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# OE

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Inpex's Ichthys FPSO sails away. Photo from Inpex.

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**Tunnel Vision.** Cyberhawk's Senior Pilot, Calum Darling, took this overview photo of Maersk Oil's *Gryphon A* float-ing production vessel, during an multi-scope aerial vi-sual inspection last summer. *Image from Cyberhawk.*



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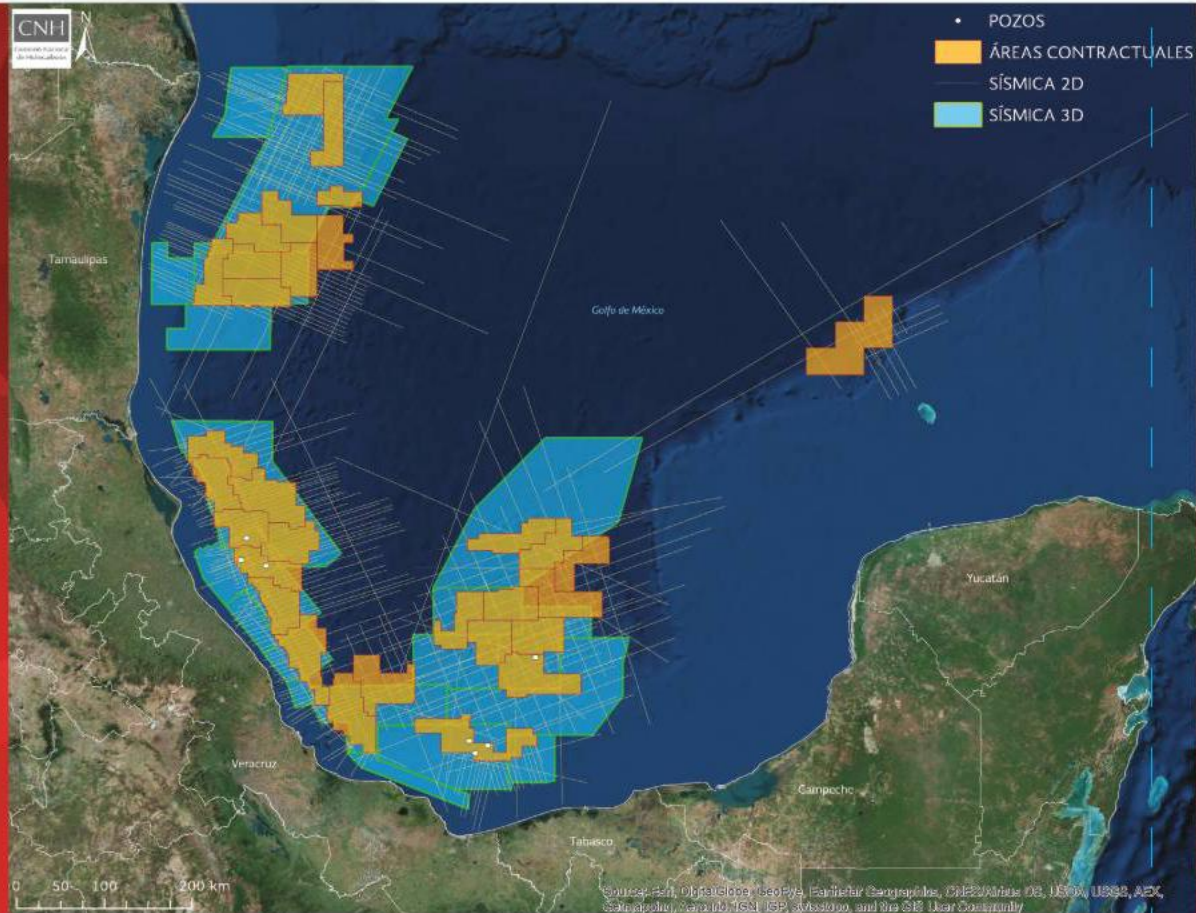
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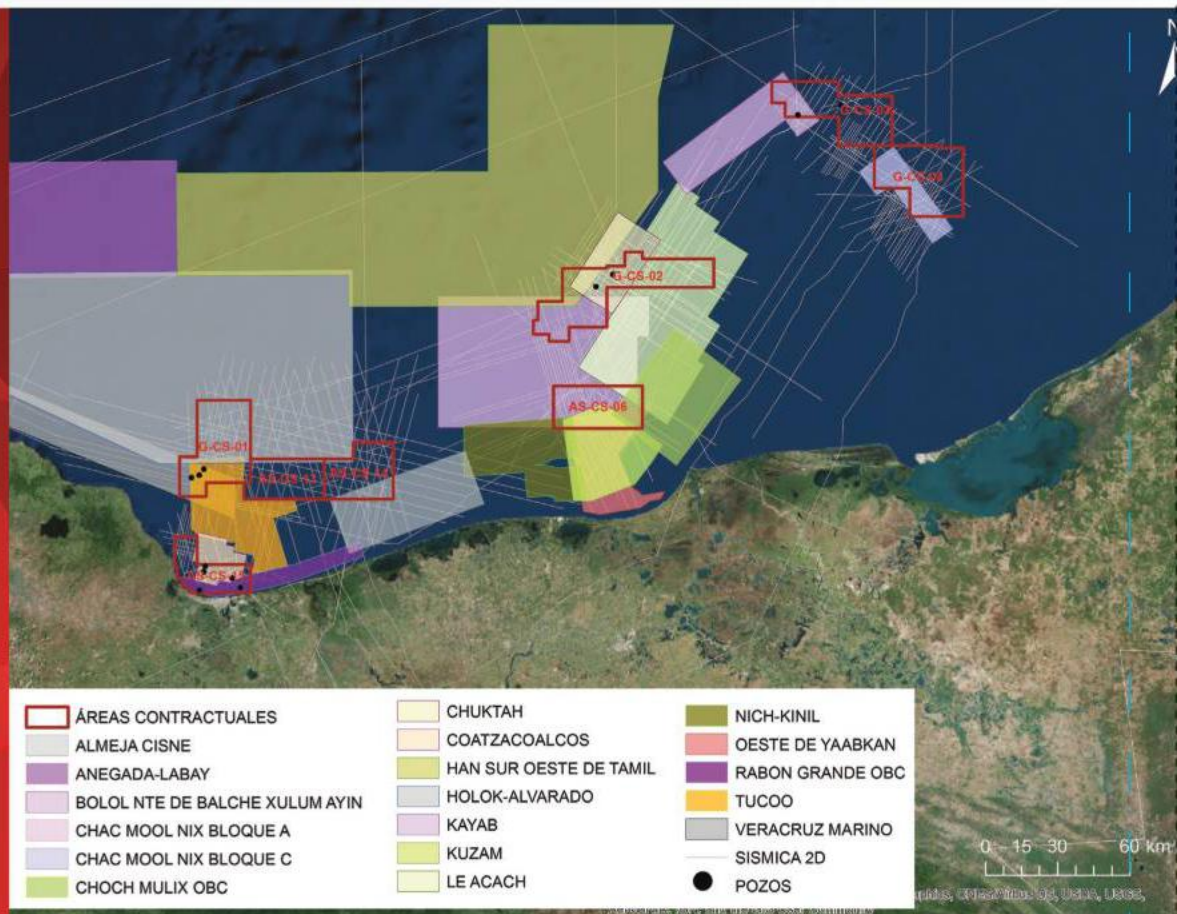
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## What's Trending

### Moving and shaking

- Talos, Stone to merge in \$1.9B deal
- GE weighs Baker Hughes exit
- Energy ministers meet in Houston

Energy Secretaries from US, Canada and Mexico meet in Houston in November. Photo from OE Staff.

## White papers

Here are the latest White Papers at OEDigital.com



### Bsquare's 2017 Annual IIoT Maturity Survey

Did you know that 86% of organizations already have an Industrial Internet of Things (IIoT) solution in place? Download Bsquare's Annual IIoT study for full survey findings.



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## People



Photo from Acteon.

### InterMoor Appoints New Global CEO

Mooring, foundation and offshore installation provider, InterMoor has named Mark Jones, global CEO. He currently serves as a vice president for InterMoor's parent company, Acteon.

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# Undercurrents



Stampede platform tow out. Photo from Hess.

## High hopes for 2018

**T**he industry has undergone much turmoil over the past three years, but it has also seen renewal. Companies learning to live within their means and keep both production costs low, but also development costs (viable projects at sub-US\$50/bbl) – are good thing; although, at times, it may not feel that way.

The downturn has allowed a resurgence and a quest for new technology to get the industry through one of its darkest, most anxiety-riddled periods. But also, a recognition that this industry doesn't just need to be competitive due to low oil prices – it will, from here on in, need to be competitive with not just shale, but solar and other renewables.

It's a whole new world for the oil and gas industry, hence our title on this month's cover, and we here at **OE** are excited as ever to report on it for you. In this new era, with operators hungry to be competitive, we're seeing talk of robotics, wireless connectivity, how to use the latest tech – artificial intelligence, machine learning – to sort through huge data streams, to optimize wells, to improve asset integrity management. The industry appears to be no longer shy about incorporating these technologies, that have worked wonders in other industries.

European Editor Elaine Maslin sheds light on how BP hopes to keep up with the times when at its Clair Ridge development, especially when the supermajor

has designed its facilities for an at least 40-year life span. You can read more about that project on page 48.

She also tackles the benefits of wireless connectivity on offshore platforms on page 44, and gives a primer on just what 4G means anyway. Plus, we report on how DNV GL has been trialing how independent verifications, which are usually done onboard, could be done digitally, from shore via video link-up – a process that could save non-productive time and increase safety.

Additionally, we would be remiss if we didn't reflect on 2017. Lower oil prices for longer is still with us, but there are projects still being constructed, discoveries that are still being made. We look at the Top 10 Offshore Discoveries of 2017 on page 18, with help from analyst house Wood Mackenzie. We also look at what the Top Five Projects by capex during 2017 were on page 20. Furthermore, we take a more in-depth look on some of the world's hottest spots for exploration activity on page 26.

As **OE** went to press, in late November, we are left with the spirit of Thanksgiving. We are thankful to an industry that keeps endeavoring to innovate, explore and produce. We are thankful for those who helped Houston and other hurricane-ravaged areas after a particularly brutal storm season. And, we are ready and excited to move on to 2018.

See you in January. **OE**

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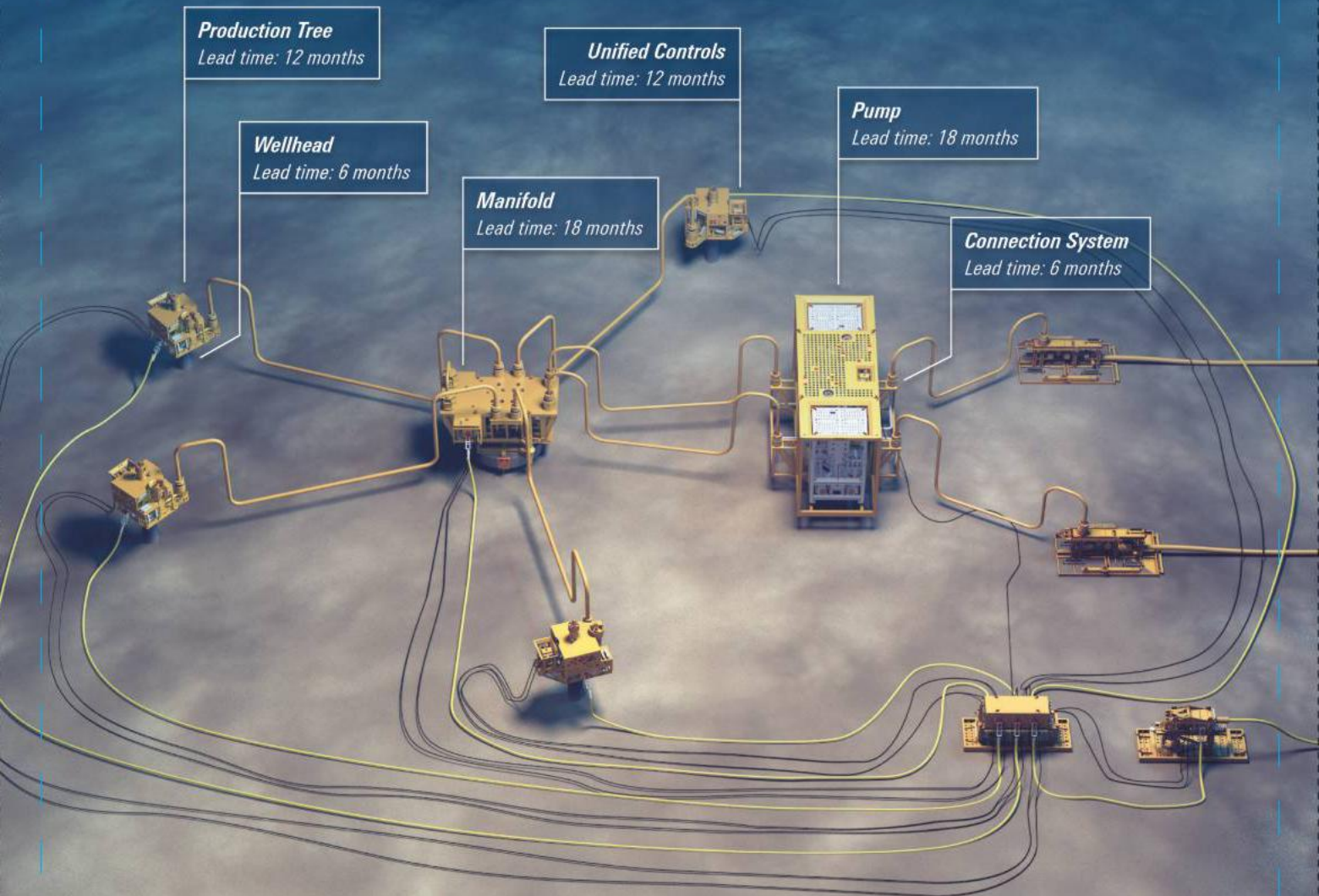
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# Global E&P Briefs

## A BP, Husky add Canada stakes

BP and Husky Energy won acreage in the Jeanne d'Arc Basin offshore eastern Canada, bidding approximately US\$11.8 million for the first of three parcels offered by the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) in its Call for Bids NL17-CFB01. Theirs was the sole bid for parcel 1, which contains 300,116 acres. No bids were submitted for parcels 2 and 3. C-NLOPB will award the new license to BP (50%) and Husky Oil (50%) in January 2018, subject to ministerial approvals.

## B Talos adds to Phoenix

Talos Energy will tie back a successful sidetrack well drilled in the Green Canyon area of the Gulf of Mexico to its existing Phoenix field subsea infrastructure, following a successful Tornado II drilling campaign.

The Tornado II sidetrack aimed to delineate the reservoir discovered in 2016 and logged about 297ft total measured depth (283ft total vertical depth) of net oil pay across the B-5 and B-6 Sands. The sidetrack well was drilled by the *Enso 8503* to approximately 21,057ft total vertical depth.

Phoenix's subsea infrastructure flows to the *Helix Producer 1* dynamically positioned floating production facility. Initial production is expected to begin this month (December).

## C Suriname duster for Tullow

Tullow Oil's wildcat offshore Suriname failed to make a commercial discovery. Araku-1 was drilled to 2685m total depth and penetrated the

objectives of the Araku prospect. No significant reservoir quality rocks were encountered, although logging and sampling proved the presence of gas condensate. The well will be plugged and abandoned. The Araku well was drilled in Block 54 in about 1000m water depth using the *Noble Bob Douglas* drillship.

Tullow had said Araku was a large structural trap, which has a resource potential estimated at more than 500 MMbbl. A 3D seismic survey was acquired over the block in 2015. Tullow said the well and 3D seismic data have de-risked deeper plays which offer significant future exploration potential.

## D US launches massive lease sale

The US has announced its largest lease sale (Lease Sale 250), offering nearly 77 million acres in federal waters offshore Texas, Louisiana, Mississippi, Alabama, and Florida. The sale, scheduled for March 2018, includes all available unleased areas on the Gulf's Outer Continental Shelf.

The estimated amount of resources projected to be developed as a result of the proposed Lease Sale 250 ranges from 210 MMbbl to 1.12 billion bbl of oil and from 550 MMcf to 4.42 Tcf of gas.

It includes 14,375 unleased blocks, 3-230mi offshore, in the Gulf's Western, Central and Eastern planning areas in water depths ranging from 9-11,115ft (3-3400m).



Interior Secretary Ryan Zinke. Photo from US Department of Interior.

## E Shell, Petrobras lead pre-salt auctions

Shell and Petrobras won big at Brazil's 2nd and 3rd production sharing rounds concerning pre-salt areas. Shell will participate in three blocks, and operate two,



while Petrobras will serve as operator for three blocks.

Both round 2 and 3 offered four areas a piece, and both rounds saw three of four areas awarded. ANP said that the 2nd round generated approximately US\$1.05 billion in

signature bonuses and \$93.4 million in planned investments. The 3rd pre-salt round generated approximately \$876 million in signature bonuses and will bring in \$140 million in investments.

## F Exxon buys into Carcará

ExxonMobil will join Statoil as a partner offshore Brazil, buying half of Statoil's interest in block BM-S-8, which contains part of the pre-salt Carcará oil field, for US\$1.3 billion. The pair also teamed up to win the Carcará North block in a consortium that includes Portuguese company Galp Energia.

The Carcará field contains an estimated recoverable resource of 2 billion bbl of





high-quality oil, and Statoil says it hopes to bring the development online by the mid-2020s. The block is approximately 200mi offshore Rio de Janeiro.

### **G** Argentinian 2D seismic underway

Spectrum began a multiclient 2D seismic survey covering the Austral and Malvinas basins offshore southern Argentina. The survey size is around 14,500km, but may vary based on input from its participating clients. Data is being acquired with a 12,000m streamer with continuous recording to enable extended recording lengths and high fold data to enable full interpretation from Moho to water bottom. The data will be

processed with pre-stack time migration, pre-stack depth migration, full waveform inversion and broadband.

### **H** Siccar Point makes Cambo plans

Siccar Point Energy is moving forward with plans to

develop the Cambo field, 125km northwest of Shetland in the UK North Sea.

Phase 1 will be an early production system (EPS), followed by a Phase 2 full-field development. The initial plan is to drill an appraisal well into the main reservoir

### **I** Engie ups Cara resources

Engie E&P has increased its resource estimate for the Cara field in the Norwegian North Sea to 56-94 MMboe from 25-70 MMboe and has reached a feasibility decision gate on the field. Cara is a gas and oil discovery in PL636 in block 36/7, about 14km from the Engie-operated Gjøa facilities. The company sees Gjøa as a tieback solution for Cara. First production is targeted for 2020-2021.

Cara was the second largest discovery on the Norwegian continental shelf in 2016. Engie and partners expect to pick a development concept for Cara by November 2018.

Engie operates PL636 with 30% interest. Its partners are Idemitsu Petroleum (30%), Pandion Energy (20%) and Wellesley Petroleum (20%).



**The Transocean Arctic drilled the Cara discovery.** Photo from Engie.

sequence and perform an extended well test, which will take place in 2018 and provide key information for the facility design.

Siccar Point acquired the field with the takeover of the OMV (UK) portfolio in January 2017. Cambo was discovered in 2002 and has five wells drilled into the structure so far.

A further appraisal well is due to be drilled on the field in April 2018 using the semi-submersible *West Hercules*.

### **J** Point plans \$2.45B Norway investment

Point Resources will invest US\$2.45 billion over the next five years in stakes it acquired from ExxonMobil in the Balder, Ringhorne, Ringhorne East, Jotun and Forseti fields on the Norwegian Continental Shelf (NCS).

Point's acquisition of the operated stakes increases its net production tenfold, to about 50,000 boe/d, making the company both a mid-sized Norwegian exploration and production company and a significant NCS player.

By 2022, the company says it expects to organically grow its production to over 80,000 boe/d, with life extension work, new seismic data acquisition, and drilling campaigns planned to increase



# Global E&P Briefs

recovery. Point Resources was formed in 2016 from the merger of Core Energy, Spike Exploration and Pure E&P.

## 3D seismic planned off Morocco

UK-based independent Genel Energy is to carry out a 3D seismic campaign across the Sidi Moussa acreage offshore Morocco, in place of an exploration well.

The firm reached an agreement with the Moroccan government over its remaining exploration commitment on the Sidi Moussa offshore licensed acreage.

Planning for the 3D campaign has started, with seismic acquisition expected to begin in 2018. The current phase of the license has been extended until February 2020.

The 3D seismic is expected to materially de-risk the prospectivity of the Sidi Moussa license.

In Q4 2014, a well on the license, SM-1, proved a working hydrocarbon system, with 26° API oil recovered to surface.

## Israel holds first offshore bidding round

Greece's Energean and a consortium of Indian companies, including ONGC Videsh, Bharat PetroResources, Indian Oil Corp., and Oil India, are among companies who submitted bids for blocks in Israel's first offshore bidding round.

The first bid round included 24 licensing blocks each of a maximum size of 400sq km. Officials will examine the bids and proposed work programs before submitting the bids for approval at the Petroleum Council.

A second licensing round

will be launched in 2018.

## Hippocampe-1 fails

Kosmos Energy's Hippocampe-1 deepwater exploration well in Block C-8 offshore Mauritania was dry.

The well, drilled in 2600m water depth, in partnership with BP, was designed to test Lower

but they were water bearing. The well will now be plugged and abandoned.

It is believed that this prospect failed due to a lack of charge access in this part of the play fairway. The *Enasco DS 12* drillship, which drilled the Hippocampe exploration well, will move on to test the Lamantin prospect.

## Hess sells deepwater Equus

Hess has sold its Equus deepwater project offshore Western Australia to the newly formed firm Western Gas. Hess had been planning a floating production platform for the project.

Early 2016, Hess launched a tender process for the engineering, procurement and construction contracts of a semisubmersible platform and other subsea equipment for Equus. The project was not expected to be sanctioned until 2017, at the time.

Equus covers 11 gas and condensate fields in the Carnarvon Basin, about 200km northwest of Onslow. Western Gas says the fields contain an independently certified resource of more than 2 Tcf of gas and 42 MMbbl of condensate. Hess' activities at Equus include the drilling of 17 exploration wells, resulting in 15 discoveries, the drilling and testing of four appraisal wells, and acquisition of more than 9000sq km of 3D seismic.

