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SUBSEA
ROV/AUV **28**

PRODUCTION
Asset Integrity **34**

DRILLING
Automation **38**

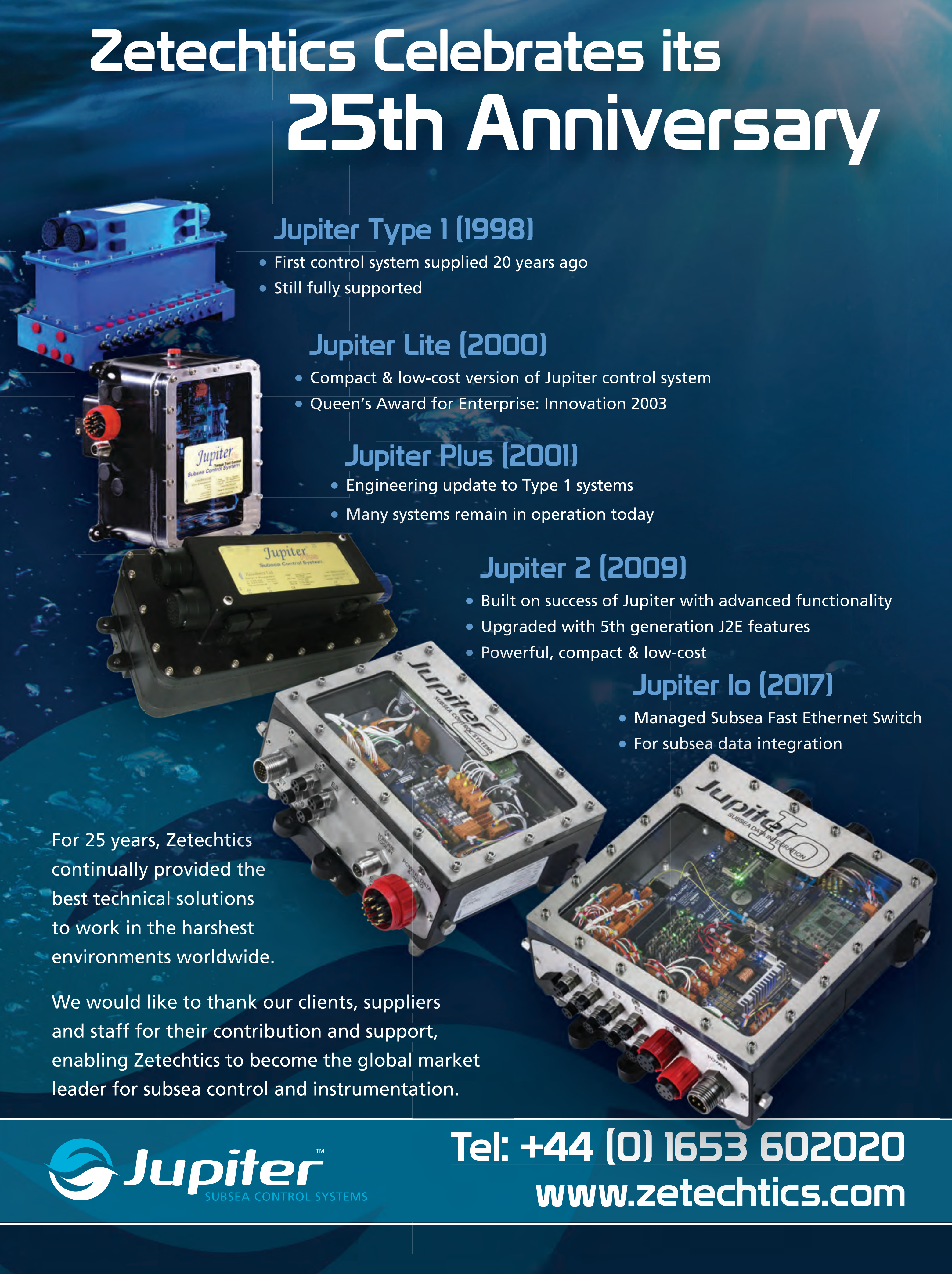
Rise of the robots

page 24

Global Offshore Market Forecast

page 18

Offshore Engineer • January 2018



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ASV Global's C-Worker 5 on a charting survey, with **TerraSond.** Photo from ASV and TerraSond.

FEATURE FOCUS

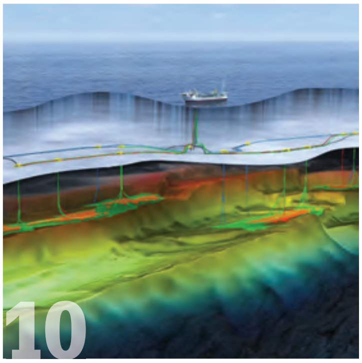
Global Offshore Market Forecast

Features

ON THE COVER

Spotlight. *OE* January chronicles the latest in subsea robotics. The cover image shows Oceaneering's Nexxus ROV and the Blue Ocean riserless intervention system (BORIS), which provides reliable access to live, subsea wells. *Image from Oceaneering.*

Departments & Columns



Corrections

In the November 2017 issue of *OE*, we mixed up the captions in the article, "Fixing Floaters," written by Vryhof's Clement Mochet. The STEVTENSIONER was pictured being used on the WindFloat project, offshore Portugal, which was also pictured in an image from Principle Power. We apologize for the error. A corrected article can be found in our digital edition: **https://goo.gl/pbqDnY**

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OE (Offshore Engineer) is published monthly by AtComedia LLC, a company wholly owned by IEI, Houston. AtComedia also publishes **Asian Oil & Gas**, the **Gulf Coast Oil Directory**, the **Houston/Texas Oil Directory** and the web-based industry sources **OilOnline.com** and **OEDigital.com.**

US POSTAL INFORMATION
Offshore Engineer (USPS 017-058) (ISSN 0305-876X) is published monthly by AtComedia LLC, 1635 W. Alabama, Houston, TX 77006-4196.
Periodicals postage paid at Houston, TX and additional offices.
Postmaster: send address changes to Offshore Engineer, AtComedia, PO Box 47162, Minneapolis, MN 55447-0162

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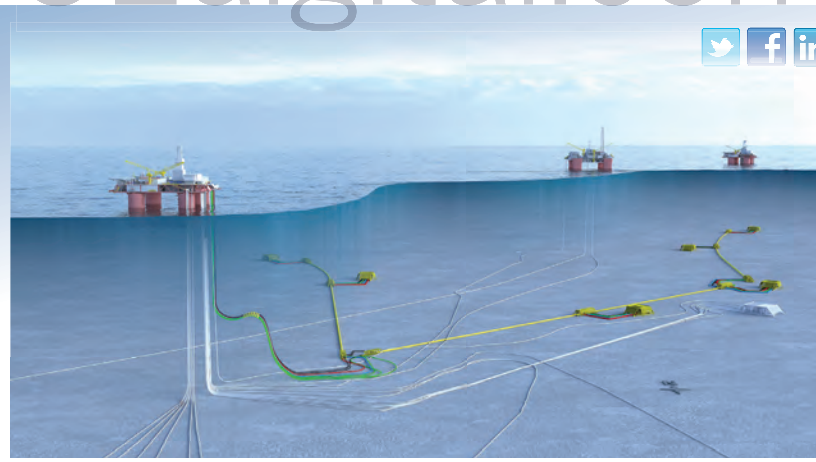

Moving and shaking

- McDermott, CB&I to merge
- First gas achieved at Zohr
- Statoil moves Snorre expansion forward

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People

New CEO for Pemex

Mexican President Enrique Pena Nieto has named Carlos Alberto Trevino Medina to succeed Jose Antonio Gonzalez Anaya as CEO of Pemex.

OE OPINION

Undercurrents

A deep loss

On December 11, 2017, a core member of Atcomedia (*OE's* publishing house), Shirley J. Ford, passed away after suffering a stroke at age 69.

Many that may have interacted with AtComedia, either as a customer of *OE,* one of our three international events – PECOM, Deepwater Intervention Forum and Global FPSO, or even our two annual directories (Gulf Coast Oil Directory and Houston/Texas Oil Directory) – over the past three decades will have known Shirley.

Shirley was our Human Resources manager and she also greeted the many callers to our offices in Houston, in person or by phone. After the passing of our production manager James W. Self in 2013, she took over the reins of the print editions of the Gulf Coast Oil Directory and the Houston/Texas Oil Directory, overseeing sales and production.

Outside of work, Shirley was an avid churchgoer and a member of the heavenly choir at St. Luke's Missionary Baptist Church in Houston. She organized many years of Thanksgiving food donations, benefiting the Houston Food Bank, and oversaw the donation competition among AtComedia employees – which we assure you was *quite* competitive. Everything was possible when Shirley was leading the charge.

Shirley was a native of Michigan, where she was laid to rest. *OE* would like to extend it's deepest condolences to her family and friends. She will be deeply missed. OE

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Global E&P Briefs

A TGS, Polarcus team up for 3D survey

TGS will start the new multiclient Alonso 3D survey in the US Gulf of Mexico in February 2018. The project will cover 6172sq km in the Atwater Valley and Lloyd Ridge protraction areas of the Gulf, where TGS says multi-level targets exist, from Miocene to Jurassic. The project allows TGS to extend coverage from a core area in Mississippi Canyon into frontier areas. TGS has given a letter of award to Polarcus to conduct the three-month survey using its XArray multiple source acquisition method.

B Nobilis-Maximino farm-out canceled

Pemex canceled its tender for the Nobilis-Maximino farm-out that was scheduled to coincide with the country's next deepwater round (2.4) this month (January).

Pemex blamed several factors for a "less than robust" interest in the farm-out, including the geological complexity at Nobilis-Maximino coupled with the current oil price environment. Pemex also stated that it believed the recent Brazilian pre-salt rounds negatively affected interest in Nobilis-Maximino.

Pemex was successful in its first deepwater farm-out for the Trion block, where it partnered with BHP Billiton in December 2016.

C Eni ups Area 1 estimate

Eni estimates Area 1 in Mexico's Campeche Bay to contain between 1.4-2 billion boe – 90% of which is oil – thanks to Eni's successful Tecoalli-2 well and revision to the reservoir models for the Amoca and Mitzon fields.

Tecoalli-2, 200km west of Ciudad del Carmen in 33m water depth, hit about 40m net oil pay in the Orca formation after reaching 4420m final depth. Eni then encountered an additional 27m net oil pay after deepening the well to the Cinco Presidentes formation exploratory target. Tecoalli sits 24km from the Amoca field and 13km from the Mizton field. Eni plans to start field production in 1H 2019.

D More Libra success

Petrobras hit two milestones at the huge Libra pre-salt field. In late November, Petrobras and its partners saw first oil flow from Libra through the 50,000 bbl capacity *Pioneiro de Libra* FPSO. Libra is 180km offshore Rio de Janeiro, Brazil, in the ultra-deep waters of the Santos basin. The field is being developed in phases. The goal now is a one-year test to evaluate the reservoirs dynamic behavior.

Petrobras also declared the Libra Northwest field commercial, renaming it Mero. Estimated to hold total recoverable volumes of 3.3 billion bbl, first oil was produced through the *Pioneiro de Libra* FPSO, through an extended well test.

The Libra consortium selected Modec to charter an FPSO. It will be used in the Mero pilot project, which will connect 17 wells to the platform. The consortium is Petrobras (40%), Shell (20%), Total (20%), CNPC (10%) and CNOOC (10%), with Pre-Sal Petróleo acting as manager of the production sharing agreement.

E Hebron flows

ExxonMobil's Hebron field development project offshore eastern Canada is now producing. The 20° API crude oil project involved the development of three fields: Hebron, West Ben Nevis, and Ben Nevis, which housed Hebron's initial oil discovery, estimated to contain 700MMbbl. Production is expected to peak at 150,000 bo/d.

ExxonMobil operates the Hebron project with 35.5% equity interest. Its partners are Chevron Canada (29.6%), Suncor Energy (21%), Statoil Canada (9%) and Nalcor Energy-Oil and Gas (4.9%).

Photo from ExxonMobil/Hebron Project.

F Catcher first oil flows

First oil flowed from the Catcher field in late December, according to BW Offshore. The Catcher area is expected to produce 96 MMboe, with peak production of 50,000 b/d.

The development will comprise 20 subsea wells (14 producers and eight water injectors) on the Catcher, Varadero, and Burgman fields, tied back to the *BW Catcher* FPSO, which was designed to produce 20 years uninterrupted, with storage capacity for 650,000 bbl and processing capacity for up to 60,000 b/d.

As of November, 12 wells have been completed and tied back.

G Forties pipeline repair near complete

Forties Pipeline System (FPS) operator Ineos reported, as *OE* went to press, that repairs on the pipeline are nearly complete and production expected to return to normal in the new year.

A hairline crack forced 400,000 bo/d and 1.2 Bcf of gas production to be shut-in in early December. The crack was found on an onshore section of the 235mi pipeline system, which in 2017 brought in 40% of North Sea oil from 85 offshore assets to onshore Scotland.

Oil & Gas UK reported that the shut-in cost operators US$26.7 million a day in lost production. FPS brings in production from the UK's two largest producing fields, the Nexen-operated Buzzard field, and Apache-operated Forties field.

H Maersk invests $3bn in Tyra

The Danish Underground Consortium – led by Maersk Oil – approved a US$3.36 billion (DKK21 billion) investment plan to redevelop the Tyra gas field on the Danish Continental Shelf.

Following the investment, Tyra will operate for at least another 25 years, and secure crucial Danish gas infrastructure (the facility processes some 90% of Danish gas production), says Maersk.

Tyra, Denmark's largest gas field, is 225km west of Esbjerg, and requires redevelopment due to subsidence. The plan involves modifying, removing and decommissioning existing facilities, and building new ones. Tyra will be shut-in from November 2019 for the work. Production is expected to restart in July 2022.

J Statoil set for Snorre expansion

Statoil will undertake "the largest improved oil recovery project on the Norwegian Continental Shelf" with the Snorre field expansion project. The plan for development and operation (PDO) calls for 24 new wells drilled from six new subsea templates to boost the field's recovery rate from 46% to 51%. The field has produced 1.4 billion bo to date. Statoil estimates the expansion will come online by 2021, tapping an additional 200 MMbo from the field, extending its life to at least 2040. Statoil has awarded several contracts associated with the project, including a 22-well contract for the semisubmersible rig *Transocean Spitsbergen*. Partners in the Snorre field are: Statoil (33.27%), Petoro (30%), ExxonMobil (17.44%), Idemitsu (9.6%), DEA Norge (8.57%) and Point Resources (1.1%). Snorre is the fourth PDO Statoil has submitted to Norwegian authorities this

I Statoil adds Roncador stake

Statoil has acquired a 25% stake in the Roncador oil field in Brazil's Campos basin from operator Petrobras. Statoil will pay US$2.35 billion, plus additional contingent payments of up to $550 million. Petrobras retains operatorship and a 75% interest.

Roncador is the third largest producing field in Petrobras' portfolio, with around 10 billion boe in place, and an expected remaining recoverable volume of more than 1 billion boe. Statoil believes it can create additional value at the field by applying its expertise in improved oil recovery, bringing total remaining recoverable reserves to over 1.5 billion boe.


The *P-54* FPSO on the Roncador field.
Photo: Statoil/Geraldo Falcão.

Global E&P Briefs

year; others include Johan Castberg, Njord, and Bauge.

K Maria comes online early

Wintershall started production from the Maria subsea tieback offshore Norway a year ahead of schedule and under budget at US$1.43 billion (NOK12 billion).

Maria is in 300m water depth, 200km offshore Trondheim, in blocks 6407/1 and 6406/3 on the Halten Terrace in the Norwegian Sea. The field makes use of three nearby platforms and an existing subsea installation: the Statoil-operated Kristin, Heidrun and Åsgard B production platforms, and Tyrihans.

Wintershall Norge operates Maria with 50% interest. Its partners are Petoro (30%) and Spirit Energy (20%).

L Lamantin disappoints

Kosmos Energy's highly anticipated Lamantin-1 exploration well in Block C-12, offshore Mauritania, failed to find hydrocarbons, hitting a water-bearing reservoir with residual hydrocarbons. Drilled in 2200m water depth to a total depth of 5150m. Kosmos will plug and abandon the well.

The Lamantin-1 well had been designed to evaluate a previously untested Lower Campanian base of slope fan supplied from the Nouakchott River system, trapped in a combination structural-stratigraphic feature, and charged from underlying, oil-prone Cenomanian/Turonian and Albian source rocks.

Kosmos will move on to the Requin Tigre prospect, a Cenomanian/Albian base of slope fan supplied from the proven Senegal River system. Kosmos operates Block C-12 with 28%. Partners are BP (62%) and SMHPM (10%).

M Spike in Norway PDOs

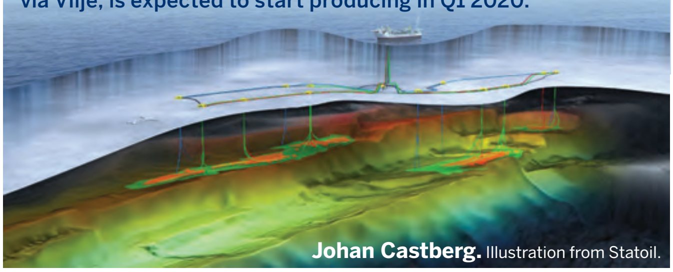
Norway's offshore has seen a huge spike in activity at the end of 2017, thanks to several companies submitting plans for development and operation (PDO) to the country's regulatory authorities.

Statoil submitted a US$5.9 billion (NOK49 billion) PDO for the Johan Castberg field, hoping to tap an estimated 450-650 MMboe recoverable resources across the Skrugard, Havis and Drivis discoveries in PL 532. Statoil plans a floating production vessel with "extensive" subsea infrastructure, with 30 wells, 10 subsea templates and two satellite structures.

First oil is scheduled for 2022, and the field, 100km north of the Snøhvit field, in 360-390m water depth, is expected to produce for more than 30 years.

VNG Norge submitted the $1.2 billion (NOK 10.2 billion) plan for the Fenja field, which will be developed via two subsea templates with three producer wells, two water injector wells, and one gas injector well, connected to the Njord A platform for processing, storage and export via the *Njord B* ship. Production is scheduled to begin in 2021 and last 16 years. Located in Block 6406/12, Fenja contains recoverable resources of approximately 100 MMboe.

Aker BP submitted three PDOs to develop Valhall Flank West, Ærfugl (formerly Snadd) and Skogul (formerly Storklakken). Ærfugl is being developed via subsea tieback to the *Skarv* FPSO. Production from the first phase is expected in late 2020; Valhall Flank West will be developed from a new normally unmanned installation, tied back to the Valhall field center for processing and export. Startup is planned for Q4 2019. Skogul, which is a subsea tieback to the *Alvheim* FPSO via Vilje, is expected to start producing in Q1 2020.



