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West Africa
Offshore Energy Outlook

VOL. 44 / NO. 3

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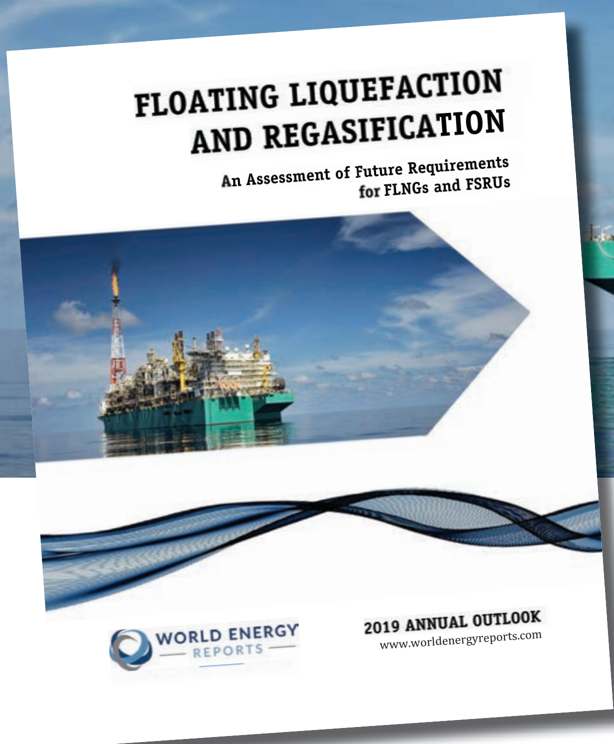

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FEATURES

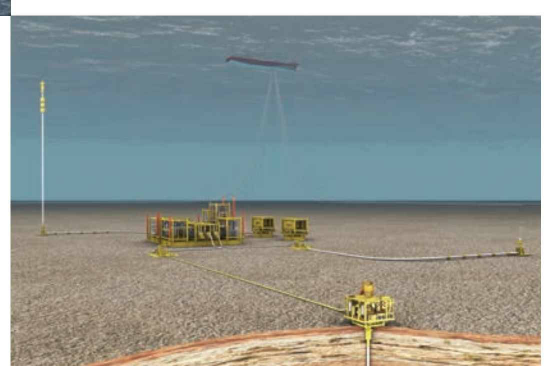
Source: Equinor

ON THE COVER: Equinor's **Hywind Tampen** project aims to use wind turbines for electrification of oil and gas installations at the Snorre and Gullfaks fields. (Source: Equinor)

FEATURES

Source: Chevron

Source: Fred. Olsen Windcarrier



Source: Saipem

Source: Ole Jørgen Bratland/Equinor

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DEPARTMENTS

Source: TechnipFMC

Source: BP

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Source: ABB

Source: NOV

BY THE NUMBERS

RIGS

Worldwide

Rig Type	Available	Contracted	Total	Utilization
Drillship	26	64	90	71%
Jackup	131	305	436	70%
Semisub	38	67	105	64%

Africa

Rig Type	Available	Contracted	Total	Utilization
Drillship	2	18	20	90%
Jackup	12	22	34	65%
Semisub	1	4	5	80%

Asia

Rig Type	Available	Contracted	Total	Utilization
Drillship	6	8	14	57%
Jackup	50	88	138	64%
Semisub	11	17	28	61%

Europe

Rig Type	Available	Contracted	Total	Utilization
Drillship	12	2	14	14%
Jackup	12	38	50	76%
Semisub	10	26	36	72%

Latin America & the Caribbean

Rig Type	Available	Contracted	Total	Utilization
Drillship	4	16	20	80%
Jackup	3	7	10	70%
Semisub	7	5	12	42%

Middle East

Rig Type	Available	Contracted	Total	Utilization
Drillship	0	1	1	100%
Jackup	24	114	138	83%

North America

Rig Type	Available	Contracted	Total	Utilization
Drillship	2	19	21	90%
Jackup	24	29	53	55%
Semisub	4	7	11	64%

Oceania

Rig Type	Available	Contracted	Total	Utilization
Jackup	2	1	3	33%
Semisub	1	5	6	83%

Russia & Caspian

Rig Type	Available	Contracted	Total	Utilization
Jackup	2	6	9	67%
Semisub	3	3	6	50%

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

Data as of June 1, 2019.
Source: Wood Mackenzie Offshore Rig Tracker

DISCOVERIES & RESERVES

Offshore New Discoveries

Water Depth	2015	2016	2017	2018	2019
Deepwater	25	13	16	12	2
Shallow water	85	66	72	46	11
Ultra-deepwater	20	16	12	17	7

Shallow water (1-399m)
Deepwater (400-1,499m)
Ultra-deepwater (1,500m+)

Offshore Undeveloped Recoverable Reserves

Water Depth	Number of fields	Recoverable reserves liquids mbl	Recoverable reserves gas mboe
Deepwater	568	23342	66949
Shallow water	3220	108452	311418
Ultra-deepwater	342	38390	52198

Contingent, good technical, probable development. The total proven and probably (2P) reserves which are deemed recoverable from the reservoir.

Woodmac Child Fields

Offshore Onstream & Under Development Remaining Reserves

Water Depth	Number of fields	Recoverable reserves liquids mbl	Recoverable reserves gas mboe
Africa	737	29253	30380
Asia	1029	16990	40014
Europe	976	20639	24746
Latin America & the Caribbean	242	40424	11502
Middle East	141	148167	116373
North America	626	25471	34724
Oceania	122	2783	23977
Russia and the Caspian	71	26933	23504

Onstream and under development. The portion of commercially recoverable 2P reserves yet to be recovered from the reservoir.

Woodmac Parent Fields

Source: Wood Mackenzie

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Maslin


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Pallanich


Stoichevski


Vatland


Venables

A RENEWED SPIRIT

It could be argued that "renewables" have traditionally been a four-letter word in offshore oil and gas sector parlance. But times and attitudes change, particularly while in a prolonged, multi-year oil pricing slump. Renewable energy offshore is here to stay, driven by a younger generation focused on sustainability, powered by the mature generation that has the experience, finance and technical acumen to bring concepts from the drawing board to reality. To be sure, the path is clear, but the pace remains uncertain. A traditional knock on renewable energy has been the high cost as compared to traditional energy sources. But rapid tech evolution has driven down the cost to deliver utility scale power from offshore renewables, particularly offshore wind. While there remains a long list of questions, this much is sure: Europe has a full generation's head start on the U.S. in terms of experience and installed offshore energy power projects, and in particular the appetite for offshore wind in Europe has grown faster than expected.

Elaine Maslin graces the pages of *Offshore Engineer* with a pair of reports on the (r)evolution in offshore wind this month. In *"Bigger, Bolder, Heavier,"* starting on page 23, the focus is on size, and in this case size certainly does matter. The size of the offshore wind blades, and the units overall, continues to grow quickly, with an industry planning for 6 MW turbines only six or seven years ago, now looking at a 10 MW prototype turbine with a 193-m diameter rotor being tested, with units as large as 14 MW being envisioned. With the prospect of much bigger individual units comes the challenge to the entire logistics chain, including strains at the port level to handle the massive components safely and efficiently, to questions regarding the installation fleet of vessels designed to lift and install them at sea.

In her second report, Maslin examines the promise and prospects for the future of floating wind units, another area where decades of offshore engineering experiences come into play. While still in its adolescence, the prospect of successful floating wind installations has the potential to rapidly expand the market for offshore renewable energy, as the units can be positioned and re-positioned to optimize production. Floating wind also helps to negate two of the top challenges facing permanently installed units: environmental concerns of affixing a unit to the seabed, and the "not in my backyard" syndrome; aesthetic concerns from waterfront communities that object to the look of the units off of their shores. This report starts on page 28.

Turning back to traditional oil and gas production, I am particularly pleased to highlight Shem Oirere's report in this edition, as Oirere has a front row seat and insightful analysis on a geographic region that can be a mystery. Starting on page 12 he reports that the outlook for West Africa's offshore oil and gas market "remains positive despite some hiccups hinged on delay by some countries in the region to align their hydrocarbon regulations to prevailing market trends and the intensifying global competition for a share of international oil companies' planned capital expenditure for deep- and ultra-deepwater resources." Global oil and gas majors have blazed the trail, with ExxonMobil, Total, Tullow, Kosmos and Oryx Petroleum establishing JVs, with participation of national oil entities in West Africa, to search for oil and gas in the region's deep and ultra-deep waters.

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CHEVRON: MATURE FIELDS, MAXIMUM PRODUCTION

By Jennifer Pallanich

Chevron is combining technology and streamlined work processes to maximize production efficiencies in its mature offshore fields. Continued investments in the fields, reservoir surveillance, analytics and portfolio optimization are some of the top methods Chevron relies on to keep fields like Okan (1965) and Meren (1968) offshore Nigeria along with Malongo West (1970) offshore Angola producing.

"It's amazing that they keep giving," says Jitendra Kikani, general manager for reservoir management, Chevron Africa and Latin America Exploration and Production. "It's heartening" to have such fields with continuing recovery, even in "remote areas where sometimes things are challenging."

Without continued investment in the form of what the company terms "small projects" – infill drilling, workovers, recompletions, deepenings, and perf jobs, to name a few – mature fields could suffer a 10% to 15% decline rate, he says.

"Chevron's decline rate is 3% to 5% annually," Kikani says. "All of these small projects allow us to manage these fields [to achieve] small decline rates year over year."

Clay Neff, president of Chevron Africa and Latin America Exploration and Production, says the company focuses on extending the economic life of existing mature fields by improving performance and driving efficiencies.

"We obtain additional profitable barrels from our mature assets by applying technologies and streamlined work processes that maximize value creation from older fields," Neff says.

Continuous optimization of each of the

In 2012, the Block 0 offshore concession in Angola produced its 4 billionth barrel of crude oil. Chevron is the country's largest foreign oil industry employer.

Source: Chevron

The Sonam platform is located in concession OML 91, offshore Nigeria. The Sonam project is designed to deliver 215 million cubic feet of natural gas per day to the domestic market.

Source: Chevron

"CHEVRON'S DECLINE RATE IS 3% TO 5% ANNUALLY."

JITENDRA KIKANI
CHEVRON AFRICA AND LATIN AMERICA EXPLORATION AND PRODUCTION

Below: Chevron's Okan Platform in Nigeria was built in 1963. Chevron is the third largest oil producer in Nigeria.

Source: Chevron

fields employs all the underlying technologies bundled under "well reliability and optimization" that has reservoir surveillance as the centerpiece, according to the company. Kikani says the company maintains longevity at its fields by producing reservoirs at the right volumes, rates and cuts. This is achieved through surveillance activities such as regular rate testing of the well stock, downhole and wellhead pressure acquisition including the use of real time instrumentation and sampling of both produced and injected fluids. Innovative methods allow Chevron to implement some of these surveillance technologies in a cost-effective manner for older fields, the company says.

"Reservoir monitoring is dependent on all the components working," Kikani says, so cross-functional teams work closely together to use data effectively and prevent bottlenecks.

One example of this teamwork is integrated operations centers, which allow experts on rigs and regional offices to collaborate on real-time operations data. The Chevron Angola integrated operations center is critical to successful operations because it offers the ability to collaborate across functions and locations while providing real-time access to operational data, the company says. In Angola, managing water and gas for injection and gas for lift across multiple fields improves production performance. This can only be done with clear understanding of pipeline specifications, volume constraints, sourcing and availability of injection and surplus gas, well capacities and requires participation across the board in real-time all the way from production operations and facilities to asset management personnel, according to the company.

Using real-time monitoring, Chevron was able to save more than $6 million in a six-month period at the Sonam gas condensate field offshore Nigeria last year by optimizing the choke settings, improving completions strategy, reducing lost production opportunities and blending the production stream, Kikani says.

Blend optimization is necessary when there are contaminants such as sulfur in the production stream. By knowing the production and composition contribution from the different reservoirs and zones, he says, it was possible to maximize value by meeting production specs and managing erosional velocities in the wells.

Given the proliferation of instrumentation and improvements in data analytics and automation, Chevron is using a number of technologies to reduce labor-intensive tasks, such as mobile apps for operators, multi-variate determination of process variance from forecasts resulting in management by exception, and maintenance scheduling based on equipment performance measures rather than defined intervals. All of these lead to improvements in production efficiency.

"This allows people to sift through data more effectively and connect the dots," Kikani says.

Recently, Chevron has taken best practices honed over the last few years from factory drilling in the Permian Basin and applied those across the rest of the company, he says. For example, certain processes such as disciplined management-of-change protocols, improved cost savings due to better streamlining of supply chain with drilling and completions, as well as drilling process standardization is helping other business units learn and adopt from Chevron's Permian operations, he says.

"Certain things are applicable everywhere," he says.

Chevron is using predictive analytics in its maintenance programs to minimize lost production opportunities. For example, there are many electrical submersible pumps operating in Chevron's assets offshore Angola. ESPs have a predetermined performance expectancy.

"The question is when will they stop working in those remote areas" where there is no easy access to the supply chain or rigs for repair work, Kikani says. By predicting the failure of that pump, Chevron can schedule the maintenance and minimize "days to weeks to months" of downtime, he says.

Kikani says the reservoir management framework, learned and transferred over decades, provides consistency and excellence across the company, coupled with opportunities generated by surveillance and monitory and portfolio prioritization drives Chevron's low decline rates.

"A thorough lookback process allows us to continuously learn and increase the value of these activities," he says.

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West Africa Offshore Outlook

By Shem Oirere

The outlook for West Africa's offshore oil and gas market remains positive despite some hiccups hinged on delay by some countries in the region to align their hydrocarbon regulations to prevailing market trends and the intensifying global competition for a share of international oil companies' planned capital expenditure for deep- and ultra-deepwater resources.

Despite the post-2014 growth pressures on the back of fast-falling global oil prices, a number of West African offshore projects, though delayed, were kept alive partly by an emerging trend of governments in the region committing to not only change their petroleum codes to attract more private investments, but also restructure their governance structures and embrace policies that support growth of free market economies.

Currently, leading West Africa oil and gas market players such as Nigeria, Angola, Ghana, Senegal, Equatorial Guinea, Mauritania, Guinea Bissau and Cameroon have several offshore projects that are already online, being implemented or approved for implementation by international exploration and production joint ventures or in partnership with national oil companies or domestic private firms.

"Investment in offshore production is on the rise in West Africa," says Olumide Adeosun, Director, PwC Advisory & Strategy Consulting.

"In Nigeria, Total's Egina, one of the world's largest floating production storage and offloading units (FPSO) came online at the end of 2018 and is expected to have a maximum output of 200,000 barrels per day (bpd). In Ghana, Eni recently contracted Yinson to convert an FPSO at a Singaporean shipyard for production and processing of oil in the country," he said.

"With similar purchases and conversions planned in Nigeria, Ghana, Senegal and Equatorial Guinea, it is expected that the West African market will prove to be an increasingly attractive export location for FPSO expertise and services, to be rendered by international partners," Adeosun added.

Global oil and gas exploration and production companies such as ExxonMobil, Total, Tullow, Kosmos and Oryx Petroleum have, through joint ventures with participation of national oil entities in West Africa, led in the highly expensive search for oil and gas in the region's deep and ultra-deep waters.

Angola's Kaombo project, in ultra-deepwater Block 32, is one of Africa's biggest hydrocarbon investments operated by Total SA, with a 30% stake and would most likely impact performance of the region's offshore oil and gas market in the short to long term.

"Kaombo is twice as big as any previous Total oil project in the Gulf of Guinea," said Cyril de Coatpont, Kaombo Project Director.

"We are going deeper – from 1,400 to 1,950 meters – and we are going further – 200 kilometers farther offshore. It is

Source: TechnipFMC

FPSO Kaombo Sul in Angola

our largest development to date, covering an area nearly eight times the size of Paris," Coatpont said.

Kaombo is linked to two FPSO units, Kaombo Norte and Kaombo Sul, through 300 kilometers of subsea pipelines with Total projecting production of 230,000 bpd in 2019.

The French oil major is also proceeding with the Egina oilfield project 130 kilometers off the coast of Nigeria at water depths of more than 1,500 meters and which the company says is "one of our most ambitious ultra-deep offshore projects." Further, the Egina project is based on a subsea production system connected to an FPSO which Total calls "the largest one Total has ever built."

"Egina will significantly boost [Total's] production and cash flow from 2019 onwards and benefit from our strong cost reduction efforts in Nigeria where we have reduced our operating costs by 40% over the last four years," said Arnaud Breuillac, Total's President Exploration and Production in the company's 2018 annual report. The project produces 200,000 bpd, equivalent to 10% of Nigeria's total production.

Elsewhere in Nigeria, ExxonMobil, trading as Esso Exploration Production Nigeria, is developing the Erha and Erha North projects in water depths of 1,000 meters and 1,200 meters within OML 133 license, which consist of 32 subsea wells that are tied back to an FPSO with storage capacity of 2.2 million barrels of oil and designed oil processing capacity of 210,000 bpd. ExxonMobil is the operator with a 56.25% participating interest with Shell Nigeria Exploration & Production Company (43.75%) as a partner.

As part of its 2019 work schedule, ExxonMobil has been preparing to recommence drilling in the shallow water blocks with an estimated daily production of 130,000 net oil-equivalent barrels with at least two rigs already under contract and mobilized.

ExxonMobil is pushing through more projects across in Mauritania where in 2018 the company acquired what it said was "largest ever proprietary seismic survey over blocks C14, C17 and C22."

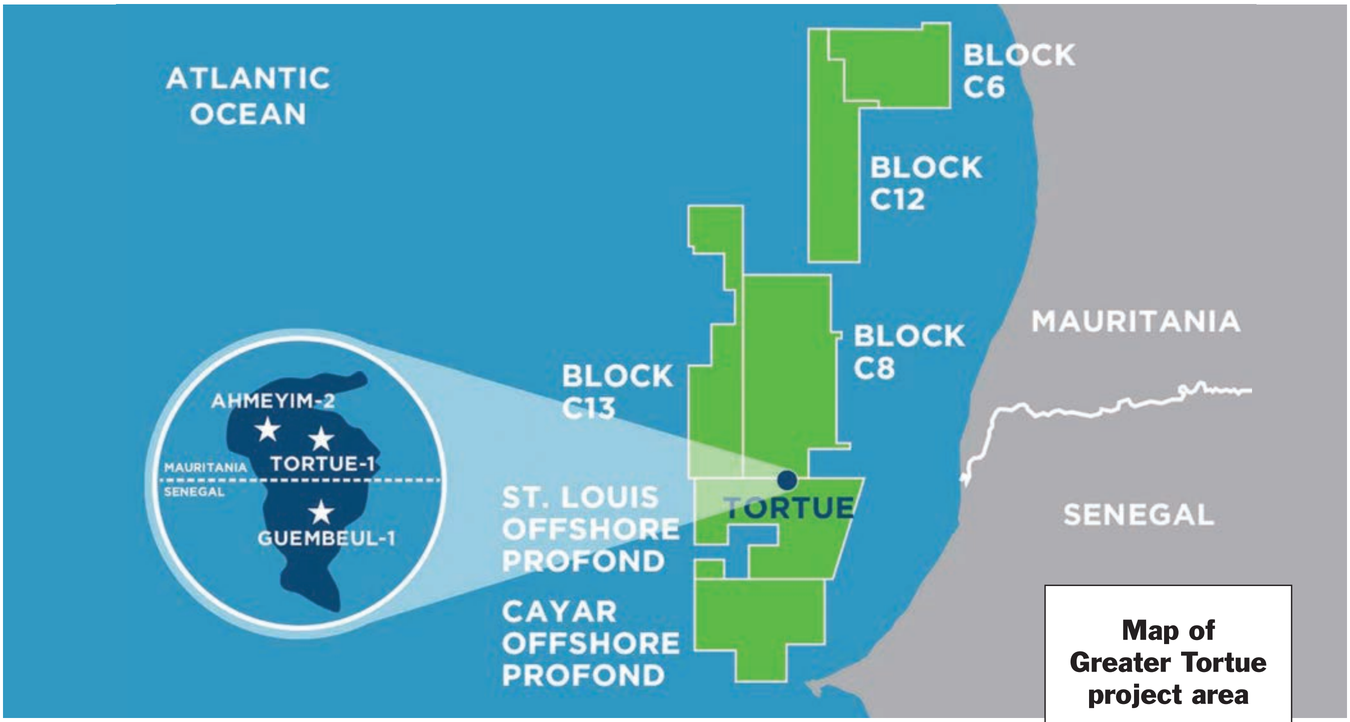
Through its affiliate ExxonMobil Exploration and Production Mauritania Deepwater Ltd, which owns 90% stake in the assets, the oil major looks forward to full monetization of the hydrocarbon resources in this area that covers 8.4 million acres in water depths of between 1,000 meters and 3,500 meters. But this will come after the evaluation of the blocks using 2D seismic data of nearly 6,500 kilometers and about 21,000 square kilometers of 3D survey work that is expected to continue for the better part of 2019.

Another key achievement for the West African offshore oil and gas market was the settlement of the maritime dispute between Senegal and Mauritania that had held back the progress of the Greater Tortue Ahmeyim liquefied natural gas (LNG) project.

In December 2018, BP announced final investment decision (FID) for the project after what it said was "the agreement between Mauritania and Senegal governments and partners Kosmos Energy and national oil companies of Petrosen and SMHPM for Senegal and Mauritania respectively.

The Greater Tortue Ahmeyim project "will deliver revenues and gas to Africa and beyond for decades to come," said Bernard Looney, BP's Upstream Chief Executive. "We see this as the start of a new chapter for Africa's energy story."

