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EPIC Deepwater **28**

PRODUCTION Carbon Capture & Storage **34**

DRILLING New semi design **42**

Big Data

- **Reducing costs** 20
- **Security risks** 22
- **Autonomous systems** 26

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Features

ON THE COVER

Deep dive. The oil and gas industry generates a lot of data from a wide variety of instruments. Liquid Robotics, a Boeing company, provides this month's cover shot of a wave glider out to sea to collect more data to feed the beast.

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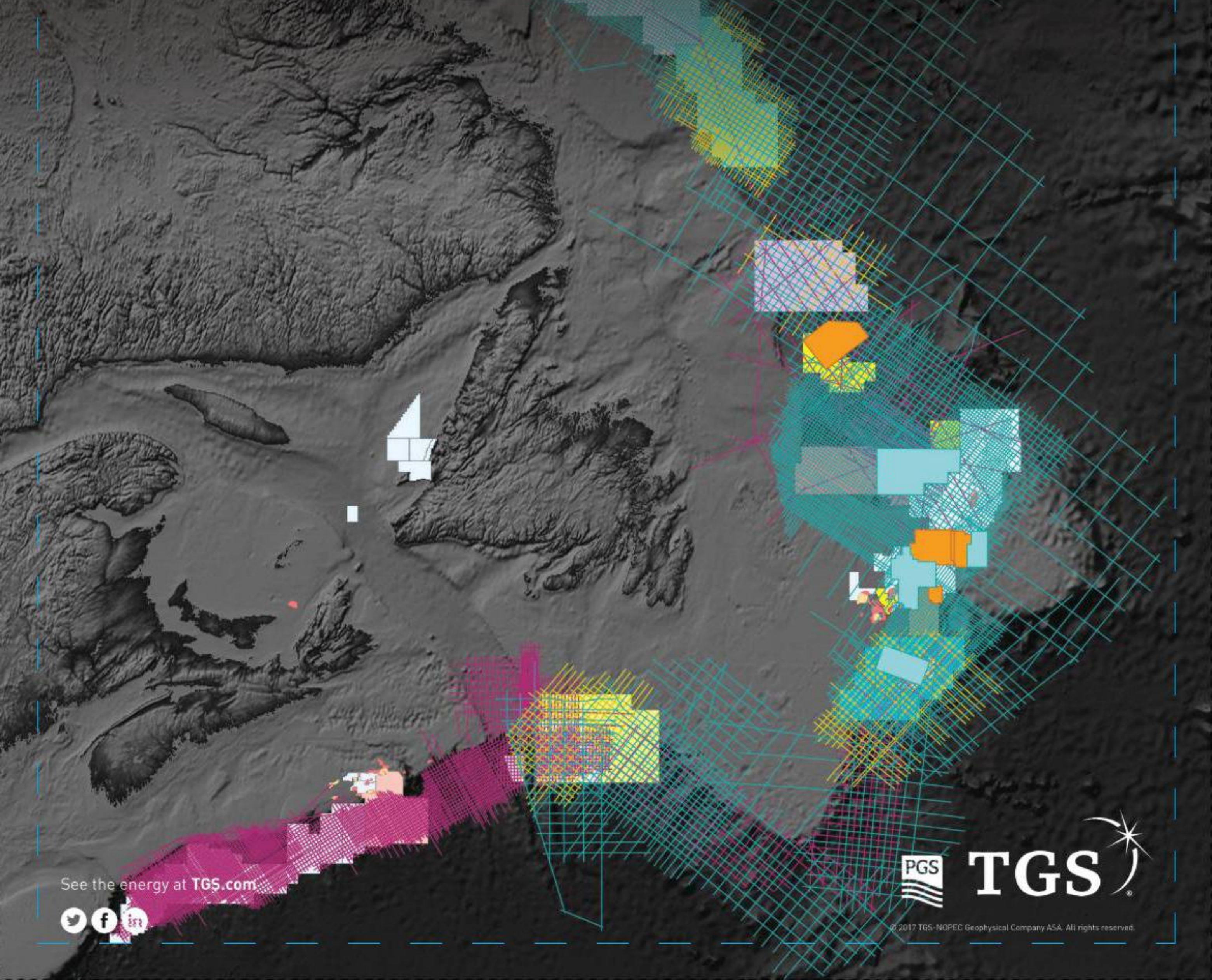

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Online Exclusive

Uruguay, take three

Karen Boman reports on Uruguay's hopes that its third offshore licensing round will attract investment needed to prove its offshore hydrocarbon resources.

What's Trending

Photo from Lee Hyeongjin/Statoil.

In Development

- Eni boosts Mexico Area 1 reserves
- Aasta Hansteen topsides on the move
- Providence forges ahead with Barryroe

People

Weatherford names new COO

Weatherford named Karl Blanchard its new executive vice president and chief operating officer.

Undercurrents

Strength in numbers

OE went to press last month before Hurricanes Harvey and Irma barreled down on the Gulf of Mexico-region with exceptional fury, bringing devastating floods and destruction in their collective wake. It is estimated that the economic cost of both hurricanes could be around US$290 billion, according to AccuWeather (as of 10 September).

Houston is home to most of *OE*'s staff. While our hearts are heavy for those who have lost so much and endured so much during these times of adversity, we are inspired by the strength and goodwill that emerged after the rain clouds dissipated. Throughout the affected regions, we saw neighbors helping neighbors and the community at-large coming together. And, naturally, those businesses in the region, came out in a big way to help with disaster relief.

It was said in many a panel at this year's SPE Offshore Europe 2017 that the industry doesn't do enough to tout the good it does for the community. Well, we thought we'd give it a shot.

Supermajor ExxonMobil, which has 23,000 employees in Texas and Louisiana, pledged $9.5 million to Harvey relief efforts. US oil major ConocoPhillips pledged $5 million. US-based supermajor Chevron, which said Houston represents the largest concentration of its employees, pledged $1 million to Harvey relief efforts and $1 million for Irma relief. Woodlands, Texas-based Independent Anadarko Petroleum pledged $1 million for disaster relief.

Anglo-Dutch supermajor Shell, which has some 20,000 employees in the US, has pledged $1 million for relief efforts. CEO Ben Van Beurden said he was left humbled by the storm and people's resilience.

Supermajor BP and its BP Foundation contributed $750,000 to relief efforts and also donated 100,000 gallons of gasoline to The Harris County (includes the Houston-region) Office of Emergency Management and the City of Houston for first responders during response and clean-up efforts. BP's US headquarters is in Houston, and employs some 4500 people in the region, and 6000 in Texas.

Norwegian oil company Statoil, which has an office in Houston's energy corridor and has said that Texas represents its largest presence outside Norway, has pledged $250,000 for relief efforts. France's Total, which has an office in downtown Houston, pledged $250,000.

Service companies have also donated. Baker Hughes, a GE company, has donated $1.1 million. TechnipFMC, which has three corporate headquarters, one of which is in Houston, pledged $1 million. TechnipFMC has about 4500 employees in the Gulf Coast region. Weatherford has pledged $50,000 to relief efforts. Houston-based Oceaneering pledged a contribution of $100,000. Wood Group has raised (at the time of this writing) $69,000 through its Hope After Harvey crowdfunding page via YouCaring.com.

Honeywell donated $2 million in personal protective equipment to support first responders and emergency personnel, giving some 100,000 pieces of safety clothing, protective footwear, rubber boots, safety gloves, disposable masks for respiratory protection, protective eyewear, hard hats and hearing protection. Red Wing Shoes, which specializes in protective gear, pledged product donations of $500,000, in partnership with Good360, to provide disaster victims with work boots and coveralls, socks and footwear.

These companies are just the tip of the iceberg. But together, that's a lot of good will and a lot of money put toward rebuilding the Gulf Coast region.

Of course, these aren't the only worries. Mexico was struck by multiple deadly earthquakes in September, and Puerto Rico has been hit hard by Hurricane Maria. There is much rebuilding left yet. But, as an industry and a community, we have demonstrated we are stronger together. **OE**

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Global E&P Briefs

NEWS

A LLOG pushes Buckskin forward

LLOG Exploration will develop Buckskin in the deepwater Gulf of Mexico, aiming to hit first production by 2H 2019. LLOG also signed a deal with Seadrill for the *West Neptune* to begin work in Q4 2017. Buckskin is in 6800ft water depth in Keathley Canyon, and extends over six blocks: 785, 828, 829, 830, 871 and 872. The field is estimated to hold nearly 5 billion bbl. Chevron walked away from the Buckskin-Moccassin project in January 2016. LLOG operates Buckskin (31.3%). Its partners are Repsol (22.5%), Samson Offshore (22.5%), Beacon Offshore Energy (18.7%), and Navitas (5%).

B Alaminos Canyon survey underway

CGG began its first complementary wide-azimuth (CWAz) survey, a BroadSeis 3D multiclient program in southern Alaminos Canyon, in the Gulf of Mexico. Extending over 130 Outer Continental Shelf blocks, it covers the Great White and the recent Whale discovery. All the data will be combined and reprocessed using the latest 3D deghosting, Full-Waveform Inversion, especially Reflection-based FWI, and Tilted Transverse Isotropy imaging technology. Jean-Georges Malcor, CEO, CGG said the survey will build upon the Encontrado survey by extending high-quality images across the US side of the Perdido Fold belt.

C Orinduik 3D survey completed

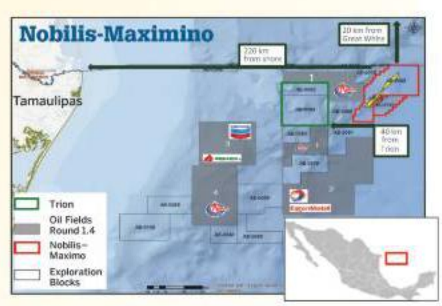
WesternGeco completed a completed a 3D seismic survey on the Orinduik Block offshore Guyana for Tullow Oil and partner Eco Atlantic. Orinduik is up dip from Exxon's Liza and Payara finds, confirming, by Exxon's estimates, between 2.25-2.75 billion bo recoverable. The partners expanded the survey from its original 1000sq km size to 2500sq km due to regional success and a review of existing and regional 2D data.

D Uruguay launches third round

Uruguay is offering 17 areas in three basins in its third offshore oil and gas licensing round. The areas will be divided in Type I, Type II and Type III according to water depth, which range from 50-4000m.

E Pemex seeks Nobilis-Maximino partner

Mexico's National Hydrocarbons Commission (CNH) published a call for bids seeking a partner for state-owned oil firm, Pemex's, Nobilis-Maximino deepwater prospect area. Nobilis-Maximino is in the Perdido Fold Belt, 40km from Trion and 26km from Great White, in 3000m water depth. It is 230km off the coast of Tamaulipas and 15km from the US maritime border. At 1524sq km, the area has 3P reserves of 502 MMboe of light oil, with estimated production of 300,000 b/d. CNH will open proposals for a farm-out partner on 31 January; the same date as Mexico's next deepwater Round 2.4.



The qualification submission deadline is 6 April 2018. Offers will open on 26 April 2018. French oil major Total drilled the then-deepest water well in the world, Raya-1, in Uruguay in 2016.

F Malvinas 2D reprocessing underway

Searcher Seismic has entered Argentina with the start of a Malvinas Basin 2D reprocessing project offshore Argentina. The project covers 15,000km of existing data over the West Malvinas Basin failed rift basin.

"The Malvinas Basin in particular offers high impact, moderate risk exploration in shallow water, with a bid round expected to be announced later this year," said Searcher Seismic.

The next phase includes the Malvinas Basin Non-Exclusive 2D seismic survey; a regional survey comprising ~11,000 km and tying 18 exploration wells and a Malvinas Basin Seep Detection Program, both scheduled to start this year.

G Lancaster EPS approved

Hurricane Energy received approval to move forward with its West of Shetland fractured basement Lancaster field early production system (EPS). The Lancaster EPS is a two-well tieback to a FPSO, Bluewater Energy Service's *Aoka Mizu*.

It is expected to produce 17,000 b/d and provide data required for a full field development for the 500 MMbbl field.

Procurement and fabrication work has already started on the subsea equipment, from TechnipFMC, and mooring buoy. The drilling contractor is Transocean.

H Additional oil for Wisting

OMV has found additional oil on its Wisting field in the Barents Sea through its latest appraisal well 7324/8-3. The well found a 55m oil column in sandstones from the Middle Jurassic to Late Triassic. Drilled in 396m water depth using the *Island Innovator* semisubmersible, the well will be permanently plugged and abandoned. OMV's previous resource estimate for Wisting, discovered in 2013, was 22-80 MMcm of recoverable oil equivalents. The company drilled the well about 2km south of the discovery well 7324/8-1 and 315km north of Hammerfest.

J Wintershall to drill Balderbrå

Norway's Petroleum Safety Authority has approved Wintershall to drill a wildcat in a prospect named Balderbrå in the Norwegian Sea. The well is in PL 894 at 1220m water depth, where Wintershall is the operator. Drilling is planned to begin by 1 October 2017, and will last 36 days, depending on whether a discovery is made. The well will be drilled with the *West Phoenix* semisubmersible drilling facility, operated by North Atlantic Drilling.

K Further testing for Fatala

Hyperdynamics will further test the Fatala prospect area offshore the Republic of Guinea for commercial resources, despite failing to encounter hydrocarbons with its Fatala-1 prospect well.

The company says it has identified in well logs 5m of calculated hydrocarbons in the upper Cenomanian channel above the primary target formation.

Fatala-1 was drilled in 2897m of water and reached total depth of 5117m below sea level, the deepest water well ever drilled offshore Africa. Hyperdynamics is going solo with appraisal as partner South Atlantic Petroleum is not moving forward with the program.

I Shah Deniz topsides installed

The BP-led Shah Deniz consortium is on track for first gas for stage 2 of the giant project next year, following the installation of the last two major topsides facilities in the Caspian Sea, offshore Azerbaijan. The second topsides unit built for the Shah Deniz Stage 2 project, the production and risers (PR) platform, was installed. The installation of the first unit, the quarters and utilities (QU) platform topsides was completed in early-July. The PR platform, weighing some 15,800-tonne and 100m-long by 60m-wide, contains a 133m-long flare boom, 10 flowline reception facilities, five production separators, two flash gas compressors and three production export flowlines. The Shah Deniz field spans some 860sq km, and is about 70km offshore Baku, Azerbaijan, in 50-500m water.

Global E&P Briefs

L Ophir hopeful on Fortuna

UK-headquartered operator Ophir Energy is holding out hope that the Fortuna FLNG project offshore Equatorial Guinea will reach final investment decision (FID) by Q4 2017, but the company still has a few hurdles to pass.

During 1H 2017, project partners signed an umbrella agreement that established the full legal and fiscal framework for the Fortuna FLNG project. The key milestone outstanding prior to FID is the completion of the project funding, which Ophir expects to be completed ahead of an FID decision during 4Q 2017. In the meantime, Ophir will focus on monetizing its net 1 billion boe of discovered resources.

M Cyprus gas probe non-commercial

Cyprus' Ministry of Energy, Commerce, Industry and Tourism said Total's Onesiphoros West 1 exploration well offshore Cyprus had gas shows in a carbonate reservoir but not in commercial quantities.

Despite being non-commercial, the government said the discovery was "highly positive, since it confirms the existence of a petroleum system and a carbonate reservoir within the Cypriot Exclusive Economic Zone, similar to this Egyptian Zohr deposit."

The well was drilled in Block 11 using the *West Capella* drillship.

N Pearl shines for Empyrean

Australia-headquartered Empyrean Energy found a new prospect offshore China, Pearl, after finalizing the preliminary internal interpretation of the fast-tracked processing of raw seismic data from 3D seismic on Block 29/11.

The preliminary interpretation confirmed the structural validity and the potential size of the Jade and Topaz prospects and has revealed a new prospect named Pearl, which is to the north of Topaz.

Data revealed that interpretation of gross unrisked mean prospective resources for all three prospects are 591 MMbbl.

Block 29/11 is about 1800sq km and is some 200km south-southeast of Hong Kong in 340-600m water depth.

O Norwest hits at Xanadu

Norwest Energy hit hydrocarbon pay at the Xanadu-1 shallow water well offshore Western Australia. The well was drilled in permit TP/15, 40km south of Dongara, as a conventional oil exploration well, designed to test for the presence of hydrocarbons in the Xanadu prospect.

Drilling results encouraged the company and its joint venture partners to commit to running a wireline logging suite that included pressure testing and fluid sampling.

Norwest and partners also agreed to extend drilling beyond the base of the High Cliff Sandstone to include the deeper sandstones of the Holmwood Shale, reaching a TD of 2035 mMDRT on 17 September. ■

Contracts

Hurricane awards Lancaster EPCI

TechnipFMC has been awarded an engineering, procurement, construction and installation (EPCI) contract from Hurricane Energy for the Lancaster early production system West of Shetland.

TechnipFMC's contract covers the provision of subsea equipment including umbilicals, risers, flowlines and the subsea production system for the Lancaster EPS. In addition, TechnipFMC will also install the subsea equipment, turret buoy and mooring system. The contract will be executed as an integrated EPCI project.

New vessel for Subsea 7

Subsea 7 has signed a letter of intent with Royal IHC for the construction of a new US$300 million reel-lay vessel and associated pipe lay equipment for delivery in early 2020.

When delivered, Subsea 7 says the vessel will its highest specification reel-lay vessel, capable of installing complex rigid flowlines including pipe-in-pipe systems and electrical trace heating.

Subsea 7 says its capability will address a market trend towards longer tieback developments. The vessel will replace the Seven Navica, which is expected to be retired. Subsea 7 bought the *Seven Navica* in 2008.

Aibel awards CIP for Dvalin

Norway-based PG Flow Solutions has won a contract from Aibel to provide a chemical injection package (CIP) for the Dvalin tie-in to Heidrun topside EPCI project. PG Flow Solutions' scope of work is a 8.5m x 3.8m x 3m CIP, which will be a part of the new M40 module to be installed at the Heidrun platform.

All work will be performed at the company's main fabrication site in Sande, Vestfold, Norway. PG Flow Solutions will manage the project as a supplier to Aibel's engineering office in Asker, Norway. The completed CIP will be delivered to Aibel's yard in Haugesund, Norway. Delivery is scheduled for Q1 2018.

Ichthys subsea work awarded

Wood Group secured a new five-year contract with Inpex to provide subsea engineering services for the integrity of the Ichthys LNG Project, offshore Western Australia. The operations of all subsea assets and the gas export pipeline will be supported under the contract, which includes two, one-year extension options and is effective immediately.

It continues Wood Group's 12-year support of the Ichthys LNG Project development; providing subsea engineering and project management services during the concept, front-end, and detailed engineering phases of the project.

InterMoor wins Mad Dog 2 work

InterMoor has been contracted by Subsea 7 to provide mooring and tow services for BP's Mad Dog 2 project in the US Gulf of Mexico.

The contract's scope includes InterMoor securing the new semisubmersible production platform at depths of 4440ft. InterMoor will install the new Mad Dog 2 platform, which includes wet tow and mooring installation. ■

showcase

Lucky for some

Alpha Petroleum is proving that there's room for small independents to make their mark in the UK North Sea. Elaine Maslin looks at the firm's Cheviot field plan.

Some fields get a second chance. For Cheviot, it could be third time's the charm, under plans by Alpha Petroleum, an independent oil firm backed by private equity firm Petroleum Equity, focused on the UK North Sea.

The field, discovered in 1975, in blocks 2/10b, 2/15a, 3/6a and 3/11b, produced from 1992-1996, and has laid dormant since.

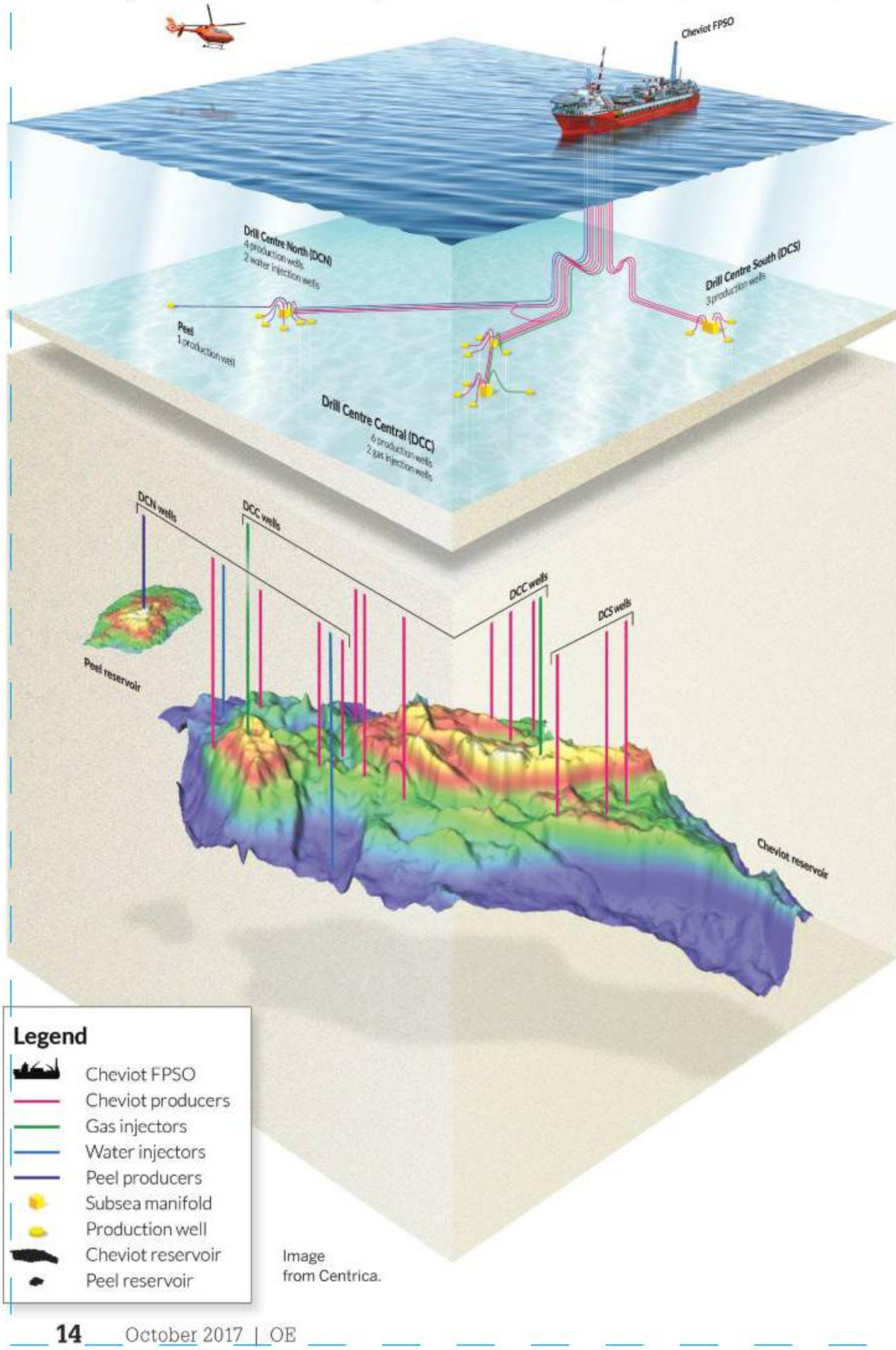


Image from Centrica.

