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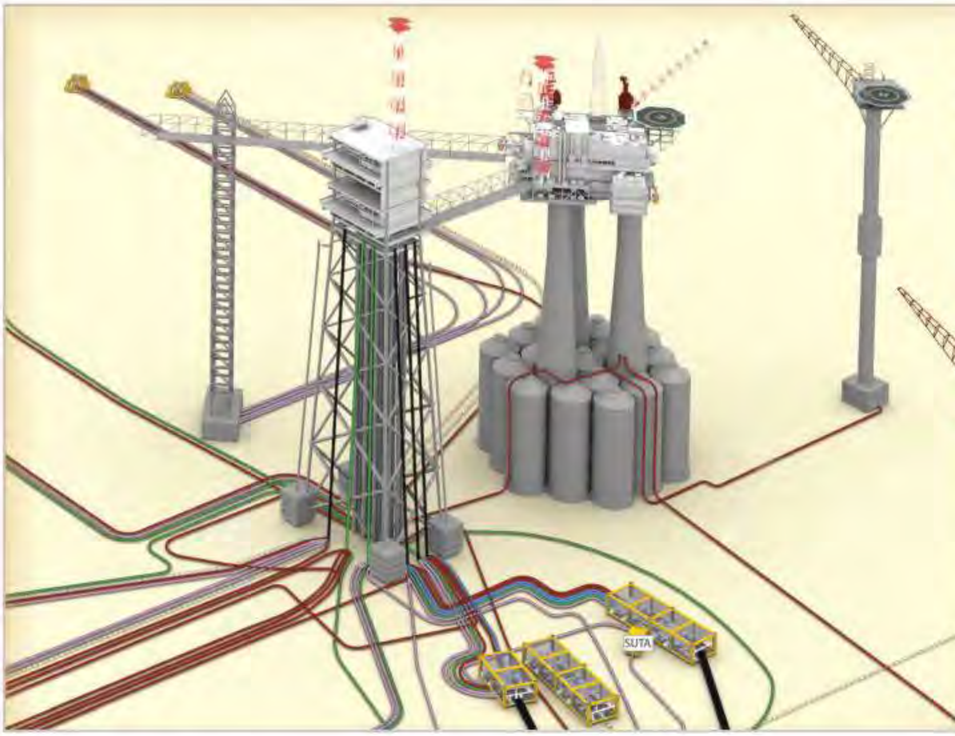

FEATURE FOCUS

Lean Oilfields

Features

ON THE COVER

Spin me 'round. This month's *OE* cover features Subsea 7's *Seven Oceans* heading out to Statoil's Aasta Hansteen field, offshore Norway. Read more about the Aasta Hansteen project on page 28. *Cover image courtesy of Subsea 7.*

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What's Trending

Big plans

- CNOOC to drill 126 wells in 2017
- Payara pays off for Exxon in Guyana
- Samsung wins Mad Dog 2 FPU

People

Shell names new CFO

Photo from Shell.

Jessica Uhl will succeed Simon Henry as Shell's CFO, effective 9 March 2017. Uhl, with Shell since 2004, will serve as an executive director and a member of its executive committee. She will be based in The Netherlands.

Activity

GE teams up with Transocean

GE Oil & Gas and Transocean signed a US$180 million contractual service agreement that will see GE provide condition-based monitoring and maintenance services for pressure control equipment on seven of Transocean's rigs over the next 10-12 years.

Photo from Transocean.

OE Expert Access Webinar with Lloyd's Register

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Undercurrents

Cautious optimism

S&P Global Platts' oil and gas outlook for 2017, published early January, painted a positive picture for the oil market – if you're in the onshore sector, that is.

While OPEC's production cut could help further the oil price recovery, all things being equal, the one spot where capital was likely to return the fastest was the US onshore shale segment, the report and others have suggested. Offshore operators – especially in the North Sea and US Gulf of Mexico – are likely to remain more cautious and will "wait and see" how the market reacts, Platts says. But, there are a few reasons for optimism.

"The US onshore, and most notably the Permian Basin, will certainly continue to receive the most attention (capex dollars) on a relative basis in the short- to medium-term, since the global supply and demand outlook remains muddied and these projects are quick and less capital intensive than their offshore counterparts," Anthony Starkey, energy analysis manager, S&P Global Platts, told *OE*. "This caution in the offshore space pertains to the Gulf of Mexico as well, as the longer term outlook for oil prices continues to be one of uncertainty... a big departure from the days of peak oil chatter not that many years ago."

He continues: "Due to their long lead times and high capital costs, offshore projects in the Gulf of Mexico will likely be pursued much more cautiously going forward, until the offshore industry gains confidence that their cost oil will be needed. That said, the offshore industry, too, is gaining efficiencies and cutting costs, with plans to incorporate well tiebacks to existing production platforms as a more cost effective way of maintaining output."

And, indeed, the industry is learning to be cost conscious and adapt to the lower oil price environment. As *OE* went to press, supermajor BP announced it had brought its Thunder Horse South Expansion project online 11 months early and US$150 million under budget. How? The firm attributed its success to using standardized equipment over "relying on customized components." It is also set to see a final investment decision made on its Mad Dog Phase II project, in the GoM, a decision that will not have been taken lightly.

OE's February issue introduces a new focus on "Lean Oilfields." Stan Bond, of Hess, wrote in a column for *OE* back in 2015 that lean is about, "transforming leadership, planning, learning and thinking. Ultimately, it's about creating value and eliminating waste." In *OE*'s January issue, we covered Hess' Stampede project, which is due online in 2018, and has been one of Hess' examples of a "lean" project. In this issue, we discuss what is being done in the UK North Sea to be leaner and more efficient (See page 18), and profile Apache's lean, fit-for-purpose FNT development in the UK North Sea (page 22).

Prelude to a rig market review

OE will present its Annual Rig Market Review in March, and as always, the industry is looking for optimism wherever it can get it. Industry advocates API (American Petroleum Institute) reported in early January that it believes the downturn is coming to an end, citing drilling statistics that show a slight increase from 2015 to 2016. The estimated total wells drilled and completed in Q4 2016 is down 8.8%, compared to Q3 2016. API said that this decrease is a drastic improvement from the same time period in 2015, which saw a 21% decrease in total wells drilled and completed.

However, according to a report from Norwegian consultancy Rystad Energy in January, the total global discovered volumes (oil and gas combined) are at their lowest since the 1940s. And even if drilling does pick up, it is unlikely to utilize the mass of rigs – uncontracted newbuilds under construction, and those sitting warm- and cold-stacked – in the market. It seems we have some catching up to do. Although, Rystad does expect activity to pick up after 2018. We'll have more to say on this in our next issue. OE

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Global E&P Briefs

A W&T hits pay at Mahogany

Houston-headquartered W&T Offshore hit oil at the SS 359 A-18 well, on the western side of the Mahogany field, 80mi off Louisiana, in Ship Shoal Blocks 349 and 359.

The well penetrated a 'T' sand interval, followed by an exploratory tail (about 950ft) into a deeper 'U' sand interval. Drilled to a total vertical depth of approximately 20,000ft, 149ft of net oil pay was logged across five zones: the target 'T' sand and four additional pay sands.

B March lease sale offers 48 million acres

The US Bureau of Ocean Energy Management (BOEM) will offer 48 million acres, offshore Louisiana, Mississippi, and Alabama, in the Central Gulf of Mexico Lease Sale 247, taking place on 22 March 2017. Sale 247 includes 9118 blocks, ranging from 3-230mi offshore, in water depths ranging from 9ft to more than 11,115ft (3m-3400m). The lease sale marks the 12th and final GoM offshore sale under the Obama Administration's Outer Continental Shelf Oil and Gas Leasing Program for 2012-2017. BOEM will live stream the results.

C Mexico delays Round 2 start

Mexican officials announced they will delay the country's next shallow water bid round, Round 2.1, until 19 June 2017, in a move that regulators hope will garner more participation, increased competition and investments. Round 2.1 was originally scheduled for March. Mexico's shallow water round consists of 15 areas in the Gulf of Mexico in Tampico-Misantla, Veracruz and Cuencas del Sureste. Mexico's deepwater round in December was considered a success with eight of 10 blocks awarded.

D Exxon's Payara pays off

ExxonMobil made a second oil discovery on the Stabroek Block, offshore Guyana, with the ultra-deepwater Payara-1 well. Drilled by the *Stena Carron* drillship to 18,080ft (5512m) in 6660ft (2030m) water depth, Payara-1 encountered more than 95ft (29m) of high-quality, oil-bearing sandstone reservoirs.

A production test is planned to further evaluate the discovery, and appraisal drilling is planned for later this year to determine its full resource potential, Exxon said. The Payara field is about 10mi (16km) northwest of the Liza discovery.

E Cobalt 'encouraged' by North Platte

Cobalt International Energy's deepwater Gulf of Mexico appraisal well, North Platte #4, encountered approximately 650ft of net oil pay. By comparison, the North Platte #3 appraisal well encountered 550ft of net oil pay. Drilled by the *Rowan Reliance* ultra-deepwater drillship, the North Platte #4 initial appraisal results indicate high quality Inboard Lower Tertiary Wilcox reservoirs on the eastern flank of the North Platte field, Cobalt said. First production at North Platte is anticipated in 2021.


Photo from Cobalt

F Hurricane spuds Halifax

UK independent explorer Hurricane Energy began drilling on its Halifax well west of Shetland on the UK Continental Shelf in mid-January. The well, drilled with the *Transocean Spitsbergen*, could help prove that the firm's Lancaster field extends further than initially expected and follows on from a successful pilot well on the Lancaster field. A previous well (205/23-2) drilled on the Halifax structure encountered oil and gas shows in sandstones immediately above the basement. In addition, Hurricane's analysis of basement cuttings from the 205/23-2 well indicated the presence of oil, mitigating the oil charge risk to Halifax.

G 56 awards in APA round

The Norwegian Petroleum Directorate (NPD) has awarded 56 new production licenses on the Norwegian Continental Shelf to 29 companies, 17 of which are operators.

Thirty-three companies applied to the Awards in Predefined Areas (APA) 2016. Of the 56 production licenses, 36 are in the North Sea, 17 in the Norwegian Sea and three are in the Barents Sea. Statoil picked up the most, with 16

operatorships, followed by Aker BP with 13.

Twelve of the production licenses are additional acreage to existing production licenses. Three of the new licenses are stratigraphically divided and only apply to levels below/above a defined stratigraphic limit.

H W. African seismic awards

Polarcus received a letter of intent for a broadband 3D marine seismic acquisition project offshore West Africa. The project is due to start in Q1 2017 and will run for approximately one month.

Seabed Geosolutions, a joint venture between Fugro and CGG, won a 4D baseline ocean bottom node project in West Africa, with a duration of six-weeks.

The project will support the optimization of the recovery rate during the development and production phases of oil and gas fields, by providing high quality data on hydrocarbon prospects, reservoir characteristics and potential geohazards.

I Spectrum starts Gabon survey

Spectrum GeoServices started the first of a series of 3D multi-client seismic acquisition programs offshore Gabon. The 3D broadband seismic will image high potential pre- and post-salt play types in under-explored areas over shallow water open blocks. Gravity and magnetic data will also be acquired in conjunction with the seismic data.

Spectrum started acquisition of the 10,000sq km Gryphon 3D survey in southern Gabon on 31 December and is expected to be completed early Q3 2017, the firm said. A further 5000sq km 3D survey over open acreage in Northern Gabon, and an additional 3000sq km 3D survey offshore Central Gabon will start during Q1 and Q2, respectively.

The new 3D seismic data is expected to start becoming available toward the end of 2017.

K Ophir prepares deepwater restart

Preparations for drilling to restart on the deepwater Ayame-1 oil exploration well offshore Ivory Coast, Africa, are at an advanced stage, says UK-listed independent Ophir Energy.

The well is expected to spud in late May and is targeting about 240 MMbbl Pmean recoverable resources, with an estimated 28%

J Stella faces new delay

First oil from Ithaca Energy's Stella field, offshore the UK, was set back to this month (February 2017), due to the results of an electrical inspection program on the *FPF-1* floating production facility. First oil was anticipated at the end of November 2016, and was pushed back to January 2017.

As *OE* goes to press, preparation for start-up of the Stella field was well-advanced, with only completion of fault remediation works on the *FPF-1*'s electrical junction boxes outstanding, although challenging offshore weather conditions were impacting the pace of activities on the vessel at times. Stella is in Blocks 29/10a and 30/6a under license 011. Ithaca's partners are Dyas (25.34% interest) and Petrofac (20%), with Ithaca holding the remaining 54.66%. First oil on the field will see Ithaca's production more than double to 20-25,000 boe/d and unit operating costs drop to under US$20/boe.

Photo from Ithaca Energy

Global E&P Briefs

chance of commercial success. Ophir has a 45% operated interest in the license.

L Eni spuds Libyan well

Eni has spudded an exploration well in Contract Area D offshore Libya, according to Libya National Oil Corp. The well, B1-16/3, will be drilled in 518ft (156m) water depth and it is about 140km northwest of Tripoli and 5km north of the Bahr Essalam gas field.

The estimated total depth of this well is 9865ft. The main objective of this well is to test the Metlaoui group reservoir and the drilling is expected to be completed in 64 days.

M Inpex extends UAE agreements

Japan's Inpex and Abu Dhabi National Oil Co. have agreed to extend the joint development of the Satah and Umm Al Dalkh oil fields, offshore Abu Dhabi in the United Arab Emirates.

Inpex will be granted an additional 28% participating interest in the Umm Al Dalkh oil field, bringing its total participating interest in the field to 40%. The Satah and Umm Al Dalkh oil fields are operated by Zakum Development Co. The fields are producing about 20,000 b/d and 15,000 b/d, respectively.

Inpex holds a 40% participating interest in the Satah oil field and a 12% participating interest in the Umm Al Dalkh oil field. The current joint development agreements for the Satah and Umm Al Dalkh oil fields are scheduled to expire on 8 March 2018.

N CNOOC unveils 2017 strategy

CNOOC's 2017 strategy includes bringing five projects online, and drilling 126 new wells, with a capex that could reach $10 billion.

Two, of the five, projects have started production in the Pearl River Mouth Basin in the South China Sea: Penglai 19-9, and Enping 23-1 in January. The Penglai 19-9 adjustment project is expected to reach its designed peak production of about 13,000 b/d in 2019. At Enping 23-1 there are currently three wells producing approximately 5600 b/d. The project is expected to reach its designed peak production of approximately 24,800 b/d in 2018. The fields have an average 90m water depth.

O Maari resumes production

The Maari oil-field, 80km off Taranaki, in about 100m water depth, is progressively resuming production, says operator OMV New Zealand.

Production stopped in November last year as a precaution, following discovery of a crack in one of the wellhead platform's 12 horizontal struts during a scheduled inspection.

As an intermediate solution, devised by specialist advisors AMOG, three clamps were installed in December by air divers to secured the damaged strut on level-3, about 4m below the waterline and verified by Lloyds, both during the design phase and post-installation.

Two options for a permanent solution are currently being investigated by AMOG and Worley Parsons. This work is expected to be completed this month and a preferred concept selected. The subsequent permanent repair will likely be completed by mid-2017.

P Carnarvon survey reprocessing begins

Searcher Seismic and partner CGG have started the PSDM reprocessing of about 1668sq km of 3D seismic data in the Carnarvon Basin, Western Australia.

The project comprises broadband PSDM reprocessing of the Western portion of the existing Foxhound 3D Seismic Survey, and includes coverage to the 2016 Australian Acreage Release.

The survey is split into two portions; the Western cube which lies northeast and on trend to the Chandon, Martell and Io/Jansz fields, and the Eastern portion which lies North-Northeast and on trend to the Pluto and Wheatstone fields.

Contracts

Aramco hands out EPCI work

Saudi Aramco has awarded engineering, procurement, construction and installation (EPCI) contracts to multiple companies for work offshore Saudi Arabia.

McDermott International will handle the fast-track project consisting of four jackets and three gas observation platforms. The total weight of all structures combined is 11,595-ton.

L&T Hydrocarbon Engineering, in consortium with EMAS Chiyoda Subsea, has won two EPCI contracts. One is for the supply and installation of four wellhead decks at the Safaniya field, and another is for the upgrade of 17 platforms in the Arabian Sea.

OneSubsea inks Utgard EPC

Statoil awarded OneSubsea an engineering, procurement and construction contract to supply the subsea production system for the Utgard gas and condensate discovery in the North Sea.

The scope includes a subsea template manifold system, two subsea wellheads and vertical monobore subsea trees, production control system, and associated intervention and workover tooling. This follows the execution of a master service agreement with Statoil in January 2016.

Atkins wins Chevron UK work

Chevron North Sea awarded Atkins a three-year framework contract for structural integrity services across selected fixed and floating platforms in the UK North Sea.

The contract covers assets including the Alba Northern platform and topsides of the Alba floating storage unit (the first to be purpose-built for the UK North Sea); the topsides of the Captain floating production, storage and offloading vessel, as well as the wellhead protector platform and bridge linked platform on the Captain field, and the Erskine platform.

Fugro bags Ichthys subsea IRM contract

Inpex awarded Fugro a five-year subsea inspection, repair and maintenance (IRM) services contract for the Ichthys project in the Timor Sea. Ichthys is about 220km from the coast of Western Australia. The contract encompasses field operations support, and IRM services, and will run for five years with options to extend. ▪


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ANALYSIS

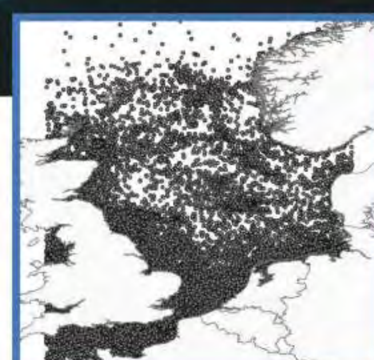
In-Depth

Plenty of fish in the sea?

North Sea decommissioning is finally happening and it means some difficult questions are starting to be asked about what should be left behind and what might benefit sea life. Elaine Maslin explores the details.

After, in some cases more than 40 years of service in the cold harsh waters of the North Sea, oil and gas production facilities are starting to be shut-in and removed.

But, while the rules effectively state everything needs to be removed from the sea, with the option to leave certain structures in place, more and more people within and outside the industry believe that removing the rest of them might not be the best thing to do.



Left: European Conger *(Conger conger)* in a structure at the seabed at Hurricane Energy's Whirlwind well at 180m depth west of Shetland. Photo from A.Gates, SERPENT Project in collaboration with Hurricane Energy. **Right: A map of mapped wreck sites in the North Sea.** Photo from Wrecks.eu.

Tom Baxter, senior lecturer in chemical engineering, at the University of Aberdeen, for example, says, while the need for plugging and abandonment is not in dispute, some suggest that removal activities will cause more damage than good. He says that this indicates that, "at the very least, the environmental case for decommissioning is not compelling," especially as UK taxpayer cash will help fund a sizeable proportion of the cost of removal and remediation.

Others make a more philosophical case. Based on the leaving behind a "clean seabed" ethos, and given there's been 50 years of exploration and production activity, "What is the North Sea's pristine condition? How do we get it back to that state? And would that really be the best thing to do," asked three University of Aberdeen professors in a joint article, published late 2016.

Being a largely sand and mud-bottom basin, manmade structures, such as platforms and substructures (1300 of them across Europe, plus about 1800 and increasing number of wind turbines, thousands of buoys and some 25,000 recorded wrecks on the seafloor*), offer scant havens for some species that like hard things to cling on to, it is suggested.

The problem is, there's been little by way of robust scientific evidence to show if these structures, often originally put in place without much thought towards how they would be removed, benefit – or otherwise – marine life.

That's changing. As well as Engie E&P's proposal to leave in place two small southern North Sea jackets, there is a significant research program underway involving scientists and researchers from across the UK. The Insite Program is seeking to assess the impact of manmade structures – platforms and windfarms – on marine life, both individually but also as a

Shoal of Pollock ***(Pollachius pollachius)*** **around the BOP at Hurricane Energy's Lancaster well at 150m water depth west of Shetland.** Photo from A.Gates, SERPENT Project in collaboration with Hurricane Energy.

network, i.e. as stepping stones for marine life.

It is sponsored by eight oil companies, but their cash is given to research projects through an Independent Scientific Advisory Board (ISAB), which also manages the research objectives and encourages the researchers to publish their findings. The research projects formally started in Q4 2015 and will run until Q4 this year.

Three of the projects are about quantifying the effects, two are about connectivity and three address both. The projects, while independent, are being run to create a coherent package. Some of the initial work was presented at an event – the Insite Science Day at Imperial College London – attended by staff from the likes of Shell, Chevron, Repsol, and Eni, late 2016.

While it's too early into the project to give any conclusive results, the work will help lay the ground work for a better understanding in this area.

The Coupled Spatial Modeling (COSM) project, for one, will help build a modeling tool that could be used to assess sites. Chris Lynam, who works at the Centre for Environment, Fisheries and Aquaculture Science (CEFAS), says that the tool will model the consequences of existing manmade structures on the "food web" and biomass. The project involves collecting a lot of data about what benthic groups (flora and fauna on the seabed), fish groups and even plankton exist and where, including bathymetry, depth, salinity, etc. Seabird and mammal movements are also due to be added into the model, including where they travel and forage.

"The North Sea is mostly sand, then mud beds," Lynam

Cod *(Gadun morhua)* and a sea urchin on a protective structure at Hurricane Energy's Lancaster well at 150m water depth west of Shetland. Photo from A.Gates, SERPENT Project in collaboration with Hurricane Energy.