Johan Castberg. Illustration from Statoil.

N Eni adds to Morocco stake

Eni has signed agreements with Moroccan state oil firm ONHYM to become operator of the Tarfaya Offshore Shallow exploration permits I-XII, gaining a 75% stake. ONHYM will retain 25%. Tarfaya is offshore the cities Sidi Infni, Tan Tan and Tarfaya in the Atlantic Ocean. The exploration rights cover an area of 23,900sq km, with a water depth ranging from zero to 1000m, and with liquid hydrocarbons potential in place.

O Zohr gas flows

Eni and partner BP have started production from the Zohr gas field offshore Egypt in the Mediterranean Sea. The deepwater field, with potential resources in excess of 30 Tcf of gas in place, started-up in less than two and a half years from the discovery.

The field, in 1500m water depth the Shorouk Block, about 190km north of Port Said, was discovered in August 2015, and is the largest gas discovery ever made in Egypt and in the Mediterranean Sea.

An initial six wells were expected to be drilled and tied into existing infrastructure as part of the first phase of development. Some 20 wells are expected to be drilled by the end of 2019.

P Two awarded Israeli blocks

Israel awarded Greece's Energean Oil & Gas five offshore licenses from the country's first offshore bid round. A consortium of Indian companies (ONGC Videsh, Bharat PetroResources, Indian Oil Corp. and Oil India) picked up one license.

Energean won blocks 12, 21, 22, 23, 31, and the ONGC-led consortium won block 32. Each license has an initial exploration period of three years.

Energean's blocks are close to its Karish and Tanin gas fields. Any economic discoveries made on the five licenses would be developed via tiebacks to the floating production storage and offloading vessel planned for Karish and Tanin, Energean said. Despite having attracted less interest than expected, Israeli Energy Minister Yuval Steinitz said the country plans to launch a second round in 2018.

Q Red Sea seismic extension

Norwegian seismic firm Magseis will extend an ongoing contract with BGP Arabia and Saudi Aramco to acquire additional ocean bottom seismic (OBS) data in the Red Sea.

The new survey is expected to run for more than seven months and will start in January 2018. The survey features complicated surface and geological conditions with a combination of deep and shallow marine work. The *Artemis Athene*, Magseis' OBS vessel, will be used for the survey.

R Eni picks up Evans Shoal stake off Australia

Eni has acquired a 32.5% interest in and operatorship of the Evans Shoal gas field offshore northern Australia from supermajor Shell.

Evans Shoal is in Retention Lease NT/RL7, in the North Bonaparte basin around 300km northwest of Darwin, where the Darwin liquefied natural gas plant is operating. Eni estimates the resource base of the field to at least 8 Tcf of raw gas in place.

The new NT/RL7 Joint Venture includes Eni Australia with 65% interest, Petronas Carigali (Australia) (25%), and Osaka Gas Australia (10%).

S Santos funds Beehive seismic

Australia's Santos has agreed to partly fund and lead a new 3D seismic survey over the Beehive prospect in Australia's Bonaparte basin in return for an up to 80% farm-in option in the permit.

Santos calls Beehive, which sits on the WA-488-P permit, adjacent to the Blacktip production infrastructure and within reach of the Ichthys infrastructure, an "exciting prospect."

Its proximity to existing infrastructure could provide options for early commercialization of any discovery, says Santos, which is acquiring the option from Melbourne-based Melbana Energy.

Funding and execution of the 3D seismic survey over Beehive will give Santos the right to earn up to an 80% interest in WA-488-P through the subsequent funding and completion of an exploration well.

Contracts

Wood inks Julimar study

Woodside Energy has awarded UK-based Wood a contract for a concept definition study for the Julimar Phase 2 project offshore Australia, and for engineering and rig modification services.

The study is for the subsea flowline and umbilical system for phase two of the Julimar project, comprising the Julimar and Brunello fields in Western Australia.

The engineering and rig modification services will be executed under a three-year non-exclusive outline agreement, which has two one-year extension options and is effective immediately.

Woodside operates the Julimar project with a 65% interest in the Julimar and Brunello fields, within petroleum license WA-26-PL, about 180km west-northwest of Dampier.

Statoil issues Snorre awards

Statoil awarded Subsea 7 an engineering, procurement, construction and installation (EPCI) contract for work on the Snorre expansion project offshore Norway. Subsea 7 will provide pipeline bundle technology, containing flowlines and control umbilicals. The project features three pipeline bundles: west, east and north. Offshore operations will take place in 2019 and 2020.

Aibel has been awarded a $190 million (NOK1.6 billion) EPCI contract through fall 2021, which will see the firm remove excess weight and equipment from the Snorre A platform. Aibel also will install a new 650-ton support module for risers. Prefabrication work is expected to begin January 2019; module installation is set for spring 2020.

TechnipFMC won an EPC contract covering the delivery of subsea production systems and includes six subsea templates and subsea production equipment.

Transocean's harsh environment semisub *Transocean Spitsbergen* picked up a 22-well contract for th expansion project, with an estimated duration of 33 months; plus, two one-well options. The contract is expected to begin Q3 2019.

Modec wins Mero FPSO

The Libra consortium, led by Petrobras, has chosen Modec to charter a floating production storage and offloading unit (FPSO), for the Mero field, which will be used in the Mero Pilot project (formerly Libra Northwest). The FPSO will have a daily operational capacity rate up to 180,000 b/d and 12 MMcm/d of gas and will be installed in a water depth of 2100m, about 180km off Rio de Janeiro.

The unit will be operated by Modec, the company responsible for the construction, and chartered for 22 years. Part of the construction is expected to be done in Brazil.

Kvaerner wins Valhall work

AkerBP has given Kvaerner a $120 million (NOK1 billion) contract to deliver the topside and steel jacket substructure for Valhall Flank West.

Kvaerner's scope includes procurement, fabrication, sea-fastening and load-out, as well as offshore hook-up and commissioning assistance. Prefabrication and assembly will start in May 2018.

The steel substructure and the topside is expected to be completed in May 2019, with hook-up and commissioning to follow in August that year.

Keppel wins SOFEC, Petrobras work

Keppel has inked new contracts worth $96.2 million with SOFEC and Petrobras. Keppel Shipyard will fabricate a turret mooring system for the newbuild FLNG vessel bound for the Coral South offshore Mozambique for SOFEC. Fabrication will start in Q1 2018 with delivery expected in Q1 2020.

Keppel FELS Brasil's BrasFELS shipyard has secured hull carry over work for the *P-69 FPSO* from the Tupi consortium, led by Petrobras. Keppel will install equipment and cables for the hull as well as the commissioning of marine systems.

P-69 is scheduled to depart BrasFELS in 2018 for the Santos Basin pre-salt region. When delivered, it will have a production capacity of 150,000 bo/d and 6 MMcu m/day of gas. It will also have a storage capacity of 1.6 MMbo.

Saipem wins West Hub SURF

Eni has chosen Saipem to carry out engineering, procurement, construction and installation work for the Vandumbu subsea field at the West Hub Development project offshore Angola, in block 15/06.

The subsea field sits at depths ranging from 1300-1500m. The project includes the realization of two production pipelines made of special material, and the laying of umbilicals and service lines of various diameters (subsea, umbilicals, risers and flowlines [SURF]).

The future of project contracting

Lower for longer oil prices are leading operators to reconsider the structure of project contracts. Many are leaning toward supplier-led solutions to cut costs and boost reliability. Karen Boman reports.

The days of the bloated mega-project are long gone. The downturn has been severe and long-lasting and exploration and production (E&P) companies are seeking to make project costs more sensible and generate long-term savings.

At higher commodity prices, it wasn't difficult for E&P companies to make profit under the traditional approach of contracting services, says Edward Hernandez, partner – vice president, Americas, with io Oil & Gas Consulting. E&P firms also worked on projects in a traditional stage-gate approach as they received funding to get through each stage.

"There really wasn't a lot of shared risk (amongst operators and suppliers) in upstream development; the E&P company owned the risk and managed their own internal economic model," Hernandez says. With no share in the asset once production flowed, Hernandez says this was the primary reason why mega-projects experienced schedule and cost overruns. "Engineering companies were selling man-hours, not really solutions, and their stake in the overall project outcome was limited," Hernandez says.

Hernandez

However, "it's a fact that if you look at most mega-projects, more than two-thirds of upstream sector projects were over budget and late," Hernandez says. "There were many projects where engineering was achieved over a year period and then the design changed and engineering was redone and redone. There was a lot of recycle."

Now, E&P companies must cut costs to make projects economically feasible at lower breakeven oil prices. Companies are looking to include suppliers earlier in the development process to ensure that the asset will operate to design life or longer, and use tried and true designs over bespoke.

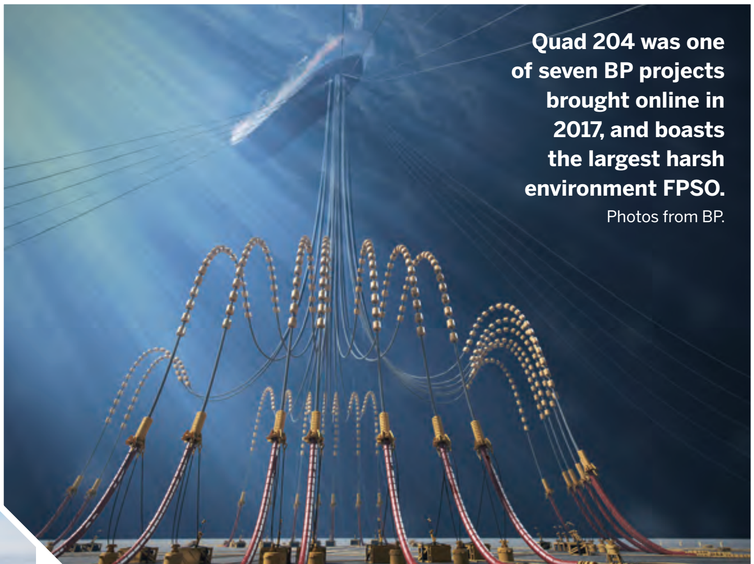
For example, when BP sought to expand its Thunder Horse project in the US Gulf of Mexico (GoM), the supermajor made sure to standardize components and work with contractors that had previously provided equipment on the field.

Steve Raymer, Thunder Horse South Expansion project manager, BP, told *OE* in May 2017, that for the project, BP wanted to use what Thunder Horse already had. "We had an existing subsea tree design," he said. "We had existing subsea equipment, the same manifold design. We did not redesign anything from scratch where we had the opportunity to use something that we already had."

But to get to this point, Hernandez says that operators had to look at their work processes to see where they were leaving money on the table.

"We (io) saw that everybody has their own standards," Hernandez says. Companies then sought to reduce goldplating by using off-the-shelf solutions. They also revisited their

The deepwater Gunashli platform in the Caspian Sea, offshore Azerbaijan, where BP is trialing one of two digital product lifecycle management pilots.



Quad 204 was one of seven BP projects brought online in 2017, and boasts the largest harsh environment FPSO. Photos from BP.

portfolios, opting to focus on the top three or five projects to reduce their exposure to so many different types of developments, he adds (*see page 17 for more*).

E&P companies then re-examined how they worked with suppliers, Hernandez says, who also were suffering from the market downturn, to ensure they could get a standard solution for the best price for the desired outcome. This included encouraging suppliers to invest in equipment leasing to increase their chances of landing contracts.

Financing models also are being framed such that consortium members are risking not only their profits, but also potential loss in the asset's commercialization. This brings more certainty to project outcomes since each member must ensure success to guarantee they do not lose money, Hernandez says.

In terms of project economics, each of the stakeholders have to give up some profit, but may still come out ahead because of greater certainty, less delays, less recycle, and lower cost of capital than private equity.

"Obviously, there is always an added cost of finance or shared investment, but now with the consortium approach, the license holder can keep a big sum of money off of its balance sheet and use for other developments," Hernandez says.

Going deep

For deepwater projects, E&P companies traditionally would go to an engineering company to design all subsea infrastructure, from wellhead to risers, and an entirely separate engineering company to design facilities, infrastructure and so on, Hernandez says. These firms would do a tremendous amount of design work, then go to the E&P company, saying that this is what each part of the project should look like. But, when E&P firms would speak directly with the suppliers and contractors, they would often tell E&P firms they couldn't provide exactly what was specified, requiring changes in engineering due to excessive cost in manufacture, construction or installation.

Today, io sees E&P firms going straight to suppliers, constructors and installation companies to conduct front-end engineering packages, many times with a financing scheme

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	2015	2016	2017	2018
Shallow (<500m)	58	40	40	0
Deep (500-1500m)	18	12	6	0
Ultradeep (>1500m)	12	9	7	0
Total	88	61	53	0
January 2018	88	61	53	0
date comparison	0	0	0	0

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 2017-21

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	11	571	2333
Deep	12	1678	1495
Ultradeep	28	9820	11,559
United States			
Shallow	6	44	71
Deep	22	1543	1822
Ultradeep	20	2168	2010
West Africa			
Shallow	93	3269	14828
Deep	23	2521	2630
Ultradeep	15	1947	4351
Total	219	22,990	38,766
(last month)	(222)	(19,088)	(36,289)

Greenfield reserves

2017-21

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	880	33,231	308,645
(last month)	(862)	(32,922)	(325,086)
Deep	134	7823	72,686
(last month)	(110)	(5036)	(62,378)
Ultradeep	73	15,888	56,712
(last month)	(60)	(13,148)	(42,875)
Total	1087	56,942	438,043

Pipelines

(operational and 2018 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,963	(41,916)
Planned/ possible	21,008	(21,348)
	62,971	(63,264)
8-16in.		
Operational/ installed	83,204	(83,262)
Planned/ possible	43,403	(44,754)
	126,607	(128,016)
>16in.		
Operational/ installed	97,991	(97,186)
Planned/ possible	47,406	(48,880)
	145,397	(146,066)

Production systems worldwide

(operational and 2018 onwards)

		(last month)
Floaters		
Operational	312	(311)
Construction/ Conversion	44	(42)
Planned/possible	272	(276)
	628	(629)
Fixed platforms		
Operational	9074	(9072)
Construction/ Conversion	61	(64)
Planned/possible	1266	(1287)
	10,401	(10,423)
Subsea wells		
Operational	5254	(5251)
Develop	368	(371)
Planned/possible	5902	(6025)
	11,524	(11,647)

Global offshore reserves (mmboe) onstream by water depth

	2016	2017	2018	2018	2020	2021	2022
Shallow	17,748.32	20,431.14	19,342.64	11,992.32	14,914.71	19,107.75	22,145.22
(last month)	(17,470.41)	(21,277.90)	(19,963.02)	(12,613.20)	(16,670.28)	(21,061.69)	(-)
Deep	4215.67	1379.22	2936.90	4650.04	3339.97	2864.86	6826.16
(last month)	(4215.67)	(2051.08)	(2389.67)	(4715.67)	(3849.87)	(3008.15)	(-)
Ultradeep	3100.14	883.85	4040.46	4151.41	7453.67	3935.92	6365.38
(last month)	(3100.14)	(883.85)	(4643.35)	(3387.91)	(7453.67)	(4398.22)	(-)
Total	25,064.13	22,694.21	26,320.00	20,793.77	25,708.35	25,908.53	35,336.76

Source: InfieldRigs 12 Dec 2017

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	89	55	34	61%
Jackup	385	229	156	59%
Semisub	98	57	41	58%
Tenders	27	13	14	48%
Total	599	354	245	59%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	28	20	8	71%
Jackup	26	9	17	34%
Semisub	8	5	3	62%
Tenders	N/A	N/A	N/A	N/A
Total	62	34	28	54%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	13	6	7	46%
Jackup	110	71	39	64%
Semisub	29	13	16	44%
Tenders	20	10	10	50%
Total	172	100	72	58%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	17	16	1	94%
Jackup	49	25	24	51%
Semisub	17	14	3	82%
Tenders	2	1	1	50%
Total	85	56	29	65%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	46	27	19	58%
Semisub	30	19	11	63%
Tenders	N/A	N/A	N/A	N/A
Total	76	46	30	60%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	117	79	38	67%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	121	82	39	67%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	14	8	6	57%
Jackup	15	10	5	66%
Semisub	1	1	0	100%
Tenders	5	2	3	40%
Total	35	21	14	60%

Eastern Europe

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	1	1	0	100%
Semisub	1	0	1	0%
Tenders	N/A	N/A	N/A	N/A
Total	3	2	1	66%

Source: InfieldRigs 12 Dec 2017

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

around it. These companies then come to the table with the best technical solution and financing arrangement with a shared risk approach. Once a project comes onstream, a deferred payment or toll payment plan is put in place. This creates an environment in which the supplier is a partner in a project, and there is incentive for all parties to achieve overall project success.

Since the downturn in 2014, many service firms have banded together to deliver integrated service packages. For instance, in 2015, OneSubsea aligned with Subsea 7 to combine subsurface expertise, subsea production systems, subsea processing systems, subsea umbilicals, risers and flowlines systems, and life-of-field services. In 2014, Aker Solutions and Baker Hughes (now BHGE), agreed to a subsea production solutions alliance. OneSubsea, Schlumberger, and Helix Energy Solutions also formed the Subsea Services Alliance. Forsys Subsea was a joint venture between FMC Technologies and Technip before the two merged.

E&P firms also are using a consortium approach. One example is the CA-KU-A1 gas compression platform project in Mexico. This is a project where Mexico's state-owned operator Pemex tendered the "contract" to various proposed consortiums of equity, facilities, EPC, and operations in order to build, own and operate gas compression facilities offshore for a 15-year term before turning the facilities back over to Pemex.

"This purpose is to move forward a very strategic project with limited cash flow. In this case, the consortium puts up the capital and gets paid back on a fee per volume of gas basis. We initially performed a gap and risk analysis on the contract model for our parent companies (io is a consultancy spun out of GE Oil & Gas and McDermott)," Hernandez explains. The project was awarded to Dragados Offshore.


Rodger

Getting projects off the ground

Most offshore projects that have been sanctioned as of late have been backed by the majors, who have the capital resources and ability to easily raise funds. They are also the most active in taking advantage of cost deflation, says Angus Rodger, Asia-Pacific upstream research director, at Wood Mackenzie.

However, small- and mid-cap companies are struggling to attract the financing needed for offshore projects, partly due to uncertainty over future commodity prices. Many entered the downturn carrying debt, adding to the struggle to get new projects going, Rodger says.

In 2014, deepwater was considered too high cost. But, overcapacity in the service and drilling marketplaces has resulted in costs falling quickly. Over time, the industry also has become leaner, and companies like Shell and BP are lowering costs by learning to drill deepwater wells faster. These structural learnings are making deepwater in the GoM and offshore Brazil much more competitive, Rodger says. As a result, companies are looking at incremental projects, such as subsea tiebacks, that can compete with tight oil investments.

