Flickr.

Features

ON THE COVER

Mighty Murchison. Heerema Marine Contractor's *Thialf* and *Balder* completed the reverse installation of CNR International's Murchison topsides in just 80 days, this year. Read more in Field of View, page 14. *Cover photo by Jan Berghuis/Flickr.*

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Departments & Columns

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Final data available December 2016

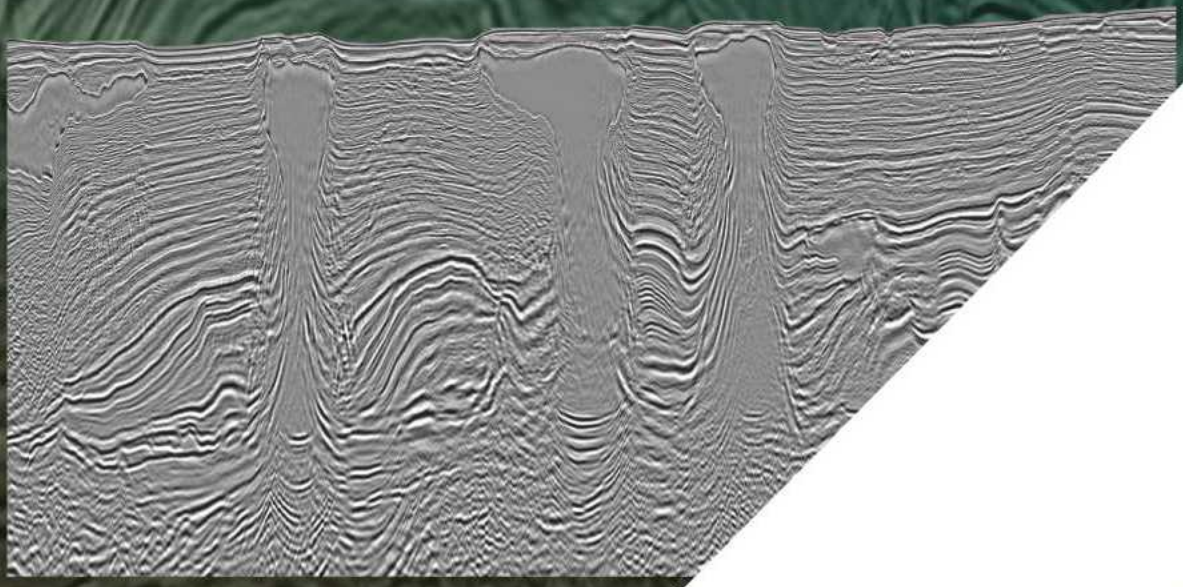
Set your sights.

Gulf of Mexico

Declaration WAZ 3D covers 8,884 km^2 (381 OCS blocks) in the Mississippi Canyon, DeSoto Canyon, and Viosca Knoll protraction areas of the Central Gulf of Mexico and was acquired to better image deep structural elements while improving subsalt and salt flank illumination.

Through integration with TGS' underlying orthogonal Justice WAZ 3D survey, Declaration provides broadband multi-azimuth (M-WAZ) data with offsets to 16 km. The data is being processed using the latest TGS imaging technology including Clari-Fi and Orthorhombic migrations. Final data will be available by December 2016.

Let's explore.



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Year in review: 2016

OE Staff reviews the top offshore oil and gas news stories of the past 12 months.

Photo from iStock.

What's Trending

(L to R) Secretary of Energy Pedro Joaquín Coldwell, Mexico's President Enrique Peña Nieto, Pemex CEO José Antonio González Anaya.
Photo from Pemex Flickr

Big plans

- Pemex plans aggressive farm-out
- Exxon in 1 billion bbl Nigeria find
- GE Oil & Gas, Baker Hughes to merge

People

Weatherford CEO steps down

Weatherford chairman, president and CEO Bernard J. Duroc-Danner resigned in early November. Robert Rayne will serve as chairman of the board while Krishna Shivram serve a dual role as interim CEO and chief financial officer (CFO) until a new CFO is named.

Undercurrents

2016: Exit

As *OE* turns the page on yet another year, it is hard not to reflect on the past 12 months. It's been a wild year of ups and downs in the oil and gas sector. It has also been a year of rebellion at the ballot box on both sides of the pond. First, there was Brexit this summer, where the UK citizens voted to leave the European Union; and then there was America's own version of Brexit, when US voters elected real estate mogul Donald J. Trump the country's 45th president (let's call it "Trexit") in November.

The effects of both Brexit and Trexit won't be realized for years, which does make one wonder what the future holds for global industry in the wake of these decisions. Will there be less regulation or will it be business as usual? Trump, being an outsider candidate who hasn't held elected office, does create some uncertainty among industry watchers. As *OE* went to press, there are only rumors of who Trump will choose to lead key the agencies, such as the Department of the Interior – which governs the Bureau of Safety and Environmental Enforcement and the Bureau of Ocean Energy Management, which are responsible for regulating the nation's domestic oil and gas industry.

Offshore renewables need the same type of engineering know-how as traditional oil and gas projects.

Trump has also not been a huge supporter of renewable energy. And, with the US's first offshore wind farm (Block Island) soon to come online, once again, one does wonder what the future lies for that emergent industry. Offshore renewables need the same type of engineering know-how as traditional oil and gas projects, and potentially opens another avenue for revenue in this down market.

But, regardless, leading industry organizations American Petroleum Institute and the National Ocean Industries Association (NOIA) both congratulated the president-elect on his win, and expressed a willingness to work with him on energy policy.

"With the right policies in place, we can produce vastly more offshore oil and natural gas, not only for US consumers, but for people around the globe as well," says NOIA President Randall Luthi.

OE looks forward to reporting on the outcome of future lease sales, and, perhaps eventually, a renewed interest in US Arctic offshore exploration.

Decommissioning

For a long time, in the UK North Sea, the huge task of decommissioning an ever aging set of infrastructure has been labelled a bow wave, forever just in front of the oil and gas industry super tanker.

OE's December issue takes a deeper look at the decommissioning sector. The work appears to be starting in earnest – *OE* covered Shell's huge Brent project earlier this year, and in Field of View this month Elaine Maslin reports on Canadian Natural Resources International's Murchison decommissioning program.

There is a debate brewing about just how much to remove from the seabed when operations cease. Many are suggesting that current rules are not workable or sensible. How authorities react to Shell's request to leave its four massive concrete and steel Brent field structures in place is likely to set the tone for this debate for the larger structures – i.e. those that can apply for an exemption from rules which say they would otherwise have to be removed. But, for the bulk of platforms that do not meet exemption criteria, the future is murkier. Engie is hoping to do something about this with its Platforms Natuurlijk pilot project in the Dutch North Sea. Find out more on page 28.

But, it's not all about decommissioning. There have been new projects coming onstream this year, and new oil and gas finds have been made, as our "Year in Review" section highlights (see page 54). We look forward to a brighter 2017. OE

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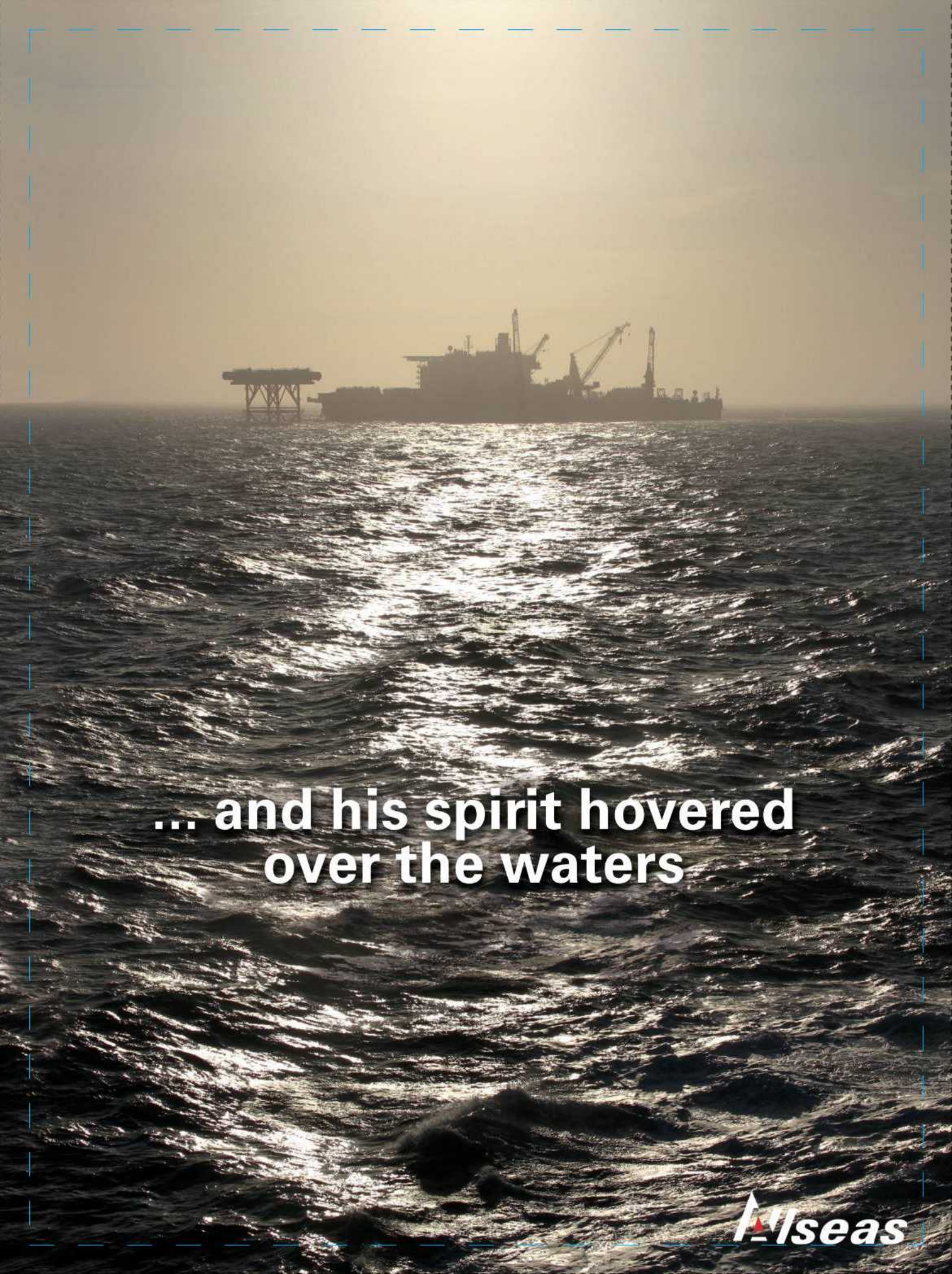

... and his spirit hovered
over the waters
Iseas

Global E&P Briefs

A BP wins out in Newfoundland round

BP, and its partners picked up four parcels offered by the Canada-Newfoundland and Labrador Offshore Petroleum Board in the latest deepwater bid round.

In the East Newfoundland (NL16-CFB01) round, 13 parcels were offered. Parcel 3, 4 and 8 were awarded to BP (50%), Hess (25%), and Noble (25%). Parcel 10, the largest parcel at 264,249 hectares, went to BP (60%) and Noble (40%). Parcel 7 went to Navitas Petroleum (30%) and DKL Investments (70%) and parcel 13 to Nexen Energy (100%). The NL16-CFB02 round, covering the Jeanne d'Arc regions offered three parcels, totaling 353,843 hectares. Husky Oil took two parcels 1 and 2.

B Arctic cut from US rounds

The US Department of the Interior (DOI) released the Outer Continental Shelf lease sales for 2017-2022 plan, excluding areas in the Beaufort and Chukchi Seas off Alaska.

"Given the unique and challenging Arctic environment and industry's declining interest in the area, forgoing lease sales in the Arctic is the right path forward," says DOI Secretary Sally Jewell.

The proposed final program offers 11 potential lease sales in four planning areas – 10 sales in the portions of three Gulf of Mexico program areas that are not under moratorium, and one sale off the coast of Alaska in the Cook Inlet program area.

C Dominican potential

The Dominican Republic's Ministry of Energy and Mines reported six areas on- and offshore that could be the starting point for in-depth research on probable hydrocarbon deposits.

The areas with the largest potential belong to the Enriquillo, Azua, San Juan, Ocoa (offshore), San Pedro (offshore) and East Cibao basins, with faults and structures that could work as hydrocarbon-retaining traps, but they still require more in-depth studies.

D Liza potential increases

Success at ExxonMobil's Liza-3 appraisal well has boosted the potential for the Liza discovery, offshore Guyana. Hess, a partner in the Stabroek block containing Liza, says estimated recoverable resources are now thought to range 800 MMboe to 1.4 billon boe.

Liza-3 was drilled by the *Stena Carron* drillship about 193km offshore. The Stabroek block is operated by Exxon's Esso E&P Guyana (45%). Partners include Hess (30%) and CNOOC Nexen Petroleum Guyana (25%).

E Anadarko plans next Colombian well

US Independent Anadarko has planned an exploration well for Q4 on the Purple Angel block.

The Purple Angel-1 prospect is designed to test objectives similar to those at Anadarko's Kronos discovery. Kronos, found in a frontier deepwater basin in the Fuerte Sur block, was drilled to 12,200ft (3720m), encountered 130-230ft (40-70m) of net natural gas pay in summer 2015.

Fred. Olsen's *Bolette Dolphin* drillship drilled Kronos prospect and is under contract to Anadarko until 2018.

Bolette Dolphin. Photo from Fred. Olsen Energy.

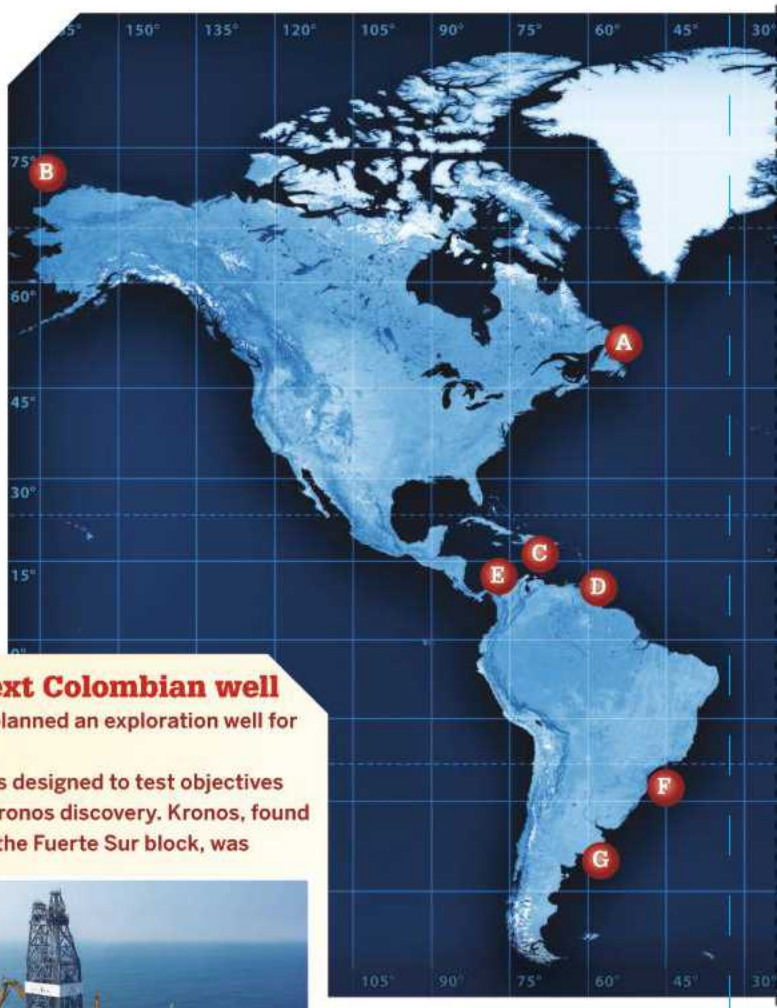
F First Libra well completed

Petrobras has completed the first well in the Libra pre-salt field in the Santos basin. The well, 3-RJS-739A (NW3), is in the northwest sector of the Libra block, some 187km off the coast of Rio de Janeiro, in 1951m water depth.

NW3 will start production in 2017, connected to the *Pioneiro de Libra* floating production and storage offloading (FPSO) unit.

G Statoil, YPF eye Argentinian coast

Norway's Statoil and Argentina's YPF agreed to study the offshore areas of Argentina.



The area extends over 360,000sq km ranging from the border with Uruguay to 45° latitude (north of Comodoro Rivadavia, Chubut province), where water depths vary between 500-3500m.

The area is thought to be high potential and high risk, and both companies believe there may be several hydrocarbon prospects to be investigated in the basins of Salado, Colorado and Argentina.

H Mafumeira Sul EPS starts

Sonangol and its Block Zero partners Cabinda Gulf Oil Co., Total E&P Angola, and Eni Angola, have started up the early production system (EPS) at the South Wellhead Platform of the Mafumeira Sul project. Mafumeira Sul

is 24km offshore Malongo, Angola, at 60m water depth. The EPS will operate with a maximum production capacity of 10,000 b/d.

I Exxon stuns with Owowo

ExxonMobil has made a potentially 1 billion bbl find at the Owowo field offshore Nigeria. Exxon spudded Owowo-3 in September, and hit some 460ft (140m) of oil-bearing sandstone reservoir. Owowo-3 extends the resource found by the Owowo-2 well, about 515ft (157m) of oil-bearing sandstone reservoir.

Owowo-3 was safely drilled to 10,410ft (3173m) in 1890ft (576m) of water. Owowo sits inside the OPL 223 and OML 139 contracting areas.

J Coral LNG gets greenlight

Eni approved the first development phase of the 16 Tcf deepwater Coral discovery offshore Mozambique, in the Rovuma Basin Area 4. Pending approval from the projects partners, a final investment decision will be made. The Coral South project will see six subsea wells connected to a floating LNG production facility (FLNG), with a liquefaction capacity of over 3.3 MTPA. Eni has already ordered a FLNG vessel from South Korea-based Samsung Heavy Industries.

L Norway, Russia share seismic

The Norwegian Petroleum Directorate (NPD) and Russia's Rosnedra agreed to exchange seismic data from the areas around the demarcation line in the Barents Sea. About the same volume of data will be exchanged.

From the Russian side, this includes all seismic that was collected in 2013 in two major licenses: the Fedynsky license and the central Barents Sea license. There will also be a line from the gas discovery on the Kildinskoye High.

The NPD has received a total of 6500km of 2D seismic from these areas. Rosnedra received 5900km of 2D seismic from the Norwegian side. This includes data collected in the northern Barents Sea (2012-2014), limited to east of 35°E and south of 76°10N. The Russians will also receive a seismic line from the stratigraphic boreholes on the Sentralbank High, as well as a long line that spans north to south in the Arctic Ocean.

M Total in deepwater Black Sea find

France's Total made a deepwater oil discovery in the Black Sea, near Bulgaria. The discovery has been identified by the Polshkov-1 well, on which drilling operations began in May using the *Noble Globetrotter II* drillship.

The well, 85km offshore, was the first on the Khan Asparuh Block and the first deepwater well in the Bulgarian Black Sea.

K Alder achieves first gas

Chevron started production at the high-pressure, high-temperature Alder field in the Central North Sea.

The field is about 160km from the Scottish coastline in Block 15.29a, in 150m water depth. Alder is a single subsea well tied back, via a 28km pipeline, to the ConocoPhillips-operated Britannia Platform, in which Chevron holds a 32.38% non-operated working interest.

The project has a planned design capacity of 110 MMcf/d of natural gas and 14,000 b/d of condensate. Production from Alder is expected to ramp up over the coming months. Chevron North Sea operates Alder (73.7%) with partner ConocoPhillips (26.3%).

Global E&P Briefs

Israel launches bid round

Israel has opened its first offshore bid round covering 24 areas, numbered 12 to 66, in the Levant Basin, in the Mediterranean Sea. With water depths from 680-1770m, each area will cover a maximum of 400sq km.

The government says licenses will be awarded for a three-year period, with the possibility of three-year extensions. Proposals may be submitted by 21 April 2017, with the winners announced in July 2017.

First oil from Vladimir Filanovsky

Russia's Lukoil has achieved first oil from its Vladimir Filanovsky field in the Caspian Sea. The field's C1+C2 recoverable reserves are estimated at 129 million tonne of oil and 30 Bcm of gas. Two horizontal production wells have been drilled, producing over 45,000 bo/d of sweet light crude, with a third under construction. The field's infrastructure will also act as a hub for new and already producing fields.

Petronas' *PFLNG Satu* online

Petronas started up gas from its first floating liquefied natural gas (FLNG) facility, PFLNG Satu, at the Kanowit gas field offshore Sarawak, Malaysia.

The *PFLNG Satu*, fitted with an external turret for water depths of 70-200m deep, will extract natural gas via a flexible subsea pipeline for the liquefaction, production, storage and offloading processes of LNG at the offshore gas field. Petronas anticipates the *PFLNG Satu* facility will soon progress towards commercial operations and first cargo.

Inpex hits Japanese gas

Inpex has discovered gas find at an exploration well offshore the Shimane and Yamaguchi prefectures in Japan.

Transocean's *M.G. Hulme Jr.* semisubmersible rig drilled to 2900m below the sea floor about 130km northwest of the Shimane Prefecture.

A thin gas reservoir in a shallow zone as well as some gas indications in deeper zones were encountered, in addition to what Inpex describes as unexpected, strong gas indications suggesting the presence of a high pressure gas column in the deepest zone.

Quadrant hits WA gas

Quadrant Energy discovered natural gas at the Spartan-1A well, offshore Western Australia.

Spartan was a successful discovery west of Barrow Island, proving up a clearly commercial accumulation of gas near existing facilities. The well is 15km to the southeast of the producing John Brookes field, and is a potential future tieback into existing infrastructure.

Spartan highlights the additional potential for exploration in these mature areas and the ability to keep facilities such as Varanus Island full to capacity, Quadrant says.

Contracts

Saipem racks up work

Saipem won new contracts totaling about US$1 billion. The most significant were two engineering, procurment, installaton, and construction contracts awarded by Saudi Aramco for the development of fields in Marjan, Zuluf and Safaniya in the Persian Gulf.

These contracts include the design, engineering, procurement, construction, installation and implementation of subsea systems in addition to the laying of pipelines, subsea cables and umbilicals, platform decks and jackets.

Forsys, Aker win Trestakk contracts

Statoil has awarded contracts to Forsys Subsea (a FMC Technologies-Technip joint venture) and Aker Solutions for its Trestakk field development that is scheduled for startup in 2019 off Norway.

Forsys Subsea will handle the engineering, procurement, construction and installation portion, with Technip supplying flexible riser, production flowline, gas injection line, flexible jumpers, and umbilicals. FMC will provide the subsea production system — including subsea trees and completion system, a manifold, wellheads, subsea and topside control systems — plus tie-in hardware and tools.

Aker Solutions will perform Åsgard topsides work, which consists of piping to connect the well stream to the vessel, and upgrading of the metering systems.

JDR gets Hornsea One gig

DONG Energy awarded UK firm JDR Cables the contract to supply subsea power cables for Hornsea Project One offshore windfarm in the North Sea, off the coast of England.

The contract is the largest array cable award in JDR's history and will see the company design and manufacture 242km of array cables, covering two-thirds of the total wind farm capacity. JDR will also provide terminations, hang-off arrangements and additional accessories as well as services at the site.

DONG Energy and JDR have a framework agreement in place to enhance current designs and develop new technologies and processes to improve the quality and price of subsea power cables.

Weir gets KOC wellhead contract

Kuwait Oil Company (KOC) has made an agreement with Weir Oil & Gas Dubai for the purchase of 295 Seaboard wellheads, valued at approximately US$12 million.

Weir will provide KOC with 11 different wellhead configurations ranging from 3000-10,000psi. The products sold include conventional wellheads along with HH cladded trees, and solid block dual completion trees. Equipment designs will accommodate casing and tubing sizes ranging from 3.5-24in in the various wellhead configurations supplied to KOC.

Wood Group gets Hibernia extension

Wood Group has secured a five-year contract to continue providing engineering, procurement, construction and maintenance services to the Hibernia platform, offshore Newfoundland, from Hibernia Management and Development Co. (HMDC).