In-Depth

ANALYSIS

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	2014	2015	2016	2017
Shallow (<500m)	77	57	24	0
Deep (500-1500m)	32	20	9	0
Ultradeep (>1500m)	13	12	6	0
Total	122	89	39	**0**
January 2016	127	114	72	-
date comparison	-5	-25	-33	-

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

Reserves in the Golden Triangle

by water depth 2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	14	350.00	2649.00
Deep	15	1249.00	2835.00
Ultradeep	35	10,783.00	12,756.00
United States			
Shallow	9	39.00	85.00
Deep	19	1150.00	1562.00
Ultradeep	15	2515.00	2520.00
West Africa			
Shallow	125	4066.00	17,404.00
Deep	31	3310.00	4400.00
Ultradeep	13	1761.00	2518.00
Total	262	**24,873.00**	**44,080.00**
(last month)	(260)	(24,455.00)	(43,050.00)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	967	37,600.00	355,948.00
(last month)	(951)	35,765.00)	(323,176.00)
Deep	149	7992.00	107,871.00
(last month)	(146)	(7647.00)	(107,641.00)
Ultradeep	76	16,274.00	49,457.00
(last month)	(74)	(16,184.00)	(46,491.00)
Total	1,192	61,866.00	**513,276.00**

Pipelines

(operational and 2016 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,715	(41,040)
Planned/ possible	22,641	(23,302)
	64,356	(64,341)
8-16in.		
Operational/ installed	82,214	(81,476)
Planned/ possible	47,977	(49,065)
	130,191	(130,542)
>16in.		
Operational/ installed	94,913	(94,263)
Planned/ possible	44,494	(44,991)
	139,407	(139,254)

Production systems worldwide

(operational and 2016 onwards)

Floaters		(last month)
Operational	304	(298)
Construction/ Conversion	45	(45)
Planned/possible	293	(295)
	642	(638)
Fixed platforms		
Operational	9116	(9105)
Construction/ Conversion	67	(72)
Planned/possible	1359	(1372)
	10,542	(10,549)
Subsea wells		
Operational	4992	(4879)
Develop	352	(374)
Planned/possible	6357	(6425)
	11,701	(11,678)

Global offshore reserves (mmboe) onstream by water depth

	2015	2016	2017	2018	2019	2020	2021
Shallow	21,262.92	32,739.24	34,476.01	11,652.79	16,382.52	19,091.67	18,710.62
(last month)	(21,242.45)	(41,358.83)	(26,780.31)	(11,369.67)	(16,406.33)	(19,157.60)	(18,986.97)
Deep	972.99	1459.11	5426.11	2670.98	3422.64	5395.94	10,025.41
(last month)	(972.99)	(1819.37)	(5356.21)	(2556.20)	(4120.72)	(4561.99)	(10,025.41)
Ultradeep	2342.82	2023.19	3100.10	1767.31	3685.74	4362.19	9972.56
(last month)	(2023.19)	(3100.10)	(1767.31)	(3685.74)	(4362.19)	(9359.68)	(5206.35)
Total	21,377.69	24,259.10	**37,298.45**	**41,669.43**	**18,009.51**	**24,167.35**	**34,460.17**

Source: InfieldRigs 6 Jan 2017

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	96	64	32	66%
Jackup	402	229	173	56%
Semisub	117	64	53	54%
Tenders	28	19	9	67%
Total	643	376	267	58%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	30	25	5	83%
Jackup	25	5	20	20%
Semisub	10	7	3	70%
Tenders	N/A	N/A	N/A	N/A
Total	65	37	28	56%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	11	4	7	36%
Jackup	117	66	51	56%
Semisub	32	12	20	37%
Tenders	20	13	7	65%
Total	180	95	85	52%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	23	18	5	78%
Jackup	50	29	21	58%
Semisub	22	16	6	72%
Tenders	2	1	1	50%
Total	97	64	33	65%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	49	30	19	61%
Semisub	38	22	16	57%
Tenders	N/A	N/A	N/A	N/A
Total	88	52	36	59%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	2	1	1	50%
Jackup	119	84	35	70%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	125	88	37	70%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	17	12	5	70%
Jackup	20	7	13	35%
Semisub	4	2	2	50%
Tenders	6	5	1	83%
Total	47	26	21	55%

Eastern Europe

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

Source: InfieldRigs 11 Jan 2017

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

Piles on a research platform, 30km offshore Germany, in 30m water depth. One shows the upper part (0-10m depth) of the platform with blue mussels, amphipods and common starfish.

points out. "There is not a lot of rocky substrate. Manmade structures could be the main substrate out there. An interesting thing is comparing the other manmade structures (such as shipwrecks, many being wooden) to oil structures. There are an awful lot of things going on we need to consider and perhaps more than we anticipated."

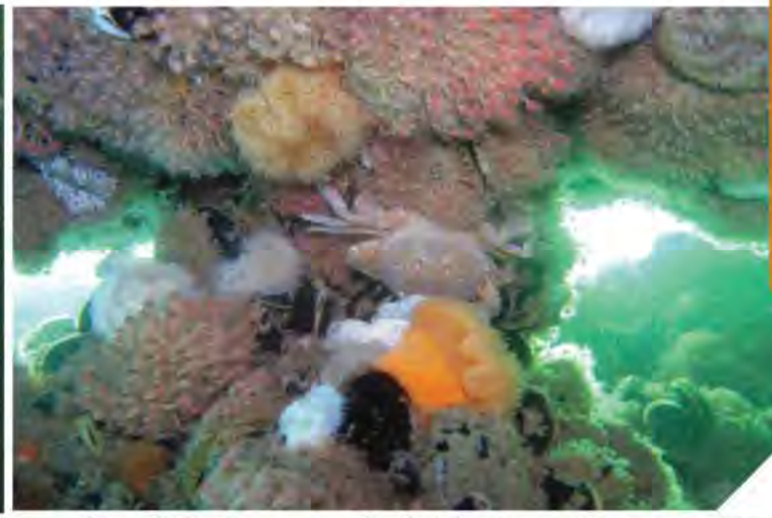
Prof. Murray Roberts, from the University of Edinburgh, is working on a project called ANChor (Appraisal of Network Connectivity between North Sea oil and gas platforms) in collaboration with Heriot-Watt University, University of Liverpool and BMT Cordah. The idea is to see if platforms connect species and ecosystems across the North Sea. It is doing this by looking at larva from various species which live around platforms and then simulating where they could travel to and what would happen if the nodes (platforms) that they travel to were removed.

The work means creating a GIS database of platform-based marine growth data – i.e. what and how many creatures live on offshore platforms. Instead of collecting data from all 487 installations, they've got data from 57 (15 in the northern North Sea, 10 in the central North Sea and 32 in the southern basin). They've also drawn on industry ROV surveys dating from 1981 to 2015, as well as other published data. As expected, species like deepwater corals are more likely to appear on the deeper water platforms in the northern sector.

Work to create larvae dispersal simulations in a 3D, 1.8km horizontal resolution model is ongoing, but studies have already shown they could travel hundreds of kilometers in just over a month. While it's early days, and the influence of pipeline infrastructure on connectivity hasn't yet been included, "it's suggesting to us there is some pretty good connection between some of these structures," Roberts says. "The platforms do have a very important role and I think this work will be fundamental in other projects. We might consider that organisms on platforms might have value in their own right. Could they be used to help restore other areas?"

Kieran Hyder, also from CEFAS, is also looking at connectivity, specifically between areas of hard substrate, such as platforms and wrecks. As well as tracking larvae, they'll look at how shipping movements could influence the marine life movement. Hyder says that what the structure is made of, i.e. concrete, steel or fiberglass, and how it is managed – i.e. if the legs are regularly cleaned – will also have an impact on

The second shows fish that tend to accumulate around hard substrate.
Photos from Jennifer Dannheim, AWI.



Piles with fouling community that develops on the deeper part of structures, such as anemones, other cnidaria and blue mussels.
Photo from Roland Krone, AWI.

whether marine life is supported.

Historic data is also used to see what the impact has already been. A long running project, called Signal, is drawing on data from a continuous plankton recorder survey, which has been running for 60 years, and offers a reference case for before oil platforms were installed. The project currently has its plankton recorder devices dangling off the back of 32 ships of opportunity, covering some 12,000km a month.

"There is evidence of a large scale move north of the zooplankton community," says Willie Wilson, of the Sir Alister Hardy Foundation for Ocean Science (named after the man who started the plankton survey). "This has a knock-on effect for commercial fisheries," he suggests. A cold water species like cod have fallen in numbers while a warm water less nutritious species have started to dominate, since 1985, he says. The question is, has this been caused by manmade structures? It could actually be more to do with the sea surface temperature, which has been warming and – in the last few years – starting to cool again and cold water species increase, while the number of manmade structures hasn't fallen. More research needs to be done.

Also, just because there is more marine life, thanks to the platforms' existence, is it good? Or could it promote invasive species? Under the Reefing Effects of structures in the North Sea: Islands or networks (RECON) project, Joop Coolen, Wageningen Marine Research, is researching what grows where in order to predict what will grow in certain locations – depending on various factors including temperature, depth, current velocity and salinity, and to see if different locations can be connected. He's been out taking samples from platforms offshore the Netherlands (with permission) using a kind of subsea hoover, with plans to do the same off Norway and Denmark next, to map species distribution. "With this data we can try to predict what might populate a platform," and looking at what are invasive and what are native species.

Jennifer Dannheim, from the German-based Alfred-Wegener Institut (AWI), is looking at a similar issue – the impact of structures in soft sediment areas. "When you introduce a structure in to a soft bottom [environment] it is really a different habitat, so there's a fundamental difference in fauna between these habitats," she says.

It's a highly complex environment and there are more related Insite Program projects running than *OE* can outline here. Some appear to duplicate certain work, but this will improve the robustness of the results, says Prof. John Shephard, who sits on the ISAB board. The impact on the fisheries will be a further important topic, especially given the fisheries were long active before the oil industry came to town and will be active for a long time after it's gone.

And, at this stage the research is more about gathering and understanding data. Coolen says that the work would be helped if operators gave more access to structures, even if it is just ROV footage, to help species mapping, a call repeated by Shepherd. Indeed, at the event, CNR International's Roy Aspden offered to allow access to the Murchison jacket as it is removed, to aid the researcher's work. Researchers and scientists will also be given access to the platforms Engie plans to leave in place, which will further aid their work. The work in the Netherlands might even help government efforts there to reintroduce the flat oyster, a species which once proliferated in their sector of the North Sea, but has since disappeared.

"We have a complicated issue that we don't really understand," Shepherd says. "The scope of work that is being done [under Insite], from larval behavior to the net benefit of a rig being there is important, because we don't yet know where in this whole complex picture the important factors are going to be. We can be confident that there is no simple answer to the question 'is rigs to reef a good thing to do?' There will be positives and negatives and we will have to work out what the overall net effect is."

In all likelihood, the result will be judged on a case-by-case basis, taking into consideration the wider ecosystem, with the help of the knowledge created by the Insite Program. **OE**

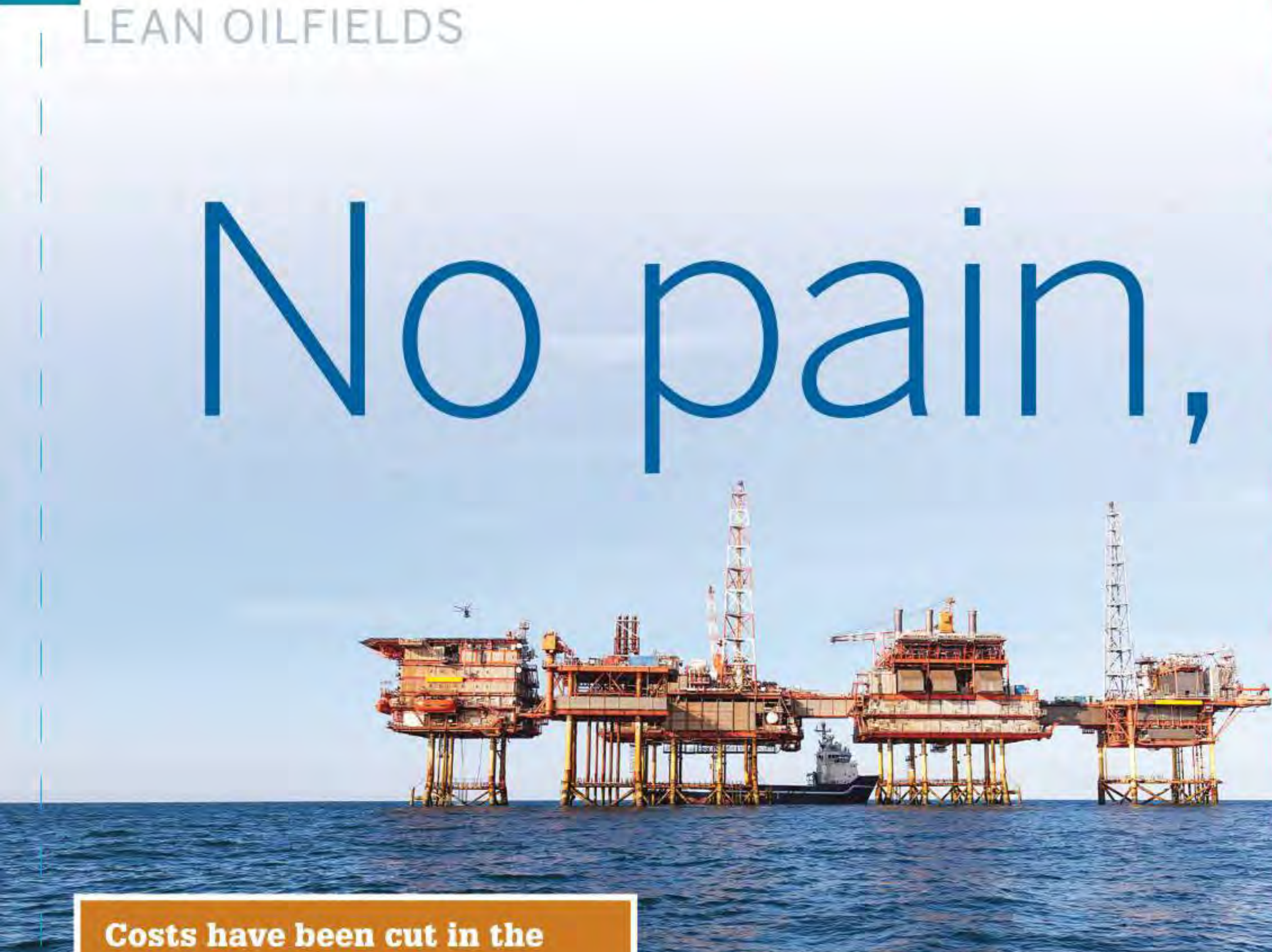
To find out more about the Insite Program and to view the Insite Science Day presentations, please visit: www.insitenorthsea.org.

**According to Joop Coolen, Wageningen Marine Research.*

FURTHER **READING**

Check out OE's December 2016 decommissioning issue, which includes coverage of the latest vessels, Opsar regulations in Europe, the Murchison field decommissioning project, and Engie E&P's proposed pilot rigs to reefs project in the Dutch North Sea. **http://bit.ly/2jhyjSx**

No pain,



Costs have been cut in the industry, but has it been enough? Elaine Maslin looks at ongoing initiatives in the UK North Sea.

The past two years of pain for the oil and gas industry is well known, but, there are some signs that the pain is starting to pay off.

While oil was US$30/bbl at the start of 2015, and has seen little movement over $50/bbl since, the prolonged downturn has forced the industry to look for long-term ways to reduce its costs – compared to earlier in the decade, when the rising oil price seemed to cover those rising costs.

In the UK North Sea, an efficiency drive, as well as some new production coming online, has helped an anticipated 45% fall in unit costs from their peak of $29.30/bbl in 2014 to $16/bbl this year. According to Wood Mackenzie's Global Upstream Cost Survey, operating costs fell 13-19% and capital spending costs fell 16-21%, between 2015-2016, with an overall 17% cost reduction.

Project costs have been reduced, both those reaching final investment decision and those in mid-development. Maersk Oil's high-pressure, high-temperature Culzean project in the UK North Sea has seen a $500 million cost cut, taking it to a $4 billion project. Premier Oil's Catcher floating production project in the North Sea is on schedule for startup later this year with a 29% reduced capital budget compared to when it was sanctioned, at $1.6 billion. Last August, Statoil's CEO Eldar Sætre stated that having had average $70/bbl capex in 2013, some 80% of the firm's project portfolio now stood at $45/bbl and that was dropping to below $40/bbl.

Unsurprisingly, given the oversupply of rigs, the largest drop in cost has been in rigs and drilling, at 23%. This has helped many projects, as well as operators managing to optimize drainage plans, so that there are fewer wells. The next biggest drop in cost has been in subsea equipment and services, at 21%; next, logistics and support, an area which has seen firms collaborating and sharing services, i.e. helicopter services. Perhaps reassuringly, operations and maintenance saw the lowest drop in costs, at 13%.

But, who is doing the cutting and how sustainable is it? According to Wood Mackenzie's survey, the perception of how much cost has been taken out differs according to whom you

no gain


Photo from iStock

speak: the supply chain thinking it's about 24%, but operators thinking it to be less. Looking forward, operators also think there are still more savings to be had, at about 7%. But, the supply chain thinks there's only about 3% more to be had. Indeed, in seismic and logistics, the supply chain thinks costs will now remain flat or even increase in 2017.

"When you talk to people in the supply chain they say, 'we are hanging on,'" says Andy Tidey, global head of performance improvement, at Wood Mackenzie. "We are hearing that the supply chain is finding it very hard to get operators to work in a different way."

Contract renegotiations and re-tendering only goes so far and may not be sustainable for the industry longer term, Wood Mackenzie warns. Indeed, the respondents themselves, who said contract renegotiations would continue to be one of the ways to reduce costs, agreed that less than half of the cost reductions made were likely to be sustainable.

Tidey suggests that the industry could benefit from taking a look at how it operates. Every operator has a different set of project management tools to which suppliers must become accustomed. "But, while it is not glamorous, if you had one standard set of documentation, that could realize a big impact," he says.

Indeed, a range of efficiency-related initiatives are being driven across the industry, including standardization. Oil & Gas UK is behind a number of projects under its Efficiency Task Force (ETF). A lot of the work falls under two headings, business processes and standardization. Under business processes comes maintenance, inventory management, logistics, compression systems and procurement; while, under standardization, subsea technology and valves are the main areas of focus.

Part of this work has led to the ETF Industry Behaviours Charter – a commitment to work effectively, efficiently and cooperatively – for which several players have signed up. Other examples of collective commitment include rising numbers of companies signing up for the Commercial Code of Practice, designed to reduce complexity in legal and commercial practices on the UK Continental Shelf (UKCS).

Tangible projects include an inventory rationalization project, which hopes to create a tool for companies to share a central digital pool of resources allowing them to reduce individual stock holdings and costs associated with storage and maintenance. A pilot program has been run, working with Ampelius Trading, and now lessons learned are being used to take it to a next phase, which is still under development.

Being more lean is also about reducing downtime. Compression system outages – the biggest cause of unplanned maintenance on the UKCS, accounting for least 20 MMboe each year in production losses – has been a key focus. Those operators responsible for the bulk of compression system outages on the UKCS have been working together to identify how to reduce the number and duration of these outages.

An industry survey and root cause analysis was carried out, followed by a workshop in May 2016 to determine what the key issues were. Some 75% of losses were found to be from just four sources: lube and seal systems, fluid conditioning, compressor power and drives, and the compressor unit itself. The main root causes for these issues were found to be operating practices [i.e. lack of or poor] (57%), poor maintenance (14%), stress corrosion cracking (13%), design, modifications and upgrades not to original designs (13%). Up until now, few of these issues – and the solutions to them – were shared. Good practice guidelines were due to be published as *OE* went to press (January 2017).

Another work group, formed to look at maintenance and

Culzean platform jacket sets sail for the UK. Photo from Maersk Oil

asset integrity to share experiences and learnings, has developed and published a document, "Maintenance Optimisation Reviews - Sharing Experience and Learning."

As it works towards first oil from the UK North Sea Mariner field, operator Statoil is working with other operators in the area – BP, TAQA, EnQuest, Maersk, and Apache – on how to optimize helicopter and freight movements, including looking at potential software development.

As in Norway, the potential for simplifying and standardizing subsea technology is also being reviewed. Some 70 people from 30 different companies, from operators to design consultants and manufacturers, analyzed potential cost savings by carrying out projects to existing industry standards rather than bespoke requirements and found savings of up to 30% were possible.

Good practice guidelines were drawn up and four case studies were worked up, looking at different scenarios (an FPSO [floating production, storage and offloading] riser system, subsea manifold and bundle, and two subsea tiebacks), with 18-28% savings identified. Cost were cut through efficiencies around field layout, umbilical optimization, and standard controls, as well as other areas. The case studies are available via the ETF section on Oil & Gas UK's website.

Valves have also come under scrutiny. Engineering and procurement of new valves accounts for 10% of operating and capex costs in a typical operating installation, according to Oil & Gas UK. Due to a tendency to over specify and a notorious diversity of specifications, re-use and sharing rates for valves are low. A strawman project was undertaken that found potential for a 30% saving in costs, if valve repairing and sharing could be made more common practice. Work to develop a standard process has started, which is due to be shared across the industry when completed.

But, Wood Mackenzie's surveys suggests the top three approaches towards cost reduction expected in 2017 are expected to be the same as last year's: retendering new contracts, renegotiating existing contracts, and deferring or canceling projects, a view shared by operators and the supply chain.

The tendering process itself is under review from another industry efficiency initiative, with a set of guidelines produced and published last year. According to Oil & Gas UK, analysis of previous tenders from four contractors was carried out and identified a potential saving of $30.5 million (£25 million), or 12-15%, on the cost of industry tender response development.

"Despite the messages from the top of many operators and great examples of innovative and collaborative ways of working, the practitioners we surveyed still placed significant emphasis on what are essentially tactical measures," Tidey says.

Such measures are not long-term, warns Wood Mackenzie. "Achieving sustainable cost reductions requires a concerted focus on the cost agenda and a willingness to make fundamental changes to ways of working, both within a business and with its supply chain," Tidey says.

So, why is it so hard for companies to make sustainable cost reductions? For the most part, the focus falls on business structures and cultures, Wood Mackenzie says.

"Many businesses lack the detailed financial, operational and headcount data to really understand where to target cost reductions and operational changes needed to deliver results," the firm says.

"There is a cultural element in the industry. People think about capex and how long to peak production. Opex is over 15 years, but irrelevant. It's fine if you're looking at just a project, but not a business," Tidey says. Indeed, to address cultural challenges in the upstream business, some firms are moving downstream execs across, he says.

Wood Mackenzie says that cost efficiency should be hardwired into performance management, driven from the top and reinforced with clear KPIs (key performance indicators), targets and incentives. Operators should work together across basins more, and not just sharing helicopters or supply vessels. This could be on enhanced/improved oil recovery, drilling rigs and infrastructure for stranded gas.

Procurement and supply chain optimization should also be looked at across the asset life cycle, Wood Mackenzie says. While a lot has been said on this front, more needs to be done, according to the firm. Finally, cost reduction programs should be risk assessed, it adds, so that individual initiatives and the whole program are understood. **OE**

Cutting **completion costs**

The UK North Sea has an industry target to cut well completion costs by 50%. Elaine Maslin reports.