The majors also have maintained a relatively steady level of development drilling in the GoM and offshore Brazil, allowing them to continuously learn how to drill better wells. In the GoM, 30 deepwater development wells were drilled this year, with 30 development wells planned for 2018 and 32 planned for 2019, says Imran Khan, senior research manager, at Wood Mackenzie. Shell leads deepwater GoM development drilling, with Anadarko and Chevron also active as well.

This continued learning is necessary as it takes longer – perhaps two to three years, often more – for real, structural cost savings to emerge in deepwater, Rodger explains. In basins where drilling has been more sporadic or ceased completely since 2014, companies considering project sanctioning "can't instantly go back and just drill wells 20% better than they did three years ago." This makes it harder for cost deflation to happen across the board, and means some basins are competing stronger than others for the scarce amount of available capital.

Rodger believes that companies will continue to focus on projects with smaller footprints, as it will be harder to convince both banks and investors that spending vast sums on big greenfield projects, particularly outside of North America, is prudent financial strategy. "Still, the majors can't just do small-cycle, high return investment projects forever, so over time we will still see the best big projects bubble to the top and move forward," he says, albeit with capital deployed in a more cautious, phased fashion. OE

Collaborative contracting

Audrey Leon looks at how BP's new approach to working with its suppliers have led to quicker project start-up.


The Juniper platform offshore Trinidad and Tobago. Photo from BP.

"We're not goldplating anymore," stated BP's Global Projects Organization Head, David O'Connor, at the supermajor's Houston Media Day in early December.

O'Connor said BP sought to change the way it does business in the hope of achieving cost cuts and boosting project efficiency and reliability amongst its many suppliers.

"In the past, we would tell our suppliers exactly what we needed and they would give us exactly what we asked for whether they could provide it easily or not," he said.

O'Connor said BP went to its suppliers to better understand what they can best deliver, and adjusted its requirements to be in line with what they deliver. He also said that BP has begun engaging their suppliers earlier in the process. "No longer do we specify to them everything that we want," he adds. "We look to them for their solutions to meet our requirements."

O'Connor said that this new approach has helped BP bring projects in under budget and ahead of schedule. All seven of BP's (operated and non-operated) projects slated for 2017 have begun – with Zohr achieving first gas in late December 2017.

Rob Kelly, vice president, Technical Functions, Global Projects Organization, also spoke about the new supplier-led approach at the event. "We have simplified and made our standards fit-for-purpose rather than over-engineered," Kelly said. "Over the last four years, we have been focused on supplier-led solutions and actually having that conversation with our suppliers where we have global agreements and long-term relationships.

"From that, we gained significant benefits because we are actually asking them to build things that they are good at building. And therefore, they know the scope very clearly, and they are very efficient in how they can deliver. Obviously, we get benefit through price and schedule, and in terms of pace, but we also benefit in terms of the quality of what they deliver, building the hundredth thing they have built before, rather than the first bespoke thing they've built for BP."

Into the wild

But, what's next? BP is looking to modernize and transform the way it currently interacts with suppliers on their global projects, and that means digitalization.

Kelly discussed the importance of digital performance management and how BP is conducting a pilot project with its supplier where the supermajor links into the supplier's database in the cloud. "Almost in real-time, that allows the project teams to see status, rather than wait 4-6 weeks to get the normal report," he says. "This is big step change for us. If you can have the right data, sooner, you can make earlier and better decisions."

Kelly said that BP is trialing this on the Tortue Phase 1a project offshore Mauritania and Senegal.

Another area where BP seeks to boost efficiency is in construction and commissioning.

Kelly highlighted the Juniper project, which BP brought online this year, where the supermajor used "e-completions" or electronic completions to cut down on paper. "When you are doing completions, you can have thousands of systems that need to be checked prior to commissioning." He said workers were outfitted with ruggedized iPads to do the job instead.

Still, Kelly stresses that suppliers are the key to a successful project. "We only do 10% of the activity – the rest – 90% of activity and man-hours is done by suppliers," Kelly said. "The change we are trying to make, in becoming more digital in the way we design, procure and construct our projects, we need to work on with the supply chain.

"We are talking about collaborative contracting. We looked at other industries – particularly the infrastructure industry in the UK – if you are working in the same database with transparency of data that is shared, it leads to a different way of working. We spent a lot of time looking at that. We are working toward implementing this in our 2018 projects. It's very exciting. You have to work more collaboratively with the supply chain." ▪

2018 Exploration: Smaller, leaner

It's a smaller, more focused exploration world as we start 2018. Elaine Maslin discusses the main themes for 2018 with Wood Mackenzie's Andrew Latham.

Deepwater is very much a key theme when it comes to the exploration hot spots for 2018. Yet, the numbers of those actually committed to exploring deepwater are low – and even fewer have the capability to see through discoveries to developments.

Looking back

First, let's look back at 2017. Wood Mackenzie's Vice President Global Exploration Andrew Latham says that the year saw the trend towards a smaller scale exploration industry, with continued attention being paid to deepwater. He expects this to continue into 2018. In 2017, operators were acreage "re-loading," and getting back to profitability, although exactly how profitable they are now was yet to be seen, as of late 2017.

Global conventional on- and offshore exploration spend was forecast at US$35-40 billion for 2017, and landed at $40 billion, according to Wood Mackenzie ($35-40 billion is 30-40% of what it was prior to the downturn). For 2018, it is expected to slip to $37 billion.

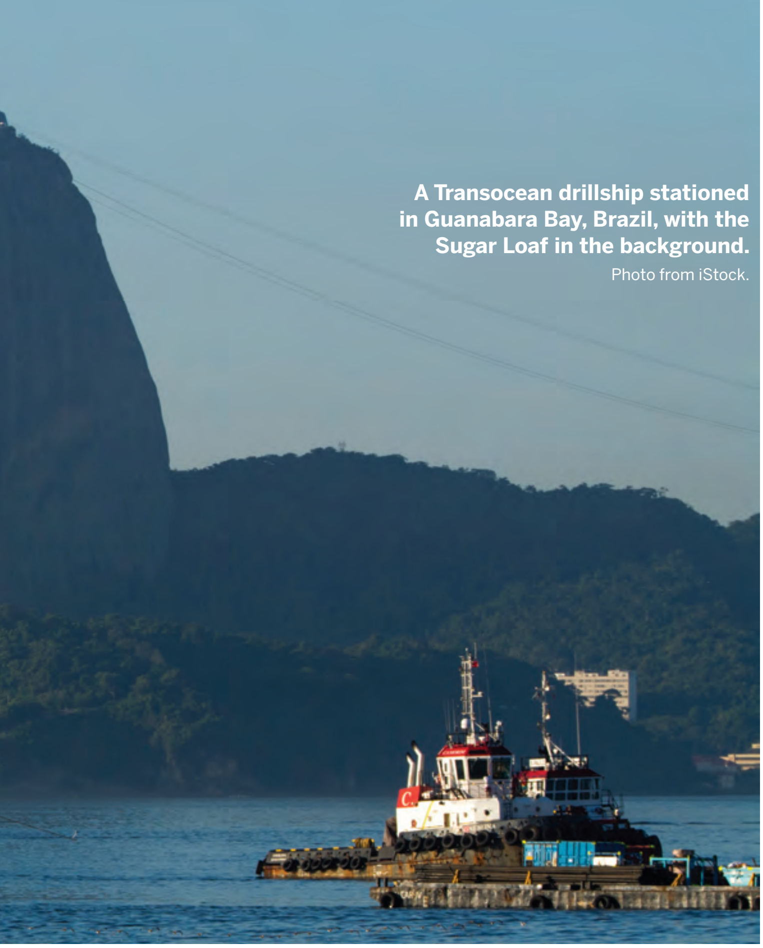
In terms of exploration results, 2017 didn't hold many surprises. The 1.4-2 billion bbl (in place) Zama light oil discovery, by Talos Energy in shallow waters offshore Mexico, was not seen as a huge exploration risk, Latham says. There were also continued exploration successes in Guyana, where ExxonMobil made its fifth find, further building on the massive 2-2.5 billion boe (recoverable) 2015 Liza discovery. There were also more gas discoveries in Mauritania, home to Kosmos/BP's "world class" Tortue field, with 25 Tcf estimated in the Greater Tortue Complex. Decent new volumes in Russia were also not unexpected.

Some discoveries in lower horizons in the Campos basin, offshore Brazil, by Petrobras, which could hold more than 700 MMboe, were more notable, Latham adds.

2018: What lies ahead

For 2018, a smaller, focused-exploration industry is set to remain in place. "There are fewer companies now that are serious about exploration than we have seen for quite a while," Latham says. "That's really an extension of what we saw in 2017. Side by side with that, there's growing awareness that most of those companies are chasing similar things – it's all about deepwater sweet spots, particularly oil prone ones, and particularly around the Atlantic Margin.

"And because they [those exploring in these areas] have



A Transocean drillship stationed in Guanabara Bay, Brazil, with the Sugar Loaf in the background.
Photo from iStock.

similar perspective on all of those, that means the level of competition is getting much higher. The most extreme example of that was in the Brazilian round in October," with higher prices paid for access to acreage, Latham says.

Brazilian regulatory agency, ANP said that the 2nd round generated approximately $1.05 billion in signature bonuses and $93.4 million in planned investments. Meanwhile, the 3rd pre-salt round generated about $876 million in signature bonuses and will bring in approximately $140 million in investments.

For 2018 licensing rounds, where big explorers see potential, big bids are likely to continue, Latham says, which could create a problem around high access to acreage costs, we haven't been seen for a couple of years now.

The refocus on deepwater exploration is partly due to it becoming more attractive commercially. "We certainly see a lot of the best deepwater oil plays breaking even (with 10% full cycle return as a breakeven) in the $40/bbl range," Latham says. "That's Guyana, Brazil, Senegal... That's being enabled by low exploration and development costs. Drilling costs in particular are much lower. It's also enabled by companies focusing on the best rocks with high-permeability, and so higher production rates per well."

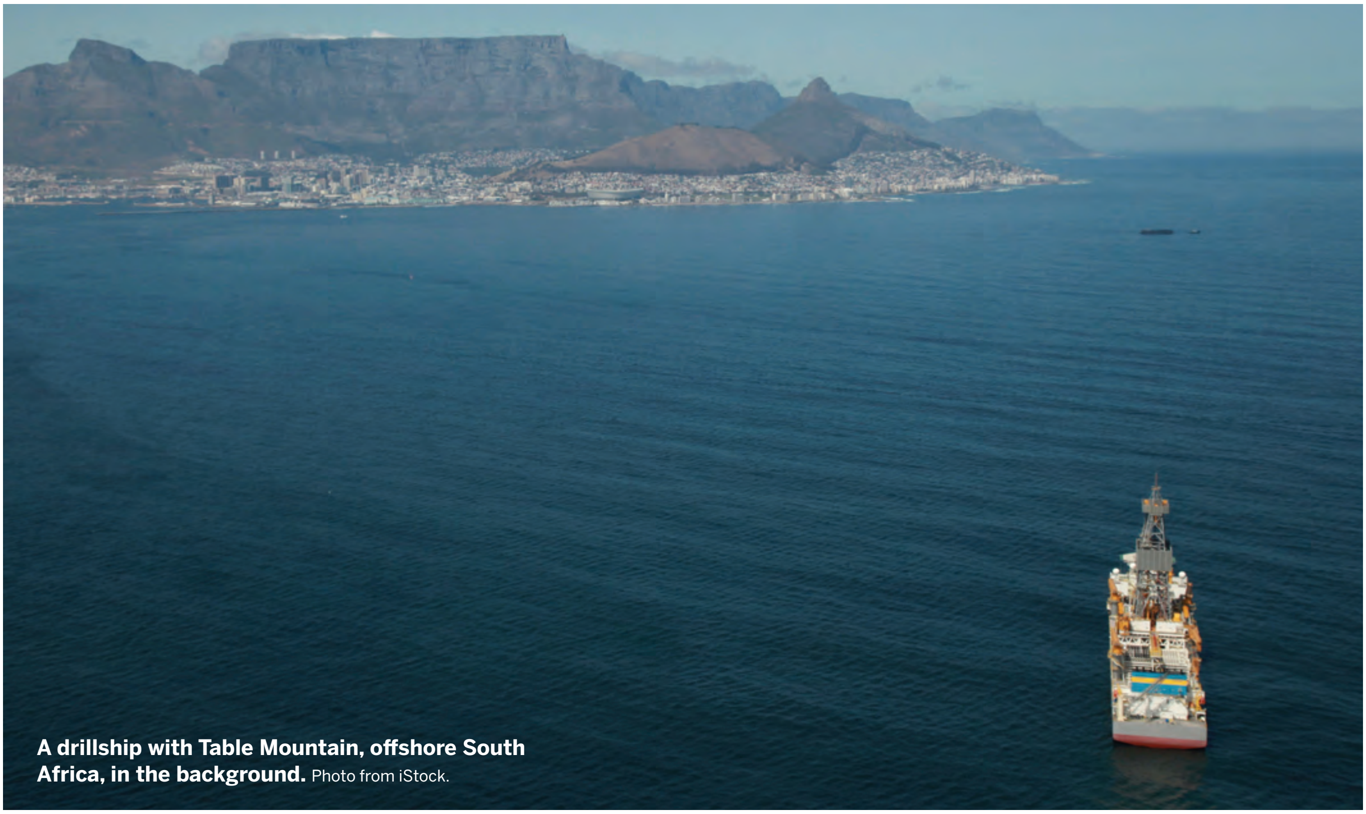
Taking a wider look, the exploration and production landscape offers up an interesting theme. Onshore unconventional is typically seen as one of the threats to the upstream offshore oil and gas business (alongside solar and other renewables in the longer term). Deepwater exploration has also been seen as an expensive play.

Yet, according to analysis by Wood Mackenzie looking at trends over the past 100 years of exploration, "A largely onshore history [of oil production] is [now] becoming polarized between deepwater and unconventionals." For many serious explorers, the choice is between unconventionals or deepwater, Latham says.

Wells to watch

So, where are the wells to watch for 2018? Latham says that 2018 has more potential than last year. His top picks are:

- **Guyana –** ExxonMobil is drilling its latest well offshore Guyana in the Stabroek Block: Ranger-1. It spudded 11 October 2017, using the *Stena Carron* drillship, and was due to take three months.
- **Brazil –** More activity is expected offshore Brazil, including possibly Total's Foz do Amazonas (Mouth of the Amazon) well, if it secures regulatory permits. An application to drill was denied in 2017, with the environmental regulator Ibama (Instituto Brasileiro do Meio Ambiente e dos Recursos Naturais Renováveis) citing lack of information. Environmentalists and scientists say it's too close to the Amazon reef.
- **Brazil –** Also in Brazil, Petrobras is planning wells in the Espirito Santo basin, which would prove new plays, Latham says.
- **Mexico –** Meanwhile, Pemex is eyeing the Yaxxtaab-1 wild cat in the shallow waters of the Campeche Basin, offshore Mexico, billed as the first pre-salt well offshore Mexico, while Total is planning a wildcat in the Perdido Fold Belt.
- **Aruba –** Repsol is planning a wild cat well off this small Caribbean Island.
- **Namibia –** Tullow Oil is aiming to start drilling on the Cormorant prospect in the Walvis Basin, offshore Namibia, in September. While it's not the biggest well, a discovery in Namibia would be significant, Latham says.
- **Senegal –** BP is due to drill the Requin-Tigre (Tiger Shark) well, with Kosmos, outboard of the Tortue discovery. It is estimated to have 60 Tcf resource potential.
- **South Africa –** Total has hired the *Deepsea Stavanger* to drill a wild cat well offshore South Africa. "Total are very excited about it. It's a challenging environment but, by all accounts, the subsurface looks very good," says Latham.
- **Gambia –** FAR is planning to drill the Samo prospect late 2018. Samo is believed to be similar to the SNE field properties, in neighboring Senegal. It will be the only exploration well to be drilled offshore The Gambia since the Jammah-1 well drilled in 1979.
- **Morocco –** Eni has lined up the *Saipem 12,000* drillship to drill in the Rabat Deep Offshore license offshore Morocco, starting Q1.
- **Nova Scotia –** BP is planning to drill a single exploration well, in the Scotia Basin, offshore Nova Scotia, Canada, starting in Spring 2018. Drilling is expected to take 120 days using the *West Aquarius* semisubmersible.
- **Norway –** Statoil may go back to the Korpfjell prospect, which failed to offer commercial hydrocarbons in 2017, and drill to test another reservoir.



A drillship with Table Mountain, offshore South Africa, in the background. Photo from iStock.

Other areas to watch include Montenegro, Cyprus and Portugal, where Eni is planning to drill, and Papua New Guinea, which Total is assessing.

"All the majors are the ones to watch in these wells and any licensing rounds coming up," Latham says. "There's also a cohort of the usual suspects, Cairn Energy, Tullow Oil and Kosmos.

"But, the number of fairly committed, fairly high-impact explorers is only about 15," he continues. "The number that can move a large discovery in deep water through to development, as operator, is smaller again. It's a pretty small club of companies outside the majors, i.e. Petrobras. There are pros and cons to limited competition. For governments and small companies, it means there's a limited range of potential operators for your projects."

"The number of fairly committed, high-impact explorers is only about 15. Those that can move a large discovery in deep water through to development, as operator, is smaller."

Deep, but effective

Water depth in which explorers were drilling reached new records in 2016, with the Raya well, offshore Uruguay. But, while water depths have remained high, well depth has seen a retreat. Deepwater exploration is targeted, and not focusing so much deep horizons with high-pressure, high-temperature objectives, Latham says.

This is part of the reason drilling has been cheaper, as wells have not been as long or complex. Drilling costs could also continue to fall, as there are still rigs out there that remain on the high day rates signed pre-2014, due to the length of term for which they were hired. As each of these finally end their term, rates will drop, reducing exploration costs further, Latham notes. "This is one of the reasons why we might see lower spend next year, but we won't see fewer wells," he adds.