The project, which is the first major one to reach FID in the basin and was initially slated to commence in the first



Source: Kosmos Energy

Map of Greater Tortue project area

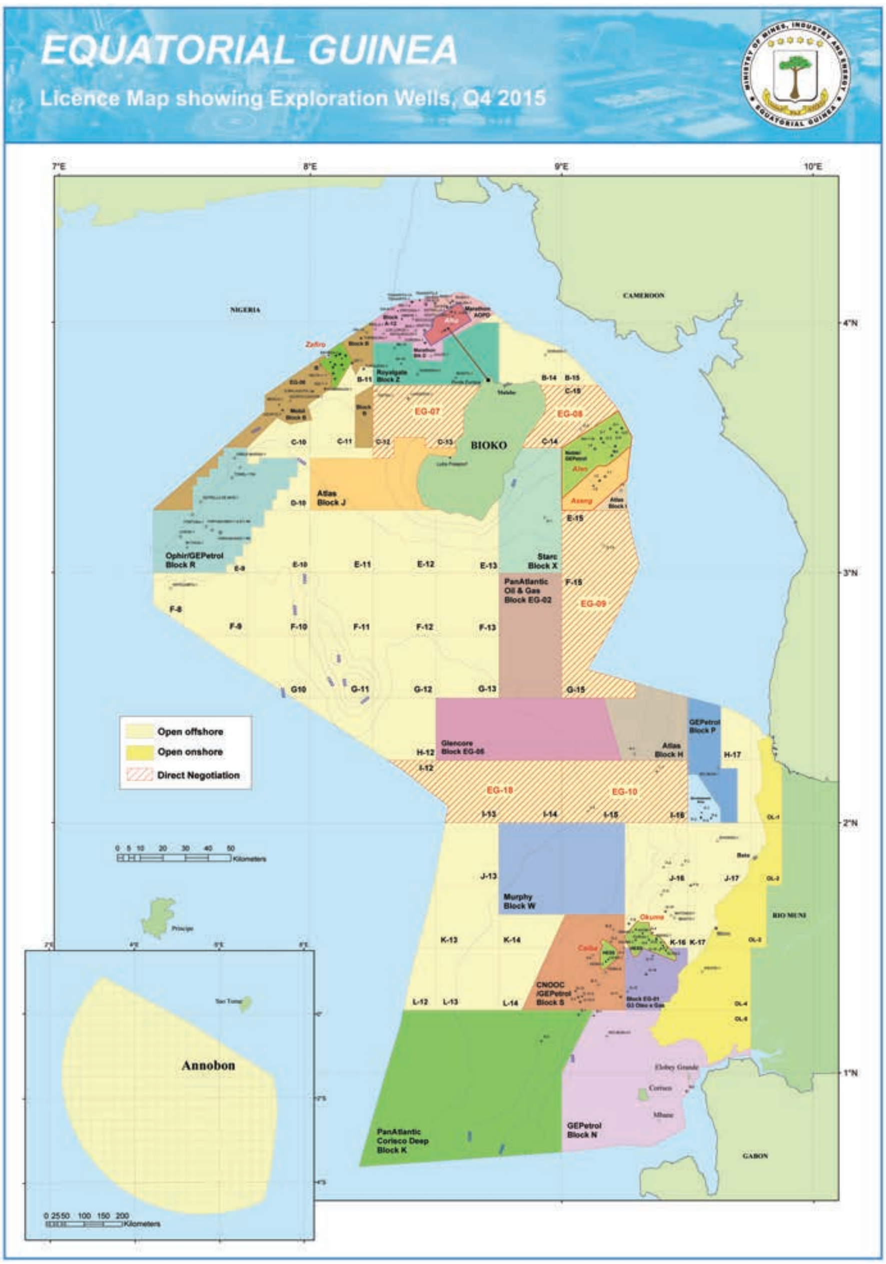
quarter of 2019, entails producing gas from an ultra-deepwater subsea system and mid-water FPSO vessels, "which will process the gas, removing heavier hydrocarbon components before the gas is transferred to floating LNG (FLNG) facility on the maritime Senegal/Mauritania border." The FLNG has capacity of 2.5 million metric tons of LNG/year with the first gas expected in 2022.

Other offshore oil and gas projects that are likely to drive exploration and production investment trends in West Africa include the Celba field and Okume complex, in Equatorial Guinea by Kosmos Energy's affiliate Kosmos Equatorial Guinea, alongside exploration blocks EG21, EG24, 5 and W.

On the Senegal/Guinea Bissau border Oryx Petroleum says it is "pursuing a carbonate edge play type in AGC Central, a play type that other operators have pursued with success elsewhere in Casamance sub-basin."

Currently, Tullow Oil is reporting good performance of the Tweneboa, Enyenra, Ntomme (TEN) offshore fields in Ghana with gross production having averaged 64,500 bpd with projections the output will surge to 73,000 barrels per day in 2019.

The deepwater project, the second biggest in Ghana after the Jubilee development, includes the use of an FPSO, John Evans Atta Mills, which has a facility with capacity to produce 80,000 bpd. The FPSO's first oil was delivered in 2016, through subsea infrastructure across the hydrocarbon-rich field.



Source: Ministry of Mines, Industry & Energy

But whether West Africa will continue attracting additional offshore oil and gas investments will depend largely on trends in global oil prices that for long have determined exploration and production spending globally.

"West Africa will get a share of the increased spending," predicts Jim McCaul, head of International Maritime Associates and World Energy Reports. "But exploration and production companies, particularly the big ones that operate globally, have choices as to where they spend capex resources."

He said for West Africa to effectively compete for a share of this much needed offshore investment, governments in the region must address concerns surrounding royalties and taxation policies and local sourcing requirements on new oil and gas projects.

"Big drivers for West Africa oil and gas production are exploration and production company capex budgets, oil and gas opportunities elsewhere, government take of production revenues, political stability and stable government rules and policies," McCaul said.

West Africa's deepwater projects must compete for investment resources against emerging shale gas opportunities in countries such as Guyana, Brazil and the US, McCaul said. "The biggest constraint on exploration and production spending in West Africa is existence of better opportunities elsewhere."

"Any policy that extracts more share of revenue for the government or adds cost to the project discourages exploration and production activity," he explained.

"The exploration and production operator will obviously prefer a deal that provides more share of the field revenue, and governments need to balance their desire to get more share of the revenue from leases, concessions, production sharing agreement, with the likelihood of discouraging new production starts," McCaul said.

According to Adeosun, government regulation remains one of the major constraints to the growth of oil and gas in West Africa. "For example, in Nigeria, the Petroleum Industry Bill (PIB) has been held up from being passed for over a decade," he observed.

He said, "The passage of various elements of the bill is expected to provide an improved regulatory structure for oil and gas activities, leading to increased FIDs being taken in the country, due to improved investor confidence."

But not all West African oil and gas markets are in limbo on regulatory framework matters if the progress in Ghana is anything to go by.

Ghana, which passed its Petroleum Production and Exploration Bill in 2016, is already considering the bill for review, according to Adeosun.

"An example of a difference in regulation is the requirement for oil mining license holders in Ghana to have the capacity to develop the blocks they hold," Adeosun said, adding that market analysts have observed hydrocarbon production more than doubled in Ghana between 2016 and 2018 since the passage of the bill.

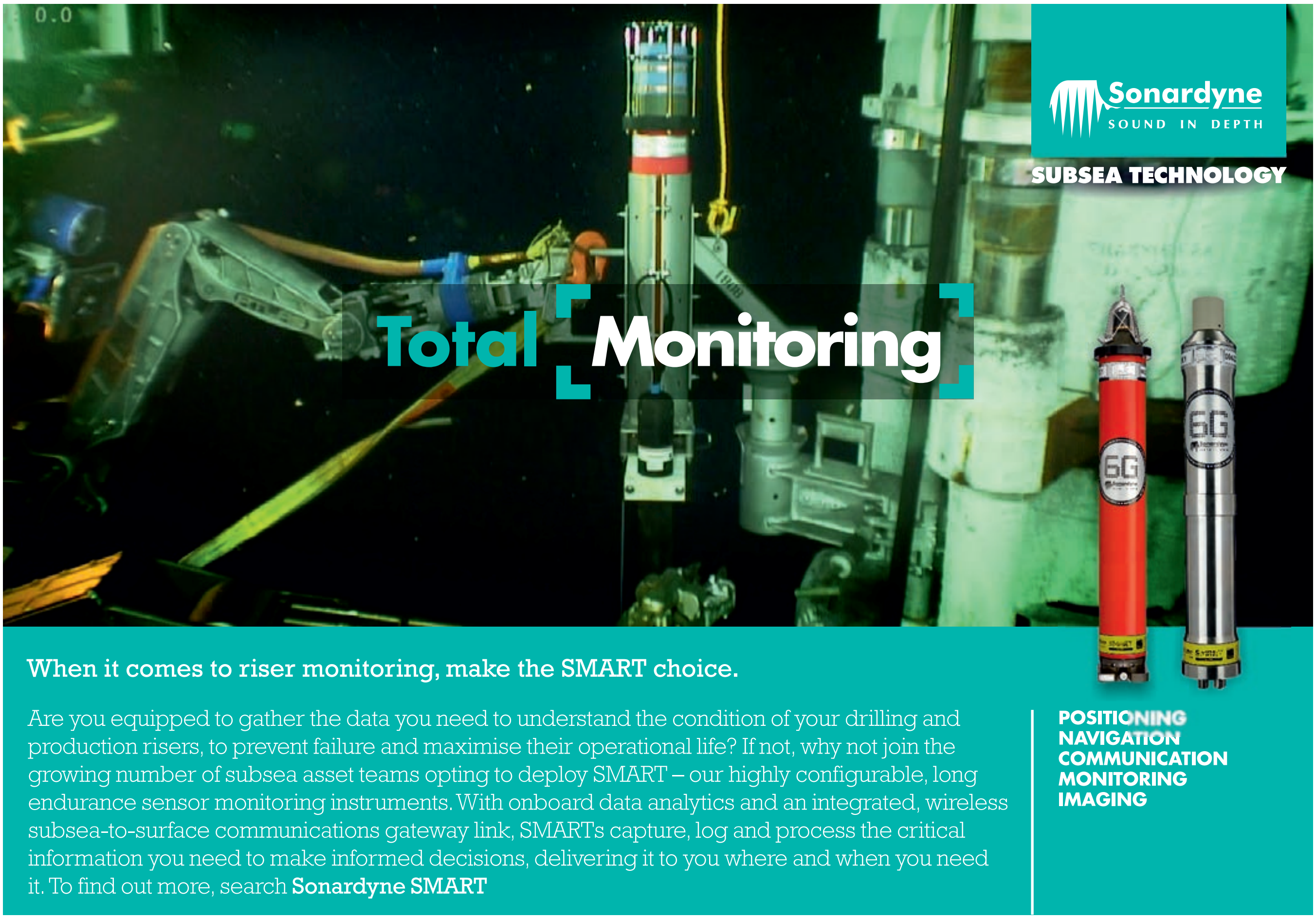
"Another major constraint that is specific to Nigeria is pipeline vandalism and sabotage in the Niger Delta region, where most of the country's oil and gas is produced," he added.

Despite some West Africa oil and gas producers predicting increased offshore investment driven by recovering global oil prices, Adeosun sees little impact of this surging oil prices on planned but yet to be developed deep- and ultra-deepwater projects in the region.

"Recovering prices are unlikely to have a major impact on deep offshore projects in the short term as these projects are very highly capital intensive," he said.

"Short term price gains will provide an initial validation for projects that have already been committed to, but not necessarily for pending projects," Adeosun added.

In the medium to long term, however, a continued rise in the price of oil is likely to incentivize exploration companies to sign off on a higher number of FIDs.



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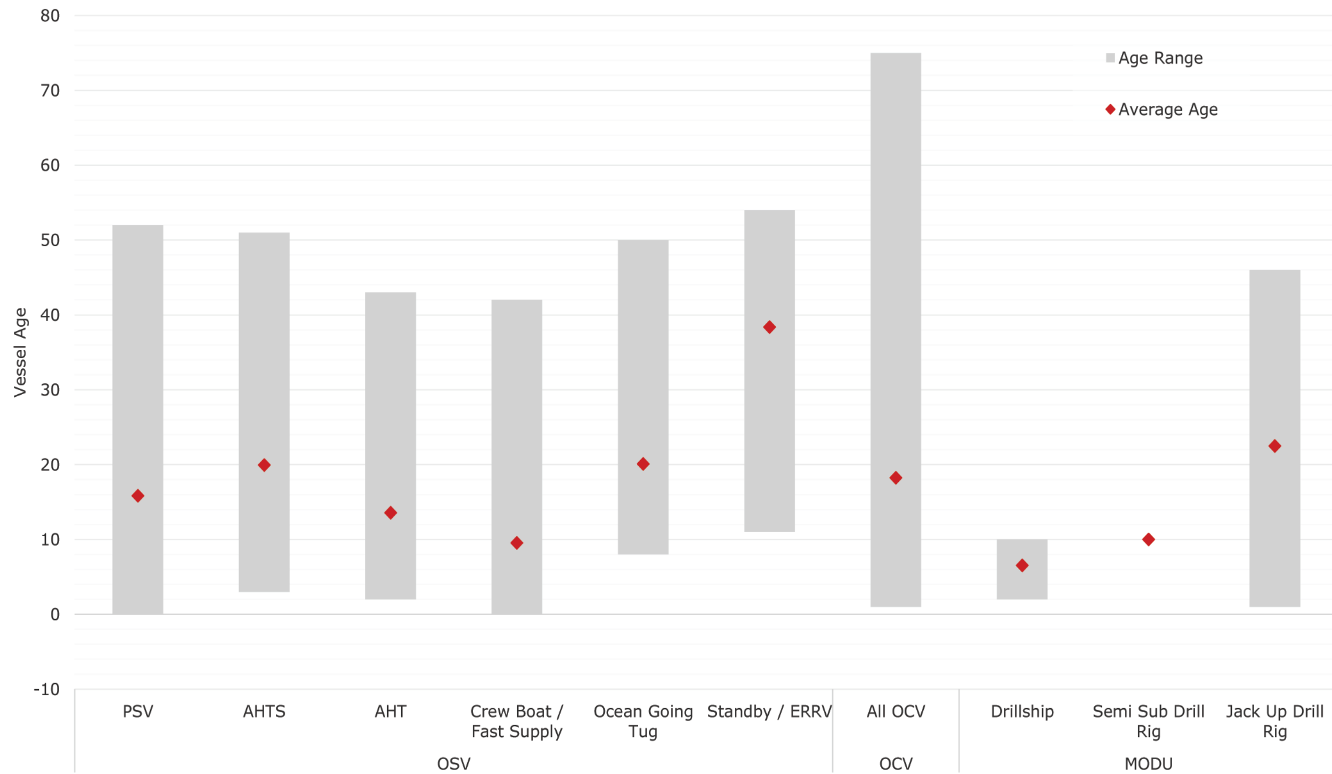
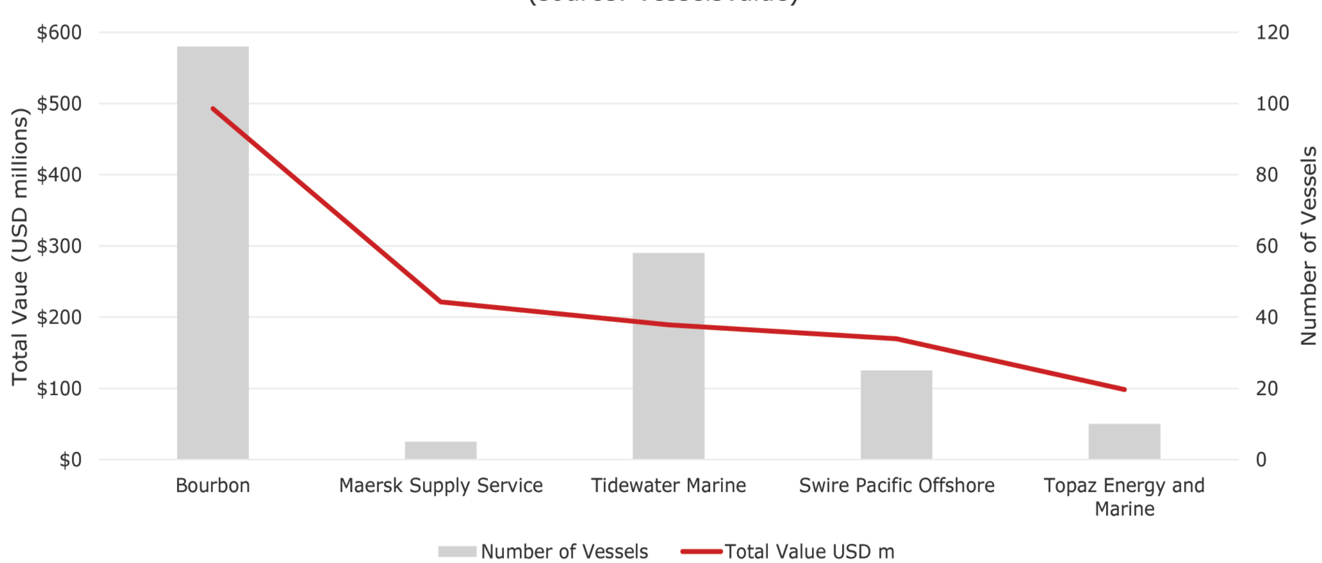
West Africa Operating Offshore Vessel Type Age Distribution

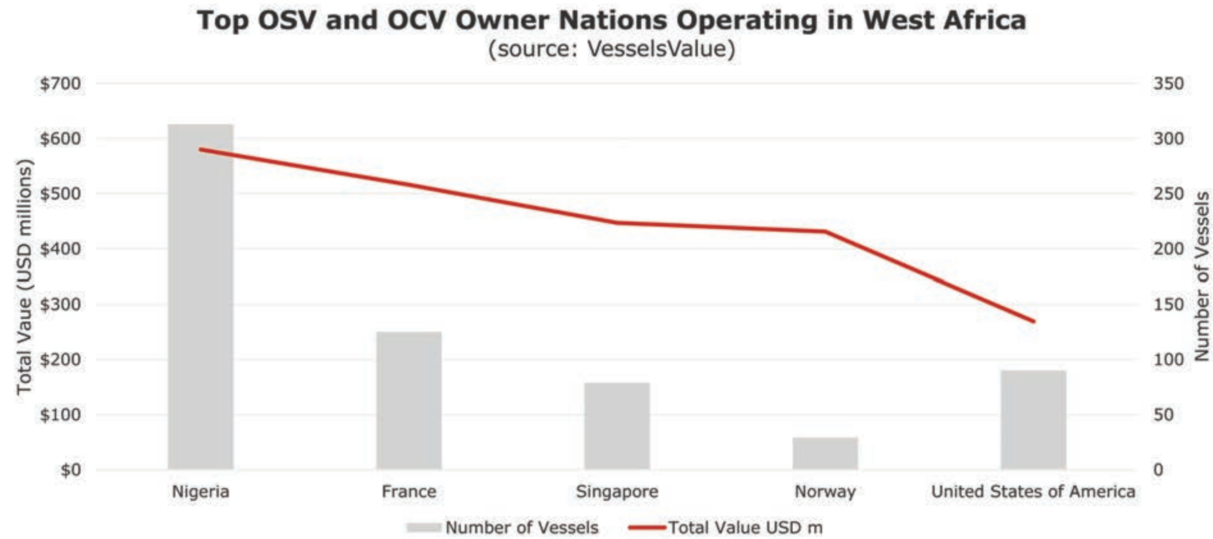
(source: VesselsValue)

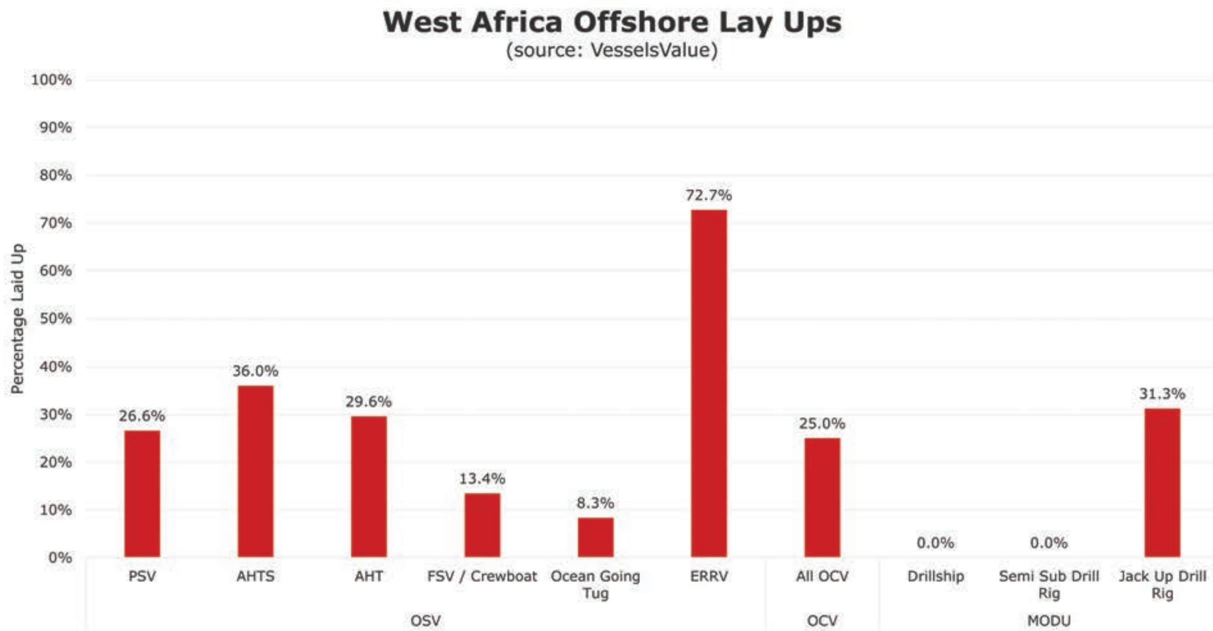


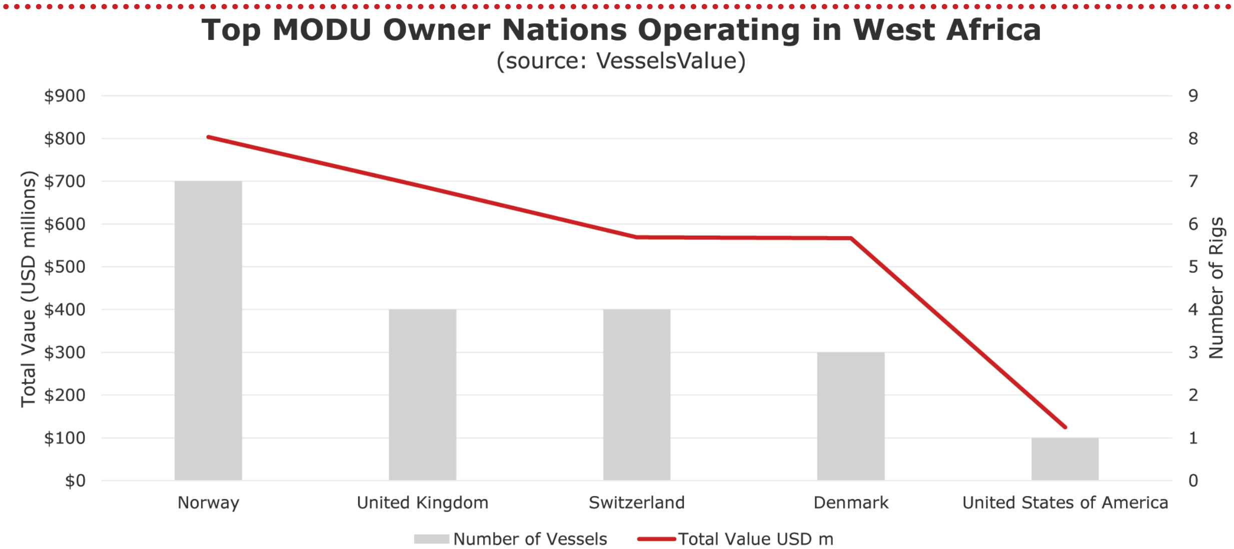
Top OSV and OCV Owners Operating in West Africa

(source: VesselsValue)




Top OSV and OCV Owner Nations Operating in West Africa
(source: VesselsValue)
Total Value (USD millions)
Number of Vessels
$0
$100
$200
$300
$400
$500
$600
$700
0
50
100
150
200
250
300
350
Nigeria
France
Singapore
Norway
United States of America
Number of Vessels
Total Value USD m


West Africa Offshore Lay Ups
(source: VesselsValue)
Percentage Laid Up
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
26.6%
36.0%
29.6%
13.4%
8.3%
72.7%
25.0%
0.0%
0.0%
31.3%
PSV
AHTS
AHT
FSV / Crewboat
Ocean Going Tug
ERRV
All OCV
Drillship
Semi Sub Drill Rig
Jack Up Drill Rig
OSV
OCV
MODU


Top MODU Owner Nations Operating in West Africa
(source: VesselsValue)
Total Value (USD millions)
Number of Rigs
$0
$100
$200
$300
$400
$500
$600
$700
$800
$900
0
1
2
3
4
5
6
7
8
9
Norway
United Kingdom
Switzerland
Denmark
United States of America
Number of Vessels
Total Value USD m

Africa looks to FLNG to accelerate its dash for gas

Source: BP

BY MARK VENABLES

BP's Tortue project was given the green light late last year and will come online in 2022.