Now, Alpha is planning to deploy the *Petrojarl Varg* floating production, storage and offloading (FPSO) unit on the field, with first oil from Cheviot and the Peel field targeted for 2019. There are 18 firm and five contingent wells planned. Late September, Alpha contracted Awilco's *WilPhoenix* to drill 18 production wells, starting Q2 2018.

"We've looked at the problem differently," says Andy Crouch, Alpha's CEO. "The issue for smaller companies is getting finance. There's no point having a good idea if you cannot get finance. We set a target of having full cycle costs from today to decommissioning of less than US$40/bbl, so that the economics are not driven by the oil price but our stand-alone development, driven by strong technical understanding and knowledge and being able to work in a low-cost environment."

A false start

The Emerald field was first brought onstream in 1992 by Midland & Scottish Energy using the *Emerald Producer* floating production unit, a conversion of the *Ali Baba* semisubmersible drilling rig, chartered from Trafalgar House Offshore & Structural.

In-place hydrocarbons were estimated to be 216 MMbbl of oil and 61 Bcf of gas, with an estimated 43 MMbbl recoverable oil by the initial development plan, according to a 1991 Geological Society paper.

But, the field was decommissioned in 1996, due to a high level of water production and low oil prices (since 2009, the *Emerald Producer*, now called the *Northern Producer*, owned by Northern Offshore, has been working on EnQuest's West Don field in the UK northern North Sea). When the field was abandoned, just 8% of the original oil in place had been produced, according to Alpha.

In 2007, ATP Oil & Gas outlined plans to develop the field, initially via a concrete gravity-based platform, targeting 2009-10 first production with up to 10 production wells and two water injection wells.

The concept was later changed to a new design, the Octabuoy, designed by Moss Maritime. It was a semisubmersible floating platform. Peak production was expected to be 35,000 b/d of oil and

60 Mcf/d of gas via 16 wells, comprising 13 producers and two water injectors and one gas producer. First production was targeted for 2014. A hull contract for the Octabuoy was awarded to Cosco Nantong Shipyard, but Cosco discontinued work in 2016, after ATP went into a company voluntary arrangement (CVA) in July 2014, following its parent company, ATP Oil & Gas Corp., filing for a Chapter 11 bankruptcy protection.

Fast forward

Cheviot, a Jurassic reservoir, will now be produced via three drill centers (driven by the field size and geometry), at 2.1-3.6km from the *Petrojarl Varg*. There will be a minimum 18 wells: 13 production wells, two water injection wells and two gas injection wells. The project also includes one production well in the satellite Peel oil reservoir and there are also infill opportunities, says Crouch, who was CEO at Gaffney Cline Associates before becoming CEO at Alpha, and a senior manager at British oil firm Lasmo before that.

There will be a subsequent "simple" development of the Cheviot gas caps and Padon satellite field. In total, Alpha says it is developing at least 55 MMbbl and future gas volumes of 120 Bcf. The firm says the Cheviot facility could also be used as a hub for other nearby discoveries and prospects, which have an unrisked potential of some 400 MMboe

Alpha has had the benefit of the previous production history on Emerald, as Cheviot was known, as well as relatively recent seismic data. "We have done a lot of work assessing different well configurations and the gas and water injection configuration," says Crouch. "A lot of reservoir engineering work and development work was done to get a firm understanding of what the potential of the field could be under different scenarios."

A new conversion FPSO was considered, but ruled out early. Instead, the firm looked at what was available in the rental market to see if anything would broadly fit the bill, and then finalize the development plan based on that concept. It might not result in the optimum technical development option, but it's the more economic development option, says Crouch.

"We have looked at the problem in a different way and how to get to the solution with what is available to us," says Crouch. "Because this is a redevelopment – it effectively had a four-year production test – we have a lot of good information on the size and productivity and what the processing requirements we need are."

The *Petrojarl Varg*, a ship-shaped, turret-moored FPSO, delivered in 1998, was picked. It has 470,000 bbl storage capacity, and 57,000 b/d oil production capacity. Alpha has signed an exclusivity agreement with Teekay to redeploy the 210m-long *Petrojarl Varg*, which has accommodation for 77 people, and 10 riser slots, on Cheviot, with project sanction expected in Q4 this year and first oil production targeted for 2019. Production is expected to be about 30,000 b/d.

The *Petrojarl Varg* had been working on Repsol's (formerly Talisman) Varg field offshore Norway, alongside a wellhead platform. Production at Varg started in 1998 and ended in 2016. The vessel has since been laid up outside Stavanger, Norway, near Intecsea's Rosenberg yard. A yard for some work ("a lick of paint" and minor process modifications) on the *Varg* was being finalized in July. Work is due to start next year. Once up and running, Cheviot is expected to have a 10-year field life.


The *Petrojarl Varg*.
Image from Teekay.

Alpha has taken a similar approach to the subsea umbilical, flowlines and risers and subsea production system packages. "Traditionally, we find a project engineering company to set out specifications and that normally takes quite a bit of time and money and you end up haggling with the contractors," says Crouch. "We engaged a different way. We had functional specifications for the trees and manifolds." After a competitive tender, GE Oil & Gas came out on top. "It reduces the interfaces," says Crouch.

Alpha has an agreement with GE Oil & Gas for it to partner on the advancement of the subsea infrastructure for Cheviot. GE Oil & Gas will also supply the project's subsea trees, a full control system, three manifolds, flexible jumpers, flowlines, risers and umbilicals. GE Oil & Gas will also provide subsea construction and installation services, and support commissioning.

In addition, GE Energy Financial Services is helping to raise the needed debt financing for the project and is in discussion with Alpha Petroleum with the intention, subject to due diligence, of making a significant capital investment at the time of final investment decision.

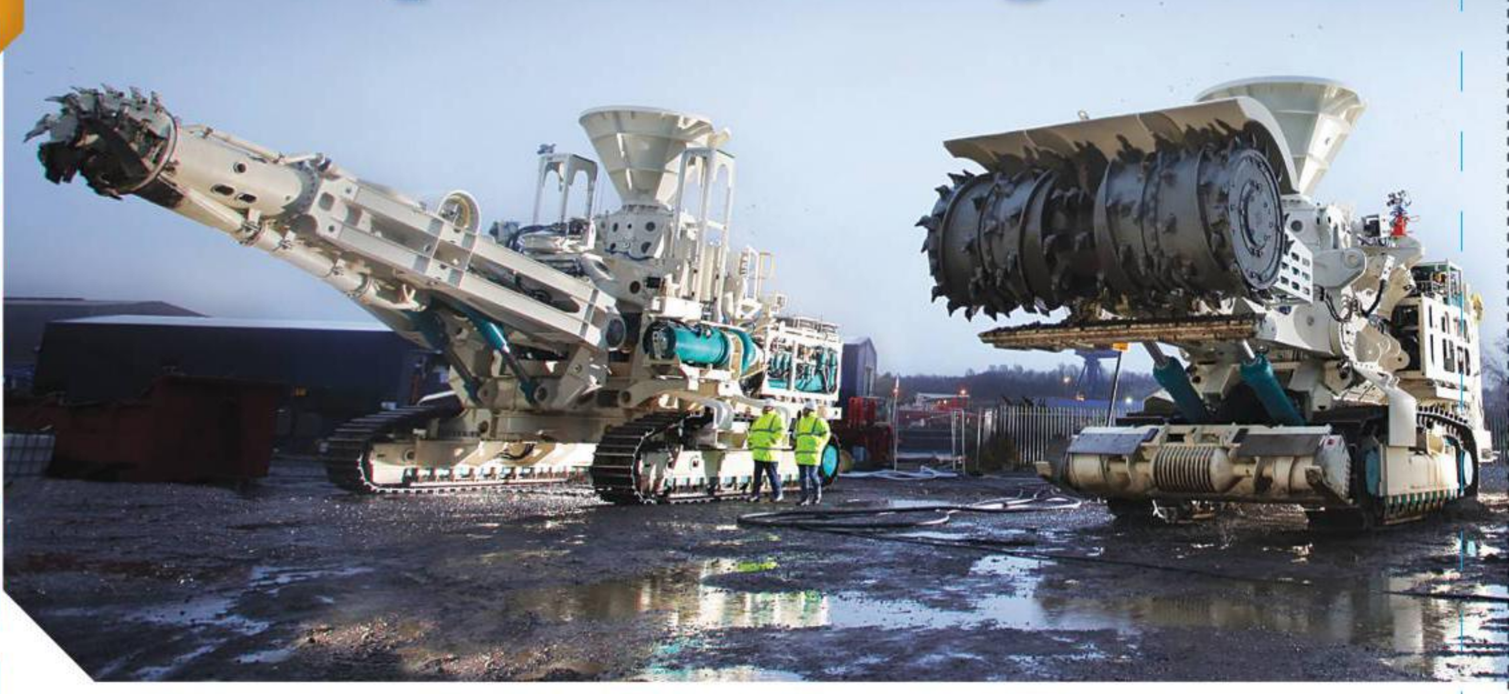
Development well drilling is due to start in Q2 2018, with a rig contract expected to be announced in July/August. Eight wells will be drilled before first oil: five Cheviot producers, one gas injector and one water injector, plus a Peel well. Nearby are three other accumulations which could also tie-in to Cheviot, one which is unlicensed and two others which are held by other operators, one with which Alpha has already had discussions.

It's a repeatable model, Crouch adds. *Varg* could be reused to produce from other abandoned or and end of life fields where platform facilities are no longer economical. Or another FPSO could be found to do similar work. Tapping small pools is expected to be part of the UK North Sea's 30th Licensing Round, with quite a few fields "that have been around for quite some time" hopeful of finding an Alpha to come along and change their fortunes. OE

ANALYSIS

In-Depth

Deep sea mining



Deep sea minerals have been seen as a potential new source for in demand metals and rare earth elements. Offshore sector firms are eyeing the potential for a new revenue stream. Elaine Maslin reports.

Many are looking to a new resource, deep sea minerals, thanks to growth in demand from emerging economies and the development of new technologies that require increased supply of metals such as copper.

While interest in mining metals from the deeps has been ongoing since the 1960s, activity has remained low, due to low metal prices and the challenges of operating in deep sea environments. This activity is also the focus of strong local and environmental opposition.

Slowly, however, the pieces have been falling into place to permit this activity. In 1982, the United Nations Convention on the Law of the Sea (UNCLOS) established the International Seabed Authority (ISA), based in Jamaica, to organize and regulate mineral-related activities in seabed areas beyond the limits of national jurisdictions.

More recently, the MIDAS project, which sought to assess the environmental hazards of deep sea mining, reported its findings. Many in the offshore sector, with technologies that could be complimentary to this space, are watching, but there are still concerns over its impact.

All that glitters

According to the MIDAS program, there are three types of resource: polymetallic (or manganese) nodules that occur in surficial seafloor sediments in abyssal plain muds, mainly in the Pacific and Indian Oceans; cobalt-rich ferromanganese crusts (CRCs) that occur as a surface encrustation on seamounts and rock outcrops in all oceans, but with the richest deposits found in the western Pacific; and seafloor massive sulfides (SMS) that are formed at seafloor hot springs along ocean plate boundaries.

Polymetallic (manganese) nodules – 2-15cm in diameter– can be found some 4-6km deep, and could provide a source of copper, nickel, cobalt and manganese, as well as rare earth elements. Mining them, and others, requires a combination of remotely-operated or autonomous underwater vehicles, pumps, suction and riser pipes, Italian shipbuilder Fincantieri's Marko Keber told the Offshore Mediterranean Conference (OMC) in Italy, in March.

Polymetallic sulfides, meanwhile, are found in 1500-3000m water depth and are made of sulfide minerals containing various metals, such as copper, lead, zinc, gold and silver. Cobalt rich ferromanganese crusts (CRCs), are found in 800-2400m water depth, and are composed of ferromanganese oxides and contain cobalt, nickel, manganese, tellurium, rare earth elements and possibly platinum, Keber says.

Nautilus' sea floor production tools, made by Soil Machine Dynamics.
Photo from SMD.

Activity

Since 2000, the ISA has signed 13, 15-year exploration contracts. Six of these contracts expired in 2016 and a seventh will expire in 2017. The areas being explored are in the Clarion Clipperton Fracture Zone, the Indian Ocean, Mid-Atlantic Ridge, South Atlantic Ocean and the Pacific Ocean, according to an ISA report from last year.

There are concerns relating to impact of the mining systems on the sea floor, the creation of sediment plumes as a result of seabed operations, the integrity of the riser pipes and the release of waste materials following pre-processing of the minerals at the sea surface, says MIDAS, which conducted research from the *Pelagia* vessel from 2013-2016. "The scale of these impacts needs to be assessed so that the development of regulations to control mining activities can be properly informed."

"New environmental issues need to be considered, such as the large surface areas affected by nodule mining, the potential risk of submarine landslides through sediment destabilization in gas hydrate extraction, or the release of toxic elements through oxidation of minerals during seafloor massive sulfides (SMS) mining," MIDAS adds.

Some of MIDAS' work on sediment-laden plumes showed that they could have significant impact on ecosystems tens of kilometers away from the mined sites. MIDAS project scientists said that investment in technology (to limit the generation of plumes during mining) and in legislation (to make sure all contractors adhere to best practice) would be needed, as well as more research. Even with legislation,

In-Depth

Quick stats

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

New discoveries announced

Depth range	2014	2015	2016	2017
Shallow (<500m)	76	57	36	17
Deep (500-1500m)	30	18	12	3
Ultradeep (>1500m)	12	11	10	4
Total	118	86	58	24
January 2017	127	114	72	-
date comparison	-10	-28	-14	24

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

Reserves in the Golden Triangle

by water depth 2017-21

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	12	287	2333
Deep	10	850	1295
Ultradeep	34	10,740	12,756
United States			
Shallow	5	45	89
Deep	22	800	1384
Ultradeep	18	2034	1725
West Africa			
Shallow	112	3669	16,454
Deep	23	2070	3130
Ultradeep	12	1611	2398
Total	236	21,819.00	39,231.00
(last month)	(232)	(22,136)	(39,491)

Greenfield reserves

2017-21

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	875	33,435	315,810
(last month)	(875)	33,365)	(320,427)
Deep	116	5193	65,828
(last month)	(119)	(5215)	(75,778)
Ultradeep	75	15,915	46,542
(last month)	(75)	(16,415)	(47,042)
Total	1,069	54,995	443,247

Pipelines

(operational and 2017 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,907	(41,862)
Planned/ possible	21339	(21,323)
	63,246	(63,184)
8-16in.		
Operational/ installed	82,901	(82,442)
Planned/ possible	46,481	(46,731)
	129,381	(129,173)
>16in.		
Operational/ installed	96,019	(96,182)
Planned/ possible	50,742	(46,895)
	146,761	(143,077)

Production systems worldwide

(operational and 2017 onwards)

		(last month)
Floaters		
Operational	311	(313)
Construction/ Conversion	41	(40)
Planned/possible	289	(286)
	641	(639)
Fixed platforms		
Operational	9075	(9019)
Construction/ Conversion	79	(90)
Planned/possible	1299	(1305)
	10,453	(10,414)
Subsea wells		
Operational	9075	(5193)
Develop	79	(326)
Planned/possible	1299	(6262)
	10,453	(11,781)

Global offshore reserves (mmboe) onstream by water depth

	2015	2016	2017	2018	2019	2020	2021
Shallow	21,385.42	32,117.92	20,854.43	20,164.01	12,361.24	16,412.81	19,213.42
(last month)	(21,290.90)	(32,117.92)	(21,875.58)	(19,968.71)	(12,360.76)	(16,216.52)	(19,410.75)
Deep	960.47	4215.67	2051.08	2580.97	4690.17	4753.11	2719.83
(last month)	(960.47)	(4215.67)	(1198.15)	(2933.58)	(2034.93)	(4753.11)	(7653.26)
Ultradeep	2000.69	3100.14	903.85	4582.16	3642.68	9520.31	5531.72
(last month)	(2000.69)	(3100.14)	(907.60)	(4828.49)	(3863.12)	(9637.94)	(5531.72)
Total	24,346.58	39,433.73	23,809.36	27,327.14	20,694.09	30,686.23	27,464.97

Source: InfieldRigs 7 September 2017

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	88	60	28	68%
Jackup	393	229	164	58%
Semisub	105	62	43	59%
Tenders	28	15	13	53%
Total	614	366	248	59%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	29	20	9	68%
Jackup	25	5	20	20%
Semisub	8	4	4	50%
Tenders	N/A	N/A	N/A	N/A
Total	62	29	33	46%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	11	5	6	45%
Jackup	114	70	44	61%
Semisub	30	13	17	43%
Tenders	21	12	9	57%
Total	176	100	76	56%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	21	17	4	80%
Jackup	50	27	23	54%
Semisub	21	13	8	61%
Tenders	2	1	1	50%
Total	94	58	36	61%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	48	28	20	58%
Semisub	32	24	8	75%
Tenders	N/A	N/A	N/A	N/A
Total	81	53	28	65%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	118	79	39	66%
Semisub	3	3	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	121	82	39	67%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	17	13	4	76%
Jackup	14	8	6	57%
Semisub	2	1	1	50%
Tenders	5	2	3	40%
Total	38	24	14	63%

Eastern Europe

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

Source: InfieldRigs 7 September 2017

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

opposition is likely to remain to this activity.

Exploration plows on

Nevertheless, activity is ongoing. Most recently, ISA and China Minmetals signed a 15-year exploration contract for polymetallic nodules over a surface area of 72,745sq km of the Clarion-Clipperton Fracture Zone in the Pacific Ocean.

China has also been sponsoring another contractor with the ISA for the exploration for polymetallic nodules in the Clarion Clipperton Zone since 2001, and for which a five-year extension was signed this year. China also sponsors the China Ocean Mineral Resources Research and Development Association (COMRA) in contracts for exploration for polymetallic sulfides in the Southwest Indian Ridge and for exploration for CRCs in the West Pacific Ocean.

In January, ISA approved a plan for Poland to explore for polymetallic sulfides in the Mid-Atlantic Ridge between the Hayes, Atlantis and Kane transform fault zones, with 100, 10x10 km exploration blocks.

Nautilus

Nautilus Minerals could be the first company to commercially explore the sea floor. The company plans to search for SMS systems, a potential source of high grade copper, gold, zinc and silver.

Nautilus is developing a production system using existing technologies adapted from the offshore oil and gas, dredging and mining industries.

Its first project, a copper-gold project, Solwara 1, is due to start development offshore Papua New Guinea in Q1 2019, subject to financing.

Canadian-listed Nautilus has been developing the kit it needs for carrying out this work, including three sea floor production tools (SPTs), a riser and lifting system (RALS), a launch and recovery system (LARS), and a production support vessel (PSV).

The SPTs, built in northeast England by Soil Machine Dynamics (SMD), arrived in Papua New Guinea earlier this year and are being put through trials. Work on the production support vessel, including integrating the LARS and ancillary equipment, is ongoing at Fujian Mawei Shipbuilding's Mawei shipyard in China.

The SPTs comprise three different vehicles, one each for three separate sea floor tasks. These are an auxiliary cutter to prepare the sea bed for the second tool, a more powerful bulk cutter. This is then followed by the third vehicle, a collecting machine, which then pumps the seawater slurry through a flexible pipe to the PSV via a riser system. Following initial processing, materials would be transferred to a Handymax vessel for shipment.

The cutting drum of the bulk cutter was designed and built by Sandvik; all the SPTs track sets were designed and built by Caterpillar. Modification to the track set for subsea operation and required cutting duty was completed by SMD in consultation with Caterpillar and Sandvik. The dredge pumps for all three SPTs were supplied by Damen. The hydraulic equipment for all three SPTs is based on existing Bosch Rexroth hydraulic equipment, with adaptations by SMD.

GE Oil & Gas has been involved in the development of the subsea slurry and lift pump. The riser has been designed by Nautilus' RALS main contractor, Technip, and built by subcontractor General Marine Contractors. An agreement for the charter of a PSV to be first deployed at the Solwara 1 Project was awarded to Dubai-based Marine Assets.

Nautilus is also weighing operations offshore Fiji, Tonga, the Solomon Islands, Vanuatu and New Zealand as well as other areas outside the Western Pacific.

Opportunities

Many others are watching. Deep sea mining could offer offshore industry firms a new business, and Italy could be at the forefront of this business, Keber told OMC. "The deep sea mining chain is practically the same as you have in other extractive industries. Exploration, seismic, production, logistics, processing, distribution and sales," he says.

Keber notes similar technologies are used in the planning and production phases, and says that the support vessel being developed by Nautilus for SMS recovery is similar to Fincantieri's Overdrill drillship design. "We are mostly interested in surface vessels," he says. "The configuration [of Nautilus' ship design] is similar," he says. "The power requirement is similar. Both are dynamically-positioned. The size is similar. The migration is a reality, it is possible."

SMD has also continued its work in this space, teaming up with South Africa-based Underwater Mining Solutions, which already supplies shallow water mining equipment, to offer full scope subsea mining equipment.

Overdrill vs Nautilus (Statistics)

	Overdrill	Nautilus PSV
Length	682ft (208m)	744.8ft (227m)
Breadth	131ft (40m)	131ft (40m)
Positioning System	DP3	DP2
Accommodations	230	180
Water Depth	12,000ft (3650m)	5249ft (1600m)

The most developed area of the supply chain is the logistics, i.e. transporting ore from the production vessel to the coast for processing. The least developed part of the chain is the subsea part, Keber says. And, a potential gap exists for the development of a nodule or CRC production vessel, he says.

Norway has also been investigating deepsea mining, with projects including DeSMO and Marmine underway.

DeSMO is a pre-study to identify technology research and development opportunities, while MarMine completed a research mission over the Mohn's Ridge area earlier this year. Work included drilling a core in 2700m water depth with an ROV-based drill rig.

The system was delivered by Seattle-based company Williamson and Associates and is custom made for ROV operations. It was deployed from the *Polar King* research vessel, operated by GC Rieber. OE

Drilling deeper into data

Digital Twin.
Photo from DNV GL.

Reducing maintenance costs is the primary focus of the oil and gas industry's quest to get more insight from Big Data. But, can they successfully navigate remaining barriers? Karen Boman reports.

Big Data – defined as datasets of unprecedented scale – is not a new phenomenon in the oil and gas industry. For years, firms have applied analytics to these large datasets to guide decision making, particularly regarding seismic data.