The contract will be executed by Wood Group's Eastern Canada operations, in St. John's, Newfoundland & Labrador, and has the potential of two additional five-year contract extensions. ▪

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Mighty Murchison – End of an era

After more than three decades' production, the mighty Murchison platform was finally down-manned this year. Work to dismantle the 25,000-tonne topsides is ongoing. Elaine Maslin reports.

On 31 March, the last scheduled flight departed from the Murchison platform, two years after production ended at the huge North Sea facility, and more than 10 years after production was expected to cease when the field was acquired by present operator Canadian Natural Resources (CNR) International.

The platform is one of the North Sea's largest, standing 254m from the seabed to the tip of the flare stack – and described as one of the friendliest. It has been subjected to the harsh environment of the North Sea, with waves of up to 28m-high and wind speeds in excess of 50m/s (110mph) over its 36-year life.

At peak production, in 1982, it produced 150,383boe/d and overall it has produced about 400 MMboe, or about 50% of the oil in place.

Now, however, the facility is the subject of an ongoing decommissioning campaign, with about 40,000-tonne of topsides and jacket to be removed.

Origins

The field was discovered in 1975 by Conoco (UK), at the height of the early North Sea boom when Texans were a regular sight in Aberdeen.

The topsides, designed for a 30-year life, were installed through 26 modular lifts and, in 1980, oil production started, initially from three subsea wells tied back to the main platform, before the main platform wells came onstream. The field itself extends into the Norwegian sector, but oil was exported to Shetland via the Dunlin and Cormorant platforms.

In 2002, CNR International took over Murchison, undertaking a major program of asset integrity management, reservoir management, well repair and infill drilling, resulting in a 10-year life extension and delivering an extra 22 MMboe. In 2005, under CNR International, production peaked at 18,000, boe/d. However, by 2013, the facility was producing just 2200 boe/d, and the time had come to shut it in.

A 25,000-tonne challenge

The size of the challenge is not to be underestimated. Murchison comprises a 25,000-tonne topside facilities consisting of some 26 modules, including accommodation for nearly 200 people. The eight-legged, 24,500-tonne jacket – excluding marine growth built up over the platform's lifetime –with 32 piles, is one of the largest in the North Sea, with main legs measuring 6m in diameter.

In addition, there were 33 platform wells and one subsea well that had to be plugged and abandoned (P&A'd), as well as a 16in export line; a 6in gas spur; three, 12.75in disused bundles; and a subsea isolation valve umbilical. Subsea wellhead protection frames also have to be removed. There is also a 22,500cu m drill cuttings pile.

In 2009, decommissioning studies were started, sparking three years of extensive surveying, data collection and studies before the decommissioning program could be submitted to the UK's Department of Energy & Climate Change (DECC – now part of a new department, Business, Energy & Industrial Strategy, or BEIS) in 2013, and approved in 2014, with well P&A starting the same year.

Because the platform had changed hands several times over the years, CNR had the job of tracking down all the information needed by the regulator for the decommissioning scope. This included carrying out its own surveys to fill in knowledge gaps. In total, 70 studies from 30 different companies, from marine contractors to environmental experts, were carried out. CNR International also had to bring the

platform's drilling facilities out of warm stacked condition, with the help of PD&MS and KCA Deutag, to enable the P&A operations, which were completed on 31 March this year.

Aker Solutions was picked to lead the engineering down and conversion of the platform to NUI (normally unmanned installation) status in 2014/2015, going on to support, as required, the preparation for removal scheduled for 2016.

Sureclean provided cleaning and waste management during the engineering-down phase, including descaling pipework and vessels to remove hydrocarbon deposits.

Bilfinger Salamis was used for support and access solutions in the early phase, including alternative system scaffold, rope access teams and fabric maintenance services.

To support decommissioning activities, Interpower supplied five, 1MW offshore containerized generators, positioned on Murchison's cellar deck over three years starting Q1 2015.

In March this year, one of the cranes on the facility was damaged during a lifting operation, but no one was hurt. The incident happened while the crane was lifting supplies from an offshore vessel.

CNR International's Murchison platform with Heerema Marine Contractor's vessels *Thialf* and *Hermod*, at work earlier this year. Photos from Jan Berghuis/Flickr.

Removal

One of the most visible work scopes is the topsides and jacket removal. AF Gruppen's subsidiary AF Decom Offshore UK and Heerema Marine Contractors (HMC) were awarded a consortium contract for Murchison platform and jacket removal and disposal.

The original removal method was going to be a hybrid approach, combining short sailing times for the piece-small tonnage (approximately 10,000-tonne) to a UK disposal yard and direct offloading of the remainder from HMC's heavy lift vessel at AF Environmental Base Vats, Norway.

However, when the consortium found it had two heavy lift vessels available in 2016, *Hermod* and *Thialf*, they took the opportunity to revise the method to a full reverse installation, using both vessels to remove the complete topsides, and shaving a full year off the project schedule. Mobilization was on 18 June and by 27 August, after just 80 days, the topsides scope was completed, via 26 heavy lifts and five vessels transits from the field to Vats.

Of the installation material to be removed, some 82% is estimated to be steel. Of the pipeline infrastructure to be removed, about 48% is estimated to be steel with some 50% concrete.

CNR International was given an exemption to allow the jacket's footings – including 32 piles, up to 44m above the seabed, or down to 112m below lowest astronomical tide – to be left in place under an Ospar derogation ruling, due to their weight and installation date. Under Ospar rules, which cover the entire North Sea, under the Oslo Paris Convention agreement, facilities otherwise have to be completely removed.

CNR International is also being allowed to leave the 22,500cu m drill cuttings pile in place in line with the Ospar recommendation on drill cuttings piles. The view is leaving it to degrade naturally will be better for the environment than to disturb it by attempted excavation (*OE*: June 2016, *Mud Glorious Mud*).

Pipelines

The main oil export pipeline will also be left in situ, with remedial rock placement over exposed sections. This involved some 75,000-tonne of rock placement in the summer of 2016, comparable to the already placed 63,000-tonne during the 1985 and 1987 operations in the field.

To remove exposed sections of the main export pipeline, totaling 17 sections, would have involved 746 cuts to lift and handle 729 x 12m-long sections, according to the decommissioning program submitted to DECC.

The program says the potential loss of life risk of the cut and lift operations of exposed sections was considered more than five times that of remedial rock placement. The cost of cut and lift would also be increased by a factor of 10. Stiff boulder clays also made trench and burying a difficult option.

The main pipeline tie in spools, at either end, will be removed, as will short early production pipeline bundles.

As *OE* went to press, the project was on schedule and below budget, with the work 80% completed. The remaining activities are to remove what needs to be removed of the jacket in 2017, to plug and abandon one suspended subsea well, and to remove the redundant subsea flowlines and wellhead protection structures.

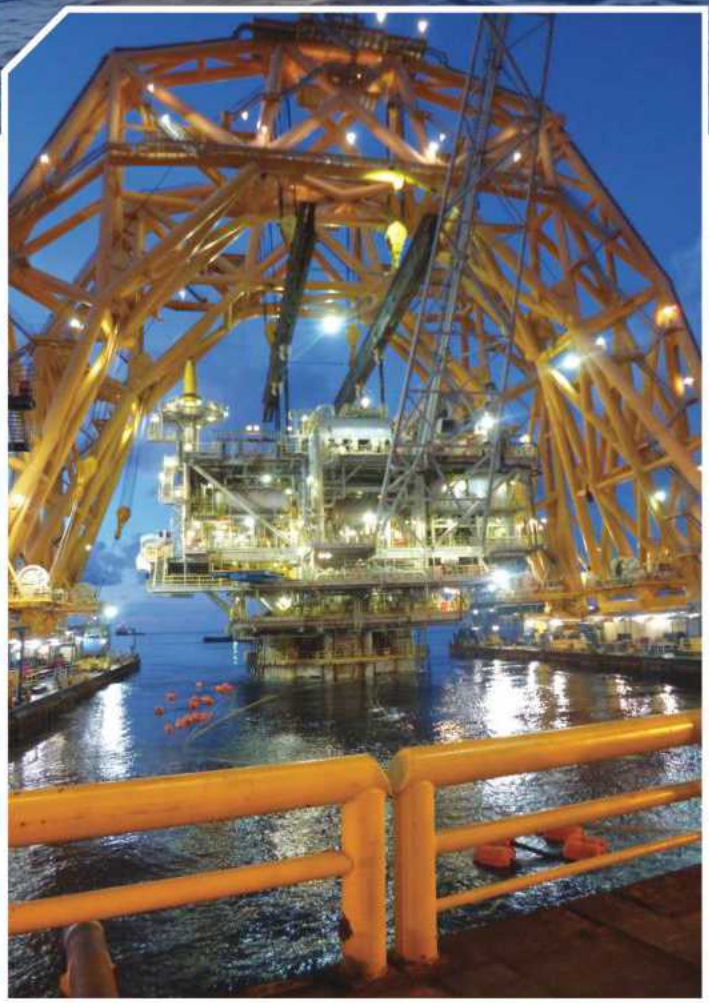
Once this is completed, together with the clean-up of identified oilfield debris, a seabed overtrawl and as-left survey will complete the program. **OE**

In-Depth

Up against Ospar

In Europe, and in other regions, the guiding principle for the rules governing oil and gas infrastructure decommissioning have been a return to a clean seabed. These principles are being challenged. Elaine Maslin reports.

Red Hawk Spar towed vertically to its reefing site.



Anadarko's Red Hawk topsides lifted off towing.
Photos from InterMoor.

As decommissioning work mounts in areas like the UK North Sea, where huge platforms were built to withstand harsh environments, there is now push back and calls for a different approach to decommissioning, i.e. one where substructures can be left in place.

Indeed, in the Netherlands, one firm, Engie, is taking the bull by the horns. Engie has proposed a rigs to reef pilot project in the Dutch North Sea (See page 28) in a move that will test the established rules – that anything weighing under 10,000-tonne has to be removed and anything, regardless of weight, built after 1999 has to be removed.

They're part of a growing group that is arguing that more not only could, but should be left in place than what is currently the norm. They say that more damage would be caused to the environment by removing the likes of footings and large seafloor-based structures than leaving them in place and that current practices need to be reassessed. This is because these structures have become marine life havens, protected as they are from fishing.

"A funny thing happens. Corals and barnacles form [on structures] and fish start feeding on them, using the platform as a habitat," says Tom Campbell, partner at law firm Pillsbury Winthrop Shaw Pittman, based in Houston. "What we have is not rigs to reefs, these platforms are the reef," he told an audience during the EXT:end event in Aberdeen in September.

"The question is," asks Campbell, who played a role in formulating the US government's response to the Exxon Valdez oil spill, "is all decommissioning appropriate?" The usual challenge is whether a clean seabed is appropriate, he says.

"But, I put forward a different challenge – the ecological cost of a clean seabed is too high and we should re-examine all our conclusions based on that hypothesis."

Scale of the challenge

While it's a global problem, with some 603 facilities in the North Sea to be removed and a staggering 3450 in the US Gulf of Mexico (GoM), the scale of the challenge differs in different basins. In the US GoM, for example, many of the facilities are small. Idle iron rules, developed to deal with hurricane wrecked facilities, have also meant GoM facilities have been removed quickly and that has meant an established removals market has been formed.

The GoM also has a rigs to reefs program and this is starting to include larger facilities, such as the Red Hawk spar (*OE*: May 2015) and soon also the Lena compliant guyed tower. However, rigs to reefs is not yet established offshore California or in the North Sea, where there are more, larger facilities, which creates a bigger challenge when it comes to removing them.

Decommissioning in the North Sea is governed to a large degree by the Ospar Commission (named after the Oslo and Paris conventions, which agreed terms for anti-dumping in the Northeast Atlantic) regulations. These stipulate that everything should be removed, but that a derogation order (exemption) could be given for structures installed prior to 1999, which weigh more than 10,000-tonne. Shell is looking to apply for an exemption for its three Brent concrete substructures and a fourth structure made from steel.

Dave Sinclair, head of decommissioning at Maersk Oil, told EXT:end the Ospar derogation helps to some extent, but that "the basic assumption of Ospar appears to be fundamentally flawed." Mark Richardson, from Apache UK, put it more bluntly: "Why aren't we cleaning up platforms [substructures] and leaving them? It causes less damage. The only people who benefit (from removal) is the supply chain and [because of the cost liabilities of decommissioning, meaning companies have to prove they can afford decommissioning programs] it [the liability] means you cannot sell on assets. It's madness. We need to take a step back."

Taking a step back

Indeed, some are taking a step back. An event, at the start of this month (December), is due to set out research being done under the INSITE (Influence of Structures in the Ecosystem) program, which is looking at the influence of man-made structures – such as oil and gas platforms – on the marine ecosystem. This, it is hoped, will provide hard evidence of how platforms and infrastructure react with sea life and whether it's of benefit. *OE* will report on that in an upcoming issue.

Some research has already been published. Campbell cites work carried out by Sylvia Earle, who has a PhD in phytoplankton and is explorer in residence for the National Geographic Society. "[Earle] says once created – the habitat around a rig – it's extremely disruptive to that habitat to remove the rig," Campbell says. Victoria Todd, a marine mammal scientist at Ocean Science Consulting, researched what influence facilities had on porpoises – and found that facilities were havens for porpoises, as well as other marine

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	78	57	23
Deep (500-1500m)	19	32	20	9
Ultradeep (>1500m)	35	13	12	6
Total	130	123	89	**38**
Start of 2016 date comparison	127	114	72	-
	3	9	17	**38**

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	35.00	333.00
Deep	11	941.00	1595.00
Ultradeep	36	10,391.00	12,113.00
United States			
Shallow	13	73.00	166.00
Deep	16	787.00	888.00
Ultradeep	19	2402.00	2318.00
West Africa			
Shallow	107	3708.00	13,791.00
Deep	31	3392.00	5000.00
Ultradeep	10	1335.00	960.00
Total	243	**23,029.00**	**36,831.00**
(last month)	(241)	(22,950.80)	(36,837.56)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	859	42,722.00	412,261.00
(last month)	(864)	33,124.84)	(404,049.86)
Deep	119	6794.00	67,663.00
(last month)	(118)	(6647.16)	(67,177.14)
Ultradeep	70	15,015.00	41,188.00
(last month)	(73)	(15,062.40)	(41,288.00)
Total	1,048	**64,531.00**	**521,112.00**

Pipelines

(operational and 2015 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	40,907	(42,126)
Planned/ possible	23,814	(24,738)
	64,721	(66,864)
8-16in.		
Operational/ installed	81,264	(83,417)
Planned/ possible	49,708	(49,666)
	130,971	(133,083)
>16in.		
Operational/ installed	94,248	(93,956)
Planned/ possible	45,421	(43,625)
	139,670	(137,581)

Production systems worldwide

(operational and 2015 onwards)

Floaters		(last month)
Operational	295	(273)
Construction/ Conversion	48	(47)
Planned/possible	300	(323)
	643	(643)
Fixed platforms		
Operational	9101	(9258)
Construction/ Conversion	78	(101)
Planned/possible	1377	(1384)
	10,556	(10,743)
Subsea wells		
Operational	4878	(4843)
Develop	354	(437)
Planned/possible	6431	(6512)
	11,663	(11,792)

Global offshore reserves (mmboe) onstream by water depth

	2014	2015	2016	2017	2018	2019	2020
Shallow	14,557.52	21,242.45	41,590.62	27,267.21	10,773.48	19,093.94	16,665.07
(last month)	(14,543.34)	(21,245.45)	(30,282.16)	(24,000.35)	(10,927.69)	(21,437.97)	(17,709.65)
Deep	4477.35	972.99	1733.40	5442.18	2556.20	4430.98	4561.99
(last month)	(4477.34)	(976.73)	(2039.73)	(5106.94)	(2585.57)	(4342.14)	(4250.39)
Ultradeep	2342.82	2023.19	3137.60	2460.70	3287.30	4096.56	9295.86
(last month)	(2342.81)	(2023.18)	(3145.58)	(2481.25)	(3333.11)	(4144.56)	(9237.36)
Total	21,377.69	**24,238.63**	**46,461.62**	**35,170.09**	**16,616.98**	**27,621.48**	**30,522.92**

Source: InfieldRigs 8 Nov 2016

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	97	65	32	67%
Jackup	401	227	174	56%
Semisub	118	70	48	59%
Tenders	28	19	9	67%
Total	644	381	263	59%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	30	25	5	83%
Jackup	25	4	21	16%
Semisub	11	8	3	72%
Tenders	N/A	N/A	N/A	N/A
Total	66	37	29	56%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	11	3	8	27%
Jackup	119	64	55	53%
Semisub	32	13	19	40%
Tenders	20	13	7	65%
Total	182	93	89	51%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	23	18	5	78%
Jackup	49	29	20	59%
Semisub	23	17	6	73%
Tenders	2	1	1	50%
Total	97	65	32	67%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	49	32	17	65%
Semisub	37	24	13	64%
Tenders	N/A	N/A	N/A	N/A
Total	87	56	31	64%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	2	1	1	50%
Jackup	117	83	34	70%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	123	87	36	70%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	19	14	5	73%
Jackup	20	8	12	40%
Semisub	5	3	2	60%
Tenders	6	5	1	83%
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	0	2	0%
Semisub	N/A	N/A	N/A	N/A
Tenders	N/A	N/A	N/A	N/A
Total	2	0	2	0%

Source: InfieldRigs 10 Nov 2016

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

life that are able to shelter from fisheries. "Todd says mammals go from platform to platform as they migrate around the North Sea. If removed, [it would] eliminate key feeding areas," Campbell says. The University of California also says some platforms in North California produce more benefit than any natural habitat, Campbell adds.

Approaches to how wildlife is impacted by oil facilities – or just oil, were challenged during the Exxon Valdez oil spill in Prince William Sound, Campbell says, who led a federal government scheme for assessing the ecological impact of the spill. He says that during that process a series of tools for measuring ecological impact was developed. One approach challenged steam cleaning a beach versus cold water cleaning. While the steam cleaning removed all the oil, it also destroyed the life on the beach.

This work, which led to the development of analysis tools such as net environmental benefit analysis (NEBA), and habitat equivalency analysis, "challenges the presumption that a clean seabed is the best option," Campbell says.

"We have come to the conclusion that ecological services come from these structures [platforms, etc.] and that these can be quantified. In our infancy, we came to the clean seabed conclusion and that wasn't based on science, it was based on emotion. Now we have information." He says, if we acted now, as we would have done 25 years ago, habitats would be destroyed. "It would be irresponsible and that should be the new paradigm going forward."

Indeed, another speaker said if the paradigm didn't change, the industry would be forced to remove the ecosystems that had been created around platform structures and turn the seabed into a "desert," like the rest of the seabed had been, due to fishing.

Such an approach is just what Engie is proposing to do. The firm is seeking to leave in place two relatively small southern North Sea steel jackets, removing a third, nearby, as a control. The trial, if it goes ahead, will run for 15 years before any substantive results can be delivered. Subject to funding, the firm plans to enhance the reef area, but, if the project isn't a success – based on criteria set out by environmental groups – it will still remove the structures.

Challenging Ospar

Challenging the Ospar regulations, may not be easy or quick, EXT:end heard. Engie is looking at a 15-year wait for results from its project. Some would like change to come sooner. But, there's a five-year review period, which is coming up in 2018. Recommendations would need to be put forward before 2018 by the Oil and Gas Industry Council, which submits them to the Department for Business, Energy and Industrial Strategy, which then submits the recommendations to Ospar.

It's a long process and it involves challenging potential public perceptions that industry's wish not to remove structures is just about cost. "It is difficult for operators to say they don't want to remove stuff from the North Sea," Sinclair says. People will say 'of course you don't.'" He says that scientific evidence needs to be built up to show why a change is needed. But, a delegate at the event countered: "For every beautiful picture of fish, it is easy to show a picture of a deformed fish from contamination," adding that the public doesn't even trust scientists at the moment.

There's also a lack of appetite by operators to stand up

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Brent field CGI - A CGI illustraton of the Brent field. Image from Shell

The Brent D platform. Photo from Shell.

and say removal is the wrong thing to do. "It's not a view expressed enough in the industry. It's just not done," says Tim Martin, managing director, UK, Ramboll. There is the work through the INSITE program, through Oil & Gas UK, an industry body. But, "I think oil companies should stand up more and say we are not doing the right thing," says Callum Falconer, director, CRF Consultants. John Warrender, managing director of Addax Petroleum, adds: "Companies are still more focused on managing uncertainty than on influencing change."

Possibly more likely is that there could be an incremental move towards leaving structures in place, through precedent allowed by the current Ospar regulations, which allow derogations in certain circumstances. Shell's Brent facilities, for example, come within the derogation rules, subject to an application to Ospar, and would start to set a precedent, as well as provide the industry with further evidence with which to make its case. Engie's work will take this further, and address the vast majority of facilities which are much smaller than the huge Brent structures. And, not every platform will provide a significant habitat, Campbell says. Each will have to be assessed on a case by case basis.

For Brian Twomey, managing director at Reverse Engineering, the key is how you interpret regulations, in the UK as well as elsewhere.

"Many are realizing how expensive it is and want to reduce costs," he says. "The secret is how to interpret and apply regulations. To make that successful, you need partnership between regulators and oil companies and the contractors delivering the work.

"Most of our work now is working with regulators and oil companies about what regulations mean. How much do you have to remove, how clean is clean… I would see the North Sea is behind the rest of the world on this point." He points to the US GoM where, while there's a mandate to leave the seabed clean, facilities like the Red Hawk spar have been disposed of on the seabed. "Ospar is not the whole problem, it is only part of it," he says.

But, if structures are left in place, what then? Who has ownership and responsibility for structures left in place in the future? Richardson says that it shouldn't be a problem. "If we meet regulatory requirements, at some point we must be able to sign off that it's now a clean seabed. There are plenty of wrecks out there that have same issue." Others point to the thousands of ship wrecks lining the UK's coasts. Rick Wenning, principal and leader ecological services, Ramboll, points to the former nuclear submarine, *HMS Scylla*, which was engineered down, made safe, cleaned and parked as a wreck dive site.

Engie's project could also help set the ground rules for such issues. It could just take some time before it can offer at least some of the answers. **OE**

FURTHER **VIEWING**

VIDEO: Red Hawk artificial reef
Anadarko discusses the decommissioning of its Red Hawk cell spar, which took on a new life as an artificial reef.
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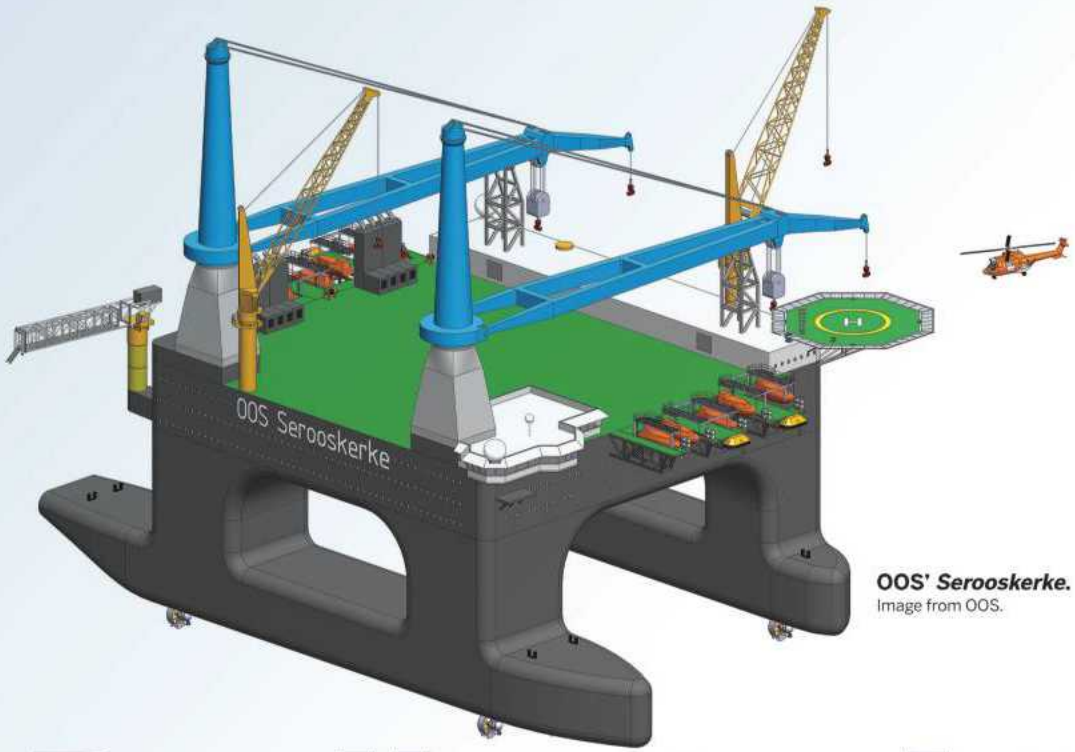


OOS' *Serooskerke*.
Image from OOS.