Since the idea of floating liquified natural gas (FLNG) was first mooted the landscape of the oil and gas sector has changed dramatically. When Shell finally pressed the go button for its Prelude FLNG project offshore Australia back in mid-2011, the oil price was pushing $115 a barrel. By the time it delivered first gas earlier this year it was less than half what it was at final investment decision (FID) eight years earlier, hovering around $55. That price depreciation has made many potential operators have second thoughts on the technology.

The International Energy Agency (IEA) estimates that Africa could overtake Russia as a global gas supplier by 2040, demonstrating the scale of opportunity should these obstacles be overcome. For the region, FLNG has been touted as a potentially lucrative way to avoid onshore facilities with all the associated planning, security and local content issues.

Africa's first FLNG project, Golar's Cameroon GoFLNG, shipped its first consignment in 2018, Eni's Coral South FLNG is under construction in South Korea and Singapore and is expected to start producing in 2022, while BP's Tortue project was finally given the green light late last year and will also come online in 2022.

However, there was no such good news for Ophir Energy who finally pulled the plug on its Fortuna FLNG project offshore Equatorial Guinea. "Financing of FLNG is always a challenge, given it's still a new technology, but the main problem with Fortuna was that the banks were unwilling to back an Ophir-led project as opposed to established oil firms like Eni or BP's projects," Ed Cox, editor, global LNG at ICIS Energy, says of the Fortuna cancellation.

Challenges for FLNG growth

FLNG is part of the solution to commercialize gas reserves in Africa, but given the production output from all existing and sanctioned projects (BP's Tortue, Eni's Coral & Kribi in Cameroon), it is only going to be a minor part of the gas sector in Africa, Cox says. "For now, conventional LNG plants and gas-to-power generation such as in Nigeria and Ghana will continue to play a major role in monetizing African gas reserves."

Although at present the share of gas produced through FLNG in the market is not significant, it has garnered considerable interest. It has several advantages in its favor. The initial capital investment is lower, and with faster construction, it offers operators access to early cash returns to balance the investment or invest in further production. This is evidenced by the FIDs taken on Coral and Tortue.

However, despite these pluses, there are challenges in developing projects. Chief among these is local content issues. Whereas onshore facilities are constructed using local labor and resources, FLNG construction or conversions are carried out on foreign soil. This has seen governments push for onshore developments, such as Abadi (Indonesia), Greater Sunrise (Timor Leste/Australia) and Tanzania.

There is also the question of appropriate fields for the technology. According to the Global FLNG Overview 2019 report from Wood Mackenzie released earlier this year, the significant reduction in exploration expenditure since the oil price crash in 2014 has yielded few suitable new gas discoveries. The lack of economy of scale is likely to limit FLNG projects to small scale and remote developments. This often requires the FLNG facility to be integrated with the upstream section of the project, resulting in projects of increasing complexity and cost.

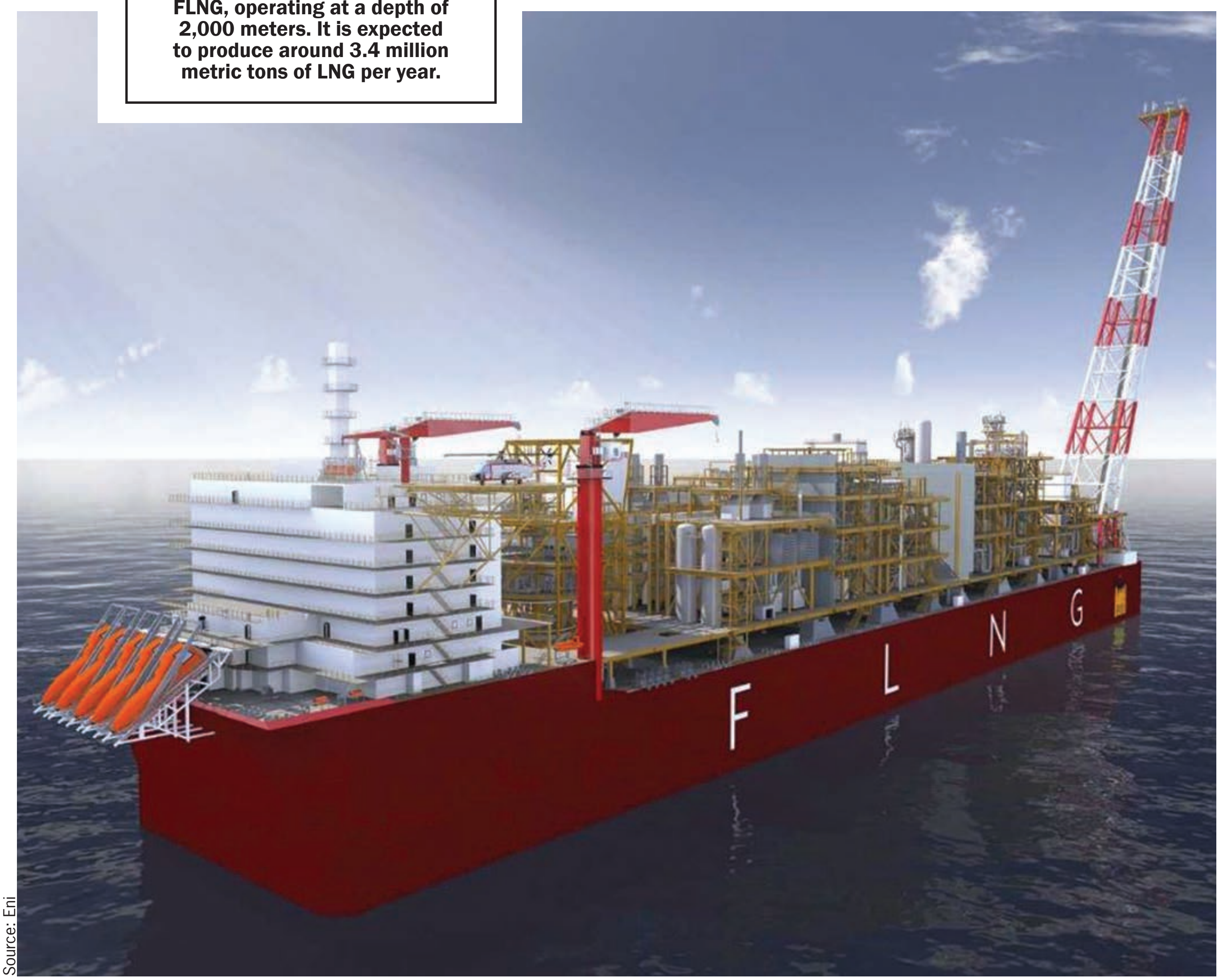
Despite these challenges, Africa is playing host to important LNG innovation, but the success of these projects needs collaboration between operators, suppliers and host governments to navigate a challenging LNG market to secure necessary off-take agreements while host governments must ensure that fiscal and regulatory regimes do not become barriers to investment.

Humble beginnings

It all started for Africa with FLNG Hilli Episeyo, moored offshore Kribi, Cameroon. The conversion of an LNG tanker into an FLNG, the optimization of Sanaga 1 offshore platform and the modification of the Bipaga treatment onshore facilities are at the heart of this project.

Hilli Episeyo was originally a conventional 1975-built, 125,000-cubic-meter (m3) LNG carrier before conversion at the Keppel yard in Singapore in 2015. It is now equipped with four liquefaction trains, each to produce between 500,000 to 700,000 tons of LNG per year with onboard storage of 125,000 m3. LNG carriers with a capacity of 70,000 to 175,000 m3 can be stowed, and the loading is carried out by three transfer arms at a flow rate of 10,000 m3 per hour.

On record as the world's first converted FLNG vessel, Hilli Episeyo is also Africa's first and currently only operational



The Coral South FLNG will be the world's first ultra-deepwater FLNG, operating at a depth of 2,000 meters. It is expected to produce around 3.4 million metric tons of LNG per year.

Source: Eni

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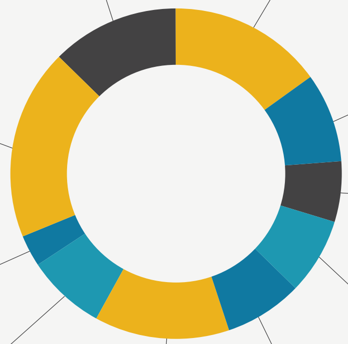
Areas of Interest



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Source: Eni

FLNG unit. It produced its first LNG from Sanaga field in March 2018 and sent its first cargo in May that year.

Second online will be Eni's Coral field, discovered in May 2012 and located offshore Mozambique within Area 4. It contains approximately 450 billion cubic meters (16 Tcf) of gas in place. In October 2016, Eni signed an agreement with BP for the sale of the entire volumes of LNG produced by the Coral South project for a period of over 20 years.

The FLNG will operate at a depth of 2,000 meters and is expected to produce around 3.4 million metric tons of LNG per year. Construction started earlier this year with the steel cut for the turret in Singapore. The other main component of the FLNG, the topside modules, will be built in South Korea at the Samsung Heavy Industries shipyards. According to Eni, construction is planned to start at the end of this year and is expected to be completed by the end of 2021. First gas is expected in 2022.

And then there were three

The Africa FLNG drive received a boost late last year when BP announced the FID for Phase 1 of the Greater Tortue Ahmeyim development. The project will produce gas from an ultra-deepwater subsea system and mid-water floating production, storage and offloading (FPSO) vessel, which will process the gas, removing heavier hydrocarbon components. The gas will then be transferred to an FLNG facility at an innovative nearshore hub located on the Mauritania and Senegal maritime border.

The FLNG facility is designed to provide circa 2.5 million metric tons of LNG per annum on average, with the total gas resources in the field estimated to be around 15 trillion cubic feet. The project, the first significant gas project to reach FID in the basin, is planned to provide LNG for global export as well as making gas available for domestic use in both Mauritania and Senegal.

The vessel conversion would take place in Singapore at the Keppel Shipyard, where Golar's Hilli Episeyo FLNG that is now operating offshore Cameroon was converted.

"By sanctioning the project now, BP is benefiting from the substantial cost deflation of recent years" Giles Farrer, director global gas and LNG, at Wood Mackenzie, says. "The real value for the project will come once BP and partner Kosmos move forwards with expanding the facility with Phases 2 and 3 in quick succession. These will deliver substantial upstream economies of scale and compelling value."

There is no word yet from BP, Kosmos or Golar whether phases 2 and 3 will entail further FLNGs.

"FID is another signal of how bullish the LNG market is," Farrer adds. "Tortue is the third LNG project to take FID this year, and its sanction is the first phase in the establishment of a significant new supply hub in the Atlantic basin."

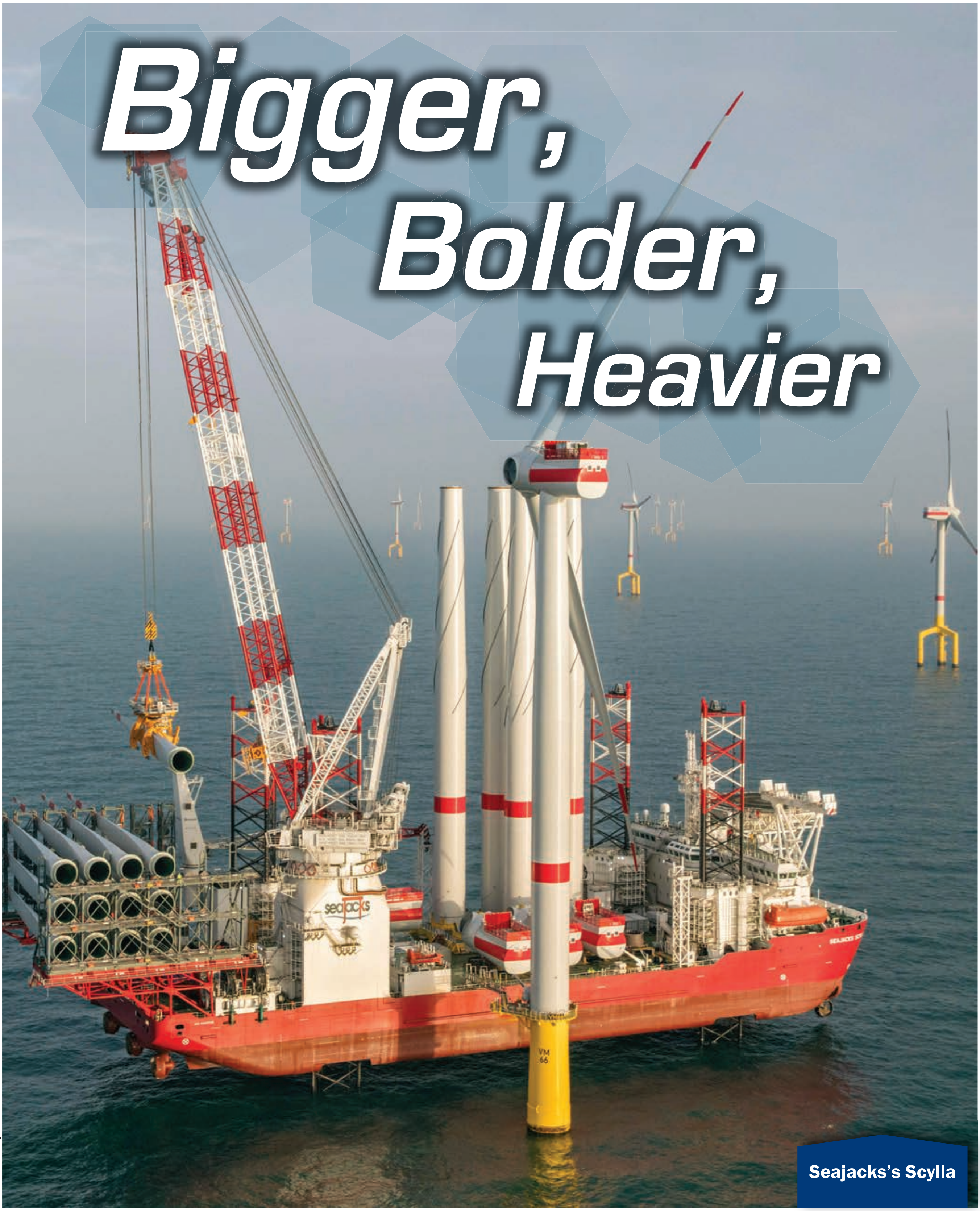
With Tortue phase one established, BP's next step in the region will be to develop the area immediately adjacent. "We are only developing the first phase of gas, but we have already identified enough gas supply for subsequent phases," Jasper Peijs, vice president of exploration for BP Africa says. "Once step one is done you would immediately look about setting up step two in Greater Tortue."

"Then, in the nearby Cayar block, there is the Yakaar discovery, which was the largest hydrocarbon discovery by industry in 2017 at around 12Tcf or two billion BOE," Peijs said. "That, together with the Teranga discovery that Kosmos had already made just to the east of that, puts between 30 and 50Tcf of gas in place. That isn't proven yet and will require an appraisal. Moreover, that is just in Senegal. In Mauritania we have acquired much seismic data that has been taken through to technical limits with some boutique processing and I'm sure that north of the Tortue gas field we will highly likely find some more gas that's material and significant, which would entail us looking at the possibility for a southern Mauritania gas hub."

Where next for Africa FLNG?

Aside from the fields under production, there are other sites in the continent that may be of interest. One potential location is Tanzania, as the Giant Rovuma basin in Mozambique extends there. Shell and Equinor have plans to develop a 10mtpa LNG plant by 2026/2027. "Maybe FLNG could be a potential option in the future," Cox says. "But as we have seen with the recent cyclone in Mozambique, situating an LNG plant in that location will have weather challenges. This is why Kribi and Tortue (Senegal/ Mauritania) are perfect locations for FLNG projects given the mild nature of the weather patterns along the West African coast."

Bigger, Bolder, Heavier



Seajacks's Scylla

Source: Seajacks

Europe's offshore wind market is growing faster than anyone expected – not least in terms of the components being installed. Could this mean a challenge for the existing installation fleet? Elaine Maslin takes a look.

While offshore wind is seen by many as a maturing market in Europe, with the first subsidy free offshore projects being planned, it's not without its challenges.

In Europe, there is more than 18 gigawatts (GW) of installed offshore wind capacity. Last year, 2.4GW was added and that's expected to be how much will be added per year over the next 10 years, according to consultancy and analysts Wood Mackenzie.

The UK, Germany and the Netherlands are the biggest markets, with France now also moving in, with plans to start feeding power into the grid in 2020/2021, and Belgium and Poland eying their potential.

A huge focus has been reducing costs, which has happened – faster than any expected, especially in the last 2-3 years. Indeed, the first zero subsidy bids were made for offshore wind parks in 2017, when Germany's EnBW and Denmark's Ørsted made bids for German projects.

"A large part of [the cost reduction] is attributed to a faster design cycle in turbine evolution," says Shashi Barla, senior analyst at Wood Mackenzie, with turbine manufacturers unveiling new, larger systems faster. "12- to 14-megawatt (MW) turbines could be available in the timeframe of those projects. That could be cost effective and provide power at zero subsidy." But, a faster design cycle means that the broader industry has to face up to shorter supply cycle, he says.

It's not that long ago – 2011/2012 – that vessel owners were building assets for an industry building out 6MW turbines. This year, 9.5MW turbines with 164-meter-diameter rotors will be installed at the Northwester 2 offshore wind farm in Belgium. Siemens Gamesa will also be prototyping its 10MW SG 10.0-193 DD turbine, with a 193-meter-diameter rotor, at the Danish National test center for large wind turbines in Oesterild, Denmark. The firm expects the turbine to be commercial by 2022. Meanwhile, GE is working on the Haliade-X, a 12 MW device. "It might not be long to go until a 14 MW is being developed," says Barla.

Meanwhile, according to the UK Chamber of Shipping, in 2017, offshore turbines were installed at an average depth of 27.5 meters and located 41 kilometers from the shore on average. Last year, the numbers were more moving into 100-150 kilometers offshore, where bottom-fixed turbines were being installed in 40-50 meters depth.

This puts pressure on installation contractors, and there are questions over whether there is capacity in the market. "If companies are not making investments today in these vessels and other balance of plant equipment, there may be a bottle neck in handling these large turbines and blades," says Barla. "We're talking already 100-meter-long-plus blades and heavy components. Some nacelle components you're talking 800 metric tons. You really need big machines, bigger cranes to handle these."

Arnstein Eknes, segment director for Offshore Service Vessels in classification society DNV GL, says there are two key dimensions when installing larger turbines; longer blades and heavier nacelles. "Today, we are talking about blades maybe 100-105 meters long. The nacelles are the heaviest component and they need to be lifted 130-140 meters up in to the air, so hoist distance is an issue. We see that the wind farm installation vessels built initially, they are too small today without retrofitting new cranes. Even those built 6-7 years ago are too small and they are retrofitting larger cranes, which is not an easy task. The cranes were maybe designed for 300 to 400 metric tons and now need to be for 700, 800, 900, maybe even 1,000 metric tons. It's about weight and altitude."

But, these are not the only issues, he says. These vessels mostly have to jack-up to perform installation operations. "Subsequently, we need to recalculate the strength and whole hoisting system of the jack-up in order to lift these components. So, it's really not straightforward to retrofit a crane, and it really is a headache for wind turbine installation vessels (WTIV) owners to know how to prepare for what the end customer will do," – i.e. how large turbines will go.

Indeed, some developers have already been seeking consent to use 20MW turbines on developments in the North Sea, which could see rotor diameters extend to 280 meters. "That's doubling the weight and capacity of the existing largest wind turbine," says Eknes.

While this could exert more pressure on the WTIV market, it may also result in fewer turbines being built; with 20MW turbines instead of 10MW units, half the number of turbines would need to be installed to create the same size farm. But, it could also mean added complexity, says Eknes, which might mean there's a practical limit to the size of turbines that comes before the technical limit. That poses are very difficult investment decision for WTIV operators.