While innovations continue in this arena – innovative seismic processing by BP, for example, helped push Mad Dog 2 over the line – Big Data is spreading beyond the geoscience realm, says Richard Dyson, CEO, io Consulting.


Richard Dyson

"The confluence of increased computing power, more sensor technology and the lower for longer oil price is driving the industry to look for a competitive edge through the exploitation of Big Data," Dyson says. "The potential for insights and value to be derived from combining subsurface, subsea, facilities and operating data derived throughput the project lifecycle is huge."

New opportunities

A major area of focus right now is using data from offshore drilling operations to reduce non-productive time (NPT) and increase drilling efficiency. Recent examples of such work include GE and Maersk Drilling's decision to expand the scope of a 2016 pilot project, in which GE supplied SeaStream Insight software to boost Maersk Drilling's drilling rig productivity and reduce maintenance costs by up to 20% on one asset. The software will now be installed on nine subsequent vessels, targeting 100 key equipment assets, including the top drive, drawworks, thrusters, and main engines.

Technology to gather more insight from Big Data will make the biggest impact on enhanced drilling process efficiency, says Tim Schweikert, president & CEO, GE's Marine Solutions, if analyzed properly.


Tim Schweikert

Against a backdrop of capital-intensive assets, in remote environments, with increased cost pressure and skills shortage concerns, Big Data is helping to change the way firms operate.

To reduce NPT related to machinery breakdowns has generated interest in moving from schedule-based maintenance to condition-based maintenance. In the latter, data is analyzed to determine when equipment needs maintenance work or replacement, Schweikert says.

"Therefore, maintenance actions are only implemented when needed to assure optimal reliability and save companies significant maintenance expenditures. With our customer pilot projects, we are aiming to achieve 20% reduction in maintenance expenditure through the program," Schweikert says.

A joint development project between DNV GL and drilling contractor Transocean demonstrated the feasibility both technically and financially to ingest data from a drilling unit continuously or in batches, to aid inspections and for avoiding corrective maintenance and reducing unplanned downtime. But the processes must be automated to manage cost and increase speed, according to a presentation by the two firms at this year's OTC in Houston (OTC-27927).

Getting more out of existing investments, extending the life of assets, and managing safety will be the main drivers behind data analytics, says Jørgen Christian Kadal, director – head of DNV GL's analytic innovation center. Distributed computing and methods such as machine learning are enabling companies to make accurate predictions using ever larger data sets. But what will really help the oil and gas industry is cloud computing, he says. Kadal says that Big Data has actually disappeared out of strategic focus, and has been replaced by the Internet of Things (IoT) and digitalization. "Digitalization encompasses everything now, from connectivity, automation, prediction, and the processing of data, which is the Big Data part," Kadal says.

Jørgen Christian Kadal

Yet, with increased connectivity, there's also more data: industrial IoT is bringing forth a paradigm shift in the amount of data available as sensors are collecting and communicating data from almost every possible component on a digital oil field, Dyson says. This vast increase in data not only brings about huge potential in terms of insight and optimization, it also increases the importance of data standards to ensure the data is structured to leverage the value and not present the erosion of value inherent in unstructured data.

Similarly, the concept of the digital twin relies on sensors and data gathered to accurately replicate the exact operating conditions over the lifetime of an asset such that the performance can be predicted, modeled and optimized.

Challenges

For Dyson, using Big Data to create digital twins of oil and gas facilities represents one of the most exciting opportunities offered by the Big Data revolution. But, this opportunity is hampered by a lack of collaboration, he adds. Instead of working together, "there is a race to establish primacy to gain a competitive edge," Dyson says. "This lack of collaboration hinders both innovation and actual delivery of the digital twin due to a reluctance to share data."

The challenges in addressing Big Data are similar to those facing the introduction of any new way of working to the industry, Dyson says. First, a coherent strategy throughout the industry is needed. This is particularly pertinent for the construction of a digital twin.

"The industry needs to consider how best to develop a Big Data capability; whether that may be collaborating with Big Data companies, attracting the best talent in the industry, training our highly skilled workforce, or a combination of all these," Dyson says.

There is good news. "As we move towards digitalization, it is producing more structured data that can be leveraged to improve business," he says. "Digitalization is also serving to normalize data for everyone, this is helping to shift the culture from one suspicious of Big Data as the next business buzzword to one where the advantages of data are apparent and embraced. Digitalization is helping companies get more out of big data."

Schweikert says that it is vital that the industry embraces the opportunity that transformative technologies can unlock to drive wholescale change. He noted that the oil and gas industry can look at the marine industry for lessons in looking at operations as an ecosystem, rather than dealing with individual vessels as isolated assets.

"As such, understanding that everything you do, every decision you make, is interconnected and will affect something else, is key to identifying opportunities for efficiency. We will continue to see digital, communication, and automation and control technologies being at the core of a connected marine industry," Schweikert says.

Yet, despite the potential for greater operational efficiencies, DNV GL anticipates only moderate investment by the oil and gas sector in Big Data technology. In a March 2016 report, DNV GL notes that, while oil and gas companies are being ambushed by start-ups and original equipment manufacturers to try new Big Data technology offerings, the oil and gas industry has been slow to adopt this technology.

This scenario remains true today, Kadal says. "One company told me that, if they wanted to, they could have meetings everyday about new analytic offerings on their existing data. They have to select the ones they want to talk to. Even though industry is slow to adopt, they're being challenged to look at all these offerings."

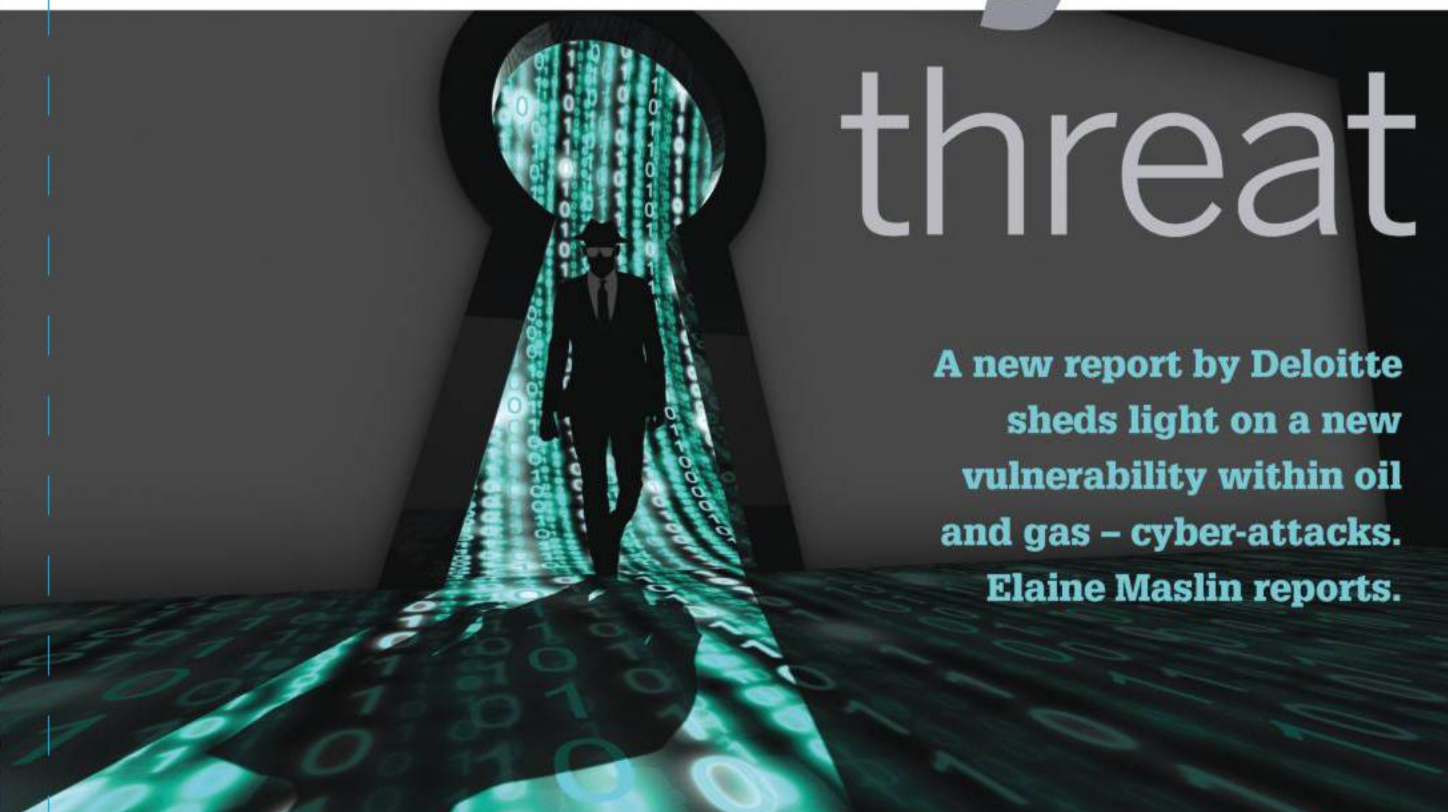
Indeed, in February this year, DNV GL launched an industry data platform, Veracity, to help the energy and maritime sectors overcome data quality issues and manage the ownership, control, sharing and use of data.

The adoption of digital technology to harness Big Data also has a downside: an increased risk of cyberattacks such as ransomware. To address the issue, oil and gas companies need to recognize the importance of information security and place it at the center of digital strategies, Dyson says.

The focus on Big Data to reduce maintenance costs is a good match of available resources and data, Kadal says. But, there's still more for the industry to do to understand how Big Data technology could impact their operations. **OE**

Digital drillship. Photo from GE.

Security threat



A new report by Deloitte sheds light on a new vulnerability within oil and gas – cyber-attacks. Elaine Maslin reports.

The oil and gas industry is often accused of being behind the times, when it comes to adoption of automation, digitalization, and IoT (internet of things) technology.

While smart phones have become an everyday item, offering seamless cloud connectivity, access to countless services, including analytics, alongside live, data-based satellite navigation and even fitness and sleep tracking, oil and gas firms are accused of conducting their major operational processes in unconnected islands of activity, with manual order entry and inventory tracking and operational data that never reaches the echelons of enterprise level use.

The new world of collaborative decision making, fueled by field data recorded by sensor-enabled smart machines and gauges, is coming, and must come, says Paul Zonneveld, Global Energy & Resources Risk Advisory Leader, at business consultancy Deloitte. "Digitalization of oil and gas is critical," he says. "It's the No. 1 business opportunity, to take the next step and be sustainable."

The risk now is that the industry might be digitalizing too quickly, without enough focus on security to prevent cyber-attacks, says Deloitte.

"It's probably our No. 1, 2 and 3 focus right now, given where the industry is and the issues the industry is trying to face," says Zonneveld. In short, industry "interconnectedness has outpaced its cyber maturity, making it a prime target," says Deloitte University Press' (DUP) report Protecting the connected barrels.

According to Deloitte, energy was the industry second most prone to cyber-attacks in 2016, with nearly 75% of US oil and gas companies experiencing at least one cyber-attack. Yet, cyber breaches are not listed by those same firms as a major risk, lumping it together with risks such as civil unrest, labor disputes and weather disruptions.

As if to underline DUP's concerns, just days after its report was released, the Petya ransomware virus struck, hitting, among others, Russian oil major Rosneft and A.P. Moller Maersk, which owns Maersk Drilling and Maersk Oil,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Part of the problem is that the industry has a "large attack surface and many attack vectors," i.e. there are lots of people, companies and systems (many dating back decades) involved, which could all offer access points to hackers. Decisions about industrial control system software are often made at the field or unit level, resulting in products from different solution providers, based on different technologies, and with different IT security standards.

Meanwhile, intelligent instrumentation at a field level—devices that can self-process, analyze, and act upon data closer to operations— are taking cyber risks into the front line of upstream operations, says the report.

Security concerns can also be outweighed by safety concerns, i.e. in a drilling room where engineers fear that stringent IT security measures could introduce unacceptable latency into time-critical control systems.

Yet, "If a cyber attacker were to manipulate the cement slurry data coming out of an offshore development well, black out monitors' live views of offshore drilling, or delay the well-flow data required for blowout preventers to stop the eruption of fluids, the impact could be devastating," says the DUP report.

> **... a hacker could access a SCADA system, change a parameter – and in all likelihood not actually know what it is they're changing – and cause a system shutdown.**

How big is the risk?

While we hear about cyber-attacks on the banking or other industries, which are by their very nature more public, less is heard about attacks on oil and gas firms. "Don't be comforted by not having seen a lot publicized," says Zonneveld. "In the last year, we have seen fishing attacks [on upstream firms] growing exponentially.

"These are people in nation states or groups trying to break in to organizations to find what they can get. We are seeing a lot more attempts. When it hits the corporate side there's a lot of technology to prevent it happening. But, the maturity and who owns and controls offshore facilities, which procured their own internet access, and engage with engineering contractors that have remote access to technology corporate doesn't even know about, and that represents a back door. Many have very porous profiles and security is non-existent."

This means a hacker could access a SCADA system, change a parameter – and in all likelihood not actually know what it is they're changing – and cause a system shutdown. This is happening, a lot, says Zonneveld. "We see this as one of the emerging areas of threat."

Some areas of the upstream business are more at risk than others, however. According to the DUP report, production has the highest cyber risk profile, followed by development well drilling and then seismic imaging.

Risk profiles

Production operations rank the highest in terms of cyber vulnerability, mainly because of its legacy asset base, "which was not built for cybersecurity, but has been retrofitted and patched in bits and pieces over the years, and lack of monitoring tools on existing networks," says the DUP report. About 42% of offshore facilities worldwide have been operational for more than 15 years, fewer than half of oil and gas companies use monitoring tools on their networks, and of those companies that have these tools, only 14% have fully operational security monitoring centers, according to the report.

This situation is then magnified by the expansive operating environment and the changed role of instrument vendors from system suppliers to system aggregators. "A large US oil and gas company has more than 25,000 producing wells, and each well has a diverse set of industrial control systems—from sensors in boreholes, to programmable logic controllers on a well, to SCADA systems in local control centers—purchased from a number of vendors with different maintenance schedules and connected using off-the-shelf technologies," says the report.

On top of these are loosely coupled but nonetheless integrated industrial control systems, which are increasingly connected with a company's enterprise resource planning systems. "With 75% of global oil and gas production controlled by resource planning systems, this part of the value chain faces cyber risks both from the top (IT systems) and bottom (hardcore legacy operation technology systems in the field)," says the DUP report. "Thus, the consequence of a cyber-attack on oil and gas production could be severe, promptly affecting both the top and bottom lines."

There's also a gap when it comes to the perception of risk in different parts of the business, with the production side maybe not having the same discipline as a CTO, says Zonneveld.

Development drilling has a high cyber-attack vector, "due to higher drilling activity, expansive infrastructure and services, both above and below the surface, and a complex ecosystem of engineering firms, equipment and material suppliers, drillers and service firms, partners, and consultants," says the DUP report.

It's a challenge to align all involved to a single cybersecurity protocol. Existing drilling and computer systems were designed around the theory of an isolated network—in the belief that hundreds of miles of ocean would be good enough defense. Real-time operations centers, with live access to the rig, and even linking geoscience and engineering databases, have changed that. Even automating pipe-lifting and stand building is making everything even more interconnected. Opensource, vendor-neutral data protocols (eg. Wellsite Information Transfer Standard for Markup Language, or WITSML) could now also make well data comprehensible to hackers.

The DUP report says that while field development planning and well completions have relatively lower cyber risk profiles, the well completion process has a high probability of slipping into the high-risk cyber zone, as smart wells take hold, with real-time monitoring connected to advanced analytical software.

Seismic imaging has the lowest risk because geological and geophysical surveys have a closed data acquisition system and a fairly simple ecosystem of vendors (the top three geophysical vendors control 50 to 60% of the market and provide a complete suite of offerings). An attack would cause less damage – to health and the environment – than an attack on a well might.

Mitigation

The good news is that there haven't been any catastrophic events so far. "Early on, when smart engineers designed these systems, they designed them to be fail safe," says Zonneveld. Which means they shut down if they start operating outside an operating range. "The industry also has safety as a priority," he says, "and where cyber becomes a threat to safety, people pay attention, and they are." Senior management are also taking the issue more seriously, he says, and developing a better understanding of what the risks are.

What can they do? Some of it is about company culture – spreading awareness about fishing campaigns, making people think twice about opening an email, says Zonneveld.

Testing new equipment before it is deployed, can reduce risk in the drilling segment. Running cyber scans on cloned SCADA and other specific systems rather than on actuals (avoiding interrupting drilling operations direct), and by searching for anomalies against a 'baseline of normal' using both physics and non-physics-based data, can help companies detect breaches before they reach their target, says the DUP report.

A risk-based approach, rather than only following the scheduled or compliance-based approach, could also be taken, based on a detailed vulnerability/severity assessment for each asset, and prioritizing and scheduling updates promptly for critical assets. Replacing legacy devices with wholly new purpose-built hardware rather than retrofitting, could also improve resilience.

The DUP report also suggests companies practice responding to an attack, through cyber war-gaming and simulations, especially with people involved in responding to incidents offshore or working in remote locations, to aid better understanding of threats and improve cyber judgment at all levels.

"It's not just a project," however, Zonneveld says. "It's a process that needs building in to management system philosophies." OE

Autonomous systems hold the key

Wave Glider tow cable/towbody supports underwater communications and surface vessel detection. Images from Liquid Robotics, a Boeing company.

Sean Halpin, of Liquid Robotics, shares the benefits awaiting the offshore oil and gas industry if it could only speed up implementation of digital oilfield technologies.

The Digital Oilfield is the transformation of sensors and structures communicating in real time, autonomously, and aided (and even potentially controlled) by artificial intelligence. The allure of instrumenting, recording, warehousing, analyzing and acting on the vast amounts of information available from an operating oilfield is certainly tempting and transformative.

The promise of the Digital Oilfield is the automation of oilfield operations to increase efficiencies, safety and reduce cost. We believe a critical component is autonomous unmanned systems, which can offload dangerous, tedious tasks from oilfield personnel and equipment while providing continuously monitoring of critical infrastructure, even during severe weather.

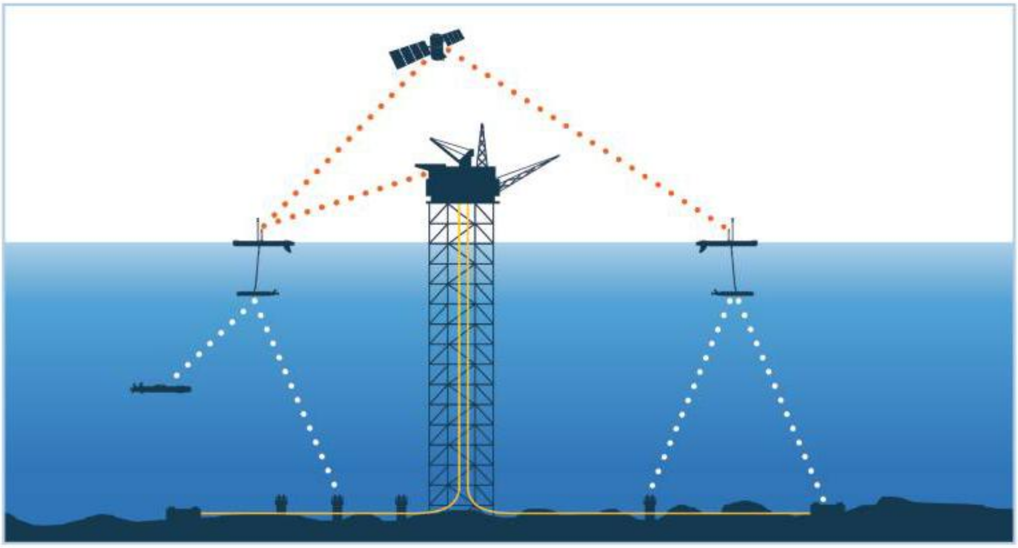
Autonomous unmanned systems will not only be the tools inspecting equipment, but the tools that enable communications between equipment. Imagine a future where these vehicles enable continuous observation of subsea infrastructure, providing operators immediate equipment status vs. waiting for annual surveys. The potential impact on offshore oilfield safety, efficiencies and profits could be enormous. As technology matures we see further integration of autonomous technology into the oilfield; however, we believe that the pace of innovation is now outpacing adoption. Why?

To achieve widespread acceptance of autonomous unmanned systems in the Digital Oilfield requires two things. The oilfield/operator must see an increase in safety (above all else) and an increase in operating profit. Integrating these systems offers a dramatic increase in both.

Two challenges: trust and technology

While you read this, you most likely have a handheld digital device close by – you may be reading articles on your smartphone or tablet. You use and trust these technologies every day. You store your life in the cloud; including photos of your family, your to-do list, and highlights of a great family vacation. This transformative technology has proven to be secure, reliable and allows instantaneously accessible information, and it has earned the public's trust. As new transformative technologies arrive for the oilfield why do we not have the same level of trust?

The issue is that new technology challenges the status quo. For some, change, even with the promise of great upside, is uncomfortable. Companies seeking to drive innovation and profit frequently use new technologies to redefine the marketplace, reduce costs and increase productivity. It wasn't long ago that remotely operated vehicles (ROVs) were viewed as fringe tools. Today, these systems dominate the oil and gas landscape. Overcoming the status quo with the adoption of advanced, autonomous technology will help companies implement the Digital Oilfield, and ultimately, will allow the industry to evolve in a 'lower forever' market.



Wave Gliders communicate with AUVs and subsea infrastructure while gathering in situ metocean data.

Challenges to technology adoption

Developing technology for deployment offshore is difficult, due to the severe operating environment, the policies surrounding technology adoption, and the pace of technology itself. By the time you've completed testing and hardening of a solution to handle the rigors of the marine environment the core technology in that solution has likely improved or changed.

Once a product is fully tested and qualified for marine use, it must then be demonstrated successfully. Few operators like to be 'first' to adopt new technology. Most, if not all, want a track record established because if new technology is placed in a critical role and fails, the consequences can be severe.

Add to this the challenge of working in the unpredictable, harsh ocean. Anything that works well onshore will likely work poorly offshore. The conditions offshore are brutal, especially for electronics.

How do we get to a Digital Oilfield?

Today, we see isolated examples of the Digital Oilfield in action, but one of the biggest missing components is a pervasive communications infrastructure. The reality of the industry's complicated and expensive offshore operations is that cost effective and instant access to offshore data below the ocean is not available.