Dedicated to decommissioning

The offshore lifting market for decommissioning has been relatively small so far, but it won't stay that way. Elaine Maslin looks at some new concepts edging into the market.

With more than 40 years of oil and gas production under its belt, the UK North Sea has reached the time in its life where some of its more than 400 facilities are being removed.

However, while a large chunk of the infrastructure in place is mature – many facilities are well beyond their design life – the topsides and jacket removals market is less so.

To date, topsides removal has used a piece-small approach, whereby modules are removed, piece by piece, largely due to what is available on the market.

The top end offshore heavy lifting market is served by just a few semisubmersible crane vessels owned by even fewer companies, namely Heerema Marine Contractors (HMC), with the *Thialf* (14,200-tonne lifting capacity) and Saipem, with the S7000 (up to 14,000-tonne).

A monumental change came earlier this year, with the introduction of Allseas' *Pioneering Spirit* twin hull, mega lifting vessel to the market. The unit, which performed its first job lifting out the Yme mobile offshore production unit offshore Norway (*OE*: September 2016), brings an up to 48,000-tonne topsides lifting capacity and up to 25,000-tonne jacket lifting capacity to the market (*OE*: April 2016). HMC is also building the two, 10,000-tonne crane (20,000-tonne combined) capacity *Sleipner*.

But, it's not all about big lifts. Of the approximately 600 platforms in the Northwest Europe – including Norway, UK, Denmark, Netherlands, and Germany – about half have topsides weighing less than 1600-tonne, according to an Oil & Gas UK database. About 200 are under 1000-tonne, 375 under 3000-tonne and just over 400 are under 4000-tonne.

However, even for smaller lifts, there are a limited number of heavy lift vessels and for many years this has been the status quo, with the exception of the occasional float over installation for the larger structures.

"It's very clear there isn't the toolbox to do it whatever size

you're looking at," says Lynne Nordby, senior manager specialized tonnage, Maersk Broker, at Decom Offshore, in Aberdeen earlier this year. "Even for the smaller piece meal, we are still looking at quite a reduced market of vessels. We haven't got all the tools in the toolbox." But, that could soon change. Existing and prospective vessel operators are taking note and there are an increasing number of concepts eager to join this market, for the small and mid-range lifts.

OOS

Overdulve Offshore Services (OOS) is a relatively new entrant to the market. In August, the company ordered two new semi-submersible combined accommodation and crane (SSCV) vessels from Chinese shipyard China Merchants Heavy Industry (CMHI).

The *OOS Serooskerke* (named after a village in the Netherlands) and *OOS Walcheren* (a former Dutch island, now part of the mainland) will be capable of lifting and positioning with two 2200-tonne capacity cranes, with combined 4400-tonne capacity, using Huisman Equipment-supplied cranes. The cranes will be used for decommissioning subsea structures, foundations, moorings, floating and heavy lift platforms for offshore wind structures in deepwater.

The vessels will each provide beds for 750 people, and will be DP3 capable and able to perform subsea lifting in up to 3000m water depth, OOS says.

The engineering and construction phase is estimated to be completed in Q2 2019 for the first SSCV (*OOS Serooskerke*) and Q3 2019 for the second SSCV (*OOS Walcheren*)

And yet, moving into decommissioning wasn't OOS' initial intention. OOS, founded and led by Dutchman Leon Overdulve, bought two newbuild semisubmersible crane and accommodation vessels, which had been due to work off Angola for Sonangol, but had been left stranded by the failure of Marine Subsea & Consafe, a partnership. OOS has since secured an opportunity with Petrobras offshore Brazil, which the units were a good fit for.

The two units, *OOS Gretha* and *OOS Prometheus*, built at CIMC Raffles in 2012 and 2013, started work in 2014 as accommodation vessels, with *OOS Gretha*, which has two Huisman 1800-tonne cranes, as well as accommodation for 618 people, also doing regular heavy lift work. *OOS Prometheus* has 400 beds and a 1100-tonne crane.

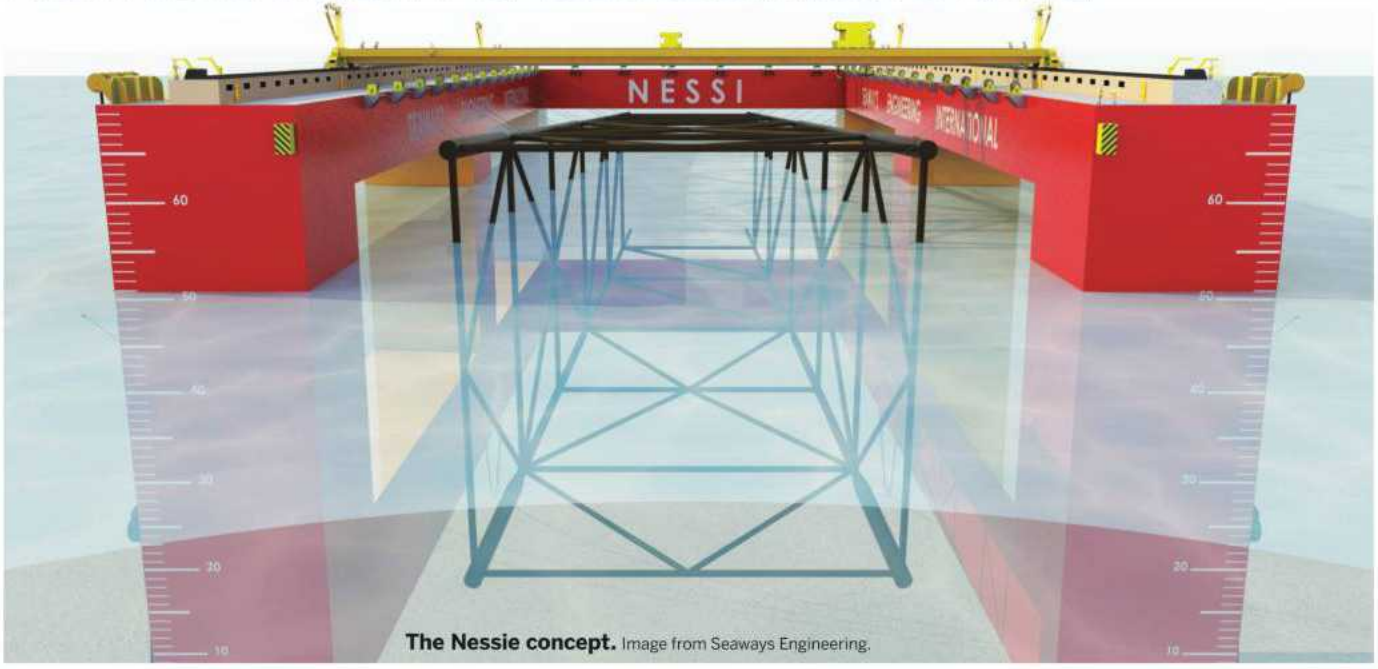
While the cranes on *OOS Gretha* made the unit costlier to run, challenging its economics as an accommodation unit, running the *OOS Prometheus* alongside and supplementing the accommodation unit contracts with heavy lifting work proved profitable. This gave Overdulve the idea that they could also be profitable as heavy lifting vessels in a wider market, by increasing the crane and accommodation capacity, thus creating the *OOS Serooskerke* and *OOS Walcheren*.

"We can operate and manage a unit like *OOS Gretha* for US$170,000 a day. So, I thought, why are these heavy lift semis in the world so expensive? We looked into the decommissioning market. Only 5-10% (of topsides needing lifting out) are heavier than 10,000-tonne. We saw huge potential for medium-size heavy lifting. We re-engineered the *OOS Gretha* design to have larger cranes and more accommodation."

After a couple of studies with oil majors, using the concept, the firm was told the *Gretha* would make the tender list. For one particular Gulf of Mexico spar decommissioning project, with its deepsea capacity, the *Gretha* would remove deepwater umbilicals and perform preparation works for topsides removals, as a flotel, before removing the topsides in five lifts. This would include a system to keep the five separate sections in their respective places during the lift program. This would all happen over six months, Overdulve says.

OOS, he says, will be able to perform these jobs on a turnkey basis. Indeed, it's already found a partner, Modern American Recycling Services (MARS) in Louisiana, which

OOS' *Walcheren*. Image from OOS.



The Nessie concept. Image from Seaways Engineering.

has disposal yards based on scrapping for zero cost – MARS makes its cash back by turning the steel quickly into scrap steel to re-sell. Historically, MARS has disposed of barges and ships, but it entered the platform decommissioning market in 2010, opening a new yard in Gibson, about 76mi outside New Orleans. Last September, MARS also secured a lease on land in Denmark for a yard there. The new site, at Port of Frederikshavn, is due to start operations in 2017, and will cover 270,000sq m with 381m of water front.

Overdulve, who has worked offshore since he was 17 and has worked in Nigeria, the Middle East and Brazil, is eyeing a global market. "Right now, in Thailand, there are 80 small units to be removed, but especially in Asia, there are a lot of small units." Because of the deep draft of the units (26m, due to not having retractable thrusters), very shallow waters will not be accessible ("there is always a piece of the market you cannot cover," Overdulve says). Norway might also be too expensive. "But still, there's 60-70% of the decommissioning market we could cover," he says. "It is a big enough pie."

Twin marine lifter

Meanwhile, a single lift system, for which a newbuild contract was placed with China's CIMC Raffles, as *OE* went to press, is being marketed by Shandong Twin Marine (SDTM). Some may recognize it as the SeaMetric concept, developed in the late-2000s. Norway-based SeaMetric had a Brent Delta topsides removal study with Shell and a long-term agreement with Fairfield Energy and started building its system in 2007, but various issues meant the project didn't come to fruition. SeaMetric went into liquidation in 2010 and the company Twin Marine Heavylift took its place.

In the UK, The Decommissioning Co. (TDC) is marketing the Twin Marine Lifter (TML) technology, now owned by joint venture Shandong Twin Marine. TML is capable of installing and removing topsides weighing up to 34,000-tonne and 16,000-tonne jackets.

The system consists of three DP3 vessels, each 206m-long and 42m-wide. Two have skid mounted lifting arms centrally balanced on the vessels, facing to starboard on one and to port on the other, so they can maneuver each side of a platform and lift the topsides free together, placing it down on to an identical third vessel.

TML would be water depth independent and able to work in up to 3m significant wave height, verified through 1:40 scale model test done in the Marintek/SINTEF ocean laboratory in Trondheim, says Mark McAllister, a director of SDTM and TDC chairman, at Decom Offshore in Aberdeen. It would be able to remove almost all North Sea topside types in a single lift and any North Sea jacket in no more than two lifts, he says.

Prior to the execution of an operation, first the topsides (and jacket) is prepared for lifting by installation of lifting interface points and any required local strengthening, etc. Then, the two lifting vessels position in towards the jacket. On the inboard side of each vessel is a buoyancy tank on each lift arm. On the outboard side, there is a ballast tank on each lift arm. Seawater is dumped from the inboard buoyancy tanks to get the lifting arms into position. Then, water is pumped from the buoyancy tanks to counter balance (ballast) tanks until 95% of the weight of the topsides is taken by the vessels, SDTM says.

The Twin Marine Lifter concept. Image from SDTM.

Each TML arm can take individual loads to make up the total weight of the lifted

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object and to suit the strength of the main structure of the lifted topside. When all is cleared for lift-off there's a second stage of dumping seawater in less than 10 seconds that lifts off the topside from the jacket.

Jacket lifts are done using winches where the 1600-tonne hooks are running from the tip of each of the arms and connected through a diver-less operation to lifting points clamped to the jacket legs.

SDTM was incorporated in April 2016 and design enhancement initiated to reflect the latest rules and regulations. This work was completed in October 2016 and submitted to the yard (to be named soon) as part of the TML construction contract.

TDC was started in 2011, led by McAllister and Terry Kimber, both of whom worked at Fairfield Energy, the former as CEO, up until 2011. Their work looking at decommissioning ideas for Fairfield's Dunlin platform led them to believe there would be better solutions to benefit the market, not just in terms of technology, but also commercially, through work with insurance companies. This led them to the TML system.

Platform installation and removal is offered by SDTM at a price fixed for several years in advance and underpinned by an insurance package developed with Munich Re and in cooperation with Aon. This means that the insurer is involved at every step of the project, from yard selection, detail and fabrication design phases, during construction, assembly, commissioning, load testing, sea trials and full scale offshore testing, SDTM says.

The result is a performance guarantee for the TML system, which underpins the price guarantee related to the contract. This helps remove some of the uncertainty around decommissioning costs, which is a burden to operators who may need to arrange decommissioning liability – funds that could be spent elsewhere.

During the Decom Offshore event, McAllister said the system will be available for the 2020 spring season.

Nessie

Another concept, based on an established idea, is being offered by California's Seaways Engineering International: the "novel extended semisubmersible" (Nessie). The Nessie is a box-section semisubmersible with six columns and a gate at the aft end. "It's basically a floating dry dock, without the bottom," says Joe Glass, managing director (UK), Seaways, with inherent stability, due to its deep draft and huge displacement.

Seaways has an outline design for two versions, one, measuring 220m by 120m, for jackets weighing up to 18,000-20,000-tonne, with a capability to carry up to 300,000-tonne in total. A smaller unit, measuring 60m x 60m, would be for smaller southern North Sea type platforms in the 3000-4000-tonne range.

The idea is that the vessel moves to within 100m of a structure to be removed, propelled by a DP system or moved using tugs. There it would stabilize and be anchored using a 12-point mooring system, if it didn't have DP. Then, it ballasts down, to move under the platform to be removed – using laser positioning for accuracy – and its gate is opened to allow it to slot under the platform.

If it's moored, winches on the mooring lines will be used for positioning, Glass says. Ballasting would either be via ballast pumps or compressed air, using an open tank methodology (water is allowed in through open holes in the hull and compressed air is pumped in to de-ballast). The gate is likely to be a latch gate, also operated using ballasting. Once under the platform, the Nessie slowly de-ballasts, to lift the pre-cut topsides off, resting on 40 strategically placed strand jacks.

Next, the Nessie is rigged up to the pre-prepared jacket (using remotely operated vehicles), also pre-cut, and de-ballasts further to lift it free. It is then swung around to horizontal, during which time it's emptied of air to make it neutrally buoyant, where it is secured for transport. The rigging for each jacket removal would be designed for each jacket, due

Damen does decom

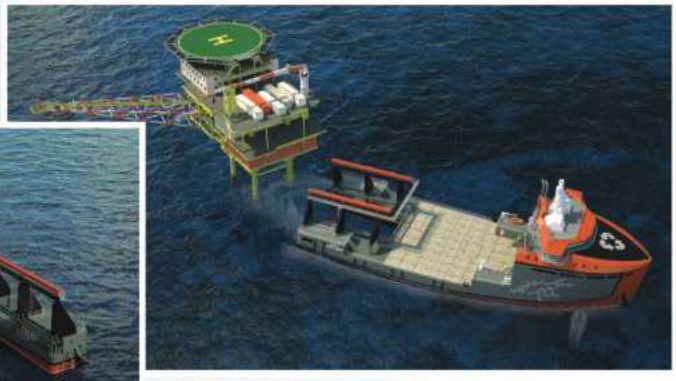
Dutch firm Damen Shipyards Group is also offering a decommissioning concept. It unveiled its offering, called the Damen Decommissioning Series, earlier this year.

It is a split stern monohull concept, which would be used for platform removal, and subsea cleaning and other removal work. The design is based on research carried out at Damen by one of its undergraduate interns. Justin Rietveld, studying Maritime Technology at the Rotterdam Mainport University of Applied Sciences, was assigned to investigate the potential niche markets for new vessel designs in the oil and gas decommissioning sector.

"This research started off with the idea of developing a decommissioning vessel based on Damen's existing portfolio," Rietveld says. "However, we soon found out that this market needs more.

"This ship will be able to reverse up to a jacket, where it will be ballasted to sink below the platform. Upon de-ballasting, the vessel will rise up to pick up the platform."

The preliminary estimations of the vessel's capabilities show that it will be able to perform decommissioning of fixed platforms of up to 1600-tonne in weight. The concept design includes modular add-ons, such as a crane, accommodation modules or helideck, which could be temporarily installed, so that the vessel could be used for other purposes. Adding a temporary platform to create a solid stern could also enable use of the increased deck space for transporting and installing monopiles and foundations for the offshore wind industry, Damen says.



The Damen Decommissioning series.
Images from Damen.

SkyJack's the limit

Dutch firm SkyJack Marine prepared another concept, a twin self-elevating semisubmersible platform, using two SkyJack 16000 units. The SkyJack was designed for bringing heavy structures, such as concrete tunnels, wind turbine foundations, etc., from the quay to the water and vice versa. But, the firm saw it could also be used for removing topsides.

The unit is based on a 70m-long, 40m-wide, monohull pontoon with four jacking systems, using a hydraulically controlled heavy duty pinning system, and four 55-80m tall, 3m-diameter spudlegs.

It would be limited to below a certain water depth, with maximum pile length below the barge at 28m. But, because it's on legs, it is less limited by wave conditions for lifting operations. Maximum operational wave height is 2m, the firm says, with maximum wind speed at 14m/s.

A SkyJack unit.
Photo from SkyJack Marine.

to the array of different designs out there, Glass says. They wouldn't be looking to perform operations in above 1-1.5m wave height, he adds.

Glass says that the cost would be low compared to building other more complex units and it could also be built in more yards, using a simple flat plate design. Seaways estimates a unit could be built in 20 months. Seaway is at an early design phase with the Nessie, however.

Glass has a long history in the industry, working on dive support vessels as a chief engineer in the early 1980s, during which time he met Seaway's CEO and owner Craig Lang. Lang also has a history with offshore heavy engineering, having designed a multipurpose semisubmersible (MPSS), back in the 1980s, and which was approved by Shell. Several versions of the MPSS are in operation worldwide, including the Shell/BP Na Kika host facility, BP's Thunder Horse, BP's Atlantis, Chevron's Blind Faith, the Ichthys LNG project, Petrobras P51 and others. Lang's inventions also include the Apache reel ship and steel risers in catenary.

He describes using hydraulic motion control as a "money pit." "The deep draft [on the Nessie] works with the pontoons to dampen any movement. The deletion of crane booms further reduces risk and costs related to hoisting. Other semisubmersible crane vessels are built to support the crane and then the crane is built to support the load and that idea is expanded again and again. It is that kind of thinking we avoid." OE

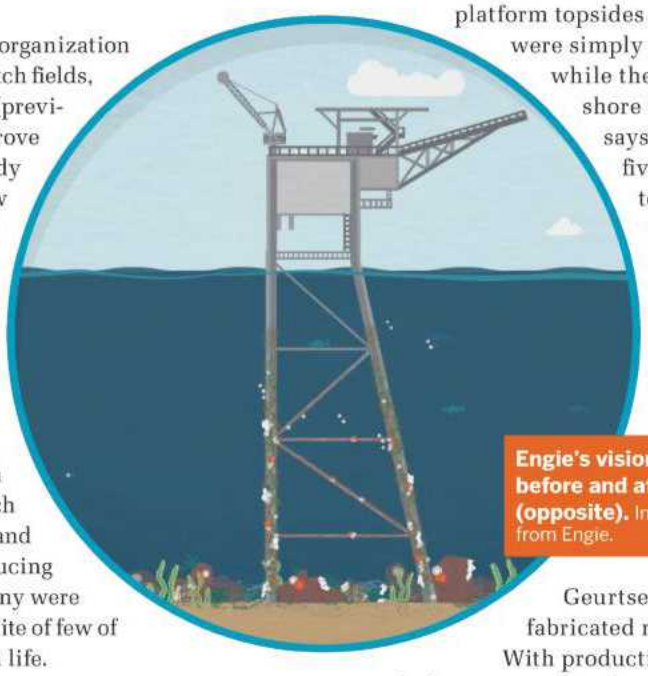
Platforms, naturally!

After proving a deft hand at reusing topsides, Engie is now looking to do the same with jackets – but instead of moving them to new sites as production facilities, the firm wants to make them into marine habitats. Elaine Maslin reports.

Leaving rusty former oil and gas production facilities in place may be a hard sell. But such a move – for just the support structures at least – is increasingly touted, not only a more viable option for the industry, but also for marine life (See page 16).

With support from Dutch state organization EBN, which has a stake in most Dutch fields, the Dutch arm of operator Engie (previously GDF Suez) is setting out to prove this assumption. The firm, already skilled at reusing topsides, is now planning to leave in place two of a cluster of three relatively small platform jackets, which are due to be decommissioned. Under the plan, a third will be removed as a control.

It's part of a wider program of decommissioning by the firm, which has 39 platforms in the Dutch sector of the North Sea, four of which are manned production complexes and 18 are unmanned, with 100 producing wells, five of which are subsea. Many were built in the 1970s and 1980s and quite of few of those are past their original design life.



Engie's vision, before and after (opposite). Images from Engie.

Reuse

Ideas for these structures include removing them, repurposing them for other fields or repurposing them for something else. "We have done the first two and now we are looking at the third one," says Aart Geurtsen, project coordinator, Engie, at the Offshore Energy conference, Amsterdam.

Indeed, in the past, Engie has removed and reused six platform topsides within the Netherlands. Three were simply moved straight to another jacket, while the other three were removed to shore for refurbishment work first, he says. The timing has been suitable in five of these projects. In the sixth, topsides were taken from an older field for use on a new, higher production field. A new platform was then built to replace the removed facility. Reuse has enabled Engie to shorten schedules, Geurtsen says.

Jackets were not reused because of different water depths involved, concerns about fatigue life of welded nodes and the risk of damage during removal, Geurtsen says. New jackets could also be fabricated relatively economically.

With production now set to be on long-term decline, permanent decommissioning is rising up the schedule. Engie's focus is on its K and L blocks, where most of the mature assets are.

Particular focus is on block L10, home to the G, D and C

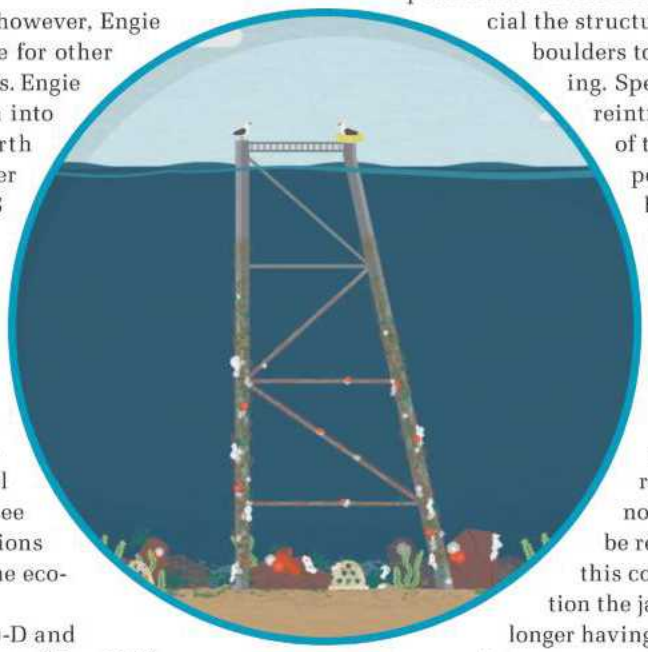
satellite platforms, where production ended in early-2016. The platforms, in 26m water depth, on 33m-tall jackets, have been cleaned and pipelines abandoned. A rig is due to come in to start plugging and abandonment work before the end of the year. Once this work is complete, the platforms will be put in lighthouse mode and removal contractors given a large window within which they can remove the topsides.

Reuse as reefs

Rather than remove the jackets, however, Engie is looking to leave them in place for other uses, specifically, as artificial reefs. Engie has been involved with research into artificial reefs, the Living North Sea Initiative (LINSI) and another ongoing program with IMARES Wageningen.

"Based on this research, we think there's potential for rigs to reef in the North Sea," Geurtsen says.

Together with EBN, Engie has taken the initiative to launch a pilot project, to put the science to the test. "We want to convert steel jackets into temporary reefs, to see whether some offshore installations deserve a second life to restore the ecosystem," he says.