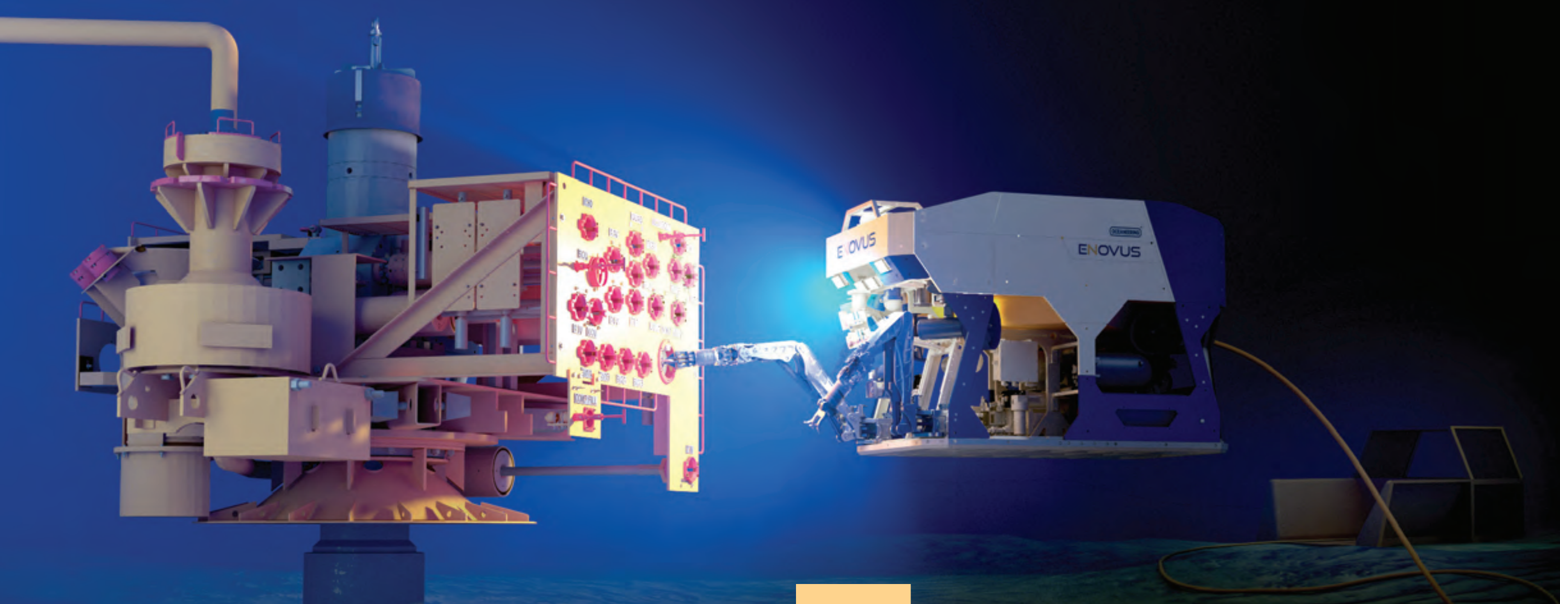
Heartlands

Looking more at specific "heartland" regions, the US Gulf of Mexico has seen success and is likely to continue with some success in infrastructure-led exploration, such as that by LLOG, which sees 20-30 MMboe scale prospects tied into existing infrastructure.

In the UK North Sea, there is also some infrastructure-led exploration, but some companies are trying some new play exploration, Latham says. "I see this as being probably what the North Sea needs," he says.

Statoil made a discovery in the eastern Moray Firth this year, while BP is drilling carboniferous prospects in the southern gas basin. "It's a slightly risker but larger test, and we'll probably see more of those generally different types of play tests this year as well, targeting 100 MMbbl." OE

Returning ROVs to work?



The ROV market isn't out of the woods yet, with plentiful supply in the market dampening any perceived uptick in activity. But, offshore wind might offer some respite. Elaine Maslin reports.

Oceaneering's eNovus compact work class ROV.
Illustration from Oceaneering.

The remote operated vehicle (ROV) market has had a tough time during the last few years due to its reliance on drilling operations.

The impact of the downturn on utilization rates and pricing, as well as the market outlook, was discussed by Andrew Reid, managing director of Douglas Westwood, part of Westwood Global Energy Group, at Subsea UK's Underwater Vehicles Conference in Aberdeen late November.

"It's quite evident that the ROV market has been in real trouble over the last couple of years," Reid says. "We've seen drops in pricing, anywhere between 10-40%, since the downturn." Utilization rates, as activity has dropped, has seen market reductions for some by as much as 50%, he adds.

ROV days have seen a 33% average reduction. Drill support ROV days are down 37%, and construction support -46%.

"We do expect a recovery, but not to 2014 levels," Reid says. "This time around we have seen IMR (inspection repair and maintenance) also hit hard, down 22%. We always saw maintenance as a relatively protected market. But, there's been a combination of a reduction in activity and a delay in work programs that were not a necessity.

"Certain work practices prevailed during the better times, which led to, I suppose, overinvestment, i.e. if someone has a construction vessel on a term-based contract, you're more inclined to do jobs because you already have a fixed cost base as an operator. Now that we're moving more to a spot market, we'll see more necessary work."

A 6000m Quasar Work Class ROV system, from SMD, which was supplied to Shanghai Salvage, with SMD's firm's first electric winch, late 2017.
Image from SMD.

Bottomed out

Hopefully the worst is over, however. "We are coming to the view that the market has at least bottomed," Reid says. "Many of the characteristics that have influenced it are starting to stabilize. There's light at the end of the tunnel. Where the tunnel ends is still quite a challenge to predict."

That's because final investment decisions (FIDs) are still being delayed, he says. There was sentiment from Tier 1 contractors that 2017 would be a bell weather year, with FIDs coming through, "but we are not seeing those yet," he says. How much the growing autonomous underwater vehicle (AUV) market chips in to the ROV market also remains to be seen.

> "There's significant investment in building out offshore wind infrastructure, and many projects are deeper offshore, with greater complexity, and lend themselves to the experience and capabilities from oil and gas."

Drilling is a core driver for the ROV sector and this segment saw a peak year in 2014, with more than 2500 offshore wells drilled. While the outlook today is improved, compared with the past two years, and is relatively stable, growth is only expected to 2022, Reid says. "This has created big issues in an industry where there was, in 2013-2014, an expected continued growth trajectory, perhaps surpassing the 3000 offshore well mark. The industry invested in capability to supply that demand, but the activity didn't come and that's led to oversupply and it's going to remain a stressed market from supply and demand."

One area of optimism is offshore wind. "It's the good news, particularly in Europe," Reid says. "There's significant investment in building out offshore wind infrastructure, and many projects are deeper offshore, with greater complexity, and lend themselves to the experience and capabilities from oil and gas. We're looking at just shy of US$355 billion (€300 billion) being spent between now and 2025, two-thirds in Europe and a third of that in the UK, mirroring that almost of drill support work."

Making up the rest of the balance of ROV activity is construction support, IMR, and decommissioning, "everyone's silver bullet," Reid says. "I don't see it particularly. There will be ROV driven activity from those programs, but it's going to represent 5% of ROV days through the forecast period, it's still small."

In summary, he says the macro outlook is improving, but it still remains vulnerable. While the ROV market will improve and "come off bottom," pricing isn't expected to grow any time soon, due to the supply overhang. "We've got more to look forward to, but it's going to be hard for us all to prosper." OE

Rise of the robot

2017 has become the year that the oil and gas industry embraced robotics. Elaine Maslin reports on initiatives in the North Sea.

While the industry has long been using autonomous underwater systems and remotely operated tooling, and more recently subsea processing equipment and aerial drones, this year the broader potential for robotics took some tentative steps towards realizing the first topsides robots.

French oil major Total completed its Argos (Autonomous Robot for Gas and Oil Sites) Challenge, in Lacq, France (*OE*: May 2017), which saw five teams pitch their robotic creations against a string of tasks on a mock-platform site. Total's aim – part of a broader project towards reducing manning offshore – was to create a robot that is able to detect and control leaks, while weighing less than 100kg, that can move between floors, and on different types of flooring, from grating and corrugated iron to cement and wet slippery surfaces, under its own power.

Chevron has also been testing so-called snake-arm robots for inside vessel inspection in the North Sea. This followed work it was involved in as part of the Petrobot robotic challenge (*OE:* April 2016), which involved vessel and tank inspection robot development, and led to the formation of the Sprint Robotics Collaborative, based in the Netherlands.

Now, another initiative has been launched with nearly US$19 million (£14.3 million) in funding from the UK Industrial Strategy Challenge Fund (ISCF). The initiative is a new research center focused on offshore robotics, led by the University of Edinburgh.

The Offshore Robotics for Certification of Assets (ORCA) Hub will develop robotics and artificial intelligence (AI) technologies for use in extreme and unpredictable environments. The hub will work to develop robot-assisted asset inspection and maintenance technologies, which can make autonomous and semi-autonomous decisions and interventions across aerial, topside and marine domains.

Terrestrial robots on show at the OGTC Robotics week. Images from the OGTC, by Rory Raitt.

"The application for robotics in the [oil and gas] industry is almost limitless, and we have only just scratched the surface," says Rebecca Allison, asset integrity solution center manager at the publicly-funded Oil & Gas Technology Centre in Aberdeen. Allison is keen on robotics and its potential to improve inspections and reduce manual involvement in asset integrity management activities, such as pressure vessel and insulted pipework inspection (which require production shutdown if human-entry is involved).

But, she also highlights use of emerging underwater survey vehicles, which can carry out simple manipulation tasks and "the next generation of UAV (unmanned aerial vehicle) technology."

"It's about improving safety, removing personnel, and being more connected and competitive," she says. "In 10 years or so, robotics will become common place, just as self-driving cars will not be viewed as robots, just like any piece of technology we use to manage assets. I would like to see future generations working alongside robots, even learning from them."

Robotics is coming to the fore now because of a drive to increase productivity, but also to reduce offshore manning, says David Lane, autonomous systems engineering professor and director of the Edinburgh Centre of Robotics. It's also being enabled thanks to the likes of the iPhone, miniaturization of electronics, the number of transistors that can now be put on a chip and developments in machine learning.

Oskar von Stryk, professor and head of simulation, systems optimization and robotics group at the Technical University of Darmstadt, Germany, was on the winning team in Total's Argos Challenge – Argonauts – alongside Austrian robotics firm Taurob, and is now working with Total to further develop offshore robotic systems.

He says that robotic systems can take very different forms but that there are three key elements that make up a robot:

- Sensors, to understand its own status in the environment
- Algorithms, to integrate the sensors and plan what to do
- An ability to act, and interact with humans and the environment.

"The key difference between robot and human is that humans see and understand. Robots just collect data – i.e. numbers – and just compute to try get some information about these numbers." For example, the information the Argonauts gathered during the Argos Challenge was just point data.

Three classic tasks for robots are those that are dirty, dangerous, and dull. Robots can be more capable, efficient and fast, Stryk says. To date, robotic systems have focused on working in planar environments, i.e. self-driving vehicles (passenger, farming, mining, etc.), logistics systems (moving shelves to pickers), auto delivery robots, and search and rescue robots. For these, navigation, self-localization and mapping systems are needed. Going into more 3D environments, such as offshore platforms, is harder, he says.

David Lane, director of the Edinburgh Centre of Robotics.

Existing robotic systems have also mostly been working in isolation, i.e. zones without human presence. But, there's much work ongoing to enable robots to work alongside humans – so-called "cobots," or collaboration robots. German firm Franka Emica has developed a robotic arm that responds to touch and moves in such a way that it can avoid collision with an also moving human.

These are some of the challenges an offshore robot might face, with the addition of having to be ATEX certified and able to handle harsh environments. Offshore robots will have to be able to navigate complex structures, including going up stairs, and might be tasked with scheduled operations, occasional operations, and emergency response, such as inspections like acoustic measurement, as well as monitoring, gas detection, thermal imagining, and even maintenance tasks, cleaning or evening valve operation. The robot could also find and fight fires.

The Argonauts' robot was ATEX certified and able to climb upstairs. "We have demonstrated it's possible," Stryk says. "Autonomous robots can be used on oil and gas sites. The vision, towards 2021, is mainly robots on offshore and onshore sites with industrial strength."

Subsea

Lane says that subsea systems, or ocean robotics, have been operating

The drone zone.

A model of Subsea 7's AIV.

autonomously for over 40 years because of the limitations of underwater communication (the boundaries of which today are being chipped away). "Autonomy has long been part of what marine robotics have been about," he says, highlighting the likes of the Remus AUV, introduced in 1990.

However, systems with more functionality are now emerging, some because of years of development work, such as Subsea 7's AIV (autonomous inspection vehicle), which has drawn on research at Heriot-Watt and spun out unmanned vehicle software specialists SeeByte. The AIV has been performing subsea inspections for Shell in the North Sea, untethered, Lane says. It's able to locate itself and can go to 3000m water depth, venture on 40km excursions and has 24-hour dive time, depending on the mission.

"Marine robotics can currently do mapping and tracking very well, inspecting pipelines over quite long distances, but it's scarier when you try to dock something," he says. Having vehicles that can dock would make tasks easier, as they'd be stationary, but it also enables recharging and data download/upload for subsea resident vehicles.

There have been projects, such as, the EU ALIVE, led by Cybernetics, which worked on docking station technology.

However, there's also been work done on whether a vehicle could dock, and then perform pre-programmed tasks such as turning a valve or adapt to the situation, using machine learning.

The Pandora EU AUV project has also investigated how to teach a robot to turn a valve. There has also been research done to stabilize the end of a manipulator arm, instead of trying to stabilize the vehicle, Lane says.

The University of Girona, in Spain, (also involved in Pandora) focused its research on auto-learning, turning of a valve, and reaction to an accident in its Girona 500 project.

"We can do these things, the next phase is to make it robust so we can take it offshore. The hard part is cognition," i.e. vehicles being able to recognize what they're looking at, map and navigate unmapped areas on the fly, says Lane.

Air

The same innovations are happening in unmanned aerial vehicles, in terms of increasing autonomy and sensor payload. Initially, drones have been manually flown to gather images as part of inspection work. Now the focus is on automated flight and being able to extend the inspection capabilities.

William Jackson, a researcher at Strathclyde University, UK, says drones can both build or use an existing CAD model to detect changes in a structure over time, for example an offshore wind turbine blade. The drone would be able to autonomously navigate around the blade, using the blade as its reference. For larger areas, drones could work in an array, with the images stacked into a high-resolution image.

But, sensor payloads are going further. Drones have already been flown inside vessel tanks. Earlier this year, Texo Drone Survey and Inspection (UKCS), a division of Texo DSI, said it had deployed the world's first UT (ultrasonic thickness testing) from a UAV. This was just part of a pilot at a test site, but would extend drone inspection capability. Texo says that it can be used on flat or curved surfaces and has been used in the offshore and onshore wind turbine structures, as well as on telecoms and maritime assets, the firm says. The inspection data is combined with a photogrammetric visual overlay of the completed survey, helping to pinpoint exact measurement locations on a structure/surface to an accuracy of sub-10mm, Texo says. Use of pulsed eddy current from a drone is also being tested, Jackson says. This is a non-connect electromagnetic technique for metal thickness testing.

The next step would be getting different robotics systems to work together, Lane says. This is something happening in the subsea industry, with autonomous surface vehicles communicating and working with autonomous underwater vehicles *(See page 28 for more)*.

Potential

With the potential seeming limitless, OGTC and Orca Hub are focused on what would be useful to the industry. At an OGTC robotics workshop in Aberdeen in early November, the results were 15 potential use cases for robotics and a gap analysis to identify areas that would benefit from future 'Call for Ideas' or new joint industry projects.

The use cases included fully autonomous aerial drones, that can plan and navigate their own flight path (something drone operators are already working on); small, highly agile robots that can autonomously, climb, navigate and perform inspections, with little or no human intervention and support (such as Total's Argos Challenge robots); and a type of pipeline inspection gauge (PIG) that is autonomous, adaptable, reliable, multifunctional and capable of working in harsh environments.

Further detail was hashed out for each area of robotics that could apply offshore:

• Air

Fully autonomous drones that could plan and navigate their own flight path would remove the need for manned inspections by using remote solutions, would enable repeatable activities, improving data quality (data collected from the same place at known intervals), with easily fitted and replicable sensors, and capability for multiple sensor monitoring and data collection.

Challenges to such a scenario include regulation around the machine learning systems used for automated flight, as well as payload limitations, drone and data security.

> **"The application for robotics in the industry is almost limitless, and we have only just scratched the surface."**
>
> —Rebecca Allison, asset integrity solution center manager at the Oil & Gas Technology Centre, Aberdeen.

The OGTC workshop suggested areas that could be worked on to enable this technology, including launch and recovery systems, obstacle awareness and avoidance systems, alternative power options, drone diagnostics, communications systems integration into simultaneous operations and permit to work systems, and regulatory acceptance. There were also questions around flying in areas without GPS coverage, around live plant, and adapting to weather conditions.

• Land

The land workshop set out a vision for small, highly agile robots that can autonomously navigate complex, 3D oil and gas installations, while localizing itself, finding points of interest and performing non-destructive testing and needing little human intervention and support.

Such a system would help reduce offshore manning, enable an increase in frequency and quality of inspections, aid fault prediction and maintenance scheduling, and deeper analysis, improve safety by reducing risk exposure to staff, and also better capture and make available working knowledge of facilities (instead of it being lost as older crews leave and younger people are less interested in jobs offshore).

No challenges were suggested to this scenario but possible areas where work needed to be done to make it happen included "locomotion strategy," i.e. how platform robots move about, navigation, localization and intelligence, power management, maintenance, payload integration, and communications infrastructure (*OE:* December 2017).

It was also suggested that multiple coordinated robots could be used, with a mother unit providing communications and navigation. How robots would adhere to various surfaces was also discussed, as well as ATEX compliance, and power/charging stations and payload, and integration with permits to work systems.

• Subsea

Subsea robotics would aid inspection and surveillance, including pipeline wall thickness, augmented using cloud-based analytics and machine learning, to identify corrosion, putting, scabs, etc. Such a system would be deployable anywhere and could adapt to new environments, leverage past inspection data, flag faults, reduce survey time, improve data reliability and make end user interpretation easier.

Challenges for this vision were around data – both security, data sharing, format and handling/management. Areas for more work included creating open cloud databases of previous inspection data and automated communications related to machine learning, i.e. an application to upload data into a cloud based system, with machine learning, and data analytics.

There were also questions around how to deal with limited availability of ground truth data and power and data management for long missions, also working in variable environments, reactions to break downs. There was also a lot of concern about commercial models and collaboration, and common data models. OE

FURTHER **READING**

UK offshore robotics center launched.
www.oedigital.com/component/k2/item/16528-uk-offshore-robotics-center-launched

The robot race.
www.oedigital.com/component/k2/item/15234-the-robot-race

Autonomous vehicles take to the seas

ASV and AUV deployment during the Autonomous Surface and Sub-Surface Survey System project. Photo from Sonardyne.

Autonomous underwater vehicles are gaining more attention in the offshore oil and gas industry as they increase in capability, but it's not yet over for the remotely operated vehicle, hybrids or even new concepts. Elaine Maslin reports.

Automation, artificial intelligence, machine learning and robotics were high on the agenda at this year's Underwater Vehicles Conference in Aberdeen.