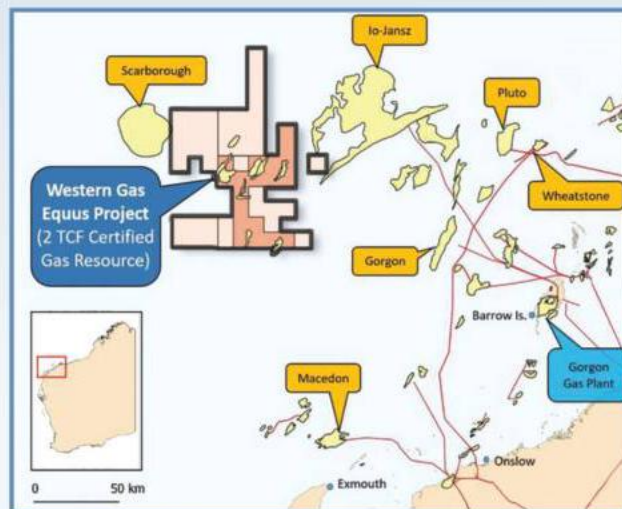


Image from Western Gas.

Cenomanian and Albian reservoirs charged from the deeper Valanginian – Neocomian source. It was drilled to a total depth of 5500m and well-developed reservoirs were encountered in both exploration targets,

## TEN drilling resumes in 2018

Tullow Oil plans to resume development drilling at the TEN (Tweneboa, Enyenra, Ntomme) fields offshore Ghana in early 2018 after a drilling moratorium related

to a boundary dispute was lifted.

Tullow had originally planned to resume drilling at the end of this year. The additional drilling will allow Tullow to ramp up production with additional wells to the FPSO capacity of 80,000 bo/d. Production from TEN in Q3 averaged about 60,000 bo/d.

Tullow holds 41.175% interest in the TEN project, which started production in August 2016. Partners are Kosmos (17%), Anadarko (17%), GNPC (15%), Petro SA (3.825%).

## Eni targets OCTP gas by 2018

Eni reports its gas development offshore Cape Three Points (OCTP), Ghana, is 63% complete, with start-up planned for 2018. Construction on the onshore receiving facility and associated pipelines are proceeding as planned. Eni achieved first oil from OCTP in May 2017, three months ahead of schedule. Eni expects to ramp up production to 5.2 MMbbl from the 2.8 MMbbl initially expected. The project is expected to reach a plateau of 45,000 bo/d by end of 2017. OCTP will allow Ghana to possibly generate up to 1500MW.

The project comprises the Sankofa Main, Sankofa East and Gye-Nyame fields, about 60km off Ghana. The fields, which contain about 770 MMboe in place, including 500 MMbo and 270 MMboe (41 Bcm) of non-associated gas, are being produced via the *John Agyekum Kufuor* floating production, storage and offloading unit. OCTP includes Eni (44.44% and operator), Vitol (35.56%), and GNPC (20%).



## Q Hail production starts off Abu Dhabi

Production has started from the Hail oil field offshore Abu Dhabi in the United Arab Emirates, says Abu Dhabi Oil Co. (ADOC), a subsidiary of Japan's Cosmo Energy Exploration & Production Co. The production from the Hail oil field is the first oil field development in the Middle East by a Japanese operator since 2011.

The field is the fourth field in the ADOC shallow water concession west of Abu Dhabi

to start production. The other three fields – Mubarraz, Umm Al-Anbar, and Neewat Al-Ghalan – came online in 1973, 1989 and 1995, respectively.

Hail is adjacent to the existing fields, making maximum use of facilities already in use. It is on an artificial island communicated via subsea pipeline to current production and export facilities on Mubarraz Island. The development includes 10 producing wells, says partner Cepsa.

## R SOCO acquires Vietnam interest

SOCO will acquire 70% operated interest in Blocks 125 and 126 offshore central Vietnam through a production sharing agreement (PSC) the company signed with PetroVietnam and SOVICO Holdings. Blocks 125 & 126 are in moderate to deepwater in the Phu Khanh Basin and have multiple structural and stratigraphic plays observed on the available seismic data. Interpretation of the existing data indicates there is good

potential for source, expulsion and migration of oil with numerous reservoir and seal intervals likely.

A memorandum of understanding was signed by the partners in 2015, and the final PSC was approved by the Vietnamese government and prime minister in August 2017. Initial exploration activities will include reprocessing and interpretation of seismic data, with a view to drilling the first exploration well potentially as early as 2021.

# Contracts

## VNG taps TechnipFMC for Fenja

VNG Norge has issued a letter of intent (LOI) to TechnipFMC for the Fenja field development project in the Norwegian North Sea. The LOI covers the engineering, procurement, construction and installation of the subsea production systems and subsea structures, umbilicals, risers and flowlines. The final contract will be signed pending a final investment decision, and subject to the authorities' approval.

## McDermott wins KG-D6 subsea work

McDermott International has won a letter of award from Reliance Industries for work on the KG-D6 subsea field development in the Krishna Godavari Basin offshore eastern India.

McDermott will provide engineering, procurement, installation and pre-commissioning of subsea flowlines, vent lines, and a pipeline-end manifold for connection with six subsea wells in the R-cluster field at a water depth of up to 6890ft

(2100m), including in-field pipelines, Monoethylene Glycol line, pipeline-end terminals, jumpers, risers, umbilicals system and the modification of the control riser platform to interface with the new facilities. Reliance chose OneSubsea to provide the subsea production system in October.

## Aramco makes Safaniya awards

Saudi Aramco gave out two contract awards for the Safaniya field, offshore Saudi Arabia. Abu Dhabi's National Petroleum Construction Co. picked up a two-year contract for the Safaniya field pipeline and truckline project. This project provides for the engineering, procurement, construction and Installation (EPCI) of one tie-in platform (jacket and deck) to serve as an additional gathering hub for future oil wellhead platforms at the Safaniya field.

McDermott International won a three-year contract for the slipover platforms and electrical distribution platform project. The workscope covers the EPCI

of 10 new slipover platforms in the South Safaniya field. The project will also involve installation of a new electrical distribution platform, which will serve as an offshore power substation, supplying the 10 new slipover platforms with electricity to power the electrical submersible pumps on each facility.

## TechnipFMC gets Sabah gig

TechnipFMC has been awarded a subsea contract by Murphy Sabah Oil for the Phase 1A Block H Gas Development Project, offshore Sabah, Malaysia, in 1300m water depth.

This contract covers the engineering, procurement, construction, installation and commissioning of the umbilicals, risers and flowlines as well as the transportation and installation of subsea hardware and controls.

## Gate wins Leviathan commissioning

Noble Energy has chosen Gate Energy to provide facility commissioning for the Leviathan platform offshore

Israel. The scope includes topside commissioning planning, onshore commissioning execution and offshore commissioning services of the production platform.

Leviathan is a natural gas mega-project offshore Israel with first gas targeted for the end of 2019.

Noble Energy is the operator of the Leviathan field, which contains approximately 22 Tcf of gross recoverable resources.

## Sembcorp picks up Castberg hull

Sembcorp Marine Rigs & Floaters signed a letter of intent to construct the hull and living quarters for Statoil's Johan Castberg floating production development in the Norwegian Barents Sea.

A contract expected to be worth US\$490 million (NOK 4 billion) will be signed at the final investment decision.

Statoil says that the construction of the hull is the most time-critical delivery for the completion of the Johan Castberg project, first production from which is targeted for 2022.



# In-Depth

## Connecting the dots

**While decommissioning is often seen as a challenge, to the Dutch it is also an opportunity. Elaine Maslin reports.**

**T**he Dutch don't have the largest patch of the North Sea by a long shot. They do however have 160 platforms, mostly small and in shallow waters, and, despite being late to embrace offshore wind, a fast-growing fleet of offshore wind farms.

These could be seen as colliding worlds, one – offshore gas production – on the wane and the other – offshore wind – set to grow. However, a number of Dutch activities are looking to see how these two industries could support each other, and indeed usher in other technologies, creating interconnected gas and power production systems alongside carbon capture and storage (CCS).

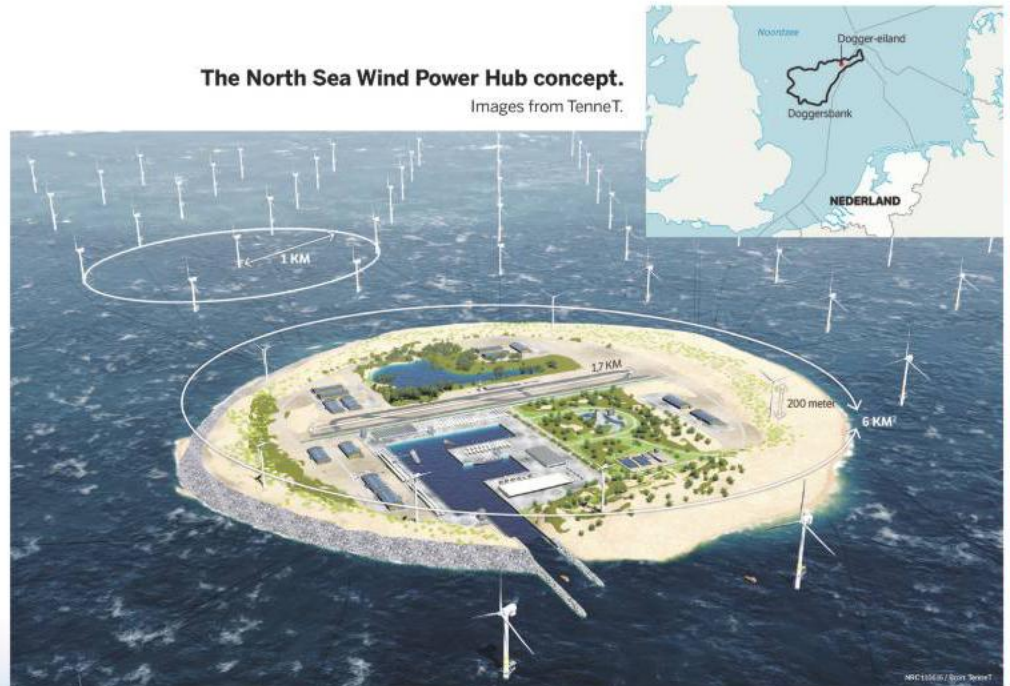
Nexstep, National Platform for Reuse & Decommissioning, was launched during the Offshore Energy Exhibition & Conference in Amsterdam. The body, led by state-firm Energie Beheer Nederland (EBN), and industry body NOGEPa, sees “an opportunity to reuse existing elements to complement renewable investments before

their eventual safe and efficient decommissioning.”

There's also the North Sea Wind Power Hub, a concept developed by grid operator TenneT, which would see an artificial island built in the North Sea in 2030-50. This would act as a hub to connect far offshore wind farms in the Dogger Bank area of the North Sea, close to where the maritime borders

### The North Sea Wind Power Hub concept.

Images from TenneT.





of the Netherlands, Germany, Denmark, and the UK meet. TenneT proposed the concept in 2016, and this year signed a trilateral agreement between its Dutch and Germany business units, alongside Denmark's Energinet.dk and most recently Dutch gas network firm Gasunie.

The hub, comprising "Power Link Islands," with interconnector cables to countries in the North Sea, would support up to 100GW of wind farms, and hydrogen production for large scale transport, power buffering/storage.

Meanwhile, there's the North Sea Energy Challenge (NSEC), a group comprising the Dutch Wind Energy Association (NWEA), the Nature and Environment Foundation, VNO-NCW, NOGEPa, Dutch research organization TNO and TenneT. NSEC is looking at joint research into possibilities for electrification of production platforms, joint innovation for system integration, power2gas, energy storage, etc.

All options should be considered, suggests Rene Peters, director of gas technology at Dutch research organization TNO Energy. This includes the potential to reduce emissions from existing platforms by electrifying them, developing gas to power, or power to hydrogen, and introducing CCS.

"Intensive use of the North Sea leaves little space," Peters says. "Five percent of gas produced is used for power generation to compress gas to send it to shore. There are increasing CO<sub>2</sub> and NO<sub>x</sub> [emissions] constraints. We also have to transport GWs of wind electricity onshore. How can we balance, store and transport it all economically? And is there a role for hydrogen?"

The Netherlands is targeting building out some 4.5GW of offshore wind power over the next 10 years (the largest turbines are currently rated at up to 8MW a piece). Meanwhile, an estimated US\$13.90 billion (€12 billion) will need to be spent to decommission Dutch hydrocarbon platforms and pipelines as they come to the end of their lives in the Dutch North Sea.

"One of the challenges passed to us is determining the value of reusing this infrastructure to the benefit of a future energy system," Peters says.

In the short-term (up to 2023), Peters suggests electrifying platforms, to reduce emissions. This could use power from nearby wind farms. While doing this for all Dutch platforms might not be feasible, the 10 largest consumers of power could be targeted. "This would cut CO<sub>2</sub> by a mega-tonne a year," Peters says. "There would also be less maintenance needs," he adds.

"It is clear the oil and gas sector has to reduce emissions. It means current use of gas to produce electricity on platforms is not useful anymore. Electrifying them is probably the best option." There's already one platform powered with electricity from shore in the Netherlands and more in Norway, which has had a policy of power from shore in place for a number of years.

Mid-term (2023-2030) could see offshore power-to-gas (hydrogen), for "peak shaving," i.e. making use of/storing the excess power when it's windy, and gas-to-wire, for power balancing (producing power from gas when it's not windy), with

## 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](http://www.infield.com)).

### New discoveries announced

Depth range	2014	2015	2016	2017
Shallow (<500m)	78	59	38	24
Deep (500-1500m)	31	18	11	4
Ultradeep (>1500m)	12	12	9	6
<b>Total</b>	<b>121</b>	<b>89</b>	<b>58</b>	<b>34</b>
January 2017 date comparison	127	114	72	-
	-6	-25	-14	34

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)
<b>Brazil</b>			
Shallow	12	287	2333
Deep	10	940	1295
Ultradeep	25	8364	10,673

#### United States

Shallow	6	45	89
Deep	19	730	1264
Ultradeep	17	1765	1508

#### West Africa

Shallow	111	3663	16032
Deep	23	2070	3130
Ultradeep	11	1511	2298

<b>Total (last month)</b>	<b>222 (223)</b>	<b>19,088 (19,331)</b>	<b>36,289 (36,536)</b>
---------------------------	------------------	------------------------	------------------------

### Greenfield reserves 2017-21

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
<b>Shallow (last month)</b>			
	862 (867)	32,922 (33,464)	325,086 (316,771)
<b>Deep (last month)</b>			
	110 (111)	5,036 (5048)	62,378 (64,508)
<b>Ultradeep (last month)</b>			
	60 (66)	13,148 (13,420)	42,875 (44,392)
<b>Total</b>	<b>1032</b>	<b>51,106</b>	<b>430,339</b>

### Global offshore reserves (mmbbl) onstream by water depth

	2015	2016	2017	2018	2019	2020	2021
<b>Shallow (last month)</b>							
	21,400.30 (21,400.30)	17,470.41 (32,101.42)	21,277.90 (20,879.08)	19,963.02 (20,068.20)	12,613.20 (11,983.08)	16,670.28 (16,758.52)	21,061.69 (20,970.91)
<b>Deep (last month)</b>							
	960.47 (960.47)	4215.67 (4215.67)	2051.08 (2051.08)	2389.67 (2580.97)	4715.67 (4697.54)	3849.87 (4417.34)	3008.15 (2655.54)
<b>Ultradeep (last month)</b>							
	2000.69 (2000.69)	3100.14 (3100.14)	883.85 (883.85)	4643.35 (4643.35)	3387.91 (3621.29)	7453.67 (8125.72)	4398.22 (4032.24)
<b>Total</b>	<b>24,361.46</b>	<b>24,786.22</b>	<b>24,212.83</b>	<b>26,996.04</b>	<b>20,716.78</b>	<b>27,973.82</b>	<b>28,468.06</b>

Source: InfieldRigs

6 Nov 2017

### Pipelines

(operational and 2017 onwards)

	(km)	(last month)
<b>&lt;8in.</b>		
Operational/installed	41,916	(41,929)
Planned/possible	21,348	(21,133)
<b>Total</b>	<b>63,264</b>	<b>(63,062)</b>

#### 8-16in.

Operational/installed	83,262	(83,112)
Planned/possible	44,754	(44,963)
<b>Total</b>	<b>128,016</b>	<b>(128,075)</b>

#### >16in.

Operational/installed	97,186	(96,974)
Planned/possible	48,880	(48,815)
<b>Total</b>	<b>146,066</b>	<b>(145,789)</b>

### Production systems worldwide

(operational and 2017 onwards)

	(last month)
<b>Floaters</b>	
Operational	311 (310)
Construction/Conversion	42 (43)
Planned/possible	276 (277)
<b>Total</b>	<b>629 (630)</b>

#### Fixed platforms

Operational	9072 (9068)
Construction/Conversion	64 (77)
Planned/possible	1287 (1277)
<b>Total</b>	<b>10,423 (10,422)</b>

#### Subsea wells

Operational	5251 (5255)
Develop	371 (355)
Planned/possible	6025 (6062)
<b>Total</b>	<b>11,647 (11,672)</b>



# Rig stats

## Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	88	52	36	59%
Jackup	388	233	155	60%
Semisub	104	59	45	56%
Tenders	27	13	14	48%
<b>Total</b>	<b>607</b>	<b>357</b>	<b>250</b>	<b>58%</b>

## North America

Rig Type	Total Rigs	Contracted	Available	Utilization
	28	19	9	67%
Jackup	26	7	19	26%
Semisub	8	6	2	75%
Tenders	N/A	N/A	N/A	N/A
<b>Total</b>	<b>62</b>	<b>32</b>	<b>30</b>	<b>51%</b>

## Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	12	5	7	41%
Jackup	112	72	40	64%
Semisub	30	14	16	46%
Tenders	20	10	10	50%
<b>Total</b>	<b>174</b>	<b>101</b>	<b>73</b>	<b>58%</b>

## Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	17	16	1	94%
Jackup	49	27	22	55%
Semisub	19	14	5	73%
Tenders	2	1	1	50%
<b>Total</b>	<b>87</b>	<b>58</b>	<b>29</b>	<b>66%</b>

## Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	47	29	18	61%
Semisub	32	18	14	56%
Tenders	N/A	N/A	N/A	N/A
<b>Total</b>	<b>79</b>	<b>47</b>	<b>32</b>	<b>59%</b>

## Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	118	81	37	68%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
<b>Total</b>	<b>122</b>	<b>84</b>	<b>38</b>	<b>68%</b>
<b>Total</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0%</b>

## Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	14	8	6	57%
Jackup	14	8	6	57%
Semisub	1	1	0	100%
Tenders	5	2	3	40%
<b>Total</b>	<b>34</b>	<b>19</b>	<b>15</b>	<b>55%</b>

## Eastern Europe

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	1	1	0	100%
Semisub	2	1	1	50%
Tenders	N/A	N/A	N/A	N/A
<b>Total</b>	<b>4</b>	<b>3</b>	<b>1</b>	<b>75%</b>

Source: InfieldRigs 15 Nov 2017

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

local CCS, as well as CO<sub>2</sub> storage from other sources.

With increasing power coming from wind, how to balance the system will be important, Peters says. While this isn't such an issue – wind farm operators currently enjoy fixed prices for their power – when they are exposed to market prices, there will be a need to look at how to balance out power production with the likes of energy conversion or storage.

“The need for storage and balance will be huge,” Peters says. “For me, storage offshore with batteries is a no go.” Peters suggests that a significant scale pilot should be set up to demonstrate offshore power to gas conversion, as well as balancing and storage options and maybe also feeding hydrogen into the grid. “We need to show this can operate remotely or with minimum maintenance costs.”

Currently, hydrogen is produced using a steam process, and natural gas, but electrolyzer type hydrogen producers have been developed. These cost more and haven't been used offshore yet, he says.

“When you are further offshore, molecules are cheaper to transport than electrons,” Peters says. “Hydrogen is a way to store power as well. There is a conversion loss, but, industries in Rotterdam and Groningen use hydrogen a lot already, from gas in these cases.” Power to hydrogen technology has been scaling up and its foot-print getting smaller. It could be deployed on out-of-service platforms or could be used as part of TenneT's energy island concept, Peters says. On site gas-to-power (gas-to-wire), could also be considered, he says.

Power-to-gas could also alleviate the possible “domino effect” of key pipeline infrastructure being decommissioned, which would otherwise leave fields stranded.

Longer term, existing infrastructure could be reused to house offshore wind substations, synthetic natural gas could be produced and the existing gas grid used to transport it and or hydrogen. Ultimately, the whole grid, with each element, will need to play a role in energy storage, transport and distribution, where each part can offset the other, he says.

TNO plans to test the impact of transporting hydrogen in existing natural gas pipelines, there being the potential for hydrogen stress cracking. Transporting the product at a lower pressure could reduce this issue, Peters says, adding that the biggest concern isn't the pipelines, but the flanges, compressors and valves up and downstream of the pipelines.

The idea behind the North Sea Wind Power Hub is to create a large connection point for thousands of future offshore wind turbines. TenneT envisions that a total capacity of possibly 70-100GW could be connected to one or more so-called Power Link Islands. Having these hubs would reduce the cost of having many power export cables to shore. Instead power would be distributed from the hub via DC connections to all countries bordering the North Sea: the Netherlands, Denmark, Germany, the UK, Norway and Belgium, with the transmission cables simultaneously acting as interconnectors between these countries, enabling them to trade electricity. TenneT says, subject to a final investment decision, a Power Link Island could be developed by about 2035. **OE**



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# 2017: Beyond

**Audrey Leon reviews the top 10 discoveries of 2017 and the top 10 projects by capex with data provided by Wood Mackenzie.**

**W**hile exploration hasn't been as hot as it used to be, the finds this year have been big and plentiful, to say the least. Wood Mackenzie has provided the year's ten biggest finds by volume and the ten biggest projects by capex.

## #1 – Yakaar, Senegal

In May this year, Kosmos and partner BP discovered gas at the Yakaar-1 prospect, saying that the find could support the development of a second LNG hub. Yakaar-1 was drilled using the *Atwood Achiever* drillship. The well may contain 15 Tcf gross Pmean gas resource, according to Kosmos.

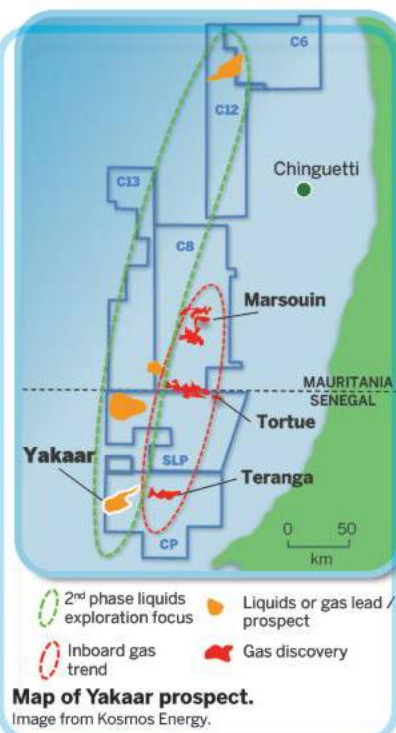
Yakaar, which is in the Cayar Offshore Profond block about 95km northwest of Dakar, was drilled in nearly 2550m water depth to 4700m total depth.