Looking up through a derrick. Photo from BP.

Well construction accounts for 30%-50% of capex on the UK Continental Shelf (UKCS) and costs have escalated in recent years, contributing to low drilling activity. According to industry body Oil & Gas UK, since 2004, well construction costs quintupled, and rigs costs doubled (although the current economic climate is having some impact on this). Wells are also taking twice as long to drill.

BP found that since 2003-2005 mud, chemicals – and engineering support around those – directional drilling, measurement while drilling, and logging while drilling services had all doubled or quadrupled. In addition, costs associated with cement, additives and related engineering support had doubled and tripled. Wellhead maintenance increased by 2-4x, mud logging and wellsite geophysics by 2-3x, logistics by 3-5x, diving and remotely operated vehicle services by 2-3x.

The result? There were an average of 51 appraisal wells per year from 2006-2010, and just 24 per year from 2011-2015, Oil & Gas UK says. While that is a concern for driller's revenues, the bigger concern is the future health of the industry – no drilling, no new production.

Katy Heidenreich, operations optimization manager, Oil & Gas UK, says that the cost increases are due to a number of factors, including rig- and service rate escalation, reduced operational efficiency, tightening industry standards, additional complexity to access smaller reserves, and erosion of experience levels. Furthermore, competition within the market has traditionally prevented sharing between operators.

BP's approach, set out at Oil & Gas UK's Share Fair in Aberdeen last year, is to use a minimum technical approach from the start to "explicitly justify design choices." BP's approach also includes, "rigorously assessing what [the company] really needs to purchase and rent for equipment and services to execute the design, keeping detailed information on spend and progress towards the 50% reduction target from a 2015 baseline (and) making progress on our aspiration of top quartile delivery on all [BP's] wells."

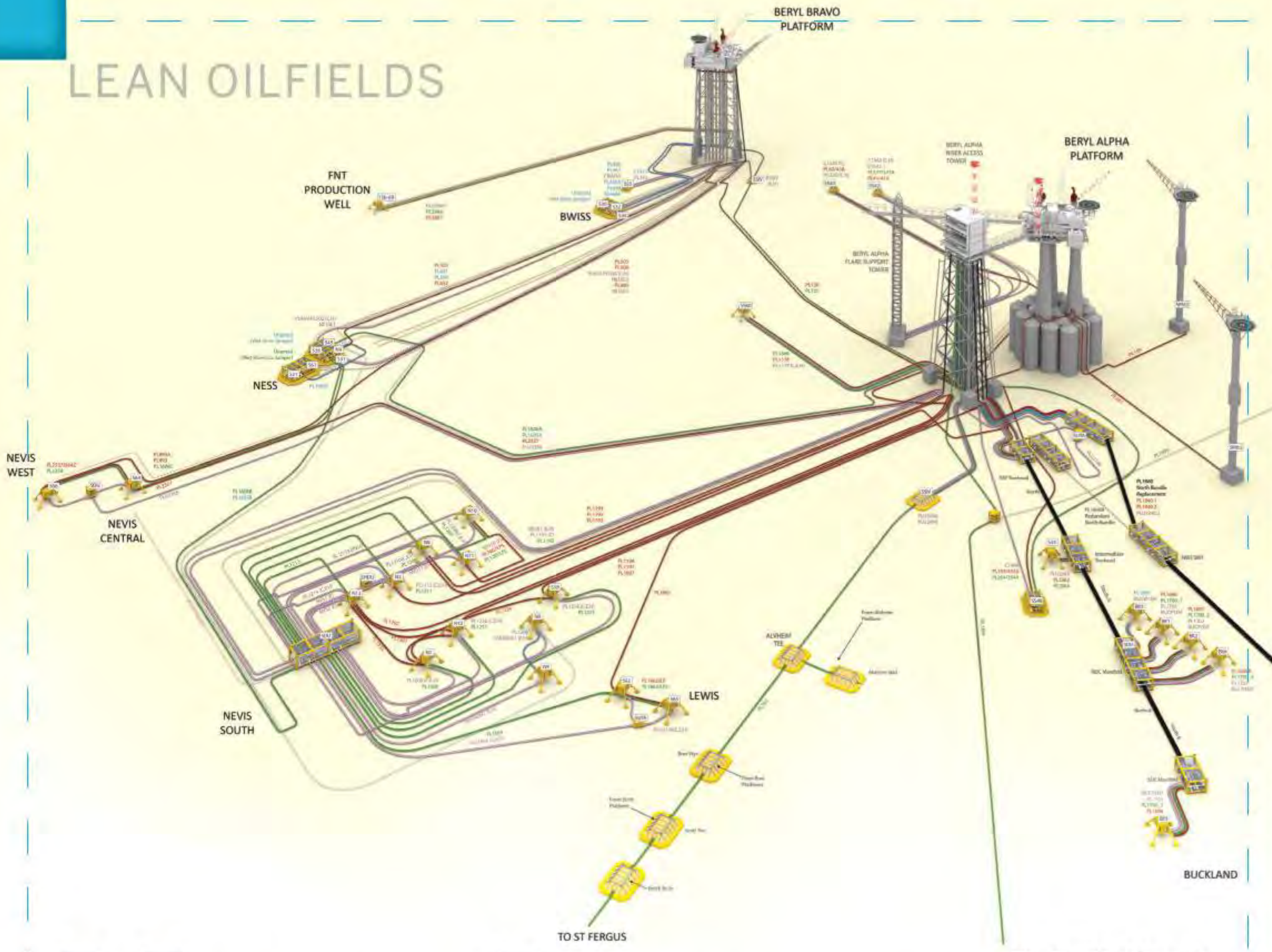
Work is underway to address these challenges through a Well Cost Reduction Initiative, set up (through Oil & Gas UK's Wells Forum) with operators, contractors and project management firms – on board. It aims to cut well construction costs by 50% and push exploration drilling rates back on an upward curve, unlocking new areas, but also helping to extend the life of existing assets. The initiative promotes well design and equipment simplification and standardization, and encourages better sharing of information and good practices.

Further work is underway aimed at reducing well construction costs, under the MER UK Technology Leadership Board, which includes studying which technologies can help drive construction efficiencies and improve well productivity.

So far, the initiative has two focus areas. The first has seen cross-industry peer reviews of wells planned for the end of 2016 and early 2017. This saw 10 operators peer reviewing well and completion designs. Workshops found areas for improvement around standardized and simplified designs, encouraging broader uptake of technology, reduced operational uncertainty through better planning, and shortened rig use. The second area is around reducing drilling time, by sharing improvements made. Eleven operators and contractors are supporting this work, which will lead to updated guidelines.

"We recognize that on an individual basis companies are running their own performance improvement initiatives and have already achieved significant cost reductions," Heidenreich says. "However, there is an even greater prize to be achieved through cooperative industry efforts and, most importantly, that operators, rig contractors and service providers work together to lock in efficiency measures, and continue to share good practices and expertise. This is the most effective way to establish a new, lower and sustainable benchmark for cost effective well operations on the UKCS."

There's a prize to be had if these initiatives work. Oil & Gas UK estimates that a 50% reduction in core well construction costs, could unlock more than 5 billion boe of known reserve potential over the next decade. To put it another way, the amount of money that could be saved could pay for 40 additional wells at today's estimated cost. **OE**



The Beryl field layout.

New lease on Beryl

Apache's FNT development may appear a bit "vanilla" on the surface, but a fit-for-purpose and fast-to-first-oil ethos under the Apache Projects Group Mission Command management system meant the difference between production and stranded reserves. Elaine Maslin reports.

Stranded pools are an endemic issue on the UK Continental Shelf (UKCS). Resources are left untapped because they're either too small or too challenging to tap.

Apache's Far North Triassic (FNT) project could have befallen such a fate, but by fast-tracking the project and keeping costs down – lean is an Apache North Sea mantra – it was brought online economically and just 11 months after the project team got their hands on it.

FNT is effectively an infill well in the Beryl field, which Apache bought from ExxonMobil in late 2011. After years without any new seismic data acquisition in the Beryl area, Apache shot new seismic and set about finding previously untapped resources, such as FNT.

The resource was originally drilled from the Beryl Bravo platform, with the plan being to produce it via a platform well. But, geographically difficult hole conditions, in what was a 22,000ft-long well, meant the firm had to re-think its plans.

"The Projects Group was challenged with finding a way to develop the field via a subsea tieback that could be economically justified rather than P&A (plug and abandon) the

Work offshore during the FNT project. Images from Apache.

well," says Mark Richardson, North Sea Projects Manager. The Projects Group delivered the full facilities for US$31.7 million (£26 million) (over 50% lower than UKCS benchmarked costs), including a tie-in point for future subsea tiebacks, in a record time. Making FNT a very successful economic development.

Not so vanilla

The FNT development comprises a 4km-long single well subsea tieback to the Beryl Bravo platform. It uses an 8in insulated production flexible, a 4in non-insulated gas lift flexible and a control umbilical, for hydraulic, electric and chemical supply to the subsea Xmas tree, plus a new subsea control system and modifications to the topsides.

The decision to develop came in early May 2015 after drilling the well, and initial engineering followed in June 2015. Offshore installation campaigns (route survey, pipeline installation, rock dumping then tie-in), conducted by Subsea 7, came next in February-March 2016, with first oil achieved on 26 April 2016.

The project was executed using the Apache "Mission Command" approach. This means that the mission and tasks were clearly defined, boundaries set, and resources allocated. A competent and capable, but lean, project team (five personnel) was allocated and given complete accountability, and tasked to work with a sense of urgency, collaborate with the supply chain and provide a safe fit-for-purpose solution.

Crawford Brown

"The remit was to get it online as soon as possible, as time spent on over optimization could eat into returns," says Crawford Brown, Project Manager, Apache. "A few things came together to allow us to do that. Especially, the current supply chain environment, which definitely worked in a number of ways to our advantage. There was an appetite to respond to our cost challenges, lead time and approach, key factors in delivering best in class results."

The appetite to work meant, despite February not being the most favorable time of year to do offshore construction work in the North Sea, it went ahead as soon as the subsea equipment was ready.

Procurement was also about being pragmatic and fit-for-purpose, which enabled use of an already manufactured flexible that was built in the UK for an Apache (now Quadrant Energy) project in Australia, but not shipped or used. The re-use of existing designs for the subsea controls system and other ancillary equipment, which had previously been developed for other projects, saved engineering hours. Valves installed for possible tie-ins were also already in stock, having already been ordered for another Apache project.

The firm also deemed it possible to re-use an existing riser, left redundant after the Linnhe tieback was shut-in, for the production line; and, after thoroughly inspecting both, to re-use a former export riser and existing J-tube to pull-in the gas lift pipeline and umbilical.

"We wouldn't have specified that flexible for the gas lift line, if we were designing new, but it was fit-for-purpose and using it was a tenth of the cost of a new one," Brown says. It also meant reducing lead time to as good as zero – a key benefit. A similar approach was looked at for an umbilical, but this time a product within Apache didn't match the requirements. "Being able to make those decisions is good, but being able to make them quickly is vital," Brown adds. "The main advantage (for Apache) of using already specified equipment was the schedule."

When it came to repeat orders, while some of the equipment may have been over specified for what was needed, because the design requirements were reduced and the supplier was set up ready to manufacture, the overall costs were less and delivery faster, Brown says.

Future

Meanwhile, the firm is also developing other recent discoveries: Callater, a significant six-well slot bundle tieback to the Beryl Alpha facility, discovered in 2015; North West Beryl 3 (NWB3), a tieback to the Ness/Nevis subsea infrastructure; plus a Skene North well tie-in to the Skene bundle, all of which are due online in 2017.

There is also Corona, a heavy oil development tapping Tertiary injectites, which surrounds the Beryl field, also tying into Beryl Alpha, due online in 2019. Then, there is Seagull, a high-pressure, high-temperature tieback, which is in pre-front-end engineering and design with host solutions being assessed.

This year [2017], Apache will continue its highly successful, exploration, appraisal and development drilling (in 2015 Apache found 50% of the new reserves in the UKCS). Two semisubmersible drilling rigs will be at work, Apache has plans to drill Skene North and then Callater wells, plus some exploration targets. Platform rigs will also be active in the Forties and Beryl fields.

The Apache Projects Group Mission Command, lean, fit-for-purpose approach will also be taken towards these future projects. Keeping costs low, delivering safely with a sense of urgency, finding new fields and developing stranded oil is what Apache does best. **OE**

Slow ahead

Petronas' PFLNG *Satu*. Photo from Petronas.

The floating production systems market remains challenging. Will cost-cutting measures made over the past two years help projects reach final investment decision in 2017? Infield's Catarina Podevyn assesses the market.

Over the last two years the offshore sector experienced an overwhelmingly challenging period and the floating production systems (FPS) market has been no exception to this.

Throughout 2016, delays and re-tenders have been seen, as operators look to bring project break-evens in line with the new "lower for longer" price consensus. With the release of Infield's latest Floating Production Systems Report to 2021, here we look at the key regions and projects expected to drive expenditure demand over the medium term and the continuing challenges faced across the sector.

Europe

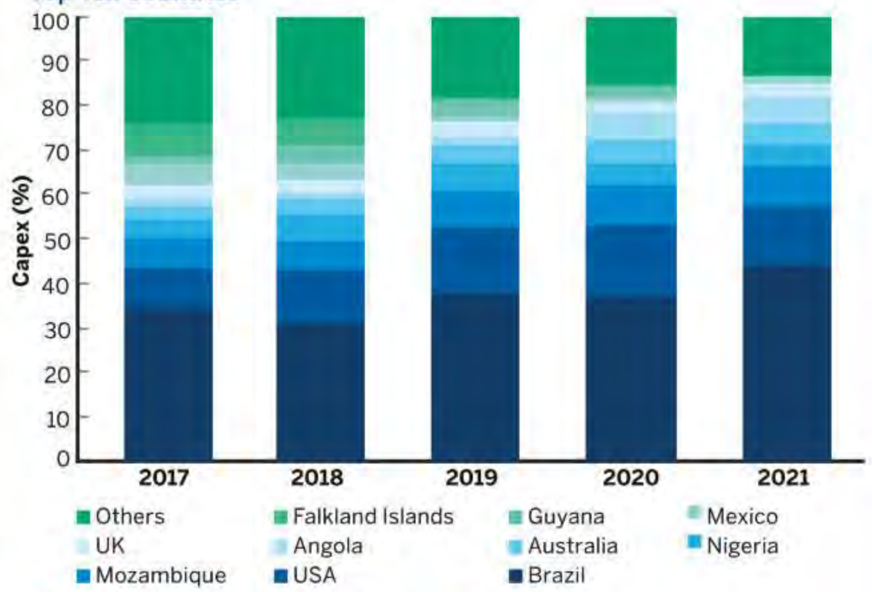
The European region has been significantly affected by the collapse in world oil prices, with depressed market conditions impacting the most on those marginal fields with already borderline project economics. Indeed, even before the current market downturn, areas of the North Sea were seen as challenging in terms of project viability.

The delay of Chevron's deepwater Rosebank project, at the end of 2013, can be seen as a tide-turning moment in the FPS market, with the following two years witnessing a raft of projects being taken back to the drawing board. Now, with break-even costs lowered across the sector, project sanction of key developments, such as the *Johan Castberg* FPSO (floating production, storage and offloading), are expected soon.

Indeed, the first phase of Johan Castberg is expected to be the standout investment project for the northwest Europe Continental Shelf and operator Statoil over the next five years. With investment projected at between US$5.85-7 billion (NOK50-60 billion), the project is expected to generate much needed activity within the northern Norwegian supply-chain in particular. In early 2016, Aker Solutions was selected for

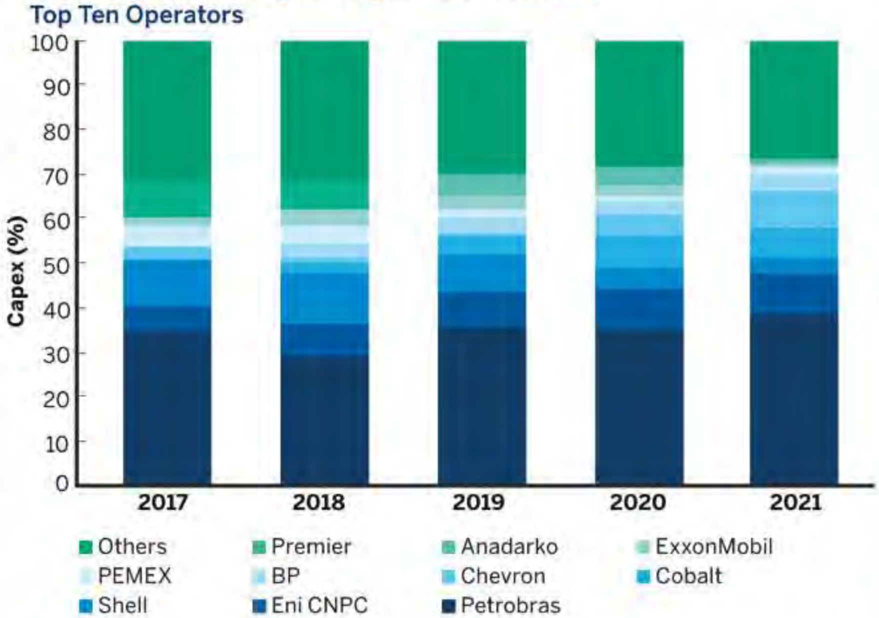
FPS Capex (US$) 2017-2021

Top Ten Countries



FPS Capex (US$) 2017-2021

Top Ten Operators



Source: Infield Systems.

the concept design study for the FPSO, which will be equipped to withstand the harsh environment of the Barents Sea.

Offshore UK, both the Premier-operated Catcher FPSO, to be a leased unit provided by BW Offshore, and Dana Petroleum's Western Isles FPSO, are expected to come onstream during 2017. In 1H 2017, EnQuest's Kraken development, which will use a Bumi Armada-leased FPSO, converted at Keppel's Singapore shipyard, is also expected to enter production on the heavy oil field in East Shetland. As a result of delays in completing the FPSO conversion, Bumi Armada has agreed to pay a compensatory sum to the operator.

Although 2017 is expected to see a number of FPS developments within the UK North Sea enter production, with no project sanctions taking place during 2016, a considerable drop-off in development spend could be seen if market conditions fail to improve. In 2015, Alpha Petroleum, operator of the Cheviot development, decided to re-evaluate the original field development plan. The field could see investment from 2017 onward.

Asia Pacific

FPS development within the Asia Pacific region has centered on the liquefied natural gas (LNG) export ambitions of Australia, with a boom in offshore construction taking place in recent years. Shell's *Prelude* floating LNG (FLNG) facility is expected to enter production during 2017/18, although the Petronas' FLNG *Satu* has now beaten the development, and won the accolade of the first FLNG to come onstream.

However, as a result of the prevailing market conditions, operators active within the Asia Pacific have continued to be faced with difficult cost reduction decisions during 2016. The Hess-operated Equus development is the latest casualty; despite being brought back on the development agenda at the beginning of 2016. November 2016 saw Hess confirm that the project is being put back on hold, with the operator also closing its Perth office. Hess has undergone significant losses during the year, with the future of its activity within the region now uncertain.

Within Southeast Asia, Petronas has led the way in terms investment into new FPS technologies; the Petronas *Satu* FLNG facility can now hold the title as the first vessel of its type to enter production, with first gas achieved on the Kanowit field, Malaysia, in November 2016. Clocking some 18 million man hours in development and construction effort, the *Satu* FLNG facility will support the Malaysian government's aims of unlocking more of its marginal and stranded gas fields.

However, while the success of *Satu* is without doubt a major milestone for the FPS sector, particularly in light of the backdrop of unprecedented market challenges, Petronas, like all major oil and gas companies, has also experienced significant challenges over the last two years. The second of Petronas' FLNG facilities has now been delayed until 2020, which also comes as a blow to shipyard Samsung Heavy Industries (SHI) as South Korean shipbuilders continue to struggle with mounting debt burdens amid the low commodity price environment.

Africa

Africa's FPS sector has traditionally been driven by West African developments, with international oil company Total commanding over 40% of total capex spend within the sector over the previous five-year period (2012-2016).

Large-scale projects continue offshore Angola, Nigeria and, to a lesser extent, Ghana – where Tullow's TEN deepwater FPSO entered production in August 2016. However, industry attention has turned towards the prospective developments offshore East Africa, in particular Mozambique.

After government approval earlier in 2016, Eni has, as of November 2016, been given the green light to go ahead with the Coral South LNG project, with a final investment decision expected in 1H 2017. The project's $5.5 billion FLNG facility is to be built by SHI, while BP recent signed an agreement to purchase the entire volume from Coral South over a 20-year period. Infield expects for the Coral South FLNG facility to hold the largest FPS capex demand offshore Africa during the next five years.

Elsewhere, Nigeria is expected to remain the second largest market for FPS development across the region, predominately driven by the completion of the Egina project and the next two potential FPSOs: Eni/Shell's Zabazaba, which is mired in ownership issues, and the Bonga Southwest project, with the operator, Shell, expected to re-start the front-end engineering and design process on the project soon.

Top: *Johan Castberg,* Image from Aker Solutions.
Bottom: *Kraken.* Image from Bumi Armada.

Offshore Angola, uncertainty remains surrounding Cobalt's sale of its stakes in Blocks 20 and 21, which hold prospective projects including the pre-salt Cameia, Cameia Mound and Orca (GOLD) fields, where FPSO installations are the most likely development options, but their timing and ultimate operators are still in flux.

North America

Offshore North America, FPS development prospects are mixed. Within the Gulf of Mexico, BP's Mad Dog Phase 2 development is now back on the table with a new semisubmersible concept favored over the originally planned Technip-designed spar. In March 2016, the project's EPCI (engineering, procurement, construction and installation) re-tender was issued and is expected to benefit from the now lower cost environment.

In early December, BP sanctioned Mad Dog Phase 2, with first production expected in late 2021. The $9 billion project will include a new floating production platform with the capacity to

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produce up to 140,000 b/d from 14 production wells. Phase 2's platform will be moored about 6mi to the southwest of the existing Mad Dog platform, in 4500ft water depth, some 190mi south of New Orleans. As *OE* went to press, BP's partners in the project have yet to give their final investment decision, but are expected to do so.