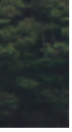
All are driving the shape of the underwater vehicles of the future, demand for which is being driven by operators' bottom lines. And in turn, what was seen as a relatively mature (or at least established), the remotely operated vehicle (ROV) is being challenged by more capable Autonomous underwater vehicles (AUVs), and in some cases working in conjunction with unmanned surface vessels and new ROV concepts.

For Ross Doak, Shell subsea engineer, automation is where the industry is headed. Speaking at Subsea UK's Underwater Vehicles Conference in November, he said there's a clear road map, or definition, of what automation means in the automotive sector. The Society of Automotive Engineers, a US-based global organization, has it set out in five levels, from Level 0, which is a car with warning lights, to Level 5, which sees no human interaction in the driving process [in between are "hands on" (1), "hands off" (2), "eyes off" (3), and "mind off" (4)].

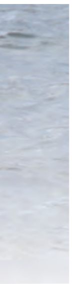
So how might this play out in the subsea sector? There's already an emerging trend (now to 2025) for AUVs with more capability, he told the conference. "For me, more and more AUVs will take over ROV market share for inspection, enabled by sensors that bridge the gap in capability… extended by improved battery technology and enhanced by better subsea communication, better bandwidth."

In the future, there will be more asset-based vehicles, for mooring inspections, etc., i.e. temporary deployed ROV/AUV systems, based on a specific platform or production vessel, enabled

SMD's FLO concept. Image from SMD.



ASV Global's C-Worker 5 on a cable route survey, with **TerraSond.** Photo from ASV and TerraSond.



by improved hardware/launch and recovery systems, but also integrated AUV and work class ROV inspection and integration campaigns.

While it's harder to predict the more distant future, Doak suggests that what does happen will be driven by trends related to access – i.e. accessing an asset physically or via a remote link to a desktop. "For [physical] access you need a vessel and technology," he says. "Digital [technology] can allow us to change that, through the cloud and artificial intelligence, robotics and drones, enabling desk to subsea access." This could include integrated AUV, UAV (unmanned aerial vehicle) and USV (unmanned surface vessel) or ASV (autonomous surface vessel) operations.

The likes of Moore's Law should also make robotics cheaper, enabling the realization of "swarm robotics," something that some suppliers are already trying through Shell's own Ocean XPrize – a competition to map large swathes of ocean floor autonomously (*OE*: June 2017).

The big opportunity, however, Doak says, is with data analytics. From now to 2025, this will see a move towards automated target detection and automated event detection. From 2025, we could see automated data processing, i.e. trained neural networks delivering reports and anomaly reporting, he says.

More with less

Work to perform surveys autonomously using an AUV supported by an ASV is already in progress. By deploying an AUV and ASV for positioning support and data transfer, from shore, you could reduce weather dependency when it comes to deployment, as well as the need for a manned mothership, says Ioseba (Joe) Tena, global business manager, marine robotic systems, at Sonardyne.

If an AUV is going to break, it is typically during the recovery phase onboard a support vessel, which is traditionally needed for positioning accuracy because there's no GPS signal subsea, he says. Deploying and retrieving AUVs from shore could help increase weather windows, Tena told the Underwater Vehicles Conference, but the AUV would rely on dead reckoning, introducing positioning error. Using dead reckoning on a 60km journey could result in 30m error and this deviation would increase the further you go, he says. However, deploying an AUV with a USV for communications and positioning – i.e. to correct dead reckoning – would resolve this problem.

Sonardyne, the UK's National Oceanographic Centre (NOC), unmanned vessel firm ASV Global, and software firm Seebyte, have been working on the Autonomous Surface and Sub-Surface Survey System project. Using an Autosub Long Range (ALR) AUV built by the NOC, Seebyte software, an ASV, and Sonardyne instruments, to do dead reckoning, sidescan sonar and communications, the group ran a trial mission from shore, out of Plymouth, south England. Once launched, the ALR and ASV lock onto each other. "The ASV doesn't have to follow blindly, just keep up. When they've done their mission, they come back to shore and are picked up in harbor."

Sonardyne's BlueComm 200 is used for communications. It's a free space optical modem, which does not have the range of acoustics, i.e. in the hundreds of meters, but is able to transfer larger volumes of data. If the systems can move close to each other, they can exchange video and side scan sonar data over a shorter period of time than acoustics, Tena says. BlueComm 200 can send up to 12Mbps at up to 150m range, depending on the environment (i.e. inshore areas with high turbidity will limit range), he says, enabling communication and control in real time.

"It's still early days," Tena says, "A lot of work remains . An autonomous long-range AUV is still in the first stages of development," but it has also been prototyped by the military, he says.

And, late 2017, the UK Ship Register signed its first unmanned vessel to the flag: an ASV Global's C-Worker 7. It's a multi-role work class ASV suitable for offshore and coastal tasks, such as subsea positioning,

The BlueComm optical communication "work horse." Photo from Sonardyne.

surveying and environmental monitoring – without the need of a ship on station or seabed anchoring. It can run pre-programmed missions using ASV's ASView autonomous control system.

Autonomous ships

Unmanned surface vessels such as the C-Worker can also work alongside manned vessels to speed-up surveys. Last year, ASV Global and TerraSond completed a 5172nm hydrographic survey in the Bering Sea, off Alaska, using an unmanned vessel. TerraSond used a C-Worker 5 ASV alongside its *Q105* survey ship for 36 days. The C-Worker 5 completed 2275nm of unmanned hydrographic survey lines operating as a force multiplier, running parallel survey lines to the *Q105*. Both vessels ran multibeam sonars and simultaneously towed side scan sonars.

"The ASV covered up to 130nm per day, doubling the coverage of the *Q105* survey vessel," said Thomas Chance, chairman, ASV Global. In addition to this, the C-Worker 5 was able to survey shallow waters that the *Q105* was not able to reach." This resulted in a 25-day reduction in time on site.

Kawasaki's AUV. Photo from the Underwater Centre.

Kawasaki trials AUV

Japan's Kawasaki Heavy Industries has completed a verification test in UK waters on an AUV, which can dock autonomously to recharge subsea.

With a focus on the growing demand for pipeline maintenance in the offshore oil and gas fields, Kawasaki has been developing AUV technology, with support from a subsidization project by Japan's Ministry of Land, Infrastructure, Transport and Tourism (MLIT).

The 15-day AUV verification tests were carried out in November at The Underwater Centre, a marine testing and training facility in Fort William, Scotland.

Tests at sea used a prototype AUV and a charging station, and included automated docking of the AUV to the charging station, contactless charging, and large-capacity optical communication operations.

Kawasaki plans to pursue full-scale development of a pipeline-inspection AUV, which uses the automated docking and other component technologies tested in Scotland, as well as control algorithms being developed in cooperation with the UK's Heriot-Watt University, with the aim of commercializing the AUV by the end of FY 2020. ▪

Multipliers

Subsea firm Ocean Infinity is taking a different tack. Instead of doing away with a manned surface vessel, it's deploying more AUVs off a single vessel. It recently claimed to have undertaken the deepest dive by multiple AUVs commercially known.

The feat was achieved on 18 October 2017, when the firm launched six Hugin AUVs, each with an independent mission, that has surpassed a water depth of 5200m. Ocean Infinity says this is also a first for six Hugin AUVs to simultaneously descend further than 5000m. The firm now plans to descend to 6000m with eight AUVs by mid-2018.

The need for speed

Another solution is gathering data faster, and that's just what SMD (Soil Machine Dynamics) has focused on with its new "high speed" compact ROV design, FLO. The unit is designed to fly at more than 6 knots and hold position against 4-knot currents from any direction for seabed mapping and pipeline inspection work. The design is based around a 250hp work class ROV system, but has been designed from scratch, using the sensor payload as a starting point.

This would make it 50% faster than a traditional ROV, said Graeme Jaques, head of ROV sales, SMD, at the conference. It would also extend the operational window in areas with high current, which are associated with the offshore renewables markets.

"We took the sensors and added a vehicle to them, instead of adding sensors to a vehicle," he says. This includes best available inertial navigation systems, doppler velocity logs, HD and stills camera systems (from Cathx), multibeam sonar, next generation pipetracker from Teledyne, multipulse sub bottom profilers, CP survey, such as the FIGS system (a field gradient sensor from FORCE Technology, now owned by Seatronics), etc. "Then we looked at where to put them and the best geometry," Jaques says.

The sidescan sonar transducer should be as high as possible on the vehicle, similar to multibeam echo sounders, while pipetracker technology should be below the ROV [min. 60cm from the ROV and 1-2m (max

3m) from the pipe being inspected] close to the sea bottom, but not too close, he says. "Then, we optimized the vehicle around the sensors," while also making it hydrodynamic (i.e. more like a Porsche than a small lorry [truck] – i.e. traditional ROV). The pipe tracker sensors are stowed during transit or in mapping mode, then drop down using a scissor frame when near the sea bed for pipeline inspection.

The entire system is 3960mm-long, making it longer than a work class ROV system, 1114mm-tall, and 1900mm-wide, and is designed with a 27mm steel armored umbilical. It weighs 2050kg, and has low drag, Jaques says. This means it can be deployed from smaller vessels.

It will be able to travel at 6.1 knots without a tether, or 5 knots with a tether in 250m water depth, Jaques says. It's able to operate in 3-knot currents, or in lateral currents of up to 4 knots.

In deeper waters, the drag from the umbilical slows the speed, so a subsea tether management system would be used, decoupling the water column drag on the umbilical from the ROV, which would be on its own 100-140m tether, and able to operate at up to 5.6 knots at 3000m. The limiting factor is the safe working load on the umbilical, Jaques says.

"It's very maneuverable, for mooring line inspection, etc., and has automated control systems, including auto-pitch, roll, and heading, and way point navigation.

It's also been designed so that it can perform in different modes. "The underneath of the vehicle is the heart and soul of a work class ROV system. You can take off a skid with manipulator arm and move back in to high speed ROV mode."

Tracking pipes

FLO would use a next-generation pipetracker from Teledyne Marine, the HydroPACT 660. It's been designed for use on small electric vehicles and AUVs, said Rolf Christensen, product line manager, Teledyne, at the conference. The 660 is based on Teledyne's 440, which was launched in the 1990s, for use on ROVs. But, the 660 is 70% of the weight of the 440 (at 14kg) and 60% of the size (at 1200mm x 600mm), he says. Despite these reductions, it's still above 85% of the quality of the 440, he says.

The HydroPACT uses pulse induction technology, which can detect any type of conductive material, including non-ferrous metals, such as brass, aluminum and light alloys. "It's similar to a metal detector people use on the beach, but it's more complicated in sea water as salt water is conductive," Christensen says.

The 660 system is not affected by terrestrial magnetism and self-compensates for any local conductive effects of the ROV, he says. Because it's lighter and smaller it creates less drag and is therefore easier for ROV pilots to control. It's designed for small electric vehicles, observation and inspection class ROVs and autonomous vehicles.

In November, the 660 was going through offshore trials. It was due to be available from this January. A DC version is also being developed and was due to be launched in Q2. OE

Propelling UK subsea innovation

Elaine Maslin profiles subsea organization National Subsea Research Initiative (NSRI) and its current work as it prepares for a change in leadership.

Gordon Drummond

Peter Blake

Since its launch in 2014, the NSRI, the technology arm of industry-body Subsea UK, has been a driving force in subsea technology development, not least in the small pools space.

Heading the organization is Gordon Drummond – who will return to his full time day job as engineering manager at Subsea 7 this month [January 2018] – aided by a board led by Peter Blake, subsea systems manager for the Chevron Energy Technology Company. With Subsea Expo, organized by Subsea UK, on the agenda next month [February 2018], *OE* caught up with the pair on what the NSRI has been doing these past three years.

But first...

NSRI is in fact the new form of an organization with an almost identical name, the National Subsea Research Institute, which was established in 2009, and led by the University of Aberdeen. Its aim was to create a focus for the development of subsea technology and expertise, linked to academic research. In 2013, Subsea 7 technology director John Mair saw the organization's potential and wanted to bring new life to it, shifting the emphasis from academic research to being an industry-led, for industry initiative. By 2014, Gordon Drummond, engineering manager at Subsea 7, had been installed as NSRI project director, on a three-year secondment, with Peter Blake as chairman, leading an advisory board.

Small pools

Small pools was picked as the first NSRI challenge. The timing was good, as small pools had been highlighted by the UK's Technology Leadership Board as a theme for MER UK (Maximizing Economic Resources). For NRSI, it was a good fit – a national industrial challenge, which played into the subsea space.

Small pools are something of a conundrum. It's estimated that there is 3 billion boe locked up in known small pools on the UK Continental Shelf. Part of the challenge is having technologies to economically develop them. The other part is commercial and about mindsets. They're not a big enough prize for the larger companies, but smaller companies don't, perhaps, have the wherewithal to tackle them, which means this resource falls between two commercial models. There may be a need for multi-company collaboration to "pool" resource to create a large enough resource for development.

Technology will play a key role, however. Blake says that's what the NSRI has tackled, starting with a hackathon, followed by workshops addressing topics such as subsea storage, predictive monitoring and digital oilfield technologies (*OE*: December 2015 & August 2016).

Handing on the baton

The NSRI's work in this space has helped give exposure to the potential in small pools, resulting in it being a focus for the Oil & Gas Authority, Oil & Gas UK, through its Efficiency Task Force, which looked at subsea tieback concepts (*OE*: April 2017), and now the Oil & Gas Technology Centre, which is largely following the framework for technology development set out by the NSRI, since taking on small pools as a challenge earlier this year.

SUBSEA EXPO

Subsea Expo next month

With the theme 'Facing the Future', Subsea Expo 2018, supported by *OE*, will look at what must be done to continue to reinvent the industry in a new reality. Key industry topics this year will include global markets, ROV developments, subsea innovation and offshore renewables. The event returns 7-9 February 2018 at the AECC in Aberdeen. ▪

There's not a rush to develop small pools, yet, however. It takes time to build the technology and the environment, says Blake, who worked on Deepstar 25 years ago.

"At the time, there wasn't really any deepwater development in the US Gulf of Mexico. Twenty-five years later there is stacks of it. Deepstar was partly accountable for that," he says.

It wasn't so much about the technology that finally made deepwater viable, and the same is true of small pools, Blake adds, although he says that time is not on their side, with infrastructure now starting to be removed. "You will see up-take of these technologies, in five years' time. The big thing NSRI did was start the debate," he says. It showed that the technology is possible, the commercial side, the mindset, needs to catch up.

Some of *OE*'s past coverage on NSRI initiatives.

Subsea springboard

NSRI has been busy in other areas, however. Early on, it launched Developer Days (now Technology Springboard), which put technology developers in front of buyers (access to which many find challenging), and its Matchmaker tool – an online "dating" service – to connect technology firms with universities and test centers with expertise relevant to their technology.

Through these events, technology developers like Aberdeenshire-based Exnics have been given a foot in the door. Since presenting at the first Developer Day, Exnics, for example, got an offshore trial of its hot rings technology with EnQuest on the Scolty-Crathes subsea tieback. We've been following Exnics progress in *OE* this year (*OE*: November 2017). Another firm, EC-OG, has been working with Shell on its subsea power hub concept.

Mapping renewables

Meanwhile, with the help of two interns, seconded from engineering group Wood, work also got underway mapping out the subsea challenges in offshore renewables and subsea mining, supported by events, and helping to build the Matchmaker database. Last year, another intern took over and is focusing on wave and tidal energy opportunities.

> **"You will see up-take of these technologies, in five years' time. The big thing NSRI did was start the debate."**
>
> — Peter Blake

Other events, including days highlighting expert skills available in academia, in materials and subsea inspection, as well as test facilities and funding routes, have also been held.

The dream, however, is to create a subsea center of excellence, which fully links the world leading UK industry, with academia, qualification and testing and deployment opportunities across the subsea sector. It would comprise an underwater test center, a technology incubator and a digital virtual community. Scottish Enterprise has been involved in assessing the testing and development center potential, which could involve building a dummy offshore asset, which could be used for testing, to get around operators not wanting to test technologies on live wells.

"That's one of the big barriers, to get in field and getting technology wet," Drummond says. Creating a subsea center of excellence would be the ultimate end goal, Blake says, even if it did mean that the work of the NSRI was complete.

Meanwhile, the next three years, under a new project manager, is set to focus more on diversification; looking at other sectors the NSRI has not tapped fully into yet, as well as areas within oil and gas that haven't been looked at yet, such as decommissioning. Changes have already been made to the board to reflect these wider interests. The NSRI also hopes to add more academic input from outside Scotland and to help map more global opportunities for the supply chain. OE

FURTHER READING

Cutting the Umbilical
www.oedigital.com/pipelines/maintenance/item/10929-cutting-the-umbilical

Tanked up
www.oedigital.com/production/fpso/item/13135-tanked-up

Grappling with integrity

Pinning down asset integrity isn't easy. Yet, that isn't stopping UK North Sea initiatives that seek to reduce cost, time and impact on operations. Elaine Maslin reports.

Work on asset integrity to date has paid off, with a consistent reduction in the number of small hydrocarbon releases (HCRs) in the UK Continental Shelf (UKCS) over the past 10 years.

But, this is still proving elusive and there's a concern it's because there's not enough focus on operational integrity. These topics were discussed at the Energy Institute's (EI) Asset Integrity conference in Aberdeen, early October.

The challenge

The challenge, says Alan D'Ambrogio, vice president, Oil and Gas, ABB Consulting, is that the North Sea is a maturing basin – 50% of UKCS installations are at or beyond their design life – with diminishing revenues.

D'Ambrogio

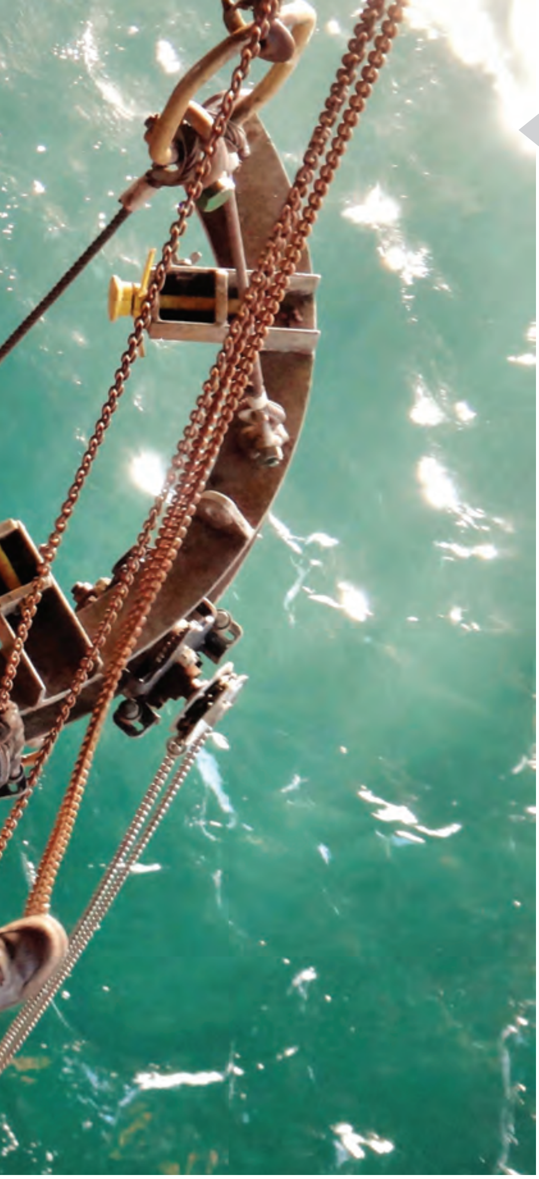
"A significant amount of inspection work is done with invasive methods at short intervals. Typically, 85% of inspection [work] requires equipment to be shut down and isolated. About 95-97% of the cost is enabling work, i.e. process preparation, cleaning, etc. Just 3% is the actual inspection," he says.