The well intersected a 120m gross hydrocarbon column in three pools within the primary Lower Cenomanian

objective and 45m of net pay. See more about Senegal and its neighbor Mauritania on page 26.

Kosmos estimates that Yakaar-1 discovered a gross Pmean gas resource of approximately 15 Tcf. An appraisal program is being planned to delineate the Yakaar discovery, the company said in May.

“The result confirms our view of the potential scale of the petroleum system offshore Mauritania and Senegal, in particular the basin floor fan systems which have now been further derisked,



with the well demonstrating that reservoir and trap both work in these previously untested fairways,” said Andrew G. Inglis, chairman and CEO, in May this year.

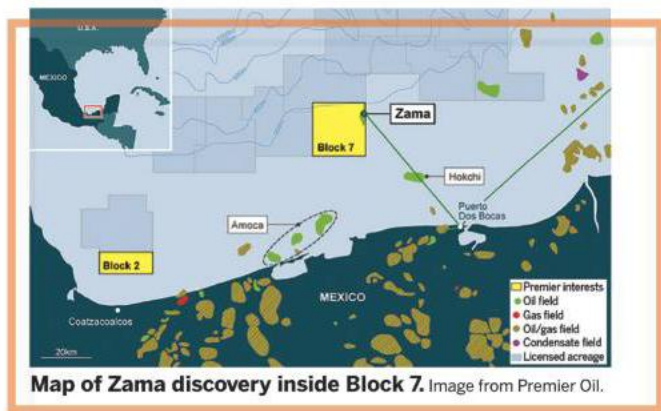
## 2017 Top 10 offshore discoveries

Basin Name	Field Type	Discovery Date	Water Depth (m)	Operator	Total resource (mmboe)	Oil (mmbbl)	Gas (bcf)
		8-May-17		Kosmos & BP	2,640		15,000
Salinas - Sureste	Oil	31-Jul-17	166	Talos Energy	500	500	
Yakaar - Yakaaranga	Oil	1-Oct-17		Rosneft	400	400	
Guyana	Oil	18-Mar-17	1,563	ExxonMobil	300	300	
Sina		3-May-17		Anadarko	264		1,500
East Sakhalin (Sea of Okhotsk)	Oil & Gas	4-Oct-17	62	Gazpromneft-Sakhalin	220	197	131
				Petrobras	200	200	
Columbus	Gas	21-May-17	83	BPTT	176		1,000
				Woodside	158		900
Gulf of Suez	Oil & Gas	23-Jan-17	45	Vega Petroleum	127	127	

Source: Wood Mackenzie.



# expectations



Map of Zama discovery inside Block 7. Image from Premier Oil.

## #2 – Zama, Mexico

Since Mexico's historic oil reform was passed in 2013, the country has made significant strides by allowing in private and foreign investment. In July this year, Talos Energy, backed by partners Sierra Oil and Gas and Premier Oil, touted the 1+ billion bbl discovery at their Zama-1 exploration well, offshore Mexico.

The find has been described as one of the 20 largest shallow water finds in the past 20 years and the first private sector oil discovery in Mexico. Zama-1 was spud in May and drilled in 166m water depth, about 37mi offshore Tabasco state, in Block 7 in the Sureste Basin, using the *Ensco 8503* semisubmersible.

The well reached an initial shallow target vertical depth of approximately 11,100ft (3383m). Talos says it hit a 1100ft (335m) oil bearing interval, with 558-656ft (170-200m) of net oil pay in Upper Miocene sandstones with no water contact. Oil samples indicate light oil, with API gravities between 28° and 30° and some associated gas.

Talos reported later that same month that Zama-1 failed to find further volumes in a deeper target. Zama-1 was drilled to a total depth of 13,478ft (4108m).

According to partner Premier Oil, the estimated recoverable P90-P10 gross unrisks resources are in the range of 400-800 MMboe, including the volumes that extend into the neighboring block.

## #4 – Snoek, Guyana

In March this year, supermajor ExxonMobil confirmed a new discovery offshore Guyana at the Snoek well, in the southern portion of the Stabroek block – the same block containing the major Liza discovery currently under development.

Exxon encountered more than 82ft (25m) of high-quality, oil-bearing sandstone reservoirs. The well was spud in February by the *Stena Carron* drillship, and drilled to 16,978ft (5175m) at 5128ft (1563m) water depth.

Snoek is about 5mi (9km) to the southeast of the 2015 Liza-1 discovery. Stabroek covers 6.6 million acres (26,800sq km). Exxon said Snoek targeted similar aged reservoirs as encountered in previous discoveries at Liza and Payara. In March, Wood Mackenzie said Snoek adds another 220-370 MMbbl to its estimate of the block.

Exxon and its partners are continuing to have success at Stabroek. In October 2017, ExxonMobil confirmed further potential with a fifth oil discovery in the Turbot-1 well, which is in the southeastern portion of the block, approximately 30mi (50km) to the southeast of the Liza phase one project.

## #6 – Neptune, Russia



Drilling at Neptune. Photo from Gazprom Neft.

In early October, Gazprom Neft subsidiary Gazpromneft-Sakhalin, completed drilling at its Neptune appraisal well at the Ayashsky license in the Sea of Okhotsk. Gazprom Neft reports initial in-place reserves estimated at 255 million tonnes of oil equivalent. A detailed assessment of these reserves will be prepared by mid-2018.

The Ayashsky block in the Okhotsk Sea forms part of the Sakhalin-3 project. The block is in the northeastern part of Sakhalin Island's continental shelf, 55km from the coast. Water depth at the field is 62m. Gazprom Neft says that 2150sq m of 3D seismic has been shot inside the Ayashsky block.





BP's Juniper platform offshore Trinidad and Tobago. Photo from BP.

## #8 – Macadamia, Trinidad

In May this year, BP Trinidad & Tobago (BPTT) found success at the Macadamia wildcat, which was drilled to test exploration and appraisal segments below the existing SEQB discovery, which sits 10km south of the producing Cashima field, offshore Trinidad.

The well penetrated hydrocarbon-bearing reservoirs in seven intervals with approximately 600ft of net pay. Combined with the shallow SEQB gas reservoirs, the Macadamia discovery is expected to support a new platform within the post-2020 timeframe, BPTT said at the time.

“Savannah [another discovery made at the time] and Macadamia demonstrate that with the right technology we can continue to uncover the full potential of the Columbus Basin,” said Norman Christie, regional president for BPTT, back in June. ■

## Top 10 fields currently under development, by 2017 capex

Rank	Field	Country
<b>1</b>	<b>Ichthys</b>	<b>Australia</b>
2	South Tambeiskoye	Russian Federation
<b>3</b>	<b>Zohr</b>	<b>Egypt</b>
<b>4</b>	<b>Buzios</b>	<b>Brazil</b>
<b>5</b>	<b>Johan Sverdrup</b>	<b>Norway</b>
6	Fort Hills Mine	Canada
<b>7</b>	<b>Shah Deniz Phase Two</b>	<b>Azerbaijan</b>
8	Ratqa Lower Fars	Kuwait
9	Kandim	Uzbekistan
10	South Iolotan (Phase 2)	Turkmenistan

Source: Wood Mackenzie Upstream Data Tool. Upstream projects in bold.

### Ichthys Venturer, part of the Ichthys LNG development.

Photo from Inpex.

### Mega-projects

OE surveys some of the industry's biggest ongoing projects. Five of the 10 biggest projects by capex were offshore projects in 2017, led by Inpex's Ichthys LNG project offshore Australia.

### Ichthys: Making progress

The Inpex-operated Ichthys LNG project hit some major milestones in 2017. The floating production, storage and offloading facility (FPSO) was moored in August this year at the Ichthys field, 220km off the north coast of Western Australia.

The 336m-long FPSO, named *Ichthys Venturer*, is longer than three soccer fields and is designed for 40 years of operations without dry dock. It also has a storage capacity of 1.12 MMbbl of condensate.

“Completing the complex operation of connecting 21 pre-installed mooring chains, weighing more than 15,000 tonnes, from the seabed to the FPSO is testament to the well-coordinated work of our personnel, including contractors and sub-contractors from around the globe,” said Louis Bon, managing director of Ichthys Project, this August.





**Ichthys Venturer before sailaway.** Photo from Inpex.

The *Ichthys Venturer* FPSO is moored 3.5km from Ichthys' central processing facility, the *Ichthys Explorer*, which was moored at the field in late May.

In September, Wood Group was awarded a new, five-year contract to provide subsea engineering services for the integrity of the Ichthys project. The operations of all subsea assets and the gas export pipeline will be supported under the contract, which includes two, one-year extension options.

The Ichthys LNG project is expected to produce up to 8.9 MTPA of LNG and 1.65 MTPA of LPG, along with approximately 100,000 b/d of condensate at peak.

In November 2017, Inpex won an exploration permit for Release Area WA-532-P, close to its Ichthys LNG development, in Australia's 2016 Offshore Petroleum Exploration Acreage Release. The permit area covering 26,300sq km in 60-250m water depth.

Inpex said in November that exploration in the area will help add value to the Ichthys project. The Japanese operator now has 18 permits near the Ichthys gas-condensate field. ■

## Zohr: On the fast-track

This year has been a busy one for the Eni-operated Zohr mega-project. In February, BP bought 10% interest in the Shorouk concession, offshore Egypt, which contains the Zohr gas field, for US\$375 million. In October, Russia's Rosneft then closed a US\$1.13 billion deal to acquire 30% stake in the concession from Eni.

Zohr, discovered in 2015, lies in the Nile Delta basin off Egypt in the Block 9 (Shorouk block), close to Cypriot waters, about 190km north of Port Said in 1500m water depth. Its acreage covers about 230sq km, with its in-place reserves exceeding 850 Bcm.

Andrew Scutter, of the EIC, wrote for *OE* in June that "Eni's 30 Tcf Zohr discovery, offshore Egypt, is a game changer in the region that has the potential to convert Egypt from a net importer back to the LNG exporter that it was 10 years ago."

IHS Markit said that Zohr holds in-place resources of 32 Tcf of dry gas, with possible recoverable resources of about 20 Tcf. A development plan for the field was approved in 2016.

The two-phased, fast-tracked project is targeting first gas by the end of 2017, by drilling six wells this year and tying them into existing nearby infrastructure, Scutter said in June. Zohr is slated to be one of the longest subsea tiebacks in the world.

In July, Saipem was awarded a \$900 million engineering, procurement, construction and installation (EPCI) contract for Zohr.

Saipem said the scope of work includes the installation of a 30in-diameter gas export pipeline and an 8in-diameter service pipeline, as well as EPCI work for the field development in



**Eni's Claudio Descalzi (top) and Egypt's Petroleum Minister (bottom) tour Zohr facilities.**

Photos from Eni/Egypt's Ministry of Petroleum.



deep water (up to 1700m) of four wells and the installation of umbilicals. Work is due to be completed by the end of 2018.

In September, Baker Hughes, a GE company (BHGE) won a subsea contract for Zohr's second phase. BHGE will provide project management, engineering procurement, fabrication, construction, testing and transportation of a subsea production system, including seven manifolds, tie-in systems, long offset subsea and topside control systems, SemStar5 high integrity pressure protection systems, workover systems and tools, and will support the installation, commissioning and start-up operations.





Johan Sverdrup phase 2 – platforms. Image from Statoil.



The Johan Sverdrup riser platform jacket being installed by Thialf. Photo: Jan Arne Wold/Statoil.

## Johan Sverdrup: King in the North

Statoil's Johan Sverdrup project is simply a giant. Like the others on this list, it is a massive, two-phased project, 160km west of Stavanger, Norway, in water depths ranging 110-120m. Statoil believes it will be one of the most important industrial projects in Norway of the next 50 years.

Resource estimates for Johan Sverdrup are 2-3 billion boe. Phase 1 is underway – 60% complete as of September 2017, with first oil to follow in late 2019.

Phase 1 of the field included the development of four platforms, three subsea installations for water injection, power from shore, export pipeline for oil (sent to Mongstad) and gas (sent to Kårstø). Statoil estimates the capital expenditure for phase 1 at NOK 92 billion.

In March, Statoil and its partners expressed their intent to proceed with phase 2 of Johan Sverdrup, with investment decision and submission of the plan for development and operation to come in 2H 2018.

In anticipation of phase 2, Statoil awarded FEED contracts to Aker Solutions (processing platform), Kværner (jacket) and Siemens (power supply from shore).

Phase 2 will build on infrastructure from phase 1, adding another processing platform, which the Norwegian major says will result in a processing capacity of 660,000 bo/d. Expected to come on stream by 2022, Statoil says 28 new wells will be drilled for the phase 2 development.

According to Statoil, capital expenditures for Phase 2 are estimated at between NOK 40-55 billion, halving the estimate since the PDO was submitted for Phase 1 of Johan Sverdrup.

Statoil operates Johan Sverdrup with 40.0267% interest. Its partners on the massive development are Lundin Norway (22.6%), Petoro (17.36%), AkerBP (11.5733%) and Maersk Oil (8.44%).



Johan Sverdrup riser platform jacket sail away.

Photo from Statoil.



## Shah Deniz 2

In September, a second topsides unit for the BP-operated Shah Deniz Stage 2 project, the 15,800-tonne production and risers (PR) platform, was installed in the Caspian Sea.

The installation of the first unit, the quarters and utilities (QU) platform topsides was completed in early-July.

Shah Deniz, discovered in 1999, is 70km southeast of Baku, Azerbaijan, in 50-500m water depth. The field, which sits on the deepwater shelf of the Caspian Sea, spans some 860sq km. The field holds about 40 Tcf of natural gas in place, making it one of the world's largest gas-condensate fields, and one of BP's largest discoveries to date.

The project consists of Shah Deniz Stage 1, with the capacity to produce some 10 Bcm/yr of gas, and about 50,000 b/d of condensate; Shah Deniz Stage 2, which will add an additional 16 Bcm per year of gas production; and the Southern Gas Corridor pipeline system that will help deliver 6 Bcm/yr of gas to Turkey and a further 10 Bcm/yr of gas to markets in Europe.

The Shah Deniz Stage 2 concept calls for two new bridge-linked offshore platforms; 26 gas production wells, which will be drilled with two semisubmersibles; and 500km of subsea pipelines, which will link the wells with the onshore terminal.

The Shah Deniz consortium consists of: operator BP (28.8%), TPAO (19%), Petronas (15.5%), AzSD (10%), Lukoil (10%), NICO (10%) and SGC Upstream (6.7%).



## Mariner

This summer, Statoil's US\$7 billion Mariner heavy oil development took a major step forward. The Mariner A platform's nine modules were installed on the Mariner A jacket using the *Saipem 7000* crane vessel, about 150km east of Shetland on the UK Continental Shelf (UKCS).

The *Safe Boreas* flotel then moved alongside to support some 480 of the up to 750 staff that will be working on the 38,000-tonne platform hook up and commissioning project over the next year or so.

First oil is scheduled for 2H 2018. Mariner, a heavy oil field development, is one of the largest projects currently under development on the UKCS.

The field contains an estimated 250 MMbo reserves with an average plateau production expected at about 55,000 b/d.

## Shah Deniz 2 topsides before sail away.

Photo from BP.





## Major 2017 projects, continued



All three Culzean jackets were installed this year.

Photo from Maersk Oil.

### Culzean

All three of Maersk Oil's Culzean high-pressure, high-temperature (HPHT) development jackets were installed this summer in the UK North Sea, about 145mi east of Aberdeen. The field will produce an estimated 60,000-90,000 boe/d at plateau production and produce for at least 13 years.

The installation of central processing facilities (CPF) and the utilities and living quarters (ULQ) jackets – together weighing 22,000-tonne – was completed on 20 July, while the wellhead platform (WHP) jacket was installed last year. All three jackets were built by Heerema and installed using the Heerema Marine operated crane vessel, the *Thialf*.

### Stampede

Stampede, in the US Gulf of Mexico, is scheduled to start oil production in Q1 2018 via a tension leg platform. Located in 3500ft of water approximately 115mi south of Port Fouchon, Louisiana, the field is estimated to hold between 300-350 MMboe in gross recoverable resources in Miocene subsalt

reservoirs. Hess operates Stampede with 25% interest.

In late October, all pipeline pre-commissioning was completed. Three wells have been drilled and completed, with six wells in total due on stream and production rates estimated at 80,000 b/d.

### Hess' Stampede platform is towed out.

Photo from Hess.







The Appomattox hull sails from Korea. Photo from Shell.

### Appomattox

The hull for the Appomattox field development in the deepwater US Gulf of Mexico arrived mid-October at the Ingleside, Texas shipyard, where it will undergo final construction before installation offshore.

The project is due on stream by the end of the decade, Shell has said. Appomattox will add about 175,000 boe/d (Shell share) when it reaches peak production,

from some 650 MMbbl resources in the Appomattox and Vicksburg fields. Future nearfield discoveries such as Rydberg could also be tied in.

The platform will tower more than 20 stories above the ocean once fully assembled. It will float in 7400ft of water, span an area larger than two football fields, and will weigh more than the world's largest naval aircraft carriers, Shell has said.



The Aasta Hansteen topside sail away. Photo from Statoil/Lee Hyeongjin

### Aasta Hansteen

Statoil's Aasta Hansteen spar platform topside set sail for Norway in September. Once in Norway, the 24,000-tonne topside will be mated with the development's spar hull in a fjord in Norway.

Aasta Hansteen will be moored in 1300m water depth

in the Norwegian Sea – the deepest previous project offshore Norway is Shell's Ormen Lange, at 900m.

The development will produce the Luva, Snefrid and Haklang gas and condensate reservoirs, jointly known as Aasta Hansteen. **OE**



**Senegal and Mauritania are set for a raft of activity as two major projects move towards putting both countries on the deepwater map, while Cyprus waits in the wings. Elaine Maslin reports.**

2017:

# Hot spots

**A**fter dwelling in relative oilfield obscurity for decades, Senegal is set to make it on the map as a deepwater offshore oil and gas producing nation. Two major deepwater projects, in 1000-3000m water depth, are brewing in the country, which has otherwise only hosted minor levels of onshore production.

Following their “basin opening” discoveries in 2014-15, first gas is targeted on the Greater Tortue Area LNG development in 2021, with first oil on the SNE (Shelf North Edge) field following, in 2021-23. Both projects have been driven by independents, Cairn Energy and Kosmos Energy.

The Tortue-1/Guembeul-1 gas find is thought to be the largest ever offshore West Africa with 15 Tcf of recoverable dry gas discovered so far, and up to about 25 Tcf with the play extending discoveries of Marsouin-11 and Taranga to the north (in Mauritania) and south (Senegal).

Meanwhile, SNE, which was 2014’s world’s largest oil discovery, is described by investment analysts Mirabaud as the “jewel in the crown.”

Rokhaya Diallo Gunning, chief of geological basin division, Petrosen, Senegal’s national oil company, told a global opportunities session at the Offshore Energy exhibition

and conference in Amsterdam, in October, that until 2014, Senegal was largely underexplored. There are eight offshore production sharing contracts at the moment and one open offshore block.

Starting in 2014, the country saw the first offshore drilling

## Path to first gas from Tortue

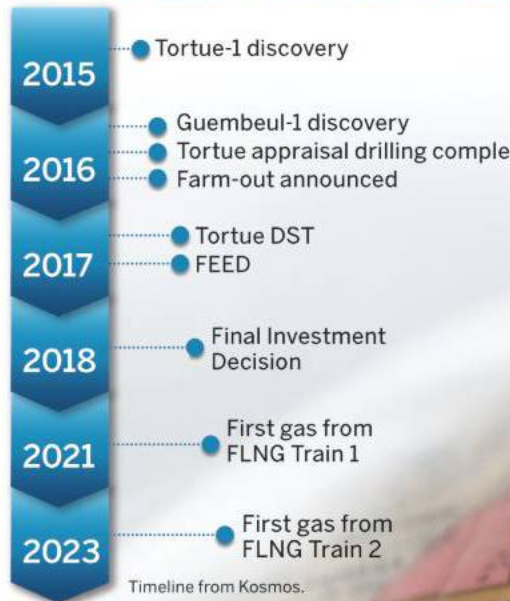
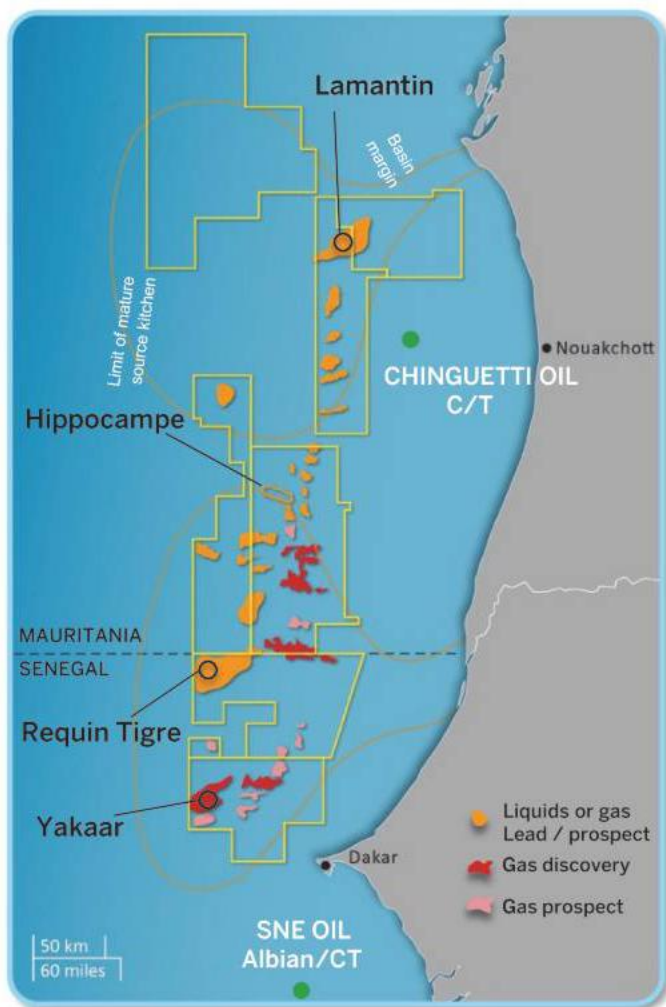


Photo from OE Staff.