To gain this subsea data, communications from subsea infrastructures requires a reliable way to get the data back to a central repository, where it can be warehoused, analyzed and acted upon. At sea, we depend on data loggers or cabled infrastructure. Even with the extensive number of sensors in the oilfield today, some placed well after umbilicals and subsea umbilical termination assemblies (SUTAs) are installed, we need to have a new and highly reliable way to get the data back to a central repository. To enable the Digital Oilfield, we need to act differently, rid ourselves of costly infrastructure and adopt more scalable and modular solutions enabled through robots.

This is an area where autonomous systems and specifically unmanned surface vehicles (USVs) like the Wave Glider are proving invaluable. Sitting at the surface of the ocean and acting as a communication "gateway" between subsea instruments, sensors, and devices, USVs provide real time, 24x7 data communications without the need of cables or costly ships. This brings instant connectivity to the subsea domain.

This type of application, real-time gateway communications, is crucial in the Digital Oilfield concept. One example is in the area of earthquake and tsunami warning or deep ocean seismic detection. Scripps Institution of Oceanography (Scripps) uses Wave Gliders in concert with bottom node seismic sensors to detect tectonic plate movement in the deep ocean. They use Wave Gliders in two ways: one to tow and deploy the long duration bottom nodes to the deep sea; and two, to hold station over the nodes once placed to listen for seismic activity. By using unmanned ocean robots to continuously monitor tectonic movement for months and up to a year, Scripps can provide real-time notification of seismic events. Even 10 minutes of early warning of an impending tsunami can have a tremendous impact in saving coastal communities. The analogies are true for offshore platforms. The ability to have continuous monitoring and early warning provides the critical timing to help minimize or avoid catastrophic events.

Where do we go from here?

Recent developments in the offshore market necessitate that we all take a hard look at incorporating autonomous systems into offshore operations. 'Business as usual' is a dead phrase in our industry. We are faced with shrinking budgets and mounting costs, and just like in the past, we should turn to technology to push our industry forward toward profitability in a low-price environment.

As an industry, we can only succeed if we make the decision to vet and adopt technology at a more rapid pace. Technology has changed our lives onshore and has enriched our businesses and families. It's time for us to leverage proven, commercial autonomous technologies to enable the Digital Oilfield, enriching our lives and business at sea. The future is up to the workers and managers of the oilfield to embrace this change in a proactive manner. **OE**

***Sean Halpin** is senior director of Global Energy Markets for Liquid Robotics, A Boeing company. He previously worked at DOF Subsea as their Global AUV Manager. He holds a BS in marine science from Maine Maritime Academy.*

Still in the game

Shell's Olympus platform. Photos from UTC Bergen.

Is deepwater still relevant? Shell thinks so, from optimizing its existing production to new projects. But when will the tap be turned? Elaine Maslin reports.

For many years, not least those leading up to 2014, deepwater exploration and production had gained a reputation for being at the expensive end of the upstream industry.

Unsurprisingly, this meant deepwater was hit hard by the downturn, as it was unable to anything like match the costs achieved by the likes of onshore unconventionals.

But, three years in to lower oil prices and the work to reduce costs and simplify projects, is paying off. Floating production vessel supplier and operator SBM Offshore noted in August that: "Break-even prices of deep water projects have substantially improved as result of cost deflation, more fit-for-purpose scope and leaner concept designs. In particular, deep water projects in areas with world class reservoirs have gained competitiveness against other oil and gas investment options."

Operators – supported by new offerings in the contractor and supply chain landscape – are starting to find ways to move deepwater forward, says analyst firm Wood Mackenzie. Investment in deepwater Egypt and Senegal by BP and in deepwater Brazil by Statoil this year, shows there's still appetite to be in deepwater plays.

According to Wood Mackenzie, 83 subsea trees were ordered in FY 2016. In 1H 2017 alone, 81 awards were made. "This result is encouraging as only part the full potential of the E&P's and supply chain's efforts have been realized. As time goes on and these efforts mature and are more widely applied, the potential for the subsea and deepwater markets is exciting," says Caitlin Shaw, research director, Wood Mackenzie.

One of the majors with a significant stake in deepwater is Shell. Shell's deepwater production is expected to increase to more than 900,000 boe/d by 2020 from already discovered, established reservoirs.

"Deepwater is a vital part of that oil and gas mix. Currently, deepwater is 7% of all conventional oil produced globally," says Robert Patterson, executive vice president, Engineering, Shell. It is forecast that by 2040, it will be almost 11% of conventional production, at about 11 MMb/d. Deepwater is important."

Patterson, who was speaking at the Underwater Technology Conference in Bergen, in June, says that, for Shell, it's also part of the company's history, being almost a decade since the deepwater Cognac facility was installed in the US Gulf of Mexico. "In the last few years alone, we have had eight new significant [deepwater] start-ups," he says, including Gumusut-Kakap and Malikai (Malaysia), Bonga Northwest and Bonga Main Phase 3 (Nigeria), BC10 Phase 3 (Brazil), Cardamom, Mars B, Stones (US Gulf of Mexico), and others. Two projects are under construction, Coulomb Phase 2 and Appomattox, both in the US Gulf of Mexico. "In 2016, with those, and our combination with BG Group, we increased production from deepwater by 50% compared to 2015."

Moving deepwater forward has meant a lot a hard work, however. "In moving forward with deepwater, we all face a challenge," Patterson says. "Over 10-15-20 years, performance in our industry eroded in a dramatic way. In 2014, it took four times as much capital to produce a barrel of oil as it did in 2004."

Productivity in oil construction fell -22%, compared to a 41% increase in the rest of the [US] economy, he said.

One of Shell's initiatives to address this and reduce costs has been to streamline standards and requirements, by building a comprehensive catalogue and then only selecting what is appropriate for a specific use. This has led to a substantial reduction in requirements. For example, in many equipment categories the reduction is as much as 80-90%, "changing the dynamic. We have a small enough set of requirements so we can talk about what risks there are to our suppliers," Patterson says. "We have completed the first step of that journey with pilot projects."

Competitive scoping has also brought "major benefits," he says. Patterson says that during the execution of Stones, Shell had the opportunity to rethink the whole design and took US$1 billion capex savings – by minimizing use of materials and rethinking drilling efficiency.

Final investment decision (FID) was taken on Appomattox in 2015, after an initial 20% cost reduction. An additional 20% cost reduction since FID was achieved – maintaining a strong focus on safety and quality. Cost efficiencies are the results of efficient execution, significant well reductions and lower market costs, Patterson says.

Robert Patterson, EVP Engineering, Shell.

Ormen Lange has been lined up to have subsea compression added to extend field life and boost recovery rates. Shell has sought a minimal safe scope and what is absolutely needed to reduce costs on a future project to make it economic. Cost have been reduced by more than 50% (since 2014). On Kaikias, estimated to contain more than 100 MMboe recoverable resources, oil and gas will be produced from four wells with flow back (single flowline) to the Ursa tension leg platform (TLP) in the US Gulf of Mexico, given FID earlier this year, a $40/bbl breakeven was achieved, "by stepping back to see what was really wanted to achieve, and how to use what Shell already had in place," he says.

"We also looked hard at flow assurance requirements," he adds. "Could we use a single pipeline and use an existing umbilical? We used standard subsea kit on Cardamom, and as a result brought costs down 50%."

Engineering tools are also coming into play. For example, Shell has run Project Vantage, an integrated engineering environment, with 3D, 4D and 5D capability, to reduce working at height and in confined spaces by about a half, Patterson says.

Shell has also sought to make better use of already available technology from third parties, typically small companies with niche solutions. Part of this is about being able to evaluate them more efficiently. "We've gone from evaluating 30 a year, taking 9-10 months each to realize, to a thousand a year and making decisions in two months," he says.

Patterson's list continues, from using foam in wells, such as on the Ram Powell TLP, to help produce from wells that had been shut-in due to severe slugging, to using hot bolt clamping, and Humidor, a coating which can be applied and cure in wet conditions, which was applied on the Ursa facility.

It's not just operators working in a silo to make these projects work, however. The supply chain landscape reacted quickly to the new norm, Shaw says. "We have seen most of the major players team up with complimentary companies to leverage their strengths and offer enhanced solutions – OneSubsea, TechnipFMC, GE-Baker Hughes. While each of these companies has its own value proposition, common themes exist around realizing cost savings via earlier engagement in the project life-cycle."

The hope is that all this work will increase FIDs. There are positive signs but no one is shouting from the rooftops. SBM CEO Bruno Chabas noted: "In today's oil price environment, characterized by continued low prices, deepwater field developments need to build on the competitiveness gained."

"While FIDs are on the increase, clients remain cautious and selective," SBM says. "As a result, the offshore services industry is gradually recovering, but with a structurally lower activity level when compared to the market over the past decade." OE

Improving subsea emergency response

Seanic Ocean Systems discusses the creation of a new subsea dispersant delivery system.

The offshore oil and gas industry is constantly looking for ways to enhance its emergency response capabilities, through the development of new and innovative solutions. BP's GWO-Subsea Wells (SSW) team, responsible for the firm's containment response system (CRS) has developed a new subsea dispersant delivery system (DDS).

The SSW team developed a basis of design for the topsides and subsea equipment that would allow for the system to be quickly and easily altered to operate in a wide range of extreme conditions, air transportable via a Boeing 747 and deployed from a typical vessel of opportunity in all of their operating regions. The DDS is capable of 180 days' continuous operation, delivering dispersant at 30 gpm at 5000psi in water depths up to 10,000ft. The system is compatible with all work class ROVs and can be configured to accommodate the specific parameters of a given well location.

Overboard chute. Photos from Seanic.

To enable these features, SSW contracted and qualified Aberdeen-based HydraSun's specialty hose, Interventor (*OE*: October 2015). The hose would be used as the primary means of delivering dispersant from the vessel to the subsea distribution reels located on the seabed. A number of other regionally sourced subsea dispersant applications have used coiled tubing, but after detailed analysis and fatigue testing, it was determined to go with HydraSun's Interventor hose. The hose is custom designed, lightweight, and capable of withstanding the various chemicals, pressure, depth, flow, temperature and constant fatigue generated by vessel motion. After extensive design and testing, two 750m hoses, and four 600m hoses were constructed.

Seanic Ocean Systems was commissioned to engineer and construct the supporting equipment that would be used both topside and subsea, and integrate the HydraSun Hose requirements into the DDS design. The scope included a deck mounted topsides system, an electric-powered hose winch, an overboard chute, and the dispersant pump skid. The subsea scope included a clump weight termination assembly (CWTA), two subsea hose deployment systems (SHDS) with dispersant wands.

On deck, the system is controlled by a control van outfitted with an integral electrical distribution panel for operating each piece of equipment. The control van also displays and records the pump skid fluid data including flow rate, pressures and temperatures. The control van is equipped with an emergency stop inside and out and is tied into the pumping skid which too, is equipped with manual shut off valves. It consists of redundant pump circuits (each at 30 gpm at 5000psi) that can be used simultaneously or independently. The triplex pumps are variable frequency driven, which is used to control output flow.

EMCE Winches, based out of Holland, were contracted by Seanic to engineer and manufacture the deck winch with specific requirements that included redundant 30hp motors, automatic levelwind, and a transpooling frame that can also be used for pre-tensioning the six interchangeable hose reels.

Clump weight termination assembly (CWTA).

Two of the reels have a pump through configuration and four have a trailing wire configuration, to keep consistent flow while changing out reels during operation. The overboard chute contains a small electric tugger winch, that works simultaneously with the deck winch, to aid in hose connections during deployment. The overboard chute has an adjustable platform, for changing clearance height depending on the vessel's deck configuration. The main chute section is Wearlon-coated for protection of the main supply hose during deployment and operation. The CWTA is connected to the main supply hose via a 1.5in stab and incorporates an independent emergency disconnect system in the case of a drive off event and can be easily reconnected subsea via ROV. It also has topsides adjustable weights, (2000lb (min) to 5000lb (max)), depending on required working conditions. Once at targeted water depth, the CWTA is connected to the SHDS, resting on the seabed, with a 1in hose that extends out up to 250ft from the SHDS, providing the CWTA a range of movement above the seabed.

Another option is to connect the CWTA to an additional clump weight on the seabed via a tether. This would improve the system operability under harsh metocean conditions in deep waters. Each SHDS hose reel contains 1500ft of 1in hose with a dispersant wand at the end. The 1500ft hose is easily pulled out from the SHDS reel with an ROV and rewound back to the reel with a Class 1-4 torque tool. Accompanied with the tooling suite is a topsides storage van for all hoses, electrical wiring, and dispersant wands along with additional consumables, spares, and ancillary equipment. The system includes a power supplied and climate controlled workshop van, fully equipped with all tooling needed to operate the system, clearly marked for quick accessibility, which also includes spares.

The equipment was designed to meet stringent requirements that included a do not exceed size due to Boeing 747 cargo access and loading restrictions, and to incorporate cargo lashing that could withstand the expected g-force criteria.

Seanic Ocean Systems engineered and constructed the supporting equipment, all while coordinating and managing the teams with intricate schedules from around the world. This helped to ensure all testing were complete on time prior to staging the equipment for the systems integration test, which took place in Seanic's in-ground test tank in Katy, Texas. **OE**

***Steve Eggert** began his career at Cameron as an interface design coordinator, specializing in subsea blowout preventer design and integration into deepwater drilling vessels. He has worked for Manatee Inc. for 15 years, providing firms, such as BP, with innovative solutions, project planning and execution leadership. Along with supporting BP's emergency response efforts, he was awarded a patent on BP's Offshore Fluid Transfer System, (Jan-30-2015).*

***Britni Plummer** has over 15 years' experience, specializing in subsea. For the past five years, Britni has lead custom engineered solutions, ROV tooling projects, for Seanic Ocean Systems. She is an active member of the Project Management Institute and with the local Houston Chapter.*

Interfacing between main supply hose through tugger winch on chute.

Going where no riser repair has gone before

Connector Subsea Solutions and Hydratight completed the world's first deepwater riser repair at 1250m depth for BP off West Africa. Pål Magne Hisdal, Andre Midtun and Ivar K. Hanson explain.

The Greater Plutonio field offshore Angola has been producing since 2007. A single hybrid riser tower connects the field's floating production, storage and offloading vessel to the subsea flowline and control systems.

Two, 4in gas lift risers had damage at the base of the hybrid riser tower, at 1300m water depth. To repair the damage, BP considered replacing the entire gas lift riser or local repair and bypass of the damaged section. The latter option was taken.

In the past, pipeline operators have been reluctant to execute deepwater repair of risers due to the complexity and lack of availability of solutions with track record.

Working with Hydratight, Norway's Connector Subsea Solutions developed a solution to make remote repair of rigid risers a cost-effective alternative to riser replacement.

The solution comprises a novel midwater connector installation system

that is temporarily fixed to the riser and used to align, install and activate the repair connectors, and a mechanism to ensure that the risers were not overstressed or damaged in any way, even for small pipe diameters. The repair connectors are equipped with flexible jumpers in order to bypass the damaged sections on the two 4in gas lift risers.

Above: Image from the installation phase. Left: The connector installation frame and anchor gripper unit, onshore assembly. Images from Connector Subsea Solutions.

Work started on the design of the system in April 2015. After going through an extensive testing, onshore and in water, the new deepwater riser repair system was field-proven, by repairing the two Greater Plutonio gas lift risers. The project was completed in April this year.

The repair work involved pulling the risers out of the tower, cutting and then preparing the risers, using Connector Subsea Solutions' ROV-operated deepwater coating removal tooling, and installing Hydratight's repair connectors with flexible jumpers to bypass the damaged location. The deepwater coating removal tooling reduced complexity and operation time, compared to a water jetting system is significant.

The whole operation was executed at 1250m depth, about 50m above the seabed, utilizing only ROVs and crane lifting support from the subsea construction vessel.

For the project, we did not have the "luxury" of having the sea-bed as a support when operating the tools and equipment needed. The ROVs were "flying" the equipment to and from the repair location, while other equipment and infrastructure were secured by cranes from the construction vessels, in which case access under the leaning riser tower became a key design criteria.

Restraining system for the tie-in location

Once the repairs were completed, a restraining system was installed to support the tie-in location and to avoid any potential fatigue related issues over the remaining lifetime of the risers.

One challenge in developing the restraining system was that an adjacent 12in riser was the only structure available for affixing the tie-in location. However, this riser was already highly utilized and embedded in the riser tower. As a result, there was no access to install the structural restraint clamp.

The solution was to develop a bespoke Buoyancy Removal Tool that was used to mill away the buoyancy around the 12in riser to create a space envelope sufficient for subsequent coating removal and the remote installation of the structural restraint clamp. Challenges around this operation included the toughness of the glass/epoxy composite and machinability, limited relevant machining experience worldwide and optimizing tool rigidity versus lightweight for ROV installation.

Since there was no previous experience from deepwater buoyancy milling, and thus no existing data regarding the behavior of either tool nor buoyancy during such an operation, it was satisfying to witness the operation being performed as planned.

The development of the technology and the successful operation with a satisfactory repair was confirmed by BP's Subsea Engineer Wadih Malouf: "Hydratight and Connector Subsea Solutions have proposed innovative solutions to a complex riser repair project. They prepared a robust testing program which provided confidence to successfully perform the repair on a live system. The delivery was underpinned by very good project planning and execution."

Project execution and installation

The project scope called for development and delivery within an extremely short timeframe, with project start in April 2015 and equipment delivery in December 2016. Since most of the equipment was bespoke and novel solutions were applied, this was a major challenge.

Achieving the delivery milestones within the time and budgets were made possible using our operation model of seamless design execution between our three engineering locations in Norway, Bosnia and Croatia. This enabled effective design processes and mobilization of the full engineering force on joint tasks. Another key to execution is having product champions that follow the equipment supply process from concept development, through detail design, testing and finally supporting the operation of the equipment in the field.

BP's Project Lead, Neil Forster, praised the work, saying: "Hydratight and Connector Subsea Solutions provided an excellent technical solution to a very challenging problem. Project management and engineering was excellent throughout, with elements of the project delivered against a very tight time frame. The testing regime was well planned and managed and the tools and hardware worked as per design, achieving the functional requirements without re-work. This transferred through to the field, where the tooling and connectors performed very well, achieving first time leak tight connections on both connectors"

Having a field proven riser repair system, the risk of executing such operations has been significantly reduced, and we already have several inquiries to use our deepwater riser repair system for similar operations.

However, no project is similar. The next project may have completely different challenges, but the experience and knowledge gained from this recent project will certainly be a valuable asset we bring with us into the next challenge. **OE**

PRODUCTION

From acorns to oaks

With oil prices expected to remain low, decarbonization targets looming and infrastructure nearing the end of its life, is it time for the North Sea industry to start taking carbon capture and storage seriously? Emma Gordon reports from SPE Offshore Europe.

The energy industry needs to be ambitious when it comes to carbon capture and storage (CCS), according to Stuart Haszeldine OBE, director of research group Scottish Carbon Capture and Storage (SCCS).

Following the lead of Norway, which began storing CO_2 beneath the North Sea more than 20 years ago, with the Sleipner project, could, Haszeldine believes, position Scotland and the UK as a provider of CO_2 storage for the domestic market as well as mainland Europe: in effect creating an industry that could last for "100 years or more, and provide an environmental service."

Speaking at SCCS' "North Sea CCS: innovation and impact" event during SPE Offshore Europe last month, Haszeldine, who is also professor of CCS at the University of Edinburgh, says the industry must start to "transition to … a new way of using our skills and assets in the North Sea, because it's clear the oil price is low, the price of oil is likely to remain low. It's also clear the North Sea is more than half way through commercial production of oil. The industry really needs to think about what comes next."

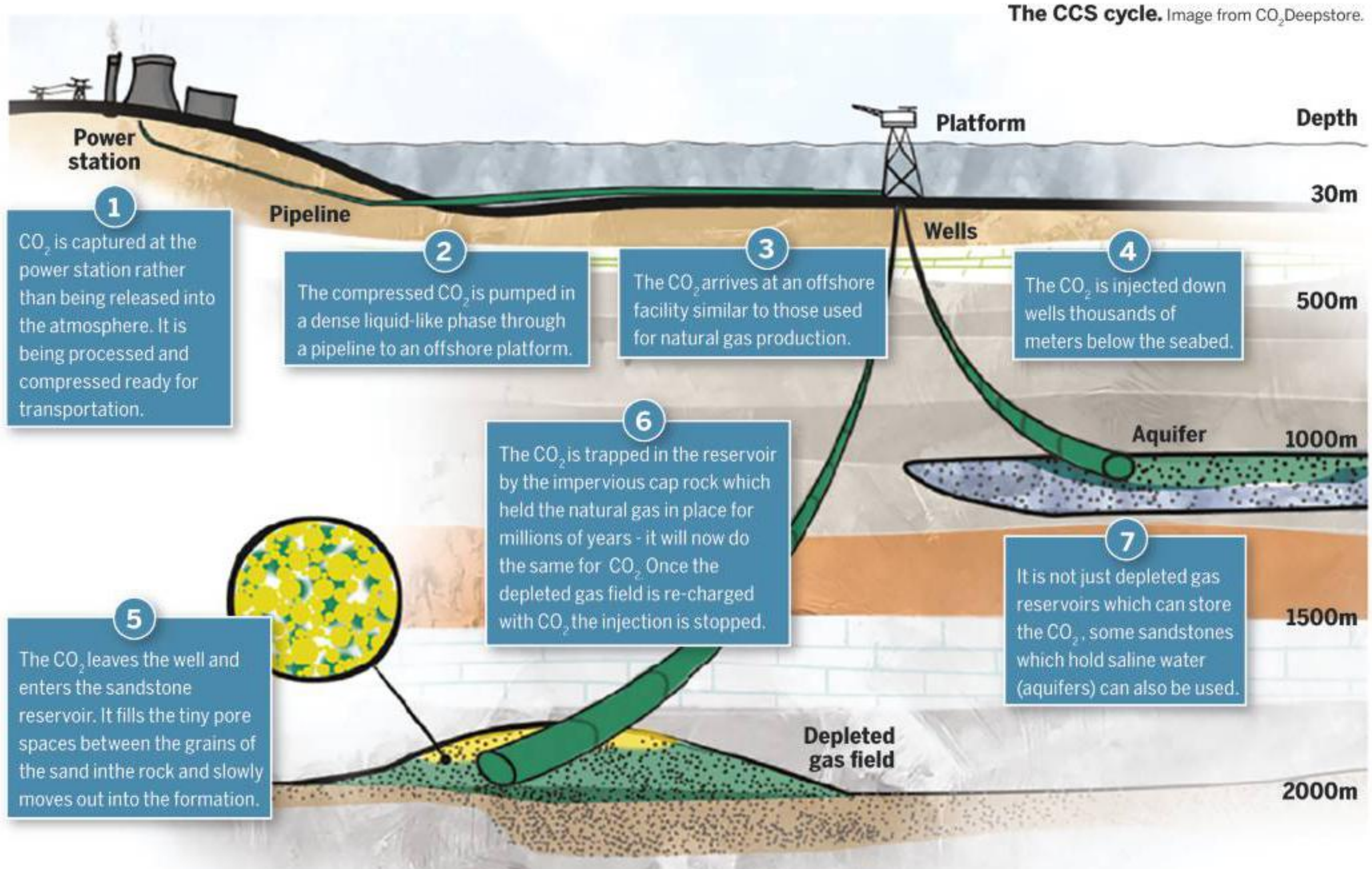
Those who promote CCS argue that even with the adoption of renewable technologies, the demand for energy and the ongoing need for fossil fuels in some industries, and not just power production, means that, to meet climate change targets, CCS is still needed.