Engie says that the L10-C, L10-D and L10-G satellites, about 70km west of Den Helder, are in a good spot for such a project, because they are on the edge of the Friese Front marine reserve area, part of the Natura 2000 program. "We think they [the jackets] could enhance the ecological foundation of that area. There used to be a lot more hard substrate, a lot more oyster grounds in this area," which this project could help reinstate. Indeed, the Dutch government would also like to reinstate hard substrate, he says.

Platforms Natuurlijk

The planned pilot project (subject to government approval) is being called Platforms Natuurlijk (Dutch for "naturally"). The plan is to leave two of the three jackets and remove one, as a control. There will be an exclusion zone of 500m and the potential to invest in measures to add to how beneficial the structures could be, by adding more boulders to the seabed, depending on funding. Species like the flat oyster could be reintroduced, Geurtsen says. The tops of the structures, which will be left poking out of the water, could also be seabird breeding grounds. Lighthouse buoys would be placed around the facility to warn any nearby shipping. The idea is to leave them for 15 years and monitor the results through environmental groups.

Criteria for the project's success will be agreed with environmental groups and if these are not met, the platforms would still be removed, Geurtsen says. While this could pose issues over what condition the jackets would be in by then – no longer having sacrificial nodes or ongoing maintenance – posing a challenge when it comes to removal, it's worth the risk, he says.

To date, the project has been presented to various non-governmental organizations and other stakeholders, and the legal and regulatory framework is being discussed with regulators, etc. The next step is applying for a permit to do the work. Many will be watching. **OE**

Dutch decommissioning

The Dutch North Sea might contain a smaller slice of the decommissioning pie, but it still has a significant installed base and the Dutch government and industry is working to quantify the work that needs to be done.

There are 150 platforms in the Dutch sector, 23 of which have already been decommissioned, and 1400 wells to be abandoned, at an estimated cost of about €4 billion (according to estimates by VBN), Dirk Jan van Orden, GM legal and government relations Petrogas E&P Netherlands, told Offshore Energy, a conference in Amsterdam. "We are not talking peanuts," he says. "A lot has to be done when these platforms cease production."

Just as in the UK sector, rules in the Dutch sector mean that mining facilities offshore of the Netherlands, which oil and gas structures come under, have to be removed at the end of their life. A master plan for decommissioning and reuse was expected to be published late-November [just as *OE* went to press].

"We think it is important to have open dialogue of each other's plans," van Orden adds, saying that "proper estimates," should be shared, but only after decommissioning plans are finalized, reuse of infrastructure for other purposes should be looked at, e.g. an offshore electricity ring of carbon capture and storage. Questions around long-term liability for any structures left also need to be addressed.

But, removing facilities too early could strand existing resources, a concern which is echoed in the UK sector, van Orden warns. ▪

To extend or end?

Operators in mature basins are facing decisions about whether to invest in life extension projects or bite the decommissioning bullet. Elaine Maslin sets out the detail.

Keeping platforms going. Work on Piper Bravo by Oxifree. Photo from Oxifree.

The decision to decommission a platform, or to keep it running isn't a clear cut one, especially in today's uncertain oil price environment.

Yet, not making that decision can make the situation worse, either resulting in a costly deferral period or missed opportunities to tap remaining resources. The issues around such decisions were discussed at EXT:end North Sea Late Life Summit and Exhibition, in Aberdeen, mid-September.

John Warrender has had to assess these options closely. He's managing director of Addax Petroleum, a role through which he's been involved in parent company Sinopec's share in the former Talisman North Sea business (now 50-50 owned by Repsol and Sinopec). Talisman North Sea, now Repsol Sinopec Resources UK, has one of the most complex and largest set of late-life infrastructure in the UK with 10 offshore assets, two floating production facilities, plus an onshore terminal at Flotta, Orkney.

Nearly half the assets have been producing since the 1970s, including Auk, which started up in 1975, Montrose in 1976, and Claymore in 1977. The rest are from the 1980s, including Buchan Alpha, Tartan, Fulmar, and Clyde, with Arbroath and Piper Bravo the newest in the fleet, having started production in 1990 and 1993, respectively.

Warrender says to extend life or end it has been a topic for a number of years. It's "a balance of lean late-life with decommissioning," he says. "When I first got involved (at Talisman), low cost operations and deferral for a time was the right

approach, but in time that becomes obsolete and it was to Talisman's cost. It is not binary. Life is a lot more complex than that."

The task of gathering disparate and independent information needed to make decisions and decide corporate policy, in a changing fiscal (tax) regime, is underestimated, he says.

Part of the problem is around actually making a firm decision over policy – to be a late-life/hub operator, i.e. a business development opportunity, or to go into decommissioning and gain an early mover advantage in this market. If decommissioning becomes the focus, it needs a different operating policy, he says. "In some ways, decommissioning is less complex [as an activity] but it demands more of the organization. It will be done in campaigns, requiring collaboration and integration, and that will be the challenge."

But, even with late-life operating models, where decommissioning is deferred, companies can fail to make the most of what they have, simply focusing on deferral rather than opportunities, he says. "I'm constantly surprised companies don't evaluate properly the life extension possibilities, i.e. subsurface resources potential and not just their own but their neighbors," he says. "In my experience, this is one of the sticking points, annually fluctuating from decommissioning to extend, with too much emphasis on justifying extend than actually quantifying the opportunities."

It's not an easy task, however. The shift in how operators have to manage their assets – and change their organization – as they move to cessation of production (COP), and how quickly this can happen, was also highlighted at the event.

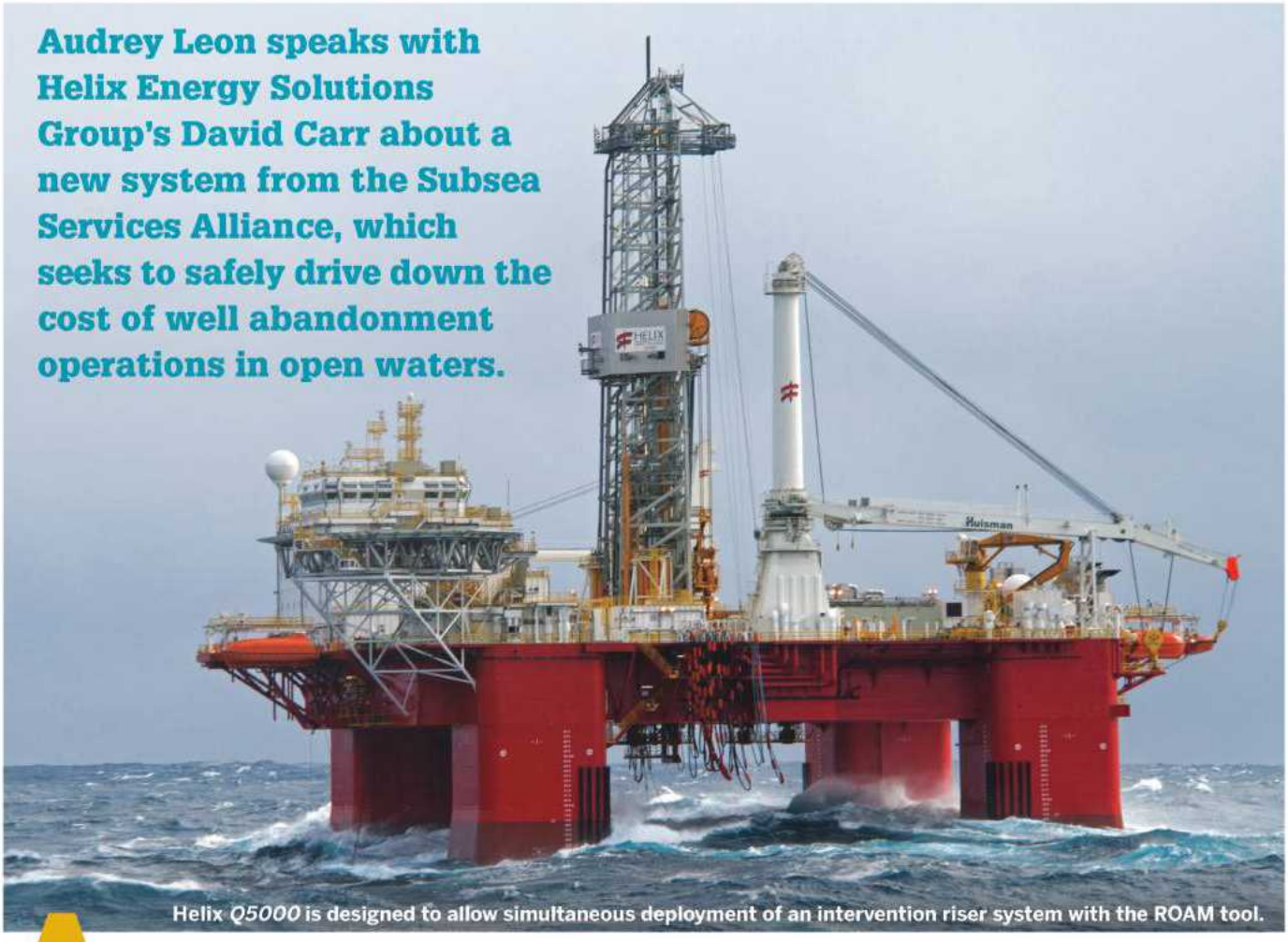
Innes Lawtie, now structural technical authority at Statoil, says when he joined the Armada asset team (under BG Group) it was a growth asset, but within 18 months it was looking at a potential COP date. A delegate in the audience, currently working for BG Group (part of Shell), says as Armada moved towards COP, it had been through a period of review around asset integrity, including bringing the function back in-house, specifying the work a contractor now does, instead of contracting the whole function, including decisions, to the contractor.

But, such work can be seen as offering little value. "The biggest battle is getting time to get inspections done," said the delegate, "as it's seen as the lowest value discipline within the organization."

Hugh Borland, lead structural engineer for BP, says that thorough knowledge and understanding of the asset would enable more critical decisions to be made, but that the industry wasn't good at data management. "We (as an industry) are so poor at it," he says. Reports are stored on single hard drives, and not available to the enterprise. "A study has been done, someone has thought about it, but there is a huge inefficiency." OE

Open water **abandonment**

Audrey Leon speaks with Helix Energy Solutions Group's David Carr about a new system from the Subsea Services Alliance, which seeks to safely drive down the cost of well abandonment operations in open waters.



Helix *Q5000* is designed to allow simultaneous deployment of an intervention riser system with the ROAM tool.

As the oil and gas industry settles into its "lower for longer" mindset, service companies are looking to help operators cut costs while continuing to ensure safe operations.

The Subsea Services Alliance (a collaboration between Helix and OneSubsea, now owned by Schlumberger) launched its Riserless Open-water Abandonment Module (ROAM) system in early October this year, with the aim of reducing both cost and risk in lower completion abandonment operations.

"One of the key drivers for developing this system was to find a way where we could extend our current riserless work in the North Sea, and take that a step further to be able to pull tubing in open water," says David Carr, vice president – Commercial, Helix. "We wanted something light enough that could go onto the older wells in the UK, but also could work at the pressures and depths down to 3000m that we find in the Gulf of Mexico," Carr says.

"Going forward, as we developed it and we discussed it with other operators, there was and remains a lot of interest

to use the system to get away from the traditional cut and pull methodology of abandoning wells."

Carr says in traditional operations, Helix will take a riserless or riser-based vessel to do a lower abandonment, where plugs are set at the bottom of the well, essentially killing the well, and then cutting the tubing. "The operator then needs a rig to come onto the well to cut and pull all the casing strings out," he says.

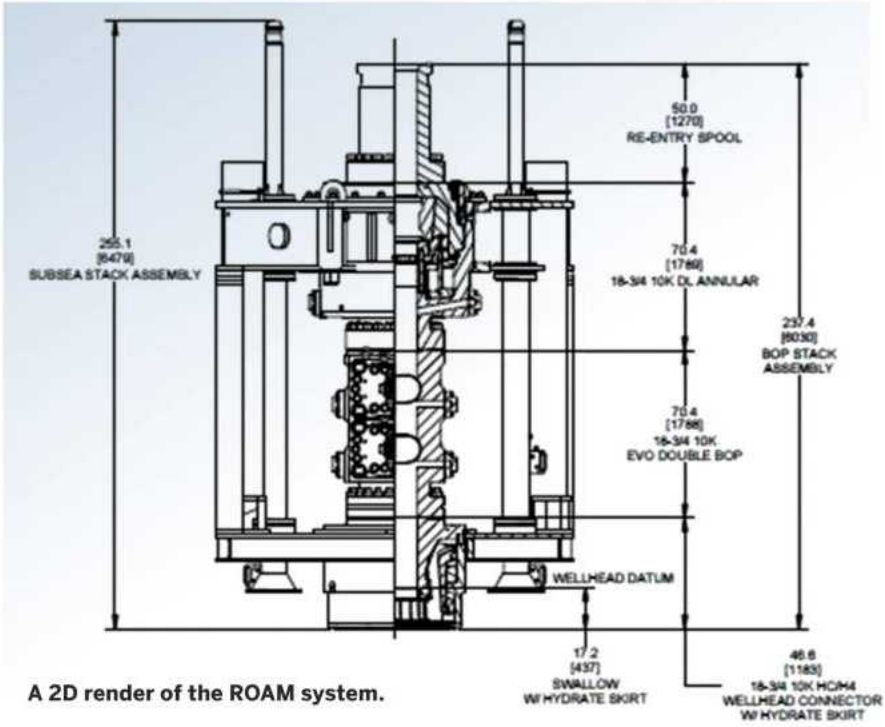
Using the ROAM system could ultimately remove the need to bring a drilling rig onto the well for abandonment, he adds, thereby reducing cost. The 18.75in large bore system, the Subsea Services Alliance members say, will enhance well abandonment capacity from a well intervention vessel by allowing tubing to be pulled in open water in a safe and environmentally contained manner.

While open-water tubing pulling is currently allowed in the US Gulf of Mexico and Helix's own vessels – *Q4000* and *Q5000* – can perform this operation already, not all operators are comfortable with the process just yet, Carr says.

But, the ROAM system seeks to address potential concerns. "We developed this system with the mitigation of the potential for environmental leaks in mind," he says. "The ROAM system gives us the ability to unseat the tubing hanger, wash behind it, and get rid of possible pollutants, before pulling the tubing out."

How does it work? Carr describes the process as follows: "First, we will go on with Helix's standard riserless or riser-based intervention system; we kill the well and run wireline or coiled tubing to install barriers, circulate out the completion fluid, place the cement and cut the tubing; once we have done that, the well is effectively suspended. We are then able to remove our intervention riser package off the well, as we simultaneously lower the ROAM system down on a crane and put it on the well.

Render of the riserless open-water abandonment module (ROAM). Images from Subsea Services Alliance.



A 2D render of the ROAM system.

"What we then have in place is a full 18.75in bore access to the well. We have two shear-seal BOPs (blowout preventers) in the well and an annular BOP at the top. Once the ROAM system is installed, we are able to run in with a tubing hangar release tool, run in on drill pipe. We latch that into the tubing hanger, shut the annular, and then unseat the tubing hanger."

Carr says that had the operation been done without the ROAM system in place, and had there been any contaminated fluid, it is at that point the fluid would get released into the ocean. "But, by having the annular closed, we are able to circulate all of that fluid to surface before we open the annular again and start pulling the tubing open-water," Carr adds.

The ROAM system, which is the second system built by the Subsea Services Alliance, will be engineered and built at the OneSubsea manufacturing facility in Aberdeen, according to a statement by the alliance in October. The system, which will complement existing intervention riser systems and subsea intervention lubricators, is expected to be available in Q3 2017. **OE**

Composite composure

Elaine Maslin surveys some of the firms creating new solutions for bonded thermoplastic composite pipes.

Frontier exploration and big vanity projects remain firmly off the agenda in the oil and gas business. In a low capex and opex environment, composite risers might finally get a look in, as operators move toward more near-field tieback opportunities to hold up their production numbers.

If so, it's good timing for a small group of firms that have been busy proving the in-service capabilities of bonded thermoplastic composite pipes (TCP) over recent months and years. UK-based Magma Global and Dutch firm Airborne Oil & Gas have fully bonded TCP offerings. Meanwhile, others are taking a more incremental approach, adding new materials to existing flexibles to reduce weight. GE Oil & Gas, for example, is offering a hybrid solution from its north-east England-based Wellstream business.

Magma

Southampton-based Magma Global has also been busy expanding, proving its product and getting ready to deploy its first, 3000m water depth, 15,000psi-rated, 3in integrated deployment package (IDP) hydraulic light well intervention rental system.

Magma's m-Pipe is a bonded TCP, made using a composite of carbon fiber and Victrex PEEK (polyether ether ketone), which is built up on a mandrel in an additive manufacturing type process, which enables dimensional control (i.e. incorporating end-fittings).

The first IDP, built with Scotland-based backdeck equipment firm Maritime Developments, had completed system integration testing in early October and was due to be deployed in either West Africa or the US Gulf of Mexico, depending on contract agreements, as *OE* went to press.

The move follows Magma's completion of a project with DeepStar to prove in principle a 4in, 20,000psi version of its m-Pipe, alongside work with Oceaneering on a 2in jumper and ROV (remotely operated vehicle) lightweight connector package, plus various other projects for clients, including gas lines and H_2S service m-Pipe and ongoing work to qualify m-Pipe as a 6in, 10,000psi riser or jumper under a project with BP and Subsea 7, which is due to complete late 2017.

Meanwhile, the firm has just moved into new factory space, doubling its

Magma's 2in jumper being put to the test at Oceaneering's facility in Houston. Photo from Magma Global.

Magma's new factory. Photo from Magma Global.

production line capacity from two to four production lines, giving it a 60km of 8in, 5000psi a year equivalent capacity. As well as adding production line capacity, the move creates more space for testing, says Charles Tavner, commercial director, Magma Global.

Being made from carbon fiber and PEEK, the product is lighter than steel by a factor of 10, Magma says, whose ultimate target is the flexible riser market, where moves towards depths beyond 3000m, and higher temperature and pressures as well as corrosive fluids have started to challenge existing technologies.

There are moves towards such a use in the market, Tavner says. "There are a few riser projects where people have very specific constraints, like trying to put a single well tieback into an existing host and the host being near payload capacity," he says. This is an issue seen particularly in the US Gulf of Mexico, Tavner adds. "The American market seems very keen to tie-in some smaller fields." This includes a few smaller companies which seem to be pushing pretty hard in these tough times using the low prices in the market, he says.

While so far it's only been downlines, booster lines, and jumpers that have entered service, these effectively lay the ground work for risers, Tavner says.

"We have now done permanent water, hydrocarbon [liquids] and gas service and we are building some H_2S and hydrocarbon jumpers at the moment. We are doing a full range of permanent service applications and the BP program will do all the qualification for a riser to a standard an international oil company would want it done to. Bring those together and you have got all the building blocks for a deepwater riser. Now, what it takes is a customer with a need and with an economic need to do it. And we are starting to see those."

While the 6in, 10,000psi riser project with BP and Subsea 7 isn't due to complete until late 2017, the work will mean less demanding product developed as part of this program – water injection lines or short-term applications – could be used before then as the final product would be for more demanding applications.

DeepStar

Magma started its project with Deepstar in 2015. The project has seen a 4in, 20,000psi flexible m-Pipe jumper produced and successfully tested to 32,500psi, then tested to destruction, seeing it reach 35-45,000psi.

A 6in TCP flowline. Photo from Airborne.

"There's a large interest in high-pressure flexibles," Tavner says. "DeepStar has been looking for several years for a high-pressure flexible. They then came to us last year. We built a 4in, 20,000psi flexible and carried out a set of tests to demonstrate its capabilities. It's not fully qualified, but it does demonstrate the performance of m-Pipe right up to the pressure range they are interested in." Deepstar had wanted to take the project further, Tavner says, but the body stopped all spending from 2016.

Earlier this year, Magma also built a 2in, 15,000psi jumper for Oceaneering, to be integrated with the firm's M5 connector. Oceaneering has been demonstrating the jumper to clients in the US, Tavner says, and is due to test it at NASA's Neutral Buoyancy Lab outside Houston. One of the key hurdles has been demonstrating its flexibility. "Until clients actually see it, they don't believe it," Tavner says. At NASA, ROV manipulation trials will be run to get ROV operators comfortable with the product, he says. "It is a big deal with them because it allows it to be used for flying leads and simplifies installation techniques."

Meanwhile, Magma is working through client projects, including some high H_2S jumpers for a national oil company in the Middle East. For Saipem, it built a 2.5in, 10,000psi gas line for subsea deployment in place of a non-bonded flexible. The system was delivered this year for use in the North Sea.

Still, the market remains fairly tough, Tavner says. "It's clearly very difficult at the moment. The number of opportunities are down, but we are seeing a lot more acceptance from operators of doing something different. Two years ago operators would say we just don't want to do anything new. At the moment, they are saying they don't want to do anything unqualified or risky, but they're happy to do something new if it saves some money. There is also much more senior engagement. Six to nine months ago, there was complete paralysis. It's all about timing and we are now seeing it (bonded TCP) becoming a project requirement."

Going Airborne

Dutch composites firm Airborne Oil & Gas secured US$23 million in funding, including $10 million from Saudi Aramco Energy Ventures (SAEV) in mid-October.

The cash is for the firm to continue developing TCP. It came shortly after Airborne started a project to qualify a TCP deepwater jumper spool application for oil major Total. Additionally, the firm announced an expansion in manufacturing capacity and an increase in sales staff.

Airborne's pipes are meld-fused together from carbon fiber and polymer tape to produce "monolithic structures," says Airborne's CEO Eric van der Meer. "There are no moving parts or friction, yet they are lightweight (80% less than their metallic equivalents), flexible and non-metallic," which means they eliminate the need for corrosion prevention and inspection measures.

Van der Meer, speaking at Offshore Energy in Amsterdam in late October, says capex costs could be reduced by 30% and opex costs by 90% using these.

Airborne Oil & Gas, headquartered in Ijmuiden (Port of Amsterdam), has been working with Total on the development of TCP since the start of the

Cost Effective Riser Thermoplastic Composite Riser joint industry project in 2009. Total is initially looking to use the technology for water injection well jumpers, however. Part of the attraction is that TCP allows installation without high-precision subsea metrology, as is the case for rigid steel spools. The project includes the manufacturing and qualification testing of full-scale, 6in internal diameter prototypes and is planned to deliver qualification to DNV GL standard RP-F119 in Q1 2017.

"The possibility with TCP to handle large deflections, the ability to cut-to-length and terminate the pipe at location and the subsequent installation with small vessels, make a compelling business case for TCP jumpers," said Frédéric Garnaud, research and development deep offshore program manager, Total, when the project was announced. "We estimate we can achieve considerable cost savings by using TCP jumpers."

Airborne has recently completed a project with Chevron to provide a 12,400psi methanol injection spool for permanent service in the North Sea, van der Meer says. This is on the Alder field, which came online in November. Airborne is also looking to deploy a system for hydrocarbon use in the South China Sea next year, which will be a first.

Meanwhile, the Libra consortium, offshore Brazil, invited Airborne Oil & Gas to perform a failure mode, effect and criticality assessment (FMECA) for a TCP riser that could be used at the giant Libra field.

Last year, Airborne supplied a TCP flowline for Petronas for use in 30m water depth offshore Malaysia as part of a pilot project. Airborne had already supplied downlines and dynamic jumpers for well intervention.

Following the investment from SAEV, the shareholders in Airborne Oil & Gas are HPE Growth Capital, Shell, Chevron Technology Ventures, Evonik, Saudi Aramco, Adveq, founders and management. But, despite strong industry backing, van der Meer, who worked at Shell before joining Airborne, laments the length of time it takes operators to adopt new technology.

If operators fail to buy product from new technology companies, which they want to promote to strengthen competition in the market, the result could end up being in those companies being bought out by larger players and the market remaining dominated by the main firms, he warns.

Some of the issues for companies' poor technology adoption rate are risk aversion, company culture, fear of failure, and organizational set-up. "There's no silver bullet," van der Meer says, but Airborne is doing its part, including working with DNV GL to produce the aforementioned recommended practice, RP-F119.

"Our company is at inflection point. We have sold several high risk applications, well intervention systems in West Africa, methanol injection for Chevron. We are well funded. We have 90 staff and are nearly 20 years old. Next for us is dynamic risers."

A GE Oil & Gas composite flexible. Photo from GE Oil & Gas.