Some are investing

Just four years into entering the offshore wind installation market, Belgian firm Jan de Nul is making a splash with the Voltaire on order from COSCO Shipping Heavy Industry in China. The newbuild, due to be delivered in 2022, will have 3,000-metric-ton lifting capacity, using a Huisman leg encircling crane and lifting capability, up to 270 meters in up to 80 meters water depth. “The Voltaire will be able to install at unrivalled hub-heights up to 165 meters with the standard boom,” says Manager Offshore Renewables at Jan de Nul Peter De Pooter. “This will allow the installation of the next generation turbines, with blade tips that might end up as high as 270 meters above the sea level.”

The Voltaire comes on top of Jan de Nul’s offshore jack-up installation vessels, Vole au vent, acquired just four years ago, and Taillevent, which are able to install turbines up to 10MW, says the firm. “They can lift all the components up to the actual max hub height of 120 meters,” says Jan de Nul.

“The next generation of turbines 10MW+ will become a challenge for all installation vessels currently available on the market,” De Pooter. “Foundations will be heavier; blades will be longer. The size, weight and heights will limit the quantity of turbines that can be transported per cycle [on board of today’s installation fleet] to one or maximum two. A vessel with the appropriate technical characteristics is the answer to this challenge.”

De Pooter sees a wider market for this vessel. “Offshore wind outside Europe and China is starting to develop,” he says. “Taiwan is working on its first full scale wind farms and Jan De Nul Group is one of the main contractors for the two first engineering, procurement and construction (EPC) contracts: the 120MW Formosa 1 wind farm in 2019 and the 110MW Changhua wind farm in 2020. Both wind farms are currently under construction.”

UK-based Seajacks has been operating in the offshore wind business since 2006. Since then, it’s built the Kraken, Leviathan, Hydra, Zaratan and, most recently, Scylla jack-ups. Seajacks expects to see the next generation turbines, eg. 12MW and, in number from 2023-25 and it is in discussion with developers over installing 12 or 15MW units with Scylla, which entered service in 2016 and has a 1,500-metric-ton leg-encircling crane and can work in up to 65 meters water depth.

“We think there is still a good number of vessels in the market that can install the larger wind turns, [dependent on site characteristics], when they arrive in the market. However, to install 10-15MW turbines, many of the current units will need to be upgraded and modified in order to stay relevant,” says Max Paterson, commercial manager at Seajacks. “The main issues for older smaller vessels in the market will be hook heights for nacelles and variable deck load, to carry heavier and larger components, and deck space. This means new cranes and leg extensions, etc., and it is likely that these necessary upgrades will have a negative effect on how fast these vessels can install.”

Having said that, Paterson also thinks demand and supply should be well balanced. “The market might become tight in some years, in the peak installation months over summer, if multiple projects are planned over the same time,” he says. Conversely, ensuring vessel utilization is also key for owners, which is why Paterson expects WTIV vessels will need to work around the world in the various new markets, like Asia and the US.

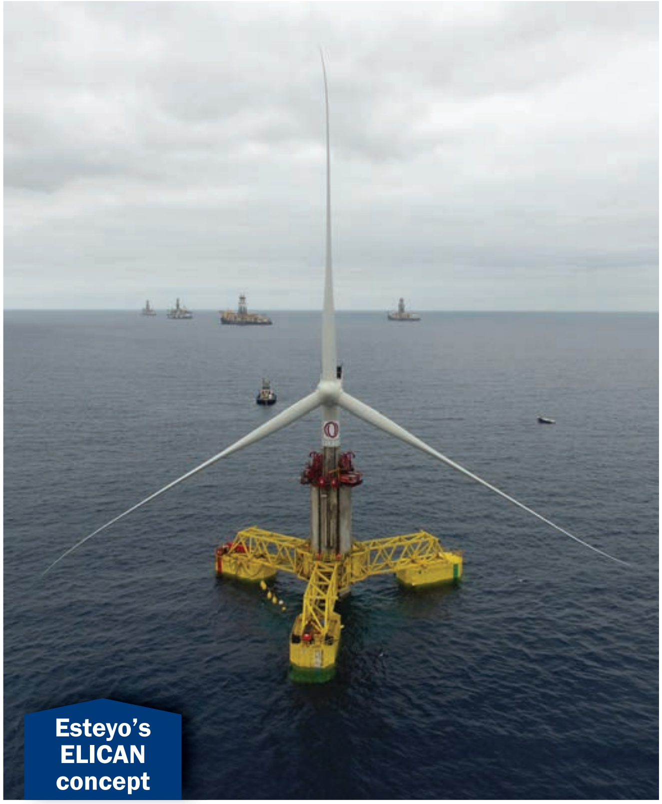
“Larger turbines, e.g. 10-15MW, will mean a smaller number of turbines will be required to reach a wind farm’s generation capacity, likely resulting in fewer utilization days for vessel owners,” Paterson says. “It is already a challenge keeping vessels occupied all year round.”

Source: Jan De Nul

“THE NEXT GENERATION OF TURBINES +10MW WILL BECOME A CHALLENGE FOR ALL INSTALLATION VESSELS CURRENTLY AVAILABLE ON THE MARKET,” ... “FOUNDATIONS WILL BE HEAVIER; BLADES WILL BE LONGER. THE SIZE, WEIGHT AND HEIGHTS WILL LIMIT THE QUANTITY OF TURBINES THAT CAN BE TRANSPORTED PER CYCLE [ON BOARD OF TODAY’S INSTALLATION FLEET] TO ONE OR MAXIMUM TWO. A VESSEL WITH THE APPROPRIATE TECHNICAL CHARACTERISTICS IS THE ANSWER TO THIS CHALLENGE.”

– PETER DE POOTER,
MANAGER OFFSHORE RENEWABLES,
JAN DE NUL

“We already have an extremely competitive WTIV supply chain,” he adds, “with a lot of cost-effective equipment in the market. Will it make sense to move the turbines weights and dimensions to a level where only two or three vessels are suitable? Only time will tell, but with the ferocious focus on lowering cost, particularly on installation, I am sure developers and turbine manufacturers will be very mindful of supply and demand dynamics in the WTIV market.”


Source: ALE

Esteyo's ELICAN concept

Source: Siemens Gamesa

Artist's impression of the Siemens Gamesa 10MW offshore wind turbine

Petter Faye Søyland, Head of Engineering, at Danish firm Fred. Olsen Windcarrier agrees that to move to 10MW+ turbines, many of the older vessels in the fleet will need to be modified to meet requirements on lifting height and capacity. "The majority of the jack-up fleet in the wind industry is capable of 8MW installations, with a few exceptions," he says.

Fred. Olsen Windcarrier's fleet is currently suitable to install a selection of 10MW units, he says. "The Brave Tern and the Bold Tern [jack-ups] have been thoroughly upgraded. Both have been subjected to 14-meter leg extensions to manage offshore sites with deeper water and higher survival storms, such as the North Sea basin. Moreover, the cranes' booms have been upgraded with a 20-meter boom insert, enabling them to install turbines with a higher hub height. Both Brave Tern and Bold Tern have replaced the deck crane to enable lifting of tools and equipment to the transition piece, for faster and more efficient installations. In addition, the vessels have undergone under-deck modifications and strengthening, as well as modifications to the tank arrangement to enhance the probabilistic damage stability; both to enable transport of higher and heavier turbine components."

Potential for disruption?

Others are looking for alternative engineering methodologies to make offshore installation easier. Last September, Heerema Marine Contractors' Aegir heavy lift vessel, launched as a kind of 'Swiss army knife' for the oil industry during its boom in 2013, installed a new design wind turbine concept, called the Delft Offshore Wind Turbine Concept (DOT), in just one hour, using the first slip joint connection concept in the industry.

The DOT wind turbine had already been installed on a monopile connected by the slip joint and was picked up in a single lift by the Aegir from Sif Rotterdam's quayside and taken to the installation site, the Eneco Princess Amalia Wind Park. There, it was installed by the Aegir as a floating vessel using dynamic positioning.

The slip joint connection was designed under the Slip Joint Offshore Research project (SJOR), launched by a collaboration between research partners TU Delft, TNO, Van Oord and Sif group, and project stakeholders Eneco and Heerema Marine Contractors in 2016. The concept is based on friction, where the weight ensures a firm and stable connection. This means that installation is done by simply sliding the wind turbine over the monopile without the use of grout or bolts, reducing costs, materials, equipment, personnel and schedule, says Heerema Marine Contractors.

Meanwhile, Spanish firm Esteyco is leading the ELICAN consortium which has designed and installed a 5MW prototype Elisa self-installing telescopic tower concept that would reduce need for installation vessels.

The prototype system was installed in 30 meters water depth in August last year – using WiFi – offshore Gran Canaria, Spain, and started producing power in March. It comprises a self-floating gravity-based structure (GBS) and a self-lifting telescopic tower, both made of concrete, with a 5MW Siemens Gamesa turbine on top. The structure can be fully assembled onshore, including the turbine, and then towed to the installation site where, after ballasting the GBS to the seabed, conventional heavy-lift strand jacks which are reused to lift one tower level after the other, lifting two sections weighing a total 960 metric tons into their final positions. The recoverable jacks that lift each level are supported by the one below, which also guides the hoisted tube as it rises, in a self-installing procedure in which the tower itself is the only supporting structure required. All works are carried out from a single access platform, which is removed once the turbine is installed.

The consortium – comprising Esteyco, Siemens Gamesa, Ale Heavylift, Dewi GmbH and PLOCAN (the Oceanic Platform of the Canary Islands) – claims this method could reduce installation costs by more than 35% when compared to jackets or XXL monopiles in deeper water (35 meters plus). The project partners also say the design is scalable and would be "a readily available means" to install new 12MW turbines.

Room for improvement

The first offshore wind project was built in 1991, at Vindby, Denmark (and is now decommissioned), and there's now more than 18GW of offshore wind capacity. "But, to put that in perspective, the global onshore wind capacity is about 600GW," says Barla. "So, from a volume perspective, offshore still has the biggest room for improvement." This could be in policy, process, technology and then supply chain, he says.

In terms of technology, there's a move toward use of carbon fiber in blades. "Historically, manufacturers have been reluctant to make investment into sourcing carbon fiber because it's expensive, and with very few supplying it, controlling the supply chain can be challenging," Barla says. "If you look at the biggest players, Siemens Gamesa, all their offshore turbines have been glass fiber. Now, they've announced the 8MW DD167, a prototype of which was installed a few months ago, and the 10MW DD193, both of which incorporate carbon fiber. There's been a paradigm shift in the largest players in the industry."

"In terms of processes, we are still not there yet," he adds. "It you talk about the automotive industry, with assembly lines and efficiency, they are far ahead, but they're a 120-year-old industry. Offshore started many years ago, but the real commercial projects only started in the last seven years. There is still a huge learning curve, Europe and globally."

But, while there's room for improvement, the lessons already learned in Europe can be replicated now in newer markets – such as in the US and Asia – to help them scale up faster.

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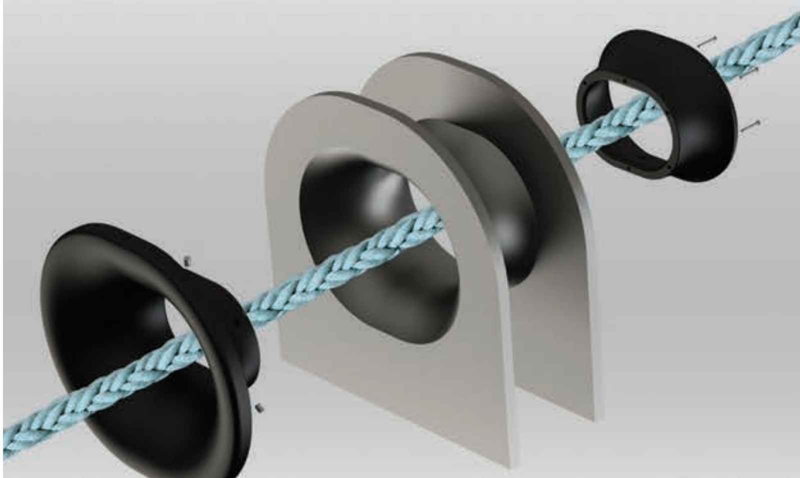

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A Future for Floating Wind

With more demonstrators in the water, more substantial players are taking interest in floating offshore wind.

BY ELAINE MASLIN

For some time, floating offshore wind has been something of a niche, but now full-scale demonstrators are in the works, and bigger players – including oil and gas companies – are taking note.

Erik Rijkers, Director – Market Development & Strategy, at Houston-based firm Quest Floating Wind Energy, says, "No doubt the entry of oil and gas players as developers/partners in floating offshore wind projects has opened a few eyes to the acceleration of this industry. Equinor now successfully operates the Hywind Scotland wind park and is planning to apply the concept to reduce the carbon footprint of its oil and gas operations in Norway, and it looks set to be followed by Aker BP."

Equinor's Hywind Tampen project envisions the use of 11 floating wind turbines to provide power to the Snorre and Gullfaks oil and gas production facilities in the Norwegian sector of the North Sea.

"Italian oil firm Repsol and Norwegian contractor Aker Solutions have also joined US-based Principle Power Inc. (PPI) while Shell has joined Denmark's Stiesdal Offshore Technologies and Sweden's Hexicon AB," adds Rijkers.

THE FLOATER DESIGNS

A number of designs have been out in the water for more than one year. Earliest off the mark was Equinor, with its Hywind spar concept. A scale prototype was tested offshore Norway before Equinor opened Hywind Scotland, a 30MW floating wind farm, off Peterhead, Scotland, in 2017.

PPI's WindFloat semisub has also seen service offshore Portugal and is now being used at Kincardine Offshore Windfarm Limited's site near Aberdeen, Scotland. The company, which is majority owned by Spanish construction company Cobra Wind International, has planning consent to build out the site to a 50MW farm using 8MW turbines on PPI's WindFloat design.

Last year, Ideol installed versions of its damping pool demonstrators in the water off France (Floatgen - concrete) and Japan (Hibiki - steel), while Toda Corporation has the GOTO project offshore Japan, with up to 10 turbines planned. For this and future floating offshore wind projects, Toda Corporation has built a dedicated 110-meter-long semisubmersible offshore wind installation vessel called Float Riser (Hatayashi).

Two further designs are due to enter French waters in 2021. EDF Energies Nouvelles' pilot offshore project Provence Grand Large will comprise three Siemens Gamesa 8.4MW turbines

Equinor's Hywind Tampen project concept

Source: Equinor

mounted on a floating structure designed by SBM Offshore and IFP Energies Nouvelles, based on a tension leg platform concept.

Eolfi's Groix and Belle-île floating turbine pilot project expects to see four 6MW turbines installed using foundations designed by France's Naval Energies, which can be built in in concrete, steel or a steel/concrete hybrid combination. This will be fixed to the seabed by an anchoring system that controls its movements, according to Naval Energies.

Stiesdal's Tetrafloat and the twin turbine Hexicon will close the ranks on the first-generation concepts that Rijkers expects to be dominant in the market out to 2022-25. A range of alternative floaters are also in various stages of development (France's Eolink, with a single point moored, four column floater; Spain's Saitec Offshore Technology's SATH technology, consisting of two connected cylindrical and horizontal hulls; Sweden's SeaTwirl, with a vertical axis turbine; and Italian firm Saipem's Hexafloat, which uses a counterweight beneath the floating substructure). Weights of these systems range from 410 metric tons per megawatt (T/MW) for a steel semisub to some 1,110T/MW for a concrete semi.

With projects in the water, larger developers and financiers are coming in and on a global scale, says Rijkers, citing EDPR, Eolfi, Copenhagen Investment Partners and Macquarie). "Equinor and PPI are (with various development partners) for now the main players in the US West Coast projects, as well as in Hawaii," he says. "While all developers and designers are eying opportunities in Asia (Eolfi/Cobra are a prime candidate in Taiwan), as well as in the recently announced 1.7 gigawatts (GW) projects in South Korea. This is also true in Europe, where Scotland is developing new rounds that will include floating wind, as well as France, which is modest, for now, but Quadran Energies Marines (behind the EolMed project) and Eolfi have already announced pre-development of the full-scale commercial follow-up of their French demonstrators. For example, Eolfi is looking at projects with a capacity of 3GW in the Gulf of Lion and 1.5GW offshore Brittany."

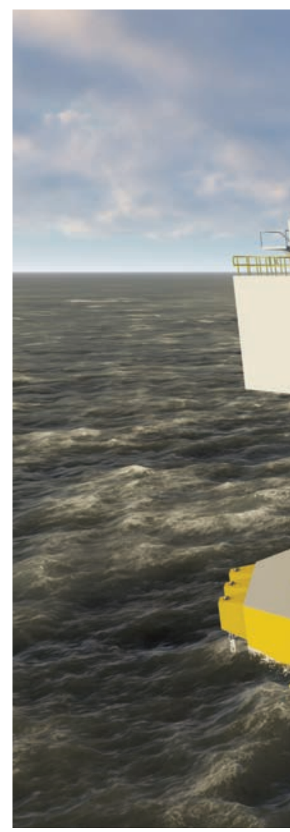
LOOKING AHEAD

While the outlook for offshore wind is generally expressed in total MW capacity, the number of floaters is considered more relevant, currently, to show the opportunity in the market, says Rijkers. "There are currently 50 floating units in projects under development out to 2022, worldwide, but this number will increase to 300 floating wind turbines by 2025 and possibly well over 1,500 by 2030, a fivefold increase," he says. "Furthermore, turbine capacities are evolving; MHI Vestas now has up to 9.5 MW turbines and GE has a 12 MW design."

Key is cost. Floating turbine unit average capital expenditure will gradually reduce from some $40 million in 2022 to $33 million in 2030, says Rijkers, but this cost reduction has a lot more potential once the full market for floaters levels out. He expects it will eventually go well below $25 million,

Equinor's Hywind Tampen project envisions the use of 11 floating wind turbines to provide power to the Snorre and Gullfaks oil and gas production facilities.

Source: Equinor



depending on turbine and cable costs.

That doesn't mean there aren't headwinds. Over the last 18 months, Quest FWE had to remove or set back the date for 20% of the projects it tracks, most of which were demonstrators that proved too hard to finance. "There is considerable interest from the financial community, however," he adds, "and it is believed that with each project coming online successfully, and the more operational feedback that is received, the risk and therefore financing thresholds on floating projects will alleviate."

FIXED BOTTOM WIND AND FLOATING WIND

While fixed bottom wind projects are reaching the water depths where some floating systems could be deployed from 30 meters of water, beyond some 60 meters floating would have a distinct advantage, says Rijkers. "On the US North East coast, the prevailing seabed and soil conditions may not be always suitable for fixed bottom concepts and pile driving falls into an expensive 'operational' window due to environmental constraints," says Rijkers. "Floating wind solutions may well show to have the advantage both technically and economically in such waters.

"New solutions such as mono buckets, a monopile with a suction device attached, are also being developed, but, until these have been proven to deal with the presence of large boulders, developers might be interested in considering floating alternatives in their concept engineering and front-end engineering and design."

A joint effort at creating a floating substation design

Source: IDEOL

FLOATING SUBSTATION DESIGNS TAKE SHAPE

Power and automation group ABB is not only eying its opportunities in floating offshore wind, the firm has joined French floating wind foundation designer Ideol and STX Europe Offshore Energy to develop a floating substation design.

The idea is being developed under a research and development project called OPTIFLOT, which also involves French industrial processes firm SNEF, and is based on Ideol's damping pool concept.

"We see the interest growing very fast to scaling up floating offshore wind," says Alfredo Parres, ABB Power Grid Division, Market Development Manager, Renewables. "We know floating offshore wind has been on the drawing board and there have been some pilots. The main focus has been the design of the floater for the turbine. That was the first step, to demonstrate you can install a turbine on a floating structure and that it can work. Now we have a few of those operating and that's pushed developers to look to what happens if you go full scale, to 500MW-1GW. As you get there you have to think about the substation."

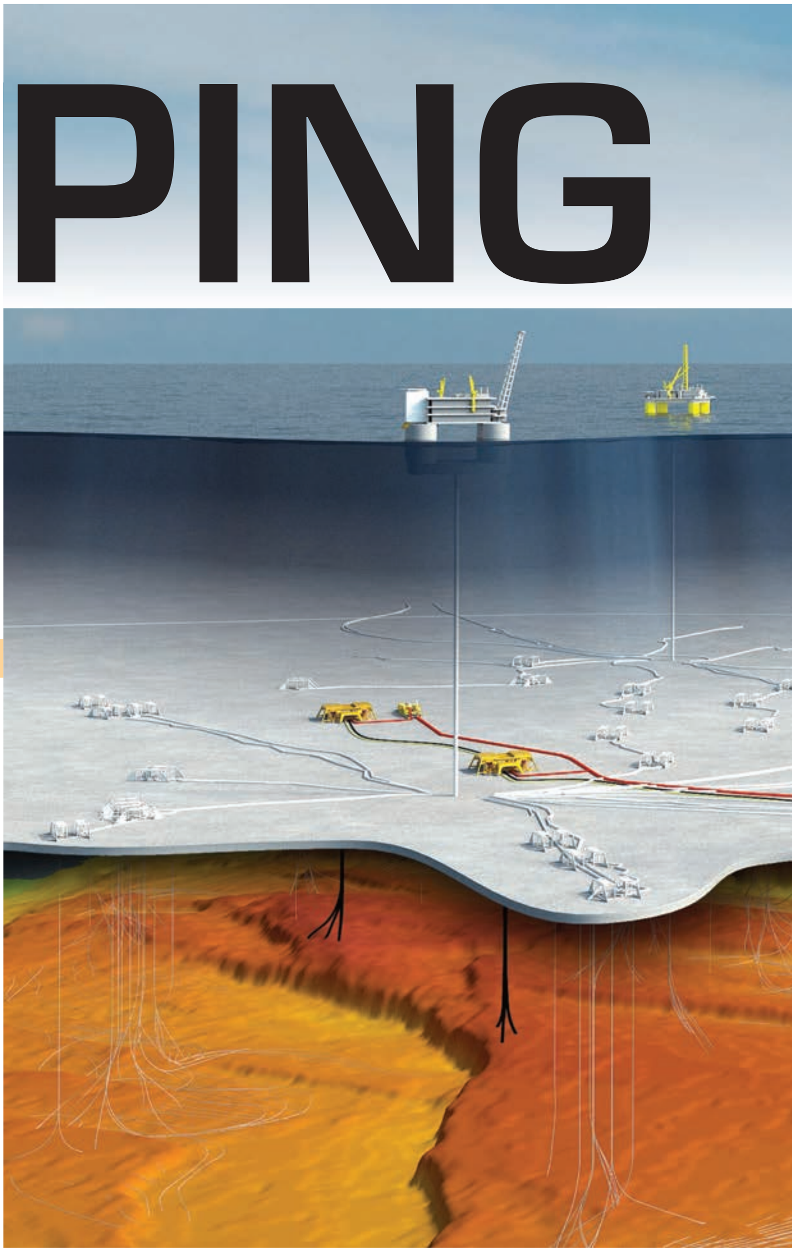
Parres expects large scale projects to be built out from 2030. By then, there are some key elements to be worked through. One is industrialization and standardization, another is making the mechanical structure operational in the floating offshore environment, he says. "Once these are addressed, the second biggest challenge is the cable (which will have to connect to the floating substation and endure the dynamic loads it will be subjected to). We see a lot of work being done on these."