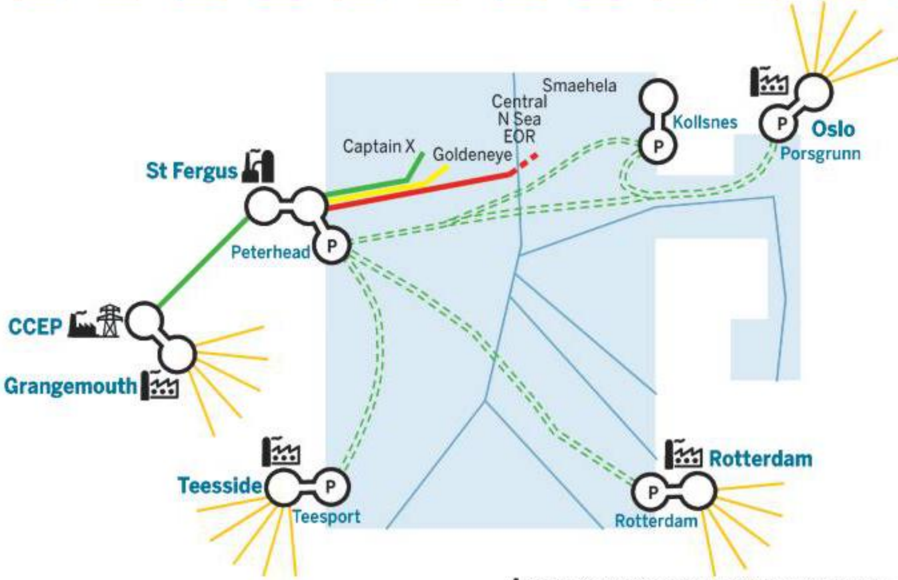
Norway's Sleipner — and the later Snøhvit project — have together collectively stored more than 21 million tonnes of CO_2, showing that CCS in the North Sea is technically feasible, Statoil's Bamshad Nazarian told Offshore Europe. Gassnova, the Norwegian state enterprise for carbon capture and storage, has assigned Statoil to evaluate the development of carbon storage on the Norwegian continental shelf (NCS) as part of plans to develop a full value chain by 2022 (*see page 36*).

While Norway's efforts have been lauded in the UK, SCCS says that the UK needs to up its game. If it doesn't develop its own industry, the UK might have to "outsource" its CCS industry, i.e. pay Norway to collect and store UK.

Support for CCS technology development in the UK has, however, been limited. In 2015, the UK withdrew

The CCS cycle. Image from CO_2Deepstore.





Acorn. Original image from Pale Blue Dot Energy.

committed funds from a CCS competition for a full-scale project just before finalizing the front-end engineering phase for two projects.

Acorn

All is not yet lost for the UK, however. A feasibility study for the Acorn Carbon Capture and Storage Project in Scotland started in September, supported by EU and Scottish Government funding.

With a potential go-live date of 2022, the project centers on the northeast of the country where it's proposed CO_2 would be captured from existing emissions at the St Fergus Gas Terminal. The CO_2 would then be transported offshore and injected underground for storage. Two sites are under consideration, including the Captain formation.

It's proposed that Acorn would reuse the existing oil and gas infrastructure — with three pipelines, the Atlantic/Cromarty (WAGES); Goldeneye and Miller pipelines considered potentially suitable for transporting CO_2. On its current timetable the project could be operational before 2022, and is planning to capture about 200,000T/y of CO_2 in Phase 1.

Alan James, managing director of Pale Blue Dot Energy, a firm leading the project that was developed by CO_2DeepStore, told SPE Offshore Europe: "We wanted to find the smallest, industrially-viable project to minimize capital expenditure to start with. Earlier projects had fallen over because of cost or issues around government spend. The key thing is to build on what's already been done. All that has been done so far is an essential foundation for going forward."

He adds that Acorn could ultimately act as a hub for a growing number of projects including the Grangemouth Industrial Cluster, the Teeside Collective, and CO_2 Sapling: a transportation infrastructure project. It could also grow by adding CO_2 from other local sources, from industrial and power sources in central Scotland transported via existing pipelines and by importing CO_2 by ship via Peterhead Harbour.

Acorn research and academic partners include SCCS, Bellona, the University of Liverpool, and Radboud University in Nijmegen; Guangdong CCUS Center, Massachusetts Institute of Technology, Costain, and Summit Power are among the collaboration partners.

However, there is a race against time for UK North Sea CCS to begin in earnest before crucial infrastructure, such as the three pipelines being considered for the Acorn project, are decommissioned, Haszeldine says.

Haszeldine says that the capital expenditure of a newbuild pipeline system would be more than US$136 million (£101 million); while repurposing the existing system would be around $44 million (£33 million): a saving of about $92 million (£68 million).

And, there is added impetus for the industry in the context of the Paris Agreement, for example. Haszeldine says that it will become clear to all industrial countries over the next few years that they are "nowhere near decarbonizing and storing enough carbon to meet their commitments. I'm hopeful that within the next 5-10 years, storage of CO_2 will become a requirement rather than an interesting side event." OE

Considering CO_2 for EOR

With an estimated potential of 5700 MMstb, CO_2 EOR has the highest potential of all EOR techniques to maximize recovery from depleted UK oil fields, says Jamie Stewart from the University of Edinburgh.

Yet, even though the approach has been used since the 1970s, so far, the technique has not been used in the North Sea.

Stewart told SPE Offshore Europe that the process sees CO_2 injected into depleted reservoirs to increase pressure and reduce oil viscosity, with the "aim of the game to drive oil stuck in the field towards a production well... with some stored in the reservoir."

In North America, there are more than 120 projects injecting around 40-tonne of CO_2 a year, with the majority, some 65, in Texas.

While these projects in the US have primarily focused on oil recovery and not storage, CO_2 EOR is increasingly being considered as a storage option, Stewart says.

CO_2 EOR has been held back in the North Sea due to lack of supply, he says. "We don't have access to the volumes of CO_2 required, low cost options for purchasing, and a fairly big investment is required for some of these projects," he says. "There is lots of competition from other types of EOR... and some of these other technologies have a lower cost, such as [lower salinity waterflood]."

University of Edinburgh research has looked at CO_2 EOR potential in residual oil zones (ROZ), where hydrodynamic tilting of the oil water contact has naturally occurred, leaving a zone of oil.

This work looked at Shell's Pierce field — 265km (165mi) east of Aberdeen — where, Stewart says, recoverable reserves from the ROZ may approach 20% of the total field recoverable reserves. He added that the field could also have the capability to store up to 17-tonne of CO_2.

"CO_2 EOR has a potential to produce relatively low carbon intensity oil from a mature basin... it's exciting that it has the has the potential to offset new exploration... and if we can focus our attention on mature fields in the North Sea, I think that's a good way to go.

"[We have] also shown there might be more potential than is currently recognized from standard CO_2 EOR in these ROZs. Obviously, lots of barriers still exist, and getting projects off the ground, and getting volumes of CO_2 needed... will be difficult, but it is something that I think makes sense in the North Sea," he says. ▪

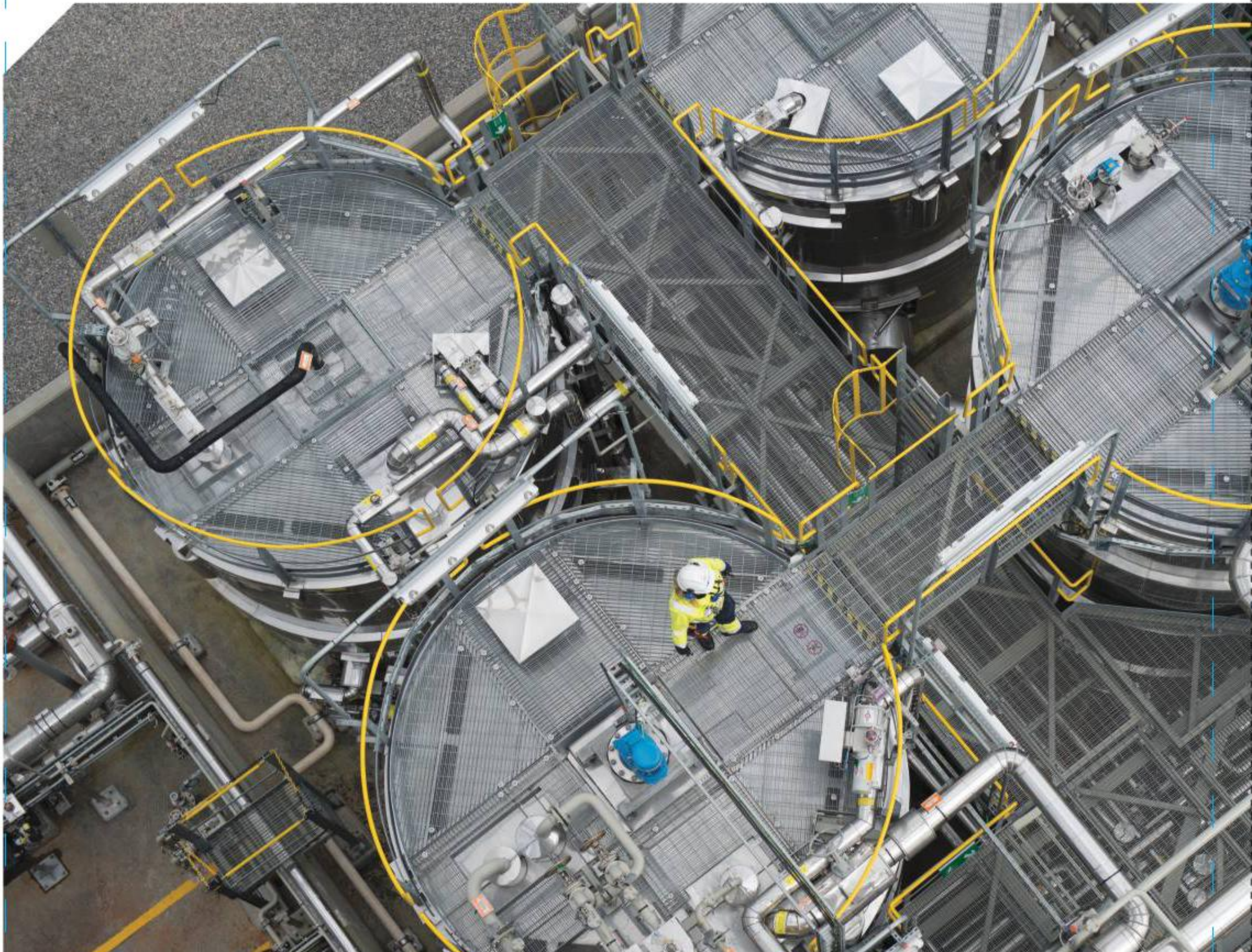
Creating a carbon store

Norway has an ambitious plan to take carbon capture and storage offshore to a level which could potentially see the country becoming a store for other's emissions.
Elaine Maslin reports.

Forty years since Norway first exported gas to international markets (September 1977, via Norpipe), the country has an ambitious goal. While continuing to export natural gas, it wants to create a "value chain" to capture and emit CO_2, potentially even importing the substance from others to store it in vast offshore aquifers. This way, Norway exports its fossil fuel, while taking other's emissions out of the atmosphere.

Globally, there are 17 CCS-projects in operation, which capture and store a total 30 million tonne of CO_2 each year.

In May 2017, there were seven large-scale projects operational, with a combined capacity of 31 MTPA: a further five, with 9 MTPA capacity in total, were under construction, while more than 100 small-scale plants



were operating, according to Norway's state-owned CCS firm Gassnova. The latest project launched was Petra Nova in North America, a retrofit, post-combustion, 1.4 MPTA CO_2 storage project at a coal fired power plant in Texas, with the CO_2 used for a nearby enhanced oil recovery (EOR) scheme.

Most of the projects are onshore. There are only two projects in Europe, both offshore and both in Norway: Statoil's Sleipner and Snøhvit projects. Sleipner was also the world's first CO_2 storage project. Since 1996, about 15 million tonne of CO_2 captured from natural gas from Statoil's Sleipner West field has been stored (and monitored with 4D seismic) in a sandstone reservoir, 1000m below the seabed. Since 2008, CO_2 removed from the Snøhvit and Albatros fields at the Hammerfest LNG plant has been compressed then transported back to the reservoir and stored in aquifer zones.

Technology Centre Mongstad.
Photos from Gassnova.

Scaling up

Now, Norway wants to go further. As part of climate change goals, and in a bid to position itself at the forefront of this technology, the Norwegian government is targeting a full-scale CCS value chain in Norway by 2022.

"We have been doing offshore capture more than 20 years," says Gassnova CEO Trude Sundset. "We have the experience. We know it works, we know it's safe, we have done a lot of monitoring, assessment and research to confirm that this is a good way of getting rid of CO_2 from the atmosphere. That's the starting point. We want to use that experience and share it with the rest of the world."

Trude Sundset

It is argued that, even with other climate change mitigation measures, CCS will still be needed to meet Paris Agreement targets. To do this, "we have to have large scale deployment globally," Sundset says.

Unlike other projects, which target carbon capture from power plants, Gassnova has awarded contracts for large-scale detailed CO_2 capture studies to ammonia, cement, and waste-to-energy plants (activities which otherwise cannot easily switch to renewables as CO_2 is a by-product) on Norway's east coast. If built, they would include the first examples of full-scale capture from cement and waste-to-energy plants, Gassnova says.

CO_2 captured from these plants would be transported by ship to a terminal, from where it would be piped to a subsea template east of Troll field, in the Norwegian North Sea, about 50km off Norway. There, the CO_2 would be injected into an aquifer in which only one exploration well has been drilled.

Statoil has a contract for concept and front-end engineering of the offshore storage and an investment decision is due to be made in 2019.

Gassnova says that under the initial plans, just 1% of the capacity of the selected storage site would be used, which means it could be open to storing other Norwegian and European CO_2 sources. Should there be enough interest, Norway would look to use other reservoirs to continue storing CO_2, but the key is to have the infrastructure in place, Sundset says.

False starts

Europe has so far tried, but failed to move CCS projects forward. Some 20 projects have been under consideration, several of which have had funding, but none of which have come to fruition. The ROAD project in Rotterdam has recently been put on hold. In 2015, the UK withdrew committed funds from a CCS competition for a full-scale project, just before finalizing the front-end engineering phase for two projects.

Gassnova says the challenge with CCS has not been related to technologies and technical matters. CO_2 transport via subsea pipeline, for example, is proven with Snøhvit, Sundset says. As long as there's not water with the CO_2, the issues are not great, she says – although repurposing pipelines previously used for natural gas export to shore, could offer challenges. The country also already has experience shipping CO_2 – captured from the fertilizer industry and then shipped for use in food production.

The issue is a lack of proper market regulation and a set of market players to take on the risk responsibility defined in a viable business model. Because it's project is a publicly funded demonstration project, it's more attractive for investors, because it carries less risk, Gassnova says.

Furthermore, by unbundling the various elements of capturing, transporting and storing CO_2, with the Norwegian state taking on the responsibly of developing a CO_2 storage site, Gassnova thinks emitters are more able focus on capturing CO_2 from their plants.

The biggest issue is having a price on CO_2 emissions. "It costs very little to make [emit] CO_2 today," says Sundset. "I think the price of making CO_2 has to come up and the cost of this [capture] technology has to come down and you need countries to engage with this. If we prove this can work, we believe others will follow."

Technology Centre Mongstad.

Ground work

Norway has also been gearing up for such a move for some time. Since 2002, Norway has not allowed new gas power plants to be developed unless fitted with CCS, and the taxation of offshore CO_2 emissions (around US\$66/€55/ton) is at a level that has made CCS commercial, Gassnova says.

The government has also provided funding for several research centers relating to CCS technology, including the Technology Centre in Mongstad (TCM). Commercially available CCS technology is based on amine absorption, Sundset says. While this is established technology, each application has to be adapted to the particular emission regime. The Norwegian government is also keen to push second, third and fourth generation technologies, as well as to develop alternatives through TCM.

Oil majors are getting interested in this technology. Shell and more recently Total have signed up as partners at TCM. "We are seeing increasing interest from the oil and gas industry," Sundset says. Where in the past they've not had regulatory pressure around CO_2 emissions – and therefore not seen as part of the business plan – it's starting to be seen as something that cannot be ignored.

Being able to strip CO_2 from natural gas and storing it at source could help gas producers get CO_2 levels in the gas down to that needed for transportation.

Creating a supply chain for CO_2 could also open its use up for EOR – a method well established onshore. One of the challenges with CO_2 EOR is that there's not been enough CO_2, at least in Norway, or the infrastructure, to make this possible, Sundset says. Statoil is also considering creating hydrogen from natural gas, which would also involve CO_2 capture. There's also been a scheme to capture storage and then sell it to greenhouse vegetable producers.

David Nevicato

Total, which has a three-year agreement with TCM, has worked on CCS in the past, with an industrial pilot project in Lacq, France, from 2010-13, through which 51,000 tonnes of CO_2 was stored.

For Total, the focus is on reducing the cost of this technology, says Jeremy Cutler, Stavanger Research Centre Manager, Total E&P Norge. "We need to do that to make the industry more competitive and to build the business case for CCS, building the case for continuing with cleaner hydrogen and gas," he says.

David Nevicato, CCS Research Programme Manager, Total, says: "More and more focus is on low carbon." Total is investing in solar and wind, for example. "For oil and gas production, if we want to maintain it in the energy mix, we have to capture and store CO_2." This means reducing the cost of CCS technology. Having a higher price on CO_2 emissions would also help. "We need to bring carbon pricing in to make this change," adds Cutler.

"The focus has been on power production, fossil versus renewables. It's right to put money into renewables. But we have to look at emissions from industry, which are 25% of emissions globally. Maybe we have not been good enough at communicating this," he says.

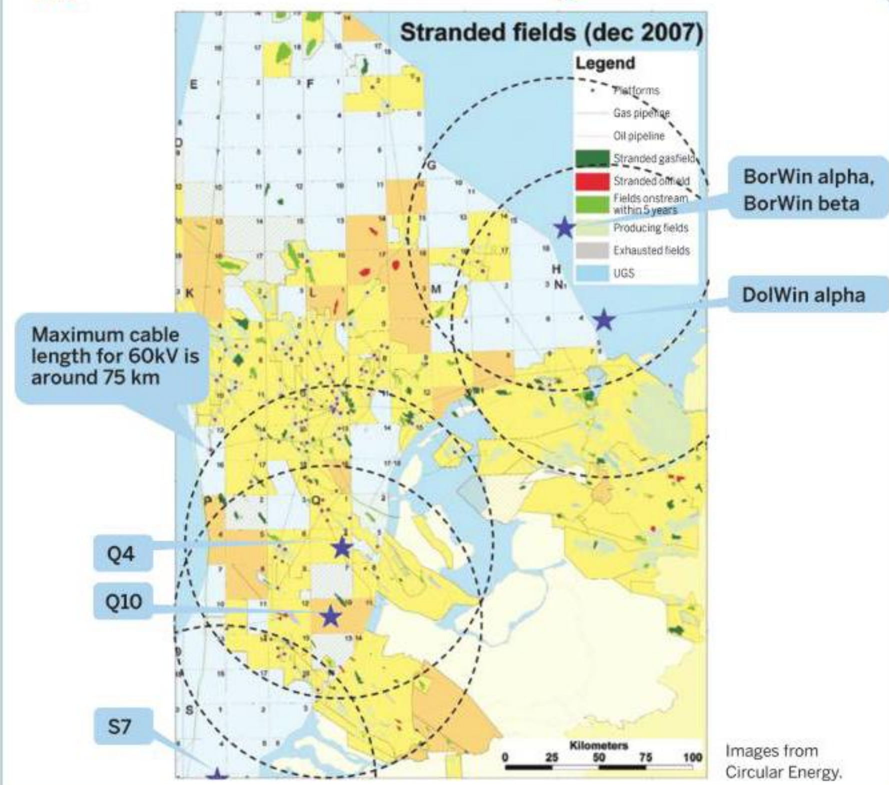
Nevicato says that challenges remain around proving storage long term, and also CO_2 transport in pipelines, particularly where existing pipelines might be re-used, but where the metallurgy isn't designed for CO_2 service, to avoid corrosion.

In the future, separating CO_2 from gas subsea could also help monetize gas fields with high CO_2 content and otherwise uneconomic to develop, says Cutler. But this technology is still some way off. First comes proving the value chain. OE

Gas to power game changer

A Dutch initiative is looking to combine gas to power production with CCS to unlock marginal fields on the Dutch Continental Shelf. Elaine Maslin reports.

Opportunities for offshore Powergen



Images from Circular Energy.

Like the rest of the North Sea, the Dutch Continental Shelf is in a mature phase. Existing resources are dwindling, new discoveries are ever smaller, and there are many smaller gas pockets which may be left stranded due to a lack of export infrastructure – and what's there is getting ever closing to being decommissioned.

Meanwhile, a new electric power system is becoming increasingly evident. The Dutch government hopes to reach 4500 MW capacity from offshore wind by 2023. It could be a grim outlook, unless you're Arnold Groot, director of Circular Energy.

Instead of producing gas and sending it down export pipelines – the cost of which limit the development of many marginal fields – Circular Energy wants to turn the gas to power, at source (a production facility), then export the power via the increasing number of power export systems being built for offshore wind. CO_2 produced in the process would be re-injected into the reservoir.

The firm, which was founded last year, is already working on a field development plan and hopes to be able to produce first gas/power in 2020.

Arnold Groot

Groot came up with the idea while working with Petro-Canada in the Netherlands. He noted that the Dutch Continental Shelf was small and operating in such a way that many smaller discoveries might never be developed.

"If you change the concept, you may open up additional opportunities for development and production. Having gas to power with CCS is the game changer. This is because one installation produces the gas, turns it to electric power, captures and re-injects the CO_2. Contrast that with the classic 'end of pipe solution' where you take an existing power station and add CO_2 capture technology. This means investment in CCS facilities near to the stack, investment in a flowline to an offshore reservoir, and investment in injection facilities. It's additional capex and no additional revenue and entirely dependent on CO_2 prices and government subsidies."