Shell's Appomattox is expected to be another key FPS project driving expenditure demand within the Gulf of Mexico over the period towards the end of the decade.

Latin America and the Caribbean

Elsewhere, Petrobras continues to press ahead with its development ambitions, with some notable alterations; the standout project for the forthcoming timeframe, Libra, is now expected to utilize a leased FPSO facility, with the operator reissuing tenders for both the Libra and Sepia fields in August of 2016.

Outside of Brazil, ExxonMobil's Liza discovery within the Stabroek Block offshore Guyana is expected to lead FPS demand, with contract awards expected to take place during 2017. Last year (2016) also saw further success for operator ExxonMobil with a second well confirming this highly prospective area and rewarding the operator for its counter-cyclical exploration strategy. Infield currently forecasts for expenditure demand on the two FPSO facilities originally slated for the development; an early production system, forecast to be installed in 2018, followed by a permanent FPSO installation in 2020 - to be now concentrated solely on the latter.

A key and highly anticipated development within the Latin America and Caribbean region had been Exmar's Caribbean FLNG project, Colombia, which saw termination in March 2016. The facility's construction at the Wison Heavy Industry shipyard in Nantong, China, has continued however, with commissioning taking place in July 2016. A number of possible destinations are rumored for the vessel, including Kitsault, Canada, and the possible development of Iran's Kharg Island area, where it has been suggested up to two FLNG units may be installed relatively quickly, pending much needed foreign investment.

This year [2017] is expected to continue to see market-driven challenges across the global FPS sector. However, with brea-keven costs across many prospective developments lowered over the previous two years, operators are now looking to take previously delayed projects forward. A number of final investment decisions are expected during the year, including Coral South, ExxonMobil's Liza and the Statoil-operated Johan Castberg project. **OE**

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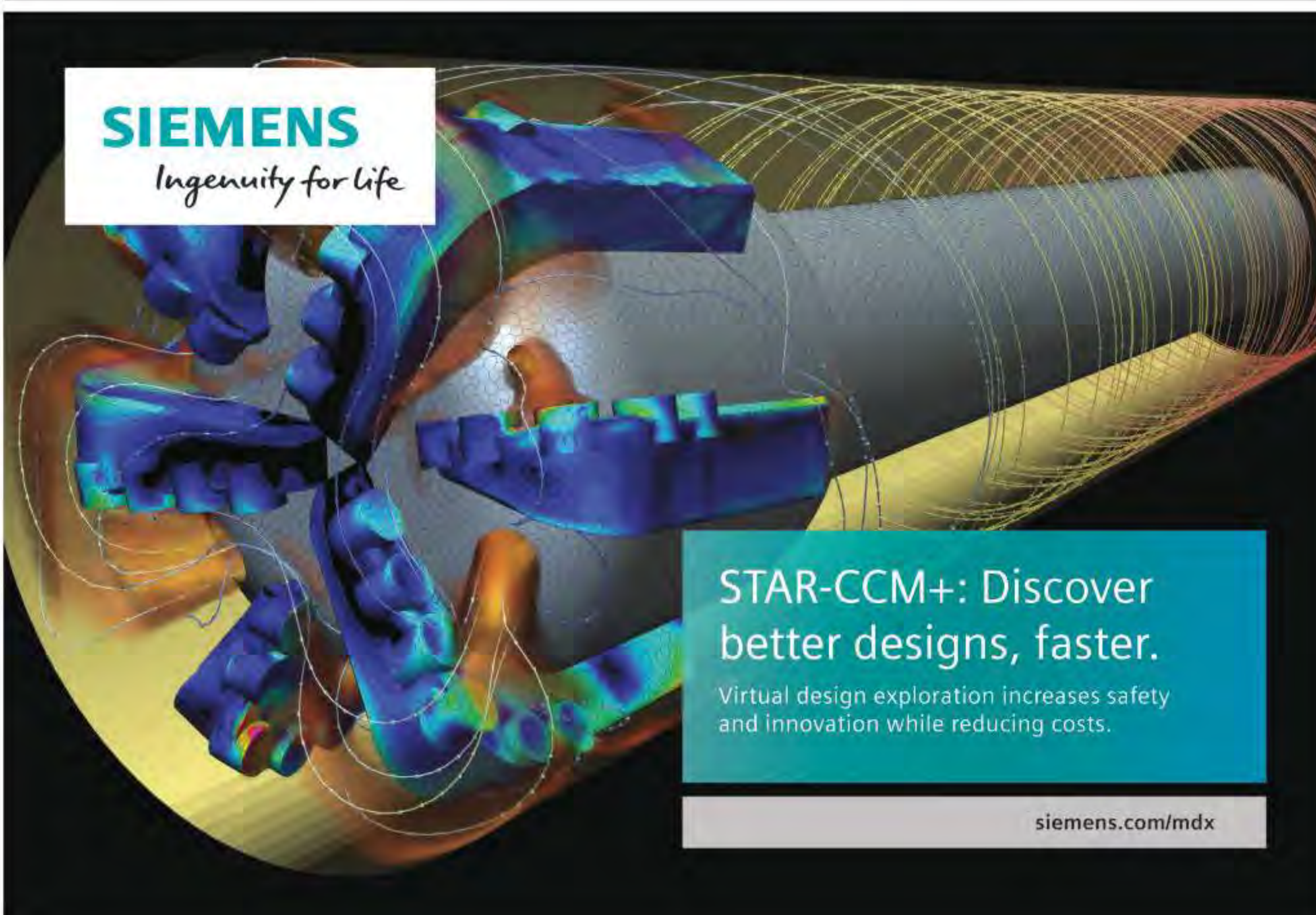


Flowline firsts

Norway's deepest yet oilfield development is bringing a string of firsts to the Norwegian Continental Shelf, not least when it comes to the field's flowlines. Elaine Maslin reports.

Statoil's Aasta Hansteen spar development is moving Norwegian offshore operations into its deepest ever environment, at 1300m water depth in the Norwegian Sea.

The move has meant a few firsts for operator Statoil and for Norway. The Aasta Hansteen facility will be Norway's first spar project (as well as being the world's largest spar), the country's first use of steel catenary risers (SCRs), the first synthetic rope mooring spread offshore Norway and the first use of mechanically lined pipe installed using reel-lay in the country.

For the latter, and for Subsea 7, the project is significant, both in terms of the scope – from engineering, through procurement and commissioning – and new technology deployment.

A rising spar

Aasta Hansteen was discovered in the Norwegian Sea in 1997, some 300km offshore, far from existing infrastructure. The development will produce the Luva, Snefrid and Haklang gas and condensate reservoirs, jointly known as Aasta Hansteen.

Under an engineering, procurement, installation and commissioning contract, Subsea 7 was contracted to procure, fabricate and install 18km of 12in mechanically lined pipe flowlines and four SCR systems, as well as overseeing the spool connections, mooring system, and umbilical and manifold installation, and performing the tow-out, hook-up and pre-commissioning of the spar.

Butting in

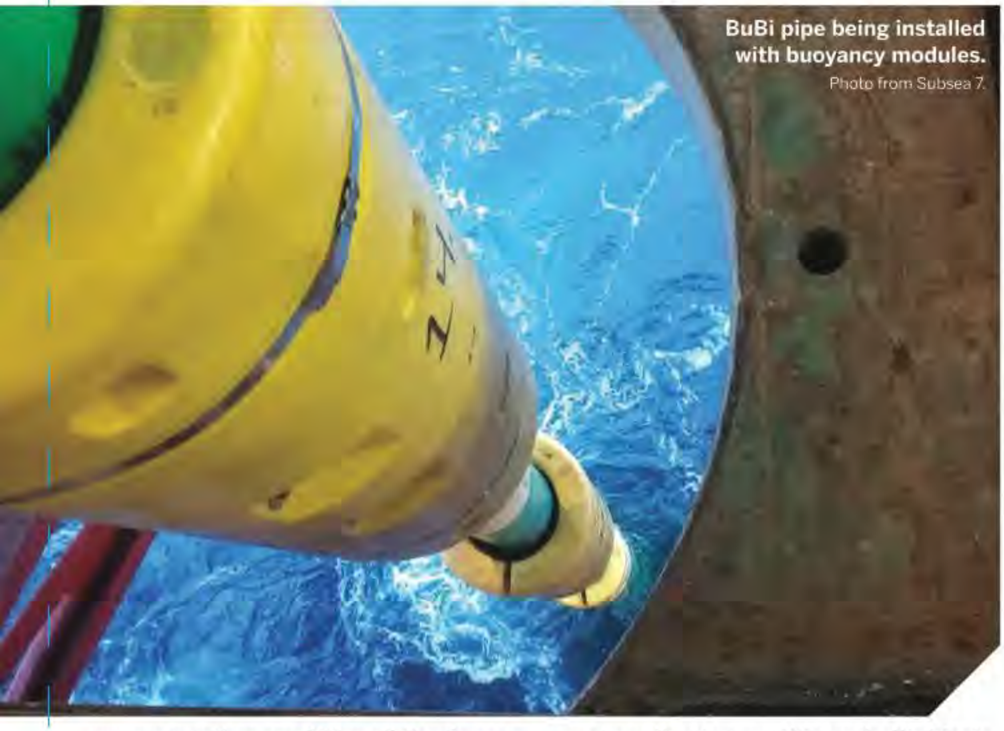
After a decade of development, it is the second reel-lay installation of Subsea 7's mechanically lined pipe, BuBi, produced by Germany's Butting. The product is used when production fluids are corrosive, which means the production lines need corrosion-resistant lining, and is an alternative to clad pipe. Clad pipe uses corrosion-resistant alloy (CRA), which is bonded to the inside of a steel pipe (a 100% CRA pipe would be too costly). Mechanically lined pipe uses carbon steel outer pipe with a CRA liner, which is hydraulically assembled inside the carbon steel pipe.

BuBi pipe fabrication at Vigra, Norway. Image from Subsea 7.

Butting has been producing such a pipe since 1994, but it wasn't until 2013 that it was installed using reel-lay on the Saphinoá-Lula NE (formerly Guará-Lula NE) project in 2013 offshore Brazil. The challenge for reel-lay installation was to resolve issues around internal buckling of the liner during the laying process, but also during its operating life.

The main benefit of using BuBi pipe is the lower cost, says Stian Sande, Aasta Hansteen project manager at Subsea 7. "BuBi pipe is a very cost efficient way of achieving corrosion resistance. It has the right properties at a lower cost [than clad pipe]." This is largely due to lower procurement costs, he says, and a reduced lead time. "We can get BuBi pipe delivered a lot quicker than clad pipe."

Lessons learned from Saphinoá-Lula, which saw 85km of 8in BuBi pipe installed in 2100m water depth, were used to help increase installation efficiency during the 2016 Aasta Hansteen installation campaign, Sande says. "On Aasta Hansteen, some of the challenges related to installation are the water depth and environment. It is deepwater with strong currents and


BuBi pipe being installed with buoyancy modules.
Photo from Subsea 7.

severe weather conditions," Sande says. "To optimize installation and reduce weather risk was a big focus area."

Subsea 7 worked with STATS Group to provide positive isolation and internal pressurization of the BuBi pipe to facilitate its reeling onto the *Seven Oceans* pipelay vessel at Subsea 7's spoolbase in Norway, ready for installation offshore. In order to allow the 12in BuBi pipe to be reeled onto the vessel, the pipe was water filled and pressurized. The internal pressure is required to ensure no wrinkling of the internal liner during the reeling process.

But, as Subsea 7 uses this type of pipe in more projects, it sees greater potential for its use, Sande says. This is particularly related to place behavior of the pipe under different – and more severe – loading conditions on the pipe during production, i.e. pressure and temperature of the production fluids, which impacts its fatigue life.

"Building on our experience from Aasta Hansteen, we have done more work to investigate the behavior and capacity of the pipe when the pipe expands and increases in length and develops lateral buckling. Our work related to the buckle zones has increased our understanding of the capacity of the pipe, which means BuBi can be used in more projects," Sande says. "We have broadened the possibilities [for its application] and this opens up more uses, including where clad pipe would have been used."

An example of this is the product's next application, on Wintershall's Maria subsea tieback development. "Two years ago, we wouldn't have used this on Maria," says Sande, demonstrating how the improved understanding is expanding the scope of BuBi pipe. For Maria, which is in 300m water depth, in the Norwegian Sea, the first reel-lay deployment of mechanically lined pipe with a piggyback direct electrical heating (DEH) system will be seen – and also Subsea 7's largest diameter BuBi pipe deployment to date (at 14in). Some 26km of the pipe will be laid starting in May.

SCR

Aasta Hansteen will also see Norway's first use of SCRs and one of the first uses of spars outside the Gulf of Mexico, where conditions are not as harsh. Three, 2km-long SCRs will connect three subsea templates to the spar, with another 2km-long SCR to be used for export to the export pipeline system.

SCRs can be used with spars thanks to the reduced motion of the platform, compared to a floating, production, storage, and offloading unit, Sande says. But, the risers have to be produced to withstand the stresses they'll still be under, which means paying close attention to welding, especially at the sag bend, near to the touchdown point, and their connection with the spar. "Which is where we came in," Sande says, "in terms of making sure there is high quality on the welding in terms of engineering and fabrication. As a result of the quality of welding during pipe fabrication, our client could extend the design life of the risers."

To make sure the risers could withstand the environmental conditions at Aasta Hansteen, the mooring system, with 17 lines, spread in two clusters of six and one of five, had to be designed as a taut system, to limit the motion of the spar. In another first, the mooring system was installed and the lines, made from Gama 98 polyester, by Lankhorst Ropes, have been wet stored on the seabed – a move which required qualification because this hadn't been done before.

Ready and waiting

Over last summer, the subsea infrastructure installation campaign was completed and now just awaits the arrival of the spar for hook-up and commissioning.

The *Seven Oceans* was mobilized to Vigra in April 2016, with flowline and SCR installation carried out in May and June. The *Normand Oceanic* then installed the spool pieces, connecting the flowline system to subsea structures. The *Seven Viking* then handled the tie-in and commissioning with flowlines preserved ready for tie-in in 2018. Finally, the *Skandi Skansen* mobilized for pre-installation of mooring system, ready for hook-up in 2018.

The Aasta Hansteen hull substructure will be floated horizontally onto the *Dockwise Vanguard* heavy transport vessel and then transported to Norway. In Norway, it will be floated off in the Stord area, on the country's west coast, and upended. There, the topsides – weighing 25,000-tonne, offering accommodation for 108 people – will be mated with the hull before being towed out to the field. The facility is expected to come onstream in 2018. **OE**

FURTHER **READING**

OE: January 2015. Reel lay gets real attention www.oedigital.com/component/k2/item/7901-reel-lay-gets-real-attention

OE: October 2016. A rising spar www.oedigital.com/component/k2/item/13633-a-rising-spar

OE: November 2016. Ave Maria www.oedigital.com/component/k2/item/13867-ave-maria

Bearing the weight

Operating in HPHT conditions have led to thicker, heavier subsea equipment that can hold up to extreme environments. Atul Ganpatye and Kenneth Bhalla, of Stress Engineering, discuss challenges associated with the design of this equipment.

Increased demand for energy has driven oil and gas exploration and production into challenging environments that place onerous demands on the equipment used for drilling, completion, and intervention activities. Estimating loads experienced by subsea equipment and assessing whether these systems can operate safely and reliably, becomes an important factor.

An understanding of the predicted loads and equipment capacities is essential in ensuring integrity of the system. This is best achieved through close coordination between various elements of the project, namely, materials selection, global system analysis, local system analysis, detailed component analysis, validation testing, and operational parameters. A coordinated system-level approach can go a long way towards ensuring safe, environment-friendly, and economical operations.

One challenge being addressed presently is drilling into high-pressure, high-temperature (HPHT) reservoirs. In the Code of Federal Regulations, the US Bureau of Safety and Environmental Enforcement defines HPHT conditions as downhole pressures greater than 15,000psi or temperatures greater than 350°F. Primary aspects of HPHT conditions that make engineering design of equipment critical are: higher levels of stored energy due to higher internal pressures, degradation of material properties at high temperatures, and limitations of available equipment needed for testing of critical components, as well as the increased complexity of testing procedures. These aspects raise the stakes for safeguarding life, equipment, and environment from the consequences of failure of HPHT equipment. Consequently, equipment and systems used in HPHT applications are subject to greater scrutiny in their design and increased robustness in their verification and validation processes.

There are two trends with respect to HPHT equipment design (with acknowledgement that design of HPHT components and systems is still evolving):

1. Subsea equipment is increasing in weight and strength. For example, equipment supported by the wellhead and casing system, such as the subsea tree, tubing head spool, or BOP stack, is becoming larger and heavier due to more demanding requirements for HPHT conditions. Moreover, riser joints and other components in the drilling system are being designed with thicker wall to meet design requirements, leading to higher failure loads on the riser components.

2. Presently, recommended practices are frequently amended to accommodate new findings and improved understanding with respect to HPHT design. For this reason, it is common to find inconsistencies in how various entities interpret HPHT design requirements. These inconsistencies often lead to each entity pursuing its own goals/objectives for their individual design/result, without adequate consideration of system-level performance. Consequently, gaps in understanding of the loads on the system and what the system can safely withstand (capacity of the system) can arise.

These trends can influence the design of sub-systems that are critically important for ensuring the sealing and structural integrity of HPHT wells; for example, the wellhead/casing systems. In this case the current design trends can manifest into one or more of the following performance characteristics for the system:

1. Restrictive operability under normal conditions and excessive loads under extreme/accidental conditions due to higher static bending loads on the wellhead/casing system for small vessel offsets from the well center.

2. Potentially increased fatigue damage at locations of interest in the wellhead/casing system due to longer natural period of the wellhead/casing sub-system when heavier subsea equipment is installed on the wellhead (see Figure 1).

3. Instability of the wellhead/casing sub-system after the drilling riser has been disconnected (or parted) at a large vessel offset due to heavier subsea equipment being inclined at large angles in the absence of restoring tensions from the riser.

4. Possible migration of the potential weak point from the drilling riser components to critical systems located below the lower flex joint due to the

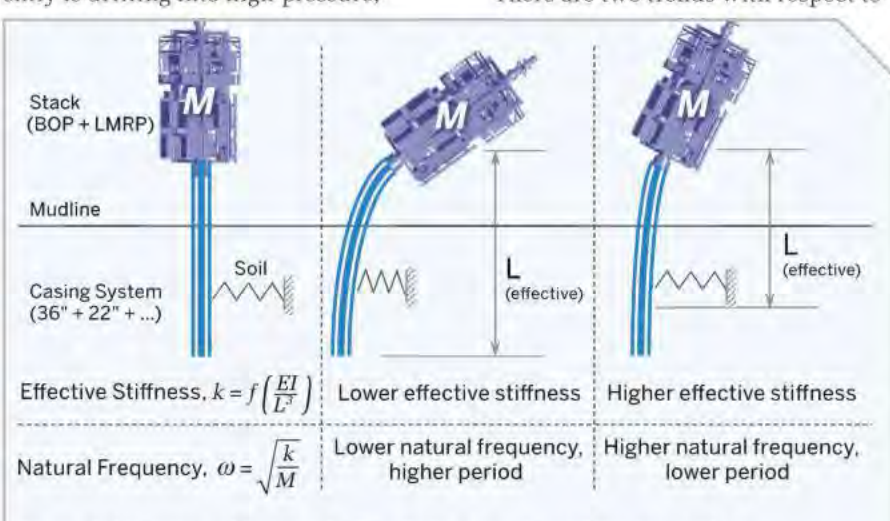


Figure 1: Influence of heavier HPHT stacks on wellhead/casing system natural period of vibration. Source: Stress Engineering.

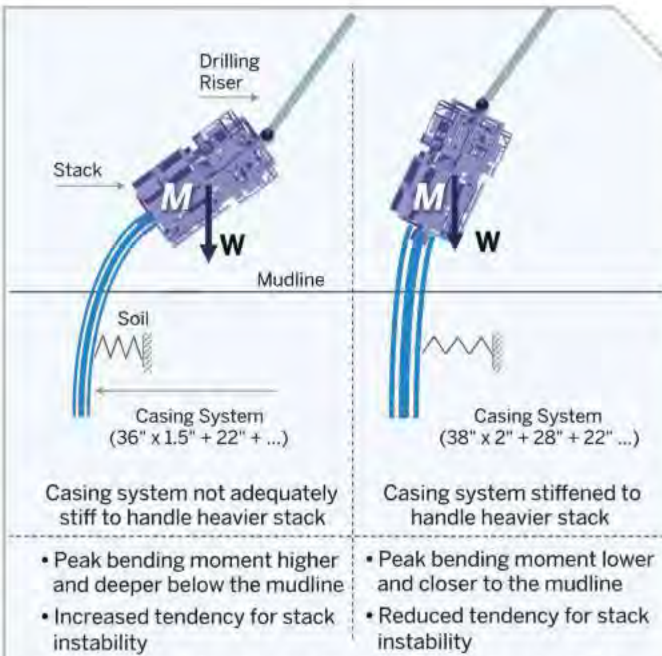


Figure 2: Schematic showing the influence of heavier HPHT stacks on wellhead/casing system response.

unintended consequence of increased limiting failure loads for the drilling riser components, which might seem desirable when considering the drilling riser sub-system in isolation.

Furthermore, the integrity of the wellhead/casing sub-system may be a concern if designs of the individual components and the interfaces between them do not work together in addressing the higher strength/fatigue demands of HPHT wells. For example, to design a system that can withstand the higher static/fatigue loads arising from the heavier subsea equipment, one would have to not only address conductor casing size and grade, but also the performance of the connectors, welds, design of internal casing strings, etc.

A less acknowledged consequence of the heavier HPHT subsea equipment installed on the wellhead/casing system is that the peak bending moment along the length of the casing tends to get pushed deeper below the mudline (see Figure 2). This effect is exacerbated when the conductor casing has inadequate stiffness (i.e., OD is too small and/or wall is too thin). This necessitates careful consideration of the type and placement of connectors and the quality of welds along the casing system. Casing connectors are typically characterized by relatively high stress amplification factors and casing welds sometimes do not meet the expected fatigue performance – both can result in reducing the fatigue performance of the system. Thus, when the peak bending moments are pushed deeper in systems in the presence of heavier stacks, it is beneficial to place the casing connectors as far below the mudline as possible to avoid exposing them to high fatigue loads; in the fatigue critical region, the fatigue life of the system can be improved by replacing casing connectors with high quality welds.