A GE Oil & Gas composite flexible pipe being tested. Photo from GE Oil & Gas.

GE Oil & Gas

By the end of this year, GE Oil & Gas was due to have completed its new composite production module at its Wellstream plant in Newcastle, England.

The facility will enable the firm to take its flexible composite riser solution a step further – qualifying a 10in product for 3000m water depth, while also enabling production of high-pressure water injection lines, jumpers or flowlines.

Work on composites has been in progress for some time, with the benefits being seen as weight reduction, especially when it's hanging off a floating

production facility, as well as installation time and installation vessel requirements, plus sour service capabilities.

"We believe in flexibles, as opposed to rigid pipe," says Alberto Matucci, CEO, Wellstream. "Flexible pipe is relatively recent, compared to rigid. Flexibles enable deeper or faster installation, so in certain environments flexibles are a more effective solution to transport the hydrocarbons to surface."

Composites are not a new idea, however, Matucci says. "People have been looking at it for flexible and rigid or semi-rigid for many years, including Wellstream and GE. Only since a couple of years ago it became more serious," however, he says.

GE Oil & Gas acquired Wellstream in 2011, and since then it has integrated and grown the business. The firm opened its innovation center dedicated to flexibles pipe in Newcastle over a year ago. It is a twin of an innovation center dedicated to flexible pipe in Rio de Janiero, Brazil, as part of GE's Global Research Centers network.

Matucci says that GE's approach has been to use proven technologies and introduce novelty where it makes the most sense. The firm has taken a conventional riser and replaced a layer of metallic armor with a composite layer. This means that connections, etc., would be able to remain as they would for a conventional riser.

"Today, flexibles are made in multiple layers of metal and polymer," Matucci says. Conventional flexible risers, for example, have an inner carcass, fluid barrier, metallic pressure armor, tensile armor layers, insulation and an outer sheath. They are individual unbonded layers.

"We replace the second metallic layer that has to hold the pressure and gives the required level of rigidity and flexibility and use a layer of composite. Everything else remains pretty much the same," he says. The fluid barrier is replaced with a bonded polymer liner, which bonds with the composite layer, made of polymer and carbon fiber. This is weaved on to the polymer liner in a resin, which is cured with a laser beam, creating a "seamless boundary with the inner body, made of polymer."

"With this approach we can take whatever plays with conventional pipe and fit it," Matucci says. "So, end fittings, etc., in our open-based approach, and not altering critical points and elements critical to failure."

The pipe will be 30% lighter, GE Oil & Gas says, making it easier to transport. More will be able to be stored on a single reel and installation vessels will be able to be lighter with smaller tensioners for handling. The number of buoyancy clamps or tethers used infield could also be reduced, GE says. The firm also says total installed cost is 20-25% reduced.

Pipes produced will include some able to handle 15,000psi fluids beyond 3000m water depth, with up to 150°C capability, GE says.

The first of a number of new composites production modules is due to be completed this year at Wellstream, so that 2017 will see produced, 10in pipe go through the qualification phase. Further modules will also be built at the firm's Rio plant. Meanwhile, the firm will also be able to produce product for less critical applications, Matucci says, i.e. water injection lines, just as Airborne and Magma have done.

"We believe in this solution a lot," Matucci says. "It will make manufacturing and the utilization and installation easier and less expensive." **OE**

A new twist on an old polymer

Audrey Leon speaks with California-based Materia about a resin the firm hopes will make waves for subsea thermal insulation and other deepwater buoyancy applications.

Proxima thermoset norbornene resins create composites, foams, and coating for use in challenging offshore environments. Photo from Materia.

Outside the oil and gas industry, Materia, headquartered outside Los Angeles in Pasadena, California, has a bit of a resume. The company's catalysts and advanced polymers are used to streamline manufacturing. They even assisted in creating a drug to treat Hepatitis C.

The company is offering its Proxima resin line of products to the offshore oil and gas industry for high-pressure, high-temperature (HPHT) environments for subsea thermal insulation – through a partnership with Bayou Companies, an Aegion subsidiary – and deepwater buoyancy applications.

The resin, says Andy Nickel, Materia's director of commercial development, is "a new twist on a rather old polymer," called norbornene thermosets.

"What we have been doing with our Proxima variety of norbornene thermosets is to take these traditional materials that are thermoset polymers with good high-temperature properties and very low water absorption, and very good toughness, and process them into forms that are broadly useful," says Nickel, who has been with Materia for eight years.

For deepwater buoyancy applications, Materia aims to compete with the tried and true, such as metal cans and foams. "We have materials that have very low density, very low water absorption and very high strength. So, they make very good syntactic foam, or high compressive strength foam that competes favorably with epoxy," Nickel says.

According to Materia, Proxima STR resins can be cast into large units >250 L in a single casting step without post-cure, unlike epoxy syntactic foams that must be processed in small multi-layer sections. The resins' low viscosity also makes it easier to process at microsphere loadings up to 60% by volume, resulting in modules that are up to 25% smaller.

For subsea thermal insulation, where low water absorption and good thermal stability are important, Materia believes its Proxima HTI polymers can offer low inherent thermal conductivity and can act as good thermal insulators. Materia says Proxima is fully compatible with line pipe and field joint insulation materials, is castable in double joints, requiring fewer field joints, and compatible with a range of epoxy coatings.

How does it compare?

Nickel says that standard materials used for subsea insulation, especially in high temperature environments, have some serious issues concerning life-span. Thermoplastics (like polypropylene), he says, generally work well, but they soften when you get much above 300°F. "And, if you have any load on a softened thermoplastic, over time, it can flow like a fluid and creep," Nickel adds. Another material, polyurethane, can be stable at high temperatures, but "will react with water at those temperatures and they will slowly break down over time, turn into butter and disappear into the sea," Nickel says. "The traditional materials are anticipated to degrade in a few months or years at more than 300°F whereas Proxima is expected to last decades."

Nickel believes that the Proxima resin is the best of both worlds, between the thermoplastic polyolefin and the thermosetting polyurethane. "[Proxima resins] are cross-linked so they don't melt and don't creep," he says. "They are basically made out of solid oil, if you will, and oil and water just don't mix."

Materia, via its partnership with Bayou Companies, has lined up work in the Gulf of Mexico, and recently announced a contract to deliver pipeline insulation for a deepwater development.

While the company is based out of California, it saw a need to be closer to its oil and gas customers. The company has a facility north of Houston in Huntsville, Texas, to manufacture resins. Application testing, product development and catalyst manufacturing are run out of Pasadena, California.

Nitin Apte, president and CEO, says the firm is in the process of expanding its Huntsville location. Currently, Materia has about 40-50 people at the facility. Materia is expanding capacity to manufacture tens of millions of pounds of resin, Apte says, who came to the company this year after a two decade-long career at GE Plastics (later owned by Sabic).

Of the Texas facility, Apte says, "the advantage we have is that we have close to 60 acres of land, a great work force and have space to grow." **OE**

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Despite oil's instability over the last few years, the underwater vehicle market is set for modest growth as well as a breakthrough in resident vehicle technology. Emma Gordon reports.

Getting down to deep business

Subsea 7's AIV. Image from Subsea 7.

Fully resident electric vehicles could be on the market in around four to seven years, it was claimed at a subsea vehicle focused event in Aberdeen late September.

Realizing such a vision will mean a step change in support infrastructure on the seabed. But, the challenge isn't putting off continued efforts to bring resident robots to the subsea business.

One such project is Subsea 7's autonomous inspection vehicle (AIV), principally designed to support activities such as outline surveys and seabed mapping, covering huge swathes of the seabed.

The AIV was developed to remove restrictions that can limit the value of conventional autonomous underwater vehicle technology, specifically high vessel dependency and weather-sensitive launch operations.

With no tether – enhancing its maneuverability into confined spaces – the AIV overcomes these challenges by using a dedicated launch and recovery basket that can be deployed in a number of ways to the seabed.

After mission completion, the AIV can remain in its basket until the vessel returns for the recovery operation.

Lee Wilson, engineering manager

Saab's Sabertooth ROV. Image from Saab.

The UHD Gen III ROV. Photo from FMC Technologies.

with Subsea 7, is responsible for the overall project and technical management of the AIV. Next up for the team is developing a seabed-hosted AIV, removing the need for launch and recovery operations, and expanding its capabilities to include tasks such as light intervention and leak detection.

"Imagine how valuable it would be to do inspections or intervention without the vessel hanging around," Wilson says. "That unlocks huge value and potential."

In the short-term, a major challenge the team faced was making sure the AIV could re-enter its basket – the vehicle's subsea "home" – successfully, every time.

SeeByte's Chris Sotzing, the project and engineering manager for the AIV's software systems, likened this process to parking a helicopter in a small garage.

"It's a bit of a challenge. You have to do it fully autonomously, and you have to do it every time," he says. "We need to know where the basket is, fly to that basket, calculate this sweet spot [the

Deep down data

The impact of improved inspection technology and data collection on operational efficiency was also under the microscope at Subsea UK's Underwater Vehicles Conference.

Access to live 3D data potentially opens the door to significant cost savings for subsea operators at a time when smarter and more efficient operations are a requirement, not a luxury.

"What if I told you now that every single ROV (remotely operated vehicle) out there already had the equipment to perform live 3D scanning," asked Sam Bromley, managing director, Whitecap Scientific.

Powered by a computer on a host vessel, the company's ROV3D technology produces live 3D data using existing ROV cameras: generating interactive information at the point of inspection. This includes real-time inspection feedback, measurement and spatial logging.

Bromley says that the technology was used on the Hibernia field, offshore Newfoundland, in the North Atlantic, generating 31 hours of 3D data: saving time on retooling for measurements, speeding up reporting, and ultimately saving six hours of ROV inspection time.

"This [time] was used to expand the scope, look at secondary targets, and deliver a much more valuable, more complete report," he says.

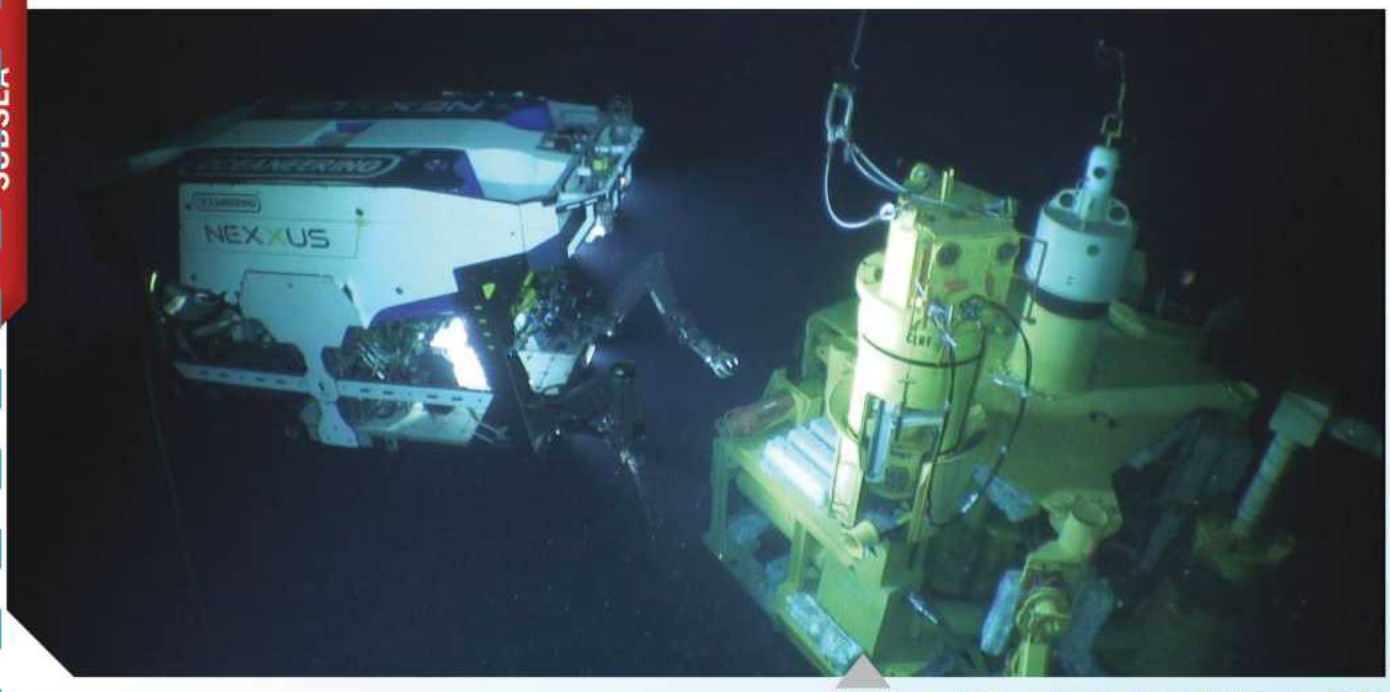
Similarly, Scott Gray, operations manager at Seatronics, said that underwater laser scanning – used for subsea survey, inspection and engineering operations as well as increasingly for integrity management – can ultimately reduce vessel and ROV time.

Seatronics' partner 2G Robotics' underwater laser scanners can be deployed by ROV, AUV, or diver for stationary or dynamic scanning.

Gray says that time for the signal to reach the receiver is instant, and the scanners generate submillimeter-resolution 3D models of subsea assets and environments from which accurate – and contactless – measurements can be taken.

"We're staying well away from the assets while we're doing it; producing real-time data; all processed subsea and sent back topside," he says.

"And there's the added value that not only are we getting hub-to-hub measurement and inclination, we're getting a digital terrain model of the seabed as well. It comes pre-calibrated," he adds. "Essentially, the key thing we're looking at is reduced vessel time, reduced ROV time, which is ultimately a money saver. ▪



The Nexxus ROV working in the Gulf of Mexico off the *Olympic Intervention IV* vessel. Photo from Oceaneering International.

Market demand drivers

Despite a drop of almost 32% in ROV demand since 2014, long-term growth of 2.5% CAGR is expected up to 2020, with deepwater plays a key factor, says Kieran O' Brien, energy researcher, Infield Systems.

The drilling market, which accounts for around 63% of total ROV demand, has seen the sharpest drop, although a gradual recovery of 6% CAGR by 2020 is anticipated, thanks to improving market conditions.

O'Brien, speaking after Subsea UK's Underwater Vehicles Conference in Aberdeen late September, says operational expenditure-related demand is less sensitive to volatility in the energy market.

"Field operators essentially pressed the panic button and cut both capex and opex-related projects," he says, due to the sharp fall in the oil price.

"Inspection and maintenance cannot, however, be delayed indefinitely, and because of HSE (health and safety and environment) and production efficiency concerns," he adds. "These activities are expected to come back in a big way. We expect to see significant growth in the repair and maintenance markets, and the intervention market."

And, with operating efficiency and reliability front of mind, there is a demand for innovation and engineering to deliver underwater vehicles that are increasingly autonomous, and capable of carrying out more subsea tasks. ▪

central entry point], and you need to be able to get in every time, otherwise you kill the business case."

Using a world model that gives the position of structures, including pipelines, risers and connections, as well as the baskets, the vehicle determines the best route home from any point in the world. Then, when within range, it uses acoustics to position and home in on the basket's location before calculating the precise entry point using sonar.

Sotzing says that offshore test success rates have been very high with Wilson adding, "This isn't pie in the sky. It's not a lab test, or a tank test, We've been offshore with Shell. The ability is here now and we can use it in multiple ways."

Similarly, Matt Bates, sales director Saab Seaeye says the ultimate step for electric underwater vehicles is having a resident system truly capable of undertaking all field support tasks. He adds that realizing this vision means a step change in support infrastructure on the seabed.

Bates says that over the past three decades electric vehicles have taken on a greater range of subsea tasks, such as Eni Norge and Tecnomare's Clean Sea program using the Sabertooth hybrid vehicle to detect early stage spills.

He sees the introduction of tetherless hybrid electric vehicles capable of carrying out routine inspection and monitoring tasks, with increased light intervention capability, possible in three to five years, with fully resident electric vehicles on the market in around four to seven years.

"Generally speaking there are no massive stumbling blocks to achieving this [vision]; there are lots of engineering challenges and specifically commercial, legal and contracting challenges," he says.

The next few years are set to be telling for the ROV sector, specifically whether technology and innovation can reliably deliver more autonomous technology capable of undertaking more tasks subsea, particularly with the shift towards deep and ultra-deep reservoirs. **OE**

FURTHER READING

ROV in residence Elaine Maslin details Statoil's journey towards the resident ROV, which uses an existing ROV design.

http://bit.ly/2flSYom

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Fighting wellhead fatigue

Close-up of a pile top assembly.
Images from Trendsetter Engineering.

Jerry Lee examines Trendsetter Engineering's Tether BOP system, which aims to curb fatigue and improve wellhead performance.

Re-entry into older wells for intervention or decommissioning can be challenging operations when pairing modern technologies with older equipment. Modern blowout preventers (BOPs) and risers are designed to be more robust, which can result in the wellhead becoming the weak point of a system, which is dangerous considering it is a critical component. To mitigate this risk, Trendsetter Engineering has developed and patented the Tether BOP (TBOP) system to reinforce the BOP and improve wellhead fatigue life.

When a wellhead is connected to a BOP stack and riser, the weight and movement of the stack and riser will result in fatigue accumulation in the wellhead. For older wellheads, there may not be much fatigue life left, so Trendsetter developed the TBOP system to arrest motion in the BOP, above the wellhead, by tethering (mooring) the BOP stack to piles fixed on the seafloor.

"By moving the point of fixity off of the wellhead and onto the spiderboard or above, the TBOP system helps preserve the wellhead integrity by isolating the movements above it," says Brett Morry, global technical manager, Trendsetter.

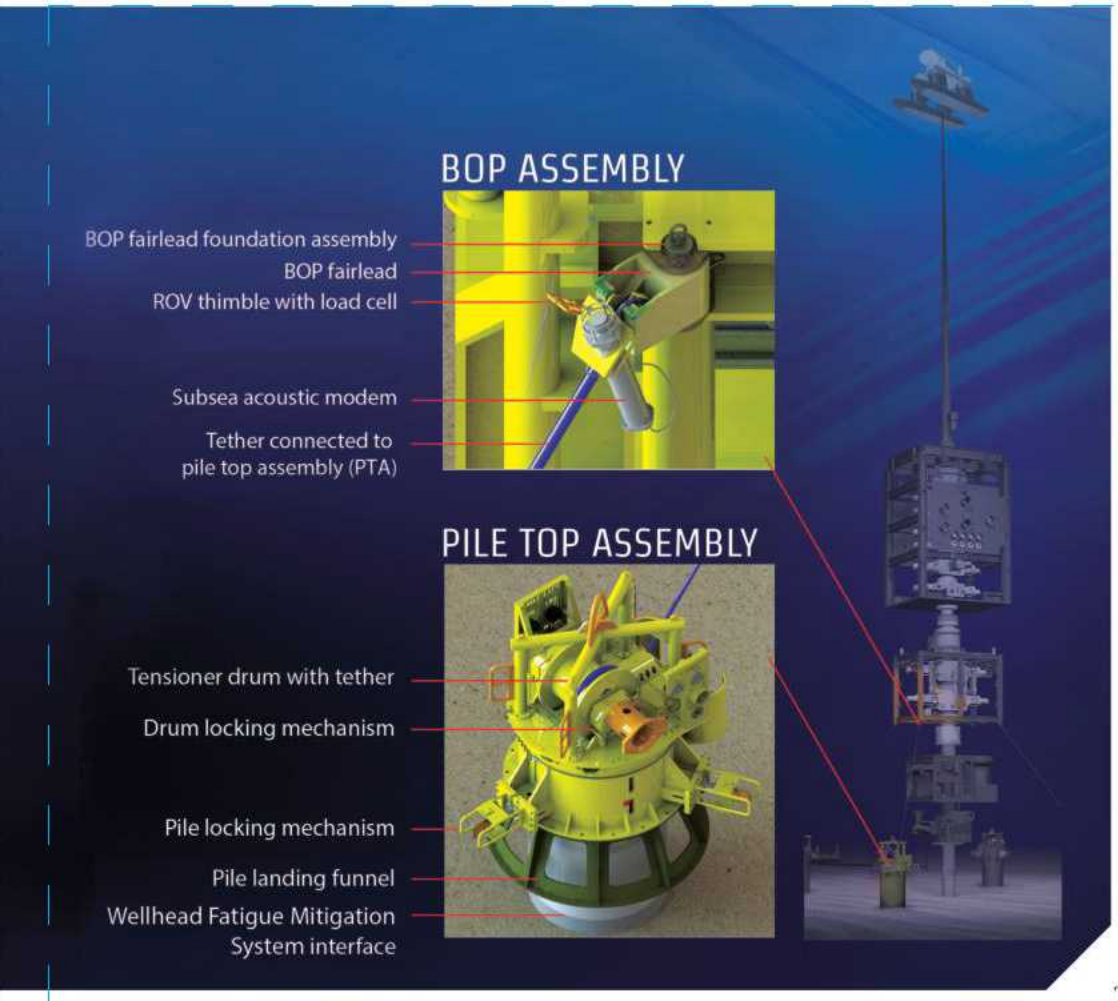
As a result, further fatigue in the wellhead can be reduced, while adding strength to the subsea equipment.

TBOP pile top assemblies ready for load out.

Equipment

The TBOP system is comprised of multiple pile assemblies connecting piles surrounding the wellhead to the spiderboard on the BOP stack. This placement prevents the TBOP system from interfering with the emergency disconnect system.

On the BOP, there must be a connection site (thimble) for the end of the mooring line (fairlead) to attach. If the BOP has recovery padeyes, they can be used with



TBOP components.

shackles or thimble assemblies, for fairleads to attach. If not, the BOP will need fairlead foundation assemblies installed on the spiderboard.

Each pile will be connected to the BOP stack through a pile assembly, which consists of a mooring line, thimble or fairlead assembly, pile top assembly (PTA), load cell – with optional monitoring equipment – and a shipping skid. The mooring line is made of two types of Dyneema rope depending on the load requirements; the thimble or fairlead assembly terminates the mooring line and attaches to the BOP connection site; the PTA is fixed on the piles and uses a winch system to induce a load on the tethers.

The piles used will depend on the soil conditions on the site. For softer, less consolidated soils, piles can be suction pumped or jetted into the soil, but for harder, more consolidated soils gravity-based piles, using steel plates for weight, would be more appropriate.

Installation

Installation of the TBOP system is performed entirely off the critical path.

First, the piles need to be installed on location before the rig arrives. For gravity-based piles, a vessel of opportunity (VOO) with a crane can be used, but suctioned or jetted piles may require a larger vessel. Afterwards, PTA installation can be performed using the downlines of the VOO. Then, following the BOP's installation, a conventional work-class remotely operated vehicle (ROV), with a torque tool, will attach the fairleads to the BOP and load the mooring lines. To prevent overloading one side, the ROV will attach the fairleads in a pre-determined sequence, and bring the tension up in stages, following the sequence until the tension is brought to the pre-calculated load.

Deployment

Though the TBOP system was only developed within the last year, it has already been deployed in the Caspian Sea and the UK North Sea.

In the North Sea, an operator was performing a two well plug and abandonment campaign 160km northeast of Shetland, in an area which has recently seen significant wave heights of 7m. To ensure adequate wellhead fatigue life, the operator decided to reinforce the BOP with the TBOP system, which is currently installed on the first well.

Due to the heavily consolidated soil, four 40-ton gravity-base piles with 2ft skirts were chosen for the site and installed in Q2 2016. Using a VOO, the PTAs were installed in Q3, and by Q4 the BOP was connected to the mooring lines and fully tensioned (4-5-ton) in an operation that took six hours, off the critical path.

Using independent third party calculations, the system was designed to improve the wellhead's fatigue life by a factor of 1000, which has since been verified by data obtained from accelerometers placed on the riser at the first well, says Jim Maher, president, Trendsetter Vulcan Offshore.

Further application

Trendsetter does not only see the TBOP system being used to mitigate issues with fatigue life, but also to mitigate the potential for drive-off/drift-off.

When drilling with a dynamically positioned (DP) vessel, operators need to be aware of the effect that drifting off center will have on subsea equipment. However, the TBOP system can be installed to strengthen the BOP, increasing the wellhead's tolerance to the stresses of rig deviation.

"A lot of clients are interested in using DP vessels in shallower waters, so we see a good market for the TBOP technology," Maher says. "The system can be used to reduce the bending associated with a drive-off event and therefore extend the operability range of DP vessels into shallower water."