"With an integrated approach, you reduce the capex because you don't need the flowline. We are sitting on our own waste disposal bin, injecting into the reservoir we're producing from, which reduces capex on flowlines that need to be made from exotic materials because CO_2 is corrosive in the presence of free water." Because the power plant, CCS and injection are co-located, efficiencies can also be made, he says. "The CO_2 can be easily captured as part of one unit, not as an afterthought. We also generate additional revenues because we are developing a gas discovery and sell power from that. This is gas that otherwise would not have been produced." Furthermore, the power from gas could help level out demand/supply at times when the wind isn't blowing.

The CO_2 would be injected into the same reservoir. The advantage is that you're putting back the same volume, Groot says. "The challenge is to prevent recirculation," he says. "As soon as the flow from the injector goes into the producer you will be recirculating CO_2, which will be detrimental to the efficiency of the scheme." The firm has technology in development to prevent recirculation by preventing the mobility of the CO_2 in the reservoir. But, "We need to prove that this works," Groot says. A patent is in place to cover Europe and includes Denmark, the UK and Norway.

Groot says that the scheme, while not as profitable as a standalone gas development, would mean stranded fields could be developed and it wouldn't need subsidies. The project has research funding from innovation programs in the Netherlands, but once commercial, it would stand on its own, he says.

The sweet spot is where there are small fields, close to power export facilities (i.e. offshore wind transformer station) in shallow water, Groot says.

Initially, the firm was looking at producing a mobile unit, which would go from field to field, tapping fields of around 1-2 Bcm. These are stranded due to having modest reserves in relation to the nearest gas export infrastructure. "The distance drives the economics," Groot says. "For us, it isn't stranded if it is remote from gas export facilities. For us, it's stranded when it's remote from wind farms."

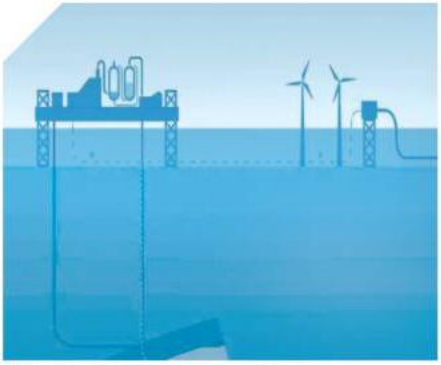
This concept is still being assessed, but having been approached by the operator of a 4.4 Bcm gas field, the firm is working on a development plan for a fixed facility concept, with a 20-year life.

There is a potential issue around the power export facilities, which, in the Netherlands, tend to be state-owned with access on the basis of offshore wind power being given preference. Groot's concept therefore also means that larger capacity export facilities able to accommodate the power from gas is preferable. Part of the work on the topsides facilities will be to make sure production can be ramped up or down to smooth out wind power peaks and troughs. Groot also hopes that the concept could be unmanned – i.e. controlled from shore, further reducing costs – but there would be some complexities to overcome around maintenance and operation, which might make it easier to man it, at least initially.

In the 4.4 Bcm project, with 175MW installed capacity, Groot says that studies show that the gas to power plant could operate 75% of the time equivalent "flat out." The remainder of that time the wind power output would be too high to accommodate the power from gas. The firm is working with CB&I on topsides design.

"It's essentially a small gas production facility with power plant and carbon capture facilities. Gas production has been done for 80 years, power plant is 150 years old, and CO_2 capture isn't especially rocket science.

"We are keen to make sure this works in offshore conditions. With the projected growth of power export facilities in the North Sea, this is likely to generate a great number of opportunities. I'm convinced the greater share of domestic energy use in the future will be from electric power." **OE**



Circular Energy's concept.

Rethinking the dry tree semisubmersible

A jackable semi improves performance and introduces construction advantages, says BP's John Murray.

Over the past several decades, designers have offered the industry a number of semisubmersible concepts aimed at effecting motions to support a dry tree. The reasons for wanting a dry tree design are straightforward. For one thing, dry trees provide direct vertical access to the well, making well intervention possible from the production platform, which dramatically reduces workover costs and supports enhanced oil recovery. Maintenance costs are lower with dry trees as well, and improved vessel stability leads to extension of operating environmental conditions.

Despite many years of creative R&D efforts, the motions inherent to traditional semisubmersible designs have precluded development of a viable dry tree unit. A number of proposed designs bring the heave natural period to a range above the wave periods by increasing the mass of the hull. Others use more sophisticated hull geometry to diminish the hydrodynamic loads of the waves to reduce the motions. Several others require major offshore modifications to complete the structure. To date, none of these alternative designs has been accepted by the offshore industry.

Installation configuration concept.
Illustrations from BP.

Dry trees, proven technology

Dry trees supported by hydraulic tensioners have been proven on tension leg platforms (TLPs) and spars and are an accepted technology for deep water. While both TLPs and spars have been used as dry tree floaters, spars remain the deepwater dry tree production system of choice because they are deployed at depths from about 2000-8000ft. And the spar is applicable beyond this depth range. They have lower motions and greater stability and are, for all intents and purposes, depth insensitive, unlike TLPs, which are not feasible beyond approximately 5000ft water depth. Unfortunately, while spars offer a solution on the stability side, they require a major offshore installation effort that involves uprighting the hull at the deployment site and offshore topsides installation.

If semisubmersibles could be designed with lower motions, they could not only support dry trees but also could use lower-cost riser systems such as steel catenary risers (SCRs). A deep draft semi could be fitted with SCRs in conditions that require more expensive lazy wave risers or flexible risers when a conventional semisubmersible is used.

Why a deep draft semi?

The most appealing attributes of semisubmersibles are its open deck area and amenability to dockside commissioning. Topsides generally are installed on the semisubmersible dockside, which in most cases means that work takes place in water depth of approximately 30ft. For a deep draft dry tree semisubmersible to be effective, the combined draft and airgap height is in the range of 260-300ft. Therefore, a deep draft semisubmersible floating dockside requires a very high crane lift to install the topsides. The semisubmersible draft is practically dependent on the crane capacity at the construction facility and is limited by the lifting height of the crane system.

Beside the limitations to the lifting height of the cranes installing the topsides modules, there are stability issues because of the shallow draft due to the limited dockside water depth.

Several designs have been proposed to circumvent this construction problem. Most suggest increasing the draft to the desirable range by installing a structural component after the main hull has been moved offshore. This would be accomplished by lowering the additional piece into position and installing it as a major structural component at sea. The associated risks and costs for an operation of this complexity have not been readily accepted by the industry.

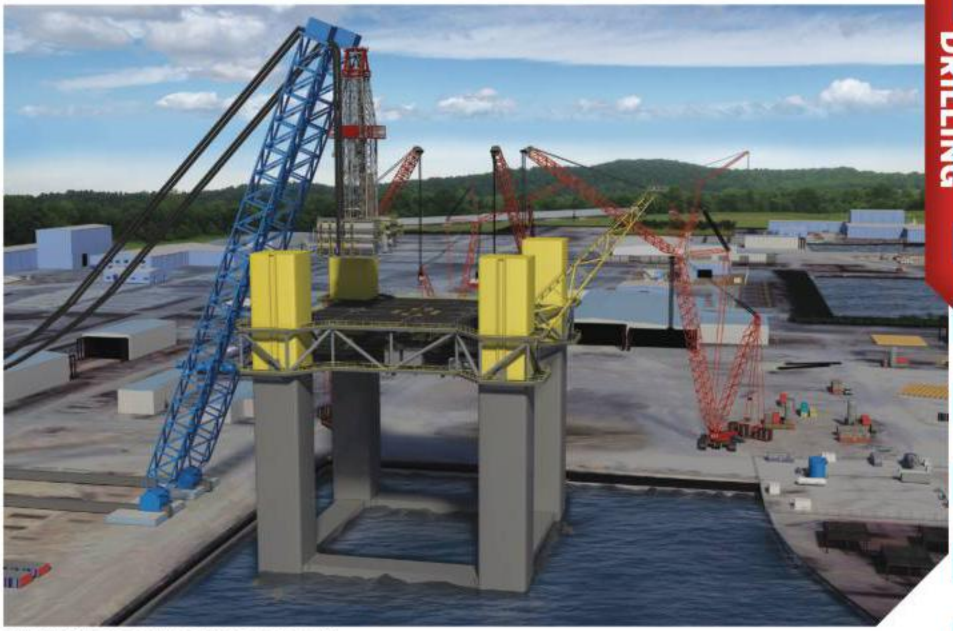
There is general agreement in industry that a semisubmersible with a deep draft would be a valuable option for exploration and production. Until now, the hurdle in getting from design to reality primarily has been construction.

Novel solution

The concept of the JackSemi offers solutions for the shortcomings of other dry tree semisubmersible designs. The structure comprises a traditional semisubmersible hull based on standard architecture, a jacking system – similar to a jackup – to raise and lower the deck, and a deck structure to support the topsides modules.

The jacking movement length required for construction would be in the order of 50-80ft in most cases to accommodate the limits of the installation crane. By comparison, a traditional jackup normally requires jacking displacements of more than twice this range. The jacking and chock mechanism, which is proven on fixed jackup platforms, is above the water line on the JackSemi and can be easily inspected and accessed for maintenance. During construction, the jacking system lowers the deck to a height that provides the necessary stability while cranes lift the topsides into place.

The ability to position the deck lower during construction to accommodate crane capacity means there are many



Dockside construction concept.

construction facilities around the world capable of building the JackSemi. Flexibility in the choice of yards can reduce transportation costs after construction and potentially enable local content requirements to be met.

Because the draft of the hull, the shape of the column and the current conditions at the site of operations are variable, it is possible that the JackSemi could experience vortex induce motion (VIM) when deployed on the offshore work site. The design addresses this possibility with columns that can be fitted with helical strakes well below the jacking racks during initial hull construction to minimize VIM. Fairleaders are attached on the columns with a standard chain jack system. Additional keel structural framework can be installed within the pontoons to support riser guides similar to those on the spar hull to allow the JackSemi to be fitted with risers.

The hull is moored using a conventional spread mooring system comprising chain and steel wire or polyester lines. The spread mooring system and the ability to adjust the height of the JackSemi deck make it useful in a wide range of applications. It can be deployed in marginal field development and redeployed to a new location with a simple change-out of the deck modules.

The unit's deep draft provides large ballast capacity and can accommodate permanent fixed ballast – using material similar to the material used in the soft tank of the spar – in addition to the water ballast tanks in the hull. Having both fixed and variable ballast provides the flexibility to increase the height of the center of buoyancy above the center of gravity and consequently, increase the pitch and roll periods into a range above the wave periods. This greatly improves the motions and increases stability.

The jacking component also could be used with other hull designs, providing a way to augment some of the designs already offered to the industry.

Although the JackSemi, is still in the concept stage, it offers a promising alternative for Innovation and application

As the industry navigates the present market conditions, there is an even more pressing need for innovation. This is the time for cooperative technology development Perhaps the "lower for longer, but not forever" view offered by BP Group Chief Executive Bob Dudley will be the impetus for opening a window of opportunity that will allow implementation of new concepts to help sustain lower development costs even as prices recover. By disclosing this concept to the offshore industry, BP hopes to contribute to reaching that goal. **OE**

***John Murray** is facilities technology production systems engineer at BP in Houston.*

Putting the IoT in drilling

The Internet of Things could help transform drilling rig technology, but it isn't a panacea, warns a Transocean official.

By Karen Boman

Though a lagging indicator, the lack of innovation in offshore drilling rig technology can be measured by the number of drilling technology patents filed. From 1945 to 2012, 36,279 offshore drilling technology patents were filed. In the year 2014 alone, the telecommunications industry filed 37,277 patents.

Plenty of technology innovation has occurred downhole. But above the hole, the offshore drilling contractor community has used the same technology for years, said Jose A. Gutierrez, director of Transocean's technology and innovation group, during a recent presentation at the Internet of Things (IoT) Oil and Gas Conference in Houston.

Six years ago, the company initiated a major innovation effort to remain a technology leader in the industry, Gutierrez tells *OE*. Transocean's technology and innovation group has focused over the past three years on how IoT can enhance Transocean's drilling rig fleet. Transocean's digital transformation program aims to improve operational efficiency, increase financial efficiency, and boost operating integrity.

Gutierrez attributes the lack of technology innovation to the high barrier of entry. A few product and service providers monopolize most of the technology offering, and until now they had little incentive to improve products their customers would buy anyway. "If we have an idea with a strong value proposition and sufficient funding, it still has low probability of success due to these high barriers to entry," Gutierrez says.

In the past, the oil and gas industry was wealthy enough that it could just throw money at a problem, Gutierrez says, so the drilling industry didn't have to worry about innovating existing performance. But, this has changed in the ongoing oil price downturn. Now, drilling rig contractors are being forced to be innovative, creating a renaissance in offshore drilling rig technology.

Transocean is using IoT technology to make decisions based on data, instead of relying solely on worker experience. IoT is allowing the company to capture data, which is then cleaned and modeled by data scientists to gather information. This information enables Transocean to perform predictive maintenance.

More than 50% of the innovation and technology group's portfolio is comprised of IoT-enabling technologies. While the technology is super-relevant, it is also not a panacea, says Gutierrez, adding that companies should first find the problem they're trying to solve, and what is relevant.

"Saying IoT can solve a business problem is like saying Microsoft Word or Excel can do the same thing – you can do great things with these programs, if you know how to use them, if they're deployed right, and what you are writing and modeling. But they're just programs. You might be trying to solve the wrong problem, or optimizing a machine when you should design a new one," Gutierrez says.

"Automating chaos is not a good idea," he adds.

The implementation of IoT technology is not about cutting human workers completely out of the loop. Until today, the oil and gas industry has been very human-centric, but measuring the reliability of a human is impossible.

"It was like the 1950s, when people fixed their own cars," Gutierrez says. In the 21st century, people take their cars to shops for repairs because the technology powering their vehicles is so complicated.

Using IoT allows firms to retain knowledge as workers leave, giving the next generation reliable information, so they're not making the same mistakes over the years, Gutierrez says.

The IoT technology is nothing new, and has been used in the processing, automotive, aerospace, biomedical, and downstream side of oil and gas. "These tools have existed for years, but were too expensive and difficult to access in the past," Gutierrez says.

As companies catch IoT fever, Gutierrez anticipates a bubble forming for IoT technology – similar to the 2001 Internet bubble – and new IoT companies fighting for market share. He also believes that the IoT community is overemphasizing the important of data. Data is nothing – it's information that's valuable.

"Saying IoT can solve a business problem is like saying Microsoft Word or Excel can do the same thing – you can do great things with these programs, if you know how to use them..."

Jose A. Gutierrez, Director of Technology and Innovation Group, Transocean

"The oil and gas industry will face a challenge in understanding what IoT can do for them," says Gutierrez. "Whoever deciphers the value of taking decisions based on data to codify knowledge will be the winner."

Transocean is following an open innovation model, and partnering with many small and large companies, as well as universities, Gutierrez says. Transocean is also leveraging learnings from the heavy industrial, military and aerospace industries in its pursuit of technological innovation. The company also has relationships with the Oak Ridge and Argonne national labs. OE

Arctic

Barents under the spotlight

2017 is set to be a record year for exploration in the Barents Sea, with one prospect in particular getting most of the attention. Edison Investment Research's Elaine Reynolds explores the scene.

The Barents Sea has been the focus of intense industry interest this year with Statoil having drilled one of the most high-profile exploration wells worldwide in 2017.

The Korpfjell prospect, at the northeastern margin of the South Barents, was described by the operator as being high risk/high reward. Partner Lundin believed that the structural closure could be over four times the size of that seen in the giant 1.9-3 billion bbl Johan Sverdrup field and that the

Tapping Korpfjell: the *Songa Enabler.* Photo from Songa Offshore.

prospect had a multi-billion barrel oil potential.

The well, drilled in just over two weeks in August, did not live up to expectations, encountering non-commercial quantities of gas. The well was the first to be drilled in this frontier area of the Barents, close to the maritime border with Russia, that was only offered for the first time as part of Norway's 23rd licensing round in 2016. Despite this disappointment, Statoil is planning to drill a further well on the license in 2018, and will also look to drill a well on the Signalhornet prospect in PL857, 300km to the south of Korpfjell.

Korpfjell was one of 15 exploration wells planned for the Barents this year, making 2017 the busiest year for exploration here since the 12-well high in 2014. In addition, in 2017 the Norwegian Petroleum Directorate doubled its estimate of the undiscovered resources held in the Barents Sea to just under 18 billion boe, by including the eastern part of the northern Barents. This has increased the Barents share of undiscovered resources on the Norwegian Continental Shelf (NCS) from 50% to 65%.

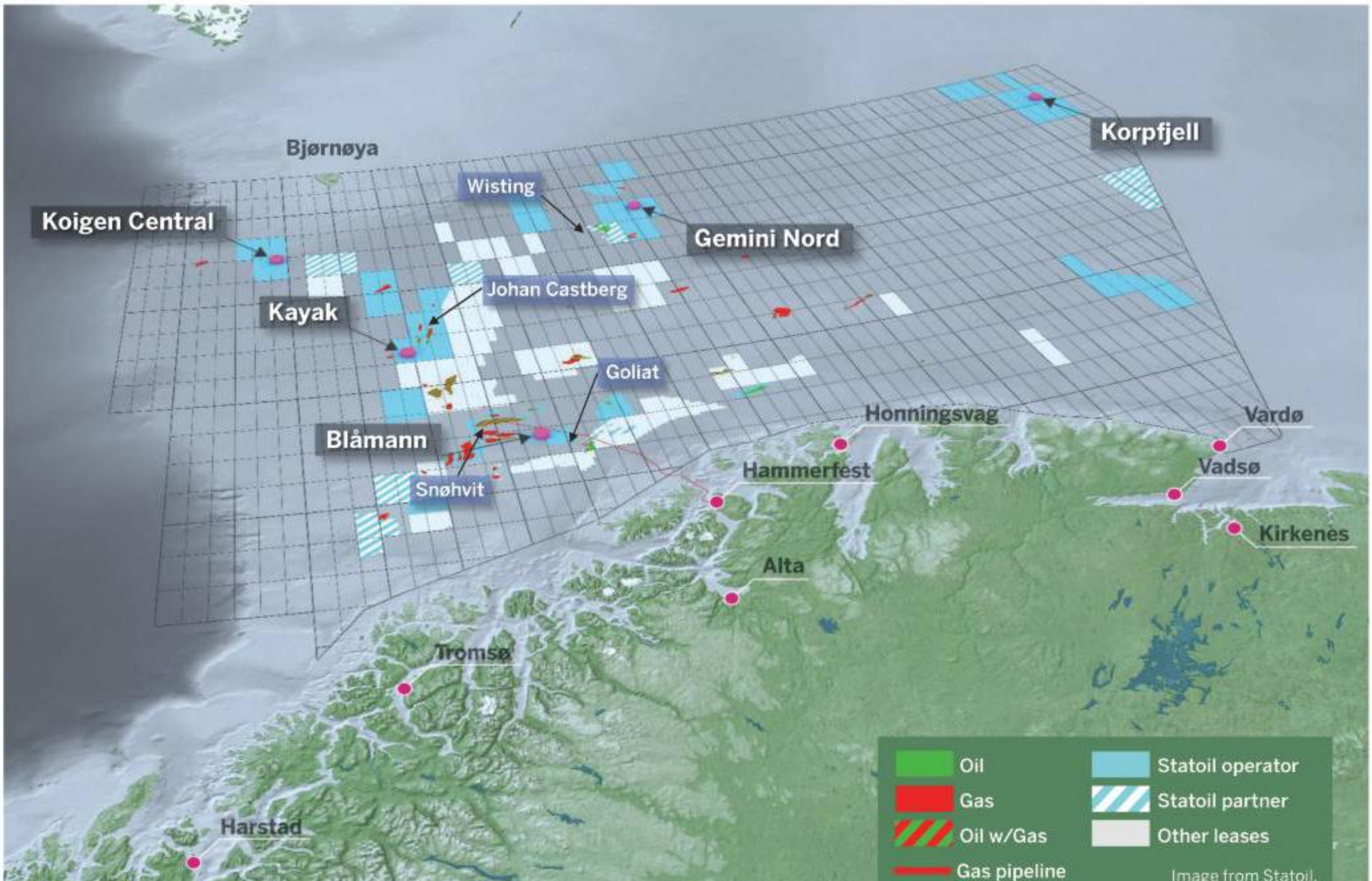
Three potential developments

Although exploration began in the Barents in 1980, to date there are only two fields onstream: the Statoil-operated Snøhvit gas development and the Eni-operated Goliat. A number of significant discoveries have been made since 2011, and in 2014 the Barents Sea accounted for the largest number of discoveries and the biggest resources proven in the NCS.

The discoveries: Statoil's Johan Castberg, Lundin Petroleum's Alta/Gohta, and OMV's Wisting, all have the potential to become standalone projects. Johan Castberg is at the most advanced stage of the three development projects, with a final investment decision due towards the end of this year and potential production in 2022. Appraisal is ongoing at both Wisting and Alta/Gohta. OMV started drilling its Wisting Central III appraisal well in August and the well is designed to gather core data to allow the evaluation of a development concept.

Alta/Gohta sits in the southern part of the Loppa High area of the Barents, which is on trend with Johan Castberg to the west. Together, they are estimated to contain gross contingent resources of 216-584 MMboe, of which 125-400 MMboe is attributed to Alta. Lundin drilled an appraisal well, Gohta-3, in 2017, to evaluate the northern part of the Gohta discovery, but the well encountered only traces of hydrocarbons in poor quality reservoir and will result in a downgrade to the field resource estimate, which is due to be updated by the end of 2017.

The company was more successful with its Alta-4 appraisal



Arctic

well, which was completed in July 2017, and encountered a 48m gross hydrocarbon column and tested at stabilized rate of 6050 bo/d. The well also demonstrated the presence of very good reservoir together with good communication across the reservoir. Data from this well and a geological sidetrack will be used to assist with placement of a horizontal well for an extended well test that is planned for next year.

Mixed exploration results in 2017

Lundin and Statoil will account for the majority of the exploration wells drilled in the Barents in 2017, with five exploration wells each. Results so far this year have, however, been disappointing for both companies. Lundin has drilled two wells focused on the Loppa High area to the north of Alta/Gohta. Neiden and Filicudi both discovered oil, with lower resources than estimated pre-drill. Neiden was a carbonate prospect on trend with Alta/Gohta targeting resources of 204 MMboe, but post results this has been revised to 25-60 MMboe. The discovery reduces the risk of the Børselv prospect, 15km north and up dip from Neiden. Børselv is now being drilled, targeting 244 MMboe with a geological chance of success (CoS) of 39%.

Filicudi discovered estimated resources of 35-100 MMboe, down from a pre-drill estimate of 258 MMboe. Although lower than expected, Lundin still estimates that the Filicudi trend holds up to 700 MMboe and plans to drill two further exploration wells this year that have been de-risked by Filicudi. Hufsa is estimated to hold 285 MMboe resources, and Hurri to hold 218 MMboe. Both prospects carry the same estimated CoS of 25%.