Another consequence of using heavier HPHT equipment is the increased tendency of the wellhead/casing system to be unstable during connected operations of the drilling riser, even when at relatively small vessel offsets (see Figure 2). When these stacks are displaced away from the well center, their eccentric weight induces a large bending moment on the wellhead/casing system. This can lead to toppling of the stack, if the casing system is not adequately designed to withstand the toppling moment. During normal operations, this toppling moment can be mitigated by applying higher tension to the drilling riser. However, for accidental scenarios such as drift-off or drive-off of the vessel, operational mitigation measures may not be available, or may not be sufficiently effective to prevent the stack from toppling. For such scenarios, a comprehensive system-level analysis and a complementary risk assessment may be required to effectively address the optimization of the wellhead/casing system design for safe operations.

At a minimum, the following is recommended to be taken into consideration to ensure wellhead and casing integrity for HPHT applications.

1. Traditionally, component and system designs have been driven by recommended practice documents (API, ASME, ISO, etc.). At times (or in some instances), these guidelines have been interpreted as "rule books", at the unintended cost of good engineering judgment. The old cliché of "there is no substitute for good engineering judgment" is especially important for HPHT applications, since recommended practices for this equipment are still being developed and pending industry-wide acceptance.

2. Operators, vendors, and service providers would all benefit from an integrated design approach with more effective communication on how their design decisions are interconnected between various disciplines. Again, a system-level approach is absolutely essential, since a seemingly benign design change in one component can potentially alter the risk profile for the entire system. An integrated approach would also manifest into cost reduction over a project life cycle by early identification of critical issues and reduction in the design iterations. This is universally true for any design process, but especially pertinent for HPHT applications.

3. A systemic verification and validation program should be implemented in conjunction with a risk assessment/hazard identification program. An effective verification and validation program would be able to identify loads for normal and accidental conditions, whereas a complementary risk/hazard assessment program will aid in the design efforts in focusing on critical outcomes under such conditions. **OE**

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***Kenneth Bhalla** is a principal at Stress Engineering Services in Houston, where he has worked for 19 years, and leads the drilling systems group. Bhalla holds a B.Sc (Eng) and M.Sc (Eng) in aeronautical engineering with fluid and structural mechanics, and mathematics, from Imperial College of London. He also holds a PhD in theoretical and applied mechanics from Cornell University.*

Handling sand

Sand erosion can cost the industry tens of billions of dollars every year. NEL's Marc Laing looks at what can be done to mitigate the issues.

Changes to oil and gas production over past decades have brought about unprecedented challenges surrounding the management of sand during hydrocarbon production. Furthermore, due to the number of declining fields, together with the push to develop from more complex fields, this trend is set to continue.

The problem

Having exploited most of the easier oil and gas pickings, and owing to technological advancements, oil and gas companies are now in the position to tackle some of the sandier fields. These are fields that generally exhibit weaker geological rock formations that shed sand easier than others.

This means it is easier to pull dislodged sand up through the wellbore and into the production stream. Controlling the amount of sand entering production is paramount, not just to the economics of the particular field, but also to the overall safety of the operation.

Unfortunately, this can be a difficult and often high-risk undertaking with disastrous consequences if not adequately managed. For this reason, there is currently a major focus on sand management in the offshore upstream oil and gas sector.

Operators have to first determine the optimum production conditions to control the flow of sand. If flow rates are too low, the sand can manifest downhole and block the free flow of hydrocarbons through the well. Conversely, if flowrates are too high, then large amounts of sand can be swept up through the well to the production pipeline and make contact with critical components along the way – with devastating results. This includes choke valves, which are the first line of defense when it comes to controlling the flow of hydrocarbons from the reservoir. Thereafter, it can wipe out major production components, such as pumps, seals, and flowlines. It can also fill the working volume of separators and reduce their overall performance.

Sand can erode flowmeters, which act as the primary measure for production control and hydrocarbon accounting. Even small amounts of sand over time can cause catastrophic damage to plant and equipment as it erodes even the toughest of materials.

At its most aggressive, sand has been known to eat through a half-inch pipe over a 12-hour shift. A worst-case scenario would be complete loss of hydrocarbon containment leading to pollution and environmental damage on a grand scale. Under certain conditions, reservoirs have been known to collapse due to the geological rock structure eroding.

There are a number of technologies in existence to monitor and reduce sand entrainment through oil and gas production systems. However, these are also affected by being in contact with sand, and can therefore be subjected to high levels of damage, which can greatly hinder their performance.

The challenges affecting sand management are further compounded as even sand-free fields can produce sporadic sand spikes over the course of their production life. These spikes can often be even more damaging and difficult to predict and manage. Furthermore, as fields mature and flow rates reduce, such as the case with many North Sea fields, there is a much greater risk of pushing sand up through the producing wells as the reservoir is worked much harder from below to extract the remaining hydrocarbons.

The key goal for oil and gas companies is therefore to accurately predict the flow of sand over the course of a field's lifetime. This informs safe process conditions, production limits and furthermore identifies hot spots i.e. areas where sand will do the most


Counting the cost: sand eroded choke valves. Images from NEL.

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damage. The latter allows the specification of critical production equipment and informs maintenance requirements. In particular, how robust certain equipment needs to be in order to survive specific conditions and therefore how frequently equipment needs to be replaced is a core consideration. Without an effective sand management strategy, such as this, oil and gas operators are subjected to very high levels of financial exposure. To put this into perspective, reportedly in one North Sea field gas production losses of up to 75% were reversed owing to predictive modeling and failure analysis.

However, as sand cannot be fully eliminated, the risk of sand monitors and protection systems failing, including downhole sand-screens, remains. The strategy of the industry has therefore been to put in place an over-engineered sand resistant infrastructure. But, this comes at a financial cost and must be balanced against the overall economics of producing a particular field.

Erosive flow testing in the laboratory

Due to the potential risks and impact of poor sand management, NEL is seeing a lot more erosion testing being undertaken by the upstream offshore sector. This includes validating erosive-resistant production equipment, such as valves, pumps, seals, flowlines, flowmeters and materials, as well as established API and ISO standards or user-defined specifications.

Sand mitigation technologies are also being put to test to assess their performance and effectiveness over wide-ranging conditions. These, amongst others things, include sand-monitors, sand-screens and chemical erosion inhibitors. However, laboratory testing on its own can be prohibitive and confined to the capability of the test house, which often struggles to reproduce today's field conditions – especially when considering the wide-ranging flowrates, pressures and temperatures associated with deep and ultra-deepwaters.

There are also so many different scenarios that would have to be tested, including different shapes and sizes of sand particles, travelling at different velocities and under different flow regimes. These factors have a bearing on the overall onset, location and magnitude of erosion. For this reason, industry is increasingly relying on flow modeling as a fast and cost-effective means of predicting erosion.

Predictive flow modeling

Computational fluid dynamics (CFD) is becoming a major tool for predicting sand erosion in the upstream sector. It allows engineers a method for validating a high number of designs and solutions in advance, covering the entirety of the production chain. It provides the ability to predict the rate and locations in which erosion will occur over the life of the field.

As well as informing the optimum production process conditions to keep erosion at bay, it can also predict failure. This is paramount, especially to support life extension of aging assets. However, CFD can also be limited and not as effective as physical testing when it comes to detecting hot spots and ill-performing equipment. This is because it is highly dependent on specialized and experienced modelers, and remains highly sensitive to different geometries, conditions and model setups. Due to the potential high level of uncertainty, it has been used cautiously by industry.

Taking a combined approach

In NEL's experience, best practice is to use a combined approach of physical laboratory testing and erosive flow modeling. This allows the models to be validated against traceable experimental data and extrapolation to wider conditions thereafter, which cannot be achieved through physical testing. This provides a much greater level of confidence and certainty in the use of flow modelling to predict sand erosion, allowing operators to anticipate the lifetime costs of the field over time, and plan for improved financial control. **OE**

Marc Laing *is the CFD Service Leader at NEL, a provider of technical consultancy, research, measurement, testing and flow measurement services to the energy and oil and gas industries, as well as government. Part of the TÜV SÜD Group, the company is a global center of excellence for flow measurement and fluid flow systems and is the custodian of the UK's National Flow Measurement Standards.*

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Chairman of the board GCE Subsea

This year, GCE Subsea celebrated its 10th anniversary. From the start in 2006, to 2016, member count has grown steadily to 140. About 120 companies and organizations now form the GCE Subsea cluster. In addition, we have 23 collaborative agreements with various Norwegian and International research and design and academic institutions, clusters and network organizations.

In our first year with status as a Global Centre of Expertise (GCE), the market situation has continued to be challenging for our members within the oil and gas industry, due to low activity and investments. A survey among our members showed that a majority are looking in to new areas and markets.

To be able to achieve the goal of increasing the cluster dynamics and attractiveness, we have focused on building collaboration with neighboring value chains in order to supply the Norwegian subsea industry with new qualifications. This can increase the rate of innovation and competitiveness and open up opportunities in new markets for the use of Norwegian subsea expertise.

Research has shown that companies in business clusters typically have higher value creation, productivity and growth than the industry in general. It is also easier to generate change, entrepreneurship and innovation within clusters, with the cluster management playing an important role as facilitator.

Through participation in typical cluster events, companies increase their networks and even find new market opportunities among other cluster members. Cluster initiated business acceleration programs help overly technology focused companies in improving their business orientation.

Benefits do not only arise within clusters; there is also much to be gained by more work across cluster boundaries in order to spark cross-industry innovation.

GCE Subsea has several joint projects with GCE NODE and GCE Blue Maritime, and all three are also part of the global MIT REAP program on regional entrepreneurial acceleration and scale-up. The GCE clusters also have many initiatives together with other ocean space clusters with the aim to position Norway as a world leader within ocean space innovation.

For the year to come, our main objectives will continue to focus on cost-efficiency, international markets, research and development collaboration and new related markets outside the oil and gas industry. ■

Inside

World-class Subsea Solutions from Norway, is a supplement to *Offshore Engineer*, published by AtComedia.

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Coast Centre Base – the centre of the activity. Photo from CCB.

Doing things differently

While cost cutting has been a top priority for many, if not all, in the industry, GCE Subsea members are also look to do things differently – to change the game. Elaine Maslin reports.

A challenge was made on the Norwegian Continental Shelf. After years of cost inflation in the subsea business, increasing engineering hours, bespoke design, there was a call for change, standardization and rationalization. And then the oil price crashed and the situation was amplified.

In this new lower oil-price order, companies have been rising to the challenge and the result could see a re-shaping of the industry, across different segments. Those challenging the established norms include GCE Subsea member companies, which are looking to change how things are done.

Coast Centre Base (CCB), which has played a strong part in creating the coastal support facilities that enable others to operate, as well as project managing rig maintenance work, is now positioning itself as a supplement to the established, original equipment manufacturer-led subsea equipment maintenance market, offering an alternative lean and more efficient service.

The product itself also has to change, says Kristian Karlsen, founder and managing director at Fjell Subsea Products. For too many years, product was being designed almost to be too complicated and geared to drive follow-on or spare parts sales, he says. While the oil prices were high, oil companies went along with it, sticking to habits and what they know. Fjell is looking offering a simpler modular approach.

"Thirty years ago, Snorre held more spares on land than it hard parts in the sea. Suppliers just wanted to sell parts. We're thinking totally differently," Karlsen says.

CCB

CCB already has a large footprint. It is looking to grow its role, however, and will be another challenger to the OEMs (original equipment manufacturers). It is already one of the two top rig recertification companies in Norway, a task that is project managed, drawing on the CCB cluster resources. Now it wants to do the same in the subsea business, becoming an aftermarket third party player.

Earlier this year, it bought a majority stake in Logiteam, which has a track record managing and maintaining subsea systems, and created a new business unit (CCB Subsea). As part of the move, CCB Agotnes, home to the likes of Aker Solutions and FMC Technologies, is becoming CCB's subsea center of excellence. Just as the firm heads up rig re-certification projects, drawing on and managing local resources, often actually on its own coast bases, it wants to do the same for subsea equipment maintenance as the OEMs. This will be overseen by its in-house expertise in the likes of engineering, standards for documentation, technical procedures, etc.

CCB Subsea has already won a contract with Statoil, for maintenance of subsea equipment and tools. This covers demobilization, maintenance and overhauling of subsea equipment under a two-year contract with two, three-year extension options. While Agotnes is the base, it will draw on CCB's and NorSea Group's bases up and down the Norwegian coast. Furthermore, the company is rolling out the model globally and taking in inspection, maintenance and repair work.

Driving forces for the move include Statoil wanting more competition in the market, but there is also an opportunity to do things differently, says Arne Aarvik Sales & Marketing Manager at CCB.

This means having one point of contact, which manages the various interfaces involved in maintaining a fleet of subsea equipment, instead of each OEM having an interface with the operator. CCB Subsea can be a leaner organization, with core in-house expertise, but leaning on the cluster. It also wants to look differently at periodic maintenance. Instead it's looking at risk-based maintenance, reducing costs for the operator, which will become more and more important as the installed base of subsea equipment requiring maintenance increases.

Recent adjustments to recertification of well control equipment barrier systems guidelines provides and opening to do this and make such services less costly, says Nils Fr. Fjærvik, CEO of CCB Subsea and previously CEO of Logiteam.

"At the moment, the cake is smaller than 2-3 years ago and there are more wanting a slice of it, OEMs and third party suppliers," he says. "But, with this model, we have an opener in terms of low cost. When volume picks up, it will be very attractive. We will have scalability. If OEMs still have ambition in the aftermarket they will have to adjust to a new cost level. This is a shift in how the market operates. The oil companies agree, it [the current market] is not a sound market."

CCB is also looking to the future, including decommissioning, i.e. plugging and abandonment. "There's no turn key supplier for this range of services for subsea decommissioning," says Fjærvik. "But, after you plug the well, there is a lot of activity and you need equipment to do this and what will you do with that equipment once you get it ashore? We are looking at that and talking with specialist providers to put together turnkey solution."

Fjell

Fjell Subsea is a new entrant to the subsea equipment market. The firm wants to offer modularized subsea equipment, which can be more easily produced and assembled from a set of standard components, reducing engineering hours, procurement time (the parts can be ready in stock), and costs.

The firm was founded in 2012, by Karlsen.

History

CCB was founded nearly 45 years ago. It is owned 50-50 by Bernhard Larsen Holding and NorSea Group and has been providing services for the offshore industry since the 1970s.

The firm has a string of sites along the coast of Norway, including Mongstad and Agotnes. At Agotnes, CCB covers 90ha, with more than 1000m of quays, 68,600sq m of workshops and warehouses and 20,600sq m of office buildings.

CCB together with NorSea Group is also involved in real estate development, with 13 sites along the coast of Norway and expansion ongoing into Denmark, the Netherlands, Scotland and Las Palmas on the Canary Islands.

To date, it has been developing its products, with the next step being commercialization. While it's still a small company, it has big ideas led by its modular philosophy.

Late last year, the firm got NOK5.2 million in public funding as part of a NOK30 million project it is working on sponsored by Shell, to qualify a "unified and modularized flying lead system.

"Many cakes can be baked from a few ingredients," as Karlsen puts it, allowing a small company to do bigger things. "Today, the industry is talking about modularization, standardization of products. We started in late 2011, and founded the company in 2012 to do this," Karlsen says.

The firm is developing a suite of subsea components, including couplers, hydraulic fluid, or chemical line connectors, ball valves and multi-quick connector (MCQ) plates, all built in a modular way. Fjell's MQC plate can take up to 52 connectors. Or Fjell can supply just one, using the same components, for example. Similarly, its connectors are designed to take different seals, so that the same components can be used even if a different seal is required, instead of having to have different design connectors.

The coupler systems and MQC plates are ready and now the firm is working on high-pressure ball valves, initially from ½in and 3/8in and then up to 6in for gas lift and injection valves.

Fjell is also starting a qualification program for flying leads, as well as the NOK30 million program to qualify a modularized flying lead system, with funding from Innovation Norway's IFU program and Skattefunn and help from Innovation Norway and GCE Subsea, which helped with the applications. The firm will also look to deliver ROV panels and larger structures in the future.

But it's not just about the design, for functionality, it's also about how product is designed for efficient manufacturing. "We are going to the machining center, seeing how we can design this to get it faster through the machine with best finish and quality," says Karlsen. "We are going through every step to make this as optimized as possible."

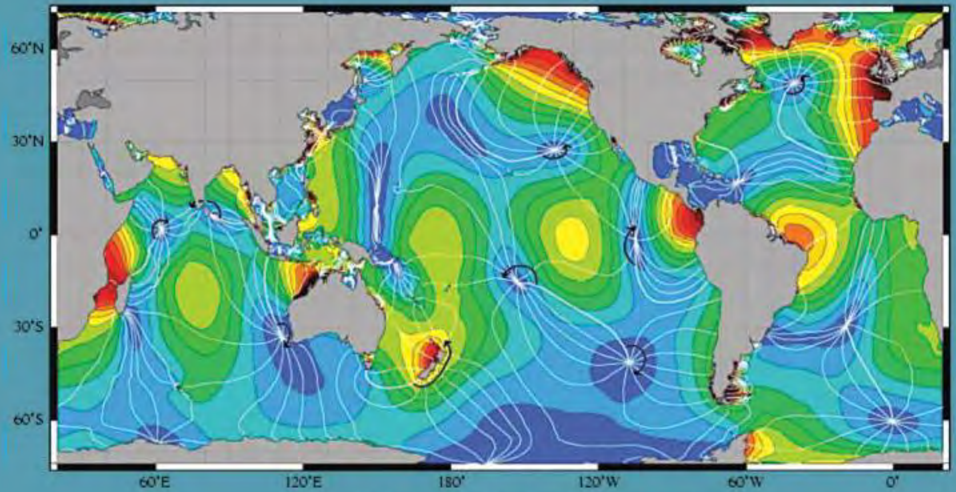
While activity is low right now, with the entire industry holding its breath for new orders, this year is looking hopeful, says Karlsen, who is eying a global market, from Brazil and Australia to Asia and the North Sea.

Fjell recently participated in a market entry program for Brazil. This program was a huge success leading to a partnership with the well-known and recognized Brazilian umbilical supplier MFX. MFX will work in partnership with FSP during the qualification program. ▪

A new player: CCB Subsea.
Photo from CCB.

Green credentials

Norway already has strong green credentials, with 98% of its electricity coming from renewable energy sources, primarily hydropower. Elaine Maslin looks at initiatives to harness the power of the ocean and to help reduce offshore wind costs.



Sites where NeoTurbine has potential. Images from NeoTurbine.

Bulgarian-born Norwegian Nikolay Hroulev hopes to add to the mix with a scalable tidal energy convertor.

The Oslo-based engineer has a varied career on which to draw, having worked in South Africa, Canada, Sweden and Norway, in the mining, food and structural steel industries – always as a design engineer. He's designed industrial conveyors, dehumidifiers, and special weighing machines. For the last 10 years, he has worked in Norway's subsea industry.

It's an environment in which he has pursued an idea he had while at university studying automotive engineering: a turbine-type engine powered by water. Now, those ideas are being put into action. In 2002, he came up with the NeoTurbine concept, working on it in his spare time.

In 2014, he presented the concept to Connect Norge and Innovation Norway. Last year, Hroulev formerly set up NeoTurbine and, with the help of some funding from Innovation Norway and backing from Global Maritime Group, Hroulev was able to build a 75cm-diameter scale prototype, and put it through testing at the Stadt Towing Tank laboratory in Måløy, western Norway. The tests were successful, Hroulev says, with 25% efficiency achieved, and now NeoTurbine is working with Sogn Industri, which is preparing a tidal test site west of Norway, at which a full scale, 2m diameter NeoTurbine could be tested, to be followed by 5m and 10m diameter versions.

"The challenges with tidal and ocean current are extreme conditions, high water velocity, environmental impact on marine life, corrosion, installation, and accessibility," Hroulev says. "Our solution is a vertical axis turbine, which is the most efficient and environmentally neutral turbine technology. It has low manufacturing and running costs and can be used in deep and shallow water. It is durable, efficient and scalable."

The idea is based on a Darrieus type turbine, a type of vertical axis turbine which curved aerofoil blades. This will be mounted inside a structure, which makes sure the water continues through the bi-directional turbine, instead of just being dissipated by the blades, unless it's mounted underneath a floating structure, in which case it would be open.

The blades, mounted vertically as two sets of four blades in each system, will generate power through a gear box to a permanent magnet generator, even in very slow water speed, Hroulev says. "NeoTurbine can perform in very lower water current, up to 2m/sec," he says. The system will generate power from as low as 0.1m/sec, compared to others which do not start until 2-4m/sec, and up to 15m/sec, which is above any current found naturally, he says.

Hroulev says full scale turbines will be 2m (40kw rating), 5m, and 10m (1MW) in diameter, with the different sizes being used according to the site or application.

"The good thing with my turbines is that they can be installed next to each other and on top of each other, like Lego bricks," he says, using concrete gravity-based foundations. "So, you can create a kind of tidal fence across a fjord, for example. You cannot do this with others." In such a scenario, fewer generators per turbine would be required as they could be connected, he says. If mounted beneath a floating, anchored facility, the generator would be onboard the floating structure.

So far a number of companies have been supporting him, including Global Maritime Group, Nordikraft, Havkraft and HydroWave, as well as organizations including Connect Norge, Innovation Norway, and GCE Subsea.

The NeoTurbine concept.

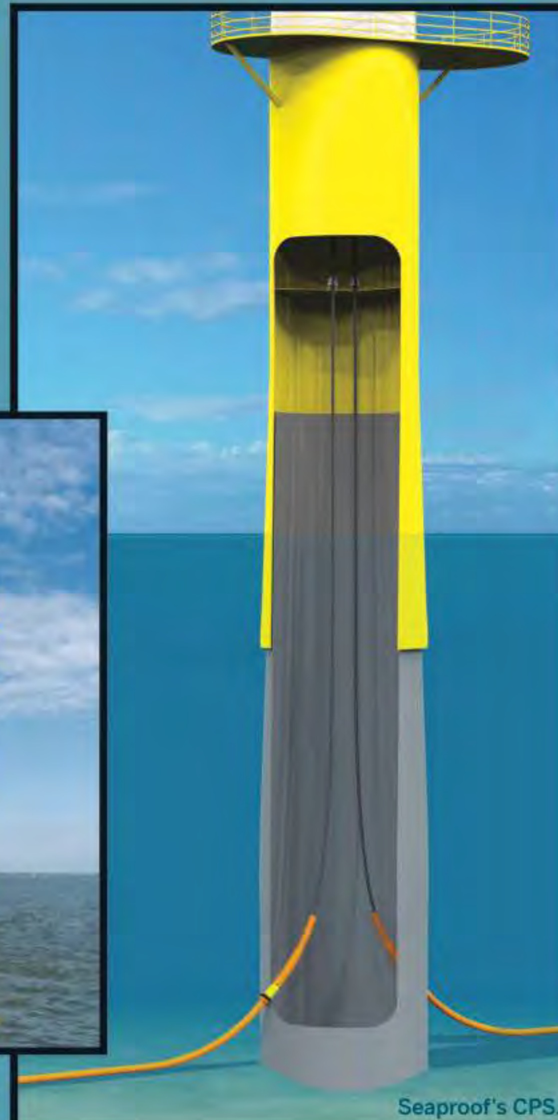
He's also been working with universities, including the Norwegian University of Life Sciences, and the University of Bergen, which have produced market analysis and engineering comparison studies.