**Map of Mauritania & Senegal assets.** Image from Kosmos.

since 1993. This resulted in Cairn Energy making the FAN-1 and SNE-1 discoveries in the Rufisque, Sangomar and Sangomar Deep production sharing contract (PSC), which stretches from the shoreline to deep offshore.

The following year, Kosmos made the Tortue-1 (Ahmeyim), discovery, followed by Guembeul-1 in 2700m water depth in 2016, both on the St. Louis Profond license, and then Ahmeyin-2, in Block C-8 in neighboring Mauritania – which together form the “GTA finds” (Guembeul, Tortue and Ahmeyim). Together, these amount to 25 Tcf of discovered gas resource along the inboard Senegal River fairway, with potential of over 50 Tcf, Gunning says.

Kosmos made the Teranga-1 discovery in 2016, in 1800m water depth in the Cayar Offshore Deep license. With BP now on board, the even further offshore Yakaar-1 discovery, in 2550m water depth, was the first successful test of the outboard basin floor fairway, Gunning says. Yakaar is also in the Cayar Offshore Deep.

### SNE options

After a string of appraisal wells in 650-1400m water depth, including drill stem tests, and further exploration wells, Cairn is planning its development options for the SNE field.

Gunning says that Cairn is planning a phased, standalone floating production (FPSO) development, targeting 75,000-125,000 bo/d, with 1-2 MMbbl oil storage, with potential for expansion with satellite developments. This could be using an existing, redeployed FPSO or a conversion or newbuild.

Initially, up to 25 wells would be drilled, comprising producers and water and gas injection, Gunning says. The first phase would target 240 MMbbl in the S500 lower SNE reservoir. Subsequent phases would target the S400 upper reservoir, with future potential for further subsea infrastructure and wells installed. Engagement of subsea contractors started prior to tendering, which was expected to start by the end of the year.

According to Gunning, updated gross 2C resources in SNE are 563 MMbbl. The firm would need 200 MMbbl to have the foundation for an economic field development, she says. SNE also has 0.3 Tcf of associated gas, and more than 1 Tcf of recoverable non-associated gas.

Life of field capex is US\$12/bbl, Gunning says, with \$2.3 billion capex to first oil, about 60% of which is development drilling, with 16 wells pre-drilled. Final investment decision (FID) for SNE is being targeted by 2018, with first oil to follow in 2021-2023.

### GTA moving forward

BP became operator of GTA after taking a major stake in Kosmos’ exploration blocks in Mauritania and Senegal in December 2016 and April 2017. BP is targeting final investment decision on the GTA – also known as Greater Tortue Complex — development in 2018, based on a near shore Floating LNG project, Gunning says. Senegal and Mauritania’s governments, whose maritime zones the fields cut across, are expected to form a cooperation agreement over the development by the end of the year.

Breakeven on the project is less than \$5/Mcf, Gunning says. Two FLNG vessels are being planned, with first gas from the first 2.3 MTPA unit planned by 2021, via four wells, and the second 2.3 MTPA train in 2023, with 15 wells in total and capacity for up to 20 wells.

The subsea infrastructure would see a daisy-chained manifold and looped flowline arrangement, with two, 120km-long, 18in production flowlines, connected to a floating production vessel, for gas pre-treatment and condensate stabilization and storage. The FPSO and FLNG trains would be located at a near-shore breakwater and sea island, which would also host an LNG carrier berth.

Both the SNE and GTA projects will drive the development new port infrastructure, Gunning says. These projects are by all means not the only games in town, however. Teranga and



**Rokhaya Diallo Gunning.** Photo from Offshore Energy.



# YEAR IN REVIEW

Yakaar, with 20 Tcf Pmean gas resource in the Cayar Offshore Deep, could form a second LNG hub, Kosmos says.

Meanwhile, in Mauritania, Kosmos is also looking at the Hippocampe and Lamantin prospects. However, in late October, Kosmos's Hippocampe-1 well came up dry. In Senegal, Kosmos is looking at the Requin Tigre prospect with an estimated 60 Tcf unrisks resource. This is outboard of the Tortue gas discovery. Indeed, Senegal's deep plays, all have extension in the ultra-deep, Gunning says.

While exploration in Senegal and Mauritania has been dominated by smaller players, the entry of BP and Woodside (subject to an argument over pre-emption rights FAR Ltd claims), as partners to Cairn and Kosmos, was followed by the entry of Total.

In May, Total was awarded a PSC for the 10,357sq km Rufisque Offshore Profond block, holding 90% interest alongside Petrosen.

Total also signed a cooperation agreement with Petrosen and Senegal's Ministry of Energy and Renewable Energy Development under which Total will perform studies to assess the exploration potential of Senegal's ultra-deep offshore and become operator of an exploration block.

## Cyprus

Exploration 2.0 is how the latest phase of offshore exploration is described in Cyprus. It could also be described as exploration post-Zohr.

Egypt's major Zohr discovery made many look at the Mediterranean differently, including Cypriot waters. Demetris Fessas, executive manager, at the Cyprus Hydrocarbons Company, told the global opportunities session at Offshore Energy there is a lot of activity in the region.

Cyprus is relatively new to offshore exploration. The country held its first offshore round in 2007, with 11 blocks awarded, followed by Block 12 in 2008, resulting in the 2011 Aphrodite discovery by Noble Energy. A development and production plan is now being discussed with the government. A base case is a floating host with export capacity up to 800 MMscf/d, Fessas says. An export pipeline could take the gas to Egypt, he says, adding that sales negotiations are ongoing. "The idea is to use the idle LNG facilities at Idku and Damietta," he says. Both have been idle since the uprising in Egypt. However, plans for LNG export were parked until the results of the next round of exploration are known. Aphrodite's FID is expected in late-2019. First gas could be late 2022.

Since then, further blocks were awarded in the 2012 and 2016 licensing rounds, with Eni taking Blocks 2, 3, 6, 8, 9 and 11 (2, 3 and 9 with Kogas and 11 with Total). Shell (via BG Group) has joined Noble Energy on Block 12, and ExxonMobil



Photo from OE Staff.

and Qatar Petroleum hold Block 10. "Today, eight of 13 blocks offered are currently under license," Fessas says.

Many are interested in "Exploration 2.0." The original activities offshore Cyprus focused on the clastic plays, Fessas says. "After Zohr, 6km from our exclusive economic zone, we reviewed the carbonate prospects [similar to Zohr] and found potential," Fessas says. "The third round was held on back of that."

The Onesiphorus West exploration well drilled using the *West Capella* drillship in 1698m water depth, on Block 11 by Eni, earlier this year, confirmed the carbonate play does exist in Cyprus, although it wasn't a commercial discovery. Results of this well are being used to plan 2-3 exploration wells on Blocks 3, 6 and 8 in 1H 2018. Reuters reported in early November that Total and Eni were planning to start drilling late 2017, early 2018 in Block 6.

Meanwhile, ExxonMobil is also planning at least two wells on Block 10 in 2H 2018, Fessas says.

"Regionally, there is a lot of activity. Israel has Leviathan (under development), Tamar (producing, but could expand), and Karish (considering an FPSO). In Egypt, there's the Zohr discovery, with first gas due by the end of the year, and West Nile Delta Deep. Lebanon is also progressing with its first licensing

round. Three companies (Eni, Total and Novatek in a consortium) made the only bids in Lebanon's first offshore licensing round, announced late October. However, as *OE* went to press in early November, the country's Prime Minister Saad Hariri suddenly and unexpectedly resigned his post during a trip to Saudi Arabia.

"There are lots of activities in Cyprus and in the region, a lot of these have used Cyprus as a mobilization base to support activities. It's not an easy neighborhood, but Cyprus being part of the EU bring stability and benefits of that." **OE**



Demetris Fessas. Photo from Offshore Energy.



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# Make or break time

The performance of the world's first floating LNG projects, which are moving from execute to operate, will form the shape of the industry to come. Elaine Maslin reports.

Ten years after the discovery of the Prelude field offshore western Australia, Shell's Prelude floating LNG (FLNG) mega-project is slowly creeping towards first production.

Sitting some 475km (295mi) north-northeast of Broome, the 488m-long vessel (one of the largest floating offshore facilities in the world) will join Petronas' 365m-long PFLNG *Satu*, which beat Shell to the first FLNG production, offshore Malaysia, late last year as the world's only FLNG projects operating globally.

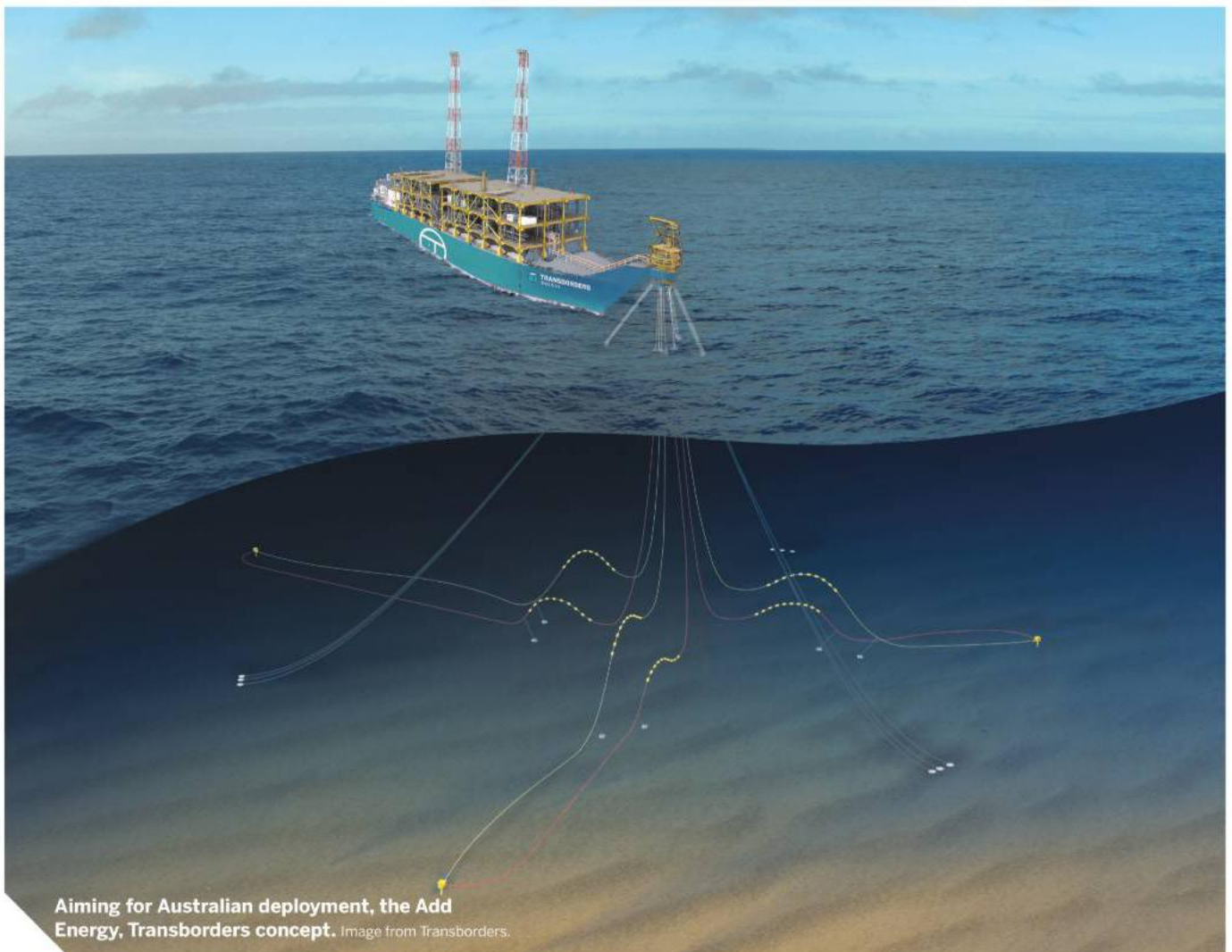
Their performance, and that of smaller scale facilities like that of Cameroon

FLNG (due onstream next year along with Prelude), will help or hinder the potential for future FLNG roll-out, says Matt Day, global gas and LNG analyst at Wood Mackenzie.

"We're in the execute and commissioning phase," Day says. "The market is looking at these projects and waiting to see if they deliver and if they can be reliable. The success of these projects will dictate what we see in the next few years."

There are plenty of possible projects waiting in the wings, including the recently sanctioned Eni Coral FLNG project offshore Mozambique and Ophir Energy's Fortuna development, for which the firm is seeking finance. In all, there are 24 FLNG proposals totaling 156.9 MTPA, as of January 2017, according to the International Gas Union's World LNG Report.

The attraction of FLNG is lower cost facilities (than onshore facilities) and flexibility to divert them to other markets. FLNG projects can be based



Aiming for Australian deployment, the Add Energy, Transborder concept. Image from Transborder.





**Caribbean FLNG seeks a new home.** Photo from Wilson.

on several development concepts – purpose-built, near-shore barge, and conversions. They generally aim to commercialize otherwise stranded gas resources, avoid much of the lengthy permitting and regulatory approvals associated with onshore proposals, and reduce costs with offsite construction, says the World LNG Report.

Six FLNG projects have been sanctioned in the last few years; Prelude, Petronas PFLNG (x2), Coral FLNG, and Golar Cameroon, plus Exmar LNG, which was canceled. These fall into two categories, Day says; large-scale, open sea projects, like Prelude and PFLNG, then nearshore, benign sea, small scale projects.

“The large-scale projects demand heavy weights like Shell and Petronas, well capitalized companies looking to develop projects with a view to expanding their expertise in the LNG space. I think that is what Eni is also doing with Coral, developing the technology to use it elsewhere. The small projects are led by partnerships between upstream companies and LNG technology providers, like Golar.”

Even between the large-scale projects, there are significant differences. A November 2016 report on floating LNG by Oxford Economics points out that Prelude uses dual mixed refrigerant (DMR) technology and will produce 3.6 MTPA on a 488m-long vessel, i.e. 1.1 MTPA/ha. The Kanowit (PFLNG *Satu*) project

uses nitrogen and produces 1.2 MTPA on a 365m-long vessel, i.e. 0.5 MTPA/ha. Different refrigerant options usually lead to different outcomes. While Kanowit’s choice in nitrogen isn’t flammable like the DMR on Prelude, and it has a smaller flare, it requires more space onboard, the Oxford Economics report found.

Go back some years and it was a much different scene for FLNG. “When Prelude and PFLNG were sanctioned, 5-7 years ago, prices were high, companies were in good shape and there were buyers for projects. As soon as the price crashed in 2014, it tied up the LNG market and LNG projects in general became difficult to move forward,” Day says. In the past two years 12 MTPA was sanctioned, across five projects, compared with 30 MTPA in 2013 and 2014, he adds. “FLNG projects in particular were challenged because of the perceived risk associated with them, being new technology, not yet tried and tested.”

Shell had seen Prelude as a “design one, build many” concept, with Browse, using three FLNG units, as its next step. Yet, this is now off the agenda for Shell, Day says, due to high costs, the collapse of prices, and lack of buyers. Meanwhile Golar, a shipping provider, is also looking at a “design one, build multiple” ethos. “They are working on Cameroon and want to replicate that with Fortuna,” Day says.

From 2017-2018, we will see the

delivery of three FLNG vessels. Petronas has already started production from PFLNG *Satu*, albeit with a pretty slow start, Day says. Prelude is on location, with start-up expected in 2H 2018, and the Cameroon FLNG vessel close to arriving in country.

“If Golar can deliver, it will bring much more projects for them,” Day says. “They need to deliver before they get more upstream resource holders subscribing to that. But, we still see FLNG as a niche technology for niche situations. When you look at the broader LNG market, there are big projects moving forward in Qatar, Russia and the US, with 5-15 MTPA [each].” In comparison, Prelude, the biggest FLNG project, is 3.6 MTPA. “That’s not to say it cannot work and cannot be competitive if the conditions are right, with the

right partners and contracts,” Day adds.

Whether the rest will come to fruition or not, the supply chain is taking note. A string of companies has set out partnerships and collaboration agreements (KBR, Wilson Offshore & Marine, Add Energy, Transborders, GTT) while others have been beefing up their LNG capabilities (Aker Solutions).

### Small scale options

Add Energy has partnered with Transborders Energy, and joined forces with TechnipFMC and Modec, to create a unique, fast-track business model that it says would free up small-scale stranded offshore gas deposits around the world.

Add Energy says there’s an oversupply of gas currently, but that it will turn into a shortage by 2020, because of demand growth globally, but specifically in Asia. “If we are to meet the future demand for gas, we will need quicker extraction models than the current long-term projects allow. We are targeting to be placed ourselves at the time LNG supply cannot cope with global demand (2024),” says Eduardo Robaina, vice president, well engineering, Add Energy.

Add Energy and its partners have set out a concept for a small scale FLNG unit (carrying up to 1 MTPA) to extract gas from proven small fields containing 0.5-2 Tcf of gas. In a reversal of the usual development process, which sees





**SBM Offshore's TwinHull concept.** Images from SBM Offshore.



**SBM Offshore's newbuild mid-scale FLNG concept.**

facilities designed for a specific field, the idea is to develop a unit to fit a range of fields, then look for fields that will be suitable, shaving off some five years engineering work, the group says.

"These fields have little value at the moment because accessing the gas is either cost prohibitive or it is not economically viable to use the more common large scale and expensive FLNG vessels on them," says the consortium. "It's about using fields that fit the pre-existing plan, not finding a field and creating a plan to suit it.

"Key to the model is the deployment of an innovative mini-FLNG vessel. Rather than investing up to five years in identifying a gas resource, understanding its size and potential and creating a bespoke development concept, the new model establishes a pre-defined process incorporating the use of the mini FLNG vessel and applies it to proven, fit for

purpose fields."

Production would be from a small number of wells (2-3), targeting "the sweet spot" and keeping the cost as low as possible. "Our basis of design looks for water depth between 100-400m and permanent mooring has been selected," Robaina says. The companies are still considering newbuild versus conversion for the hull.

"We are working towards proven technology and as part of our resource selection criteria we want to remain in shallow waters, up to 2 Tcf of gas in place, normalized pressure," Robaina says. "We want to focus in the development of mini-FLNG topsides technology and 'where possible' avoid the need for additional processing topside modules."

The first field to be targeted will be offshore Australia. The field will be confirmed early 2018 and production of gas is expected to start in 2020, Robaina says. After this, the model will be

available globally, he adds.

"Our initial concept is to be deployed within Australia waters, given our proximity to end users (Asia market), political stability within the regions and our strong operational knowledge in the area. The sweet spot is driven by the resource/reservoir and not by an area/region in specific. Western and north-western Australia, are known for their active cyclonic activities, so we will be taking harsh sea/ storms condition as part of our design concept. "

### TwinHull

SBM Offshore launched its FLNG solution, TwinHull LNG, for stranded gas fields in 2015. SBM has offered a mid-scale FLNG unit (1.5-2 MTPA) conversion, suitable for what it says are some 700-plus stranded gas fields between 0.5-2 Tcf. SBM Offshore suggests converting LNG tankers into FLNG facilities – in much the same way as has been done for FPSOs.

"The advantage of this concept includes lower costs and a shorter schedule," SBM says. Process facilities, storage and crew living quarters would be on deck. The layout would be achieved by joining together two LNG tankers in a 'twin hull' concept, to allow adequate space for the process facilities and sufficient LNG storage capacity. SBM has performed generic pre-FEED work, together with LNG experienced engineering firm Linde Engineering, to cater for a wide range of potential reservoir compositions and environmental conditions, which can then be optimized for specific fields. It would use a pre-cooled dual nitrogen expansion process without natural gas liquid (NGL) recovery.

SBM also has a newbuild LNG FPSO concept, targeted towards small to mid-scale fields (1-2.5 MTPA) with a storage capacity up to 241,000cu m. It is suitable for at shore, nearshore and offshore applications, the firm says. **OE**

### FURTHER READING



**Making room.** Choosing the right FLNG topsides equipment can be a complex process. Audrey Leon reports on some of

the solutions presented by Black & Veatch at OTC 2016. [www.oedigital.com/energy/lng/item/12626-making-room](http://www.oedigital.com/energy/lng/item/12626-making-room)



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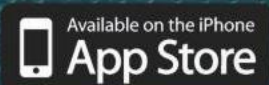
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# Float your boat

Elaine Maslin looks at some of the ongoing and proposed FLNG projects around the globe.

**W**est Africa has seen a good amount of floating LNG project activity this year with three developments underway.

Golar Cameroon will use the *Hilli Espiseyo* floating LNG (FLNG) vessel (the first FLNG conversion, by Keppel), using Black & Veatch liquefaction technology. It will produce the remaining reserves from the Sanaga field, which was the first offshore gas field to be developed in Cameroon. It had been produced from two gas wells via an offshore production module, with gas exported to a gas processing plant at Kribi, onshore. Perenco and the national oil company signed a deal in 2015 to develop the remaining reserves of Sanaga into gas petroleum liquids for the domestic market and LNG for export through an FLNG unit. The project is due on stream in 2018.

The next project waiting in the wings is Ophir Energy's Fortuna FLNG development in Equatorial Guinea.

Earlier this year, Ophir Energy awarded an upstream construction contract for Fortuna (West Africa's first deepwater FLNG project) to OneSubsea and Subsea 7's Subsea Integration Alliance. The firms will provide engineering, procurement, construction, installation and commissioning (EPCIC) work on subsea umbilicals, risers and flowlines (SURF) and for the subsea production systems.

The end result will be delivery of 440 MMscf/d of gas through infrastructure comprising four wells (three into the Fortuna field and one into the underlying Viscata field) at 1790m average water depth. First gas is planned for 2020. A final investment decision (FID) was due by the end of 2017. Fortuna sits in Block R, some 140km west of Bioko Island, in the southeastern Niger Delta complex.

OneLNG, a joint venture between Schlumberger and Golar LNG, is exploring FLNG potential in Blocks O and I offshore Malabo, Equatorial Guinea's capital, which sits on Bioko island, off the mainland. In addition to this, OneLNG, which was originally formed to work on Ophir's Fortuna project, is also working on 3-4 additional projects, each involving one or

more FLNG unit, the firm said in May this year.

BP and partner Kosmos are assessing an FLNG development for the cross-border greater Tortue development between Mauritania and Senegal. According to the World LNG Report, a conversion is being considered with first export targeted for 2021.

In October, KBR was awarded pre-front end engineering design (FEED) and project support services contracts by BP. The work will provide pre-FEED and project support covering design of the subsea, pre-treatment floating LNG production storage and offloading (FPSO) facility, inshore hub/terminal, and interfaces for FLNG unit for the Tortue project.