This means long and frequent inspections and more frequent turnarounds (TARs) – and production losses as a result. In fact, D'Ambrogio says that the UK has gone from TARs every two years to annual TARs (2004-2014), and they're taking 50% longer.

But, this effort, and its results, doesn't appear to be well monitored. Rebecca Allison, asset integrity solution center manager at the UK's Oil & Gas Technology Centre (OGTC) – a publicly funded body to boost technology development in the UK North Sea – says most operators don't actually know how much they're spending on asset integrity.

"If they don't know how much they are spending, how can they identify what added value is," she said at the event. "It sits in the campaign budget, or part of TARs. You can identify how much is spent on inspection, but that's not asset integrity. What about all the brownfield work?"

However, work has been done to make the job easier, safer, cheaper and faster. The OGTC has a set of goals: to reduce inspection costs 50% by 2021; eliminate failures by corrosion under inspection (CUI) by 2026; and have no vessel entry



Late 2017, CENSIS, the Scottish Innovation Centre for Sensor and Imaging Systems and TRAC Oil & Gas, along with the University of Strathclyde, set out to work together to tackle non-destructive testing of corroded pipes under insulation and engineered temporary pipe wraps. The group will look at what improvements can be made in this area, including developing new techniques for accurately identifying and measuring areas of corrosion.
Image from TRAC Oil & Gas.

due to inspection by 2026 (i.e. use non-intrusive inspection [NII]).

New technologies to help meet the OGTC's goals have been identified. Two years ago, Lockheed Martin published a report into CUI and NII for pressure vessel inspection, but the take up in NII has been limited for the latter, Allison says, and some 40-60% of pipework failures still are due to CUI, she says.

D'Ambrogio agrees that NII is mostly not considered and risk-based inspection (RBI) is often not used or poorly applied, he says.

As part of a project with the OGTC, ABB spoke to 6-8 operators about their use of NII. There was a reluctance to use NII, he says. Where it was used, it was mostly done as a deferment for invasive inspection. Some had a bad experience with it, "or should that be bad experience in managing asset integrity," he posited.

The project looked at how many vessels operators had, how many could be inspected with NII – as not all are suitable – and how many were being inspected using NII. On one operator's set of six platforms offshore Baku, there were 261 vessels, 145 of which were suitable for NII, amounting to 56% (<5% were being inspected using NII). Changing this regime helped increase the TAR interval to three years, D'Ambrogio says.

Looking at a North Sea operator's assets, there were 419 offshore vessels, 60% were found to be eligible for NII (zero were inspected with NII until then). The number could be increased to 66% following a RBI revalidation, helping increase the interval between examinations by 13%.

D'Ambrogio says that NII reduces the risk of the chance of leaks when breaking containment for inspection, and that invasive inspection can result in damage to internals or coatings, as well as risk to personnel in confined spaces. Furthermore, "Inspections are sometimes also not actually focused on the real failure risks – and even carried out on non-degradation mechanisms," he says.

D'Ambrogio warns that NII needs to be used appropriately, however. "Not all vessels are suitable for NII. The key is understanding deterioration mechanisms, and if all deterioration mechanisms can be detected with plant online," he says. Operators also need to understand the capability of non-destructive testing, what can be seen and what can't, and what the degradation mechanisms are.

Field trials

North Sea operators are making tentative steps in this direction. This summer, working with the OGTC, French oil major Total conducted field trials with NII tools, which were then verified with vessel entry. The results of this work will be published, Allison says. "It's quite a change," D'Ambrogio says. "The tradition is to enter vessels. Some vessels you need entry [into] anyway."

There is also work into determining how to manage caissons and conductors, pipeline integrity and subsea infrastructure, and well integrity. How to handle all the data produced from this work also needs to be looked at, Allison says. "One of biggest pieces of feedback is 'don't bring us technology, that gives us more data.' We need to look at how process data more effectively. We are drowning in data."

Next generation unmanned aerial vehicles (UAVs), with phased array ultrasonic sensors and live video feed, are also coming, alongside better flight stability, and longer battery life, to expand the scope of UAV inspection. There are also technologies being developed that could offer laser cladding using additive manufacturing for in-situ remedial repairs, as well as new sensor technologies. But, Allison says, these need to be designed with brownfield applications in mind, so they can be fitted easily and cheaply.

But, technology alone will not solve the problems, she says, nor will just changing work procedures. Both are needed. Understanding the wider picture is also important.

"Increasing production increases margins more than trimming the cost of inspection," she says. "There has to be an integrated approach to understand how integrity impacts operations and how maintenance is integrated with inspection."

Cameron Stewart, upstream technical manager at the Energy Institute, says that there has been a "re-recognition" in the industry around addressing asset integrity and aging and life extension. This includes looking at new technology, such as drones, where it's used and how to use them to the best benefit.

In Q2 2018, the body is due to publish the third edition of its 400-page corrosion management guidance – known as an industry bible on the topic. Alongside this, it will have published 8-10 corrosion documents in 2017. These provide good practice on the likes of microbial-induced corrosion as well as chemical injection and fire water deluge systems. The topics are picked by a science and technology advisory committee that investigates where there are gaps or a need for updates. The aging and life extension (ALE) committee, which has published a range of papers, too, following a review of ALE activity, which itself came on the

Last year, Chevron tested a snake-arm robotic inspection system, the P100 from OC Robotics, to inspect inside pressure vessels on its assets in the North Sea, following onshore trials. Image from OC Robotics.

back of the Health & Safety Executive's KP4 program on ALE (*OE:* September 2014). Guidance on bolted joints and HPHT are due soon and ongoing work includes looking at caissons, and also floating structures and improving risk based inspections, or RBIs, Stewart says.

Focus on operations

If asset integrity is about preventing leaks, more focus needs to be put on operational integrity, however, said Ashley Hynds, principal inspector of Health & Safety - Process Engineering, Health & Safety Executive (HSE), at the EI event. He says that while a focus on asset integrity has helped reduced the number of minor and significant HCRs in the UK North Sea, it hasn't reduced major releases.

Reporting and investigating the causes of HCRs was a key recommendation of the Cullen Inquiry into the Piper Alpha disaster in the UK North Sea, where 167 workers died.

Over the last 10 years, there's been a year-on-year reduction in the number of minor releases. But, major releases – which pose the greater threat to life – remain unpredictable, with 2-8 per year recorded between 2005-2015 (3 in 2011, 8 in 2012, 6 in 2013, 3 in 2014).

"The smaller HCRs are the most common and tend to be associated with asset integrity, i.e. hardware, a valve stem leak or pin hole corrosion, poor mechanical design, ineffective equipment," he says. Larger releases are different, however, and tend to relate to loss of operational integrity, i.e. adherence to procedures, safe reinstatement of plant, control of overrides, permit to work.

"Our inspections show that many operators' HCR reduction plans focus on asset integrity rather than operational integrity and rely heavily on reactive learning from HCRs. Minor leaks are well investigated, but if they are minor they don't address the major leaks. They will replace a pipe or put in a different monitoring system."

In comparison, operational integrity topics are about process safety culture/leadership, safe operating limits, and plant documentation, process operating procedures, process operator competence, permit to work system.

Of 5-6 investigations into major leaks over the last few years, start-up procedures, where a valve wasn't fitted correctly, were found to be at fault. This is something simple, "but similar to Piper Alpha."

Of nine recent major HCRs, two were asset integrity-related (CUI and maintenance, and corrosion, inspection and maintenance). The rest were operational integrity-related, i.e. around management of change, procedures, supervision, competence.

A causal analysis of 21 major HCRs, in 2011-2016, found that in 67% of the incidents were issues related to procedures – they weren't adequate or weren't being followed, Hynds says. Risk management was identified in 43% – a hazard hadn't been identified or controls applied – isolations and reinstatement in 33%, design was identified in 33%, competency in 19% and supervision in 10%.

Examining the issue another way, Hynds says that an HSE inspector asked an asset manager how well the permit to work system was working, what the weak areas were and what was being done about them. The asset manager referred the inspector to the offshore installation manager (OIM). In turn, the OIM referred the inspector to the operations supervisor, who then referred the inspector to supervisor on the back-to-back shift. Hynds quotes from the Public Inquiry into Piper Alpha: "Senior management were too easily satisfied that the permit to work system was being operated correctly, relying on the absence of any feedback of problems as indicating that all was well."

"Fortunately, there are not that many major HCRs, but that also means there are not that many to learn from," Hynds says. Even with what information there is available, "Operators are not willing to share," he says. Since 2010, there have been 27 major HCRs. Step Change in Safety has an alert database (Sadie) where operators can share information about incidents. Only one of those incidents were shared on Sadie to date, that was by Apache.

There is a Toolkit, a document produced by Step Change in Safety, called the Hydrocarbon Release Reduction Toolkit, but it focuses on asset integrity and it acknowledges this, Hynds says. For hardware, there's third party verification. This doesn't exist for operational integrity, Hynds says. New guidance is due to be shared towards the end of the year. **OE**

FURTHER **READING**

Subsea asset integrity is a growing challenge on the UK Continental Shelf and elsewhere, with each basin having its unique set of often complex demands. This applies to traditional oil and gas plant as well as the new generation of renewable energy structures. Matthew Kennedy, CEO and cofounder of 1CSI, looks at ways approach the challenge in an online exclusive for *OE*.

Kennedy

www.oedigital.com/component/k2/item/16774-navigating-subsea-integrity

Looking after your assets

A project by the UK's Energy Institute has paved the way for new guidelines on how best to look after aging gas turbine packages. Elaine Maslin reports.

Aging equipment is a challenge anywhere, but not least on a platform in the middle of the North Sea.

The basin has a lot of equipment, including a large fleet of gas turbine packages, ranging from new sets to packages that are more than 40 years old – with an API design life of typically 20.

Work by the Energy Institute (EI) has sought to offer guidance into how best to keep these units running. A work group, the North Sea Rotating Equipment Users Network in 2013, comprising oil and gas operators, was set up under the EI umbrella to share knowledge and best practice.

The group was set up following the UK Health and Safety Executives KP-4 program on aging and life extension, out of which guidelines were developed by the EI for centrifugal compressors.

Having proved successful, the idea to publish a suite of documents on rotating equipment tackling key areas was launched, starting with guidance for aging gas turbine packages.

Repsol Sinopec Resources UK has 54 operational gas turbine packages, "one of the largest fleet" of a total ca.300 in the UK North Sea. A challenge is that there is a diverse mix of types varying from large industrial turbines that have to be maintained in-situ through to lighter weight, modular units that can be removed and repaired or replaced, Karl Grieve, lead rotating equipment engineer, Repsol Sinopec Resources UK, told the Energy Institute's annual Asset Integrity conference in Aberdeen.

Assets that were typically designed for 20 years' life and are operating beyond that or have aged prematurely need a different maintenance regime.

Rotating equipment is a key part of the asset infrastructure and aging needs to be managed effectively, Grieve says.

"Within the [North Sea Rotating Equipment] group, many have suffered in silence," Grieve says. "This was an opportunity to share experience." Experience included that environmental and operational conditions can accelerate aging. The group shared experience around premature and aging-related failures, different maintenance and inspection strategies and different solutions – repairs, modifications and improvements – as well as experiences with different suppliers.

The principal aim of this document is to assist operators with identifying, planning and performing inspection routines that are applicable to aging gas turbine equipment; effectively assisting with the development of a rotating equipment integrity management system.

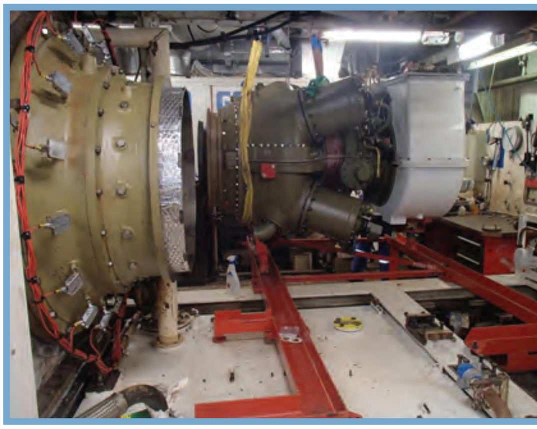
While gas turbine maintenance is well understood, there also needs to be more understanding about the ancillary equipment and understanding different assets and different equipment types and their different issues.

"Routine inspection and auditing forms a key part of managing the aging," Grieve says. "It is a practical document containing guidance on considerations for determining an appropriate approach to inspection, maintenance and monitoring as well as a failure modes and effects analysis (FMEA) of key aspects of gas turbine packages.

The FMEA was further developed to provide suggestions for failure mitigation and improvement options for systems or components based on the collective experience of the group. The intent is for this knowledge and best practice to be shared." The guidance document is due to be published early 2018. OE

GE Frame 6 heavy industrial turbine rotor lift. Photos: Karl Grieve/Repsol Sinopec Resources UK.

Rolls Royce Avon aero-derivative gas turbine.



Ruston TB5000 light industrial gas turbine changeout.

Eyes along the string optimize the Barents in real time

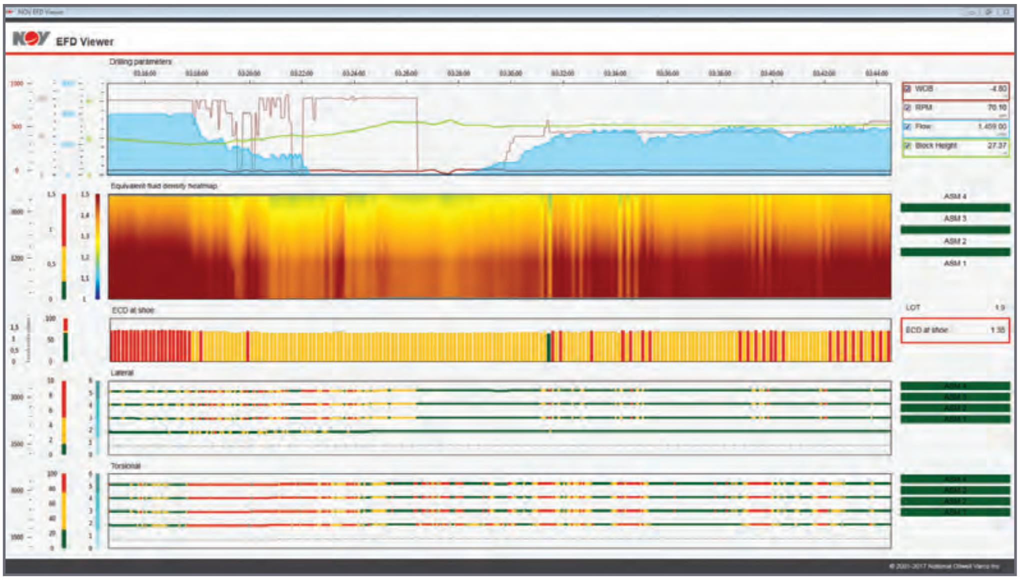
Sanna Zainoune and Stephen Forrester, of NOV, and Børge Nygård, of Statoil, discuss how wired drill pipe helped Statoil understand downhole conditions while drilling the Barents Sea exploration wells.

The persistent need to increase uptime, cut project costs, and improve drilling performance has driven implementation of more advanced technology in the oilfield. The relative stagnation of the current oil price and future pricing forecasts, which have stalled at around US$50/bbl, have made it clear that companies must research new ways of achieving profitability in this market.

As wells become more and more challenging, the amount of issues that can occur downhole continues to increase. This problem, compounded by both the technological complexity and high costs of deployed equipment and tools, means that it is now more important than ever that downhole conditions be analyzed and understood in real time. National Oilwell Varco (NOV) developed a suite of integrated downhole products and technologies, including BlackStream along-string measurement (ASM) and enhanced measurement system (EMS) tools, an equivalent fluid density (EFD) viewer, and IntelliServ wired drill pipe with a high-speed telemetry network, to enhance real-time understanding of borehole conditions in wells around the world. NOV partnered with Norwegian operator Statoil to use this product/technology suite in its Barents Sea exploration drilling campaign in 2017, with several key objectives:

- To prove that wired drill pipe is a viable technology.
- To use accurate real-time downhole

Above: ***Songa Enabler.*** Photo from Songa Offshore.



EFD Viewer. Photo from NOV.

- To use accurate real-time downhole measurements for increased efficiency and safety in environment-sensitive wells.

- To implement wired drill pipe as future part of Statoil's digitalization and automated drilling strategy.

Statoil started the drilling campaign in the spring of 2017. The campaign involved a five-well project for the Blåmann, Kayak, Korpfjell, Gemini Nord, and Koigen Central prospects, which are expected to clarify viable opportunities for future drilling in the Barents Sea. The *Songa Enabler,* a floating, self-propelled, winterized rig designed specifically for use in cold climates, was chosen for the exploration campaign because it is one of the most technologically advanced rigs in the entire Statoil fleet. The rig has advanced automated drilling control system installed. Automated drilling, for Statoil, refers to a group of technologies that provide significant and remarkable benefits. High-speed telemetry is part of the group and regarded as an enabler for future drilling automation. NOV delivered a high-speed telemetry system consisting of:

▪ Wired drill pipe and associated telemetry network

The telemetry network enables instantaneous, bidirectional transmission of downhole data. Telemetry speeds reach up to 57,600 bits/sec versus the significantly slower rates achieved with current mud-pulse or electromagnetic telemetry methods, ensuring the downhole tools are connected in real time. To create wired drill pipe and enable this real-time data transmission, the double-shouldered connections of each tubular joint are embedded with a high-strength coaxial cable and low-loss inductive coils.

▪ ASM and EMS tools

ASM tools are compact, collar-based tools that can be placed along the drillstring to acquire downhole drilling dynamics and hydraulics measurements. Connection to the networked drillstring provides streaming visualization of downhole data for immediate analysis. EMS tools acquire high-frequency downhole data from positions in the bottomhole assembly (BHA) for analysis and optimization of drilling parameters, transmitting data to the surface in real time via the wired drill pipe network, with or without flow.