The next step is securing funding for a prototype to be tested at sea. He needs about US$240,000, which he would be able to get matched by government funding. ▪

Cable protection

Using expertise developed for the oil and gas industry, Seaproof Solutions has carved out a market in offshore wind.

Seaproof's J-tube interface.
Images from Seaproof Solutions.



Seaproof's CPS.

In a short period of time, Seaproof Solutions has gone from having zero market share in cable protection systems (CPS) for the offshore wind industry to a 20% market share and growing.

Over the past three years, it has sold some 700 of its systems and, while they've proved a hit, the company is hard at work making systems that are even easier, faster and safer to install.

It's a critical area for the offshore wind industry. While offshore power cable installation isn't the highest cost segment of wind farm installation costs, it has been one of the more troublesome areas, due to cable damage.

Seaproof, based outside of Bergen, used its 25 years of expertise in polyurethane composite engineering to design a solution for seismic cables as well as applications in the defense and research sectors.

It is a modular system created from sections of hard, fiber reinforced polyurethane tubes, a monopile interface unit, a ventilated section where the cable in the tube is out of the water, with pull-in head, and hang off connector interfaces. These can be pre-installed offshore, ahead of cable pull-in, or installed as part of the cable pull in – with both methods protecting and reducing stress on the power cable.

The system has been designed without need of ROV intervention or a diver, and has been deployed with installation times of just 30 min achieved on some projects.

"This type of application didn't exist in oil and gas, so something new had to be designed," says David Vallee, technical sales and key account manager, Seaproof.

The CPS addresses concerns around stress points, where cables enter and hang off offshore wind turbine structures. In many, there's a pre-made 34cm-diameter hole in the foundation, about 2.5m from the seabed, into which the cable is pulled through. It then hangs from this hole, creating a free span out to the burial point, which means there are significant stress points, during and after the pull-in.

Seaproof's fiber reinforced polymer tubes have monopile interface units that allow the cable end to be pulled in through the hole, using a messenger wire, and up into the turbine, without the cable being exposed, put under stress or strain.

The system, which is flexible and strong, is pre-installed on the cable, either on the quayside or on deck, surrounding a section of the pull-in end of the cable. It is then pulled up into the turbine hole. Once the monopile interface section reaches the hole, it locks in place under tension, then releases the cable to run free up into the turbine to its termination point.

The system comes in 4m-long sections, which are connected to create what are usually 20-25m-long systems, but can be up to 60m, says Vallee.

One of the benefits of using fiber is the ability to create end connections that can work with steel work, something which has been difficult for other technologies, says Vallee. Seaproof has a patented system to allow this, which is also used to connect the 4m sections. Small steel flanges connect the sections with fiber running between each flange, which creates a rib-stop net preventing breaks and effectively stops cracks in the polymer.

But, Seaproof is not resting on its laurels. The push to reduce costs in offshore wind is as hard, if not harder, than in the current oil and gas market. Some cost reduction can be made by making operations simpler and by doing them onshore, before offshore work starts.

Seaproof has designed a new, diver and ROV-less system, which is a little like a J-Tube. The pre-installed CPS, into which the cable is pulled-in through a wide opening at the bottom.

But, now that Seaproof has developed these systems for renewables, the firm is looking at introducing similar technologies into the oil and gas industry, although not in exactly the same form. ▪

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Digitizing riser inspection

The AMOS concept. Photo from 4Subsea

Elaine Maslin reports on how technologies we've come to take for granted in the connected onshore world are making their impact offshore, reducing man hours and increasing insight.

In most public spaces, there is a very clever piece of kit. It's a wall-mounted defibrillator, which anyone can use by following simple instructions. These machines have made what is otherwise the work of a highly skilled medical professional easy to do.

Now imagine that system can issue an immediate report on the current heath of the patient, comes with an iPad on which time series data (aka trending) can be seen and a chat function through which the user can discuss (via a "chat" system, Skype or even phone) the results with an expert – who also has access to the same data – based somewhere else in the world.

Sounds good? Norway's 4Subsea, founded in 2007, has developed such a system allows operators to learn about the health of their flexible risers. The rapidly growing firm, which started life as a consultancy, has been providing automated riser monitoring services since 2013. This year, it has taken the technology to another level.

Peter Erik Jenkins is the firm's CEO and one of its founders. While initially more of a consultancy, 4Subsea invested in its own in-house software systems, supported by Microsoft, to manage the data it handled. This has evolved into systems – such as AMOS (annulus monitoring system) – that provide the hardware and software to offer health monitoring services for risers. These systems can alert the operator if there is any change in the riser, such as water, oil or gas ingress, so it can be resolved quickly and avoid any potential damage it might cause.

Peter Erik Jenkins

AMOS, launched in 2013, helped to take riser integrity assessment from a manual periodic test to a permanently installed, continuous monitoring system (typically retrofitted). 4Subsea is one of a few vendors offering such a system. Now, the firm has launched PAT, a portable riser annulus testing kit ("a very small AMOS," Jenkins says), for sites where permanent systems are not installed. The PAT can be used by offshore staff, a little like the defibrillators, reducing bed space and strain on logistics. The staff can have a hand-held device where the results can be displayed on screen and make use of a chat function to talk to 4Subsea (they can also phone or use Skype). The system saw its first offshore deployment in September last year [2016].

4Subsea currently does about 250 tests a year offshore, involving sending two staff out, which can now be eliminated, by just sending the PAT machine out, saving 30-50% costs, Jenkins says. The operator subscribes to 4Subsea's service and rents the PAT. "They do the test and get immediate results and trending data. The data also comes back to us and they then get a 4Subesa report," says Jenkins, who previously worked at DSND Subsea and Kongsberg SeaFlex. "The process is also a lot quicker (than sending the

An AMOS kit.

team out)." And it's the only such system on the market.

All the data can also be used across the operator's suite of risers to help monitor across assets – and can be seen, from fleet wide to individual riser detail, through a web portal (FlexTrack) from 4Subsea.

But, the firm recognizes that being a specialist in this field isn't just about offering a service. The firm has also been heavily involved in research projects to better understand fatigue and aging mechanisms in flexible risers. This information can then feed into the monitoring service, along with actual data from monitored risers, helping to constantly improve the results in order to predict failures before they happen – or start to happen.

"The key is digitalizing the services, developing automated test equipment to monitor risers and providing the software to monitor the integrity of these assets," Jenkins says. "We've built this based on operational experience we have from managing assets for operators, but also our knowledge and experience from the research that we do."

One of the research programs the firm is involved in is Flexible Pipe Annulus Corrosion Monitoring with the Research Council of Norway Petromaks 2 program. This two-year project aims to improve the assessment of structural integrity and to close technology gaps on the understanding of corrosion mechanisms within flexible pipes, with the aid of laboratory testing at the Institute for Energy Technology (IFE) and with support from Shell, BP, ExxonMobil and Statoil.

"We're looking to understand how corrosion mechanisms work in flexible risers," Jenkins says. "It is a challenge if you have a damaged riser. Many risers, if they have water ingress and are treated correctly, can live happily ever after. In some instances, which are fairly rare, but do happen, the same riser type, with the same damage, corrodes very suddenly. We are working on understanding how this happens and what the drivers are. The ultimate goal is knowing what we are looking for, to use in monitoring systems."

Today, the firm is looking after about 300 risers on the Norwegian and UK continental shelves. The goal is to increase that number rapidly, Jenkins says, without being drawn on a more specific time frame. Our goal is to cover about 30% of the global market. He adds: "We think that's pretty realistic with a digital service."

"From our perspective it is about reducing cost," Jenkins says. "The industry has gone from being focused on finding new resources to focusing on being more effective with the resources they have." ▪

GCE Subsea members are at the center of Norway's subsea industry. Images from GCE Subsea.

A world-class subsea cluster

More than 100 companies and organizations form GCE Subsea: a cluster, representing a near complete cross-section of the subsea life of field supply chain. When coupled with the innovation ecosystem in the region of southwest Norway, it becomes even stronger.

The GCE (Global Centre of Expertise) status is the highest level in the Norwegian Innovation Clusters program (see fact 1). The cluster members and partners in GCE Subsea, comprise a near complete subsea life-of-field supply chain. Approximately half of the members are system and equipment suppliers, including the three leading subsea engineering, procurement and construction (EPC) contractors: Aker Solutions, FMC Technologies and OneSubsea.

The second largest segment is inspection, maintenance and repair (IMR), technical services and yard services, which account for approximately 20% of the members. Support services is also a significant segment, and includes non-technical support services such as financial and legal services, transport and logistics services, insurance and other consultancies.

Size-wise, GCE Subsea has the full range; from the large multinationals with thousands of employees, to one-man-bands.

Capital

Among their sponsors (Innovation Norway and the Research Council of Norway, and some of

Clusters program

The Norwegian Innovation Clusters is a federally funded three level cluster program (Arena, NCE and GCE) that contribute to value creation through sustainable innovation. Each program extends over 10 years.

The program aims to trigger and enhance collaborative development activities in clusters. The goal is to increase the cluster dynamics and attractiveness, the individual company's innovativeness and competitiveness. The program is organized by Innovation Norway, and supported by Siva (The Industrial Development Corporation of Norway) and the Norwegian Research Council.

their members and associates), GCE Subsea has actors providing pre-seed and seed funding, pre-project and project funding, business start-up grants and risk loans. Although they do not have equity and venture capital actors as members, they make a point of keeping up to date with this sector as well, to be able to advise their members on which funding is best suited for the different stages in the life of a company.

International Efforts

The export of Norwegian subsea technology has grown considerably, and with it the cluster members' international ambitions and engagement. Small- and medium-sized enterprises often have limited resources, and it is important to learn from each other, and customers, to succeed in new markets. Bigger companies are eager to get Norwegian sub-suppliers to join them internationally.

GCE Subsea works closely with its members and help them join forces towards international markets and have increased the collaboration with related ocean industries to help their members expand into new subsea related markets.

One part of its plan has been to hire an EU (European Union) Advisor in collaboration with the NCE Seafood Innovation Cluster. The EU Advisor will especially contribute in strengthening research, development and innovation (RDI) cooperation in the ocean industries on themes where the subsea and seafood clusters are world leading and complement each other.

Their main goal is to mobilize to increased participation in international RDI projects, which will strengthen the knowledge base and competitiveness of the cluster companies. The EU research and innovation programs are key instruments in achieving this.

Exhibitions and Conferences

To form new ties with international business partners and RDI environments, GCE Subsea is actively present at several international conferences and exhibitions every year. As in 2016, this year it is organizing a joint Norwegian delegation, called Norway2OTC, for OTC Houston 2017. Furthermore, it is an organizing partner of the Underwater Technology Conference in Bergen, in June.

Cluster-to-Cluster Collaboration

Benefits do not only arise within clusters; there is also much to be gained by more work across cluster boundaries in order to spark cross-industry innovation. The Houston-based Pumps & Pipes initiative is a good example of this, where medicine, oil and gas and space industries innovate together.

In Norway, GCE Subsea has several joint projects with GCE NODE and GCE Blue Maritime. They are all a part of the global MIT REAP program on regional entrepreneurial acceleration and scale-up. Furthermore, they collaborate on a project regarding the fourth industrial revolution, commonly labelled Industrie 4.0. They, also have several initiatives with other ocean space clusters.

Why Cluster?

Research has shown that companies in business clusters typically have higher value creation, productivity and growth than the industry in general. It is also easier to generate change, entrepreneurship and innovation within clusters, with the cluster management playing an important role as facilitator.

Through participation in typical cluster events, companies increase their networks and even find new market opportunities among other cluster members. Cluster initiated business acceleration programs help overly technology focused companies in improving their business orientation. Cluster theory and experience have shown that it is very important to stimulate increased collaboration within the innovation ecosystem between industry, government, finance, academia and research and development (R&D) institutions. GCE Subsea have therefore enrolled many of the major universities, university colleges and R&D institutes, along with county and municipal authorities. ▪

GCE Subsea Services and Benefits

GCE Subsea strengthens innovation and knowledge collaboration in the subsea cluster. Increased innovation and internationalization is the main goal. All our activities and services will target six focus areas, where we aim to:

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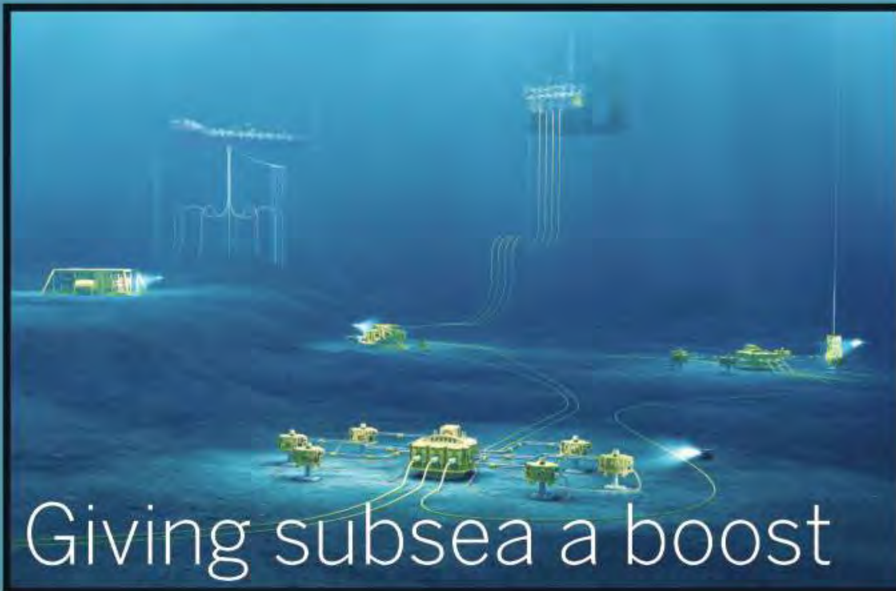

Subsea infrastructure. Illustration from DNV GL

Giving subsea a boost

A bid to reduce costs to increase subsea processing deployments is bearing its first fruit. Elaine Maslin reports on the first phase of a subsea processing joint industry project.

Subsea processing holds considerable promise for the offshore oil and gas industry. But, high cost levels and bespoke system design leading to relatively few deployments (there are only about 17 subsea boosting systems operating globally) has meant the industry is stuck in a bit of a chicken and egg situation: with more deployments, costs could come down, but until costs come down, deployments will be limited.

Cost inflation across the industry, up to 2013, hasn't helped. Subsea-costs on the Norwegian Continental Shelf tripled in that period, according to calculations made by Norway's OG21, a situation replicated elsewhere around the world.

Last year, building on several recently completed joint industry projects, targeting the standardization of forgings, documentation, and subsea electrical power, Norway's DNV GL launched a subsea processing joint industry project (JIP), with the first target being standardization of subsea pumping. The first phase of the project, which had operators Woodside, Petrobras, Shell, and Statoil on board, alongside technology firms OneSubsea (part of Schlumberger) and FMC Technologies (now merging with Technip), completed in December. Phase 2 is set to start imminently and future phases could tackle other areas, including subsea compression, separation and injection.

"There's considerable potential for subsea processing," says Kristin Nergaard Berg, Principal Engineer on the JIP, with DNV GL. "It's a technology the oil and gas industry needs, but the cost level, maybe combined with there being some decision makers who think it's still fairly new, makes it challenging to get projects sanctioned.

Kristin Nergaard Berg

"There are other options than subsea pumping and if they're seen to be cheaper and with more experience, the decision could be to go for the more conservative solution. It is a chicken and egg situation. If the cost would go down I think the volume would go up. But that's what we're trying to attack in this project," she says.

Finding out where exactly costs could be saved isn't easy. "It's very complex because the cost is added through the different parts of the supply chain," Berg adds.

A mapping exercise looking at costs throughout representative pumping systems and found that there wasn't one particular area that stood out as a cost driver. "One way of interpreting that is that the cost is spread out and that could be due to the fact that we have different standards and requirements and systems, custom made from project to project," Berg says.

In addition to looking at areas that impact cost, the JIP is also looking to capture industry practice, through input and review from suppliers and operators, find alignment on key areas and reference standards and limit operator specific requirements (a task akin to taming a mythical sea monster).

Early December, after going through many iterations, the first phase of the project delivered a functional description, and defined classes, for subsea pumping, as a platform for working toward standardization in phase two.

"Of course there are different opinions, priorities and outlooks, different business cases and different levels of experience, but I feel we have had very positive contribution, including from the suppliers that have really broadened and supplemented the team," Berg says. "There's always a trade off when working with standardization. Of course each field is different and we cannot change that. So we have to tried to focus on what can been common from field to field and left space for optimization."

As an example, module classes, welding, engineering philosophies, and documentation, have potential for commonality, and so could be standardized and save cost and time. These are some of the areas that will be focused on in the second phase of the project, as standards, functional requirements and specifications become more defined. Other areas include control systems and instrumentation, power systems, materials and qualification, work processes and test requirements.

Standard pump system data sheets, as well as standard documentation and where pump module, structures and pressure containing equipment size and interfaces could be standardized will also be looked at. "We're not likely to standardize 100%, but we want to align on key principles to allow for as much repetition as possible," Berg says.

It's also important that the project leverages rather than duplicates existing work, such as the Subsea Electrical Power Standardization project, DNV GL's Forging Material recommended practice (RP), the DNV GL Subsea Documentation RP and API's 17X Subsea Pumps RP, Berg says.

"There's also some work to be done on system design. We plan to look at standardizing minimum upfront tie-in solutions," she says, i.e. future proofing. It's also making sure that brownfield applications are covered, as subsea pumping could have an important role to play in enhanced oil recovery schemes, as well as greenfield projects.

It's a complex project, but progress is being made, Berg says. "At last we're getting away from talking about whose fault it was that costs became so high, to finding solutions instead." ▪

Kystdesign's Ægir 6000 ROV. Photo from Centre for Geobiology, University of Bergen.

The Midas touch

Scientific research in deep Arctic waters is helping to discovery more about new species as well as the potential for mineral mining.

A potential area of growth for the global offshore industries could be the emerging deep sea mining market.

It's an area already under sharp focus at the University of Bergen, one of GCE Subsea's partners. The university's Centre for Geobiology (CGB) is exploring active geothermal springs on the Arctic Mid-Ocean Ridge, in order to both find new animal species and examine how mining operations on the seabed could impact the environment.

The center is using a new sonar technique called synthetic aperture sonar (SAS), which provides images with more than one hundred times the resolution attained previously. Using this technique, researchers from CGB survey collect samples from recently discovered volcanic deep sea areas around the island of Jan Mayen, a volcanic island in the Norwegian Arctic Ocean.

In these icy waters, 600km northeast of Iceland, and at depths ranging from 150-2500m below sea level, CGB has identified active geothermal vents. The researchers are now mapping the unknown animal life and potential mineral deposits found near these vents.

"This [work] provides important new knowledge about volcanic and hydrothermal activity. It has also given us new information about the presence of metal deposits in the seabed," says Prof. Rolf Birger Pedersen from CGB.

Rolf Birger Pedersen

Life in extreme conditions

The researchers use the University of Bergen's Ægir 6000, a 6000m-rated remotely operated vehicle (ROV) – named for the Norse god of the sea and built by Norway's Kystdesign in 2015 – on their expeditions aboard the *G.O. Sars* marine research vessel.

To date, the researchers have collected geological and biological samples from the seamounts (up to 3000m-high submarine mountains) along the Mohns Ridge, some 80km north-east of the Jan Mayen islands, as well as the Kolbeinsey Ridge and the Loki's Castle vent fields.

The samples include unusual animals, including microorganisms that can survive in extreme temperatures. These microorganisms may provide insights into the first life on earth, Pedersen says.

"We have discovered more than 50 new species in these areas since the center commenced operations in 2007," Pedersen says. "We are talking about newly-formed geological landscapes and unique ecosystems. The data and samples we collect provide important, unique information about deep sea biology and geology."

Going for gold

The researchers are also interested in identifying metal deposits. Large amounts of minerals and metals such as iron, copper and zinc, as well as gold and silver in some instances, are deposited around the geothermal springs.

"The geological experiments are part of the EU-financed project Midas (Managing the Impact of Deep Sea Resource Exploitation)," Pedersen says. Midas is a multidisciplinary research program investigating the environmental impacts of extracting mineral and energy resources from the deep sea environment. This includes the exploitation of materials such as polymetallic sulfides, manganese nodules, cobalt-rich ferromanganese crusts, methane hydrates and the potential mining of rare earth elements.

"The goal is to gain an understanding of the possible environmental impact of mining operations in the deep seas," Pedersen says. "Norway has enormous deepwater areas with large amounts of resources. Even though we are, first and foremost, conducting basic research, this research may result in commercial operations in the long-term."

The CGB researchers will use special incubators to attempt to cultivate microorganisms on and below the seabed in their natural environment. "These include bioprospecting experiments, searching for special enzymes that can be used in industrial processes in the pharmaceutical and chemical industries," Pedersen says. ▪

Centre for Geobiology

- The Centre for Geobiology is a research center at the University of Bergen.
- The center is funded under the Research Council of Norway's Centre of Excellence scheme.
- CGB's objective is to bring together researchers from different academic disciplines in an international and multidisciplinary group to generate new, fundamental knowledge in a new field at the intersection of geology and biology.
- Project website: uib.no/en/geobio

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Drilling into data

Imagine a library where the books are written in a language so old, few alive can speak it; and the pages crumble to dust when turned. In data terms, this is the state of the UK oil industry's 50+ years of exploration archives. Elaine Maslin reports on one project aiming to fix it.