Statoil has also had mixed results from its 2017 exploration program in the Barents. Prior to spudding Korpfjell, it had drilled three of its five planned exploration wells. The first, Kayak, sits to the north of Filicudi and found 25-50 MMbbl of recoverable oil in moderate to poor reservoir. Statoil will consider tying the discovery back to Johan Castberg, which is around 23km to the north east of Kayak. The remaining two exploration wells, Blaamann and Gemini Nord, were both expected to be oil bearing, however both encountered gas. Blaamann is estimated to hold 1.5-3Bcm gas and could add volumes to Snøhvit, 21km away.

Gemini Nord sits to the north east of Wisting and has been declared to be a non-commercial gas discovery. Following Korpfjell, Statoil's final exploration well this year is expected to be Koigan Central to the north west of Wisting, but beyond 2017, Statoil is likely to continue exploring the region, with recent reports that it is looking to secure two additional rigs to drill in the Barents in 2018 and 2019.

Planned exploration drilling programme 2017

Image from Statoil.

24th round announced

A positive result at Korpfjell would have been a potential game changer for the Barents. One of the first ways to gauge any increased industry interest will be in the 24th licensing round, with applications due by 30th November and awards expected in 1H 2018. Some 102 blocks are on offer, of which a record 93 blocks are up for grabs in the Barents. More than half of these blocks are north of the most northerly discovery so far, Wisting, while a number are located in the eastern portion of the Barents, including three blocks immediately to the south of Korpfjell.

The round also includes 20 blocks that sit within 100km of the Bear Island nature reserve and this has attracted criticism from environmental groups. Norway's Environment Agency has called for the blocks to be withdrawn from the round and to reduce the perimeter around the island to 65km.

The Barents has become a focus for environmental groups, with Greenpeace now targeting Statoil as its main target following Shell's withdrawal from the Arctic. However, given the undiscovered potential believed to be sitting in the Barents, combined with relatively benign conditions compared to other Arctic regions, exploration and development activity is set to continue. **OE**

***Elaine Reynolds** is an analyst in the Oil & Gas team at Edison Investment Research. Prior to joining Edison, she worked as a Petroleum Engineer for Texaco and Shell in the North Sea, Oman and The Netherlands. She holds a BSc in Chemical Engineering from Heriot-Watt University.*

Askeladd advances

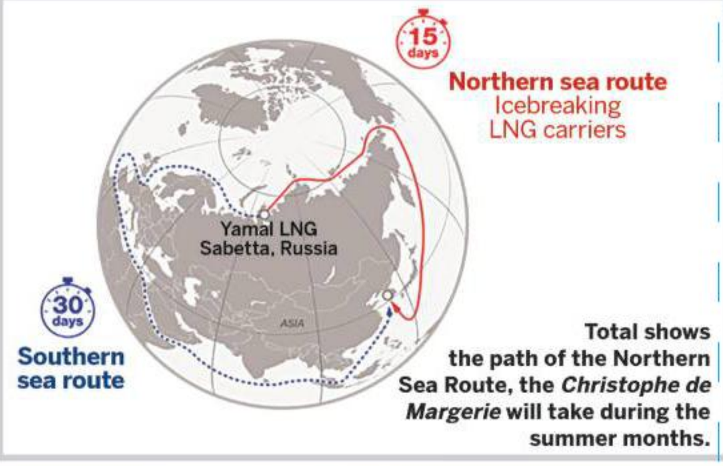
As *OE* went to press, it was reported that Statoil is planning development of the Askeladd field. It will connect into Snøhvit, a subsea tieback to Melkøya LNG plant near Hammerfest. Start-up is expected in 2020-21. Earlier this year, Danish engineering house Ramboll won a front-end engineering and design contract for the project.

Arctic

Heading North

Despite disappointment at Korpfjell, there's optimism in the far North.


The *Christophe de Margerie* LNG carrier in icy conditions.
Photo from Total.



Total shows the path of the Northern Sea Route, the *Christophe de Margerie* will take during the summer months.

High hopes were pinned on the multi-billion-barrel potential Korpfjell prospect, at the northeastern margin of the South Barents Sea. While the well, drilled by Norwegian operator Statoil, failed to prove commercial quantities, finding just a small amount of gas, the industry's continued move further north appears to be unchanged.

By 2040, a majority of Norwegian oil and gas is expected to be produced in the North, says Kåre Storvik, of Storvik & Co., an independent consultant for business development in Northern Norway and Northwest Russia, with activities focused on Norway and neighboring Russia.

Indeed, the Norwegian Petroleum Directorate estimates that 68% of the remaining petroleum resources in Norway will be found in the Norwegian Barents Sea. Meanwhile, "The European Arctic has enough resources to cover the world's energy needs for one hundred years," Anatoly B. Zolotukhin of Moscow's Gubkin Institute told participants at the Arctic Europe seminar during SPE Offshore Europe in September 2011.

The region is already home to the Hammerfest hub, which serves Statoil's Snøhvit gas development and Eni's Goliat oil field. Further developments are coming, with Statoil expected to issue a positive decision on its Johan Castberg development this month (October) with first production targeted for 2022. Lundin Alta/Gohta project and OMV's Wisting oil field are expected to follow, with first production expected before 2030.

All these fields are expected to be developed by floating production, storage and offloading vessels (FPSOs) with the oil either shipped directly to the markets or by shuttle tankers via a land terminal in Veidnes, North Cape, says Storvik.

The activity is attracting industry to Hammerfest, including offshore support from NorSea Polarbase and ASCO, as well as a cluster of international oil industry service providers.

Thanks to continued acreage availability, the activity is set to continue. As part of the 23rd round, the Barents South East, close to the Russian border was opened. "This area is considered very promising," says Storvik. "The first well on the

Chinese seismic vessel *Hai Yang Shi You* 720 in Kirkenes.
Photo from Henriksen Shipping Services.

Statoil Korpfjell license in this area proved, however, dry. But, this is just one well in an area the size of the Norwegian North Sea. It has to be remembered that there were 33 dry wells in the Norwegian North Sea before anything was found. Both knowledge and tools were poorer 50 years back. But in fact, the Barents Sea geology has proved complex. Next year, three more wells will be drilled. One by Statoil, one by Aker BP and the third by Rosneft-Eni, the latter on the Russian side of the

The *Christophe de Margerie* during its naming ceremony in St. Petersburg, Russia. Photo from Sovcomflot.

border. Exploration in these waters is technically supported from Hammerfest with crew transport, medical and SAR support from Kirkenes and Vardø. A likely scenario is that oil production in this area will be handled by FPSOs and shipped by shuttle tankers via Veidnes.

Meanwhile, the 24th round licenses are due to be offered in November, with awards during 1H 2018.

While arctic exploration maybe seen as challenging, "with large finds and good productivity, the fields in the Barents Sea can be profitable, such as Statoil's Johan Castberg, with a break even at US$35/bbl," says Storvik. "Operational conditions may be different from other parts of the Norwegian shelf, but they're not difficult. Researchers and industries in the North are working on Arctic climate and survival technologies to secure safe work conditions."

There are 18 operating companies cooperating in the Barents Sea Exploration Collaboration (BaSEC). Building on existing knowledge and experience, the cooperation working on high and cost-effective HSE standards for Norwegian Barents Sea exploration, particularly in the new areas opened for oil and gas activity in the 23rd round.

Looking East

However, while Western firms are involved in the North, the region is also looking to the East. Recently the Sovcomflot-owned icebreaking LNG carrier *Christophe de Margerie* – named after the charismatic Total CEO who died in a plane crash in Moscow in 2014 – sailed from the Snøhvit LNG export terminal in Hammerfest, Norway, to Boryeong, South Korea in 19 days using the Northern Sea Route (NSR).

Russia's Sovcomflot said back in August that the ice class Arc7 vessel set a record crossing the NSR in six days, averaging approximately 14 knots, and encountering ice fields 1.2m thick.

"The LNG carrier covered 2193nm (4060km) from Cape Zhelaniya of the Novaya Zemlya archipelago to Cape Dezhnev at Chukotka, Russia's easternmost continental point," the company said in a 22 August statement.

The voyage is the first unescorted (i.e. without an icebreaker) merchant LNG vessel ever to take this route. The route makes it possible to reach Asia via the Bering Strait in 15 days, versus 30 days via the Suez Canal.

"For the past 30 years, Northern Norway has built up business expertise and relations with Russia and served both Russian vessels and Western vessels working in Russian waters," says Storvik.

The *Christophe de Margerie* is part of an LNG fleet being built up to transport LNG from Yamal LNG in Sabetta, Russia, to Asia. Yamal LNG's stakeholders are Russian firm Novatek (50.1%), France's Total (20%), China's CNPC (20%) and the Silk Road Fund (9.9%).

Yamal LNG was the first to demonstrate Chinese ambitions in the North. Since then, the Chinese have, assisted by Western sanctions, taken over from Western companies the market for oil and gas exploration activities on the Russian shelf, including seismic surveys and drilling activities, as witnessed by the seismic research vessel *Hai Yang Shi You* 720 working in the region.

"Northern Norway has, however, been able to continue their support services to the Russian shelf activities," says Storvik. "The Chinese seismic vessels and drilling rigs are getting their services from Kirkenes. Whereas, Hammerfest is in position to offer technical support. This proves, in our opinion, Northern Norway's strong position as a supporter of Russian logistics and industrial activities, developed over the last 30 years." **OE**

Arctic

Electrifying the Barents

Having a power hub, to supply future Barents Sea developments, could help operators mitigate CO_2 emissions – and the regulations that they could come up against. Marius Kluge Foss, of Rystad Energy, explains.

The Barents Sea is the last Norwegian oil province with anticipated future growth. From currently accounting for a mere 5% of total Norwegian oil and gas production, Rystad Energy estimates it could account for around one-third by the mid-2030s.

Several of the largest non-sanctioned fields in Norway are in the Barents Sea, of which the most notably are the three oil discoveries made up of Statoil-operated Johan Castberg, Lundin-operated Alta, and OMV-operated Wisting. The long investment and production horizons of these projects make the consideration of carbon risk highly relevant. Once developed, these fields will produce beyond the 2040s, in a period that might be associated with declining global oil demand and stricter CO_2 regulations. Making decisions today to minimize this risk may be worthwhile.

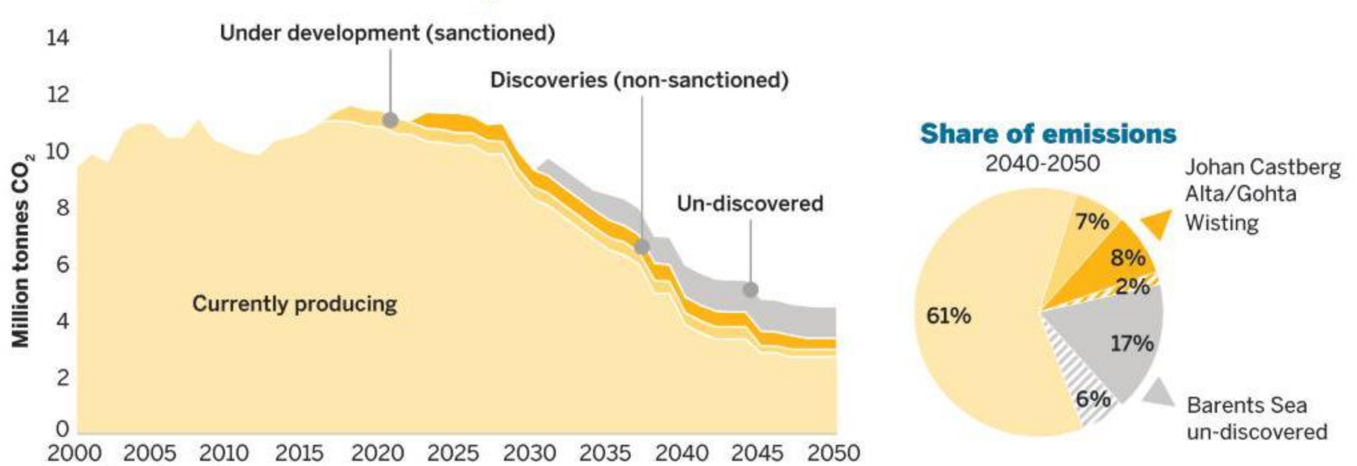
Figure 1 outlines CO_2 emissions associated with upstream oil and gas production on the Norwegian continental shelf (NCS).

Looking ahead at accumulated emissions over the period 2040-2050, Rystad Energy expects the three Barents Sea discoveries closest to sanctioning – Johan Castberg, Wisting and Alta – to make up about 8% of total NCS emissions. Adding future volumes expected to be discovered and put into production in the Barents Sea within 2040, increases the potential of electrifying the Barents Sea to 25% of total NCS upstream emissions during 2040-2050.

The Barentshub concept

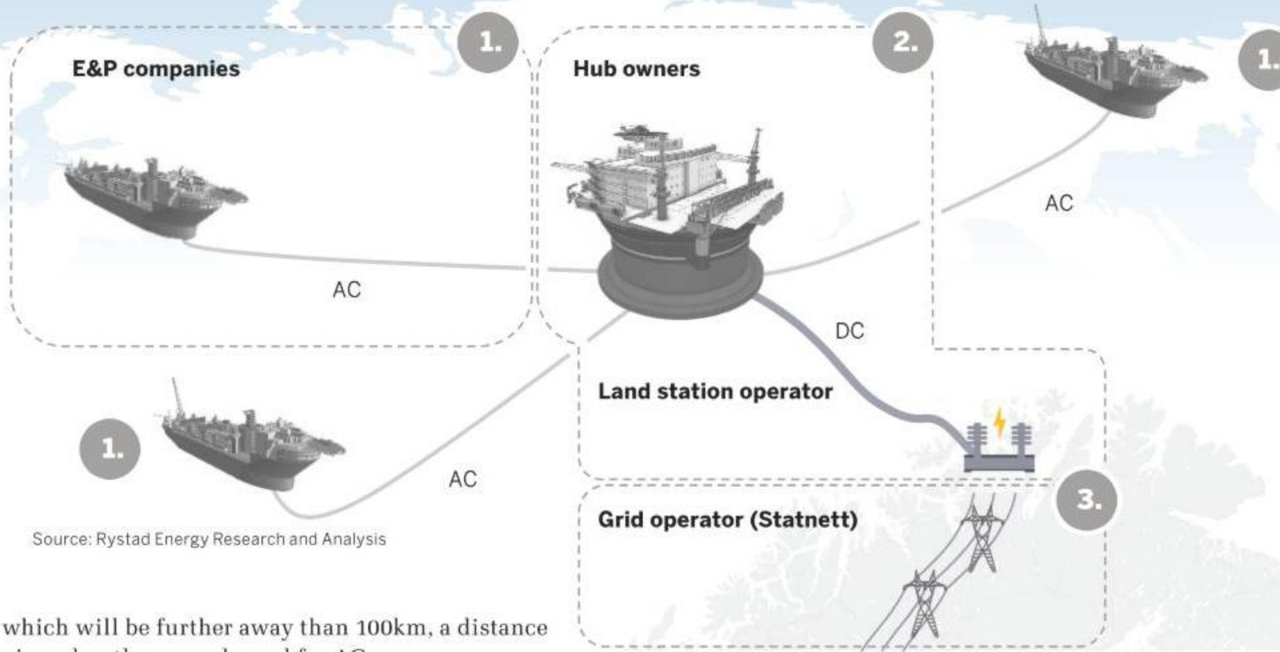
The primary challenge with electrification of fields in the Barents Sea is the vast distances. Rystad Energy addresses this issue with a suggested electrification solution for the three ongoing Barents Sea developments, Johan Castberg, Wisting and Alta, as well as potential future discoveries. The proposed solution envisages a separate host platform, a Barentshub, supplied with DC power from shore. The hub distributes AC power to the three surrounding platforms, none of

Figure 1: NCS upstream CO_2 emissions by field status.



Source: Rystad Energy Research and Analysis

Figure 2: Barentshub - overview of concept and stakeholders



Source: Rystad Energy Research and Analysis

which will be further away than 100km, a distance viewed as the upper bound for AC power.

The main components making up the exploration and production companies' power demand is electric power, heating, and gas injection. These can all be served by electrical power from shore in a full electrification scenario estimated to generate an annual average power load of 298 MW/year at peak. The corresponding reductions in CO_2 emissions throughout the three fields' lifetime is estimated to 22 million tonnes.

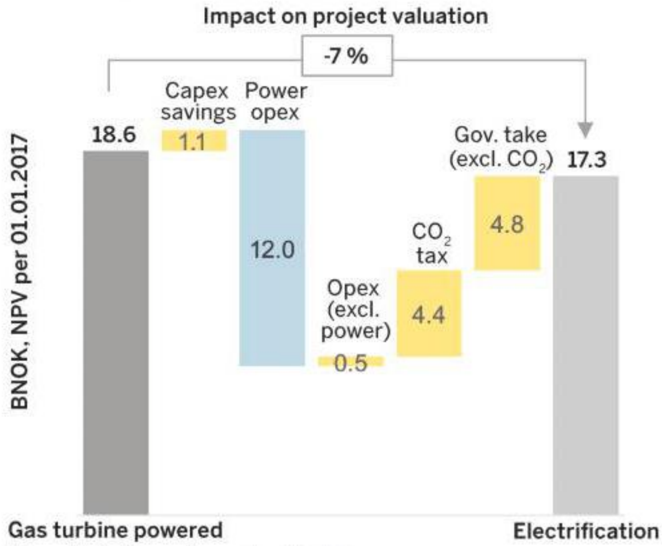
Figure 2 illustrates the various stakeholders consisting of 1) the exploration and production companies owning and operating the facilities on the three fields, 2) the Hub owner and 3) the grid operator, in this case Statnett. Each stakeholder has its own set of considerations in the proposed setup. The exploration and production companies will be most concerned about operational performance and project economics, while the Hub owner group's key priorities will be predictability in power demand and hence revenue.

Obstacles and cost impacts

- **Timing:** Johan Castberg has been through concept selection while Wisting and Alta are still at the pre-FEED stage. Progress and final concept selection have significant bearing on Barentshub.
- **Power grid:** The surrounding power grid capacity and supply is of vital importance for Barents hub. Planned upgrades with minor additions is likely to be sufficient to support electrification of all three fields.
- **Hub cost:** The Barentshub is estimated to require an initial investment of just below US$1.16 billion (NOK9 billion), with the power cables making up close to 50% of the cost.
- **Carbon cost:** The combined CO_2 cost for exploration and production companies on the NCS (EU Emissions Trading System + Norwegian carbon tax) is expected to increase to more than $83.58/tonne (EUR70/tonne) (real 2017) by 2040 as regulatory frameworks tighten in Europe.
- **Power prices:** Future Nordic power prices are likely to see an incline towards 2030, reaching 300–$48.92/MWh (NOK380 /MWh) (real 2017)–from the current 200.

Figure 3: Asset valuation and impact of electrification

(delta vs. gas turbines) BNOK, NPV per 01.01.2017



Source: Rystad Energy Research and Analysis

Figure 3 outlines the combined effect on asset valuation for Johan Castberg, Wisting and Alta by switching from gas turbines to full electrification with production startup in 2023, 2025 and 2026 respectively. For the oil companies, the only negative value contribution is power opex, with capex savings, opex savings (excl. power), reduced CO_2 tax and government take all contributing in the positive direction. The combined value for the three fields drops by 7% from $2.39 billion (NOK18.6 billion) in the gas turbine case to $2.23 billion (NOK17.3 billion) with electrification. This highlights the limited impairment that electrification actually has on these fields. Albeit expensive, the total implications of electrification on valuation is just a 7% reduction compared no electrification, and the future threat of carbon risk, both in terms of global carbon budgets and carbon taxes, is eliminated. OE

Review

A balancing act


Bob Dudley
Photo from SPE Offshore Europe.

Balancing digitalization, decommissioning, and a need to remain relevant and the lower "for the foreseeable future" scenario made for a complex range of topics at SPE Offshore Europe 2017.

The industry has worked hard to improve efficiencies and cut costs but, more needs to be done to ensure long-term health, remain relevant and attract future generations of technology savvy individuals to the industry, the opening plenary session at SPE Offshore Europe 2017 heard.

The concerns were raised by plenary speakers, comprising BP CEO Bob Dudley, Shell CEO Ben van Beurden, Wood Group CEO Robin Watson, Petrobras chief exploration and production officer Solange Guedes, Exchequer Secretary to the Treasury Andrew Jones MP, and SPE President Janeen Judah, alongside conference chairman Catherine MacGregor, who is also Schlumberger's Drilling Group President.

This year, 35,000 people attended SPE Offshore Europe at the Aberdeen Exhibition and Conference Centre, in early September, according to co-organizers Reed and SPE, down from >50,000 in 2015, and >63,000 in 2013 (a record). Look to the pre-boom figures, however, and it's less of a drop, the show attracted 48,000 in 2011. Among the exhibitors, 44 countries were represented, with delegates from 100 countries.

With a lack of major news announcements, the event was reflective but forward looking. A key to industry reinvention will be new technologies, but the industry will also need the people to use them, Watson told the plenary session. He said that some 350,000 industry jobs had been lost globally since the downturn started three years ago. "Some of these jobs will never return. This is a generational shift," he said.

The shift the industry is experiencing was highlighted by industry body Oil & Gas UK during the event. Its Economic Report 2017 was launched at a business breakfast and showed that UK oil and gas industry job losses had slowed to 13,000 in 2017, compared to 60,000 in 2016.

The report also said an estimated US$6 billion worth of mergers and acquisitions were made in the UK oil and gas sector in 1H 2016, pointing to a turn in fortunes for the basin. Much of the activity has been driven by private equity backed firms, whose approach to doing business in the basin is enabling new business models, particularly around closer working relationships with contractors, including where the latter works in return for future payments or production.

The $6 billion figure didn't include Total's acquisition of Maersk Oil, however, a move that could signal further job losses due to the $400 million annual synergies Total said could be made by joining the two firms. Uncertainty over Brexit adds further to the murky path ahead for the North Sea industry.

Significant focus at this year's event was on digitalization and decommissioning. MacGregor told the event: "Whatever you think about high power computing, or the advent of digital construction, or fully utilizing production data to make systems run better... The impact is enormous. And it will make the industry more attractive."

Robin Wye, BP Group Technology research commercialization manager, told the event that digital is going to change how the industry does business. "We have subsurface engineers and scientists looking at cutting their workflows by a factor of 10 or 100, as well as getting a better result," he says. "But it may take a decade before we're seeing a major impact of that transformation, but every bit of our business is being impacted by how we use digital technology."

BP sees this area as worth investing in. BP Ventures, for example, has invested in Beyond Limits, an artificial general intelligence software company, which has artificial intelligence (AI) technology on board a Mars rover, he said.