## East Africa

The discovery of large gas reserves offshore East Africa has resulted in FLNG proposals in Mozambique and Tanzania. Eni made a final investment decision (FID) on its Coral FLNG project in Area 4 offshore Mozambique this year, with start-up planned by 2022.

The FLNG facility will be moored in 2000m water depth and will be designed to produce 3.4 MTPA of LNG (5 Tcf in

The *Hilli Espiseyo* floating liquefaction vessel.  
Photo from Golar LNG.



total) from six subsea wells.

In June, TechnipFMC, together with JGC Corp. and Samsung Heavy Industries, all partners in the TJS Consortium, were awarded a contract for the Coral FLNG facility EPCIC and start-up work, as well as its risers and subsea flowlines system, and installation of the umbilicals and subsea equipment.

In August, Baker Hughes, a GE company (BHGE), was awarded a contract by the TJS JV for rotating equipment for the power and gas refrigeration process of the new FLNG facility. SOFEC, a Modec Group company, was awarded the turret mooring system supply contract for the project.

Anadarko Petroleum has also finalized agreements with Mozambique's government, paving the way for its LNG project in Area 1. Anadarko says it is developing Mozambique's first onshore LNG plant, consisting of two initial LNG trains with a total capacity of 12 MTPA to support the Golfinho/Atum field in Offshore Area 1.

**Australia**

FLNG is considered the lead development option for ExxonMobil's Scarborough gas field based on a balance of economic, environmental and social considerations. Scarborough, discovered in 1979, is located off the coast of Western Australia 220km northwest of Exmouth in 900m of water. It is one of the most remote of the Carnarvon Basin gas resources.

**Asia**

Meanwhile, Wison Offshore & Marine is working with KBR on Kumul Petroleum Holdings's 1.5 MPTA FLNG project in Papua New Guinea, Southeast Asia. KBR

had already won a contract from Kumul Petroleum for feasibility studies services for an energy hub in the Kikori region of the Gulf Province of Papua New Guinea. Wison, meanwhile, has also signed a strategic cooperation agreement with LNG transport and containment system firm GTT to work together on projects including LNG floating storage regasification units and FLNG.

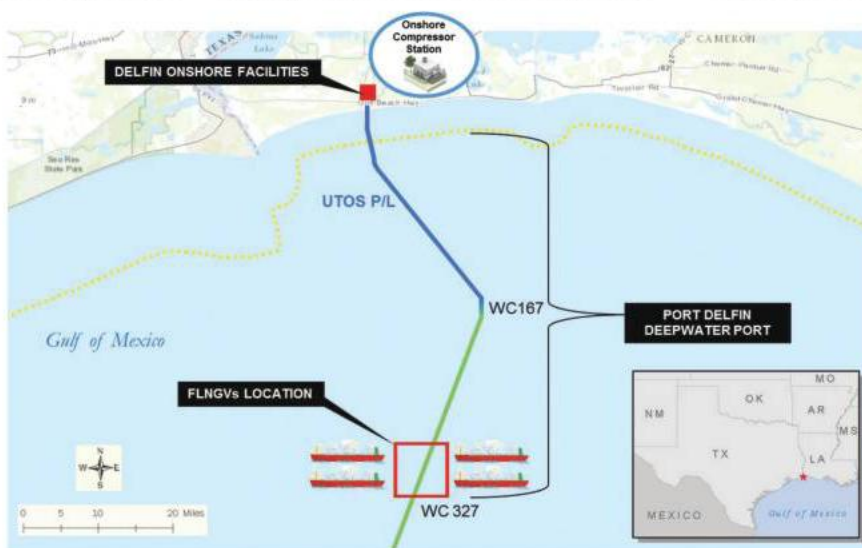
**North America**

In the US, the Delfin LNG Deepwater Port project offshore Louisiana, has made greater strides toward FID, which

Golar's FLNG technology. The agreement will see Golar develop a third floating liquefaction vessel, the *Mark II*, based on its *Hilli* and *Gandria* designs, to be used offshore Africa. The *Mark II* will have >3.0 MMTPA (million metric ton per annum) of liquefaction capacity.

The Delfin LNG project, a brownfield deepwater port, will be designed to support up to four FLNG vessels, capable of producing 13 MMTPA of LNG. It is the first FLNG project under development in the US, and the company is targeting first LNG by 2021-22.

The project has four major components, including the UTOS subsea pipeline that Delfin purchased from Enbridge in 2014. A new onshore compressor system will allow gas to flow through UTOS from onshore to the Delfin LNG Deepwater Port, 50mi offshore. The port will be the site of four mooring systems to house the four FLNG vessels.



An overview of the Delfin LNG project. Image from Delfin Midstream.



The *Hilli Espiseyo* floating liquefaction vessel. Photo from Golar LNG.

is being targeted for 2018. This summer, the firm received approval from the US Department of Energy for long-term exports of LNG to countries that do not have a Free Trade Agreement with the US.

Delfin signed a joint development agreement with Golar LNG in June this year. The agreement will see the project, off the coast of Cameron Parish, use

FLNG partners – Altogas, Idemitsu, EDF Trading, and Exmar – halted development work in early 2016.

But, there's still focus on projects with smaller capacities. Indeed, the Browse FLNG partners in Australia put the 11 MTPA project on hold in 2016, but they are examining smaller-scale options, according to the World LNG Report. **OE**

**On a break**

Petronas had plans for a PFLNG 2 project, but this was put on hold earlier this year, says the World LNG Report.

The Caribbean FLNG project offshore Colombia was originally slated to be the first operational floating project. Following delays, it was cancelled altogether in 2016.

In Canada, the Douglas Channel



# World's 10 longest

Subsea tiebacks have been pushing the envelope over recent years. We look at the longest projects out there, with the help of Wood Mackenzie.

Did you know that the world's longest subsea tieback is 190km-long? Strung together, the longest 10 subsea tiebacks alone would stretch 1199km in length. Here, we take a closer look at those 10 longest tiebacks, all of which have been, or are currently, in production, with the help of Wood Mackenzie's *Upstream Data Tool (UDT)* and *InfieldLive OED database*. To make the list, projects had to have no above-water structure involved at the field location (i.e. original hydrocarbon source). We include tiebacks to third party infrastructure, as well as to shore.

## 1. 190 km – Australia Gorgon (Chevron)

The most expensive gas/condensate development in the industry's history, Wood Mackenzie's estimate for the mammoth Australian LNG project up to first gas from Train 3 is US\$60 billion. Its first cargo of LNG sailed in March 2016.

## 3. 143 km – Norway Snøhvit (Statoil)

Snøhvit was the first LNG production facility in Europe and the first anywhere north of the Arctic Circle. It was also the first major development on Norway's continental shelf to have no surface installations. Snøhvit came onstream in 2007.

## 5. 120 km – Norway Ormen Lange (Shell)

Ormen Lange is the second largest gas field in Norway after Troll. The reservoir is a gigantic dome structure, 40km-long and at points 10km-wide. Development was complicated by the uneven, debris-strewn seabed, due to the Stor Egga landslides around 5500 BC, the fourth largest landslide in Earth's history. Production started in 2007.

## 2. 149 km – Israel Tamar (Noble)

Tamar is a dry gas field, 85km off the coast of Israel in the Eastern Mediterranean. It has been developed to supply the Israeli domestic market and gas been in production since 2013.

## 4. 140 km - UK Laggan and Tormore (Total)

These two remote fields are in the West of Shetland area of the Atlantic Margin, to the north of the mainland UK. They have been tied back via two, 18-inch, 140km-long multiphase pipelines to a new gas plant at Sullom Voe on the Shetland Islands. The complex started production in 2016, having been delayed several times due to gas plant construction, weather and drilling-related issues. Laggan and Tormore were the first fields in the UK to be developed at over 600m water depth.



# subsea tiebacks

## 6. 110 km – US Gulf of Mexico Mensa (Shell)

Mensa was a deepwater gas field in the US Gulf of Mexico, developed via subsea wells tied back 109km to a shelf hub platform. When production began in July 1997, it held the record for the longest subsea tieback. Mensa ceased production in September 2013.

## 8. 88 km - US Gulf of Mexico Aconcagua (Total)

Aconcagua has ceased production, but when it came online, it was deepwater field in the US Gulf of Mexico that produced 204 Bcf of gas over its 11-year field life. First production was achieved via two wells, in September 2002, and achieved peak output of 224 MMcf/d. Gas was exported to the Canyon Station platform via the Canyon Express pipeline.

## 10. 83 km - Ireland Corrib (Shell)

First production from the 1 Tcf Corrib gas field offshore Ireland was achieved in 2015, 12 years later than initially planned. The delays were due to disputes over approvals for the onshore facility and pipeline route. Corrib uses seven subsea wells collated at a central manifold, which is tied back to an onshore terminal in County Mayo.

## 7. 90 km – US Gulf of Mexico Bass Lite (Apache)

Bass Lite is a deepwater gas field in the US Gulf of Mexico, commercialized via a two-well subsea tieback to the Devils Tower spar. Bass Lite produced 131 Bcf during its seven-year field life, ceasing in December 2014.

## 9. 86 km – Egypt Scarab/Saffron (Shell/Petronas Carigali)

These two deepwater gas fields sit in the West Delta Deep Marine block offshore Egypt. In August 1999, approval was granted for Saffron and Scarab to be developed via subsea completion and tied back to onshore processing facilities. First production was in 2003.

Source: Wood Mackenzie's *Upstream Data Tool (UDT)* and *InfieldLive OED database*.



# Solan SOST sees success



**Premier Oil says early operations of its steel subsea oil storage tank (SOST) at its Solan field have proven a success. Karen Boman reports.**

Examples of subsea oil storage can be seen in large gravity-based concrete platforms in both the UK and Norwegian sectors of the North Sea, such as Harding and South Arne, said Stuart Wheaton, UK business head and director for Premier Oil, at this year's SPE Offshore Europe conference in Aberdeen. But, the use of a standalone unit is innovative.

Located in the North Atlantic, 135km West of Shetland, Solan was discovered by Hess in 1991. Hess delineated the 26.3 API oilfield with a 1992 appraisal well and a 260sq km 3D seismic survey was shot in 1993. At that time, however, the field's estimated resource size of a little over 40 MMbbl did not make it a commercial proposition.

"We were a very different industry

in the late Noughties, with higher oil prices and a very hot contract market," Wheaton said. Costs were also quite high, making it difficult to stir interest in developing a marginal field. In 2011, Premier Oil acquired a 60% stake in the field from Chrysaor and became the field operator. Chrysaor had conducted appraisal drilling at Solan in 2008 and 2009. In 2015, Premier acquired the remaining 40% stake from Chrysaor.

Premier also considered floating production system, including floating storage, but, FPSO leasing costs and a shortage of contractors available for work meant this route wasn't feasible, Wheaton said. Hostile marine conditions and remoteness from existing export structure with spare capacity meant subsea tiebacks weren't possible

either. Solan is in Block 205/26a on the UK Continental Shelf; the nearest production facilities are 35km north-northeast (BP's Foinhaven and Schiehallion fields, both produced via FPSOs). Premier also had to consider hydrogen sulfide management and the potential for oil spills on the environment, Wheaton said.

To address these challenges, the company wanted a system that could produce oil while offloading oil every 7-10 days, in an environment with frequent winter storms. Given these considerations, the field's modest size, and a planned production rate of 20,000-25,000 b/d, Premier looked to a design concept that would optimize costs, mean few or no people offshore and minimize maintenance over a 30-year life cycle, Wheaton explained.

In 2012, after exploring several options, including a fixed articulated tower, Chrysaor, which was still operator, decided on and received approval to use a subsea oil storage tank (SOST)





The Solan subsea oil storage tank. Photos from Premier Oil.

capable of holding 300,000 bbl of oil, connected to a minimal facilities, to be normally unmanned steel jacket supported platform. Designed by engineering house Atkins and constructed from steel by Dubai Drydocks World, it weighs 10,100-tonne in the air and measures 45m x 45m x 25m. It sits, piled to the seafloor, in 140m water depth, at a 300m offset from the platform, to avoid possible dropped objects incidents (it also has a dropped object protection frame to protect valves and piping), which produces from two subsea production wells and supports two subsea injection wells.

The tank features a honeycomb of small chambers, containing some 20,000 internal anodes, to ensure integrity as waves pass over and to prevent corrosion on the steel, and biocides and biopenetrants will also be used to prevent corrosive bacteria and marine life from forming inside it, a National Subsea Research Initiative event on subsea storage heard (*OE*: August 2016).

The facilities were installed in 2014, using Heerema Marine Contractor's heavy lift vessel *Thialf*. Production started in April 2016, and the first cargo offload took place on 25 July 2016.

Details of the SOST's performance were outlined by Wheaton and co-authors S.R. Clark and P. Cruickshank said an SPE Offshore Europe paper: "The Solan Field Subsea Oil Storage Tank after

One Year's Operation West of Shetland, UK – is it a Concept that has Delivered?"

### Designed and delivered

The detailed design of the SOST took 2-3 years. It was then constructed in modules, similar to the block building method used for ships. Premier had planned for its construction, plus load-out and sailaway to Lerwick, Shetland, to take about 18 months, but it ended up taking 23 months, due to construction challenges involving the 120km of welding required. In some cases, welds had to be ground out and rectified.

Once construction was underway, fatigue analysis indicated the original design intent of the fillet welds in some areas did not provide for the required integrity and longevity of the tank, Premier said. To address this, Premier switched the specification to full penetration welds in all areas. This change and the initial high rate of weld rejection rates meant a five-month delay in fabrication, Premier said.

Premier found that, by using the relative height of the topsides to the stand-pipe inlet and outlet depths inside the tank, intrinsic design features could be incorporated into the SOST to mitigate oil spill risk.

Another design feature used to reduce oil spill risk was a submersible pump to draw down the level in the ballast water caisson on the platform, which creates a

net positive pressure in the tank. If a leak is detected, outflow is then reduced to a low or even negligible rate until the tank is repaired or emptied, Premier stated.

Within the first year, 11 offloads of around 250,000 bbl each were carried out via Aframax-sized tankers. Premier initially targeted a 250,000 bbl oil offload delivered in 24-30 hours connection time with a 3-4-hour upfront operation time to safely connect. The actual duration accounts for the time needed for tanker hose pick-up and connection, the connection integrity test, and slower rate ramp up and slowdown periods, each of about one hour's time, on either side of the main offload, Wheaton and co-authors said.

Oil has been produced through the platform and to the tank largely with low water cut production from the reservoir. "Rag" layer emulsion development in the SOST has been minimal to date, but is still expected in the future, Wheaton said in the paper. Premier will handle this emulsion development by removing it to oil tanker slop tanks when necessary.

So far, the SOST has only been operated in one winter season, but export system capability of 100% was delivered through the total offload process with no days or barrels deferred because of SOST "tank-tops," Wheaton said. The company added that it looks like 90% availability can be achieved through the winter season using the SOST concept throughout the field's life.

Solan's field development scheme also was designed to be fully automated and controlled from an onshore operations center in Aberdeen. Currently, the SOST is monitored continuously via the platform ICSS in the topsides control room, and the onshore control room has yet to take full control of monitoring the Solan facility. Premier plans to make the Solan field fully controlled from shore in 2018/2019, a Premier spokesperson told *OE*. **OE**

### FURTHER READING



**Tanked up.** Subsea oil storage solutions could help unlock marginal fields; how easy would it be? Elaine Maslin

reports. [www.oedigital.com/production/item/13135-tanked-up](http://www.oedigital.com/production/item/13135-tanked-up)



# Downhole data drive

Nexen's Golden Eagle platform.  
Photo from Nexen.

Elaine Maslin reports on how the oil and gas industry is getting more data from downhole thanks to fiber optics.

The big data revolution is being felt in the oil and gas industry with a large focus on the gains to be made from the mass of data the industry already generates.

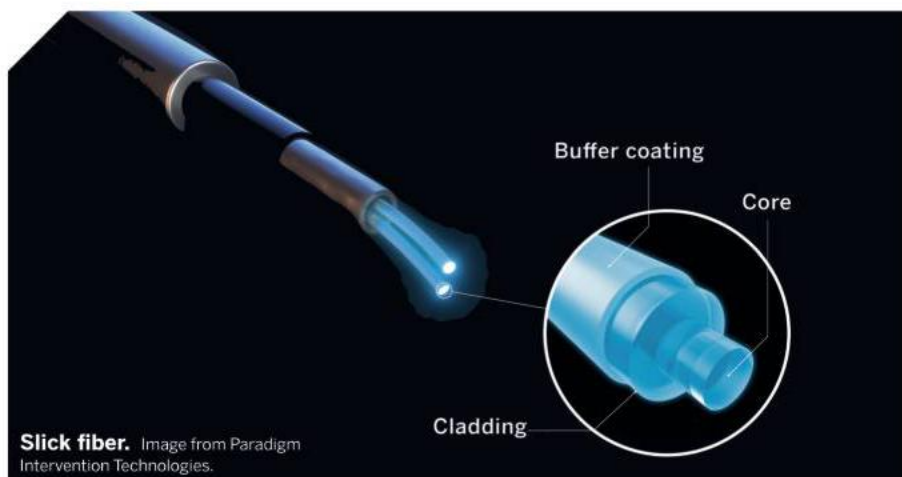
But, there are yet more gains to be made if more information could be extracted from downhole, not least in

an environment where operators want to get more out of their existing assets. Such ideas were discussed at the SPE Aberdeen Inwell Flow Surveillance & Control Seminar early October.

"Wells are not disposable assets. We have to make the most out of the well stock we have got," says Mike Webster, chairman of the event. "For me, the only way of doing that is through robust and frequent surveillance."

The problem is justifying the expense, he says. However, the payback can be many times over. "We don't get the value unless we then use the data in some shape or form," says Webster, who previously worked in senior roles for BP and is now director of Production Petrophysics, a consultancy.

So, how do you get more data from downhole? A large focus in the well surveillance space in recent years has been on fiber optics. For the converts, this is a technology worth putting downhole,



Slick fiber. Image from Paradigm Intervention Technologies.





Well-Sense's Dan Purkis.

Photo from Well-Sense.

even if you don't quite know what you'll get from it.

"With fiber optics you can get data down the length of the well, for every meter it's deployed,"

Webster says. "When you stick fiber in the ground you don't know everything you are going to find out, and there will be multiple ways of using all that data."

According to downhole technology development firm Well-Sense's founder Dan Purkis, fiber optics are set to take off. He told the SPE event that there are about 200-300 installations a year at the moment, but this will become thousands in not that many years' time.

### A renaissance

It's taken a while for the industry to come to grips with fiber. It was introduced in the late 1990s, but there were problems getting the fiber into the well and the longevity of it, Webster says. The fiber darkened due to exposure to water and hydrogen and other by-products of corrosion in the well environment. There were also connectivity issues, and mechanical issues with fiber could damage it.

It was initially used for distributed

temperature sensing (DTS), but the introduction of using fiber for distributed acoustic sensing (DAS) has led to a "renaissance" in the technology and its potential, however.

"A big change was the advent of DAS," Webster says. "Only so much can be done with temperature and it was over-egged. With the addition of acoustic, the utility of both is far more robust and created renaissance in fiber. Plus, there is now increased reliability and an increased choice in deployment [methods], which opens it up to use in a larger choice of wells." At the same time, the capabilities of DTS are also growing.

Fiber can be installed permanently or used in temporary interventions. Permanent installation could be with a downhole pressure/temperature

(PT) gauge cable down to just above the production packer, which doesn't cover as much of the well as you might want. Going below the production packer in a multi-trip completion means using a wet connect downhole, which have proven problematic. Otherwise, it could be installed via a hydraulic conduit, which means cost. Various well intervention methods can be used, including coiled tubing, carbon fiber rod, which has the benefit of being able to be pushed down horizontal wells, or in conventional wells using slickline and e-line, Webster says.

### Slickline

Paradigm Intervention Technologies has developed a standard 0.125in slickline deployment system, able to be packed into a 5700kg container (total loaded weight), which can use existing slickline infrastructure on facilities. The fiber wire, housed on a drum, is terminated with optical connections.

It's CO<sub>2</sub> and H<sub>2</sub>S resistant, can withstand up to 150°C (and could be higher), and comes in up to 6km lengths (currently manufacturing standard), but has a lower tensile strength than standard slickline because it's hollow (1400lb), Webster, who presented for Paradigm, said. It contains

single mode fiber for acoustic monitoring and multi-mode fiber for temperature sensing. Paradigm has its own depth control sheaves and stuffing box, but it can be used with existing onboard systems, Webster says. The system also has DTS and DAS optical interrogation units feeding data into a laptop.

The DAS in Paradigm's system typically uses a 100-nanosecond pulse width, which gives 10m spatial resolution, for application such as looking for leaks and defects in the well, Webster says. The DTS has 0.06°C thermal resolution, 1.02m spatial resolution, using a 5min stack time increment.

These are sufficient for well integrity type applications, Webster says. A system for the likes of seismic application would require higher sensitivity.

Giving an example, Webster says the system was deployed to investigate an A annulus leak and took 13 hours from rig up to rig down, with five hours survey time, collecting 1.9TB of raw DAS data and 14.3MB raw DTS data, which was decimated to 1GB, and integrated with other well data within three days. With optimization of the workflow this can now be done in 24 hours, Webster says.

### Temperature readings

Garth Naldreth, vice president, Oil & Gas, at fiber sensing firm Silixa, told the SPE event that DTS resolution has improved, to below 50cm, and with increased temporal resolution. It can be installed behind the casing or with a wireline or slickline type system for flow profile, leak detection, gas lift monitoring, etc. "For one product in the well there are a lot of opportunities," he says, including getting production profiling and phase information.

In work Silixa has done, slugging within a well was monitored and the data then interpreted and visualized, so that it could be shown when and where the slugs form and how they travelled along the well towards an electric submersible pump (ESP). This helped an operator to see where gas was coming into the well to cause the slugging – information was used to take action and prevent damage to the ESP. Normally, you can't production log across an ESP, Naldreth says. As fiber systems continue to improve more can be done with these measurements and now Doppler shifts in acoustic data are being used to generate enhanced flow profiling he says.





**Fiber by slickline, on deck and downhole.** Images from Paradigm Intervention Technologies.

Heriot-Watt University Professor Khafiz Murador told the SPE event that temperature measures used for monitoring near-well conditions are better than traditional pressure, as the temperature signals propagating less. But, while pressure transient analysis has been well-developed, temperature transient analysis, not so much.

“It’s not been used much before because of the many different influences on temperature making it complex to model, but with the help of the data available from Nexen’s Golden Eagle field, this work has been made easier,” Murador says. The field’s platform and subsea wells have been fitted with permanent DTS, as well as downhole pressure and temperature gauges (*OE*: Gaining Control, April 2017).