In the UK, for example, the Carbon Trust has a project looking at dynamic offshore cables. "Dynamic cables are already used in the offshore industry now, but this will require a higher voltage, and that's more challenging," Parres says. "The level of development is lower than other aspects, but still you need to make sure equipment design, specification and standards are there. And the standards are not yet fully designed. Standards are important to streamline the industry." This will cut the power grid equipment, from transformers to breakers.

"Then we work on the footprint, the size and weight," adds Parres. "Weight and size are ken and how they are put together in a smart way so that all the system design is most efficient. Digitalization will play its role. We have started already in the digital, but much more could be done. The digital substation concept could reduce the amount of copper needed to transfer signals to the control room, could help in terms of maintainability, and reduce the footprint of the substation.

Parres is confident the solution will be viable. "Offshore platforms will not be the show stopper here," he says. "The biggest part is the turbine development and the cable will have to step up. But, moving toward full scale substations, I don't think will be the main challenge."

TAPPING



Operators continue to look for fast returns via subsea tiebacks while vendors look for technical solutions to help unlock more fields for less.

BY ELAINE MASLIN

A tide is starting to turn on the subsea industry, not least thanks to subsea tiebacks. It's a theme that's been underlying the last four years. While large capital-intensive projects have been put on hold, operators have been targeting "cost efficient" barrels close to existing infrastructure, representing quick return, low capex, low opex projects.

"Tiebacks are still very much the flavor of the month," says Mhairidh Evans, Principal Analyst, Upstream Supply Chain, Wood Mackenzie. "In 2018, the majority of subsea tree awards were for either tieback projects or infill drilling."

It's been a torrid time for subsea production system vendors. Orders for subsea production systems dropped to a low in 2016, but the numbers have been increasing, with a clear trend toward there being a larger proportion destined for brownfield projects (e.g. tiebacks), compared with new, greenfield developments, says Evans. She highlights recently sanctioned projects in northwest Europe, including Equinor's Troll Phase 3, in Norway, with nine wells, Total's Zinia 2 project, offshore Angola, also with nine wells, and CNOOC's Buzzard Phase 2, in the UK North Sea, with eight wells.

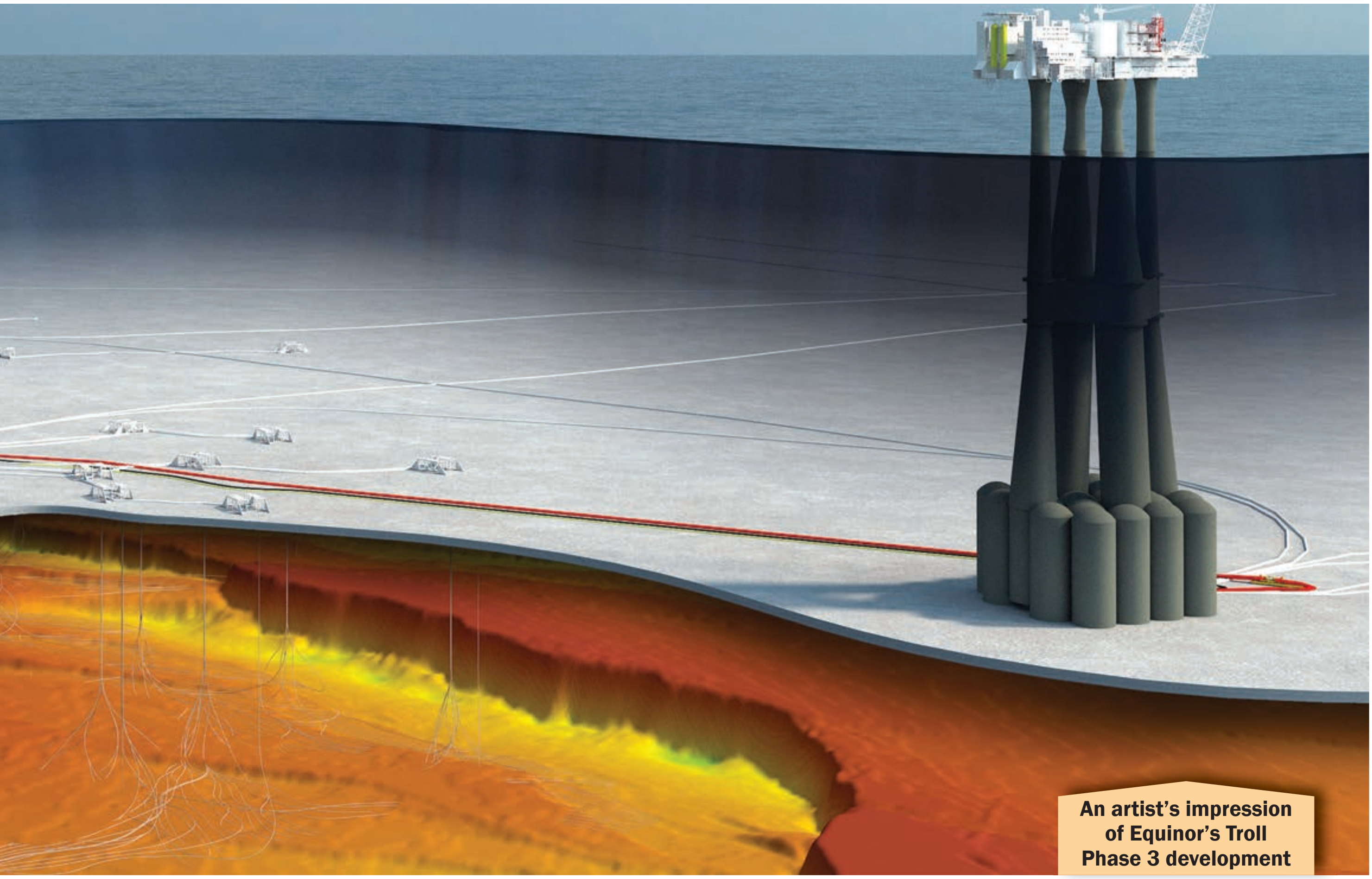
"Some of these projects are quite sizable," Evans says. "They have got off the ground because they have the key enabler of existing infrastructure, which lowers project economics." For example, Troll Phase 3 will extend the plateau production for gas from the Troll field by about seven years, and the expected productive life by about 17 years, according to Equinor.

In the US Gulf of Mexico there's been a similar trend. Anadarko, for example, has been pursuing what it this year called a "highly economic" tieback strategy to 100% owned infrastructure. Indeed, Chevron, which had recently come close to clinching a deal to take over Anadarko before losing out to a counter offer from Occidental, said the independent firm's tieback opportunities in the US Gulf were one of the reasons for acquiring it.

"Operators are very much still looking for that fast payback," adds Evans. "It's real driver. It's not just about absolute value or huge volume; it's thoughtful investment and how quickly they can get a return on that investment. That's why they have done relatively well through the downturn."

Yet, it's not always an easy decision. For small, marginal

TIEBACKS



An artist's impression of Equinor's Troll Phase 3 development

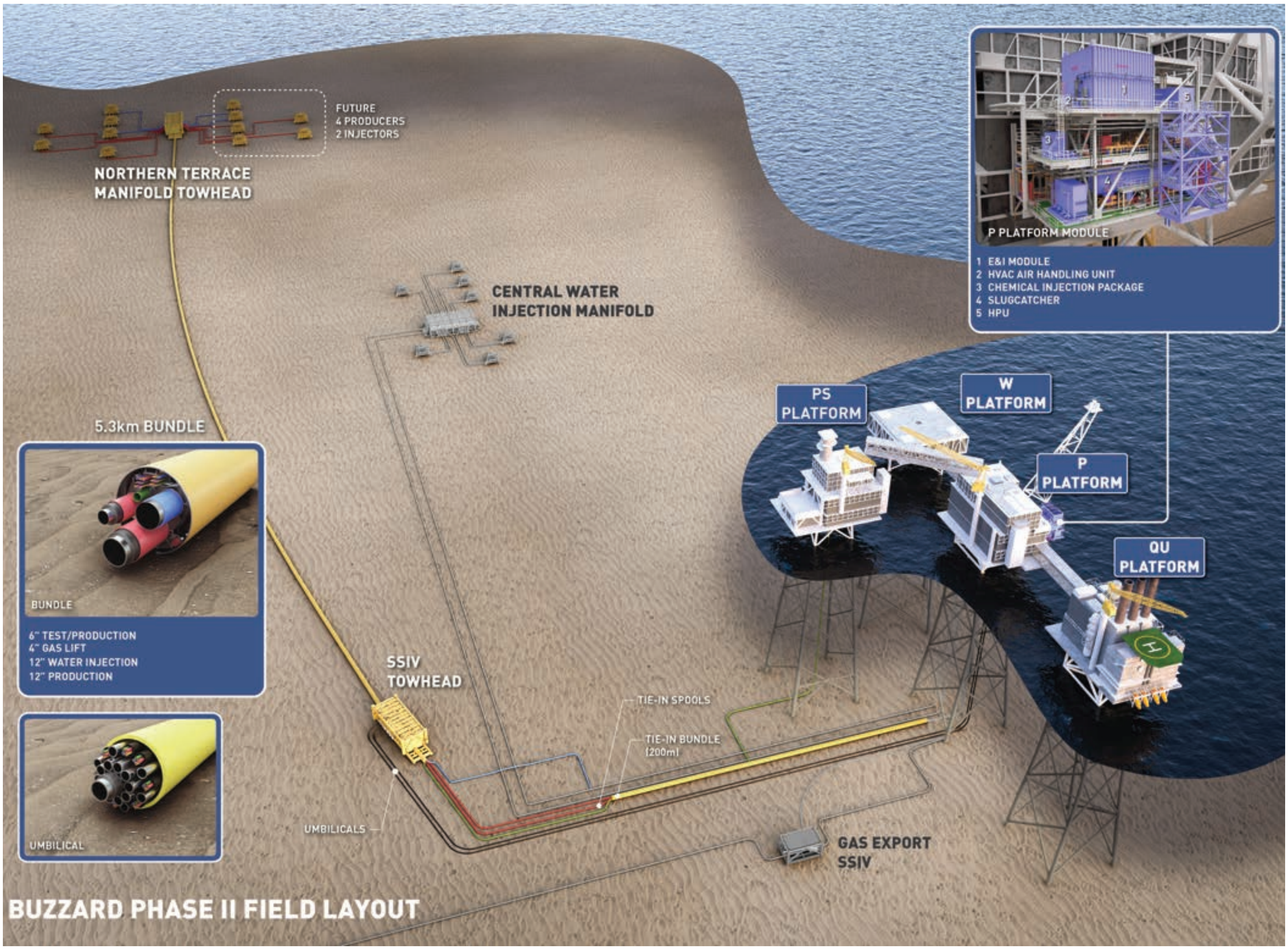
Source: Equinor

fields, low-cost solutions are needed to make fields viable. For other fields, where nearfield exploration could tip the balance toward new infrastructure, access to a still buoyant market in redeployable floating production, storage and offloading (FPSO) vessels, excess capacity in the yards and vessels coming off contract makes a standalone project an attractive option. This has been shown at Eni's Kalimba oil field discovery in Angola. Initially earmarked as a long subsea tieback to the East Hub facilities, Eni is now considering a standalone development, thanks to nearfield exploration success, Evans says.

"Operators had to pick their projects carefully going through the downturn, and now they are even more thoughtful about the projects that go through to sanction, and only the very best are getting through still," Evans adds.

LONGER OIL TIEBACKS

There would be even more opportunities if you could extend the distance that oil fields can be economically tied back, Saipem's Giorgio Arcangeletti told the Offshore Mediterranean Conference (OMC) earlier this year. Traditionally, oil tiebacks are within a 10- to 30-kilometer range. Increasing that to 50 kilometers or more would enable more fields to be tied into existing infrastructure. The biggest challenges to doing this would be flow assurance related. In conventional and



Source: CNOOC

shorter tiebacks, the most common field architecture solution to solve issues such as wax and hydrates is a combination of chemical injection and use of thermally insulated looped flowlines (to enable a separate service line or easier displacement of fluids).

For longer distances, alternative solutions are needed, such as heated flowlines, to enable a single production line instead of a dual line or loop, combined with subsea boosting and subsea power distribution to feed both consumers (heated pipe and pumps), by minimizing the deployment of subsea power cables that are very costly items. This architecture, combined also with subsea seawater treatment and injection and a subsea all-electric control system, would enable a single flowline and single power and (fiber) communications cable requirement to subsea (with no hydraulic lines needed) and reduce topside footprints.

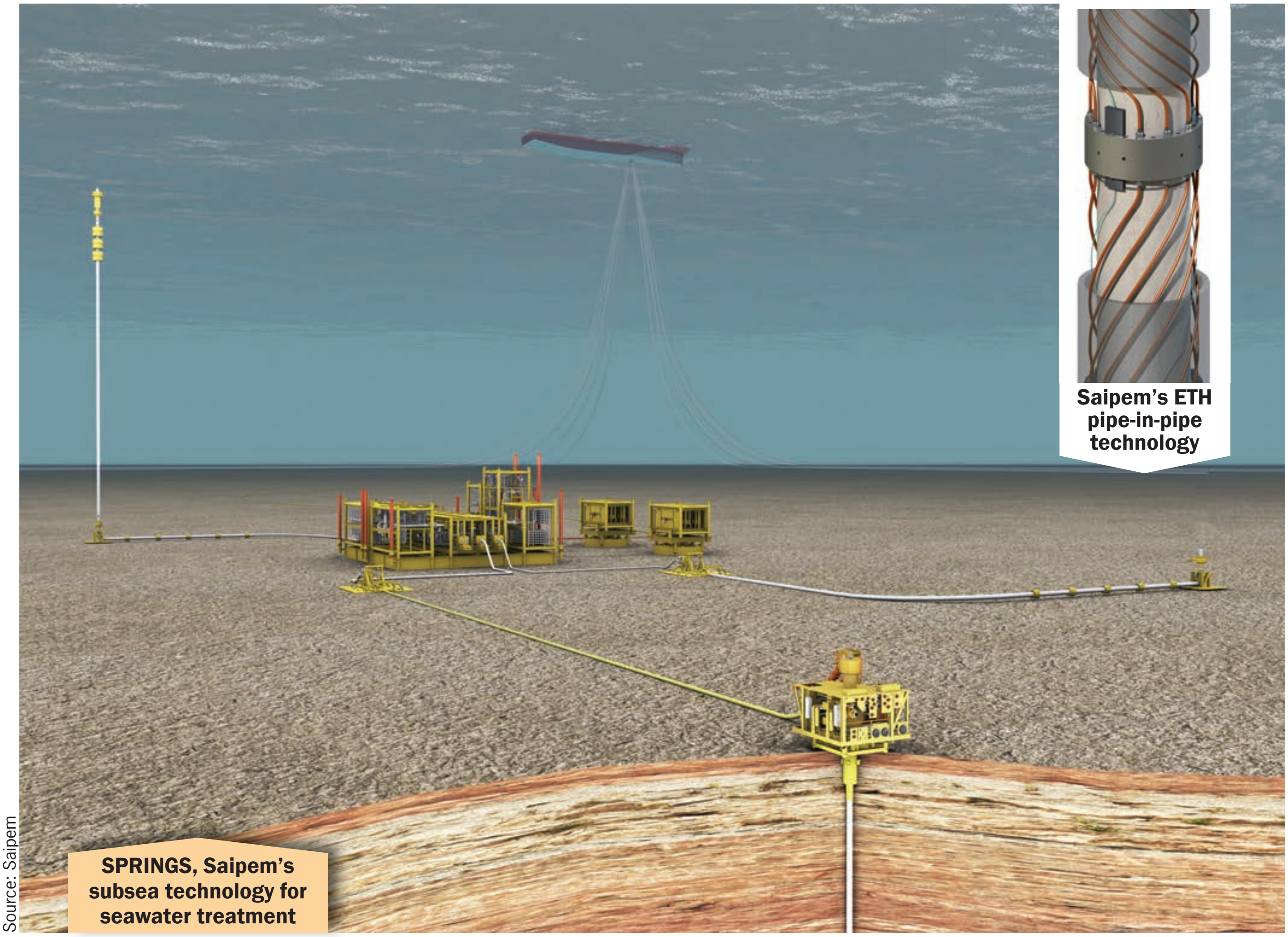
Most of these technologies are here or almost ready, says Arcangeletti. Direct electrical heating (DEH) or electrically trace heated pipeline heating (ETH) technologies are now proven in field, while Saipem is also working on an ETH pipe-in-pipe technology, and a qualification program for long tiebacks is ongoing and expected to be full-scale qualification tested by the end of this year, taking it to TRL4.

Subsea power distribution is an emergent technology a number of suppliers are working on and have either qualified or are close to qualifying.

Subsea power distribution would enable the power to be distributed subsea using subsea switch gear, variable speed drives (VSD) and transformers. This could then be used for all power needs on the seafloor – from pumps to the pipeline heating – in a more flexible and cost-effective architecture than by feeding each consumer from topside by deploying several cables.

Saipem has been working with Siemens to design and optimize the all-electric control systems. This has included using an all-electric control system with its SPRINGS ‘seawater treatment for injection’ technology. Saipem estimates that by using all-electric controls, removing the steel tube for hydraulic control, would bring savings to overall field development costs.

“This is a great achievement because with this, the electro-



hydraulic actuators of the valves are replaced with electric actuators, so you don't need hydraulic lines feeding a hydraulic power unit and the valves," Arcangeletti says. "The control umbilical [size] will shrink and reduce costs."

Saipem and Siemens have successfully concluded the joint development program for the all-electric subsea control system, aimed at promoting and qualifying an open framework subsea system, according to the Saipem mindset, hence providing additional flexibility to the subsea controls and applications.

The control system is based on Siemens DigiGRID and uses a limited number of standard interfaces, thanks to the integration of different communication networks, logically segregated, into the same physical infrastructure, rather than having separate subsea electronics modules and cables for each specific function such as process control, condition monitoring and safety.

The new technology reached TRL 4 (API 17N) with a factory integration test completed in April 2019. The main hardware is comprised of Module SubCU, an all-electric subsea control unit fit for highly demanding subsea processing applications as well as for traditional applications (including subsea brownfield projects and tieback fields); a subsea power manager unit (SPM); and a low voltage power distribution system fit for power consuming subsea processing applications and enabling new subsea users such as subsea chemical injection skids. The SPM unit is also a communication distribution unit and, if needed, can act as a functional hub in place of the topside master control station.

The last piece in the puzzle, to complete the subsea factory, would be moving chemical injection subsea. "Moving topside chemical injection subsea, close to the seabed, would remove the chemical lines, further reducing the umbilical size," Arcangeletti says.

Bringing all of these technologies together would enable a new field architecture, he says. "The technology has progressed a lot and is ready to go to market or a development, or is close to completion. The flexibility gained by adopting heated pipelines is much greater than having a dual pipeline (loop) and needing to displace the fluid on shutdown, etc.", thus also operational expenditure could benefit from this.

GETTING GAS TO SHORE

For long-distance gas tiebacks, there are other concerns, which Saipem has also been looking at. In a study for Total, looking at solutions for a 2,000-meter water depth, 150-kilometer-long gas field tieback, Saipem proposed a two-phase project. In phase one, there would be one production export line, using reservoir pressure to produce as much gas as possible. In the second development phase, subsea processing would be used to increase recovery. Subsea processing options could be either subsea separation or subsea compression, the latter providing the greatest recovery rates and, with use of a smaller diameter pipeline, lower costs, Amelie Pauplin hydraulic and flow assurance lead at Saipem, told OMC. She also said low-dosage anti-agglomerates could be used instead of monoethylene glycol (MEG), for hydrate inhibition, as well as a subsea MEG injection skid for shutdown and startup operations. For this system, all-electric would also be beneficial, by reducing the size of the umbilical required, she says.

Subsea compression was proven in 2016, on Equinor's Åsgard field offshore Norway. Now, Chevron has agreed a front-end engineering and design (FEED) contract with Aker Solutions for what could be the world's second subsea compression project, targeted for the Jansz-Io gas field, 200 kilometers offshore Australia in 1,350 meters water depth. This will enable a tieback to an onshore liquefied natural gas (LNG) facility, backfilling as excess capacity opens up. "Chevron backfilling LNG is one of the best business cases for subsea compression, and that's probably a growing market," says Evans. "Thinking about the next phases of projects like Ichthys or even bringing in to final investment decision (FID) stage for a big project like Browse [all in Australia]. It's compelling there, because there's little other infrastructure, so you are reliant on really good recovery rates."

Another idea to tap gas, that's maybe otherwise stranded, was presented by Lee Thomas, project engineer at Intecsea, at Subsea Expo earlier this year. It's been dubbed a pseudo dry gas system, and he says it could extend the distance gas tiebacks could achieve to in excess of 150 kilometers. It would involve placing multiple, in-line piggable separators to remove liquids from the wellstream and that condense from the gas during transportation. Supported by small, single phase centrifugal pumps, larger pipeline diameters can be used to optimize back pressure – by some 50-80 bar.