▪ EFD viewer

The EFD viewer was developed to display time, depth, and along-string measurements in a user-friendly way. It combines surface parameters, equivalent circulating density (ECD) in a heat map, interpolated ECD at the shoe, and vibrations. Measured depth is shown on vertical axis, while time is displayed on horizontal axis. Data is appended on right hand side before moving along screen. Diagnostics are also color-coded and make it easy to make decisions based on the continuous measurements.

Using the high-speed telemetry system enabled Statoil to achieve impressive operational and performance benefits. Wired drill pipe raised the rate of penetration (ROP) limit by removing constraints on data acquisition while still providing confidence that the hole was being cleaned while drilling. The telemetry significantly increased the quantity of streaming data for analysis and transmitted LWD-quality memory data in real time. The telemetry system achieved an average uptime of 98.2% over the five wells and four pilot holes, and Statoil only experienced eight hours of non-productive time (NPT) in total. The high-speed telemetry of the wired drill pipe network improved connection times by eliminating the need to pump up data, such as surveys or leak-off tests (LOTs). Weight-to-weight time was reduced by 23% due to the increased focus on efficiency during connections.

Real-time flow-off pressure readings from sensors distributed along the drillstring help monitor how the annulus gets loaded or unloaded with cuttings, depending on drilling parameters. While drilling the first riserless section, a sudden annular pressure increase was seen on the LWD sensor after the connection was made, and the pumps were immediately shut down to prevent a full packoff. The pressure increase was not indicated by the EMS tool placed right above the BHA, indicating that the cuttings accumulation was located between the LWD and EMS sensors. Distributed readings enabled the operator to follow the cuttings as they were circulated out of hole using low flow rate and RPM. EMS measurements helped in understanding the exact location of the tight hole conditions, with the packoff monitored up the annulus using both downhole torque and annular pressure.

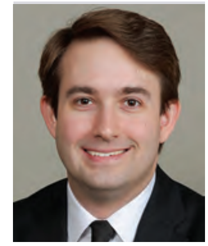
Having knowledge of the packoff event allowed Statoil to optimize their sweep strategy. The along-string sensors were then used to monitor the sweep pills' position and manage pumps in an extremely accurate manner. The RPM measurements, noted as the curve separation between maximum and minimum RPM (stick-slip), from the ASM and EMS tools were also used to monitor the efficiency of the sweep pills.

Drilling vibrations are potentially very damaging and can cause early drill bit or BHA failure. The BlackStream sensors, placed along the drill pipe, helped in understanding those vibrations in real time while drilling through some relatively hard formations. Downhole torque was used to ensure the bit was responding to changes in parameters, including RPM and weight on bit (WOB). Following some spikes in downhole torque, the PDC bit torque response changed and did not increase with higher WOB. Off-bottom stick-slip also appeared, indicating tight hole conditions, and erratic internal pressure readings were measured by the BlackStream tools while circulating off bottom. While the ECD was consistent with flow rates, internal pressure indicated that there was obstruction in the flow path. After pulling the bit to surface due to low rates of penetration, the bit was found under gauge, confirming the diagnostic indicated by the BlackStream measurements.

Statoil commented that, "for drilling operations, understanding downhole conditions is key. In addition to advanced modeling of downhole conditions, high-speed telemetry and wired drill pipe enable us to monitor downhole data in real time, which was not available before. Our goal for the future is to act upon real-time downhole data to improve drilling efficiency and to avoid problems related to downhole conditions. Also, high-speed telemetry will potentially improve placement of our wells in the reservoirs."

Integrated technology packages will continue to grow in importance as the industry searches for safer and more efficient ways of drilling in challenging frontiers, and operators such as Statoil, who are eager to implement digital solutions, will continue to drive future developments of more advanced products and technologies. **OE**

Sanna Zainoune *is a senior dynamic drilling solutions engineer. She has worked in the oil and gas industry since 2005, joining NOV in 2015. Sanna provides technical support to operational projects in the North Sea, advising on hole cleaning, vibration analysis, and drilling optimization. She holds a master's degree in process engineering from Engineering School of Grenoble, France.*



Stephen Forrester *has worked at NOV as a marketing/technical communications writer since 2014. He researches and executes strategic marketing communications and technical writing opportunities to support the company's diverse businesses. Before joining NOV, Stephen worked for the oil and gas division of Lloyd's Register as a technical editor. Stephen holds both a BA and MA in English from the University of Houston.*

Børge E. Nygård *is leading advisor on drilling practices and tools at Statoil. Børge started his career with Schlumberger in 2001 and has worked with planning and execution of drilling operations on- and offshore for 15 years. He holds a master's degree in marine technology from the Norwegian University of Science and Technology, Trondheim, Norway.*

Optimizing well construction

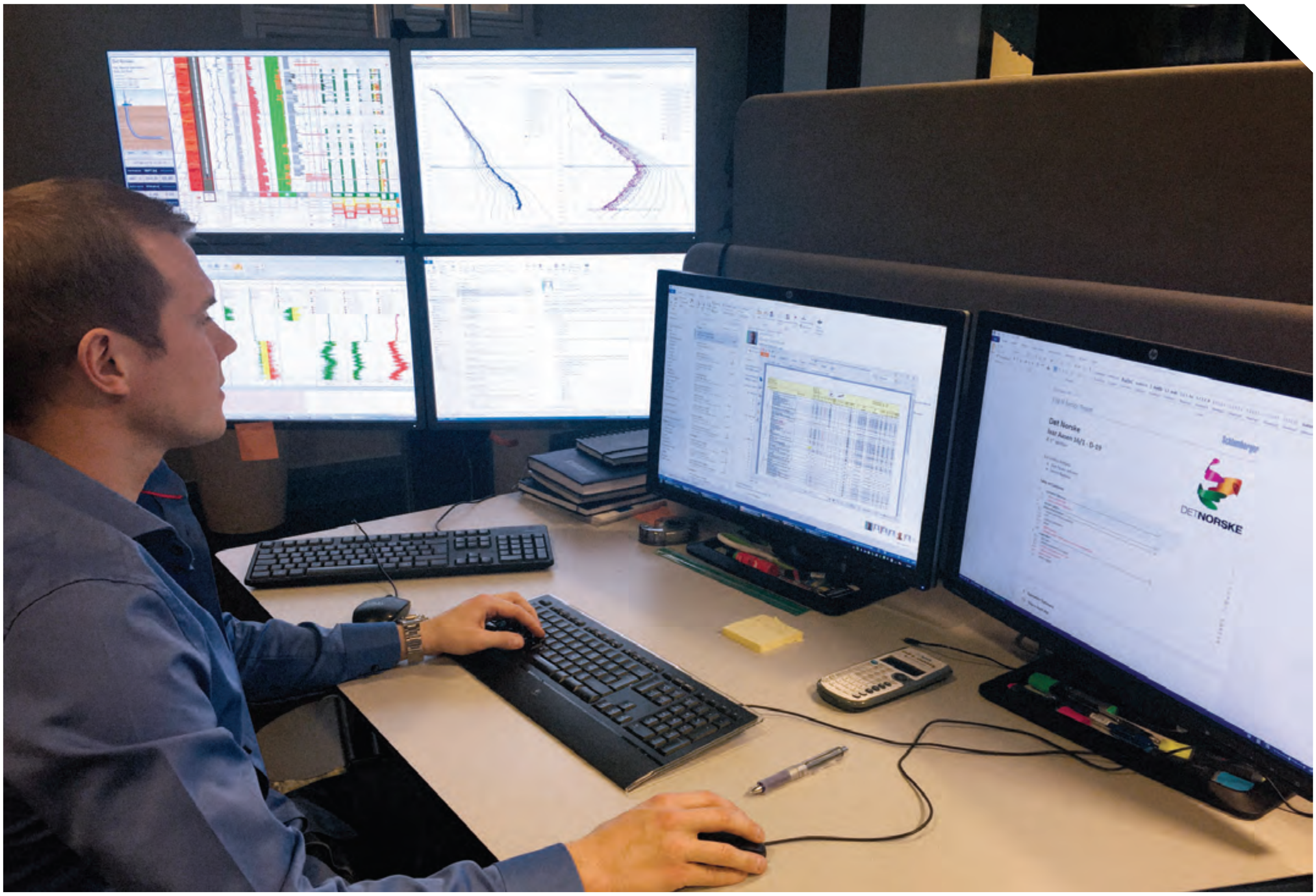
Karen Boman speaks with Schlumberger's Slim Hbaieb about the firm's new OptiWell service to find out how operators can leverage data to improve well construction performance and ensure wellbore quality.

***OE*: Can you discuss some of the challenges that operators have faced prior to 2014 with offshore oil and gas well construction?**

Slim Hbaieb: business development manager, Schlumberger: Offshore oil and gas well construction has always been challenging due to the high rig spread rate. Ensuring the prevention of any potential environmental incident that could occur due to a lack of well control has and always will be of paramount importance.

The industry's focus has historically been on reducing non-productive time (NPT) while optimizing drilling performance and the on-bottom rate of penetration (ROP). Between 2009 and early 2014, over 100 newbuild deepwater projects began operating. Improvements in well design, surface and downhole tools and technologies, modeling and simulation techniques in recent years has resulted in a considerable improvement in risk reduction and drilling performance.

***OE*: How has the 2014 oil price downturn impacted the oil and gas industry's focus on well construction?**



Real-time continuous well monitoring services enabled Det Norske (now part of Aker BP) to improve ROP and reduce issues related to undesirable tripping performance. Photo from Schlumberger.

Slim Hbaieb: Prior to 2014, a capital inflation for offshore development and exploration projects led to an increase in cost per barrel. This was compensated by a high oil price, but the consequence is more pressure on the offshore drilling business following the recent downturn.

Challenging the status quo and reducing the cost per barrel without compromising safety and wellbore integrity is essential. In addition to maintaining the focus on risk management for NPT reduction, and drilling performance for ROP increase, identifying invisible lost time (ILT), or the time between actual and technically achievable duration for individual well construction, and eliminating areas of inefficiencies is crucial.

Achieving operational efficiency across rig fleets and reaching the technical limit for each well operation, is one of the OptiWell well construction performance service value propositions.

OE: What other factors are contributing to this new outlook?

Slim Hbaieb: Remote monitoring and support services are allowing us to centralize experience and domain knowledge while offering enhanced support for more informed decision-making for multiple projects. The OptiWell service centers cross domain expertise, including but not limited to the domains of drilling, mud logging, and geomechanics.

Advances in remote operation technologies and workflows are progressively reshaping well construction service delivery models. Frequently, we are able to meet customer requirements using remote decision-making. This eliminates the necessity for dedicated experts to be physically located on every rig.

OE: What kind of technology/ technologies make the OptiWell service possible?

Slim Hbaieb: Offshore projects can generate a large stream of real-time data captured from hundreds of surface and downhole measurements and sensors. The OptiWell service is enabled by new software and data processing techniques leveraging domain analytics.

> **"New platforms allow us to integrate and process large amounts of data in a timely fashion to support informed and collaborative decisionmaking."**

This is made possible by high power computing. The automation of workflows such as data management and key performance indicator generators, enables the teams to allocate more time to process optimization and value extraction.

New platforms allow us to integrate and process large amounts of data in a timely fashion to support informed and collaborative decision-making. The OptiWell service is dedicated to improving well construction performance by minimizing ILT and closing the gap to the technical limit. From 24/7 monitoring for drilling hazards to identifying well operation inefficiencies, the OptiWell service mitigates health, safety and environment risks and both ILT and NPT.

OE: What kind of time and cost savings have been realized through the OptiWell service?

Slim Hbaieb: In the deepwater Gulf of Mexico, Schlumberger collaborated with an operator to customize a plan using the OptiWell service. Consequently, the operator broke a record for the most footage drilled in the Gulf of Mexico in 24 hours—2826ft [861.4m] drilled in the 16½in × 19in section. Over the course of three wells, BOP test times were reduced from 11.4 hours to 3.6 hours per test, and average connection time was decreased from 28.5min to 17min. Additionally, average on-bottom ROP increased 93% from 73ft/hr to 141ft/hr. The improved efficiency enabled by the OptiWell service saved the operator 36 drilling days and US$13.3 million.

Det Norske used the OptiWell service in the multi-well field development project, offshore Norway, to increase ROP and improve tripping practices. On the recent D-19 well, Det Norske achieved a project record for net and gross ROP in the 8 1/2in and 12 1/4in sections. The operator experienced a 48% decrease in slip-to-slip tripping time compared with the project average and achieved improved casing slip-to-slip performance.

OE: What kind of trends does Schlumberger see for offshore well construction in the next five years?

Slim Hbaieb: Drilling automation, remote operations, and digital transformation are reshaping the drilling domain. In September, Schlumberger launched the new DrillPlan digital well construction planning solution—the first step in the DELFI cognitive E&P environment. The DrillPlan solution is part of a fully integrated well construction offering, which transforms planning and execution performance, and enhances the efficiency and quality of every well drilled. The solution delivers well planning programs in days rather than weeks during field tests.

Well construction is entering a new digital era where data will be better utilized, collaborative teams will be better connected, and a step change in efficiency will be achieved from planning through to execution. This will reshape the workforce and workflows of the future. The next generation of offshore cogitative drilling rigs will also help us enter a new era of well construction performance. OE

***Slim Hbaieb** is the Business Development Manager for Drilling and Surface Acquisition at Schlumberger based in France. Prior to that, he held various positions in field operations, engineering, research and marketing in multiple countries. His previous assignment was as the Drilling Technologies Research and Development Program Manager at Schlumberger in Rio de Janeiro, Brazil. Hbaieb holds a Master's degree (1999) and a PhD (2002) in Control & System Engineering from Ecole Supérieure D´Electricite (SUPELEC) in France.*

Middle East and Caspian

EPIC activity

Saudi Aramco has been driving the highest amount of EPCI activity in the Middle East in 2017. IHS Markit's Mirzi Moralde takes a look at the region, history and context for *OE*.

Saudi Arabia's state-owned oil company, Saudi Aramco has been leading the way in the tendering and contracting activities in the Middle East Gulf offshore construction market in the current low oil price environment.

Seven offshore engineering, procurement, construction and installation (EPCI) projects were awarded by Saudi Aramco, between January and November 2017, covering the Safaniya, Zuluf, Marjan, Berri and Manifa oil fields, as well as the non-associated Hasbah gas field. It is the highest number of EPCI contracts awarded since the market downturn in 2H 2014.

Saudi Aramco has the highest number of EPCI tenders released and projects awarded in 2017, which are under its offshore Maintain Potential Programme (MPP), compared to other operators in the region. Rolling out MPP will aid in sustaining and maintaining Saudi Aramco's production capacity, which is at maximum around 12 MMb/d. In 2016, Saudi Aramco produced 10.5 MMb/d.

Urbanization in developing countries and rapid growth in global population in the decades ahead are expected to result in increased demand for reliable energy sources, like oil and gas, until a long-term transition to alternative energy sources to counter climate change could possibly meet a portion of future energy needs. Total primary energy demand is expected to increase by 35% in the period to 2040, and oil is expected to have the largest share in the energy mix in the forecast period, based on the Organization of the Petroleum Exporting Countries (OPEC) World Oil Outlook 2017.

Through the implementation of the MPP, Saudi Aramco will be able to readily respond to demand. It has earmarked around US$300 billion over the coming decade to secure its eminent position. A part of the investment plan aims to sustain Saudi Aramco's spare oil production capacity as well as to carry out exploration and production focused on conventional and unconventional gas resources. The firm is also looking into innovation, technology and collaboration with nine other oil and gas companies in finding low-emissions solutions to provide clean energy as part of its commitment to the $1 billion Oil and Gas Climate Initiative (OGCI) investment fund.

EPCI awards

From 2015 to November 2017, 18 offshore EPCI projects were awarded by Saudi Aramco, after the price of oil plummeted.

Coming in second to Saudi Aramco in the contracting front in the Middle East Gulf region are Abu Dhabi National Oil Co. (ADNOC) subsidiaries Abu Dhabi Marine Operating Co. (ADMA-OPCO), Zakum Development Co. (ZADCO) and Abu Dhabi Gas Industries (GASCO), which are now collectively known under one brand identity, ADNOC. It awarded seven EPCI offshore contracts from 2014 until 2016, involving the Zakum, Nasr, Bu Haseer and Dalma fields. This is in line with Abu Dhabi's goal of increasing production capacity to 3.5 MMb/d by 2018, in anticipation of a future hike in energy demand.

Looking back to 2H 2008, oil demand dropped at the onset of the global financial crisis, which also resulted in a low oil price environment until the global economy slowly showed signs of recovery by 2011, coupled with global disruption in supply in 2012, that brought back the oil price up again to over $100/bbl in 1H 2014. Thereafter, the oil price began its sudden

descent to a low of around $40, triggered by higher supply than demand, as the global economy continued its slow recovery, while supply from non-conventional or shale oil in the US surged.

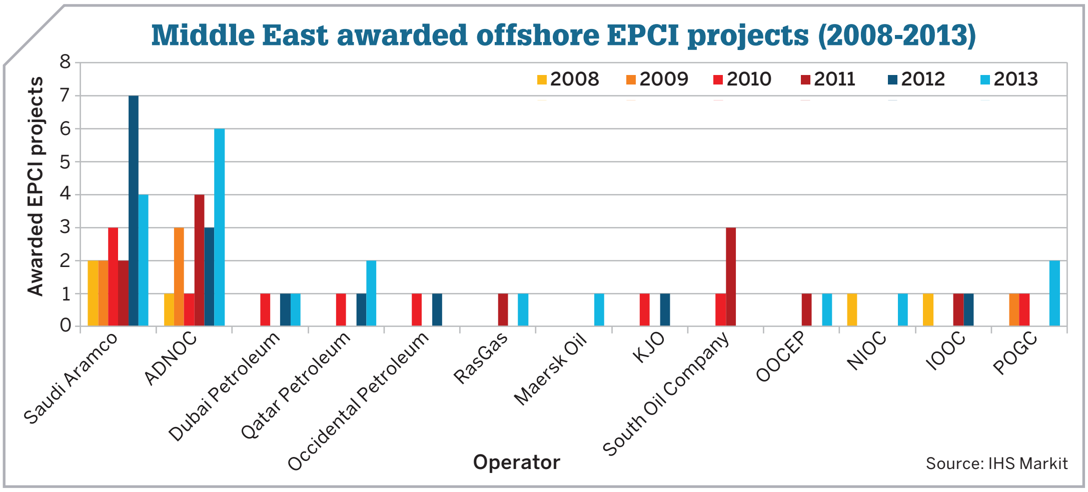
FieldsBase by IHS Markit shows that in 2008 and 2009, Saudi Aramco awarded two EPCI projects each year, closely followed by ADNOC, with one and three project awards, respectively. Saudi Aramco's multi-billion Manifa oil field redevelopment project, covering platforms and pipelines, was granted to EPCI contractors in 2008, while in 2009 it started the development of its first offshore non-associated Karan gas field.