To date, 19 wells have been completed on the field, which came onstream in October 2014. Data from the DTS system and downhole PT gauges has given Murador the data needed for work on temperature transient analysis. “This type of analysis could provide insight

which could compensate for failed ICVs or sensors and reduce well or zonal flow tests,” he says.

#### Soundings

Acoustic data is also giving operators a lot of information about their wells. DAS was used for

sand ingress monitoring and remediation on BP’s Azeri, Chirag and Gunalshi fields in the Caspian Sea, Webster says. These are reservoirs with long production intervals, but soft unconsolidated rock prone to sand production. The wells were installed with fiber in many cases via a hydraulic conduit.

DAS was used to see where there was sand ingress, using digital processing – having done testing and then correlation with a surface sand meter – to discriminate from other forms of noise in the well, such as sand transportation, Webster says.

“A sand log was created for targeted remediation in as near real-time as possible,” he says, compared to the early days when DAS measurements were delivered in stacks of hard drives. This helped visualize the slugs and aid understanding of the mechanism for sanding in the well, which then enabled remediation work and a 70% sand production reduction, with oil production increasing by 2000 b/d (from one well). With the data now able to be visualized real-time, engineers can respond real-time, Webster says.

#### A small sacrifice

Well-Sense has been developing technology to take measurements downhole using fiber, but in single shot runs using a sacrificial fiber and deployment system (*OE*: Downhole disintegration, June 2016). It would be sent down the well, with readings taken, then left in the well to erode (the materials used to make the sub chosen for this purpose). Well-Sense is now working on a version which could be pumped down the well, for long horizontal wells, where using gravity deployment wouldn’t be feasible. It’s hoping to do a 10km vertical well deployment in Germany also, Purkis says. **OE**

#### FURTHER READING



**Gaining control** Inflow control valves and in-well fiber-optics have given Nexen far greater visibility of what’s going in and out of their reservoirs on the Golden

Eagle field. Elaine Maslin reports. [www.oedigital.com/production/well-operations/item/15004-gaining-control](http://www.oedigital.com/production/well-operations/item/15004-gaining-control)

**Downhole disintegration** A new concept

in well tools could see one-off tools built, run and left downhole to disintegrate. Elaine Maslin reports. <http://www.oedigital.com/technology/item/12631-downhole-disintegration>







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# IoT goes offshore

Tampnet's vision of North Sea connectivity. Image from Tampnet.

**The Internet of Things, a world in which equipment and instrumentation can talk to each other and modify operating parameters – across platforms, fleets and whole businesses – accordingly, is close at hand. Having the communications infrastructure in place is what will help make it happen. Elaine Maslin reports.**

**I**n an industry with a large fleet of production facilities designed and built before the dawn of the internet, with limited communications infrastructure, embracing the likes of Big Data and the Internet of Things (IoT) can be a challenge.

The industry already has a significant amount of instrumentation and more data than some say they can cope with. The challenge has been around gaps in connectivity, connecting devices, and dealing with the data generated.

Fiber optics have taken the industry a huge step forward, while 4G LTE cellular networks are expanding wireless communications capabilities offshore. The next step to enabling an offshore IoT is plugging the gaps, with the likes of newer networks, such as LoRa wide area networks (WAN), offering possible solutions.

This infrastructure would help realize the world in which equipment can communicate. It would also allow technicians out on the plant to talk to onshore experts via the likes of live augmented reality video links.

This world is coming. In a trial offshore the Netherlands, an onshore surveyor was able to verify an inspection offshore via a 4G data link. BP is fitting out its latest North Sea developments, Clair Ridge and Quad 204 (the Schiehallion/Loyal redevelopment) with the latest technologies, including wireless networks across both facilities, as well as trying to future proof them (See page 48).

IoT and its possibilities for the offshore industry were discussed at a joint Censis and Oil & Gas Innovation Centre (OGIC) event, "IoT goes Offshore," in



Aberdeen early October.

“It’s the start of a disruption that is set to be as big as the internet in the 1990s,” says Mark Begbie, business development director, Censis, an industry-led Innovation Centre for Sensor and Imaging Systems, who says perhaps in the past it would have been called telematics, or machine-to-machine communication.

**OT phone home**

The backbone of this revolution is communication infrastructure. For the past 17 years, Tampnet has been connecting fixed facilities with fiber optic cables, laid out throughout across the North Sea. In the UK North Sea, there’s 26,500km of this fiber alone, giving 240 facilities in the UK, Norwegian and Danish North Sea a fast data link to onshore. In 2013, with the introduction of 4G LTE in the Tampnet network, low latency, high capacity communications were extended to were then introduced to mobile assets.

LTE (Long Term Evolution) is a standard for high-speed wireless communications for mobile devices using the likes of GSM (Global System for Mobile Communications, a second-generation digital cellular network).

Tampnet is building its coverage through placing base stations on facilities around the North Sea, using the existing network as a backhaul to onshore.

“Using existing infrastructure, we [have] deployed 4G LTE base stations covering a similar area to 75% of the UK,” says John Main, sales manager for Tampnet. “Installing our base station on a 100m tower can give 40-50-60km range,” enabling coverage for mobile assets in those areas. He says 28 base stations have been installed, most recently on Talisman Repsol Sinopec UK’s Clyde platform in the UK North Sea. Another will be installed before year-end, with a further 9-10 due to be installed next year. This coverage has provided an alternative to VSAT (very small aperture terminal – a satellite communications system), with reduced latency from 600 milliseconds (ms) down to 40ms, and increased bandwidth connectivity speed: testing the system on a new facility, staff were able Skype home to family using a 4G hotspot created on a vessel’s bridge.

In November, the firm won a contract to operate the offshore communications



Tampnet’s 4G LTE coverage, as at the end of 2017. Image from Tampnet.



Tampnet’s North Sea fiber network Image from Tampnet.

networks in the Dutch North Sea, which will include tying the area in to the existing subsea fiber network and merging the LTE network into the wider basin.

**Looking in**

However, says Main, 4G LTE doesn’t just have to be used for communication between facilities or to shore. Pointing

a single 4G LTE antenna into a facility could cover 85% to 100% of the platform for mobile devices, Main says. This could enable an operator to video conference with an onshore subject matter expert on the spot. Tampnet has 24 projects in the pipeline involving internal-focused antenna, Main says.

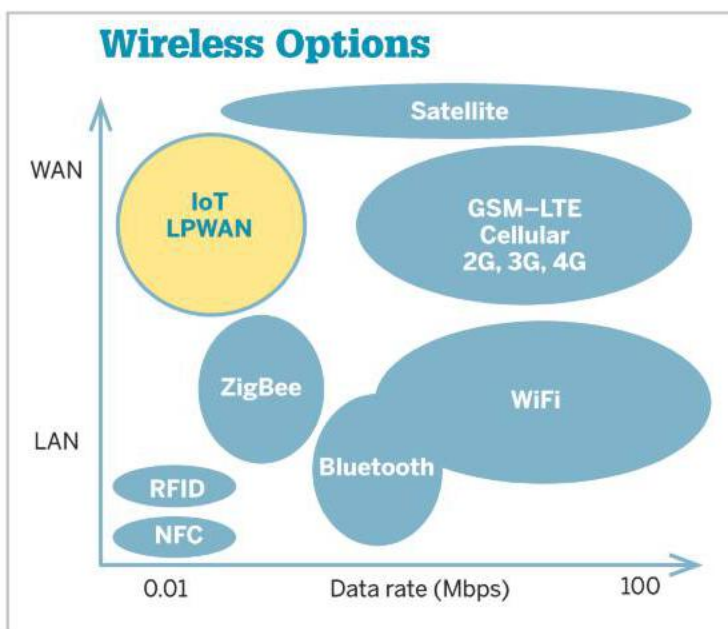
For IoT, where thousands of sensors might be connected to a network, most



of which don't need to send huge amounts of data, especially if they're smart or use edge analytics (i.e. process at site and only send what they need to), network capability doesn't have to be so high.

Øyvind Skjervik, Tampnet's chief architect, says the firm is looking into NB-IoT (narrowband internet of things) and CAT-M1, a narrow band, low frequency, IoT-friendly version of LTE. While LTE has a high bandwidth, working at 20MHz with 240 megabits per second (mbps), CAT-M1 works at 1.4MHz

with 1mbps and NB-IoT at 180kHz with 60kbps bandwidth. It can reach areas conventional LTE cannot and, because it requires less power than LTE, a NB-IoT device can operate up to 10 years on a battery, making the technology ideal for sensors. Cat-M1 will be used where extended coverage is needed to connect devices relying on more bandwidth consuming, always on, applications like voice and video CAT-M1 connected devices to do their thing for longer. Such technology is being used to monitor shipping containers, with the signal able to go through 4-10 layers of containers in a shipping hold, Begbie says.



Wireless options. Image from Censis.

"There's a lot of gathering of information today. IoT brings in a new era," says Skjervik – sending what's needed. Sensors can be low cost with a long battery life and with "extreme" network coverage. Tampnet hopes to run a pilot next year.

**LoRa**

Low power wide area networks (LP-WAN) such as LoRaWAN are offering something similar. They have a long range, i.e. 3km in an urban environment or 10km in rural environment, equating to 12.5sq km. LoRa is a type of radio modulation technology using

license-free radio frequency bands, with a protocol.

For more local applications, there's also near field communications (used for contactless payments), radio frequency identification (used for tracking parcels in warehouses etc.), and bluetooth, among others. "LP-WAN is the new kid on the block," says Graham Kerr, technical director at Censis. "It has a high-range, low-rate data rate, which doesn't matter so much for IoT."

Cults Telecom Services has been developing an LP-WAN network as part of a trial within Aberdeen. But, the firm also worked with the Oil & Gas Technology

Centre and Rowan Drilling to see how an LP-WAN network would perform on a drilling rig. The firm set up a network on the Rowan Gorilla VI jackup, with a base station positioned on top of the radio room. The rig was in the Port of Dundee at the time and the trial a success, including covering below deck and over the water by the rig, says Tim Everitt, of Cults Telecom.

Big data, digitalization, and IoT have become this decade's buzz words. Slowly but surely, they're also actually starting to shape and become more than just words in the offshore oil and gas industry. **OE**

**Wireless explainer**

Andrew Stirling, managing director, Larkhill Consultancy

4G stands for Fourth Generation mobile network technology – designed for delivering efficient broadband access to people on the move, usually via mobile devices. Sometimes referred to as cellular networks (especially in the US), these networks cover an entire region or country using a network of base stations. Each base station provides coverage within a range of up to 20km – more typically 10km. The area covered is referred to as a cell. The operators typically use licensed radio frequency bands, to protect against interference from other spectrum users.

While the term 4G could embrace a family of different technologies\* with the

same broad capabilities, it has become synonymous with a technology called LTE (Long Term Evolution), with the name implying that the technology is capable of much further development in the future. Indeed, LTE Advanced networks can deliver many hundreds of megabits per second.

Fifth-Generation (5G) networks are now in development, with the aim of meeting a wider range of connectivity requirements than 4G, ranging from Gigabits per second for ultrafast Internet access – to the lower performance but more robust data transmission often required for Internet of Things applications.

There are also new narrowband low-power, wide area networking (LPWAN) standards appearing. One of these is LoRaWAN (Long Range low power WAN),

which uses license exempt frequencies and is cheap to integrate into devices. It is also inexpensive to provide coverage, wherever the end-users choose to deploy the equipment. Another proprietary standard is promoted by SigFox, and its local distributors, whose business model is that of an operator – providing coverage and then charging for usage. In this case, end-users depend on the operators deciding to deploy in their locations.

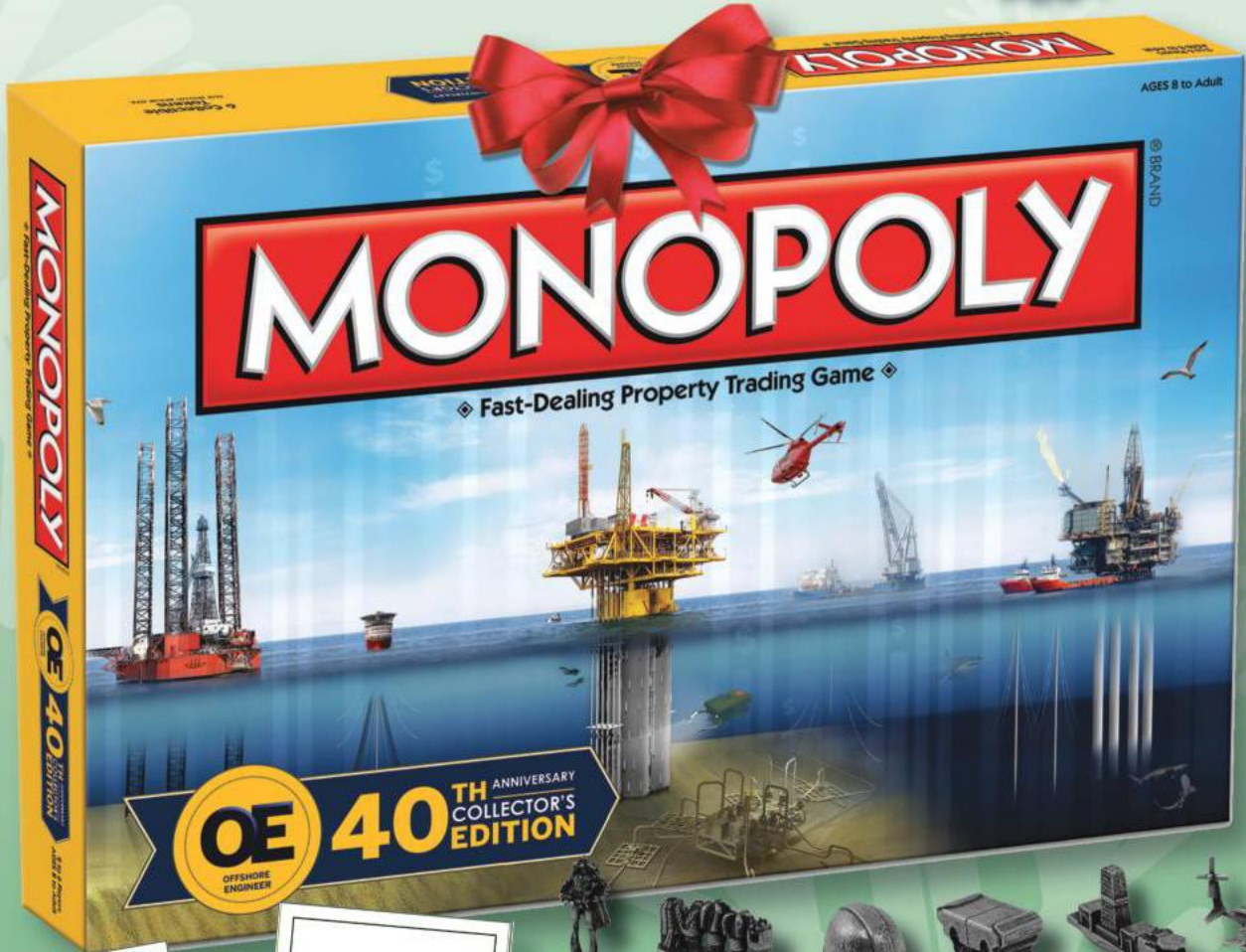
If you want Gigabit connectivity today, then the answer is provided by the latest Wi-Fi standard (IEEE 802.11ac) [with its successor 802.11ax offering even greater performance]. ■

\*Other technologies such as WiMAX appeared on the world stage for a few years, positioned as 4G, but have since fallen away to leave LTE virtually unchallenged.



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# Installing a wireless hart

**When design-to-first-oil takes 10 years, keeping up with communication technology can be a challenge. Elaine Maslin details what BP has done for its latest North Sea projects.**

**W**ith new technologies appearing all the time, it's a job to keep up. BP's Steve Cottam is doing his best to do just that, however. Cottam is Clair Ridge project lead, instrument and control engineer for BP. Clair Ridge is the second phase of the Clair field, with first oil planned for early summer 2018, via a new fixed facility able to produce some 120,000 b/d.

The facility has been designed for a 40-year life and BP wants it to be in the top quartile for production efficiency, Cottam says. Part of the plan is connectivity and the same plan has been applied to the new *Glen Lyon* floating production (FPSO) vessel, BP's replacement for the *Schiehallion* FPSO, as part

of its Quad 204 redevelopment. *Glen Lyon* came onstream in May 2017 with 100,000 b/d production planned.

Design work on these projects started in 2008, the year the iPhone 3G came out, Cottam says. It's nearly 10 years from design work starting to first production, and the plan is to make it work for 40 years – that's the challenge.

Both Clair Ridge and *Glen Lyon* are fiber-connected with wireless infrastructure on board. All the instrumentation is smart, with some 50,000 data points on Clair Ridge, and more on *Glen Lyon*, Cottam says. The data is sent onshore for long-term historization. Onshore, there is also a full facility operator training simulator with dynamic simulation, and a 3D PDMS model.

Offshore, the wireless infrastructure is based on hazardous and non-hazardous areas, with an instrumentation level WirelessHart, linking into process control systems, and a second separate wireless network. WirelessHART is wireless based on the Highway Addressable Remote Transducer

**BP's Clair Ridge facilities, during installation in 2015.** Photos from BP.

Protocol (HART), which was developed as a multi-vendor, interoperable wireless standard, enabling secure, remote access for vendors to support their equipment. "This is huge for our drilling vendors," says Cottam, who was speaking at the Censis and Oil & Gas Innovation Centre joint event, Internet of Things goes Offshore, in Aberdeen early October.

On Clair Ridge, there are 125 wireless internet gateways across the plant, with good wireless coverage across the facility, Cottam says. This means staff out on the plant can connect on the spot with an advanced collaborative environment (ACE) at office, but also to experts – where ever they might be. "This is now standard for BP," Cottam says. With the advent of 4G LTE, which could also be used for connectivity within the platform, there now further options, Cottam suggests.

Enabling this world isn't just about hardware, however, Cottam says. As well as the ACE, there's a functional support





BP's *Glen Lyon* FPSO, west of Shetland.

and not symptoms, as previously."

Having the network on older facilities means wireless instrumentation can be deployed, such as wireless corrosion instrumentation, which can be clamped or glued on existing facilities, he says.

organization, standard maintenance procedures, an onshore team monitoring plant and maintenance performance, dashboards, KPIs, trending, online engineering calculations, etc.

As well as applying these technologies to its latest facilities, BP is looking at installing wireless networks on existing facilities, including its oldest. "We need to move from reactive to predictive, onshore and offshore," says Cottam, from automated analysis of heater exchangers, predicting failure, to comparison of rotating equipment performance across assets – "focusing on the problem

Looking ahead, event monitoring, and early warnings can be enabled and then the knowledge captured and shared, he says. As this revolution kicks in, BP will be looking to incorporate more use of ATEX approved portable devices offshore, for inspections, material tracking, all improving "wrench time," as well as non-intrusive, quick deploy wireless instrumentation. Tracking personal outside the cabins would also help account for staff in the event of a muster event, instead of having to search for someone across the plant (when it can take 20 minutes just to walk from the control

room to the furthest part of the plant).

Such a world could prove problematic for staff – who would have to carry PDAs, a gas detector, tough book, radio, tools, etc. Instead, Cottam suggests that workforce clothing could incorporate much of these devices, i.e. introduce wearables. The gas detector would be incorporated in the suit, radio in the helmet, etc.

But, it would also enable the likes of augmented video conferencing out on the plant, where an onshore expert can draw over the field technician's field of view or show them a step by step procedure.

Meanwhile low-power, low-cost smart sensing feeds cloud analytics, which support cognitive automated alerts. Onshore staff will be able to access interactive 3D models, containing process data, P&IDs and maintenance routines, all in one place.

But, Cottam warns, there are "soft issues," such as staff use of social media during an incident, or use of non-certified devices, if a mobile network is in range of plant, and offshore work force buy-in. "We used to design these facilities on paper," he reflects. **OE**



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# Virtual independent verification

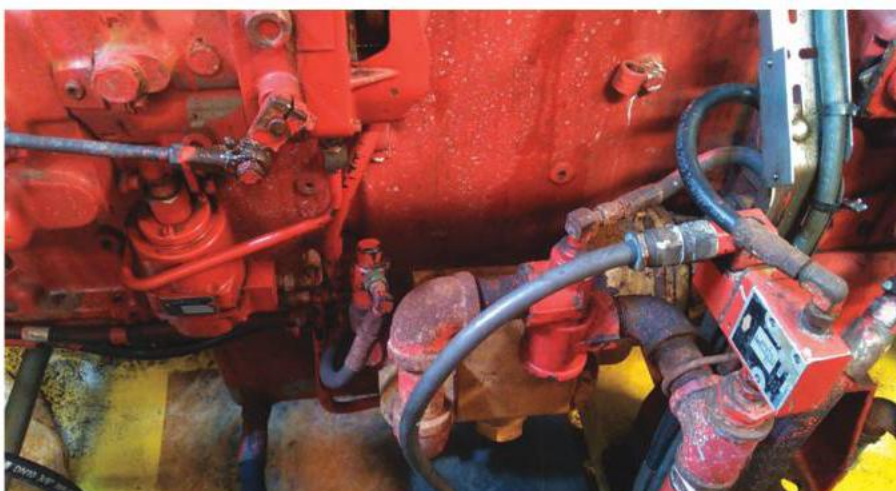
Elaine Maslin reports on how 4G connectivity has helped connect independent surveyors onshore verify procedures offshore – via live video link – to save time, money and reduce HSE risk.

**W**ireless networks on offshore platforms could make much lighter work of independent verification body (IVB) services, says Pieter Verhoeven, senior consultant, DNV GL. And, the theory has been proven. Working with NAM (a Shell/Exxon joint venture), then Wintershall, DNV GL performed two IVB pilots onshore and then offshore, where the DNV GL surveyor was based onshore in Esbjerg, Denmark, while the operation being verified was in the Netherlands. Normally, the surveyor would have to go offshore to witness the procedure.

Verhoeven, who was speaking at the Offshore Energy conference in Amsterdam, said that there are challenges to IVB today. There's a significant amount of non-productive time, from travel to waiting on weather, etc. There's also limited availability of competent staff with offshore certificates and, of course, the safety risks associated with sending people offshore in helicopters and also working offshore.

Henk van Nieuwpoort, senior maintenance and integrity engineer at NAM, says the firm has some 300 sites on- and offshore, with some 180,000 safety critical elements (SCE), resulting in at least 10,000 SCE assurance tasks a year.