Ragnhild Ulvik, vice president, Innovation GSB Corporate Strategy and Innovation, Statoil, said the firm expects to invest NOK1-2 billion (£100-200 million) from now until 2020, in addition to current IT investment the

Forging ahead

While field development announcements were thin on the ground during SPE Offshore Europe, there some positive stories for the industry to digest.

Aker Solutions announced it had secured a front-end engineering and design contract from Nexen Petroleum UK for a second phase development of the Buzzard field. The project could see up to 12 subsea trees added to the field. FEED is due to complete by the end of the year. Buzzard, which has a four-platform complex in place, is 100km north-east of Aberdeen and has an estimated 1.5 billion bbl in place.

Hermod – in 1979 on its first job, the Piper A platform.
Image from Heerema Marine Contractors.

Subsea 7 signed a letter of intent with Royal IHC in the Netherlands for the construction of a new, <US$300 million reel-lay vessel and associated pipe lay equipment for delivery in early 2020. A firm contract is expected to be awarded before the end of 2017.

The vessel will be targeted towards longer tie-back developments and will replace the *Seven Navica*, which is expected to be retired from reel-lay operations in due course.

Boskalis won contracts, including transporting the West White Rose platform topsides in North America, transport of offshore wind jackets in Europe, and taking Heerema Marine Contractor's *Hermod* semisubmersible crane vessel to China to be scrapped. The vessel set sail late September from Rotterdam for Zhoushan, China, where *Hermod* will be delivered to be dismantled and recycled at the Zhoushan Changhong International Ship Recycling yard. HMC's new semisubmersible crane vessel, Sleipnir, which will be equipped with two 10,000-tonne cranes, is due in service in 2019, with contracts for Noble Energy on the Leviathan development and Maersk Oil on the Tyra Future project already booked. ▪

company is making.

"We have a vast amount of data and we only use a small fraction of it. The amount of data increases 25% each year. We have so much data that we don't even know what we know," Ulvik said.

However, a joint study by software company AVEVA and Westwood Global Energy Group, released during SPE Offshore Europe, found that while the benefits of digitalization, using tools such as intelligent data management and laser scanning to create a Digital Twin, are generally recognized, the industry's risk averse culture coupled with reduced budgets and common misconceptions has been preventing its full potential from being realized.

Recognizing the rapidly expanding decommissioning sector, SPE Offshore Europe devoted one of its six halls to the discipline this year, including a themed exhibition and dedicated conference space.

"Are we thinking big enough, or is the challenge smaller than we think," was the key questions asked at the decommissioning keynote, led by North Sea industry leaders, including session moderator Steve Phimister, who is upstream director UK & Ireland for Shell.

One of the challenges is reducing the £60 billion bill to remove the UK North Sea's oil and gas infrastructure by at least 35% – a target set by the UK's Oil and Gas Authority and described as ambitious by Phimister, but thought achievable.

Phimister told SPE Offshore Europe: "We really do have to think quite deeply and differently about it [decommissioning], and draw on all the expertise in the industry, take on the issues… find the solutions and smart ways of working together whether in execution strategies or contracting strategies."

CNR International's decommissioning project manager, Roy Aspden, said an important question is how the industry was developing the capability to respond to the sheer size of the decommissioning challenge: around 470 installations will need to be decommissioned over the coming decades in the UK North Sea alone.

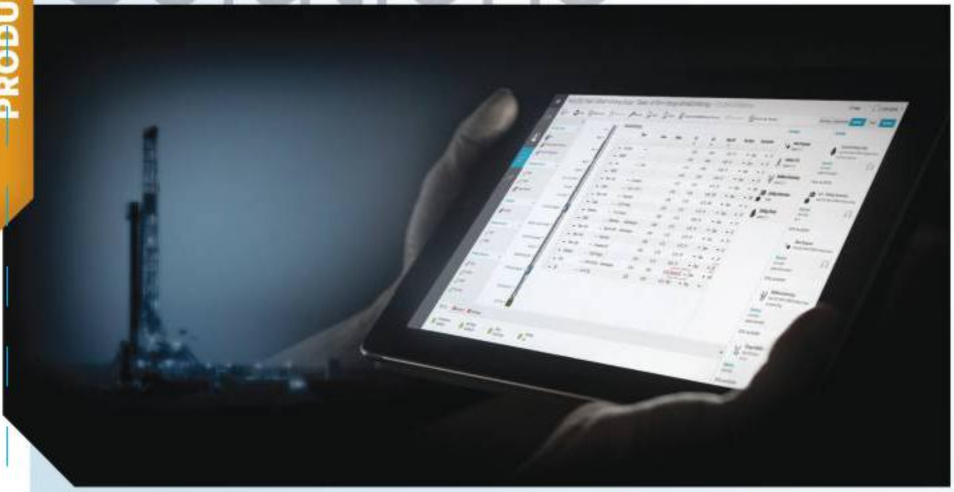
He said: "Six years ago, we had zero [decommissioning] capability in the company, and faced decommissioning the tallest, deepest, most northerly [installation] in Murchison. So, we needed to build capability pretty quickly." **OE**

FURTHER **READING**

Read more show news here:


Robin Watson
Photo from SPE Offshore Europe.

Solutions



Schlumberger unveils DELFI

Schlumberger unveiled the new DELFI cognitive exploration & production (E&P) environment, which will enable collaboration across E&P teams and leverages the full potential of all available data and science to optimize E&P assets.

The DELFI environment leverages digital technologies including security, analytics and machine learning, high performance computing (HPC) and Internet of Things to improve operational efficiency and deliver optimized production at the lowest cost per barrel.

The DELFI environment will provide a new way of working for asset teams by strengthening integration between geophysics, geology, reservoir engineering, drilling and production domains. The openness and extensibility of the DELFI environment will enable Schlumberger customers and software partners to add their own intellectual property and workflows in the environment.

With the launch of the DELFI environment, Schlumberger deployed an E&P Data Lake on the Google Cloud Platform comprising more than 1000 3D seismic surveys, 5 million wells, 1 million well logs and 400 million production records from around the world, demonstrating a step change in scalability and performance.

The DELFI cognitive E&P environment will enrich Schlumberger software, including Petrel E&P, Techlog wellbore and Omega geophysical data processing platforms as well as foundation technologies such as PetroMod petroleum systems modeling software, INTERSECT reservoir and OLGA multiphase flow simulators.

www.software.slb.com/delfi/

Motor-compressors boost Asgard operation hours

MAN Diesel & Turbo says two of its 11.5 MW HOFIM motor-compressor units enabled both subsea compression trains at Statoil's Asgard field, the world's first subsea gas compression facility, to achieve more than 25,000 operation hours, with availability close to 100%. The motor-compressor units, which have operated since Asgard production began in September 2015, are the world's first compressors to operated 300m below sea level. The few interruptions the system experienced occurred due to power supply failures from the vessel.

The motor compressors were provided to Statoil contractor Aker Solutions. They will extend the reservoirs' productive life on the Åsgard field for another 15 years and add an overall 306 MMboe. The adapted subsea HOFIM features a tailored motor design, casings designed for 220 bar pressure, a 7-axes active magnetic bearing system and a special cooling gas extraction.

www.dieselturbo.man.eu

Barrier unveils new LED floodlight

Barrier Group unveiled at this year's Offshore Europe conference its innovative new hazardous area zone 1 floodlight, Quazr. The floodlight has been designed for use in sectors with hazardous operating areas, including petrochemical, water and waste treatment, ports and terminals, military and in environments such as distilleries, and pharmaceutical plants.

The technology meets stringent standards laid out in the ATEX Directive, Electromagnetic Compatibility Directive and the Low Voltage Directive. It is also compliant with the BS EN60079-18 standard and will be IECEx certified.

The new Quazr floodlights give off luminosity at 55W using 24 LEDs. The LEDs are fully-encapsulated, giving high-optical clarity, dielectric strength and moisture protection. The product will be sold with user-changeable lensing options as standard. **www.barriergroup.com**

Nexans touts new jacketed loop

Nexans AmerCable's AmerLink jacketed top drive service loop completed 400,000 cycles without failure at a leading top drive manufacturer's service loop test facility in the US. AmerLink also complies with the upcoming 2017 API RP14F revision which is more applicable to offshore applications than land. This patented service loop was designed for use on land and offshore.

The firm says its jacketed loop has a mold-cured outer jacket and are lighter, more flexible, smaller and have a significantly longer service life. Nexans says its unique design and reinforced outer jacket effectively support the loop's weight and dynamic loads, reducing component stress during operations and handling.

The loop features lighter overall weight (up to 21%); more flexible/smaller bend radius (up to 37%); smaller overall diameter; 58% greater pull-out/breaking strength; direct drop into existing brackets; virtual elimination of water ingress; redundant, mold-cured jacket reinforced with stainless steel armoring and aramid fibers; centered loop conductors, which balance stress on the components. **www.nexans.com**

Emerson launches handling clamp device

Emerson Automation Solutions launched the PolyOil JAR Handling Clamp – for increased safety and well integrity aimed at reducing the risk of jars firing prematurely at the surface prior to being deployed into a well.

Jars are mechanical devices used downhole to deliver an impact load to another downhole component and include a firing mechanism that activates when the necessary compression or tension has been applied to the running string. The inadvertent firing of such jams prematurely, however, Emerson says, can pose a hazard and lead to possible injuries and the dropping of the bottom hole assembly if pins are sheared.

The PolyOil JAR Handling Clamp acts a safety device to prevent the jar from cocking and firing, with the jar unable to fire unless the fishing neck – designed to enable running and retrieval tools to reliably engage and release – is closed, Emerson says. Therefore, when the clamp is fitted to the jar, the rod is kept in the open position, thereby preventing premature firing during the handling of the jar at the surface. The clamp also prevents the jar rod from being damaged during transportation and keeps it debris-free during storage. Applications for the new JAR Handling Clamp include drilling, drill stem testing jars, coil tubing and wireline applications. **www.emerson.com**

Hydraulic retractable coupler qualified

Scotland's Subsea Technologies Ltd. (STL) completed qualification testing and delivery of the first 2in, 10,000 psi hydraulically retractable coupler designed for use with STL's XR and HB high angle release connectors. It enables large bore, high-pressure annulus and choke and kill lines to cross the XR and HB interfaces and, due to being retractable, enables the XR and HB connectors to release in an emergency without any restrictions on maximum release angle. The coupler is qualified for use with hydrocarbon containing fluids and is both ISO 13628-7 (API RP 17G) compliant and PR-2 qualified. STL have since received orders for a further three couplers.

Additionally, STL racked up £3.8 million in new contracts. The firm will supply multiple STL connectors over 18-month period for an international service company, including SLIC connectors, electric line and slickline pressure control heads and associated support equipment, the development and supply of STL's new HB Connector, as well as the supply of a number of bespoke handling and shipping skids. The SLIC connectors incorporate STL's new proprietary ¼in subsea hydraulic couplers, and the HB Connectors include STL's new 2in hydraulically retractable couplers. For major operator, STL will upgrade an existing SLIC connector and well intervention system, to enable integration of a subsea grease injection system. **subseatek.com**

Activity

2018 OAA launches

The 2018 Offshore Achievement Awards (OAA) was launched during the first day of SPE Offshore Europe 2017 in Aberdeen. The annual awards, organized and hosted by the Society of Petroleum Engineers Aberdeen Section (SPE Aberdeen), and supported by *OE*, was launched by Ian Phillips, Chairman of SPE Aberdeen, and Donald Taylor, managing director at principal sponsor, TAQA.

"The awards highlight excellence and serve as a prestigious platform for those operating in the oil and gas and renewables sectors. I would urge both companies and individuals to start thinking about their award entries, and allow us to shine a spotlight on their success," Phillips says.

"Celebrating success, innovative thinking and great accomplishments in what continues to be a challenging climate is more important than ever. We're looking forward to sharing the stories of the inspirational work that continues to happen in our industry."

Opening for entries on Monday, 2 October, categories will continue to celebrate both company successes and individual achievements, covering a wide variety of topics including innovation, collaboration and business growth.

Entries from UK-registered companies operating within the renewables or oil and gas industries will be accepted. The awards ceremony will take place at the Aberdeen Exhibition and Conference Centre on 22 March 2018. Find out more here: www.spe-oaa.org. ▪

Last year's winners L-R: Young Professional Award - Marianne McKevitt; Above & Beyond Award - Sam Lisney; and Significant Contribution Award - Oonagh Werngren. Photo from SPE OAA.

Fugro to establish hydrography center

Fugro said it will establish a new Hydrography Centre of Excellence for the Americas in Houston. Using specialist resources that include autonomous vessels and aircraft, integrated data acquisition techniques, remote processing and large data transfer, the focus is on reducing risk, increasing accuracy and streamlining project timelines for clients.

The center will handle a wide range of hydrographic project types, including nautical charting, cable routing and Law of the Sea boundary claims. With continued delivery excellence as its objective, Fugro is formalizing its coastal zone mapping services using complimentary geophysical and geotechnical techniques to benefit a wide range of applications including resource development, infrastructure siting, coastal management and emergency response.

The new center is part of Fugro's reorganization of its hydrography services in the Americas, relocating key staff and assets from its San Diego office to its US headquarters in Houston.

"The need for hydrography services continues to increase," said Ed Saade, Fugro USA president, citing as evidence the company's recent collection of more than 1 million sq km of high resolution bathymetry data annually, as well as involvement with seabed mapping initiatives such as the Shell Discovery XPRIZE and Seabed 2030.

Nabors takes Tesco

Nabors Industries will acquire Tesco Corp. in an all-stock transaction of US$145 million, net of $72.5 million cash. The move will combine Canrig, Nabors' rig equipment subsidiary, with Tesco's rig equipment manufacturing, rental and aftermarket service business. Additionally, Tesco operates a tubular services business in numerous key regions globally, which will immediately benefit Nabors Drilling Solutions.

From the Nabors point of view, the acquisition fits the company's strategy of moving from being just a provider of land and offshore drilling rigs to also using rigs as a delivery platform to provide drilling products and services, Byron Pope, managing director with Tudor Pickering and Holt, told *OE* in mid-August when the news was first announced. Tesco will enable Nabors to provide those ancillary services. The acquisition also gives Tesco the critical

Activity

Balmoral takes stake in ACE Winches

Northeast Scotland's Balmoral Group has agreed to take a "substantial stake" in mooring and listing firm ACE Winches for a US$13.56 million (£10 million) investment.

The two firms are to work together to "maximize global opportunities in the offshore, renewables and decommissioning markets."

ACE Winches provides mooring, lifting, pulling and deploying solutions provider in more than 50 countries. Balmoral specializes in subsea buoyancy, flotation, insulation, elastomer and renewable energy products, property development, civil/environmental engineering liquid storage and treatment solutions.

Both companies have seen success on the global stage, however, since the beginning of the oil price slide in 2014, manufacturing business has slowed for ACE Winches and the company has restructured to optimize global rental opportunities.

With the new investment, ACE is eyeing opportunities to expand its equipment hire business on a global basis and the two companies say there are synergies between their organizations.

Alfie Cheyne, CEO and founder of ACE Winches is looking forward to the opportunities ahead: "Both ACE Winches and Balmoral Group have extensive experience of opening up new markets. We see the renewables and decommissioning sectors, in particular, offering strong growth potential both in the immediate and longer term."

Jim Milne, chairman and managing director, Balmoral Group, joins the ACE Winches board as non-executive chairman and Balmoral's finance director, Bill Main, also joins as non-executive director. ▪

Left to Right: Valerie Cheyne, Alfie Cheyne, Jim Milne, Bill Main. Photo from Balmoral.

mass it needs to grow that it couldn't get on its own.

Advisory group backs Ensco-Atwood combo

Advisory firm Glass Lewis has recommended that Ensco shareholders vote "FOR" the US$839 million proposed all-stock transaction with Atwood Oceanics at the company's upcoming general meeting of shareholders on 5 October 2017.

"We find that the proposed transaction appears strategically reasonable and, on balance, financially acceptable from the perspective of Ensco and its shareholders," Glass Lewis said in its recommendation.

"Strategically, the proposed transaction would create a larger offshore drilling company with a broader portfolio of assets and greater scale. Atwood and Ensco currently have limited customer overlap and the combined company would have a broader and more diversified customer base as well as a diversified geographic profile.

"Moreover, the combined company would have a strong balance sheet and a reasonable leverage profile, in our view, with a pro forma net debt to capitalization ratio of 29% as at 31 March 2017."

Ensco announced in May that it intended to acquire Atwood Oceanics in an all-stock transaction worth US$839 million, creating a company with the largest jackup fleet in the world.

Royal IHC, GranEnergia form GranIHC Services

Dutch company Royal IHC and Brazil's GranInvestimentos have formed a new partnership, GranIHC Services to deliver innovative and integrated life cycle solutions, increase their operational and service activities, while expanding their presence in Latin America.

GranIHC Services will provide integrated services in the fields of offshore maintenance and repair, logistical services and infrastructure facilities.

The new organization combines the strong operational platform of GranEnergia in Brazil with IHC's know-how in designing, building and servicing equipment and vessels for the offshore, dredging and mining markets. Together, the companies will contribute to all stages of the value chain: designing, building, commissioning, installation, maintenance and decommissioning of equipment and vessels. ▪

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❑ 51 Exploration, Geology, Geophysics
❑ 52 Drilling, Production, Operations
❑ 53 Executive & Other Senior, Mid-Level Mgmt
❑ 54 Field Operations
❑ 55 Consulting
❑ 56 HR, Staff Recruitment
❑ 99 Other (*please specify*) ____________

2. Which is your company's PRIMARY BUSINESS ACTIVITY *(check one box only)*

❑ 20 Oil / Gas Company, Operator
❑ 24 Drilling, Drilling Contractor
❑ 30 Pipeline/Installation Contractor
❑ 25 EPC, Main Contractor, Subcontractor
❑ 36 Engineering, Consulting
❑ 31 Ship/Fabrication Yard, FPSO
❑ 32 Marine Support Services
❑ 33 Service, Supply, Equipment Manufacturing
❑ 34 Finance, Insurance
❑ 35 Government, Research, Education, Industry Association
❑ 99 Other (*please specify*) ____________

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

❑ 700 Specify ❑ 701 Recommend ❑ 702 Approve
❑ 703 Purchase ❑ 704 N/A

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

❑ 101 Exploration Survey
❑ 102 Drilling
❑ 110 Production
❑ 103 Subsea production, construction (including pipelines)
❑ 104 Topsides, Jacket Design, Fabrication, Hook-Up & Commissioning
❑ 105 Inspection, Repair, Maintenance
❑ 106 Production, Process Control Instrumentation, Power Generation etc.
❑ 107 Support Services, Supply Boats, Transport, Support Ships etc.
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PEOPLE

Spotlight

Experience transferred

Karen Boman chats with industry veteran Tony Duncan about his plans at Magma Global and experiences selling operators on new technology.

Tony Duncan has faced many challenges in his career in the oil and gas industry, including convincing operators to take a chance on new technology. He was previously tasked with setting up CSO Aker Maritime's subsea business in the Gulf of Mexico, which included the pipelay and construction vessel *Deep Blue* and later a spool base at Mobile, Alabama. He now brings this experience to a new role, vice president of Magma Global's Americas operations.

Tony Duncan

CSO Aker Maritime was once the Houston subsidiary of Coflexip Stena Offshore Group, which later merged with Technip in 2001 – which now owns and operates *Deep Blue*, which is still in operation today. When *Deep Blue* entered the market in 2001, it was the first of its kind, with J-lay and reel-lay capabilities suitable for deepwater projects in the Gulf of Mexico and West Africa.

The ship was built by Hyundai Mipo Dockyard near Ulsan, South Korea. It measures 206.5m-long, has a gross tonnage of 33,791-tonne, and is able to work in water depths up to 3000m (9842ft)

"While clients 'needed' the asset to support the developments, you had to spend a lot of time explaining the technical systems on the vessel," Duncan says.

***Deep Blue* leaving the spoolbase prior to mobilizing to Na Kika.**
Photo from Technip.

"When it came to work on projects such as Shell's Na Kika (7600ft water depth), many of the offshore operations had never been attempted before so the engineers needed to develop new processes and in some cases technology to allow the successful completion of complex projects."

Duncan's key takeaway from his experience with *Deep Blue* is to deliver or exceed promises. "When a new vessel or technology starts to be introduced, it has to deliver, especially in the first few applications," Duncan says.

New applications

The bulk of Magma Global's current applications are offshore topsides. But, the firm sees significant uptake of its product in subsea, particularly on the back of its recent announcement that Magma Global is the first Thermoplastic Composite Pipe manufacturer to qualify its product for subsea applications to DNV GL's Recommended Practice 119.

Magma Global's composite pipe utilizes materials that have been around for a while, but represents as new application of this material. Convincing operators to try new technologies is difficult, even more so in today's lower oil price environment.

"People like certainty and managing their risk profile," Duncan says of this reticence. But, he believes Magma Global is changing people's minds.

While senior-level executives want to support new technologies, working-level employees who are more risk adverse are the ones that need convincing. This is a trend Duncan sees across the industry, as project managers' performances are measured in terms of capital costs and safety. It's especially true in the deepwater sector as oil prices are making investment difficult, he says.

"You need to tackle the challenge (of selling new technology) in a number of ways," Duncan explains. "You need to demonstrate on a technical, commercial and risk front that the client will be better off."

Spending time and effort with the engineering design houses that are working on pre-FEEDs and FEEDs and the contractors, is also critical. Each of these companies are key influencers in the recommendation of using new technologies and each of them have different drivers, the key to success to understand these drivers.

Lessons learned

Duncan's time in the merchant navy convinced him he didn't want a career where he was stuck in an office doing the same thing every day. This desire – and the growth opportunities he expected in the subsea industry in the mid-1980s – led him to a career in oil and gas.

"The challenges have been significant, but those challenges have brought opportunities," Duncan says. He sees more challenges in store for the offshore oil and gas industry, which he believes will rebound, but not to the same intensity as previously seen in 2013-14.

The biggest challenge will be the lack of experienced people, he says. "During my visits to operators/contractors, it is very noticeable that the resources have been cut dramatically to the extent that there is very little scope to accommodate an increase in workload."

***Deep Blue* working alongside Shell's Na Kika platform in the Gulf of Mexico.**
Photo from Technip.

Historically, when prices stabilize and operators start to progress final investment decisions, we have seen in the past "rush" from operators to be first in line, that is for larger projects that require specific technology/assets we have seen a race to secure this type of resource in order to secure the best schedule possible this tends to lead a mini boom for suppliers before we then drop back into steady state.

"The challenge for deepwater projects is that there is a finite resource pool available," he says. Once the industry returns to a steadier state supply/demand position, there will be in a number of areas (vessels) of oversupply, which the industry needs to address. OE

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