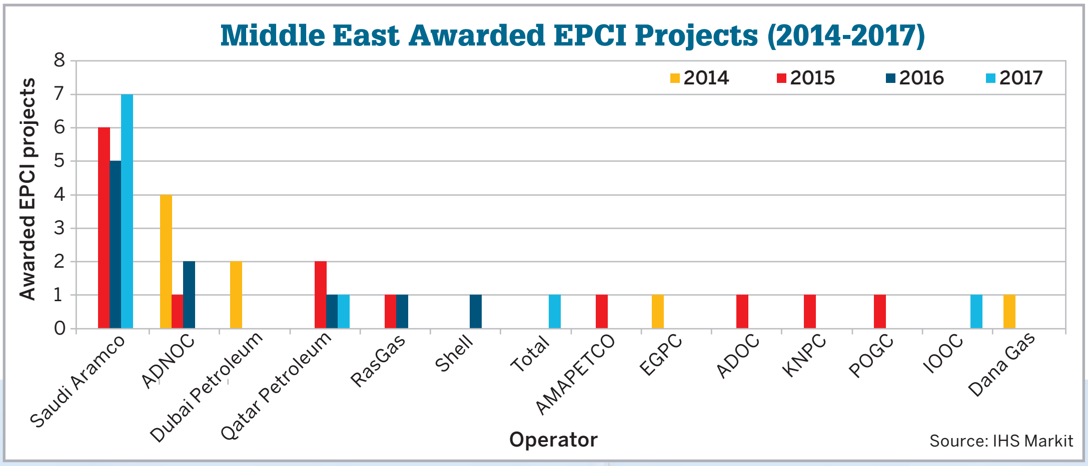
In 2010-2013, there were 16 projects awarded. Seven of these projects were granted in 2012. While for ADNOC in the same period, 14 projects were given green light. Data on awarded contracts from FieldsBase shows that Saudi Aramco has been consistent in implementing the MPP in a volatile oil price market. However, it has also been cautious in granting contracts during the most challenging times. In 2014, there were no visible offshore EPCI projects awarded by Saudi Aramco, but a year after it granted a total of six MPP EPCI campaigns, followed by five in 2016 and seven until November 2017.

Initially, OPEC stood its ground to protect its market share but then eventually decided before the end of 2016, together with participating non-OPEC producing countries, to implement production adjustments or output reduction to help restore market balance. The adjustment commenced in January 2017, and initially ran for a period of six months until it was extended for nine more months or until the end of March 2018. This has been further extended to December 2018, following re-affirmation of the OPEC and non-OPEC Declaration of Cooperation with agreed voluntary production adjustments on 30 November last year, which aided in propping up the Brent crude to above $60/bbl.

Downward pressure on day rates

The low oil price has contributed to the downward pressure on day rates of construction vessels in the Middle East region,





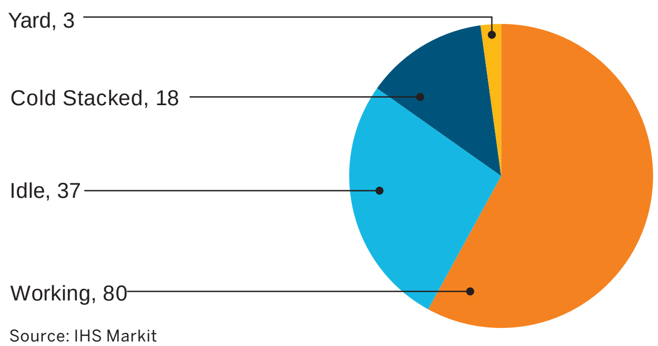
The McDermott Derrick Barge 27 and Derrick Barge 30 installing the GOSP-3 Electrical Auxiliary Platform in the Marjan oil field through dual lift configuration.
Photos from McDermott

Middle East and Caspian

Platform installation in progress. Photos from McDermott.

Oil and gas installations offshore Saudi Arabia.

Number of Construction Vessels in the Middle East in Q4 2017



Source: IHS Markit

Saudi Aramco platforms to be installed

Installation Year	Number of platforms to be installed
2018	48
2019	57
2020	11

Source: IHS Markit

which started to gradually drop in 2015, after pre-downturn ranges tried to hold out until Q4 2014. The subsequent years became a period of re-calibration for contractors and operators. Although previously awarded projects are progressing to completion, some renegotiations for existing long-term contracts, which were awarded prior to the downturn, were also carried out to reflect the current EPCI market. The 2017 Q4 ranges for construction vessels' bareboat day rates are now around half compared to 2014 ranges. Although, there seems to be a positive sentiment in the market with the oil price above $60 by the end of November, day rates are anticipated to recover likely in around eight months to a year's time or until the $60/bbl price is stably sustained or improves further.

Based on data from ConstructionVesselBase by IHS Markit, as of November 2017, there are 138 construction vessels in the Gulf, and their utilization rate stands at 57%. This is higher than the average utilization rate of 41% worldwide. The global construction vessel fleet consists of 851 vessels. In the Middle East Gulf, there are 80 units currently engaged in work programs, 55 are either idle or cold stacked while three are inshore for repair, refit or survey. Out of the total number of units carrying out campaigns, 40 are performing either platform and pipeline installation, providing saturation diving or ROV support while another 40 are engaged in accommodation support services for either ongoing offshore construction or field maintenance work.

Most of these campaigns are being carried out in Saudi Arabia and Abu Dhabi in the United Arab Emirates (UAE). Other areas of activity are located offshore Egypt in the Gulf of Suez, Qatar and Iran in the Persian Gulf. With almost half of the Gulf fleet being out of work, discussions for a potential commitment could further bring down day rates, especially for low-end vessels.

At present, FieldsBase by IHS Markit indicates that Saudi Aramco has more than 100 offshore platforms under construction, which have been awarded as part of the MPP EPCI projects that are set to be installed in 2018 -2020. These projects went to Saudi Aramco's pre-qualified LTA (long-term agreement) contractors: Dynamic Industries, Larsen & Toubro Hydrocarbon Engineering (LTHE) and its partner EMAS Chiyoda Subsea, McDermott, National Petroleum Construction Company (NPCC), and Saipem.

Under the LTA, they are qualified to bid for MPP work scopes. Several other platforms in the years ahead are also anticipated in upcoming EPCI packages, which are expected to be brought to tender as Saudi Aramco continues to carry out its MPP campaign to sustain production capacity of existing and mature fields. Platforms and pipelines are usually among the infrastructure involved in the MPP plan as well as modification and brownfield works. OE

Mirzi Moralde *is a senior analyst for Petrodata by IHS Markit based in Dubai. Moralde covers the Middle East Gulf offshore oil and gas construction market, focusing on field development activities from discovery, engineering, procurement, construction, installation and production phases.*

Halliburton launches Geometrix shaped cutters

Halliburton has released the Geometrix 4D shaped cutters, a line of four distinct geometric profiles to help improve cutting efficiency and increase control to reduce drilling costs.

"The launch of Geometrix cutters demonstrates our ability to collaborate with customers and translate knowledge into solutions that can help lower drilling costs," said Scott Regimbald, vice president of the Halliburton Drill Bits and Services business. "Each cutter is tailored for specific applications so operators now have the most complete portfolio to meet their drilling challenges."

In a recent offshore job in Mexico where an operator was drilling a limestone-shale formation, the Geometrix bit doubled the rate of penetration over a 700m section saving the operator three days of drilling time compared to offset wells.

www.halliburton.com

OOS unveils world's largest semisub crane vessel

Dutch firm OOS International Group has signed a memorandum of understanding to bring the largest semisubmersible crane vessel (SSCV) to the market.

The *OOS Zeelandia* would be ordered from China Merchants Industry Holdings, a fully owned subsidiary of Hong Kong headquartered China Merchants Group.

The basic design is already in progress. OOS describes the unit as a next-generation SSCV suitable for platform removal and installation in deep water. The 225m-long, 117m-wide platform will be equipped with two cranes, each with 12,000-tonne lifting capacity.

The dynamically positioned ICE Class 1B LNG vessel will be able to transit at up to 15.4 knots and has a low fuel consumption due to its ship shaped asymmetric design.

Dutch heavy lifter Heerema Marine Contractors is currently constructing what has been called the world's largest semisubmersible crane vessel, *Sleipnir*, in Singapore. *Sleipnir* has a two, 10,000-tonne lifting capacity and is due to come into service in 2019.

www.oosinternational.com

Subsea VSD wet tested

Work on a subsea power grid, which could support all-electric subsea process, took step forward in Finland with the successful testing of subsea variable speed drives.

A full-scale prototype of a subsea variable speed drive (VSD) developed by ABB was successfully tested in a sheltered harbor in Vaasa, Finland.

The subsea VSD, designed for subsea gas compression, was operated, over three weeks in November 2017, in a back-to-back configuration directly with the grid, without motor loads. This so-called "power-in-the loop" test, means that only a few hundred kilowatts of losses need to be supplied from the grid.

The work, which subjected the VSD to simulated harsh subsea environment, proving reliability, is part of a joint industry project (JIP) between Statoil, Total, Chevron and automation group ABB, which started in 2013.

The JIP aims to develop transmission, distribution and power conversion systems for subsea pumps and gas compressors, operating at depths of 3000m and over long distances.

By providing the large power needs closer to the reservoir, production improves due to the increased flow and pressure of the stream, says ABB.

www.abb.com

Integra ROV/AUV launched

Sydney, Australia-based UUV Aquabotix launched a second-generation hybrid underwater vehicle, the Integra autonomous underwater vehicle (AUV)/remotely operated vehicle (ROV).

The Integra AUV/ROV, available for 100 and 300m water depth, can be configured with multiple sensors and maneuvered by an intuitive platform from any web-enabled device.

The vehicle can search wide areas using AUV mode (untethered) while conducting detailed inspections using ROV mode (tethered). Users can easily switch from AUV mode to ROV mode by attaching the tether to remotely control the vehicle's six degrees of freedom of motion. When running the vehicle in autonomous operation, all mission planning is completed in a Windows-based application.

Integra has five high-torque motors, can support live remote control and data sharing, and has a configurable sensor suite (including side scan sonar, multi-beam sonar, scanning sonar, DVL, USBL, INS, Wi-Fi, Bluetooth and environmental sensors).

The sensor package includes depth, temperature, orientation and GPS. It has a 1080p true high-definition camera with pan and tilt, 5lb of payload capability, up to eight hours battery life, and high intensity LED lighting (4400 Lumens). **www.aquabotix.com**

Activity

New umbilicals facility opens in Houston

Seanamic Group firm Umbilicals International opened a new quayside manufacturing site in Channelview, Texas. The site, near the Houston Ship Channel, is home to a horizontal helix machine, extrusion line, and supporting equipment. The group says that the new facility allows them to offer typical longer-length cables and umbilicals required for subsea, umbilicals, risers and flowlines packages. The facility includes 12 neutralized positions, 1.8m bobbins (10-tonne maximum load per bobbin, 12 filler positions, three 5.5m take-up/payoffs for in process, 152mm diameter extruder, with 40mm co-extrusion for striping, and outside storage and carousel area for system integration test, load out, testing and storage.

Read more about the facility here: http://bit.ly/2zgRrq3

McDermott, CB&I to merge

McDermott International will merge with CB&I in an all-stock transaction valued at US$6 billion. Company officials say the deal would create a fully vertically integrated onshore-offshore company, with a broad engineering, procurement, construction and installation service offering. The combined company would have a complementary portfolio, uniting McDermott's established Middle East and Asia presence with CB&I's robust US operations, creating scale and diversification to better capitalize on global growth opportunities. Global market shifts due to commodity prices, geopolitics, and environmental concerns, as well as substantial growth in shale, renewables and deepwater, have bolstered customer needs for predictivity and efficiency gains wherever possible. A combined company would be better able to serve those needs, says McDermott President and CEO David Dickson. He will lead the new company. The merger is expected to close Q2 2018.

Subsea 7 invests in Airborne

Subsea 7 has agreed to make an investment in Dutch themoplastic composite pipe (TCP) manufacturer Airborne Oil & Gas (AOG). Subsea 7 joins Shell, Chevron, Saudi Aramco and Evonik as shareholders in AOG.

Manufactured out of a composite of fibers and polymers, TCP is light-weight, non-corrosive and non-permeable composite pipe. The fully bonded can handle pressures up to 15,000psi/1050 bar design pressure (and 40,000psi/2800 bar burst pressure) and temperatures up to 121°C/250°F. TCP is flexible and spoolable with continuous lengths up to 4km and higher.

Ashtead, Forum form JV

Ashtead Technology and Forum Energy Technologies have agreed to form a joint venture, creating a new provider of subsea survey and ROV equipment rental and associated services. Forum will contribute its subsea rentals business, currently trading as Forum Subsea Rentals.

The combined group, with a rental fleet of 19,000 assets valued in excess of US$139 million will service all major subsea hubs from its bases in Aberdeen, Singapore, Abu Dhabi, London and Houston.

In addition to offering the largest equipment rental capability in the sector supported by a team of 120 skilled personnel, Ashtead Technology will provide advanced engineered measurement solutions and asset management services.

The joint venture is anticipated to complete during Q1 2018. Houston based Forum Energy Technologies, owner of Forum Subsea Rentals, will retain a significant stake in the combined business.

AOG 2018 offers insight on changing Australia oil, gas sector

Oil and gas industry specialists will offer insight into the future of the Australian oil and gas sector at the 37th annual Australasian Oil & Gas Exhibition & Conference (AOG 2018), to be held 14-16 March 2018 at the Perth Convention Exhibition Centre in Western Australia.

This year's Collaboration Forum will include discussions on reliable, competitive greenfield projects, operational excellence for brownfield development, decommissioning, and the workforce of the future. The AOG Knowledge Forum aims to educate, inspire and inform bringing specialized industry sectors together to discuss the newest in techniques and technology, such as robotics and artificial intelligence, to address current and future challenges. The Society of Underwater Technology, Subsea Energy Australia and Subsea UK have joined together to sponsor AOG 2018's Subsea Forum, which will focus on how the Australia subsea industry can adjust to the changing market.

This insight will be critical as industry seeks produce Australia's oil and gas resources, more than 80% of which are in deep, remote offshore areas. Australia's oil and gas industry also faces challenges such as higher production costs and wages due to remote locations, as well as the need for new ideas, policies, practices and behaviors in oil and gas companies.

Editorial Index

INDEX

What's next

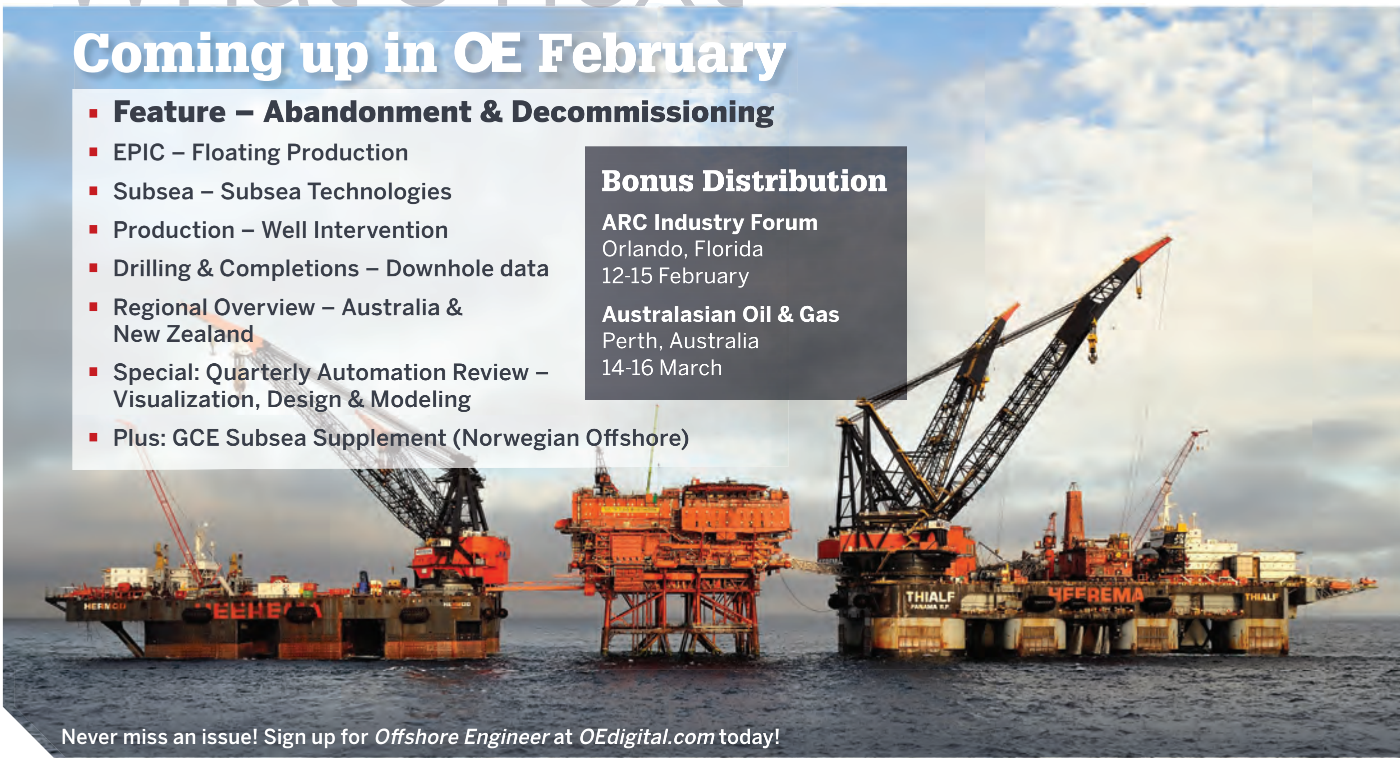
Coming up in OE February

- **Feature – Abandonment & Decommissioning**
- EPIC – Floating Production
- Subsea – Subsea Technologies
- Production – Well Intervention
- Drilling & Completions – Downhole data
- Regional Overview – Australia & New Zealand
- Special: Quarterly Automation Review – Visualization, Design & Modeling
- Plus: GCE Subsea Supplement (Norwegian Offshore)

Bonus Distribution

ARC Industry Forum
Orlando, Florida
12-15 February

Australasian Oil & Gas
Perth, Australia
14-16 March



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Heerema Marine Contractor's *Thialf* and *Hermod* performing decommissioning operations at Murchison. Photo: Jan Berghuis/Flickr

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