The firm is working to implement the new EU Offshore Safety Directive and NOGEPa (the Dutch regulator) standards, using third party independent verification. The challenges include the geographic spread of assets, planning, i.e. aligning IVB engineers' availability with the execution of assurance tasks.



Images taken via the media during the pilots. Photo from DNV GL.

Development in video and audio technology and wireless data connections could avoid all these issues, Verhoeven says, although there still needs to be better connectivity, and improved data analytics and document mining would help further. The two pilots saw the surveyor stay in an office and the offshore technician, employed by the operator, wear a camera.

First, an onshore pilot – on an actual IVB – was done with NAM at a gas production facility, with the technician connected wirelessly using a 3G network to Shell's office and the DNV GL office. The second pilot was offshore,

using 4G, and “more or less real IVB.”

“We did a normal inspection, but with the surveyor in Denmark and people in NAM's office witnessing the whole procedure,” Verhoeven says. It was an IVB on fire water pumps using a handheld camera and guided by DNV GL surveyor in Denmark.

The final pilot was with Wintershall on the L8-P7 platform in the Dutch North Sea. There was no 3G network, so DNV GL worked with Dutch firm Rolloos to set up a 4G signal. The surveyor was based in in Esbjerg and the IVB was carried out as expected with high quality picture. The surveyor and



the technician were also able to communicate by drawing on a screen both could see.

However, there's another way. Nieuwpoort says, having questioned how to do IVB better, NAM did a further pilot. After the project streaming over 3G, the firm decided to record the task to be verified, so that it could then be sent for witnessing.

"The positive for streaming is that it's real-time and the IVB witness is looking directly over his [the technician's] shoulder and can direct him," Nieuwpoort says. "You can bring a specialist in at anytime, anyplace, anywhere [subject to having a data link]."

"Recording is very efficient and you don't have to worry about planning and it's independent of connectivity," Nieuwpoort adds. "Availability of connectivity is something we're very reliant on and it's not very robust. Equipment has to be ATEX and there is the human factor – there's someone looking over their shoulder."

Nieuwpoort says, for the time being, due to the limitations with connectivity offshore, NAM has set itself up to make recording of IVBs available, making



In a more traditional world, the surveyor onboard.

them "independent of connectivity and for us an appropriate way to verify routine tasks: send it to the beach and then [they surveyor] can then do the verification at any time."

"The technology is available and it can

reduce costs and increase safety and help us utilize our surveyors," Verhoeven says. "There is greater availability of them this way. The connectivity is still a challenge, especially offshore, but also the human factor and camera mounts." **OE**

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# To the moon and back

**BHGE's Tom Thissen explains why automation is drilling's biggest milestone.**

It's amazing to think that the first offshore well was drilled in 1947, 17km off the Louisiana coast in the Gulf of Mexico. The platform of the drilling rig was no larger than a tennis court, and several refurbished naval barges from World War II provided storage spaces and a living area for the crew. Looking back, it is easy to see why drilling oil and gas wells had been considered an art form by the industry. The pioneering spirit needed to venture 17km off the coast and look for oil required an element of luck and circumstance that would not be acceptable in today's data-driven world. Industry 4.0 has led to an increase in automation and data exchange in manufacturing and operations that cannot be ignored. This, coupled with the burgeoning pressure to safely reduce the cost per barrel, has meant that the oil and gas industry has begun to approach drilling as a science rather than an art.

In the 70 years since this historic first offshore well, the oil and gas industry has been forced to gain a better understanding of reservoirs to determine where to drill and how to place the wellbore and how to navigate efficiently to the sweet spot and stay there – thus optimizing the entire drilling process, not just penetration rate. Since then, we have seen many significant milestones.

One of the earliest innovations to improve oil drilling was the rotary drill, first used in the 1880s. It used a rotating drill bit to continuously break the rock to create the wellbore, and was a stark improvement over the previously-used method of cable-tool drilling that lifted and dropped a drill bit, creating the wellbore through intermittent impacts.

With news reports that oil flows on Saturn's moons, and the US National Aeronautics and Space Administration (NASA) looking to drill on Mars in 2018, there are surely many more milestones to come. However, at Baker Hughes, a GE company (BHGE), no milestone has been more significant for the future of drilling than automation.



## It's all in the history

In one form or another, automation has been around since the mid-1700s, when an English blacksmith filed a patent for an automated system to keep windmills properly oriented for maximum power. The concept quickly caught on as people realized that automation helped solve challenges of consistency and efficiency, and it grew to be a key driver of the first industrial revolution. Automation isn't new to the drilling process, either; auto-drillers and surface stick-slip mitigation systems have been around for a long time.

Digital equipment automation, however, is relatively new, and drilling process automation is very new. The first applications of digital automation in drilling were focused on helping access reservoirs that we couldn't reach

before. Today, it is helping us efficiently access much more of the reservoir than before – with limited downtime and much more targeted drilling.

In 1987, about 500km from Celle, in Windischeschenbach, Bavaria, the German government was looking at ways to keep a deep wellbore straight. This project led to the development of an automated drilling system, which was later commercialized as the Baker Hughes VertiTrak vertical drilling rod. It used pads on the side of the drilling assembly to correct every deviation from 0° inclination. It is impressive to note that 30 years later, the well that the system drilled is still one of the world's deepest wells – 9101m, deeper than Mt Everest is tall. The first 7458m were drilled with the automated system, with a deviation



of only 12m. The remaining 1524m were drilled conventionally, with a deviation of 286m. Despite being a simple goal, the results spoke for themselves, and the VertiTrak project was a massive milestone for drilling automation.

With successful automation underway, the next challenge for the industry was how to bring in additional data



Photo from iStock

points. The industry wanted to be able to control not just inclination, but also angle, the horizontal angle or direction of a compass bearing, and to be able to rotate while continually steering. The Baker Hughes AutoTrak rotary steerable system (RSS), introduced in 1997, accomplished this. The well could be steered while rotating at all times, and inclination could be achieved and held automatically through closed-loop control, while hydraulic steering ribs in a non-rotating sleeve were used to adjust azimuth and inclination. This has formed the enabling technology for today's complex wells.

#### Automated drilling today

Today, accessing more of the reservoir, particularly in tight oil and gas plays,

means drilling long laterals and staying in narrow windows for greater distances. The complexity of wells that we can drill has increased tremendously over the last couple of decades, and often it is one innovative breakthrough that leads to another. The AutoTrak RSS led the way for technology such as AutoTrak Curve RSS, which has enabled high-build-rate horizontal drilling, reducing time on location and exposing more of the reservoir per well. Automation now enables the control of complex profiles by mitigating risk, such as steering risk and wellbore collision, while allowing operators to control and predict cost.

The highest degree of automation is in downhole autonomous or semi-autonomous drilling systems, such as rotary steerable systems, which compare favorably with anything developed in any industry, especially considering the operating environment of high pressure, high temperature and high vibration. In terms of human and computer monitoring, advanced wellsite-based and remote systems are readily available and are being used daily. There has been significant progress in computer-based advisory systems that interpret data downhole and transmit compressed diagnostics to surface. Directional drilling applications – geosteering, for example – are often executed remotely or at the wellsite.

However, while automated drilling systems deliver many productivity, economic and safety benefits, the entire process is not yet automated, and efficiency and cost improvements are incremental and fragmented. The ultimate goal is to automate the entire drilling process.

#### BHGE, drilling past, present and future

The combined expertise of Baker Hughes and GE Oil and Gas and the reliability, performance and outcomes benefits of the new Baker Hughes, a GE company were realized recently on a drilling project in the North Sea. Micro-geosteering was used with look-ahead seismic-while-drilling in a digital downhole assembly with dual digital reamers. The system – operated with high-speed digital connectivity – provided a cumulative extra 1000m of pay over four wells, which resulted in an increase of reservoir sand from an

expected 67% to 81%. With an average reservoir section of 1600m in the four wells, this represents a drilling productivity increase of 40% and illustrates the impact of digital technologies on drilling productivity.

But why stop there? BHGE is building a data aggregation server for the wellsite. This system combines data from the rig, surface logging systems and downhole tools and is built with an open architecture and protocol, ensuring that third-party companies can add or extract data in a secure manner. This server is the platform of BHGE's drilling automation service that is currently under development and in field testing. It will form the basis of our automation service, which will allow us to implement many digital products developed by BHGE. Among these is a new automation platform, which is in early field deployment. These servers enable the automation of drilling systems at the wellsite.

#### Drilling in the future

From rigs made with refurbished naval submarines, to platforms of 200,000 tons, to being able to drive productivity increases of 40% through automation, there have been many notable milestones in the drilling industry. BHGE is constantly looking to create new milestones and invent smarter ways to drill wells that will safely reduce the cost per barrel in a price environment that is not only lower for longer, but may be lower forever. **OE**



*Tom Thissen is president of Drilling Services, BHGE, based in Celle, Germany. Prior to his current position, he was the president of Baker Hughes'*

*Africa region for four years. Since joining Baker Hughes in 1990, Tom has been the vice president of Drilling Fluids for the Europe, Africa, Russia, and Caspian region, and he has held a number of management and operations positions in Caspian, Central Europe, Nigeria, Kazakhstan and Oman. A member of the Society of Petroleum Engineers, Tom holds a bachelor of science degree in drilling & production technology from the Hogeschool of Amsterdam in The Netherlands.*



## Year in Review

# Making plans

**UK operators have gone a long way to reducing their costs and are even starting to look at investment, delegates attending the Oil & Gas UK Share Fair Aberdeen Share Fair in Aberdeen early November learned. Elaine Maslin reports.**

**M**ost in the oil industry are keen to start hearing some good news, ideally in the form of new contracts and investment.

While it may not have been an announcement about a major new project, a comment by Apache's supply chain manager Stephen Duncalf at the Share Fair was enough to keep those in attendance alert.

"In the Beryl area, there are so many potential barrels that it could potentially be one of the last producing assets in the

North Sea," Duncalf told the event. Given that the Beryl facilities are one of the older facilities in the UK North Sea (Beryl came on stream in 1976 and was bought by Apache from ExxonMobil in

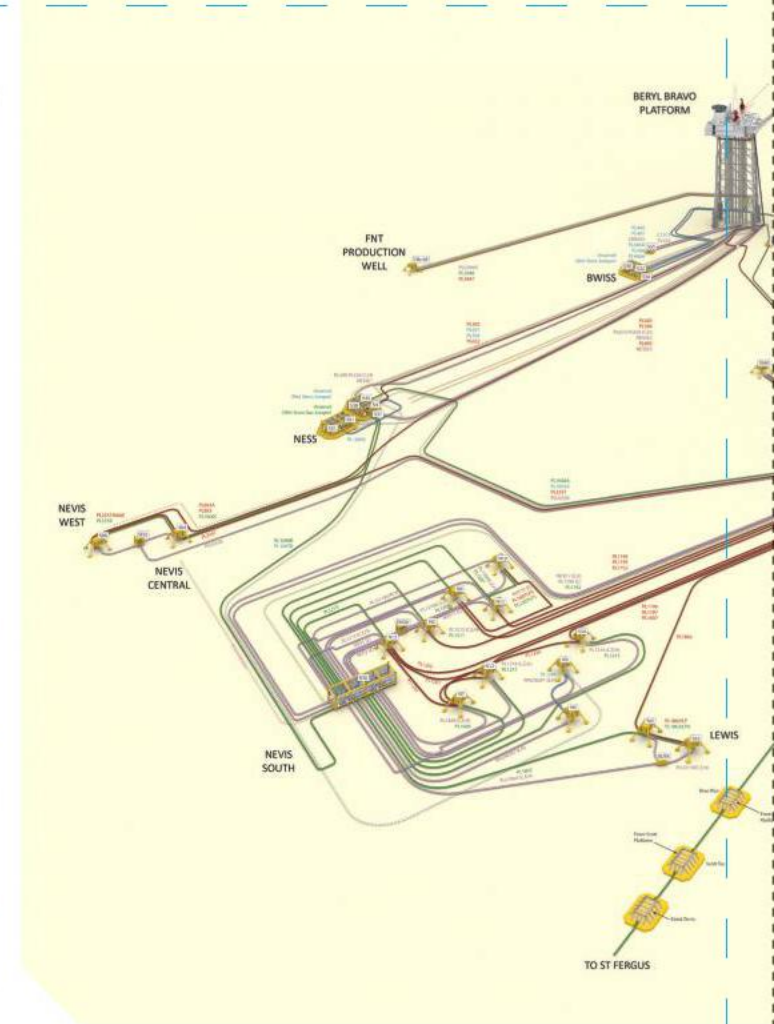
## In brief

- Nexen planning 2000m water depth exploration well offshore Ireland in 2019
- Beryl area to be one of last producing fields in the UK North Sea
- Apache plans one subsea tieback a year
- EnQuest drills world's longest Optipac gravel pack

2011) and that new projects are still coming online and indeed are yet to be developed, it's a bold statement.

Behind the comment, and others' comments at the Share Fair, is a focus on low operating costs. Apache, since its entry to the North Sea in 2003, acquiring the Forties field assets (also from the 1970s) from BP, has kept its costs low. Faced with the low oil prices, having gotten used to a US\$100/bbl world, many others are following suit.

Apache's operating costs put it seventh out of 26 in Oil and



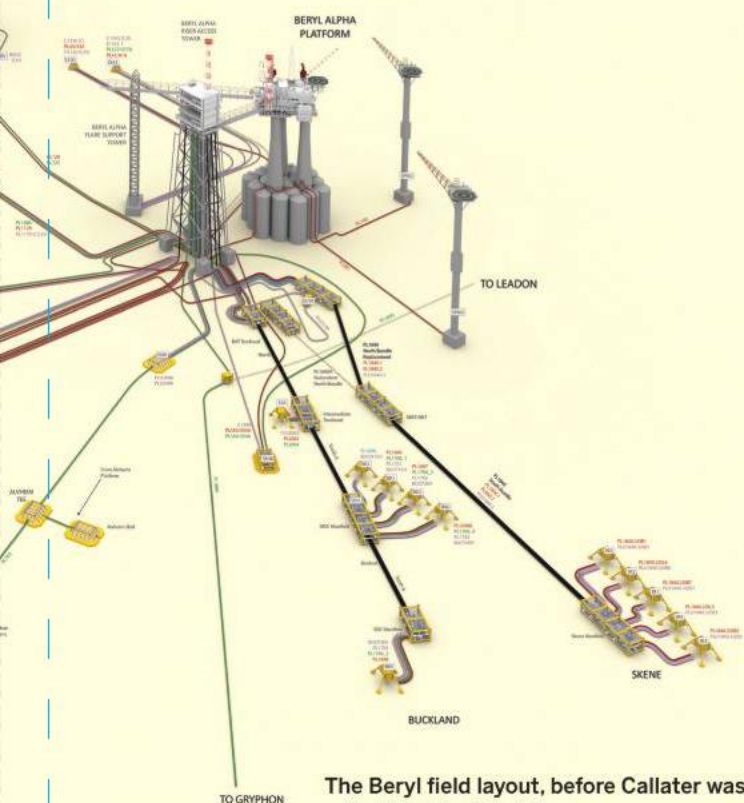
Gas Authority rankings (pitting it against far newer facilities with higher daily production levels). Nexen, which also presented at the event, and is a company with newer facilities such as Buzzard and Golden Eagle, lays claim to the lowest lifting costs in the basin, at \$6/boe – down from \$10/boe last year.

Not all have been performing so well, but some have still improved in recent years. Repsol Sinopec Resources UK, again, also presenting at the Share Fair, meanwhile says it has reduced its lifting costs from \$116/boe to \$37/boe, showing the amount of work some operators have had to do to become near profitable.

Production efficiency (PE) is also a key metric of how well firms are operating. Apache's, by hub, is 95.2%, compared to a basin-wide average at 73% (up from just 60% a couple of years ago), edging close to the top of the performance rankings. Repsol has managed to increase its PE from 33% to 66% in the past couple of years (HSE performance has also improved – something likely linked), a Repsol presenter told the event. A lot of this has been about increasing production – the firm saw its lowest production levels in 2014, in what looked like a terminal decline curve. But, in 2017, it expects to achieve the same production levels as it had in 2012 – while having also ceased production on its Saltire, Beatrice and Buchan assets in the intervening period. Part of Repsol's focus has been working with more contractors – it has increased the number of tier one contractors it works with from eight to 27.

Having low operating costs and high production efficiency





The Beryl field layout, before Callater was tied back to Beryl Bravo. Image from Apache.

is not just about enabling profitability, however. A key driver for many of these firms is pushing forward decommissioning. It's also about making the business competitive compared to other parts of their respective global businesses – if they're not competitive, the group will not invest. "We're returns focused, not production focused," Duncalf says. It's about holding production flat, maintaining opex/bbl, extending asset life and delaying decommissioning, he says. A representative from Nexen also said: "The key challenge is pushing out the cessation of production date as far as possible and globally we need to compete with capital."

Apache, Nexen and Repsol, alongside EnQuest, presented some of their investment plans at the Share Fair. *OE* takes a look at each below.

### Nexen

Nexen is in the define stage of its Buzzard Phase II project. The proposal is an 11-slot combined production and water injection manifold at a new drill center tied back about 5km to the Buzzard facilities.

Detailed design for the subsea infrastructure and topsides modifications is running from Q4 2017 to Q1 2018, led by Aker Solutions. Contracts to be agreed include a semisubmersible for drilling and the subsea EPIC contract.

Nexen is also working on a water injection project. Water injection facilities were installed 1993 on the Scott development. Water injection

is by three water injection clusters east, south and west of the Scott platform. Nexen wants to replace about 10km of pipelines and umbilicals in the system. It's at the select phase. Design considerations on the project include how much umbilical and pipeline to replace. A decision is due to be taken, and Nexen expects to go to the market in Q1-2 2018, with an installation date still under review.

Meanwhile, the firm is drilling the ST37 infill well on Scott and it has a future infill drilling program there. It also has a Telford infill program, eyeing three prospects (Dunkeld, Rossini, and Comet) and one lead, Daffodil, and considering tiebacks, with two discoveries already made, Ravel and Bugle South, which will go through a stage gate process.

It will have semisubmersible drilling rig requirements for infill drilling on Golden Eagle. It was nearing an award for a semisubmersible for plugging and abandonment drilling on Ettrick and Blackbird, and an invitation to tender has been issued for Buzzard Phase II drilling.

Nexen will use the CJ18 jackup on Blackbird to drill a well on the Glengorm high pressure, high temperature (HPHT) prospect in 2018. Maersk Drilling was awarded a contract for three wells, plus options, for drilling over the Buzzard platform, starting July 2018.

Nexen is currently drilling a well at Craster, west of Shetland. The firm also is planning an exploration well in license LO 16-7 in the Porcupine Basin about 215km offshore Ireland, in about 2000m water depth, in summer 2019, with a drillship, following its success in the 2015 Irish Atlantic Margin Licensing Round. Drilling is expected to take 90-120 days, with four license options.

Project challenges over the last year include intelligent pigging, tool reliability challenges such as being stuck, and related operational risks. These challenges also include obsolescence and sustainability related to subsea systems, controls and pipelines for existing assets and infrastructure life extension.

### Apache

Apache is targeting one subsea tieback per year, Duncalf says. Its latest tieback, the Callater tieback to the Beryl Alpha



Nexen's Golden Eagle platform. Image from Nexen.



# Year in Review



The Kraken FPSO, onstream since June this year. Image from EnQuest.

platform came on stream in May 2017, following the FNT tieback (OE: February 2017) to the Beryl Bravo platform in 2016. Corona is likely to be next, via two subsea wells with hydraulic submersible pumps, with Storr following that. “Any future investments will be infrastructure-led,” says Duncalf says.

Since Corona is a heavy oil field this presents a potential challenge relating to comingling fluids, says Duncalf, due to the Beryl Alpha facilities, to which it will be tied, being designed to produce light crude. Challenges will include ways to stop the crude separating out in the concrete storage cells beneath Beryl Alpha. Apache is in the process of submitting a field development plan for Corona and expects first production at the end of 2019.

The firm is operating two platform rigs and one semisubmersible and says there’s potential to add more. 4D seismic acquisition has helped the firm develop targets, although the firm must assess these carefully as it’s slot-constrained on its assets, Duncalf says. “Long-term, the focus is on having drillable targets and focusing on one constant platform drilling string, so we have to be prudent with reservoir management,” he says. Water injection and slot reuse will be part of that.

The firm will be looking for normally pressure or HPHT pipe-in-pipe solutions, or bundles, gas lift, ESPs (electric submersible pumps), HSPs (hydraulic submersible pumps), etc., as well as alternative contracting and commercial models. It’s also looking for solutions to help either extend the life of the single point moorings (SPM) in the Beryl field or replace one of them. Crude is stored in the Beryl platform’s concrete cells and offloaded to tankers via SPM 2, with

SPM 3 acting as a backup.

“Maintaining them is a challenge we have had for several years now,” Duncalf says. “There’s a challenge of accessibility, and being able to maintain and inspect them appropriately throughout the year. We’re looking for smarter solutions for maintenance and inspection, also possible alternatives so we could perhaps remove at least one of them.”

## EnQuest

North Sea independent EnQuest has been growing. The firm, which estimates 37,000 boe/d production for 2017, increasing to 50,000 boe/d

by 1H 2018, brought the Alma/Galia development on stream earlier this year, followed by the Kraken heavy oil field, a floating production project, which will continue ramping up into 2018. It also purchased the Magnus asset from BP, giving it 215 MMboe 2P reserves plus 150 MMboe contingent resources to work on.

To date, 38mi of hole has been drilled on Kraken, a spokesperson for EnQuest said. The field is now home to the world’s longest OptiPac (alternate path) gravel pack, at 4347ft, completed in June 2017. The drilling program is 288 days ahead of April 2014 pre-drill estimates, EnQuest says. Some of this has been due to batch drilling, using video footage of operations to train staff before they go offshore, and cost reduction through supply chain management and drilling performance. All top holes have been drilled with riserless mud recovery, enabling 45-degree angles in the tophole section, cutting 45ft off the length of each well, reducing casing string requirements.