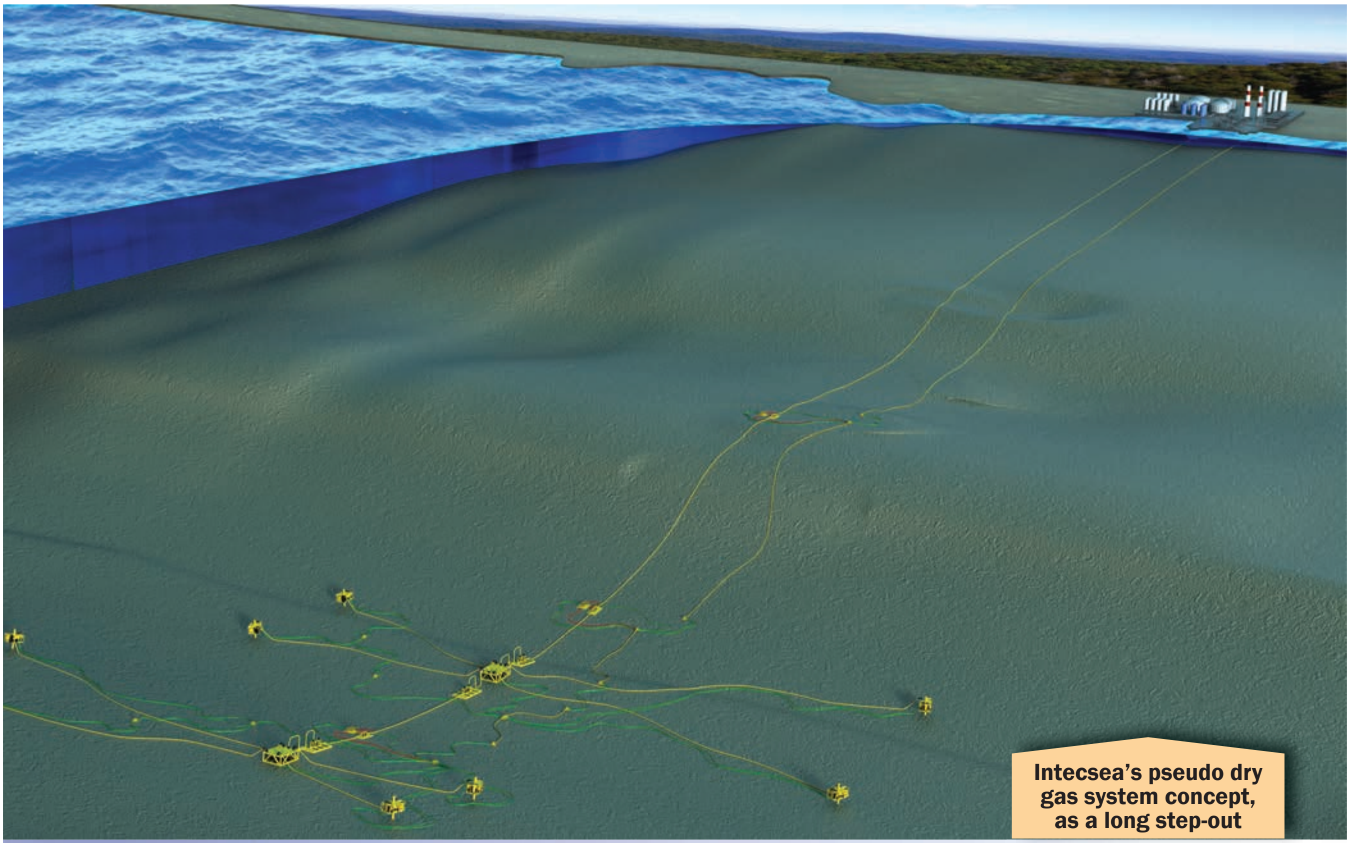
It's a concept already used onshore in coal seam gas gathering networks, Thomas says, and could be used for gas tiebacks to onshore LNG facilities. In a case study for a 183-kilometer tieback, with nine satellite wells, Thomas says six pseudo dry gas units could be installed at various points along the pipeline, the last being 80 kilometers from shore, after which the gas no longer condenses.

A study was also done looking at a 200-kilometer tieback, for a West of Shetland field in 1,700 meters water depth. Various options were looked at, including using a floating production system, single (22-inch) and dual subsea tiebacks, a tieback with west gas compression, and a tieback using the pseudo dry gas system. Thomas says the latter would just need four passive units across the system with a 30-inch pipeline.

The system could be used for tiebacks out to 200 kilometers, and even 300 kilometers, and could reduce cost by 40% to 60% compared with alternative concepts, says Thomas, who came up with the idea in 2016 in his home attic office. Worley (previously Worley Parsons, which Intecsea is part of) took on Thomas and the idea in 2017, and the concept has since had Oil and Gas Innovation Centre (Aberdeen) funding and University of Strathclyde support since then, with a client feasibility study performed last year, and the Oil & Gas Technology Centre (OGTC) supported West of Shetland study started in late 2018. A flowloop facility is being built to test the idea, working with the OGTC, and testing was due to start in May alongside another client feasibility study.

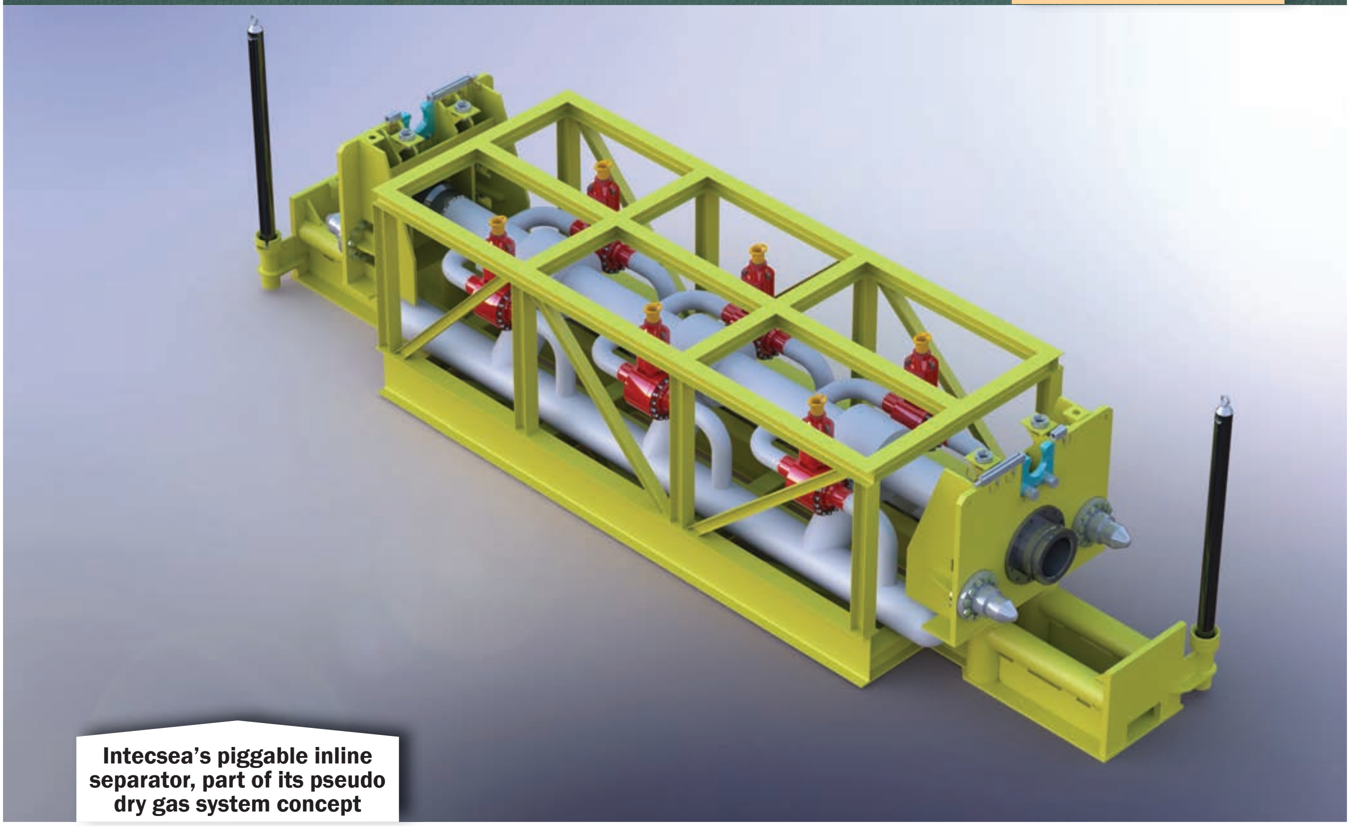
Source: Harald Pettersen, Equinor

The Troll Phase 3 project will tie into Equinor's Troll A platform.



Source: Intecsea

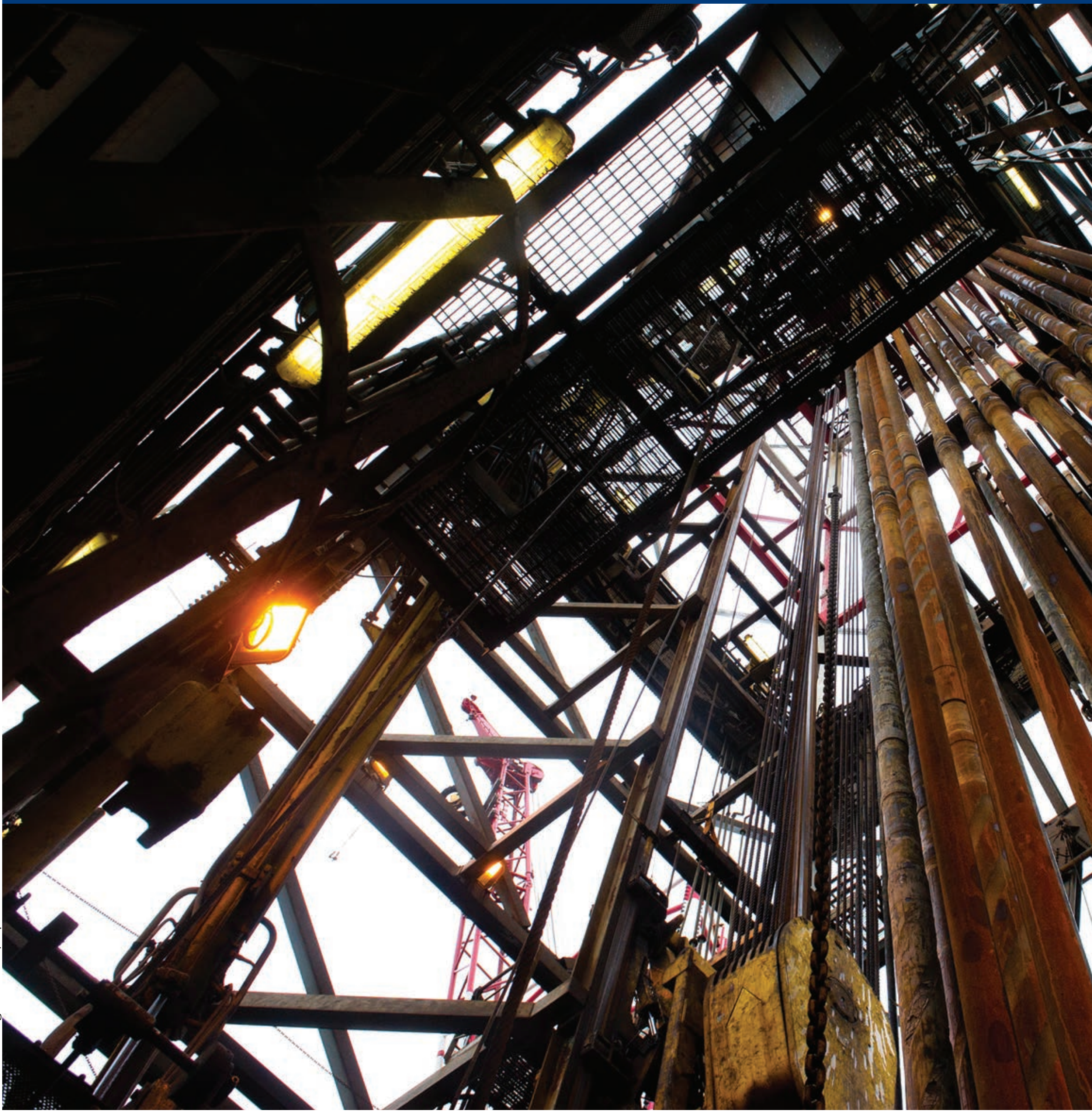
Intecsea's pseudo dry gas system concept, as a long step-out



Source: Intecsea

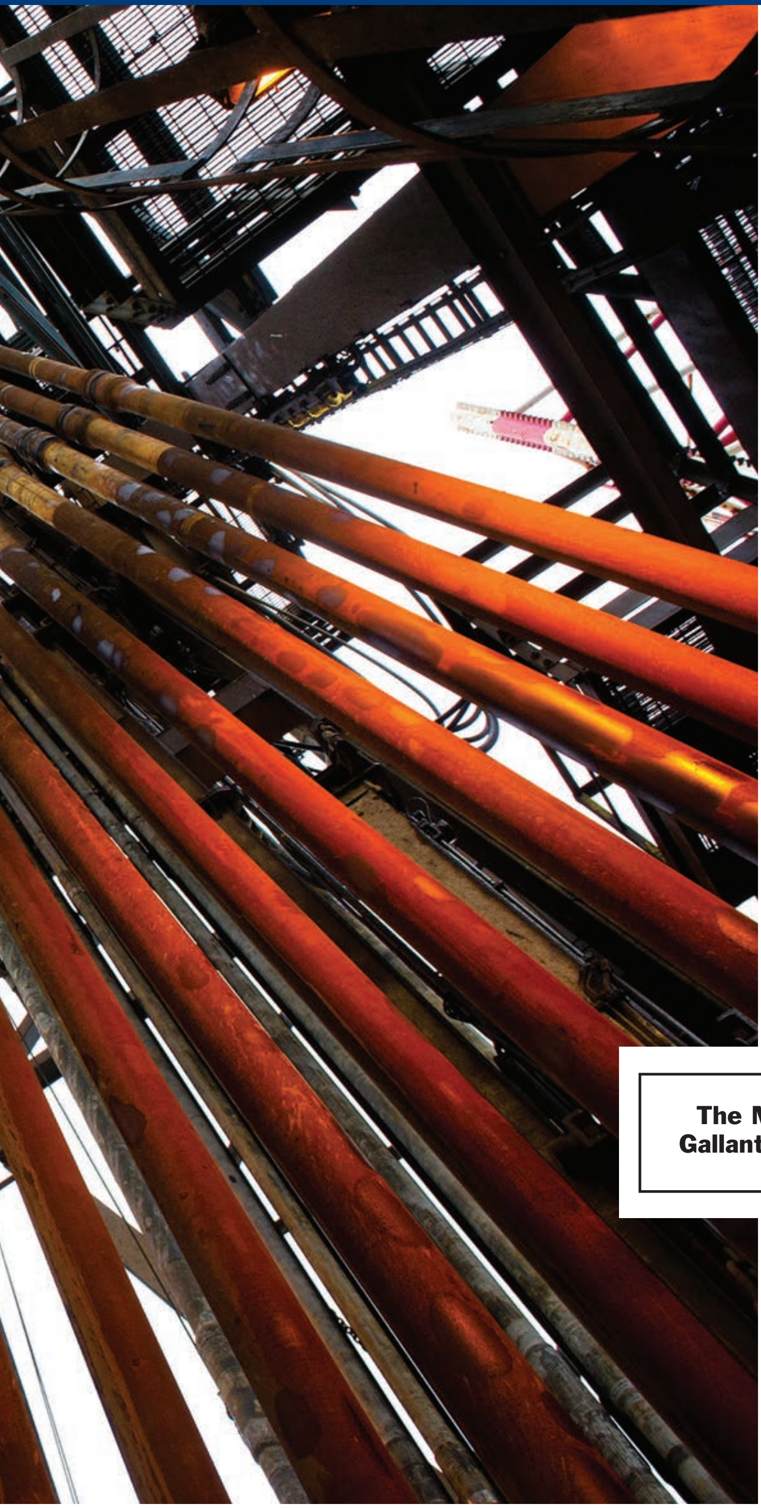
Intecsea's piggable inline separator, part of its pseudo dry gas system concept

Drill-tech trends:



Source: Ole Jørgen Bratland/Equinor

Hybrid rigs, automated drilling



The Maersk Gallant jack-up

By William Stoichevski

Fully-automated drilling aboard a semisubmersible or jack-up drill rig powered by batteries has just become a reality. As May 2019 got underway, new, modern rigs were being ordered on more exploration, and no fewer than eight modern rigs — seven semisubs and a jack-up — were known to be mobilizing for drilling campaigns after upgrading along the way with digitalized automation and/or battery power. At stake for operators are faster, cheaper completion times, green credentials and the ability to offer the recruitment pool a safer, "cloud-friendly" workplace.

At stake for rig owners in Norway, at least, is the right to drill here as well as rebates on 80% of green investments from Oslo' NOx Fund, an incentive scheme for businesses to reduce nitrogen oxide (NOx) emissions. That's the reason Denmark-based Maersk Drilling and Norway-based Northern Drilling are now upgrading their "sixth-generation" and "seventh-generation" drill rigs to the world's first battery powered offerings.

Egged on by clients like Equinor and Wintershall Dea, Maersk is combining the hybrid power with ship-style energy emissions efficiency software to manage and monitor the power levels and the sharing between main engines and electric DP power. The new electrical aboard the five-year-old, "ultra-harsh environment XLE jack-up" Maersk Intrepid will pave the way for "all-electronic" automation systems. For now, though, "data intelligence" will be applied to lower fuel consumption and emissions for Equinor at the Martin Linge field. Maersk's unnamed system integrator will not perform the electrical upgrade at a yard but "on the water", as the rig is already under contract.

In December 2018, Northern Drilling took delivery of the West Mira semisub. When we contacted Northern CEO, Scott McReaken, the rig was leaving a sheltered Norwegian shipyard after being equipped for more automation and new battery power and McReaken was getting dressed for OTC in Houston. A most-modern semisub, West Mira is equipped to get wells drilled and completed in record time.

McReaken was feeling the pride of a new car owner: "About 30% fuel efficiency is expected plus a similar reduction in NOx. That means we qualify to join the NOx Fund, and if we deliver and show the reductions, we'll get a partial reimbursement [on the investment in battery power]."

Yet, fuel efficiency is only a part of the savings for Wintershall Dea at the Nova field. "We're leveraging the technology big-time. The beauty of the rig management system and the drill tech is that other drilling efficiencies come into play on

Source: Equinor/MHWirth

pipe-handling, data-collecting from wire, etc. It's a seventh-generation rig that allows us to put all sorts of technology onto it. Seadrill ordered it that way. We bought it from the yard."

According to a future-tech report by DNV GL, more efficient drilling — and by 2025 automated drilling operations — will be "in operation". It suggests these are early mover steps taken by rig contractors at the request of oil companies wanting to comply with new Norwegian emissions standards as well as the fuel savings and "online" drilling that can yield detailed well and reservoir reports (see Schlumberger) in real-time enabled by emerging digital drilling equipment.

Early movers

"There's no one tech in particular, but a wholistic approach to making a difference for their customers," says AGB Sundal Collier rig analyst Lukas Daul about the trend of rigs becoming more competitive by loading up on the latest kit. "The ultimate goal being to lower or speed up the time needed to drill the well and to lower the overall cost from the well. That's the mantra."

We chat about the other rigs now also upgrading — Odfjell's, Awilco's, Transocean's, EnscoRowan's — the work being done under new drill-tech alliances and licenses and by industrial affiliates linked by ownership shares. Early out was Seadrill, original commissioners of the West Mira specs. In August 2018, they hired Kongsberg Maritime and Kongsberg Digital to put real-time monitoring systems aboard the semi-subs West Hercules and West Phoenix. The goal was to put everyone's expertise online for the benefit of look-ahead drilling ops, preventive maintenance and well safety, with well history data built-in for electronic Well Specific Operational Guidelines, or eWSOG. Odfjell Drilling was quick to follow suit and hired Kongsberg Maritime for its own real-time "advisory solution" aimed at augmenting safety and eliminating downtime for the sixth-generation semisub Deepsea Stavanger, which could then benefit from shore-based online expertise for operations in remotest offshore South Africa. A Kongsberg riser management system and a Kongsberg information management system were part of the package.

It's easy to see how the battery powered West Mira and Maersk Intrepid then pile on the savings for operators — and that's what's happening. In April 2019, Equinor informed shareholders that it was drilling more wells faster and for 10% less money than a year ago, while spending more "quality time" testing. Whatever the Big Data being derived from each spin of the drill bit, a Lloyd's Register report called The Technology Radar suggests oil companies really believe a rig's predictive analytics are saving "$325,000 per rig using machine learning to predict drill-bit locations."

"In the end, I don't see one particular feature being a game-changer, except, perhaps, digitalization and automation," says Daul, who watches rigs all day for institutional investors, and who had just returned from a tour aboard a rig receiving a digital upgrade at a yard near Bergen.

New standard

For deepwater heavyweight Transocean, the move to automate became more frenetic in February 2019, when management decided to upgrade five offshore rigs with centralized automated drilling control (ADC) which reins in the best of drill-tech suppliers, MHWirth, NOV and Sekal for "higher rates of penetration while drilling, highly stable bottom hole pressures and avoiding (surge) effects and early detection of (kicks)". The Transocean Enabler was the testbed of a first ADC system in 2017 and immediately delivered faster turnover times for Equinor. Well integrity and safety benefited from countless electronic tags or sensors that comprise an early-warning. As we write these lines, the Transocean Spitsbergen, Transocean Norge, Transocean Encourage, Transocean Equinox and Transocean Endurance were all upgrading to ADC.

While NOV is known for its already digitalized drilling control packages, the Akastor-owned MHWirth is known for big-hardware items like tensioners and hydraulic cylinders. Yet they, too, are busy applying automation and a new line of electric-hydraulic rather than purely hydraulic riser and string tensioner systems. That'll provide more force with less energy while integrating with control electronics. Sister companies in the (Akastor investment family) include drillers Awilco and Odfjell.