This benefits operators by allow them to utilize DP vessels, already on charter, in shallower areas rather than having to charter separate moored vessels, Morry says.

"We also see potential applications as the industry looks into using 20K or high pressure/high temperature BOPs," Maher says. "Some operations may be easier if they're able to tether it and strengthen the wellhead." **OE**

Cooking with gas

John Sheehan reports from French cables group Nexans' technology round table, and finds how the firm is staying afloat during the downturn.

Nexans' *Skagerrak* installation vessel. Photo from Nexans.

Despite the unprecedented downturn in the oil and gas market, umbilical and power cable manufacturer Nexans has managed to keep its head above water, with equipment supplies ongoing to a number of key projects around the world.

Nexans as a group is relatively well-sheltered from the worst of the oil and gas downturn, because of its work in a variety of sectors including telecommunications, buildings and railways.

In the oil and gas sector, however, Ragnvald Graff, Nexans' sales and marketing director for the subsea market, said field developments are under constant evaluation and pressure to reduce capital and operational expenses.

"There is high activity on concept development, tendering studies, front-end engineering and design (FEED) concept evaluation and cost pressure throughout the value chain in order to make projects viable in this low oil price environment," Graff says.

"The target for the oil companies is to reduce hardware costs by at least 30%. That affects us, it affects everyone. We have, however, managed to secure an acceptable order backlog for umbilicals and direct electric heating (DEH) systems in this difficult market."

The company has a number of ongoing projects keeping it busy, before a hoped-for pick up in 2017 or 2018.

Graff cites gas projects as being one positive area for Nexans, which turned over US$5.18 billion (€4.7 billion) in 2015. "For some reason it seems like gas projects are being sanctioned and developed, especially in countries like Egypt where there is a great need for gas. These countries are importing billions of dollars-worth of gas every year, but they require 100-150km-long step-outs in order to be self-sufficient in gas as soon as they possibly can."

Nexans has just supplied the West Nile Delta Taurus/Libra project offshore Egypt with 50km of umbilical that was recently loaded out from the deepwater quay at its Halden fabrication plant in northern Norway.

It is also supplying 100km of umbilical for BP's Giza, Fayoum, Raven project, part of phase 2 of the West Nile Delta project, with delivery scheduled for 1H 2018.

Greater Enfield

Meanwhile, Graff describes winning a contract from OneSubsea to supply 32km of power umbilicals and accessories to be installed in 915m water depth for Woodside's Greater Enfield project off Australia as a "big milestone" for the company. Delivery is due in Q1 2018.

The oil field, which is 60km from the coast of Exmouth, will be developed using a 31km subsea tieback to a floating production, storage and offloading facility. Six subsea production wells and six water injection wells will produce around 69 MMboe. OneSubsea will supply subsea pumps for the project.

Graff says that Australia is a target market for Nexans going forward. "We are aiming to complete a good project and make a name for ourselves down there." The deal includes Nexans' SUTA-FLEX modular umbilical termination assembly, a unit that is lighter than rival systems. It can weigh in at between 1.5-4-tonne and handle up to 20 electric and 32 hydraulic connectors. The SUTA-FLEX system is based on standardized components, which are assembled in accordance with the project's specific needs.

SUTA-FLEX can accommodate hydraulic, electrical or fiber-optic components–or any combination of the three–within its compact outer dimensions. The design contributes to significantly improved reel packing as well as smoother handling and lifting operations.

Nexans' biggest ongoing project is work on Shah Deniz in the Azeri sector of the Caspian Sea. It is supplying both umbilicals and DEH systems to the world's largest industrial project, with deliveries scheduled for 2018, 2019 and 2020.

A study on cost reduction has reduced the diameter of the umbilicals from 184mm to 149mm, with resulting cost savings.

"It is a big logistics project," Graff says. "The umbilicals are supplied on drums, which are picked up at Halden on barges and taken to the Baltic Sea, and then transferred onto barges that can take them through locks into the Caspian Sea. There are limitations as to when you can do this because of the climate and risk of icing."

Graff also warns of the risk of freezing out staff on the long-term health of the oil and gas business.

"Another challenge is that the industry could go from a full-stop to full speed ahead in a very short time. How do you handle that? There is a risk of a competence drain – that you lose the people who know how to do things," he adds. OE

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Fertile fiber

New products, more data and leaner ways of working can change the way the industry identifies, develops and produces reserves. AnTech's Tim Mitchell outlines the role fiber optics have to play.

AnTech's hybrid wellhead outlet.
Photos from AnTech.

The economic environment our industry is currently operating within has dramatically changed. The oil price is recovering, but is unstable, preventing robust business planning and forecasting. While it is easy to see this as only a negative, there are a few positives to capitalize on, for example changing industry attitudes and perceptions towards new and existing technology.

This drive to improve efficiencies means that engineers are looking at the outputs of each product and technology. Consequently, engineers are more interested than ever before in monitoring and analyzing big data. As a direct result, the use of fiber optic and hybrid wellhead outlet technology (the ability to accommodate two different types of control lines) is becoming increasingly popular within in the oil and gas industry.

The oil and gas segment of the global fiber optics sensor market was valued at over US$661 million in 2015 (from under $200 million in 2006)*, and it is expected to dominate the fiber market until 2020, according to Technavio.

Indeed, major service companies have seen an ever-increasing demand for fiber optics, with one installing in excess of 17 million ft of fiber in over 1500 wells and another commenting on installations rising from one or two systems per field up until a few years ago, to tens per field today.

While a 2015 market forecast, conducted by the Photonic Sensor Consortium and published by Information Gatekeepers said their 2014 prediction of a $1.8 billion market by 2018 wouldn't now be reached, due to the drop in oil prices, the segment was still expected to grow in the longer-term.

The history of fiber optics

Fiber optics are flexible glass fibers or transparent solids that transmit light signals and possess advantages such as much greater bandwidth than metal cables and they are immune to electromagnetic interference. Fiber optics have been used in the industry since the 1990s, in the form of distributed temperature sensing (DTS) systems.

However, initially, short lifespans were experienced as the delicate fiber was not able to withstand harsh downhole conditions and suffered from calibration drift. Since then, cable strength and capabilities have been improved, mainly from the improvement in the manufacturing of the fibers, producing much purer glass, and these developments have allowed the market to grow rapidly.

How fiber is used has also been developed and expanded, including use as a microphone or hydrophone, i.e. distributed acoustic sensing (DAS). Analyzing the laser-light reflections inside the fiber enables the temperature and strain of the glass to be determined at any point in the well.

Additionally, advances in computer processing speeds and better algorithms have made the process of interpreting raw data easier and fast enough to monitor in real-time. As a result, monitoring and data transmission using optical fiber in cabling, fiber optic sensors, and DTS and DAS are becoming increasingly popular for applications, such as well monitoring. The technology is also well-suited for more complex installation work, in high-pressure, high-temperature wells due to major improvements in glass chemistry from the material sciences sector.

A particularly valuable application of fiber is in intelligent wells, where data collection, transmission and analysis is paramount.

Using fiber optics, oil firms can carry out pipeline hydrocarbon content assessment and measurement, allowing them greater knowledge of what is flowing through the well and from where at any time, including changes in chemistry. It can also help monitor cracks and water cut.

Thanks to their ability to transfer large amounts of downhole data at any given time using fiber (almost at the speed of light), engineers are able to manage production using live streams of production data, enabling more informed decisions on location.

Applications around the world

As a result, the appetite for fiber optic and hybrid monitoring solutions is growing. Australia, the Middle East, and particularly, Oman, are embracing the potential of fiber optics for onshore and offshore applications.

Across the region, high producing wells are being converted to single and multi-sensor intelligent wells and even lower value fields are required to provide data for well performance analysis. This has driven an interest in both high specification and lower cost wellhead connection solutions, to meet the variety of well types and technical requirements needed by oil companies.

To monitor downhole sensors with fiber, fiber optic wellhead outlets are required as when the cables reach the surface, they need to be terminated safely and securely connected, while keeping optical losses to a minimum to ensure that the resolution of the sensors is not affected.

AnTech has developed a new range of fiber optic wellhead outlets called the Type F Wellhead Outlet family, comprising Type FA, FB and FC, all of which

AnTech's Type FC Wellhead Outlet.

are NACE/MR0175 compliant. Through years of experience in wellhead outlets, AnTech is also the first company able to offer a product complies to Offshore Fire Test API 6FB (Type FB) and accommodates up to four fibers.

Furthermore, AnTech has recently developed a range of hybrid wellhead outlets in response to requirements for a single wellhead outlet that has the capability to contain both fiber optic and electrical control lines. The Type H range gives clients the choice of high specification units for lower cost operations.

Conclusions

New products, more data and leaner ways of working can change the way the industry identifies, develops and produces oil and gas reserves.

Adopting fiber optic and hybrid technologies to increase efficiency does not guarantee instant success, but it can help save costs for operations now and can be hugely advantageous when oil prices do recover. OE

Tim Mitchell *is product sales manager at AnTech. He has more than 12 years of experience in the oil and gas industry, holds a BSc (JtHons) in chemistry and geology and heads up the products sales for the company's global product ranges in the areas of permanent monitoring, coiled tubing, wireline and downhole tools.*

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* According to Information Gatekeepers Inc

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A CT first

Helix's Compensated Coiled Tubing Lift Frame in its operational position.
Photos from Helix Well Ops (UK).

Seeking additional gains from subsea wells on a tight budget has paved the way for the implementation of a new technology to the market. Elaine Maslin reports.

When Shell found the potential to recover more oil from one of its subsea wells in the UK central North Sea, it was not inevitable that a suitable method could be found in the current low oil price environment to make the sums add up to move forward with extraction.

While there was the potential to get more out of the well, existing methods to unlock that potential: perforations via wireline using a vessel or coiled tubing using a semisubmersible, made the job uneconomical due to the time it would take by one method, and overall cost by the other.

Aware of the industry's need for alternative approaches to performing low cost interventions, Helix Well Ops (UK) approached Shell and proposed using its coiled tubing deployment technology, developed in conjunction with Altus Intervention, as a possible option – using coiled tubing from a vessel – to overcome the economics of traditional methods.

The system is comprised of an Altus Intervention provided coiled tubing unit, which incorporates a bespoke fatigue management system, called Talos. This system is combined and interfaced with Well Ops' own compensated coiled tubing lift frame (CCTLF) technology, which virtually eliminates the effect of vessel motion and reduces coil fatigue towards that of a fixed installation or platform.

"The riser system is designed to operate in 80-200m water depth and to deploy up to 23,000ft of 2.375in diameter coil. The system was first launched in 2010 and while it was proven successful, the job was curtailed due to severe weather conditions. The market at the time was extremely buoyant and the demand for riserless intervention was so great that the CT equipment was placed into hibernation not long after the initial deployment," says Steve Nairn, vice president, Helix Well Ops (UK).

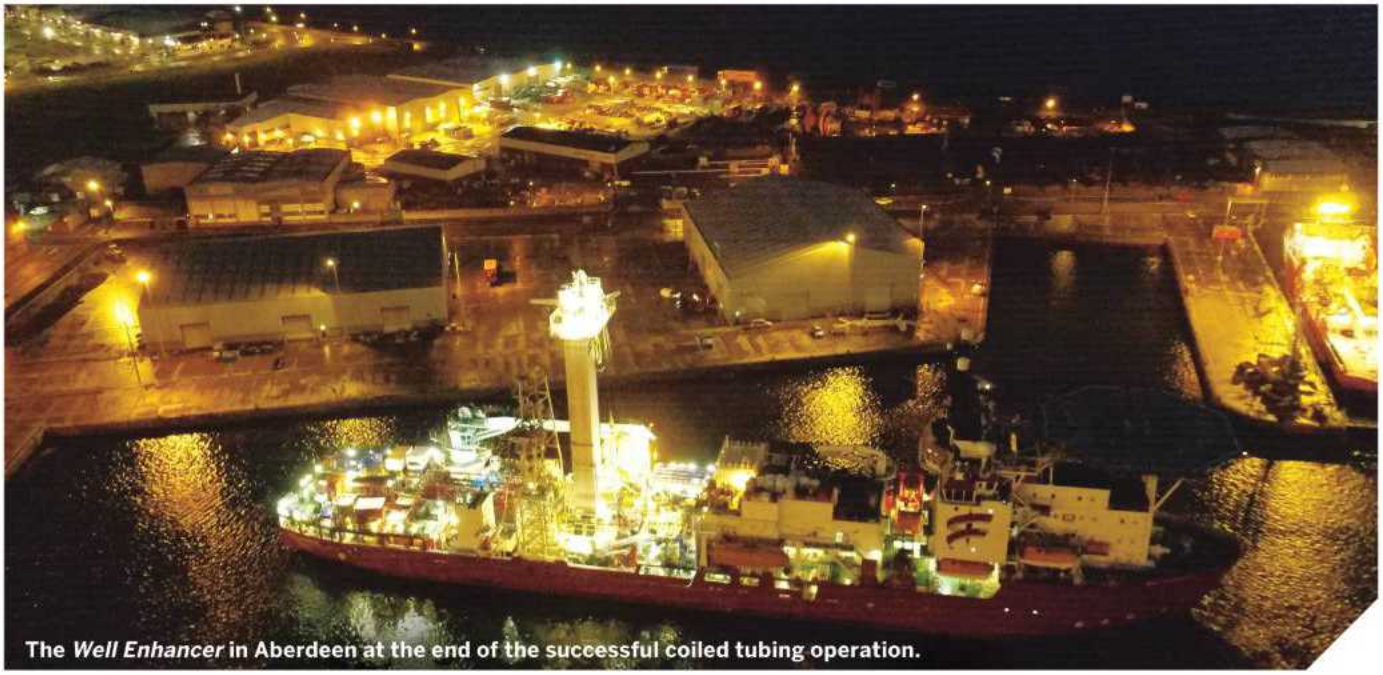
Going back further than the initial deployment of the *Well Enhancer* system in 2010, the concept of coiled tubing from a vessel was originally performed on the vessel that pioneered vessel interventions, the *Seawell*, another Helix asset, in the late 1990s. That vessel, which recently went through an extensive refit, had some limitations with its moon pool size and deck space so accommodating the equipment required for coiled tubing was a long-term challenge.

Realizing the potential for this application resulted in Well Ops designing and commissioning its new build *Well Enhancer*. This vessel, which like *Seawell* also supports dive operations, was designed with coiled tubing in mind where often the opposite is true: the vessel already exists and technologies or applications are reverse engineered onto them. Here, the thinking was different and started on paper following the experiences of the *Seawell*. "One of the biggest challenges is managing coil fatigue," Nairn says. Fatigue, a result of repeated bending and straightening of the tube itself, is the enemy of coiled tubing. The greater heave from a vessel compared to a rig only serves to magnify the problem.

On the *Well Enhancer*, there are three compensation systems. The Talos system provides a length of slack coil tube by using a secondary injector between the coil drum at the rear of the vessel and the main injector. The main injector, pre-built and tested in the Well Ops CCTLF prior to mobilization, sits directly above the moon pool during operations. The CCTLF incorporates a passive compensation system which operates in conjunction with the Talos system to maintain the slack coil thus reducing fatigue.

The CCTLF, in turn, is held by the 150-tonne capacity Huisman tower, which is used in active heave mode during the deployment and recovery of the equipment subsea, but also acts as a failsafe should any of the other elements of the system fail, which provides a level of redundancy over rigs. It is also an integral part of the emergency shut down (ESD) system, which enables the vessel to close the valves and shut the well in and allows the vessel to move away within 35 seconds of an ESD being initiated.

While it takes longer to set up than a riserless system, it's more efficient once you're there, especially for projects like



The *Well Enhancer* in Aberdeen at the end of the successful coiled tubing operation.

scale milling or accessing long or horizontal wells, Nairn says. The benefit, he adds, is not having to reactivate a rig for work on a short duration project or even a single well with intervention taking less than a month.

It should also be noted that rigs are not necessarily designed to conduct coiled tubing operations. They may require additional equipment including the coiled tubing itself to be transported to the rig by a supply vessel, and then assembled and tested before being used. *Well Enhancer* can do all this in port as part of its normal mobilization activities and as such is largely self-sustaining throughout the campaign.

To run the system, Well Ops' 7.375in subsea intervention lubricator (SIL) is deployed in wireline mode through the moon pool. Once landed out in active heave on the subsea Xmas tree on top of the well, the system is split at the "high-angle" disconnect package and the vessel steps away a short distance from the well, while the upper half of the system is recovered back to surface and suspended below the vessel hull.

The lower section remains connected to the tree and provides control of the well preventing any environmental release while the upper section is progressively lowered back to depth by the addition of sections of 6.625in riser, riser monitoring components and stress joints.

Once deployed back to depth the vessel then moves to take up position directly over the well and the upper half is landed and latched back onto the lower section, an operation which can be done in sea states up to 5-6m, according to Nairn. Then, the coiled tubing frame is brought into the tower, with the injector head but not before the tooling is loaded into the riser.

Known as the bottom hole assembly, these are the tools that are going to perform the work within the well and are connected to the end of the coiled tubing. On a rig, these are inserted into the riser at some height above the rig floor and require men on harnesses working at height in order to do so. With the Well Ops system this is all conducted at deck level on a stable flat work site without any need for harnesses or working at height which greatly reduces the risks associated with coiled tubing operations.

Shell decided to use the system on its Pierce well this past summer, working closely with Well Ops and Altus Intervention. Because this was initially just one job, other operators were persuaded to join Shell and Well Ops to make the investment needed to re-commission the system.

The project included focus on familiarization time and training, as the system hadn't been used for some time. Offshore deployment was in June.

Pierce is produced via Bluewater's *Haewene Brim* FPSO, over blocks 23/22a and 23/27a in the central North Sea, 265km east of Aberdeen close to the Norwegian maritime border. The field was discovered in 1975, with first oil in 1999.

Working in 83m water depth, the project involved drifting and milling to 4400m (14,500ft) and performing a reservoir saturation tool log before perforating 267m (877ft) of reservoir section in four runs, followed by a venturi clean-up.

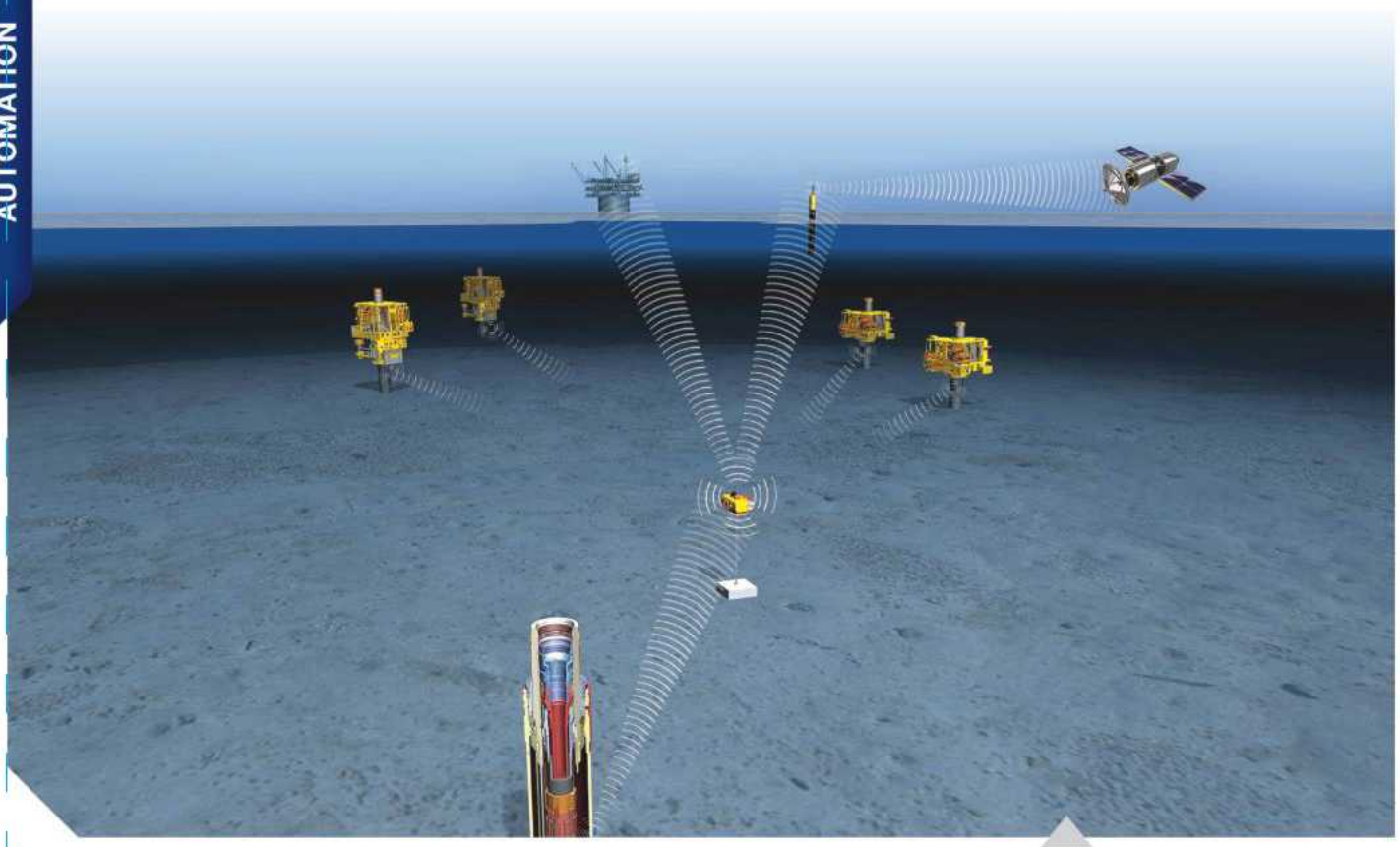
The operation was on budget with no HSE incidents and production gains 25% above expectations.

The project on Pierce has been billed as the first live well coiled tubing operations from a mobile offshore drilling unit class light well intervention vessel. It has been shortlisted for an ICOTA European Charter Innovation award and been described as a potential game changer for Shell and the wider industry. **OE**

Winners

Helix Well Ops, Shell and Altus Intervention received this year's Intervention & Coiled Tubing Association (ICoTA) Innovation Award during the SPE ICoTA Well Intervention Conference in Aberdeen early November. The three firms had been up against CannSeal and Centrica/Island Offshore as finalists.

Neil Greig of Helix Well Ops said: "Helix Well Ops, are delighted to be joint recipients of this prestigious award along with Shell UK and Altus Intervention. It is an acknowledgement of the investment in a concept developed over many years by Helix Well Ops in conjunction with Altus Intervention and we are grateful for the support of Shell UK who committed to using the system and enabling it to be successfully deployed for the first time in a live well." ■



Communicating beneath the waves.
Images from FMC Technologies.

Wireless wells

For the first time, wireless technology has been used downhole on a subsea well. John Sheehan speaks with FMC Technologies to learn more.

An annulus monitoring system (AMS), which has been installed and tested in a Petronas-operated offshore exploration well in Malaysia, will save time and drive down operator costs, according to developer FMC Technologies.

The AMS is a wireless communication system that provides crucial, independent condition-monitoring within a subsea wellhead to operators for the first time, from the onset of drilling and throughout the life of the well.

The technology, a winner of the 2015 OTC Spotlight on New Technology award, delivers real-time information to the operator about annular fluid and components during critical phases of well installation and startup, when well conditions are most unpredictable.

Up until now there has been no annulus measuring capability subsea because valve penetration into the annulus is not allowed, unlike for surface operations.

Bernard McCoy, Jr., director of subsea drilling services, FMC Technologies, explains that the technology provides the same data that would be available for surface type wellhead applications, but subsea – for the first time.

Explaining how it works, he says: "We measure the annulus pressure under the casing hanger with a standard pressure/temperature sensor so it can detect the pressure and temperature of the fluid beneath the hanger.

"The real value of the technology is the ability to transmit that data – the reading of that pressure/temperature sensor through the casing annulus and the wellhead housing itself wirelessly to a receiver that is on the outside of the conductor housing. There are no wires and no required intermittent communication between each of the casing strings."

He says the proprietary technology allows for direct communication from the annulus through metal, cement and brine into the receiver on the conductor housing.

EM and acoustics

The technology, first developed for submarines and which has been adapted by FMC over the last five years, uses a combination of electromagnetic waves and acoustic data.