Once EnQuest gets its hands on Magnus, the firm is planning to drill three wells. Other projects the firm is working on include optimizing the Scolty Crathes tiebacks with a new pipeline and chemical treatments in 2019. EnQuest is targeting its Eagle development planning, looking at subsea electrical subsea pump workovers on Alma/Galia, continuing scale squeeze work on Kittiwake and the Dons, and performing plugging and abandonment work on Thistle and Heather, which will help open space for a new Heather development well. EnQuest is planning ESP workovers on Thistle, possibly using coiled tubing. The Dunlin bypass is due to be awarded (with a view to 2019 execution), as well as the Thistle gas compressor project. **OE**



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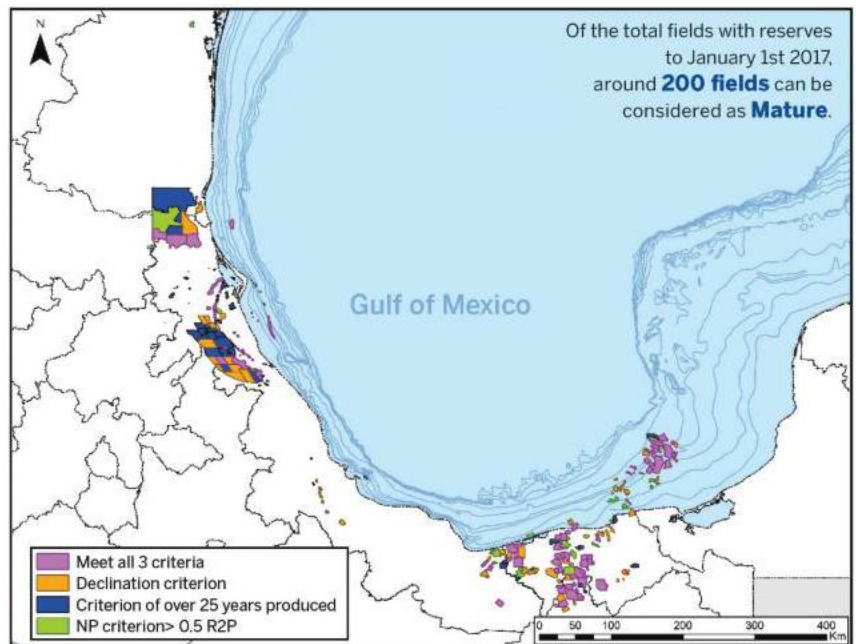
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## Year in Review

# Opportunities in Mexican mature fields

**Gaspar Franco Hernández, of CNH, discusses the abundant opportunity to develop Mexico's over 200 mature fields.**



Map of Mexico's mature fields. Image from CNH.

There are several definitions of mature fields, which are based on different criteria of the production degree that the oil field presents, all definitions refer to those with additional hydrocarbon recovery potential, through the implementation of geoscience technologies, oil engineering and many other disciplines applicable at reservoir, well and facility level.

Some ways to define a field as mature are the following:

- 1.  $N_p \geq 0.5 R_{2P}$ .** When the accumulated field production is equal or greater than 50% of the original 2P reserves, it is considered as mature.
- 2. Production  $\geq 25$  years.** When a field has been producing for 25 years or more, it can be considered as mature because, despite not having produced half or more of the 2P reserves, the useful life of the surface and sub-surface facilities may present the need for some new strategy.



**3. Declining Trend.** When observing the production history of the fields, those that have already passed their peak of production and tend to decline, are also considered as mature fields.

**4. Economic limit after primary and secondary recovery.**

When revenues from the sale of hydrocarbons equal the costs incurred in extracting them, it is said that the field has reached its economic limit. This definition, although accepted for mature fields, could be understood as marginal fields.

Some suppliers of information associated with the oil activity have their own definitions of a mature field:

**1. Wood Mackenzie:** Mature field is one with a Remaining Reserve  $\leq 33\%$ .

**2. DAKS IQ:** The Mature stage is the final period of initial production and is characterized by a relatively low production rate (with respect to peak) and a low rate of decline.

There is no standard or general definition of a mature field for the whole industry, a country or an oil company can classify a field as mature according to the considerations fitting its strategic objectives.

Based on information from the International Energy Agency and the US Energy Information Administration, the average global oil production in 2017 is 97.89 MMb/d (IEA) and 98.3 MMb/d (EIA), respectively; It is estimated that approximately 70% of world oil production comes from mature fields.

In the case of Mexico, by July 2017 oil production was 1.988 MMb/d and it was associated with around 200 fields in production, more than 90% of the producing fields are mature and contribute over 80% of national production. In addition, mature fields account for more than 60% of national 3P equivalent crude oil reserves. Additionally, in the world, the average final oil recovery factor is estimated to be 35%, while in Mexico it is estimated that the average final oil recovery factor is around 24%. To reach the international average of hydrocarbons recovery in the country's reservoirs would represent an increase of 11%, 7.415 billion bbl and almost double the proven reserves of the nation.

According to the Mexican Reserves to 1 January 2017, there are 39 offshore mature fields located in shallow waters within the Cuencas del Sureste basin:

### Offshore Mexican Mature Fields

Total Fields	39
Reserves 1P (MMbpce)	4,221.8
Reserves 2P (MMbpce)	6,335.6
Reserves 3P (MMbpce)	8,008.1
Recovery Factor (average)	28%

Of the 39 offshore mature fields, 36 are still in production and to July 2017 they report a production volume of 1.263 MMbo/d.

While the new hydrocarbon discoveries and the findings of greater potential in fields that are being evaluated will contribute to increasing Mexico's reserves and production, the potential of mature fields represents a great opportunity and is something that should be exploited through business models that involve the application of the optimal technology

combination that allows for cost reduction and optimization of hydrocarbon recovery.

Involvement in the extraction of hydrocarbons in mature fields has the disadvantages of dealing with the aging of the facilities and deciding on the allocation of investments to develop the remaining resources, however, they have the advantages of having a large amount of information, existing infrastructure, production is connected to a transport system, registration of the implementation of different methods, technologies and development strategies, greater knowledge of mature field reservoirs and in some cases, with feasibility studies of additional recovery methods or processes to rejuvenate the field.

Oil companies that wish to take advantage of the potential of mature fields in Mexico will have technical information that will allow them to make decisions for the implementation of best practices, as well as create scenarios for the implementation of secondary recovery technologies, enhanced recovery and advanced hydrocarbon recovery, according to the specific characteristics of the country's reservoirs and fields, to increase production and reduce costs.

Following the Energy Reform of 2013, Mexico offers new forms of participation and investment in the oil industry; the new energy model allows the competition of national and international oil companies, which individually or in consortium can access the opportunities offered by the hydrocarbons exploration and extraction sector.

Likewise, bids have been made for areas containing mature fields with adjacent zones that also allow exploration, increasing the technical-economic feasibility of projects in the short- and long-term, which in addition to producing immediately or almost immediately, will allow the identification and increase of hydrocarbon reserves and production.

It is clear that the volumes of hydrocarbons with less uncertainty are found in mature fields and, as happens worldwide, a great share of Mexico's production will come from this type of fields in the next few years, so the Mexican State will continue to generate the necessary conditions that make the implementation of projects proposed by the oil operators more efficient. **OE**



*Gaspar Franco Hernández is Commissioner for the National Hydrocarbons Commission in Mexico. He spent 14 years with Petroleos Mexicanos (Pemex) in many positions such as field engineer, well engineer, programming and evaluation coordinator at Cantrell, and Superintendent of Hydrocarbon Reserves and Production Projects in the Northeast Marine Region of Pemex Exploration and Production (PEP). He joined CNH as Deputy General Director for Production projects and has held several roles within CNH, eventually being elected Commissioner by the Mexican senate in April 2016. He holds a bachelor's degree in Petroleum Engineering from the National Autonomous University of Mexico (UNAM). In 2004, he earned his master's degree in Management Skills from the Autonomous University of Carmen (UNACAR).*



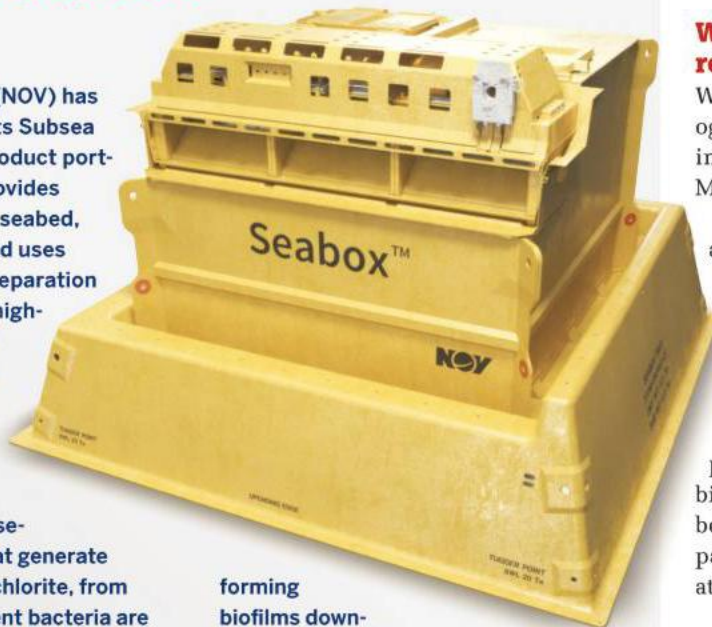
# Solutions

## NOV introduces Seabox

National Oilwell Varco (NOV) has introduced Seabox to its Subsea Production Systems product portfolio. Seabox, which provides water treatment at the seabed, has no moving parts and uses electrolysis and plate separation technology to provide high-quality subsea treated water without compromising safety, operability, or reliability.

Raw seawater enters Seabox through a grid of purpose-designed electrodes that generate oxidants, such as hypochlorite, from the seawater. The present bacteria are then subjected to the oxidants on its way through the parallel plates, which aid particle sedimentation, to a second treatment stage where powerful hydroxyl radicals are introduced. Hydroxyl radicals and other highly reactive oxidants are produced using a proprietary technology that use boron-doped diamond electrodes to alter the molecular structure of the organic matter present.

The result of this process is a thorough disinfection of the water, eliminating the possibility of bacteria proliferating and



forming biofilms down-hole or turning reservoirs sour. Microbial-induced corrosion downstream the equipment is also avoided.

Seabox is designed to be very flexible in all aspects. It is well suited as a distributed solution to be installed based on reservoir dynamics, providing the volume and type of water required for the specific reservoir. Seabox can also be used for pretreatment of existing process equipment on an FPSO/topside.

[www.nov.com](http://www.nov.com)

heads and drill stem testing (DST) tools for underbalanced perforating applications.

[www.exprogroup.com](http://www.exprogroup.com)

## Well-Centric releases milling tool

Well integrity and production technology solutions firm Well-Centric has introduced the Well-Centric Gate Valve Milling Tool (GVMT).

The GVMT is designed to provide access to restricted wells by drilling through stuck gate valves or other blockages. Originally developed as a solution to mill through stuck gate valves, the tool has further applications. Mill bits can be changed out for magnets, brushes or scrapers, providing additional clean-out capability. Additional drill rods can also be added to reach deeper into the well, past the Xmas tree, to mill obstructions at the tubing hanger.

The GVMT can be used both onshore and offshore, is modular in design, has a small footprint and extended stroke to reach deeper into the wellbore. Lubricators are not required to install drill rods, enabling more efficient rig-up and a reduced overall footprint.

With a powerful hydraulic motor and

## Expro launches TCP gun system



Expro released a new extreme high-pressure tubing conveyed perforating (TCP) gun system, which it says can deliver the largest perforation hole area available for frac and gravel pack completions.

Designed specifically for the

deepwater Gulf of Mexico environment, the Extreme Pressure Series 30,000psi TCP gun system uses super big hole charge technology, providing best-in-class area-open-to-flow (AOF) to support frac-and gravel-pack operations. Delivering 18-22 shots/ft using steel HMX charges, standard casing sizes of 7in through 7 3/4in, in combination with the 4 3/4 in outer diameter (OD) system, will achieve 6-7in AOF. However larger casing sizes of 9 5/8 through 10 3/4in, utilizing the 6 5/8in OD system, will deliver 13-15in AOF.

Developed with high performance gun system provider, GEODynamics, the system is complemented by Expro's fully rated dual hydraulic firing





safer operation, thanks to fewer exposed rotating parts, the GVMT means demanding jobs are completed quickly and efficiently, milling out a gate valve in under three hours. The tool is used in conjunction with relevant valves/pump-in subs to maintain well control, Well-Centric said.

[www.well-centric.co.uk](http://www.well-centric.co.uk)

### Hydratight compact connect wins DNV GL approval



Hydratight has won DNV GL Type Approval for the lightweight MORGRIP compact connector.

The connector, which is 80% lighter than traditional connectors, was developed as a viable alternative to welding and is suitable for 1-4in carbon steel pipelines.

The MORGRIP connector features metal graphite composite sealing to provide a chemically resistant, high temperature, high pressure seal that does not degrade in extreme environments. It provides a permanent, temporary and reusable mechanical repair solution on critical and non-critical pipeline systems.

[www.hydratight.com](http://www.hydratight.com)

### Huisman unveils ultra-deepwater fiber rope system

Huisman has developed a new system for the application of fiber rope in subsea deployment crane applications.

The system includes a Hybrid Fiber Rope System, which combines the advantages of fiber rope with subsea deployment, while the heave compensation is done with traditional steel wire rope systems.

Proper spooling of the fiber rope is done using Huisman's Traction Winch and Storage Winch setup, while AHC is done using a steel wire rope on a direct winch.

The system is available in various capacities. For traditional knuckle boom cranes, a 120-tonne and 200-tonne version is available, while the recently introduced Hybrid Boom Crane can be delivered with larger capacities of 400-tonne and 600-tonne. This could provide a step change in subsea



which has been active for over 10 years, has shown that the fiber rope with the best lifetime performance would require some serious active cooling of the fiber rope on the crane when performing active heave compensation (AHC). However, the actual thermal behavior

of fiber ropes in AHC have proven to be unreliable to predict and hard to measure. On top of that, having the active cooling system of the fiber rope as an essential part of the crane's safety system is not the way we see robust and reliable crane design."

Cees van Veluw, Huisman's Product Manager Cranes says: "Our extensive research and development program,

of fiber ropes in AHC have proven to be unreliable to predict and hard to measure. On top of that, having the active cooling system of the fiber rope as an essential part of the crane's safety system is not the way we see robust and reliable crane design."

[www.huismanequipment.com](http://www.huismanequipment.com)

## Halliburton launches JetPulse

Halliburton business Sperry Drilling has released the JetPulse high-speed telemetry service, which it says provides consistent, high-data rate transmission of drilling and formation evaluation measurements. This new telemetry system helps operators make faster decisions to optimize well placement and improve well control while increasing drilling efficiency.

The JetPulse service transmits downhole data over wide depth ranges and complex well trajectories with physical data rates up to 18 bits/sec. It provides the highest lost circulation material (LCM) tolerance of any high-speed telemetry system, helping the operator pump the required LCM concentration to cure mud losses without changing or plugging the bottom hole assembly. The system also reduces flat time on the drilling curve, maximizes rate of penetration and optimizes reservoir contact by combining new telemetry technology with measurement/logging-while-drilling (M/LWD) services. This allows operators to make earlier and effective decisions to drill long sections in a single run.

The service also includes JetPack 3D downhole data management, which compresses and configures multiple data sets in one package, giving effective data rates of more than 140 bits/sec so operators can get the right data while drilling for enhanced decision-making. [www.halliburton.com](http://www.halliburton.com)





# Activity

## Schlumberger unveils digital integration of rock and fluid analysis services

Schlumberger inaugurated its expanded reservoir rock and fluid analysis laboratory in Houston in early November. The 123,000sq ft, state-of-the-art lab brings several services from across the country together into one centralized location so that petrotechnical experts can better leverage physical and digital rock and fluid analysis for comprehensive reservoir characterization.

The Houston laboratory features several Schlumberger reservoir characterization technologies, which span downhole rock and fluid data and sample acquisition through wellsite and lab analysis. Integration of data and insight from field and lab measurements in the DELFI cognitive E&P environment enhances collaboration across exploration and production teams to realize the full potential of all available data and science in optimizing oil and gas assets.

“Digital technology is fundamentally changing the way the

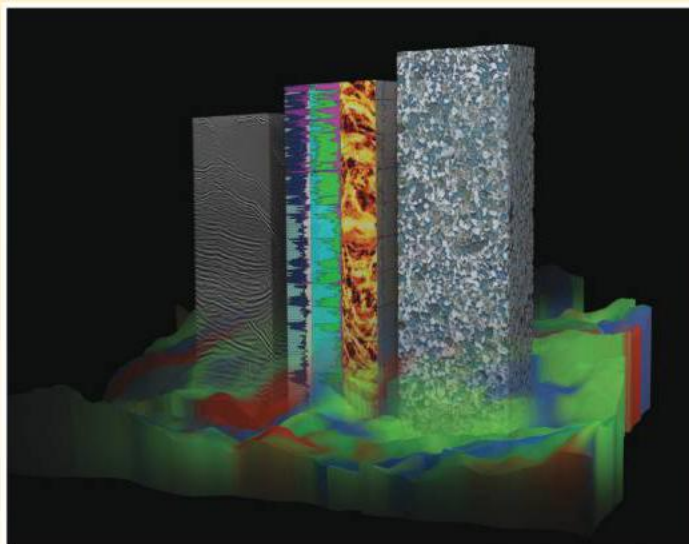


Image from Schlumberger.

CoreFlow digital rock and fluid analytics.

As part of the Schlumberger global network of rock and fluids analysis laboratories, the Houston lab also houses the Schlumberger Production Technologies Center of Excellence for conducting research, formulation and testing of production chemicals. ■

E&P industry works,” said Hinda Gharbi, president, reservoir characterization group, Schlumberger. “The expansion of the Houston Reservoir Laboratory accelerates our customers’ access to our proprietary technologies, digital models and petrotechnical domain expertise to overcome technical challenges across the life of the field.”

The facility includes services such as Maze microfluidic SARA analysis, unique Fluid Inclusion Technologies (FIT), Malcom interactive fluid characterization software and

### GE weighs Baker Hughes exit

Just months after GE and Baker Hughes completed their high-profile merger in July this year, GE’s new CEO John Flannery has said the company is looking at its exit options regarding the newly combined business, BHGE. Flannery is tasked with slimming down GE’s portfolio of businesses; BHGE could be problematic as it is tied to oil’s ups and downs. GE owns 62.5% of BHGE; according to the merger terms, GE will stay put until July 2019.

Despite the news, Flannery said the integration between GE Oil & Gas and Baker Hughes was going well.

“[We’re] fully committed to getting the synergies that we outlined there, those are on track and [we’re] fully committed to getting the value creation of mixing things like GE Digital capabilities with Baker Hughes service capabilities. So, we like the team, we like the business, and we expect good growth in this business over the next two years or three years in terms of topline and earnings.”

### Emerson chases Rockwell with \$29 billion offer

Emerson Electric has once again offered to buy Rockwell Automation, this time proposing to acquire all of Rockwell’s outstanding shares at US\$229/share, including \$135/share cash and \$90/share of Emerson shares, in a deal valued at \$29 billion. Rockwell’s board of directors will review the offer and respond to Emerson in due course.

Over the past several months, Emerson has attempted to engage with Rockwell privately regarding a combination of the two firms. In a 16 November letter to Rockwell President and CEO Blake D. Moret, Emerson Chairman and Chief Executive David N. Farr said a merger would create a leader in the \$200 billion global automation market that would offer an unmatched technology portfolio that addresses customers’ current and future needs for a fully connected enterprise, where process, discrete, and hybrid work seamlessly together

rather than relying on single, disparate platforms.

### Nigeria’s first oil, gas training center opens

Halliburton and Nigeria’s Akwa Ibom state government have opened the nation’s first oil and gas training center fully-equipped with oilfield operations tools. The Akwa Ibom Oil and Gas Training and Research Center will provide courses in field development, drilling and completions engineering, well intervention solutions and digital technologies to local energy employees and students. Halliburton Landmark will provide the training curriculum, instructors, software, workstations and tools to be used in the classroom. The Akwa Ibom state government provided the facility infrastructure. The Akwa Ibom Oil and Gas Training and Research Center will support over 3000 students annually and will provide more than 50 courses in oil and gas development.



# Tributes paid to former Subsea UK CEO

Following his untimely passing in November, the industry remembers subsea stalwart David Pridden.

Industry stalwart and inaugural Subsea UK CEO David Pridden, 66, passed away in early November following a battle with cancer.

Pridden became the first CEO of industry trade group Subsea UK in 2004, several months after the organization was formed by the UK government and industry.

With a long career in the oil and gas industry, Pridden also served as chairman of Seanamic Group, chair of the trustees of the UK's National Marine Aquarium in Plymouth and was a member of the Simmons Private Equity Investment Committee.

Over the years, he held a variety of senior positions in both large and small subsea contractors, including launching and successfully growing his own business.

After studying mechanical engineering at Manchester's Salford University he went straight into the offshore industry, joining Y-ARD in Glasgow, then worked on the trailblazing Shell/Esso underwater manifold center at Vickers Offshore.

He worked for BP from 1977 for five years before moving back to the contracting sector for five years in Norway, latterly as managing director of Kongsberg Subsea Developments.

At this point, he, together with three others, launched front-end subsea designer Mentor Engineering Consultants. By 1992, Mentor had grown to a £10 million revenue group and was sold to McDermott.

In 1997, he returned to Manchester and assumed the role of chief executive of UMITEK, which invested in consulting businesses to the energy sector. These included Capcis and Smith Rea. Pridden added TNEI and other renewables businesses to the stable



David Pridden Photo from Subsea UK.

before selling the oil and gas interests to Intertek and the renewables side to Petrofac in 2010.

Pridden held the role of Subsea UK CEO for five years. During this time, he spear-headed a campaign to raise the profile of the subsea industry, which included getting the word "subsea" into the dictionary.

Subsea UK's chairman Bill Edgar said it was a privilege to work Pridden in the early days of Subsea UK. "He was passionate about the subsea industry and promoting the UK's

world-leading expertise in this field," Edgar said. "The initial strategy and initiatives he rolled out at Subsea UK laid the foundations from which the organization has grown to become the highly successful, self-sustaining one it is today.

"He was also committed to promoting the industry to young people and had the ability to spot and employ competent young engineers into senior positions with identifiable management potential. He is a huge loss to our industry and will be sadly missed."

Seanamic Group said in statement following Pidden's death that, "Without him, the Seanamic Group could not be what it is today."

Seanamic's statement added: "David was an earnest and steadfast

leader throughout the challenges we've faced in the last two years. For us on the management team he was a genuine friend, and we are truly thankful for the time, help and inspiration he gave us. He will be sorely missed, and never forgotten."

TNEI added: "David was something of a visionary as, while renewable energy is now commonplace, it was not so in 2001 when David first became involved in TNEI. He leaves a strong company and a lasting legacy and we will miss him very much." **OE**



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

- |   |   |
|---|---|
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(check all that apply)

- |                                       |  |                                      |
|---------------------------------------|--|--------------------------------------|
| <input type="checkbox"/> 700 Specify  | <input type="checkbox"/> 701 Recommend | <input type="checkbox"/> 702 Approve |
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