The UK North Sea industry formed the Common Data Access (CDA) organization over 20 years ago to host subsurface data from the basin and share it within the industry.

Over the years, CDA has amassed an enormous amount of documentation, some of it dating back 50 years, and describing more than 11,000 wells and 2000 seismic surveys. The archives hold some 12 million well logs and half a million different reports.

But, as the industry looked for ways to unlock more value from the North Sea, which is viewed as a mature basin, with untapped potential, some looked to CDA's data, particularly a category of it known as unstructured data, for inspiration. Unstructured data is information currently not stored in a way that makes it easy to read, or for computers to analyze or use.

While the time it would take to filter through it manually would perhaps be longer than the oil industry has on this planet, it was thought that a growing fleet of data science firms, with the latest software tools might have more luck.

Some 3.6 terabytes of data was offered to data science firms worldwide to see what they could do under the Unstructured Data Challenge. Nine companies participated and some of the results were presented in Aberdeen late 2016.

Three things were clear. First, a lot of this data would be more useful had it been submitted in a more structured and uniform way in the first place. Each operator has its own well report style, different terminologies, different structure forms, some were hand written, or scanned as images, rather than as text, etc. Second, there are plenty of tools out there to deal with these issues and for the issues that cannot be dealt with, new tools will come. Third, overcoming the first two could unlock a lot of potential.

Indeed, one firm goes so far as to suggest that by mining the data you already have could prove more fruitful than that data derived from drilling a new well.

Tools

By looking at relationships in the data, useful information can be extracted, says Ed Evans, ex-BG Group and Halliburton and co-founder (2004) and managing director of New Digital Business (NDB).

For a Norwegian client, the firm looked at available wells data for oil and gas shows information adjacent to currently producing fields. NDB ran a project and linked shows to GIS data, partnering with Geofabryka, a firm which crunches spatial or GIS data. The results, screening 50 wells per day, were similar to the company's manual search, which had taken two months.

For the Unstructured Data Challenge, NDB ran a similar project, looking at 100 wells across the Mid North Sea High. Instead of a manual process, which could see only five wells a day assessed, NDB's system screened 50 wells a day. It plotted non-productive time on a map and assessed the data to see if the formation or drilling operations were the cause. "Thirty percent of drilling costs are non-productive time. That's valuable knowledge," Evans says.

Analogs

It sounds easy, but, the devil is in the detail. Dave Camden, who founded Flare Solutions in 1998, looked for formation analogs in the data. The key, he says, is organizing data so that it's easier to search.

Camden used open source software and his own tools to process the text in CDA's documents, to look at the frequency with which different terms were found together: "you can know a word by the company it keeps," he says.

The job isn't made easy by each oil and gas company using different names

Photos from iStock.

and acronyms to describe the same things. Nonetheless, Camden analyzed the text of 25,000 reports to build a set of language fingerprints for geological concepts that could be used to work out how similar one formation is to another, filtering on lithology, formation age, and other geological terms.

There's more work to be done, he says, and future steps include moving his system from a traditional database into a graph engine – better to explore the potential of machine learning and natural language processing tools for use in the subsurface, and in other document-rich parts of the industry.

Going to the movies

Hampton Data Services (HDS) also had issues with the data, and took a different approach. Simon Fisher, Data Management Application Product Manager at HDS, says document titles and sub-titles often don't truly indicate what is in the data, as documents are copied so much. HDS focused on well logs, curves, and the other images in the documentation, working with Zorroa, a Californian firm, which usually does work in the film industry.

Images were classified using neural network systems – a variety of deep learning – helping businesses understand what valuable geological data may be hidden within the body of a standard report. "This was reasonably successful but the next step is putting in bigger data sets as training exercises," Fisher says. The more images in the system, the better it can identify them.

Meanwhile, Colin Dawson, Regional Manager, Europe & Africa at Independent Data Services (IDS), put two Robert Gordon University students to work using open source tools to look at information relating to stuck pipe, shallow gas and formations associated with drill bit wear, combining data from CDA and the Norwegian Petroleum Directorate for a full North Sea view.

To mine the data, the students used Elastic Search, an open source text analytics tool that includes Log Stash, to add structure to the data, and Kibana, for visualization. If the data wasn't machine readable, i.e. a scanned image in a PDF, Tesseract, an OCR tool, was used.

The students found 778 well documents mentioning stuck pipe, which were then geo-referenced, and displayed on a map to give a fresh insight into the knowledge available on drilling hazards for use in well planning.

AGR carried out a similar project using its own iQx software to tackle the CDA data, looking specifically at final well reports, many of which were handwritten with no consistent structure. This meant it was important to distinguish between what in the report was of value and what was added just to comply with the regulator, says AGR's Håkon Snøtun.

He also stressed that context is important in analyzing data, including knowing what you don't know, as well as what you do. Håkon referred to a World War II project that looked to have fighter planes reinforced based on data about where the planes that made it back had most often been hit, until someone pointed out that the bit to strengthen was actually where they had no data – from the planes that didn't return.

Supercomputer firm Cray focused on finding information about the Palaeozoic and non-productive time. The firm concentrated on establishing an analytics pipeline – that combination of the right people and right tools – suited to working with subsurface data, and then applying that pipeline on the entire CDA data set. Their initial results, presented for analysis using Jupyter notebooks, highlighted the difficulties in extracting information from old oil and gas documents in non-standard formats, but set the scene for their next analytical step: applying their graph engine to delve into the detailed relationships between the data.

As the CDA data comes from many different companies, the first step in using it, says Paul Coles of Schlumberger, is to harmonize it – addressing gaps, and applying consistent names, units, and labels so that it can be worked with as a single data asset. He applied machine learning techniques to classify well curves, apply the right units of measure, and join curves together to build a single geological model out of an organized, but highly unstructured raw data set. Coles supplemented his model with geological tops from the Oil and Gas Authority and stratigraphic information from cuttings reports.

"Adding existing, structured data helps the process and complements what is already there," he says. Then that's the hard work done. "[There's] no shortage of tools you can use for analysis," he says.

Schlumberger tested the approach on 46 wells on the Piper field, generating an automated petrophysical model for the field in just six hours. This would take six weeks manually by a petrophysicist, Coles says. A cloud platform was used to handle the data, as it can scale from a few wells to all of the UK Continental Shelf (UKCS). The idea is to create an evergreen model, maturing through machine learning and automated interpretation, he says.

Challenges

Maria Mackey, energy sector lead, EMEA-APAC, at Cray, says over half of the UKCS documents provided were stored as images, and must be processed to extract the text – a potentially long winded and expensive process.

"The analysis part is the least time consuming part of the exercise," she says. "It's the gather, understand, parse, OCR, clean and organize that takes the longest."

Documents that can't yet be analyzed by computers have "locked in potential," one delegate said. "The biggest question is, have we got the time and money to invest in fixing this? It all comes down to ROI (return on investment)."

However, Camden points out that the machines will quickly catch up. If a human is able to look at a blurry scanned image today and interpret it, machines will soon be able to do this, too.

Indeed, according to one delegate, "data science is the new oil." If one approach doesn't work, firms shouldn't give up, she said. "There's a lot more potential."

Malcolm Fleming, CEO of CDA, said: "The challenge is, in the future, how we use these tools to improve subsea and subsurface data. What we do in the data area directly impacts the business. We can reduce costs, add value, improve quality and automate."

But, one of the challenges around data science is less about technology or even the data itself. It's a corporate challenge: because information management isn't always directly linked to the business it serves, its value isn't often appreciated. This could be changing. **OE**

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21st century visioneers

Elaine Maslin examines how virtual reality goggles and augmented reality offshore platforms are quickly becoming part of the 21st century oil and gas industry.

While it has been a few decades since science fiction films "The Terminator" and "Lawnmower Man" brought augmented reality into our imagination, the technology is now a reality.

Virtual reality (VR) goggles were one of Christmas just past's popular presents and even the offshore industry has embraced such tools, not least on industry exhibition floors, where you can crash VR drilling rigs, tour the insides of concrete gravity based structures and "fly" around massive subsea structures, without getting so much as your feet wet.

But, beyond the marketing booth, how are companies using such visualization tools in their engineering work? We decided to ask some of the engineering houses. Their responses highlight the fact that these technologies are being adopted across the board. But, it also highlights that they can be used in many different ways, from using gadgets to connect people and data, to creating digital twins of entire platforms as part of a management system or using simulations to minimize operational risk. And, there's more to come.

Gadget show

Amec Foster Wheeler (AFW) has a strong focus on connecting people with people and people with information, including a real-time visualization of a particular platform, in whatever way and from wherever they want to access it, individually or in remote teams. To do this, the firm uses what it calls an Asset Information Hub (AIH).

"This is a digital representation of the physical plant, hosted by Amec Foster Wheeler, providing a powerful information management solution to control, link, review and deliver almost any type of data or document in a secure environment throughout asset lifecycle," says Alick Watt, project delivery director, AFW. "The AIH collates all models, documents and data, including functional and physical attributes for all plant items."

Alick Watt

One of the tools AFW uses to access the AIH is Aveva's "Engage" touchscreen technology, which provides an "interactive window" into the AIH, with real-time links between onshore and offshore, complete with "in context."

Simulation solutions. Photo from Aker Solutions.

"The combination enables collaborative, effective decision making in providing instant access to data, documents, models and information," Watt says. "This supports reliable decision-making in both capital projects and operations."

AFW also uses other gaming-type technology, from virtual reality visors (to enable very convincing first person walk-throughs) to offshore compatible tablets, helmet cameras and Bluetooth technology. Such tools can help prepare staff for work offshore, using a real-time representation of the offshore working environment, but also connect them more easily with those onshore, Watt says. "Recently we used virtual reality to prepare people for an offshore hookup, and we believe this is a first in the oil and gas industry," Watt says.

Getting social

It's not all about kit, however. AFW has adopted the social networking service Yammer to improve communications between onshore and offshore, particularly to facilitate collaboration and the sharing of videos and pictures.

Although the kit and development does come at a price, once implemented the cost efficiencies are huge, Watt says. "For example, a direct and real-time link from onshore (anywhere in the world) to offshore (anywhere in the world) has obvious benefits from an efficiency point of view. Jobs can be completed faster, risk removed, with much reduced man-hours and improved safety," Watt says.

"Engage, which is accessed via a secure web portal, means users have complete visibility of the live project information and documents in context within the 3D model to enhance understanding and promote rapid, effective and collaborative decision making.

Watts continues: "As every tagged object is selectable and is linked to its full contextual information, visual queries can be developed by theme to overlay multiple types of information, from multiple information sources onto the model for simple, instant visualization and greater understanding of the information. This allows experts, wherever in the world they might be, to be instantly connect to problems."

VR vision. Photo from Ramboll.

Visioneering

Having adopted 3D models in the 1980s, sophisticated digital tools are a standard for Aker Solutions, says Astrid Skarheim Onsum, head of Digitalization at Aker Solutions. "We see visualization technologies as an integrated part of project execution," she says.

Interactive presentations and animations based on 3D models, which are checked off against laser scans when an existing plant is involved, are used by the firm to optimize designs and visualize complex work scopes.

Astrid Skarheim Onsum

"We use 3D animation and simulation capabilities to make projects more predictable, reduce costs, mitigate risks, improve product development and better plan complex logistical operations offshore throughout the engineering, procurement, construction and installation (EPCI) cycle for brownfield and greenfield projects," Onsum says.

Using its own Visioneering system, at Aker Solutions' Simulation Center in Stavanger, the firm takes operatives and crew through full, life-like procedures, such as crane operations, marine operations or mechanical handling, complete with walkie-talkies and headphones, etc., before they go offshore.

"By visualizing installation plans in an optimal sequence, surprises and late changes are avoided and execution time offshore is optimized and reduced," Onsum says. As a result, she notes, "all of the complex projects simulated at Aker Solutions simulation center have been flawlessly installed offshore, completed at or ahead of schedule and without safety incidents."

"A good example is a successful flare replacement project in 2015. Due to the age of the platform, no proper drawings for the old flare were available and the weight was uncertain," she says. "A scenario with a dynamic center of gravity for the old flare was prepared, enabling simulation of different behaviors when the flare was released. During training, the team gained valuable understanding of the complexity and inherent risk of the planned tasks and was able to significantly improve the work process."

Such systems are used across the full life-cycle, with interactive 3D models and digital engineering tools used to aid the early engineering process and smart connected systems aiding operations and asset management. "For workover systems, for example, 3D scanning during rig visits can reduce uncertainty regarding the integration of completion and workover equipment onto a drilling unit. We also have smart, connected systems and software products within our asset integrity management services, to more effectively managing integrity and optimizing work processes. A number of other opportunities exist to further develop these concepts."

VR

Ramboll's uses 3D data from in-house high definition laser scanning technology to create immersive environments of an existing offshore facility or a newly designed structure.

"The goal is to achieve what appears to be a real-life size, 3D virtual environment, without any boundaries or restrictions where engineers can have the same experience as they would travel offshore," says Riyaz Ahmad Malik, team leader, Scanning & Survey, at Danish engineering house Ramboll.

The system needs a PC to run the model, a headset to display the model, and head and hand tracking and controllers, which mean the image will appear as it would in front of you even if you move.

Ramboll is using the newly released Oculus Rift headset. "The main advantage of using this system is that all elements required for VR experience are compactly packed in box," Malik says. "Basically, the system follows a 'plug and play' philosophy, with touch tools

Photo from iStock.

(wireless controllers) designed to make you feel like you're using your own hands. To interact with different objects within the model, we use eye-gazing technology, which has a very simple principle: to activate a simulation or to turn on/off any switch you just need to gaze at the icon for a few seconds to stimulate the function."

Riyaz Ahmad Malik

Ramboll recently completed a digitalization project in the Middle East, in which 19 offshore platforms were converted to their digital version using laser scanning technology to capture the as-built conditions. The laser scanning point cloud was then converted into 3D CAD models and delivered to the client in VR format. After that, each specialist was assigned with a specific ID and avatar, and all the members of the project team were able to meet on the platform, explore the components and talk to each other.

"VR is also a great tool for spotting potential flaws and risks prior to design implementation," Malik says. "Currently, we are working on a project that entails developing a fire and gas (F&G) detection mapping system using VR technology. We practically perform a simulation of the coverage areas of each sensor to mitigate the risk of hazardous situations. Not only is it a fascinating experience to actually be on the platform with your team mates, but the technique also enhances the efficiency of overall F&G mapping system by locating blind spots that are not covered adequately."

Life of field

For Wood Group, asset visualization is as much about information as the actual facility. "We see the value in having access to the relevant information in offshore facilities throughout the asset lifecycle," says Tony O'Shea, director, Operational Management Solutions, Wood Group.

"Asset visualization provides a multi-dimensional, global collaboration tool for managing the facility with the project team and all involved parties, no matter their location," he says. "This allows for a collaborative environment, which is key to ensuring engineering design is delivered to specification and is fit-for-purpose."

Wood Group's Operational Management Solutions business unit works across the asset lifecycle, creating and developing information within a greenfield environment then transferring, managing and updating it within a brownfield environment, including digital content tagging – of equipment, etc. - providing operations, maintenance and integrity information, as well as design information such as drawings, specifications and dimensional measurement.

Tony O'Shea

"This allows personnel – from the operator to the service company – access to the right information at the right time. For example, if a user wished to see the location of a pump on an asset, they can login online and review maintenance records, operating procedures and spare parts, without having to visit the asset."

This work goes hand in hand with Wood Group's dimensional control function, which uses traditional survey techniques, such as electronic total stations, as well as high definition laser scanners and HDR photography to build accurate as-built data of facilities and equipment. These models can be used to compare designs to what was built, then mass captured laser scan data can also be overlaid onto proposed designs to ensure they are clash free and tie into the existing facility.

This can be extended to subsea infrastructure, which can also be virtually modelled to provide a visualization of the whole asset from topsides to subsea, O'Shea says.

Last year, the firm used spherical photography on a processing facility in the Caspian region. Multiple 360° HDR images were taken in and around the facility, with particular emphasis on the work pack locations, in order to identify and read data such as equipment ID tags. The digital capture was then processed and incorporated into asset visualization software to provide a 360° high resolution virtual tour, available online. This was then used to assist in the planning of future engineering work, allowing the operator to update work packs and supporting materials, as well as for pre-visit site familiarization.

"In this project, the software system also included a measurement capability, which ensured the operator and service teams could obtain onsite dimensional data from their desktops," O'Shea says, allowing the client to increase efficiency, reduce risk, operating costs and downtime. Importantly, it provided a visual portal into operations, allowing engineers to easily and accurately identify priorities. Design teams were also able to work together to access engineering work packs from a common area."

The future

Where else will new technologies for visualization take us? Watt says most of what has been used today is technology we might already see in our lives, and so not exactly new, just new to offshore.

"However, we are now looking at some game-changing applications and approaches, challenging the status quo to do things really differently," Watt says. "Some of that means looking at what the gaming industry is doing, and applying that to the real world offshore.

We are also looking at some of the most basic elements of offshore processes and working to see what can be done completely differently."

Malik says there is great potential for VR technology. "Essentially [VR] takes the typical online meetings we already know to the next level, but we should not underestimate it," he says.

"Looking forward, VR has great potential for training and security simulations, monitoring and emergency scenario applications."

For O'Shea, there's a digital transformation underway. "We're collecting more data than ever before. In the future, we should be able to access information related to an asset at any time and review best practice from other installations in the operator's portfolio. This will allow for quick data-dependent decisions that are safe and compliant.

"We also see the potential to visit assets in remote locations, reduce survey times, link to equipment remotely via video, condition-based monitoring and drone capture. However, the key will always be controlling and analyzing this information in an asset visualization portal so it can be applied efficiently," he says. **OE**

FURTHER **READING**

Changing realities—Audrey Leon spoke with Houston-based FuelFX to see how this augmented reality can be implemented in the oil and gas industry for training. **http://bit.ly/2iweOit**

Taking augmented reality subsea—Mark Stevens and Bob Moschetta, of Oceaneering, discuss the benefits of using augmented reality for subsea training. **http://bit.ly/1k4L7en**

Beware the GDPR
George Scott, Director for KPMG's Cyber & Privacy practice in Scotland, warns companies in the upstream energy sector of impending changes to EU data protection laws in the form of General Data Protection Regulations. **http://bit.ly/2k8zrrT**

George Scott

Augmenting operations

An Aberdeen company is looking to punch above its weight with technology which could change the way technicians operate offshore.

Cadherent, founded about 10 years ago, started in the engineering and drafting space, mostly geared toward brownfield work. But, a move into using augmented reality has given it an idea that could help streamline plant maintenance.

"About eight years ago, we increasingly found clients looking to improve safety during installation work on modifications," says David Thomson, managing director. "We started giving them animations about how something should be installed and used. That's when visualization was brought in. It was an easy step from there to start using augmented reality (AR)."

Initially, Cadherent used AR as a sales tool, to show what it could do with CAD visuals and how these could be visualized within a live video – i.e., if your camera points at something tagged it then imports a 3D visual into the frame which can be viewed in 360°, as if it was actually there.

"Using a portable device, you can look at and manipulate [e.g. dissemble a structure to see how it's constructed] 3D drawings as they would appear in-situ," Thomson says. The same could be done wearing heads up display units (or HUDs), with handheld devices (like those used on gaming console) used to manipulate what is within the field of vision.

However, the firm is looking to take these techniques into the operational space. Instead of just using this for visualizing something where it is due to go, it sees the potential for the technology to be used by operators to take them through and record procedures, as well as being able to view PDMS (plant design management system) data, etc.

"Instead of procedures being written, they are visualized on screen and [actions] can be verified by the user, which can include taking a photo. This creates a maintenance record and an auditable trail," Thomson says. "We would like to see it tied in with SAP (enterprise software) or whatever system the operator is using so it can be part of the plant maintenance, including permits to work and even equipment and materials check lists."

By using technology such as Google glasses, the offshore technician can also be supported by onshore experts who would be able to view what the technician is viewing in real-time, including overlaid 3D visuals, plant data, etc., Thomson says.

Cadherent is working with Robert Gordon University's School of Computing Science and Digital Media in Aberdeen, through the Oil & Gas Innovation Centre (OGIC), to develop its technology. The firm wants to streamline the offshore data capture process and create recognizable targets that the software can spot, and then overlay data such as procedures, PDMS data, etc. It also hopes to work with industrial partners on the project. ▪

Instructions in-situ. Image from Cadherent.

Although Australia has some of the most progressive fiscal regimes for offshore oil and gas, the country is being short-changed in LNG exports, which is on the verge of further expansion this year. Audrey Raj reports.

Aussie tax changes **could risk investment**

Australia is a nation rich in energy resources, with about 95% of its petroleum production coming from its offshore sedimentary basins in the Western Australian and Northern Territory coast. Although prices of key commodities including liquefied natural gas (LNG) have fallen, new supply of LNG has successfully come onstream in the country with exports expected to quadruple over the new few years.

While the LNG boom is likely to deliver enormous export earnings, local reports suggest that Australia gets the lowest share of government revenue from its oil and gas production compared to other LNG producers like Qatar, Malaysia, Indonesia, and Nigeria.

The country's petroleum resources rent tax (PRRT), for example, is a profit-based taxing system that applies to a bulk of offshore projects. A report by The Sydney Morning Herald showed that currently only 5% of 150 oil and gas ventures are paying any PRRT.

In fact, since 2013, revenue from the PRRT had halved to US$600 million (AU$800 million) and crude oil excise collections had also fallen by more than half. As a result, the government of Australian Prime Minister Malcolm Turnbull said it will review the PRRT and associated commonwealth royalties ahead of next year's budget.

An initiative aimed at ensuring both local and international companies are paying the right amount of tax on their activities in Australia, the review will be led by former treasury official Michael Callaghan, with the support of the commonwealth treasury.

The tax review comes after the Australian National Audit Office (ANAO) published its finding indicating that the North West Shelf (NWS) joint venture, including Woodside, Shell and Chevron, may have underpaid millions of dollars in royalties. The NWS development is Australia's first LNG project.

According to ANAO, revenue reported by producers from NWS petroleum sales between July 2014 and December 2015 was $14.7 billion (AU$19.7 billion). From which, $1.4 billion (AU$1.9 billion) in royalties was collected, with $450 million (AU$600 million) retained by the federal government and the remaining $975.1 million (AU$1.3 billion) paid to Western Australia.