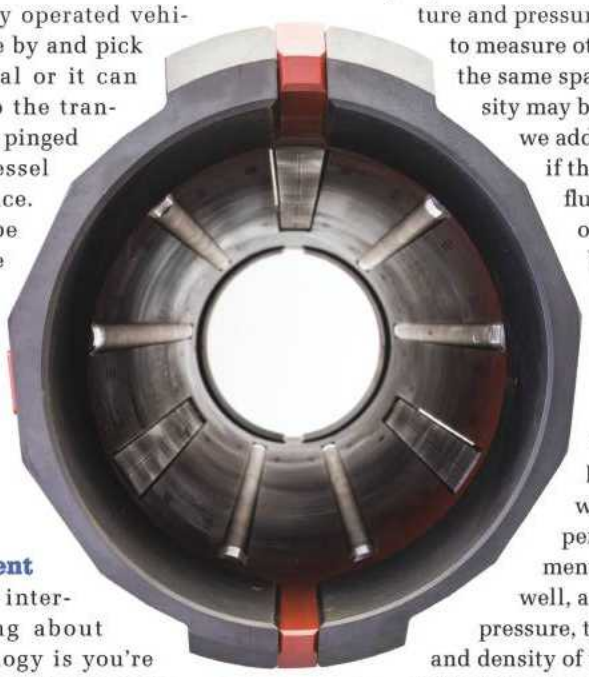
"We install this at the time of initial casing hanger installation, so it is there from moment one, when the casing hanger is landed in the wellhead housing," he adds. "From that moment on it is able to transmit the data passively, so, actually, the receiver on the outside of the conductor is really doing almost all the work to detect the pressure/temperature underneath the casing hanger."

The sensor is designed as a modular

sleeve that goes around the casing on the casing hanger, so it is able to work on various casing sizes and thicknesses across the whole range of casing types.

"It is designed to work through the known casing programs that are out there for our wellhead systems, so it is uniquely honed to be able to ping right through the casing strings as well as the wellhead housing," he says. "To detect that signal it is approximately 25in away from the sensor itself and then once it gets to the conductor housing its able to be transmitted using various techniques that are already out there in the industry."

A remotely operated vehicle can drive by and pick up the signal or it can be linked to the transponder and pinged back to a vessel on the surface. It can also be pinged to the blowout preventer communication system and sent back up to the surface.



A wireless well.

Aiding abandonment

"The really interesting thing about this technology is you're able to measure the pressure and temperature in that annulus over a longer period of time as the formation is sealed in, as it is potentially abandoned or as you continue into production you can monitor the characteristics of that annulus," McCoy says. "This is much like you would on a surface wellhead where you can open a valve and measure the pressure that is there in the annulus."

He says the data that is collected can be used to help design production casing programs more efficiently. "Today, when you perforate the casing to pull it back and you cut the casing, you have no idea if there is pressure behind that casing hanger. It is a limitation of our industry at the moment for subsea applications. This would be able to help you determine if you had pressure and then you could go through changing your mud or changing the way you are going to do that cutting and perforating operation versus going in blind, where you don't know what the pressure is back there."

McCoy says that the Petronas exploration well on which the AMS was tested went directly into abandonment, and the technology helped them save rig time. Petronas isn't the only operator that has shown interest in the system, McCoy says a number of other FMC customers are in the finishing stages of preparing to run the equipment.

Going further

McCoy says that in addition to temperature and pressure, FMC wants to measure other things in the same space. "Fluid density may be one thing that we add to determine if that annulus fluid can change over time if it breaks down or becomes mixed with other types of annulus fluid."

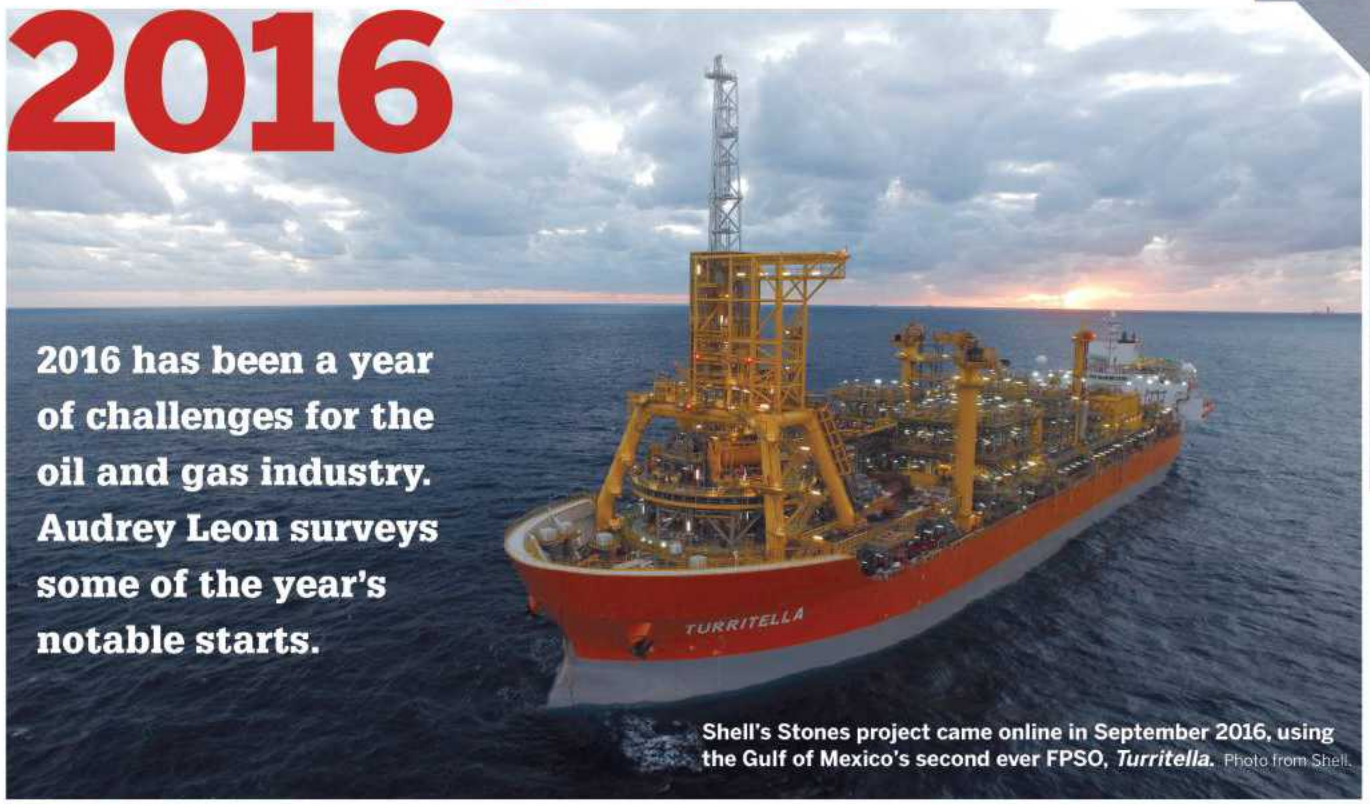
He says after that, the next logical thing would be to perform measurements deeper in the well, and make sure pressure, temperature, and density of the fluid across both of these measurements are consistent or changing.

"Right now in the industry, because we don't know what those pressures are, we typically grossly over-design our casing programs for this annulus pressure," he says. "You can't really determine what you need, so when in doubt make it stout. That ends up providing a lot of extra casing weight, a lot of extra pipe, wall thicknesses, etc. This will allow you to design exactly to what the well is, providing some degree of savings in the future."

He says that as well as in Asia Pacific, there is a lot of interest in Brazil and South America.

"Most of the interest is around frontier space where exploration hasn't really been done before, so you have no idea what you may find or what the well may look like or what the pressures are going to be," McCoy says. **OE**

Making strides: 2016



2016 has been a year of challenges for the oil and gas industry. Audrey Leon surveys some of the year's notable starts.

Shell's Stones project came online in September 2016, using the Gulf of Mexico's second ever FPSO, *Turritella*. Photo from Shell.

This year hasn't been one to envy. When *OE* surveyed 2016's most read stories online, the most common theme that emerged was bad news: layoffs, accidents, and cancelled projects and contracts.

However, there were some positive strides made this year. Allseas' US$2.7 billion mega-vessel *Pioneering Spirit* passed its trials and completed its first commercial job, lifting Repsol Norge's 13,500-tonne Yme mobile offshore production unit, 100km offshore Norway, this August.

And, of course, in spite of the low oil price environment, several notable projects came onstream this year. It is not certain what kind of year 2017 will be, but we hope to report on more project start-ups in the coming months.

Notable starts

▪ Laggan-Tormore comes onstream – February 2016 Total achieved first gas from the Laggan-Tormore gas and condensate subsea-to-shore development in February (*OE*: May 2016).

Originally due onstream at the end of 2014, the Laggan-Tormore development suffered delays and cost increases.

The development, in 120-600m water depth, will produce 90,000 boe/d. It is a four-well subsea tieback via two, 143km-long 18in export pipelines to the new onshore, 500 Mcf/d Shetland Gas Plant.

It is also due to provide the export infrastructure for two further subsea fields, Glenlivet and Edradour.

The Laggan field was discovered in 1986, Tormore followed in 2007. Development approval was obtained in early 2010. Following treatment at the gas plant, the gas is exported to the mainland via the Shetland Island Regional Gas Export System and the condensates are exported via the Sullom Voe Terminal.

▪ Goliat achieves first oil – March 2016 Production started from Norway's first Arctic oil field at the Goliat floating production facility in the Barents Sea in March 2016.

Discovered in 2000, Goliat is both the first producing oilfield in the Barents Sea and the northernmost offshore producing field. Holding some 180 MMbo, it is expected to produce 100,000 bo/d once all 22 of its subsea wells are onstream. Currently, 17 wells have been completed.

The 360-420m water depth project is based on a powered-from-shore, via subsea cable, cylindrical floating production facility, sitting 85km northwest of Hammerfest, offshore northern Norway. The 107m diameter, 64,000-tonne, 1 MMbo storage capacity Sevan 1000-design floating production and storage, offloading (FPSO) vessel, moored using 14 anchor lines, was built by Hyundai Heavy Industries in South Korea. It was designed to be manned by about 40 staff and to be operated out of Hammerfest.

Goliat was originally scheduled for start-up in Q4 2013, but, like Laggan-Tormore, suffered setbacks. Now that the field is

The Goliat FPSO achieved first production in March 2016. Photo from Eni.

in production, it hasn't all been smooth sailing. Production was briefly halted on 26 August due to gas being detected in an unwanted area. Gas was being vented as part of a maintenance operation. This led to an automatic power shutdown to eliminate ignition sources. Production eventually resumed on 27 September.

▪ ExxonMobil in Julia start-up – April 2016 ExxonMobil started oil production at its US$4 billion Julia oil field in the Gulf of Mexico in April 2016.

The US supermajor's initial development phase for Julia uses subsea tiebacks to the Chevron-operated Jack/St. Malo production facility located 15mi away, which reduces the need for additional infrastructure and enhancing capital efficiency. The company is also utilizing subsea pumps that have one of the deepest applications and highest design pressures in the industry to date.

Julia is approximately 265mi southwest of New Orleans in the ultra-deepwater Walker Ridge area in more than 7000ft water depth.

The field development plan was approved in May 2013. The Julia field, discovered in 2007, is thought to contain approximately 6 billion bbl of resource in place. Exxon said the initial development phase will be designed to produce 34,000 bo/d.

▪ Noble online at Gunflint – July 2016 Noble Energy brought its deepwater Gunflint field in the Gulf of Mexico online in late July 2016. The Gunflint oil development, in Mississippi Canyon Block 948, is a subsea tieback to the Gulfstar One facility owned by Williams Partners and Marubeni.

The two-well field is expected to reach a minimum gross production of 20,000 boe/d. Noble Energy operates the Gunflint field with 31.14% stake. Partners include Ecopetrol America (31.50%), Samson Offshore Mapleleaf (19.13%), and Marathon Oil Corp. (18.23%).

▪ TEN delivers first oil – August 2016 Tullow Oil achieved first oil from the Tweneboa, Enyenra, Ntomme (TEN) fields offshore Ghana with MODEC's *Prof. John Evans Atta Mills* FPSO vessel back in August.

TEN is expected to ramp-up oil production gradually towards the FPSO capacity of 80,000 b/d through the remainder of the year. The TEN average in 2016 is anticipated to be 23,000 b/d gross, and 11,000 b/d net for Tullow.

The *Prof. John Evans Atta Mills* is moored some 60km offshore Western Ghana in about 1500m water depth. In addition to the capability of processing 80,000 b/d, the FPSO is also able to process 180 MMcf/d of natural gas, and has the storage capacity of approximately 1.7 MMbbl of crude oil.

▪ Shell brings Stones online – September 2016 Supermajor Shell started production from its Stones development in the deepwater Gulf of Mexico in September 2016. The field's FPSO, *Turritella*, is the deepest floating production unit in the world, operating in 9500ft of water. It is Shell's 13th project to use an FPSO unit, and the Gulf of Mexico's second FPSO behind the *BW Pioneer*, which operates at Petrobras' Cascade/Chinhook development.

Shell says it expects production to ramp up to 50,000 boe/d by the end of 2017. OE

NOTABLE MERGERS

2016 has also seen some notable players opt to merge businesses and combine synergies.

In the beginning of the year, Shell closed its US$70 billion merger with BG Group, making Shell the world's second biggest non-state oil company, surpassing Chevron. ExxonMobil remains the largest.

In April, service companies Schlumberger and Cameron completed their $14.8 billion merger, less than a year after the deal was proposed. Both companies had held stake in the OneSubsea joint venture. By contrast, Schlumberger and Cameron's merger was smooth sailing compared to the attempted Halliburton and Baker Hughes combination, which eventually fell apart in May this year. Baker Hughes received a $3.5 billion payout for the terminated agreement.

But, Baker Hughes wouldn't stay single for long. In late October, the service firm and GE Oil & Gas announced that the two would combine under the Baker Hughes brand. GE Oil & Gas CEO Lorenzo Simonelli will lead the new company, which will have a combined revenue of $32 billion. The deal was unanimously approved by the boards of directors of both companies, and closing is expected in mid-2017.

Somewhat unexpectedly, in May, engineering firms Technip and FMC Technologies announced they would combine under the brand TechnipFMC, creating a $13 billion business. Like with Schlumberger and Cameron (which shared the OneSubsea joint venture), Technip and FMC shared the Forsys Subsea joint venture, created in 2015. In a statement, the firms said the move will "create a global leader that will drive change by redefining the production and transformation of oil and gas."

Together, in 2015, Technip and FMC generated combined revenue of about $20 billion. As of March 31, 2016, the two companies together had consolidated backlog of approximately $20 billion.

Thierry Pilenko, Technip chairman and CEO, will serve as executive chairman of TechnipFMC. Doug Pferdehirt, president and COO of FMC Technologies, will serve as the CEO of the new company. ▪

2016's Top Finds

Elaine Maslin reports on the year's top discoveries to date. The largest discoveries were smaller in 2016, but the average ranged between 396-524 MMboe.

Despite continued cutbacks in exploration spending, operators large and small have continued to drill in 2016, but average find sizes have fallen.

The size of the finds pale compared to last year (Zohr, offshore Egypt, was 3960 MMboe and Ahmeyim, Mauritania, was 1408 MMboe). The average size of a find in last year's Top 10 was 700 MMboe. This year, it's 524 MMboe – or 396 MMboe if you don't include Tulimaniq, the biggest find so far this year.

OE pondered whether to include Caelus Energy's massive Tulimaniq discovery in Smith Bay on the North Slope, Alaska, in the Top 10 offshore discoveries for 2016. Technically, it's offshore – sitting in <2m water depth. However, for a large part of the year this is frozen over, drilling is from a land rig and production would likely be from man-made islands. Given its size, we decided to include it and let our readers decide.

Five of the top 10 biggest discoveries up to 11 November have been in West Africa. Discounting the Talimaniq discovery, the top two finds were in Senegal, discovered by the same operator, Atlantic Margin expert Kosmos Energy – which describes Mauritania/Senegal as "potentially the largest new petroleum system opened on the Atlantic Margin. Kosmos is planning a second exploration phase in this area, but outboard of existing discoveries, starting mid-2017, targeting oil. Another operator, Cobalt, found a further two of the Top 10 finds, in Angola.

The rest were in the Gulf of Mexico, Mexico, Egypt and Myanmar. East Africa and the Eastern Mediterranean are notable by their absence, having been high on the list in previous years.

Despite the Tulimaniq outlier, and majors not having a strong show in the Top 10, deepwater remained the focus of most exploration. Gas finds, while not as dominant as last year, thanks to the massive Zohr find offshore Egypt, also remains a significant part of this year's new resources.

This table will also likely change as we go into 2017 and more is learned about some of the already found resources and wells, still being drilled, complete. Resource estimates for Total's Raya well, for example, are yet to make it into the public domain. The well, drilled offshore Uruguay, broke records for deepwater drilling.

2016's Top 10 offshore discoveries

Discovery	Location	Water depth	Operator	Resource (MMboe)
Tulimaniq*	Smith Bay, North Slope, Alaska	<2m	Caelus Energy	1800
Guembeul	St. Louis Offshore Profund Block, Senegal	2700m	Kosmos Energy	1320
Teranga	Cayar Offshore Profond, Senegal	1800m	Kosmos Energy	880
Owowo	Deepwater Nigeria	576m	ExxonMobil	500*
Thalin	Bay of Bengal	836m	Woodside	266
Golfinho	Kwanza Basin, Angola	1330m	Cobalt	244
Nobilis	Perdido Fold Belt, Mexico	3000m	Pemex	203
Zalophus	Kwanza Basin, Angola	1760m	Cobalt	188
Fort Sumter	Mississippi Canyon, Gulf of Mexico	2152m	Shell	125
Baltim South West	Nile Delta, Egypt	25m	Operated by Petrobel (JV between Eni and Egyptian General Petroleum Corporation), 50/50 owned by Eni/BP.	111

Data from Wood Mackenzie, as of 11 November 2016.

*While offshore, Tulimaniq is in very shallow water (<2m), drilled using a land rig from the frozen ice during winter and likely to be developed using man-made islands, so it's our find number zero, hence there being 11 finds in this Top 10 table.

*Exxon said 500 MMbbl-1 billion bbl recoverable resource.

Guembeul

Part of the Greater Tortue Complex, the Guembeul-1 exploration well encountered 101m of net gas pay in two "excellent quality" reservoirs, including 56m in the Lower Cenomanian and 45m in the underlying Albian. Importantly, Kosmos says, Guembeul-1 demonstrated reservoir continuity as well as static pressure communication with the Tortue-1 well in the Lower Cenomanian, suggesting a single, large gas accumulation. Guembeul-1 was drilled approximately 5km south of Tortue-1, which is expected to be the anchor for a development hub. The Tortue development concept is currently a near-shore FLNG concept.

Taranga

Sitting in the Cayar Offshore Profond block, about 65km northwest of Dakar in nearly 1800m water depth, the Teranga-1 well was drilled to a total depth of 4485m. The well encountered 31m of net gas pay in good quality reservoir in the Lower Cenomanian objective.

Well results confirmed that a prolific inboard gas fairway extends about 200km from the

Marsouin-1 well in Mauritania through the Greater Tortue area on the maritime boundary to the Teranga-1 well in Senegal, Kosmos says.

Owowo

The Owowo-3 well encountered about 140m of oil-bearing sandstone reservoir. Owowo-3 extends the resource discovered by the Owowo-2 well, which encountered about 157m of oil-bearing sandstone reservoir, according to Exxon.

Owowo-3 was drilled to 3173m in 576m water depth. Exxon says that the Owowo field spans portions of the contract areas of Oil Prospecting License 223 and Oil Mining License 139.

Thalin

The Thalin-1A exploration well, drilled about 60km west of the Daewoo-operated producing Shwe field, in Block AD-7 in the Rakhine Basin intersected a gross gas column of about 64m. About 62m of net gas pay was interpreted within the primary target interval.

Block AD-7 is in the Bay of Bengal, approximately 100km offshore of the west coast of Myanmar. Water depth at the Thalin-1A well location was 836m.

The well reached a total depth of 3034m. The discovery followed an earlier gas discovery by Woodside at the Shwe Yee Htun-1 well in Block A-6, but Thalin proved a working petroleum system and a new play type different to that encountered at Shwe Yee Htun-1.

"The logical development option for the Thalin-1A discovery is a tieback to the nearby Shwe field," said Woodside CEO Peter Coleman, earlier this year. "Our strategy is to fully appraise the discovery in one campaign, thereby facilitating concept select in 2017."

Atwood Oceanic's Atwood Achiever drillship, which has been drilling for Kosmos. Photo from Atwood Oceanics.

Woodside is currently the largest acreage holder in the offshore Rakhine basin with interests in six blocks. The six permits make up about 47,000sq km and represent 20% of Woodside's global exploration acreage.

Golfinho

Golfinho was Cobalt's final exploration well commitment on Block 20 offshore Angola. The firm said initial analysis of the Golfinho well results indicated potential for another large mound feature with Cameia-like fluid and reservoir properties. Cobalt is currently marketing its Angolan assets. OE

Troubling trends

For the offshore oilfield equipment and services industries, 2016 was a difficult year. Douglas Westwood's Joel Hancock looks forward to see if there is a light at the end of the tunnel.

The global trend of declining offshore oilfield equipment (OFE) and oilfield services (OFS) expenditure, which began in 2015, continued through 2016.

Between 2015 and 2016, offshore OFS expenditure contracted by 16% to US$49 billion, while OFE expenditure fell by 2% to $67 billion over the same time period.

Longer term, Douglas Westwood's (DW) analysis suggests that the decline in expenditure will persist through to 2020, indicating that 2016 marks the start of a barren period for the offshore OFS and OFE sectors. Low rig day rates, coupled with a significant drop in project sanctioning will result in offshore OFS expenditure stagnating in the long-term, averaging $49 billion between 2016 and 2020, while annual OFE expenditure is set to decline from $67 billion in 2016 to $43 billion in 2020.

At a regional level, DW's analysis suggests that the largest offshore OFS year-on-year decline in expenditure will be seen in Africa, which is forecast to undergo a 3% year-on-year decline between 2016 and 2020.

The *Maersk Deliverer* was one of many rigs that had its contract cut this year. In March, Chevron's Angola affiliate, Cabinda Gulf Oil Co., sent an early cancellation notice to Maersk Drilling for the ultra-deepwater semisub, ending a contract in effect since May 2012. Photo from MEDVIND/Bent Medvind Sørensen/Maersk Drilling.

Hard hit Africa

Much of the decrease can be attributed to the lack of project sanctioning in high-cost deepwater plays, such as the Kwanza Basin offshore Angola, which have been particularly hard hit in the low oil price environment. Similarly, negative trends are present within the offshore OFE market. Significant contractions between 2016 and 2020 of 18% and 15% year-on-year, respectively are seen in Asia and Latin America. Capex cuts by Asian national oil companies (NOCs), driven by the low oil price environment, are the cause of this especially poor forecast for Asia. In Latin America, financial pressure for Brazil state player Petrobras has resulted in a downward revision of 25% to its investment plan for 2017-2021 compared with the previous iteration.

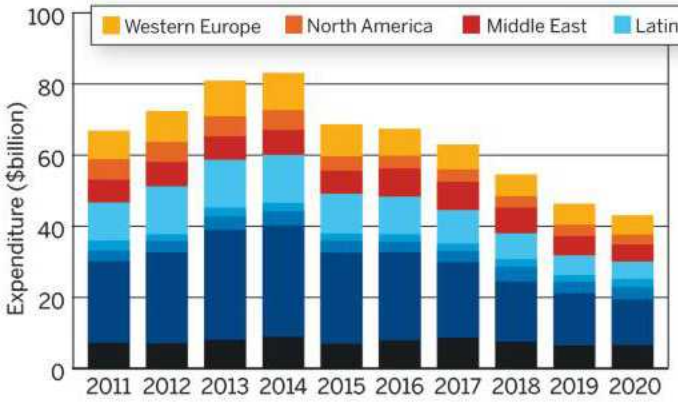
Offshore production is set to increase by 16% through to 2020, primarily due to projects sanctioned prior to the 2014 oil price downturn being brought online. The vast majority of OFS and OFE expenditure associated with these projects has already been spent during the project development stage, therefore these projects have little influence on the forecast.

Much of the production growth seen through 2016-2020 will occur in the medium-term, with a lack of project sanctioning in the near-term affecting greenfield additions in the long-term due to lead times in the order of several years for offshore projects.