Model-based automatic drilling-control company Sekal will embed its DrillTronics software in the drill-control systems (DCS) of all five Transocean rigs slated for upgrades. This will automate most of the driller's repetitive tasks by controlling draw works, top drive and mud pumps to avoid wellbore events. Preventively, the software determines the possible actions of a driller — string accelerations, speeds, rotation, pump startups and flow rates — to stabilize down-

Source: Odfjell Drilling

State-of-the-art: the Deepsea Stavanger semisub

hole pressure. This early detection and instant avoidance of "deteriorating drilling conditions" has solidly preempted a range of the costliest drilling mishaps and minor events. So, package item DrillTronics, alone, seems able to cut drill times by from 4% (Equinor) to 8% (some say 20%). The trouble for some is that they can't have it unless they're already somewhat digitalized.

West Mira

"I think it's a good thing," McReaken says of automated drilling. "The safer we do it, the better. The quicker we do it, the more efficient the drilling effort becomes. The bonus is that there's a structural change as well, as the focus changes to drilling and completion times rather than just drill rates."

One of the reasons Northern Drilling pursued the battery powered West Mira was to have a low-emissions, modern rig with the digitization to enable the best that automated drilling brings.

"We saw the potentiality in understanding what our equipment and especially what the drill bit is doing and in working more efficiently. It's a trend, a change," McReaken says, adding, "Manual [drilling] breaks are still out there, but they're not drawing a premium, and they're not garnering the relationships or contacts we have."

Meanwhile, another rig — the Deepsea Stavanger of Akastor-owned Odfjell Drillig — is on its way to the arctic having stopped at a Norwegian yard for its e-upgrade. It reportedly has "third-party" drilling equipment on board, and that could be MHWirth's, although another Odfjell business division makes its own drill-tech.

With many rigs having been scrapped, those that remain are extra competitive for providing the savings, compliance and holistic digitalization that operators want. Apart from sensory data from the drill bit in real time (again, see Schlumberger), operators employing digitalized rigs can now see the promised benefits of predictive analytics, as more engineering outfits present digital, analytical software tools covering the derricks and the drill floor.

The upgrades are just in time. Oslo says there's $31.12 billion in exploration, production and appraisal wells to be drilled between 2019 and 2021 by rigs and platforms: 60 exploration wells this year alone. That has tightened up rig markets, and only the truly digital seem to be getting any work.

"One advantage we have is that we're not having to catch up [technologically]," says McReaken. "It's cool that we can embrace this now. We've been talking about it for so long. It's great that we can bring it all and tie it in."

Some rig contractors, however, ordered advanced rigs years ago and are only now, because of 'The Downturn', diving into the automation they ordered. And then there are the modern, if not-brand-new, rigs.

"It's not like you can take a 30-year-old rig and turn it into PlayStation. Not having a more automated process to begin with is the difference between new assets and old assets," McReaken says.

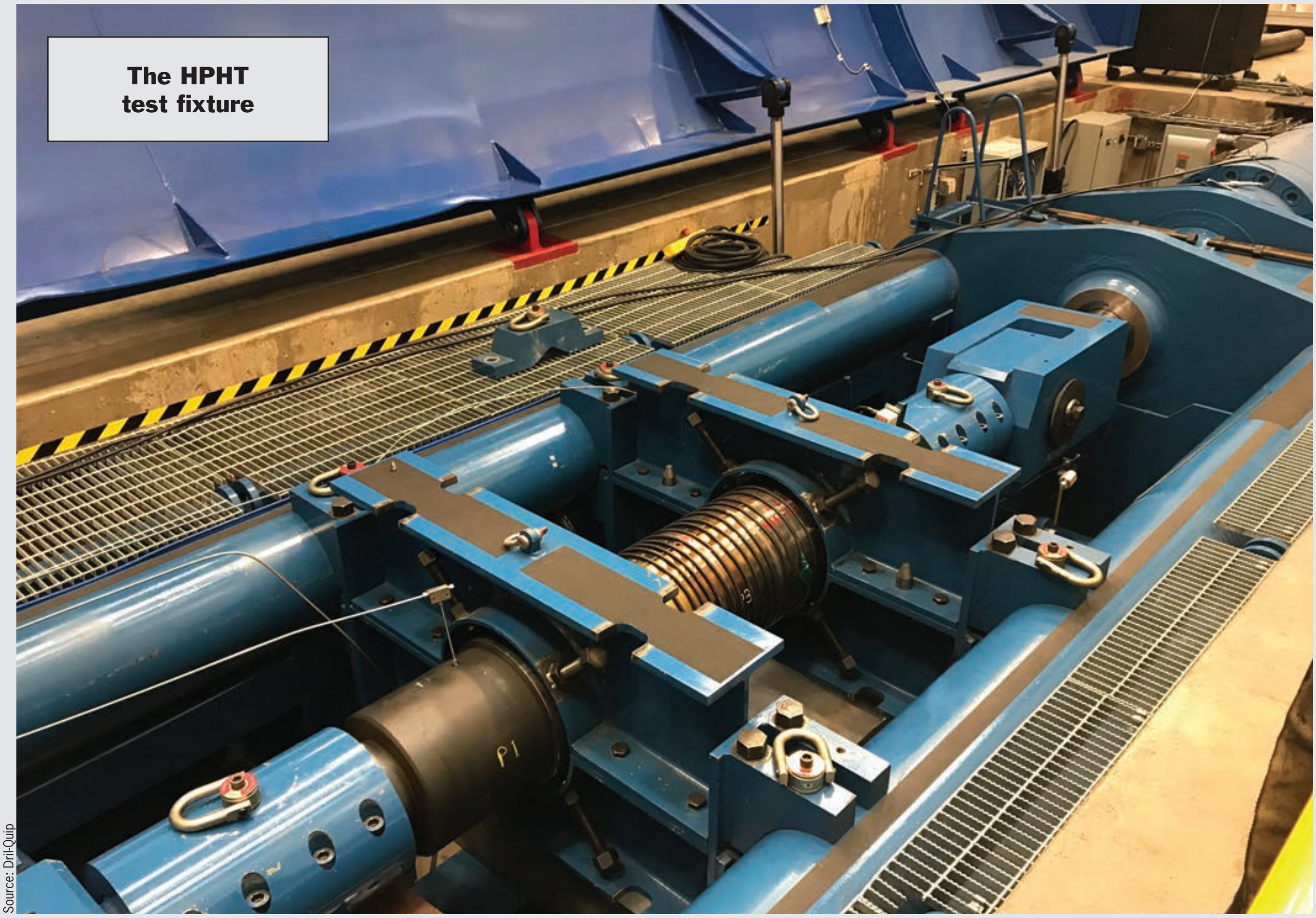
"With sensors tracking everything, you get a heads up with a newer rig. How many sensors? Maybe 15,000 on a newbuild, or two on a 20-year-old rig," he adds. "That sort of sums it up. Just talk to the engineers. They can talk about it all day long."

Expandable Liner Hanger Designs Evolve

Expandable liner hanger designs are advancing to meet the ever-increasing demands of deepwater well construction. **By Jennifer Pallanich**

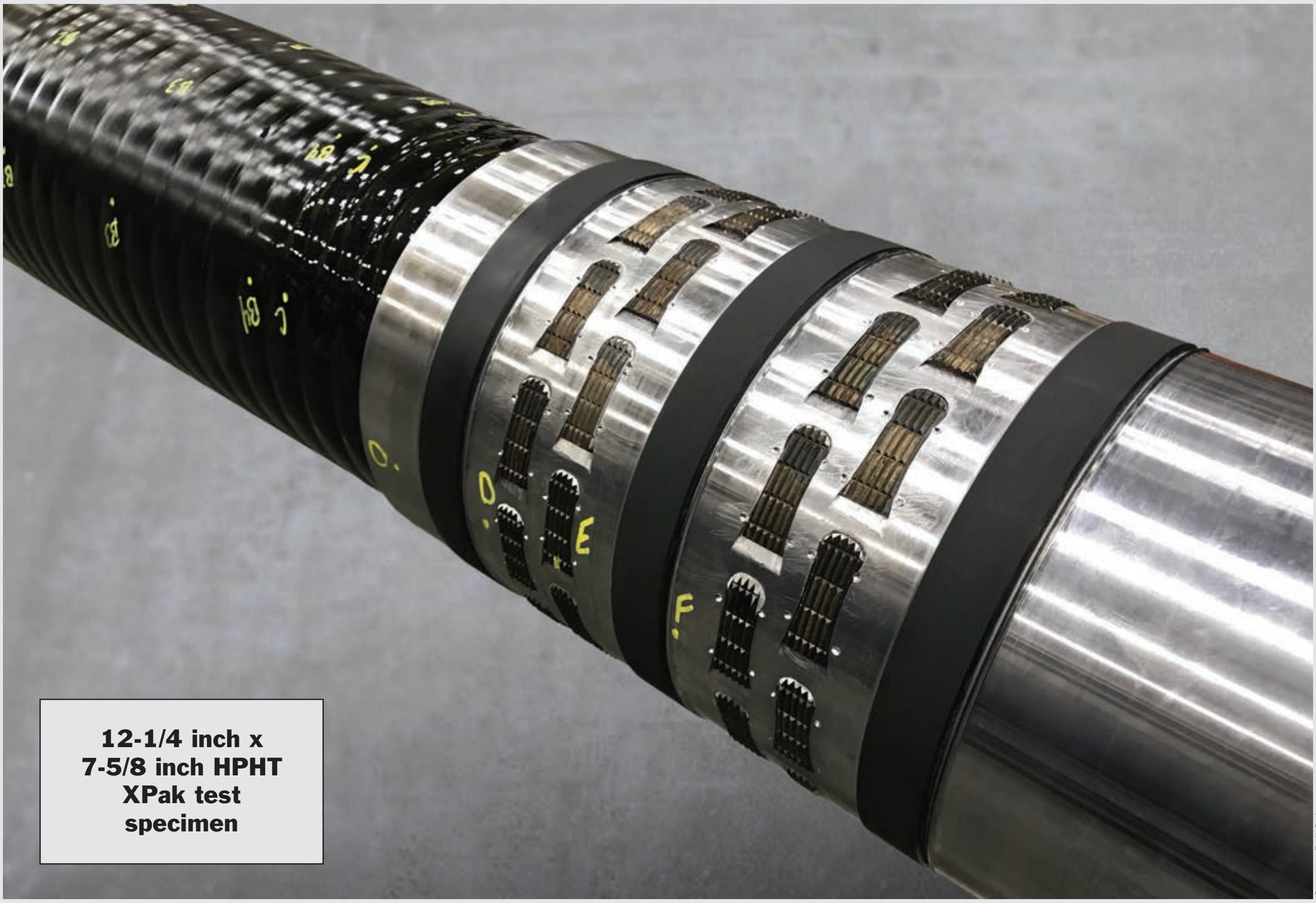
A new expandable liner hanger design provides an effective liner top seal for high-pressure, high-temperature (HPHT) well conditions while another provides double expansion capability as an option to submudline hanger systems installed in large diameter surface casing.

Expandable liner hangers, such as the TIW XPak Expandable Liner Hanger System, are engineered to mitigate risk by ensuring an effective liner top seal. The XPak is a fully-integrated system that provides both pressure sealing and



The HPHT test fixture

Source: Dril-Quip



Source: Dril-Quip

anchoring capabilities in a compact package, says Edward Royer, engineering manager for downhole tools at TIW, a Dril-Quip company.

The two-component linger hanger/packer system delivers redundant metal-to-metal sealing and elastomer seals to provide assurance for inner diameter casing irregularities. The system also provides for a tieback capability at the liner top with various seal bore lengths to meet future installation needs.

TIW's XPak system is designed differently than its competitors.

"We expand our hanger body to the host casing by using an expander," Royer says. "The expander remains installed in the liner hanger body after expansion," which offers better collapse pressure resistance compared to other expandable liner hangers. This structural support remains intact for the life of the installation, in contrast to other expandable liner hanger systems which retrieve an expansion device as part of the running tool after installation is complete, he says.

The XPak Expandable Liner Hanger system, which has been installed in over 1,000 wells globally, was designed for offshore use, although it has been used onshore as well, Royer says.

"Our system is compact at the liner top where it's in contact with the host casing," he says, adding the XPak system needs less than two feet of contact with the host casing to provide an effective seal and anchoring capability.

One advantage of the XPak system, Royer says, is the simplicity of installation, which involves deploying the expandable liner hanger downhole on a multi-piston hydraulic running tool, cementing the liner and pressuring up, then expanding the XPak liner hanger onto the host casing. Once the install is complete, the running tool is released with drill pipe weight down or right-hand rotation and recalled to the surface.

The XPak's optimized outside diameter increases the bypass area, so it's possible to run the system faster, which saves operators money and time, Royer notes. The larger bypass area also permits higher flow rates for circulating and cementing the well while mitigating risks concerning effective circulating densities, he adds.

He calls the XPak the "most robust liner top hanger seal in the industry," citing a track record of high reliability. "We've minimized liner top leaks to almost zero," he says.

The XPak Expandable Liner Hanger system is available in sizes ranging from 4-1/2 inch OD x 5-1/2 inch OD to 18-5/8 inch OD x 24 inch OD.

Because of evolving industry needs, TIW developed variants on the XPak theme, including one for HPHT conditions and the Double Expansion XPak Liner System, which eliminates the need for fixed landing profiles and risk associated with sub-mudline hangers when installing casing in larger diameter surface casing, thus increasing operational flexibility and providing cost savings.

Doubling down

The Double Expansion XPak (DE XPak) deploys through wellhead restrictions to provide a metal-to-metal sealing within seamed, thin-wall surface casing (22 inch OD x 1 inch wall) and offers high hanging, lockdown and pressure capacities. The expandable liner hanger system is intended for large bore wells with thin walls. As with the XPak, the DE XPak expander remains installed in the hanger body, providing structural support that permit higher loads and pressures.

The double expansion process is achieved with a pressure activated, multi-piston hydraulic tool used to expand and displace an expander, which in turn expands the XPak hanger body to contact and interfere with the host casing. The expander provides tieback capability via a polished bore receptacle and remains installed inside the hanger body for the lifetime of the installation.

The DE XPak can be placed as desired after running the 22-inch casing rather having to be installed in a fixed location, Royer notes. It will seal inside a seamed pipe.

A supermajor has expressed interest and applications for the DE XPak in the Gulf of Mexico and offshore Brazil using the double expansion technology, Royer says.

The DE XPak is available in 18 inch OD x 22 inch OD (1 inch wall).

Under pressure

Following a customer request in late 2017, TIW set about engineering a version of the XPak that could meet 15,000 psi and 375 degrees Fahrenheit conditions and loads of 1 million pounds in tension and 800,000 pounds in compression.

The 7-5/8 inch OD x 12-1/4 inch OD hanger design required enhancements from the standard XPak offering to meet the challenges of HPHT conditions. For example, Royer says, the slip design changed some to provide better anchoring capability with the use of multiple rows of staggered slips.

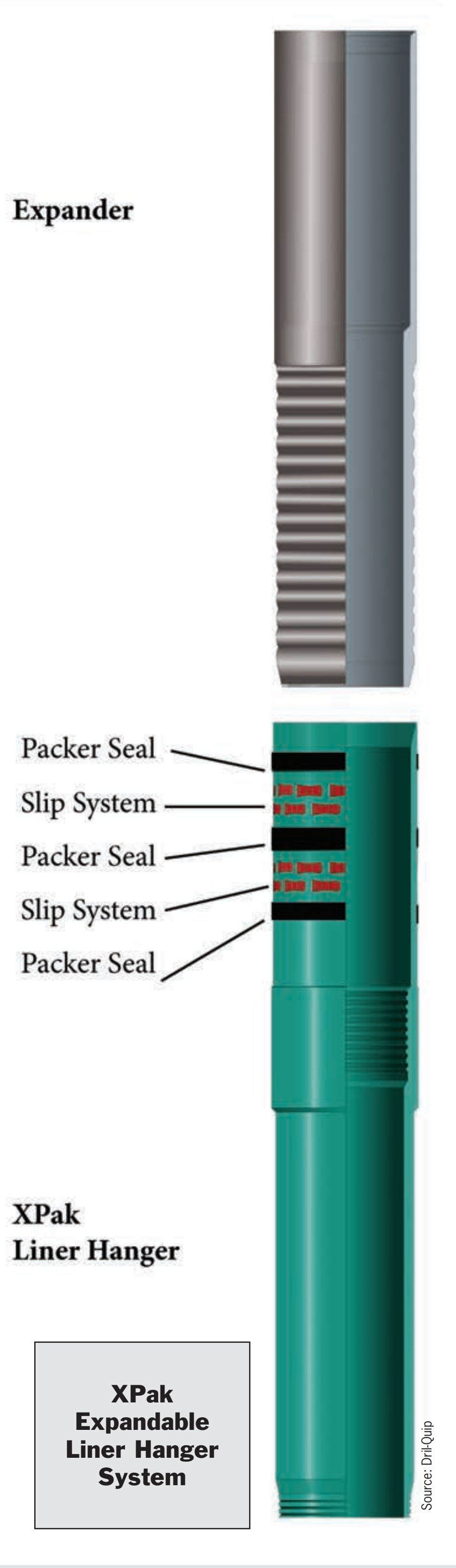
For the qualification test, Dril-Quip built a full-scale replica liner hanger and built a test fixture around the assembly. Testing subjected the XPak hanger system to combined loading, tension, compression and internal and external pressure. "For HPHT, we exceeded the burst pressure ratings of the liner," Royer says.

Third-party facility testing revealed the system could withstand internal pressures of 21,750 psi at 60 degrees Fahrenheit and 15,000 psi at 375 degrees Fahrenheit to meet the customer's statement of requirements.

"What makes this HPHT qualification unique is we are satisfying two different drilling groups: injection wells with lower temperatures and production wells with higher temperatures," Royer says. "It's a pretty dramatic temperature difference for a system that has to seal and anchor the way this liner hanger system will have to perform."

Testing wrapped up in early 2018, and the customer has deployed the HPHT XPak Expandable Liner Hanger system four times in the deepwater Gulf of Mexico, Royer says.

System development and qualification of the 7-5/8 inch OD x 12-1/4 inch OD HPHT XPak Expandable Liner Hanger system has allowed the customer to run 7-5/8 inch OD and 8-5/8 inch OD liner systems using the same hanger system. The design incorporated the request to make the hanger system more versatile and applicable for future installations.



XPak Expandable Liner Hanger System

Source: Dril-Quip

"What makes this HPHT qualification unique is we are satisfying two different drilling groups: injection wells with lower temperatures and production wells with higher temperatures."

– Edward Royer, TIW, a Dril-Quip company

HPHT XPak

Source: Dril-Quip

REGULATORY & CLASS UPDATE

*Senior representatives from "thought leaders" ABS, DNV GL and Lloyd's Register weigh in on some of the top class and regulatory issues facing the offshore industry today, from decommissioning and decarbonization to cyber security, unmanned surface vessels and beyond. And what discussion of regulatory matters would be complete without at least some mention of Brexit? These topics and more are explored by **Matthew Tremblay**, ABS Vice President – Global Offshore Markets; **Liv Hovem**, DNV GL Oil & Gas CEO; and **Mark Tipping**, Lloyd's Register Offshore Technology Manager, in the following roundtable discussion.*

BY ERIC HAUN

With all the financial cuts that have taken place in the past four years, has cost compromised safety?

HOVEM: We recognize that the industry has been under immense pressure to cut costs and improve efficiencies in the last few years. This has resulted in examples of cost savings such as maintenance and training expenditure being deferred. It is too early to say whether this has resulted in reduced levels of safety performance, as the impact of these cost saving measures is not immediate in terms of a safety impact. Last year, we published a 'State of Safety' white paper, following our annual industry outlook survey. We found that nearly half (46%) of the 800 senior professionals that were questioned believed there had been under investment in inspection and maintenance of facilities and equipment the year before.

One could argue that the industry could never spend enough on maintenance, however. We believe that the industry is well aware of the implications of cutbacks or deferral of maintenance, and their potential impact, not only on safety, but also on production efficiency.

Despite the impact of cost cutting measures across all areas of the oil and gas industry, safety and environmental management should never be compromised.

TREMBLAY: In general, we observe that offshore operators have done a good job as an industry in optimizing their performance without sacrificing safety standards. Many companies, including ABS, have been able to focus on optimizing capacity without negatively affecting capability. For example, the opex efficiencies gained in drilling have been made through improved asset integrity management which has enabled cost reductions. From the numbers we see, this has not contributed to an increase in unplanned incidents related to safety.

TIPPING: The downturn has put pressure on all aspects of the industry, however our engagements across our clients have always looked to ensure safety, and where necessary invest in new solutions, this of course being particularly attractive if the 'win win' involves a safety enhancement and cost saving. Utilizing technology to remove people from hazardous locations, and hence improve safety, is one of the key strategies. LR aims to promote safety even further with its Safety Accelerator program led by the LR Foundation.

As offshore decommissioning activity ramps up, do you see regulatory or technical shortcomings that need to be addressed?

HOVEM: 100 offshore platforms and 5,700 kilometers of pipeline are forecast to be decommissioned or reused over the next decade on the UK continental shelf (UKCS), with the Oil and Gas Authority (OGA) estimating the total cost of oil and gas decommissioning to be £58 billion ($73.4 billion). The UK regulator has set a cost reduction target of more than 35%. The

Source: DNV GL

challenge is that when the oil price is high, operators push back abandonment, and this makes planning of decom programs difficult, particularly where operators may wish to share the costs of decommissioning capabilities, such as heavy lift vessels.

The economic burden of decommissioning liabilities has long been the subject matter of debate in the UKCS. Historically, oil and gas companies were able to access tax relief on their decommissioning costs. This was wholly dependent on their tax payment history. This put new entrants, who do not have a tax history, at a disadvantage

From November 1, 2018, a new transferable tax history (TTH) regime was initiated to provide transfer of tax history between buyers and sellers of late life assets in the UK, to maximize tax relief for decommissioning expenses. This allows a seller to transfer some of its tax history to the buyer. This subsequently allows the buyer to set the decommissioning cost against the TTH. It will be available for license transfers that receive OGA approval. Even so, there is still lack of UK public limited company (PLC) investment focusing on removal of redundant infrastructure. An industry led resolution will not deliver the optimum decommissioning solution.