More than $3.7 billion (AU$5 billion) worth of deductions were claimed against the petroleum revenues in the 18 months to December 2015 that were not legitimate. These deductions were claimed under broad categories of operating costs, cost of capital, and joint venture participating costs, to name a few.

Wood Mackenzie's Saul Kavonic said the country has some of the most progressive fiscal regimes for its oil and gas, and is one of several countries worldwide with purely profits based fiscal systems for offshore oil and gas, alongside countries like


Chevron's Wheatstone project near completion. Photo from Chevron.

Shell's *Prelude* hull float launch in South Korea in 2013. Photo from Shell.

David Campbell speaking at OSEA. Photo from OSEA.

the Netherlands, Norway, Denmark, and the UK. This means Australia's tax take rises for more profitable projects, but falls when they are less profitable.

"We still expect over $20 billion (AU$26.6 billion) in LNG investment possible in Australia over the next decade," the senior research analyst for upstream oil and gas told ***OE***. "This investment could potentially be put at risk if any major fiscal changes were implemented without proper consideration of their impact on Australia's relative competitive position amidst an increasingly competitive LNG market."

Kavonic continues: "A comparison of fiscal take between Australia and other countries can be misleading, as each jurisdiction has different project costs, economics, and are at different stages in their productive lives. The recent wave of Australian LNG projects are forecast to deliver relatively low returns, well below the returns that Qatari projects have realized.

"So, the value pie in Australia is smaller to share between government and investors. Despite a number of projects that will struggle to pay back their capital cost, over $50 billion (AU$66.6 billion) in tax value is still forecast to be realized from the recent wave of Australian LNG projects over their lives," Kavonic explains.

The Australian Petroleum Production & Exploration Association (APPEA) believes that the PRRT regime that the Labor Party introduced in the 1980s is a major reason why Australia has attracted more than $150 billion (AU$200 billion) worth of new investment in recent years.

APPEA chief executive Dr. Malcolm Roberts announced in November 2016 that a fact-based review of the PRRT by the treasury would show the profit based tax was working as intended. He said that the APPEA's latest financial survey of its members shows that – despite the industry recording its first-ever net loss in 2014-15 – it paid more than $3.7 billion (AU$5 billion) worth of taxes during the same period.

"The continued payment of taxes at a time when the industry is under severe pressure debunks critics' suggestions that the industry is not somehow paying its way. Much of the debate about PRRT has been characterized by grossly misleading information, distortion and a willingness to ignore the facts," Roberts said in November.

"For almost 30 years, the commonwealth has used the PRRT as a super profits tax," Roberts said. "The tax encourages investment by only taxing projects when upfront costs have been recovered and profits exceed a modest benchmark rate. Australia's oil and gas industry is at a crossroads. Exploration has collapsed."

80% underexplored

As other countries, Australia too understands that openness to foreign investment is critical to unlocking its natural resource wealth which is 80% underexplored. Most of its oil resources are condensate and liquefied petroleum gas (LPG) associated with giant offshore gas fields in the Browse, Carnarvon and Bonaparte basins.

Oil reserves, however, are modest as the story in Australia is really LNG, David Campbell, senior trade and investment commissioner of the Australian Trade and Investment Commission said at the 2016 Offshore South East Asia Conference and Exhibition (OSEA) in Singapore.

"Around 92% of Australian conventional gas resources are located in the Carnarvon, Browse and Bonaparte basins off the coast of Western Australia and the Northern Territory. There are also resources along the offshore basins along our southern margin as well as onshore basins, and the potential for additional commercial discoveries is significant. With unconventional gas we have significant resources in coastal basins around Queensland and New South Wales," he said.

New LNG market

Australia is home to several LNG projects such as Pluto LNG, Gorgon LNG, Darwin LNG, Gladstone LNG, Asia Pacific LNG and Queensland Curtis LNG. In October 2015, the country's LNG exports climbed to a record of $1.3 billion (AU$1.75 billion) – the best performance in 22 months, data from Adelaide-based energy advisory firm Energy Quest showed.

The Asia Pacific region will be the driving force behind LNG demand growth, which is also a rapidly growing market for Australian exports. To maintain its competitive edge, the Australian government is expanding oil and gas market opportunities through free-trade agreements with China, Japan, and Korea. These countries combined, purchase more than two thirds of Australian resources in energy exports, worth about $87.7 billion (AU$117 billion) in 2014-15.

"But it's not only about China, it's also India," Campbell told OSEA, adding that there are reasons to expect why the Australians will play an important role in meeting the growing gas demand there.

"India's LNG demand is expected to double by the end of the decade while it seeks to provide electricity to its population. We are geographically close to the four east coast LNG regasification terminals that are currently under construction in India. At the moment, over 85% of their gas comes from Qatar," he said.

Year of the mega project

Three large Australian LNG projects that extract gas from fields off the north coast of Western Australia are expected to come online this year. Currently, at various stages of development it includes Shell's Prelude floating LNG (FLNG) facility, Chevron's Wheatstone LNG project, and Inpex's Ichthys LNG development.

The Chevron-operated (64.14%) Wheatstone project, west of Onslow in Western Australia is expected to achieve first LNG in mid-2017. Wheatstone features a huge offshore gas-processing platform, with a topside weight of about 37,000-tonne. It also includes two LNG trains with a combined capacity of 8.9 MTPA and a gas plant. It comprises the WA-17-R and WA-253-P gas fields in the NWS, in water depths of 70-200m.

Chevron's partners in the project include Kuwait Foreign Petroleum Exploration Co. (13.4%), Woodside Petroleum (13%), Kyushu Electric Power Co. (1.46%), and PE Wheatstone (8%).

Since discovering a giant gas and condensate field in the Browse basin offshore Western Australia, Inpex has been developing Ichthys LNG, which involves a central processing facility and a floating production, storage and offloading vessel.

Scheduled for startup in September 2017, the project is expected to produce 8.9 MTPA of LNG and 1.6 MTPA of LPG, along with up to approximately 100,000 b/d of condensate at its peak.

Inpex operates Ichthys with 62.2% interest. Its partners are Total (30%), CPC Corp., Taiwan (2.625%), Tokyo Gas (1.575%), Osaka Gas (1.2%), Kansai Electric Power (1.2%), Chubu Electric (0.735%) and Toho Gas (0.42%).

Shell's Prelude FLNG is one of the largest offshore floating facilities ever built. It has around 260,000-tonne of steel in the facility alone, around five times the amount of steel used to build the iconic Sydney Harbour Bridge.

The FLNG unit is designed to withstand a category five cyclone while moored above the Prelude and Concerto gas fields in the Browse basin, for the next 25 years. Once operational in late 2017, Prelude will produce at least 5.3 MTPA of liquids: 3.6 MTPA of LNG, 1.3 MTPA of condensate and 0.4 MPTA of LPG. Shell serves as operator. Its partners include Inpex (17.5%), KOGAS (10%) and OPIC (5%). **OE**

Slow **going**

Activity is picking up down under. But, it'll be at a slow pace, says the Energy Industries Council's (EIC's) Neil Golding.

During the early part of this decade, following significant gas discoveries in the 2000s, several projects geared up for development with significant front-end engineering and design (FEED) contracts awarded on Woodside's Browse gas discovery, Shell's Crux gas condensate field and Hess' Equus gas field.

Significant engineering, procurement and construction (EPC) activity also took place with multi-billion dollar contracts signed for the development of the Inpex's Ichthys and Chevron's Wheatstone projects.

While contracts continue to be awarded, there has been a significant drop off in activity since 2013.

Why is this? The continued increase in contracting costs from 2013-2014 for offshore developments saw operators put on hold both oil and gas developments. The huge gas projects that were already under construction, relating to liquefied natural gas (LNG) developments, meant that additional gas developments were not needed and would have only added to the current supply glut. All these factors brought into question the commercial viability of future developments.

2016 highlights

We saw some positive activity in 2016, and contracts continued to be awarded. In the Greater Enfield oil development, Technip, OneSubsea and Aibel all won significant contracts. It must be noted though that projects continued to be put on hold, which in turn delayed the award of EPC contracts, the most notable of which was the Equus gas field, where Hess decided in November 2016 to postpone the floating production system project.

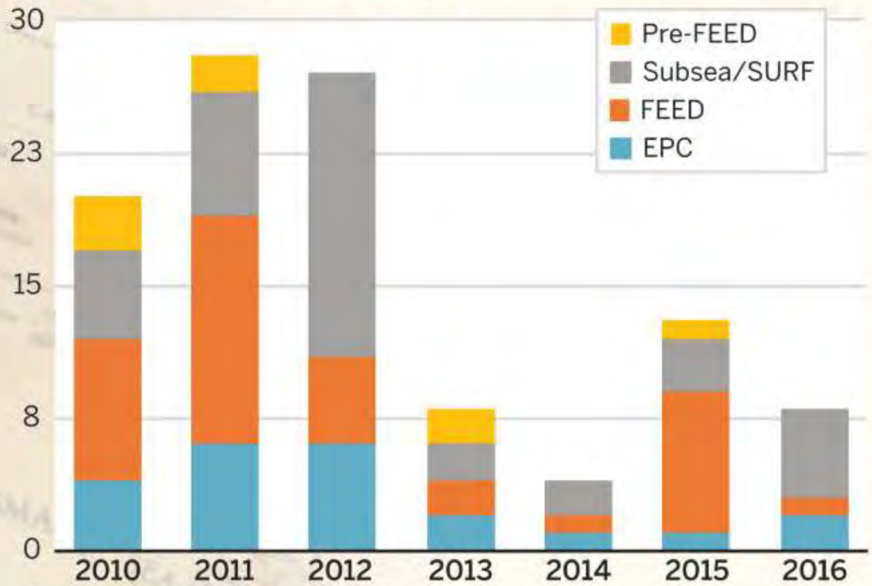
Prospects for 2017

The expectation is that projects will move forward, albeit at a slower rate than the early part of the decade, with contracts being awarded during 2017.

The Caldita-Barossa gas field being developed by ConocoPhillips is one development where activity is expected to ramp up. The field is in water depths of 320m, off the Northern Territory, with approximately 3.5Tcf of reserves. Currently, construction for a floating production, storage and offloading vessel is planned to separate gas, condensate and water, and remove the bulk of the carbon dioxide. The project includes a subsea production system and umbilicals, risers and flowlines, and a 260km, 26in gas export pipeline to the Darwin LNG plant. FEED and EPC tenders are expected in 1H 2017.

The Santos-operated Sole gas field offshore Victoria, in the Gippsland Basin, could also see activity. A binding sales gas agreement has been signed and the final investment decision

Major upstream contract awards: Australia



Source: EICDataStream.

is expected imminently, with EPC work likely to start in 2017.

Significant opportunities

The sizeable Crux, Scarborough, Tassie Shoal and Equus discoveries will all require major investment to be brought into production. New finds continue to be made and it must be mentioned that Australia still has some very exciting frontier regions that have seen little exploration, and which could contain significant reserves. Australia is a market full of opportunities for the supply chain in both the short- and long-term. **OE**

Neil Golding has over 16 years' experience of working in the oil and gas industry in various roles and currently heads up the Oil and Gas and Product Development teams at the EIC. The teams' main objective is to support the UK supply chain in identifying business opportunities in the global oil and gas market. Golding is joint product owner of the EIC project database EICDataStream which tracks over 8000 global energy projects throughout their development lifecycle.

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Activity

Offshore Achievement Awards finalists

Finalists for the 2017 Offshore Achievement Awards, supported by *OE*, have been unveiled. Hosted by the Society of Petroleum Engineers (SPE) Aberdeen Section, the annual awards recognize some of the industry's most innovative technology developments as well as talented individuals and exceptional large and small company performance.

"The sheer quality and variety of entries we have received this year reflects everything that is great about our industry, particularly our ability to adapt to a volatile economic environment," said Ian Phillips, chairman of SPE Aberdeen.

The 2017 Offshore Achievement Awards finalists are:

Innovator (sponsored by OGIC)
- **Delphian Ballistics**
- **Enpro Subsea**
- **M-FLOW Technologies**

Emerging Technology (sponsored by Nexen)
- **Exnics**
- **M-FLOW Technologies**
- **PlanSea**

Safety Innovations (sponsored by Offshore Europe Partnership)
- **Cape plc**
- **Cyberhawk Innovations**
- **RigDeluge**

Environmental Innovation
- **BP**
- **Exnics**
- **TWMA**

Export Achievement
- **Churchill Drilling Tools**
- **Cyberhawk Innovations**
- **JDR Cable Systems**

Collaboration
- **Decom North Sea**
- **Maersk Oil/Amec Foster Wheeler/ Bilfinger Salamis**
- **Wood Group**

Outstanding Skills Development Program (sponsored by Heriot-Watt University)
- **Fabricom Offshore Services**
- **TAQA**

Young Professional (sponsored by BP)
- **Marianne McKevitt - BP**
- **Richard Eckersley - Nexen Petroleum**
- **Mandy Johnstone - N-Sea**
- **Sam Lisney - Petrofac EPS West**
- **Richard Turner - RS Clare & Company**
- **Natalie Jackson - Shell**

Above and Beyond
- **Mandy Marriner - JDR Cable Systems**
- **Bob Banks - Petrofac EPS West**
- **Sam Lisney - Petrofac EPS West**
- **Sharon Robertson – Wood Group PSN**

Great Small Company (sponsored by Wood Group PSN)
- **Churchill Drilling Tools**
- **Enpro Subsea**
- **Step Change Engineering**

Great Large Company
- **Aker Solutions**
- **JDR Cable Systems**
- **Wood Group**

Significant Contribution (sponsored by Aker Solutions) - **Announced at the ceremony**

The winners will be announced at a black-tie ceremony on 23 March 2017 at the Aberdeen Exhibition & Conference Centre.

Dril-Quip acquires OPT

Houston's Dril-Quip will acquire OilPatch Technologies (OPT) in a US$20 million cash deal.

Founded in 1990, Houston-based OPT provides offshore riser systems and components, proprietary threaded connections and other products, with a focus on deepwater spar and tension leg platform systems.

"We welcome OilPatch Technologies and its employees to Dril-Quip and are confident their product offerings will complement and further strengthen our position as a leading provider of dry tree systems and associated riser products," said Blake DeBerry, Dril-Quip president and CEO.

GEODynamics adds perforating business

GEODynamics has established its UK operating company after acquiring Paradigm GeoKey's Aberdeen-based perforating business unit, effective 1 January 2017.

Chris Chalker, former managing director of Paradigm GeoKey, has joined the GEODynamics team as vice president – eastern hemisphere and will be based in Aberdeen to manage and grow GEODynamics' business throughout the region.

"Our Aberdeen-based team members are very familiar with GEODynamics' perforating technology," Chalker said. "GEODynamics' REACTIVE Perforating Technologies and their latest ECLIPSE Casing Removal Perforating Systems for the P&A (plug and abandonment) market, will help clients operate better in the difficult North Sea market."

Guyana creates petroleum directorate

Guyana's Ministry of Natural Resources says it is planning to have a new petroleum directorate established and functioning within Q1 this year.

The move comes as the South American country eyes its first offshore oil production, following ExxonMobil's Liza and Payara discoveries on the giant deepwater Stabroek Block.

Guyana's Ministry of Natural resources says the new directorate follows international models, which separate policy development from regulation monitoring.

Minister of Natural Resources, Raphael Trotman, says: "We now need to start preparing and using the opportunity (of) 2017-2020 when we hope to start producing, to put things in place, as many of the things as possible."

Approximately US$1 million (GY$200.7 million) has been allocated in the 2017 budget for petroleum management. This will be used for renting a building to house the directorate, procurement of equipment and furnishing.

The government has been updating and drafting policies and legislation that will govern the new sector, including an oil and gas policy, revised Petroleum Act and regulations, local content policy and regulations, petroleum commission bill, petroleum taxation and fiscal legislation, HSE (health, safety and environment) regulations and a bill to provide for sovereign wealth/ generational savings, stabilization, infrastructural, social welfare and citizens participation fund.

Mexican revival

Reinvigorated following recent energy reforms, Mexico's oil and gas industry will be on full display at the Petroleum Exhibition & Conference of Mexico (PECOM) in Villahermosa, Tabasco, this March.

Mexico is beginning to see progress following the painful rebirthing process its energy sector has undergone, opening to foreign investment for the first time in over seven decades.

In 2016, Mexico scored many milestones, including its first deepwater round – where 8 of 10 lease areas were awarded; its first-ever farm-out for the state-owned oil company Pemex – which was awarded to BHP Billiton for the Trion field; and, finally, Eni was approved to drill its Amoca 2 prospect, which it was awarded in Round 1.2 in September 2015. And of course, more good news is on the way, with Pemex pledging a more aggressive farm-out plan as part of its 2017-2021 business plan.

There's no doubt that 2017 will be a year of continued interest and success in Mexico. With that in mind, the 23rd annual Petroleum Exhibition & Conference of Mexico (PECOM) returns to Villahermosa with a who's who of Mexico's government and oil and gas industry leaders, who will be on hand to start discussions on the current and future potential of Mexico's oil and gas industry.

Attendees will be able to hear from experts in the Mexican energy community, including Mexico's Agency for Safety, Energy, and Environment (ASEA), National Hydrocarbons Commission (CNH) Center for Control of Natural Gas (CENAGAS), and the Mexican Petroleum Institute (IMP).

Several high-profile executives and industry leaders will serve as keynote speakers at PECOM 2017, including: Guillermo García Alcocer, President of the Energy Regulatory Commission; Federal Deputy Georgina Trujillo Zentella, President of the Energy Commission of the LXIII Legislature; Oscar Roldán Flores, Head of the National Data Center for CNH; Aldo Flores Quiroga, Deputy Secretary of Energy for Hydrocarbons; David Madero Suárez, General Director for the National Center for Control of Natural Gas (CENAGAS); Ricardo Fitz Mendoza, Secretary of the Ministry of Energy, Natural Resources and Environmental Protection, State of Tabasco; David Gustavo Rodríguez Rosario, Secretary of Economic Development and Tourism for the State of Tabasco; and Ernesto Rios Patron, Director General of IMP.

PECOM 2017's agenda also features updates on the country's energy reforms; new production and subsea technologies; case studies; geophysical challenges and opportunities; shallow and deepwater developments; drilling and completions; and subsea market trends and strategies.

Post-energy reform, Mexico's future burns bright, with the country's Round 2 just on the horizon. Round 2.1, now to be held in June 2017, follows Mexico's highly successful deepwater round, Round 1.4, which was held in December 2016. Round 2.1 will auction 15 shallow water areas in the Gulf of Mexico, in Tampico-Misantla, Veracruz and Cuencas del Sureste.

For more information on this year's conference and exhibition, please visit **pecomexpo.com**. OE

A capacity crowd listens to Pemex E&P's José Antonio Escalera Alcocer in 2016. OE Staff Photo.

Spotlight

Pain points, BOPs and enthusiasm for Big Data

Scott Weeden drills down with NOV's Hege Kverneland to find out why she is excited about using Big Data to predict component failures before they occur.

Just how exciting is Big Data? If you talk to Hege Kverneland, NOV's chief technology officer, she will tell you that Big Data will change both how the company and industry work.

"Outside our industry, Big Data is really market intelligence. Walmart probably knows what I'm going to buy before I know it," she laughs. While that's not her main focus, Kverneland is focused on an application called condition-based maintenance (CBM). "We can use Big Data and the computer capacity we have now to transform how we work."

For example, NOV can now predict which valve in its blowout preventer (BOP) stack will fail at least 14 days in advance. If the company can predict that, then the operator and drilling contractor can plan downtime better.

"If the BOP fails, we need to lift it up, replace the part and lower it down again, in the worst case. If we can avoid taking it up and then down again just one time, that can be a lot of money saved," she explains.

NOV started work on CBM for its BOPs more than a year ago. "Instead of saying we want to do this on all the equipment, we're focusing on the BOP. We have legacy data from our own BOPs from 14 years back. We've taken all that data, focused on one well and one failure mode, which we can then

Hege Kverneland

identify," Kverneland says.

The company is working very systematically, taking on one component at a time. NOV started with its subsea BOPs since there are some really big cost savings in offshore operations.

"We're also looking at putting this technology on all our drilling machinery—top drives, drawworks, mud pumps and pipe handling equipment. But we needed to focus on the biggest pain points at the beginning. Then we will add all the other components," she adds. The company will also begin using Big Data for both drilling and production optimization.

There are five or six major failure parts that the company has focused on. "We can never guarantee that we will always predict the failure before it actually happens. It will never be 100% accurate, but we will be able to say that we can reduce it tremendously," she says.

Kverneland's excitement about Big Data can be heard in her voice. But, how can that excitement spread to others in the company and its customers? Money, of course.

"To get the best use of their equipment by making sure that uptime is much better will hopefully save the industry a lot of money in the future. I believe Big Data will be more important on offshore installations. It will help on land, but offshore it will really help us reduce the cost," she says.

The engineers are very excited, and they see that this is an opportunity for NOV. "In order to make a lot of people excited about it, we need to be able to make money on it. It is difficult to get a lot of people excited just because it is new technology. It needs to be a business benefit. We cannot just make it better for the drilling contractors and operators, we also need to make it beneficial for the company," she says.

"I'm convinced this will be a win-win-win for the industry. It will be a win for us, a win for the drilling contractor and a win for the operator," she emphasizes.

Kverneland has been with NOV for more than 20 years, starting in 1991. The original company has been purchased, acquired or merged at least four or five times. She took a three-year break in 1998-2000 and came back to the company. "Most people that have grey hair have been with the company for a while. I have grey hair," she laughs. **OE**

The BOP has an overlay showing the status of the component. Photo by Katy Weintritt; provided by NOV.

NOV's customer portal for BOP condition monitoring. Images from NOV.

Editorial Index

What's next

Coming up in OE March

Feature – Annual Rig Market Review

- EPIC – Greenfield
- Subsea – Subsea Technologies
- Production – Artificial Lift
- Drilling & Completions – Extended Reach Drilling
- Regional Overview – Latin America

PLUS

- Annual Offshore Mexico Review

BONUS DISTRIBUTION

SPE/IADC Drilling Conference and Exhibition
The Hague, Netherlands
March 14-16, 2017

PECOM - Petroleum Exhibition & Conference of Mexico
Parque Tabasco, Villahermosa, Tabasco, Mexico
March 28-30, 2017

Offshore Mediterranean Conference & Exhibition
Ravenna, Italy
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