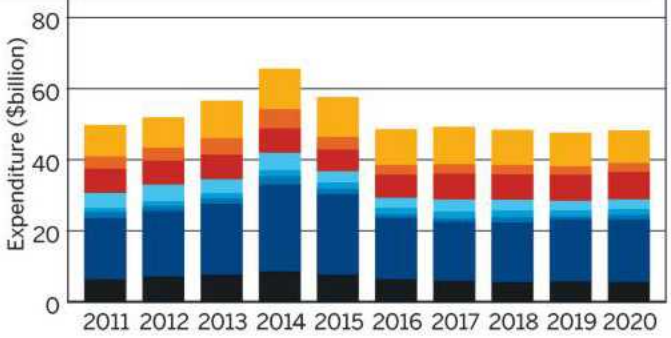
Developments in Brazil and West Africa will contribute to strong deepwater production growth through the remainder of the decade, from 7.5 MMboe/d in 2016 to 9.8 MMboe/d by 2020. However, the recent oil price downturn has affected project sanctioning and will result in a significant drop in drilling in deepwater basins in the medium-term.

Even in the event of a rapid recovery in oil prices, offshore activity will be suppressed due to the deferral of final investment decisions for several developments in key offshore basins. Bonga South West-Aparo (Shell) and Etan (Eni) in Nigeria, as well as Cameia (Cobalt/Sonangol) and Chissonga (Maersk Oil) in Angola are amongst the high-profile deferments that will contribute to the poor offshore OFS outlook through to 2020.

Offshore oilfield equipment expenditure



Offshore oilfield services expenditure



Source: Douglas-Westwood's World Oilfield Services Market Forecast Report Q3 2016

Too many rigs

In addition to the drop in offshore activity, offshore rig supply will be a major issue for offshore OFS and OFE expenditure. The offshore drilling sector is currently heavily oversupplied with units brought to market during the boom years of 2011-2014, despite widespread scrapping of older rigs.

The resulting low levels of utilization have and will continue to drive down dayrates for rigs entering new contracts. DW estimates offshore rig and crew spending will decline 2% year-on-year over 2016-2020, after already experiencing a sharp 18% drop from 2015-2016.

The largest decline will once again be seen in Africa at 6% annually, as project deferrals mount up and reduce the drilling backlog as well as operators scaling back on exploration plans. Even in a scenario of a rapid recovery in oil prices, it is unlikely dayrates will recover to 2014 levels until well into the 2020s due to the saturated market.

The oversupply will also result in extremely low levels of rig construction – DW's forecast shows the construction of just 17 mobile offshore drilling units (MODUs) over 2016-2020, down from the 298 built in the preceding five-year period.

Bright spots

Despite the depressed market conditions, DW's analysis has picked out bright spots through the remainder of the decade for both OFS and OFE expenditure. Australasia bucks the trend in a weak OFS market – expenditure in the region is set to increase 8% year-on-year between 2016 and 2020, driven by growth in offshore gas developments. Inpex's Ichthys project, expected to ramp-up production over the next four years, is a particular highlight that will drive expenditure through the forecast period.

Australasia will also show positive trends in the offshore OFE market, along with Eastern Europe and the former Soviet Union (FSU). Both of these regions historically account for a small proportion of total offshore OFE spend, with Australasia and Eastern Europe accounting for 5% and 3% of cumulative 2011-2015 expenditure, respectively. From this small base, DW has identified growth potential as these regions develop their offshore resources through the forecast period.

By 2020, DW expects Australasia and Eastern Europe's share of offshore expenditure to have increased to 6% and 4%, respectively.

As with OFS, Australia's liquefied natural gas (LNG) projects are the key driver for Australasia's positive offshore OFE outlook. Despite cost overruns and difficulty in obtaining long-term supply contracts, DW expects LNG projects, fed by offshore gas fields, to increase Australia's offshore gas production 66% over 2016-2020. This drive will boost offshore OFE spend, with Ichthys (Inpex), Scarborough (ExxonMobil) and Greater Western Flank Phase 2 (Woodside Energy) in particular.

Production in Eastern Europe and FSU has historically been dominated by onshore fields, with 92% of total production in the region attributed to onshore developments in the five-year period ending in 2015. A similar dominance is expected in the forecast, however, numerous high profile offshore developments will cause a surge in offshore OFE expenditure – resulting in the region's positive offshore growth outlook. BP's Shah Deniz 2 project, due onstream in 2018 with a subsequent four-year ramp up, is one such project.

Looking for easier work

The negative picture for offshore OFE and OFS expenditure is reversed onshore, with both OFE and OFS onshore expenditure set to record strong growth profiles through to 2020. For OFE, expenditure is set to recover from lows of $61 billion in 2016, global onshore expenditure is set to increase at a rate of 8% year-on-year through the forecast period to $83 billion by 2020. For onshore OFS, DW expect 2016's total onshore expenditure figure of $125 billion to represent an industry nadir, with expenditure increasing 10% year-on-year between 2016-2020, reaching $187 billion in 2020. Both these recoveries are linked to a rebound in North American drilling – in particular in the US shale plays where rising oil prices will bring lower-quality shale acreage back into economic viability.

The recovery of onshore expenditure, coupled with decreased offshore spend, will result in the market share of offshore, in terms of total expenditure, declining through the majority of DW's forecast period. The offshore proportion of spending will decline to from 38% in 2016 to a low of 27% in 2019 as operators switch focus to less challenging onshore developments. **OE**

Joel Hancock *joined Douglas-Westwood after graduating Imperial College London with a geology MSci in June 2016. Hancock now works in DW's Drilling & Production (D&P) team that authors DW's D&P, Oil Field Services and Oil Field Equipment market reports.*

Solutions

Technip introduces new DSV

Technip launched its new diving support vessel (DSV), *Deep Explorer*, a DP3-classed ship, purposely designed and certified for subsea projects in the demanding North Sea/Canadian markets.

Deep Explorer has the latest technology diving control system, 400-tonne box boom crane, large deck area, working moon pool and work-class remotely operated vehicles. It is designed to work on diving and subsea construction projects, even in extreme weather conditions. The vessel will start operational duties in 2017.

The vessel hull was built by Vard Tulcea shipyard in Romania, and then towed to Vard Langsten in Norway for equipment outfitting and commissioning. The vessel features a 24-man twin bell saturated dive system rated to 350m. The dive system was designed, built and commissioned by JFD, part of James Fisher and Sons plc.

"This event marks an important milestone in this three-year project to design, build and deliver this impressive fantastic new ship," says Bruno Faure, Technip's senior vice president subsea projects and operations. "We are proud to welcome the *Deep Explorer*, an impressive key asset for the Technip fleet and for our clients."

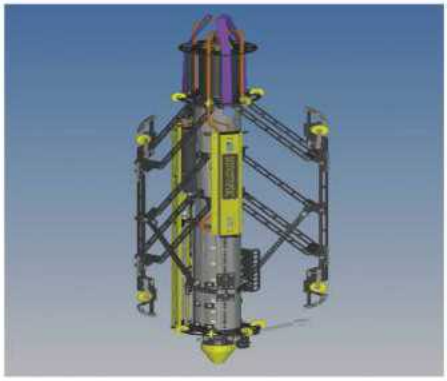
www.technip.com

Sonomatic develops internal caisson tool

Sonomatic's research and development group has developed a new internal caisson tool (ICT) for internal caisson inspection.

"Obtaining reliable inspection data from the inside of caissons has long been recognized as a challenge in the industry," says Scott Bulloch, topside project manager, Sonomatic. "This was one of the main drivers for development of the internal caisson inspection tool."

The ICT's first field application was to inspect three caissons for a North Sea operator. After all interior scale and marine growth was removed, the ICT inspected the internal surface of the caissons, using 0° corrosion mapping. Data scan files were collected at 500mm axial intervals in a helical scan pattern. All the ultrasonic data was processed in making several million thickness measurements for each caisson, and was used to create corrosion maps that provide a colored graphic representation of areas of wall loss. **www.sonomatic.com**



GE, BP launch digital advisor

BP and GE have deployed Plant Operations Advisor (POA), a new digital resource tool, which some have dubbed a "Fitbit" for the oil and gas industry, at one of BP's platforms in the Gulf of Mexico.

POA, built on GE's Predix operating system and using GE's Asset Performance Management technology, is a digital solution incorporating big data, cloud hosting and analytics. The two companies say that POA will help prevent unplanned downtime and improve facility reliability.

The technology was created as part of a development partnership between GE and BP, which was announced earlier this year. Using GE's Asset Performance Management and Predix capabilities, POA rapidly integrates operational data from producing oil and gas facilities to deliver notifications and analytical reports to engineers so they can identify operational performance issues before they become significant.

The system provides simplified access to a variety of live data feeds and includes visualization capabilities including a real-time facility threat display. It also incorporates an extensive case management capability to support learnings from prior operational issues. BP says it hopes to deploy POA at other fields, pending a successful trial run. "When fully deployed, these advanced digital technologies will change the way we work and improve the integrity and performance of our assets around the globe."

www.ge.com

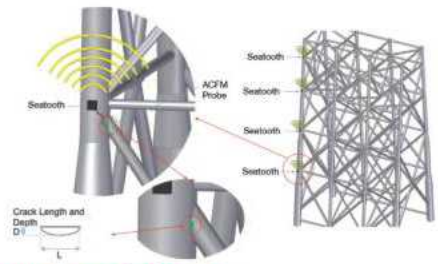
Integrated drone solution released

Sky-Futures and Flyability partnered to provide a fully integrated solution for drone-based industrial inspection. The Expanse-Elios package uses Flyability's Elios drone and Sky-Futures' Expanse software for data capture, processing and distribution to all stakeholders.

The Elios is a collision-tolerant drone allowing access to complex and confined spaces where manned entry is not possible or desirable.

Expanse provides end-to-end management of inspection data, allowing clients to manage operations, data analysis and creating intuitive reports accessible to all stakeholders through the cloud. Clients are also able to present inspection findings in a 3D environment.

"Through this bundle package, we intend to provide our customers with the greatest flexibility and efficiency in the way they can disseminate and post-process data gathered with Elios," says Patrick Thévoz, CEO and co-founder of Flyability. **www.flyability.com**



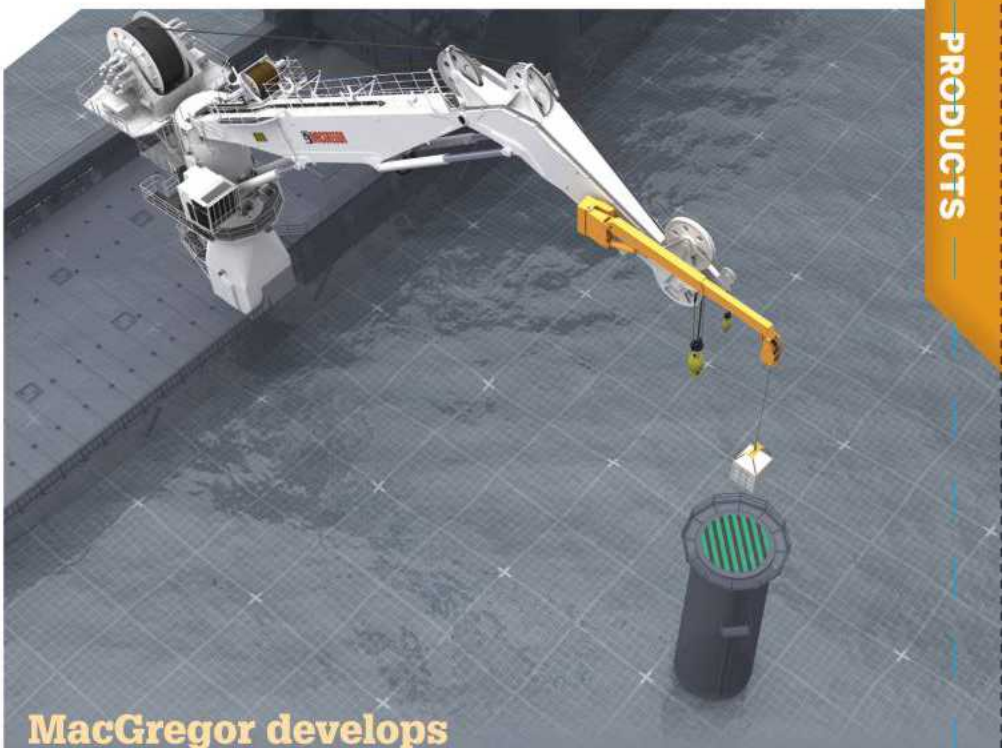
WFS, TSC debut Seatooth ACFM

WFS Technologies and TSC launched Seatooth ACFM (alternating current field measurement), a wireless smart non-destructive testing monitoring solution.

TSC's ACFM array probe monitors the growth of surface breaking cracks, while the Seatooth subsea wireless communications system provides communications through seawater and the splash zone, and is resistant to biofouling, surface noise and turbidity.

Together, Seatooth ACFM is a non-intrusive, wireless network solution that can be retrofitted to offshore structures and subsea assets, and can be user-configured to take readings as required.

Seatooth ACFM can be configured as standalone sensors or within subsea wireless networks, comes with an internal battery pack to support 5-15 years of operation, and are installed by light-class remotely operated vehicles deployed off platforms.
www.wfs-tech.com



MacGregor develops 3D motion compensator

MacGregor, part of Cargotec, introduced the 3D Motion Compensator (3DMC), a flexible retrofit device designed for subsea/offshore cranes to compensate for the roll, pitch and heave motions of the vessel to minimize any movement of the load in relation to a fixed point in space.

The 3DMC can be fitted to the knuckle jib of several new or existing MacGregor cranes and makes use of the existing hydraulic power unit and control system of the crane. Fully incorporated into the crane's control system, all operations are performed from the existing interfaces in the crane cabin. When not required, the 3DMC simply remains fixed to the side of the crane's knuckle jib allowing normal lifting operations using the main and whip winches.

The 3DMC/crane interface is also designed so that the unit can be mobilized to a crane with the relevant fittings. This allows flexibility within a fleet of vessels that can share one or several 3DMCs between them. **www.macgregor.com**

Boskalis to add new vessel to fleet

Dutch marine contractor Boskalis revealed details of a new offshore transport and crane vessel to join its fleet. The unit will be a conversion of an existing F-class heavy transport vessel. It is being equipped with a 3000-tonne capacity mast crane and will have DP2 and accommodation for up to 150 people.

The unit already has a backlog, thanks to a contract awarded by DONG Energy Wind Power for the transport and installation of the foundations for a part of the Hornsea Offshore Wind Farm Project One, approximately 120km off the Yorkshire coast (UK).
www.boskalis.com

Activity

US' BOEM, Mexico's ASEA sign pact

Directors from BOEM and ASEA move to strengthen ties. Photo from BOEM's Facebook page..

The US Bureau of Ocean Energy Management (BOEM) and Mexico's Agency for Safety, Energy and Environment (ASEA) signed a letter of intent in early October to strengthen cooperation, coordination and information sharing on environmental matters related to offshore hydrocarbon activities in the Gulf of Mexico.

BOEM Director Abigail Ross Hopper and ASEA's Executive Director Carlos de Regules signed the agreement at BOEM's headquarters in Washington, DC.

"The signing of this agreement is an important step in an increased level of environmental coordination and cooperation between our agencies on offshore oil and gas issues," Hopper said. "It is critical that we work together to ensure the highest levels of environmental protection on both sides of the US–Mexico border, treating our shared Gulf of Mexico as one ecosystem."

Cooperation between BOEM and ASEA is in keeping with broader bilateral efforts for cooperation in the environmental and hydrocarbons sector between the two countries, BOEM said.

"Formal cooperation between ASEA and BOEM is an important step towards creating a familiar regulatory framework in the Gulf of Mexico, which is essential to the successful implementation of Mexico's Energy Reform," de Regules said. ▪

Oceaneering acquires Blue Ocean Technologies

Oceaneering International has acquired privately-held Blue Ocean Technologies, a provider of riserless light well intervention (RLWI) services, in a US$30 million cash deal.

Oceaneering CEO Kevin McEvoy said the acquisition enables further market penetration in the subsea well intervention segment, and will allow them to support new and existing customers.

Included in the acquisition are three RLWI systems, two of which are currently under construction, and are expected to be fully functional by mid-2017. Oceaneering expects to invest approximately $10 million to complete construction of the two RLWI systems.

Emerson acquires Permasense

Emerson has agreed to acquire UK-based Permasense, a provider of non-intrusive corrosion monitoring technologies. Emerson said that the acquisition is in line with its strategy to invest in its core business platforms and expand in markets that hold significant long-term growth opportunity.

The Permasense product line will become part of Emerson's Rosemount portfolio of measurement and analytical technologies. Emerson said that Permasense technologies complement Emerson's Roxar intrusive corrosion monitoring and non-intrusive sand management systems and strengthen the company's pervasive sensing applications that provide customers a more complete view of their operations and facilities.

Frank's International, Blackhawk to merge

Frank's International agreed to aquire Blackhawk Group Holdings, Inc., the ultimate parent company of Blackhawk Specialty Tools, for US$321 million.

The merger consideration comprises a combination of approximately $150 million of cash on hand and approximately 12.8 million shares of Frank's common stock, on a cash-free, debt-free basis (with approximately $80 million of Blackhawk debt being repaid at closing with proceeds from the transaction), subject to adjustment.

Frank's expects that Blackhawk's specialty cementation tools will augment its tubular running services business by providing Frank's the opportunity to diversify its offerings. Blackhawk also provides well intervention products.

Neptune opens Houston office

Neptune Marine Services opened a new office in Houston operating under the name Neptune Subsea in November. The move will enable the firm to provide the full suite of Neptune's services to clients within the Gulf of Mexico and the Americas, Neptune says.

John Allen, a Houston-based strategic business development advisor, formerly of GE Oil & Gas, has been appointed to drive the expansion in the region, which has been supported by Scottish Development International, the international arm of Scottish Enterprise.

Saudi Aramco, Rowan form rig joint venture

US offshore drilling contractor Rowan Companies and Saudi Aramco have signed a deal to create a new offshore rig outfit, to be based in Saudi Arabia.

The new organization will be a 50-50 joint venture, which the pair will own, operate, and manage offshore drilling rigs in Saudi Arabia, including newbuild units to be built inside the country.

This will initially include three Rowan jackup rigs and two Saudi Aramco-owned jackups, plus the management of five further Rowan jackups, until their current contracts expire. Rowan will contribute a further two jackups, when they complete their current contracts, due to end late 2018, for Saudi Aramco. Operations are expected to start in Q2 2017.

Tenaris opens Kazakhstan facility

Tenaris has opened a new premium threading facility in Aktau, Kazakhstan. The new plant will support Tenaris's long-term agreement with Karachaganak Petroleum Operating, plus key operator Tengizchevroil.

From this facility, Tenaris will thread seamless pipes and gas-tight premium connections, and is equipped to apply its proprietary Dopeless technology – a dry, multifunctional coating – which offers operational and HSE benefits.

The facility already employs 40 people and is scheduled to hire up to 90 direct employees once at full capacity with 95% local jobs. The US$40 million state-of-the-art facility has the capacity to produce 45,000-ton of oil country tubular goods.

Oil India, UH ink technology MOU

Oil India Ltd. (OIL) and the University of Houston (UH) have entered into an agreement to collaborate on technologies required to maximize recovery from aging oilfields in India.

The duo will cooperate in the fields of improved oil recovery and enhanced oil recovery; seismic interpretation and reservoir characterization studies; drilling and well intervention practices; and unconventional hydrocarbon studies.

Petroleum Minister Dharmendra Pradhan said this partnership would lay huge impact in the country's exploration sector, as innovation, scientific temperament, and institutional handholding is the way forward for growth.

Dril-Quip to acquire TIW for US$143 million

Dril-Quip has entered into an agreement to acquire Houston-based TIW Corp. for approximately US$143 million, subject to closing adjustments.

TIW is a 100-year old manufacturer of consumable downhole products for the global oil and gas market, which provides liner hanger systems and related equipment and services worldwide.

TIW is being acquired on a debt-free, cash-free basis and Dril-Quip intends to fund the consideration with cash on hand. It is anticipated that the closing of the transaction will occur during Q4 2016.

TIW reached peak revenues of approximately $140 million in 2014. Revenue is expected to trough between $60 million and $70 million in 2016 and is expected to increase to between $80 million and $100 million by 2018. EBITDA margins are expected to be similar to Dril-Quip's margins once synergies are realized.

Polar Duke. Photo from Dolphin Geophysical.

GC Rieber, Rasmussengruppen form Shearwater GeoServices

Norwegian outfits GC Rieber Shipping and Rasmussengruppen have set up a new 50-50 owned marine geophysical company, Shearwater GeoServices, which will be headquartered in Bergen. The deal is expected to close in Q4 2016.

Shearwater will be an integrated provider of marine geophysical services to oil and gas and multiclient companies worldwide, the firms say. The move will see Shearwater take over the four ex-Dolphin Geophysical seismic vessels; *Polar Empress*, *Polar Duke*, *Polar Duchess*, and *Polar Marquis* from GC Rieber Shipping, and the corresponding vessel loans will be transferred from GC Rieber Shipping to Shearwater.

The total value of the four seismic vessels is about US$228.5 million, GC Rieber says. The current outstanding balance of these vessel loans is $198.5 million. Shearwater will also purchase the seismic equipment (including streamers) and the processing business from the former lending banks of Dolphin Geophysical.

The pair will inject $60 million in liquidity (GC Rieber Shipping, $15 million; Rasmussengruppen, $45 million) to fund operations. ▪

M² Subsea acquires Harkand ROV fleet

A recently formed subsea services business has secured private equity investment in order to buy a fleet of 32 remotely operated vehicles (ROVs).

Aberdeen- and Houston-based M² Subsea was able to buy the fleet from the administrators of failed subsea services firm Harkand after getting the investment from a fund advised by Alchemy Special Opportunities.

With the new fleet, the firm expects to create at least 50 onshore and 100 offshore jobs operating primarily in the North Sea, Gulf of Mexico, West Africa and eventually Asia Pacific and the Middle-East by the end of 2017.

The firm is being led by Mike Arnold, the founder of Rovtech, in 1986, as well as Hallin Marine UK and Bibby Offshore's ROV services unit. He is joined by a strong management team of other subsea veterans including Mark Wood and Mike Winstanley. Wood has also worked at Rovtech, Hallin and Bibby. Winstanley founded Bowtech products, after working for Bergen Underwater Services, Subsea Services and Bennico. Bowtech was acquired by Teledyne in 2014.

Arnold said: "The time is absolutely right for a new ROV services provider with a fresh approach that can, through experience, expertise, the correct asset base and lean management, dramatically reduce both cost and risk whilst continuing to provide a professional and quality service. Key to this will be the company's collaboration with vessel owners and operators, helping them to maximize utilization of vessels and offering competitive solutions to meet our clients' demands."

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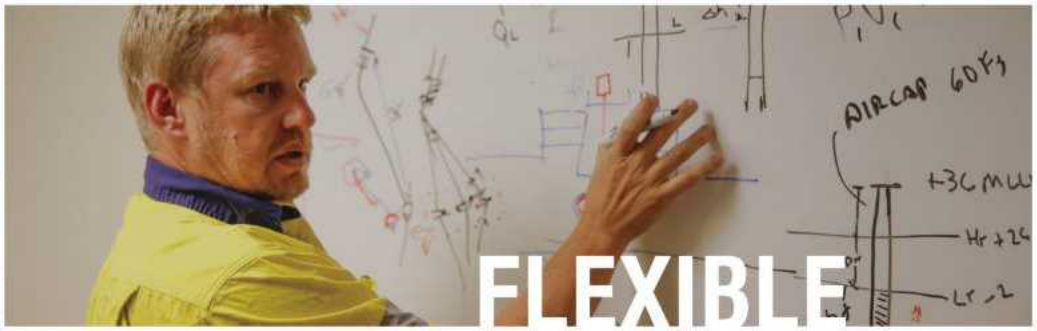

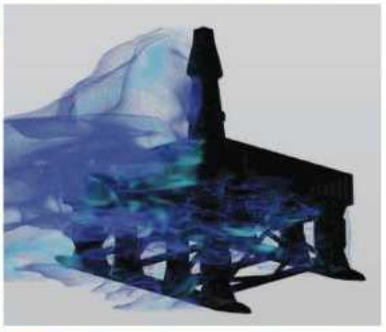

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