The OGA has set out three priorities for decommissioning, cost certainty and reduction; decommissioning delivery and capability and decommissioning scope, guidance and stakeholder support.

The market undoubtedly is mature, opportunities are abound and innovation will be central to the efficiencies expected by the OGA.

From a technology perspective, there is lack of investment in dedicated plug and abandonment rig and associated supply chain capacity and capability for the full range of well types and depths required. As favorable oil price returns, costs may rise for decommissioning in line with increased rig utilization.

Many see new digital solutions as the next wave set to shake up the offshore industry. From your point of view, what are the greatest benefits – and challenges – posed by digitalization?

TIPPING: Cost and safety – both can be positively impacted by digital solutions. Analytics have the potential to help predict future behaviors at the equipment and system level ahead of an event occurring. This provides considerable advantage in that damage can be avoided to equipment or systems optimized for future predicted parameters. Additionally, crew can be prevented from entering an area where they may be exposed to harm in advance of the dangerous conditions occurring.

TREMBLAY: The ABS position is that digital is an enabler not an end or a solution in itself. It is there to enable the right solutions. The benefits of digitalization from an ABS perspective are related to greater transparency and availability of more detailed and timely data relative to asset performance and health, whether for performance improvements and integrity, or the optimization of survey and inspection. It all feeds into the ability to better inform owners and class on the real time condition of assets.

The risk for the industry is that we are applying new technologies at the fastest pace ever seen and this could be getting ahead of our understanding of the potential scale and complexity of the risks that might result. The systems of statutory regulation we have had in place for a long time may struggle to keep up with the pace at which new technology is being incorporated. This is something we as an industry need to be very aware of and understand how to manage the risks as a community, with class and industry groups working together with statutory bodies so that we continue to deliver these changes safely.

HOVEM: There are so many fascinating things happening in the industry right now. Digitalization is opening up new opportunities that were previously unthinkable. Cloud solutions, the Internet of Things, artificial intelligence (AI), data volumes, remote services, autonomy, advanced robotics and velocity, for example, are causing a transformation toward enhanced efficiencies, transparency, new decision models and new ways of working together. Expertise in physical systems and their operations must be combined with deep knowledge of data and information technologies to realize new possibilities.

As new technologies are causing significant changes, it is crucial for businesses to take the right steps in the challenging transformation toward a digital environment. If they fail to do so, their competitors who do adapt will leave them far behind.

With new technologies come other risks that were not there previously and that organizations need to be resilient against. That is where cyber security plays an important role to ensure operators are not vulnerable to attacks.

Where are the industry's main weaknesses in terms of cyber security, and is enough being done to counter?

TREMBLAY: While shipping and offshore have focused their efforts at information technology (IT) improvements in the last few years, both sectors are still coming to terms with cyber risks in the context of operational technology (OT), and there is much more to be done. Even some companies with advanced IT capabilities are coming to terms with the improvements in policy and practice they need to make to manage OT cyber risks, in their own operations and those of vendors and suppliers with whom they are integrated. ABS is highly focused in the area of OT cyber risk, providing training, evaluation and advisory services in the marine and offshore sectors.

TIPPING: According to the International Energy Agency (IEA), companies and public spending in cyber security is insufficient, driven by an underestimation of the threat. Due to the lack of cyber security in standard Supervisory Control and Data Acquisition (SCADA) communication technology, the offshore industry remains highly vulnerable to attack, and the existing policies and regulations do not seem adequate to tackle these issues.

Cyber security in offshore environments should relate to real time requirements, with cascading effects, and combining legacy systems with new technologies.

Unfortunately, most of today's offshore facilities are managed by industrial control systems designed with efficiency in mind rather than security. An increasing number of legacy components are also connected to the internet, which makes them more efficient and cost effective, but also more vulnerable to cyberattacks. Additionally, for new projects, cyber security requirements are not clearly defined in construction contracts or are covered in service agreements, which are usually discussed at the final stages. Retrofitting a non-secure SCADA system costs far more than installing the correct security measures up front.

To counter the cyber security challenges despite the shortage in spending, the offshore sector must take a systemic approach and assess cyber security risks across the entire supply chain.

From your perspective, how mature is the offshore renewables industry in terms of risk and safety? Where could more be done to improve?

HOVEM: The maturity level of offshore renewables has increased tremendously over the last decade. Turbine size is constantly increasing and frequently requires completely novel technologies to be applied. Everything new brings potential risk. Will it work? Will it be safe? Will it deliver the power outputs and financial returns predicted? One of the key tools in mitigating risks is the development of technical standards which keep pace with the rapid technology developments and the certification against these standards. In order to fulfil this purpose in an increasingly price sensitive environment, certification will have to evolve from a compliance-based to a state-of-the-art, risk-based approach.

TREMBLAY: From what we observe, the maturity of the offshore renewables industry is no different to the mainstream offshore energy industry. Offshore renewables is in effect a business and engineering offshoot of many of the technical resources that have been proven in offshore operations.

Risks are evaluated through a similar safety case methodology, while class and other statutory approvals are undertaken in a very similar way to the marine and offshore sectors. The end product is different, but we don't see much difference between offshore wind and wave technology and offshore drilling and production; both rely on the development and approval of once novel technologies that become proven and accepted into everyday operations.

The design, operation and maintenance of high-pressure, high-temperature (HPHT) wells is an important topic for many in the industry today. What key challenges persist in this area that regulation and class can help address?

HOVEM: HPHT, as defined today, is a novel environment for which the industry has been working diligently to develop and qualify equipment so that it performs as expected, in a

"THE SYSTEMS OF STATUTORY REGULATION WE HAVE HAD IN PLACE FOR A LONG TIME MAY STRUGGLE TO KEEP UP WITH THE PACE AT WHICH NEW TECHNOLOGY IS BEING INCORPORATED."

MATTHEW TREMBLAY
VICE PRESIDENT – GLOBAL OFFSHORE MARKETS, ABS

safe and reliable manner. Over the past few years, equipment manufacturers, operators and service companies have identified technical challenges and new failure modes and mechanisms for which current technical standards do not give guidance for. Hence the need to execute proper technology qualification process where the risk assessments are performed in the light of the new loading conditions. The Bureau of Safety and Environmental Enforcement (BSEE) in Gulf of Mexico have developed a guideline to provide clarity to what the US government will require to approve for the drilling and production of a HPHT well. The American Petroleum Institute (API) is also focusing efforts to expand that knowledge through industry collaboration and may be able to address technical challenges such as fatigue, material selection and qualification, and others.

Do you see instances where technology has outpaced regulatory development? Or vice versa?

HOVEM: Most of the concern that exists in this area relates to the ability of regulators and regulations to keep pace with the rapid changes arising from digitalization. Remote operations, remote survey and inspection techniques, and the potential autonomous operations are all examples of where technology is changing faster than regulation. Many of these new digital solutions also open up new risk areas such as cyber security, which is another example of where new challenges to existing risk management practices arise.

TIPPING: Autonomous ships, at least at the smaller end, are now with us, and the classification – LR already provides extensive rules and guidance in this regard – and regulatory needs have been identified and are being enacted. This is not as clear with the floating offshore industry. While fixed structures employing unmanned approaches have been in service for several years, floating offshore structures are different, with different needs and highly complex hydrocarbons processing plants. This need is becoming clear as many of the new projects look toward unmanned floating production, storage and offloading unit (FPSO) scale facilities.

And, while aspects of the marine autonomous requirements are applicable in many instances, it does not provide a complete and tailored approach. LR have recognized this need and will be releasing proposed requirements in this area and will also be keen to work with and engage with the coastal state and flag state authorities to provide a consensus approach to this fast-moving area.

Is more widespread industry collaboration needed to tackle new or persistent challenges? Please give an example.

TREMBLAY: If there is a particular opportunity for enhanced collaboration it is around the challenges in application of new technologies, a particular example being the concept of the digital twin, where a successful and accurate outcome requires the input and agreement of designers, operators, owners and regulators, in order to deliver the potential benefits.

The only way to realize the benefits from a digital asset management tool like the digital twin is to have all these stakeholders aligned with the intended outcomes and objectives of the technology, whether that is performance optimization, environmental impact or survey and inspection planning.

TIPPING: Collaboration has always been important and historically differentiated the best from the rest. However, collaboration is now a hygiene factor necessary to manage complex issues that bridge multiple stakeholders, deliver high levels of efficiency required to remain competitive within the industry and innovate to continually improve performance.

So, what is meant by widespread collaboration? The pooling of information and insight from a wide group of stakeholders for the general good. We do see leading companies sharing insights and coming together to improve safety, the environment, human rights and society. A good example of this is the Oil Companies International Marine Forum (OCIMF) which over many years has implemented a framework that addresses the safety of ship staff, terminal staff and the environment leading to significant industry-wide improvement.

HOVEM: Yes. We cannot work in separate silos anymore. Technological leaps often require industries that were previously separate to work more closely together and learn from each other. We have to think differently about collaboration and system integration.

Please discuss a particular regulatory development underway globally that you see as especially important.

TIPPING: The offshore industry by its nature has a more fragmented regulatory makeup. A more interesting dynamic within the industry is decarbonization of production. Discussions with numerous companies have shown a deep awareness of the need to address the carbon issue which may seem at odds with a hydrocarbons industry. However, all energy models show hydrocarbons as being a major partner in energy provision well into the future, hence the need to demonstrate a responsible model for the carbon dioxide (CO2) that is released. Many companies are looking to ensure minimum CO2 release in production. In fact, many organizations believe that future sanction of projects may indeed need to demonstrate this or carbon offsets to get regulator approval in the future.

TREMBLAY: ABS has been active in helping companies understand, prepare for and comply with numerous environmental regulations and/or core priorities long term are making the necessary preparations for the low carbon economy. One of the most important elements to this work is the management of safety during the transition and afterwards. Decarbonization will mean radical changes for the way the industry operates, and our priority is to help industry maintain safety as these changes take place.

We are undertaking several initiatives that will make a major contribution to a more sustainable industry moving forward. We are working across a number of categories including the use of digital technology which will be a key enabler as well as the promotion of greater efficiency, the use of alternative fuels and new energy sources. Each one of these categories has multiple projects within it and includes timelines and pathways to adoption.

HOVEM: A key development, without question, is the UK decision to leave the European Union (EU). Article 50 was enacted in 2017 and the government has ratified the European Union (Withdrawal) Act 2018, which will remove the power of EU law over UK domestic law following the UKs withdrawal from the EU, subject to adaptation as required.

From a regulatory perspective, it is unlikely that Brexit will have any impact on the structure of UK upstream oil and gas and its governing legal regime, including the licensing system. The regulatory framework applying to the to the upstream industry, particularly the environmental and health and safety regulation, is highly developed independently of EU law, and at this stage, the industry's view is that any impact is likely to be minor. The UK offshore safety case model was used as an exemplar by the EU when it considered the development of offshore directives post Macondo, so it is very unlikely to change.

Downstream, the impact will largely be determined, dependent on whether the decision is taken to participate in the single European gas market.

There is no doubt the situation in the UK leads toward a period of uncertainly weakening investor confidence, and the probability of exposure to charges and restrictions on the import of goods and services. There is also the possibility of Scottish referendum being reinstated following the UK exit from the EU.

In terms of offshore focused R&D, what tops the agenda at your organization?

TREMBLAY: One of the areas that tops the agenda at ABS is the development of new inspection technologies, including remote inspection technologies and the use of Machine Learning and Artificial Intelligence tools in our inspection and survey processes.

In particular, we are currently completing feasibility studies into the application of AI to image recognition in order to better identify corrosion in marine and offshore assets.

The use of technologies such as drones is being developed to reduce the risks of manned entry to tank spaces, together with technologies such as LIDAR image scanning, all of which contribute to enhancing capability and increasing safety in structural inspection.

ABS has undertaken numerous trials of remote inspection technologies, including an inspection using a UAV, the results

Source: Lloyd's Register

"MOST OF TODAY'S OFFSHORE FACILITIES ARE MANAGED BY INDUSTRIAL CONTROL SYSTEMS DESIGNED WITH EFFICIENCY IN MIND RATHER THAN SECURITY."

MARK TIPPING
OFFSHORE TECHNOLOGY MANAGER, LLOYD'S REGISTER

of which clearly demonstrated the potential benefits. We believe remote survey can provide immediate operational improvements such as optimized scheduling, which helps to foster an efficient survey process for class and owner alike.

TIPPING: In terms of focused R&D, the agenda is to take cost out of operations without negatively impacting safety. Hence the push is to reduce or eliminate the permanent manning of facilities in continuous production operations. This drives to the development of systems that have the reliability and resilience for long-term isolated operation, this however is not as simple as deploying advanced control systems, it comes down to a fully integrated design and operations philosophy that to date has struggled to bridge the capex and opex project phases.

Not only does equipment need to be selected for long service life with minimum intervention but also how this can be accomplished in discrete maintenance windows. The best solution is to eliminate the need for equipment, however where this cannot be done for example elements exposed to the marine environment new approaches to how we consider efficient design occur; for example the hull of a floating facility might be considered for optimization to reduce steel weight – however in operation this may lead to higher stress values, greater criticality around corrosion and a consequent higher cost of ownership which is especially impactful if the intent is to operate with reduced or no manning. In conclusion while new technology, such as digital health management and maintenance analytics provide the key to unlocking these opportunities, it is their linking to the old technologies which will prove fundamental to success.

HOVEM: There are a couple of projects for offshore which come to mind. WIN WIN is DNV GL´s concept for a new generation of oil recovery technology. Using a wind turbine to power water injection systems will reduce costs, increase flexibility and avoid CO2 emissions. The oil and gas industry is under significant pressure to reduce both costs and emissions from extraction activities. Maximizing oil recovery from new and existing fields is therefore of paramount importance. Water injection is a frequently used and highly effective means of improving oil recovery from oil reservoirs. However, conventional methods entail high power consumption, significant emissions and costly infrastructure.

Secondly, we have developed a new a solution that reduces the risk of offshore floating vessel mooring line failure going undetected by replacing physical sensors with a machine learning algorithm that accurately predicts line failure in real time. The DNV GL team developed the Smart Mooring solution by training a machine learning model to interpret the response of a vessel's mooring system to a set of environmental conditions and are then able to determine which mooring line has failed.

Subsea and beyond, but not without a few global challenges

Ahead of this year's Underwater Technology Conference (UTC) in Bergen, Elaine Maslin spoke with key members of the program committee to hear their thoughts on the state of the nation.

BY ELAINE MASLIN

From its humble beginnings in the offshore oil and gas industry, just 50 years ago, Norway has become a front-runner in subsea technology development.

While through its early years, it leaned on expertise from Houston, it now supplies technology to the world. Yet, there are major changes coming within the industry driven by global trends. In the short term, there's been a welcome increase in activity following four long years in a downturn characterized by job losses, unrelentless cost efficiency and standardization. As it comes out of the downturn, the industry is re-shaping itself, into a cleaner more remote operated, automated business. At the same time, climate change and its implications are now discussed on a daily basis – the pressure is on.

The subsea industry has a history when it comes to being able to adapt. It's familiar territory for UTC, which has now tackled the industry's challenges for 25 years. From June 11-13 in Bergen, Norway, under the theme, "Subsea and beyond – The power to transform", UTC is set to discuss the current environment we're in, including energy transition, the increasing role of gas and the development of ocean renewable technologies, as well as to how to make the industry attractive to coming generations.

UTC program committee member Bjørn Kåre Viken, who is also Vice President of Projects and Technology Collaboration in Equinor Research and Technology, says, "The downturn has really made some scars. International oil companies are, in general, investing in smaller projects than they were five-six years ago, and they are really considering the bottom line," says Viken. "But, there is more optimism."

However, "there are also already signs of cost creep," says Viken. Indeed, according to analysts at Rystad, costs are increasing for subsea umbilicals, risers and flowlines (SURF) products. A contract in 2018, similar the 2017 engineering, procurement, construction and installation (EPCI) contract for 150 kilometers of 30-inch flowline for the Zohr project off Egypt, cost $300 million more, said the firm recently.

COST CREEP

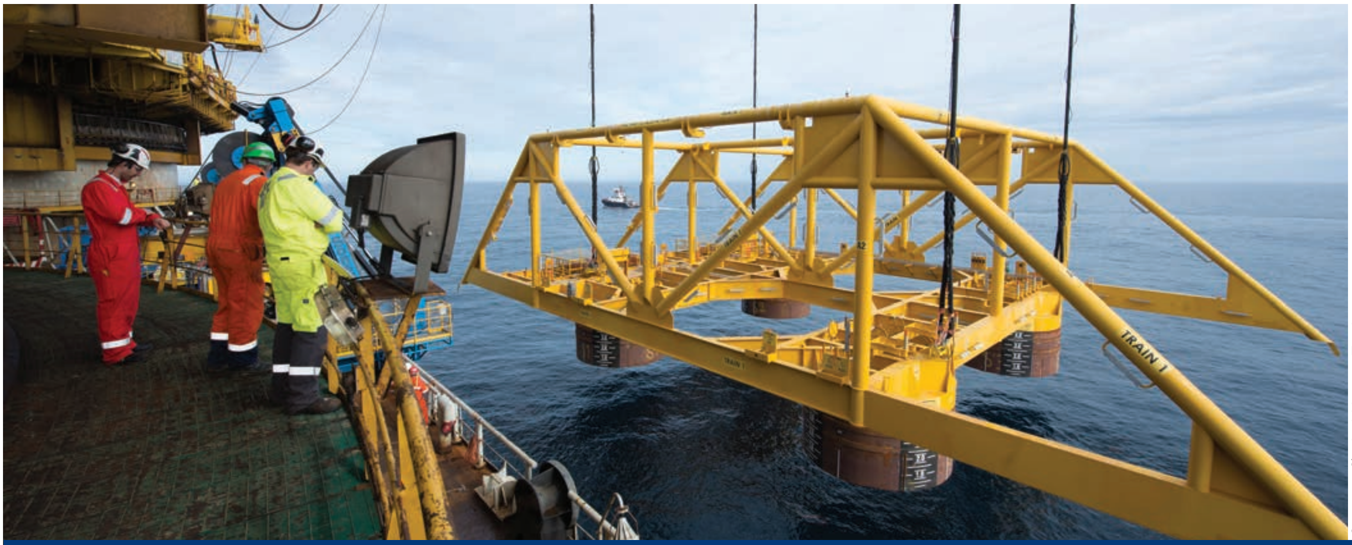
It's a concern for the subsea industry. Cost has very much been on Equinor's agenda even before the oil price crashed. Viken was head of subsea at what was then Statoil between 2007-2010. "Then, subsea was replacing platforms," he says. "There was, in general, a high activity with continuous technology development and innovation." But then, up to 2014, costs grew out of proportion, and when the oil price crash came in early 2015, the tables were turned. Equinor started to look at alternatives to subsea, such as the "wellhead on a stick," which we now see borne out in the Vestflanken (West Flank) development on the Norwegian continental shelf (NCS). These moves were high on the agenda at previous UTCs; the industry took note. "That was turning out to be a competitor to subsea trees and that gave a strong signal to the subsea industry. That's not to say that subsea isn't a choice. It's a key part of the toolbox; it just faces competition from other ways of doing things," adds Viken.

Subsea processing is one area becoming increasingly viable. The industry has made huge leaps by installing subsea gas and multiphase compressors on the seafloor, at Åsgard and Gullfaks, in recent years. But, "it's important for the industry, going forward, to better industrialize, standardize and simplify these, in order to keep the costs down," says Viken.

STILL STANDARDIZING

Standardization is a key mantra for Equinor for existing and future technologies. It's developing an open standard for its underwater drone recharging station so that all vehicle vendors and all operators can use it. It's also keen to make sure future all-electric subsea systems are standardized. While all-electric – another common topic at UTC – is still on the horizon, albeit closer than ever before, operators are working together on joint specifications for it. "We want to reach an early industry standard from day one," says Viken. "In the past, we have wasted a lot on all these [non-standard] interfaces and 'black boxes'. We want to avoid that happening with all-electric. This electrification of Xmas trees, also blowout preventer perhaps later, is representing a reduction in cost because it's cheaper to build and operate. But through testing it needs to prove it's 100% reliable and I am convinced that the industry will respond on that."

Indeed, UTC program committee member Tim Crome, Director, Global Technical Management, at TechnipFMC, says



Source: Øyvind Hagen/Equinor

Åsgard subsea compression template

TechnipFMC should have a complete offering fully qualified to technology readiness level (TRL) 4 by the end of next year.

THE ENERGY TRANSITION

"While costs and future standards must be controlled, the industry also needs to adapt further toward the energy transition and climate change," adds Viken. It's a theme rising on the broader industry agenda. "Greta Thunberg (the Swedish teenage climate activist) has started something that we as an industry need to pay attention to," says Viken. "In Equinor, we fully accept being a part of the problem, when it comes to emissions. But, we definitely want to be part of finding the solution to it as well."

"At Equinor, we are investing a lot in new energy and we have many exciting initiatives ongoing. At the same time we also need to keep on track with producing oil and gas with as low carbon dioxide (CO2) emission footprint as possible." Today, Equinor is the oil company with lowest CO2 footprint per barrel produced, and it takes a lot of effort to keep this position, he says. "That's a position we want to keep, and I am sure we will," says Viken. "One of the ways to obtain this is by doing more remote operations and to implement digital solutions," he says; digitalization, automation and use of robotics. Another way Equinor is working to reduce its carbon footprint in the oil and gas business is by developing floating wind energy parks to provide power for offshore production facilities – a topic on this year's UTC agenda. Remotely operated subsea factories and/or unmanned facilities will also support this goal, as well as reducing risk and operational costs.

"For example, by introducing CO2 taxes on a global scale, these kinds of developments would highly benefit and could drive our industry into a direction with significantly lower carbon footprint. As an industry we need to respond and adapt, and subsea equipment will continue to play an important role," says Viken.

A CHANGING SKILLS SET

The changing operating paradigm in the industry – to more remote, digitalized operations – could also alleviate concerns there will be skills shortages as activity picks up, Viken suggests. With the digital revolution happening, he says there will also be different types of skills needed. "And those skills are definitely available," he says. "Unmanned installations, onshore operation centers and updating existing fields require a lot of digital capability and competency. This opens a new chapter for our industry," he says. "I believe we are going toward lean, smaller operations, taking advantage of digital technology and remote operations – subsea and unmanned – from onshore."

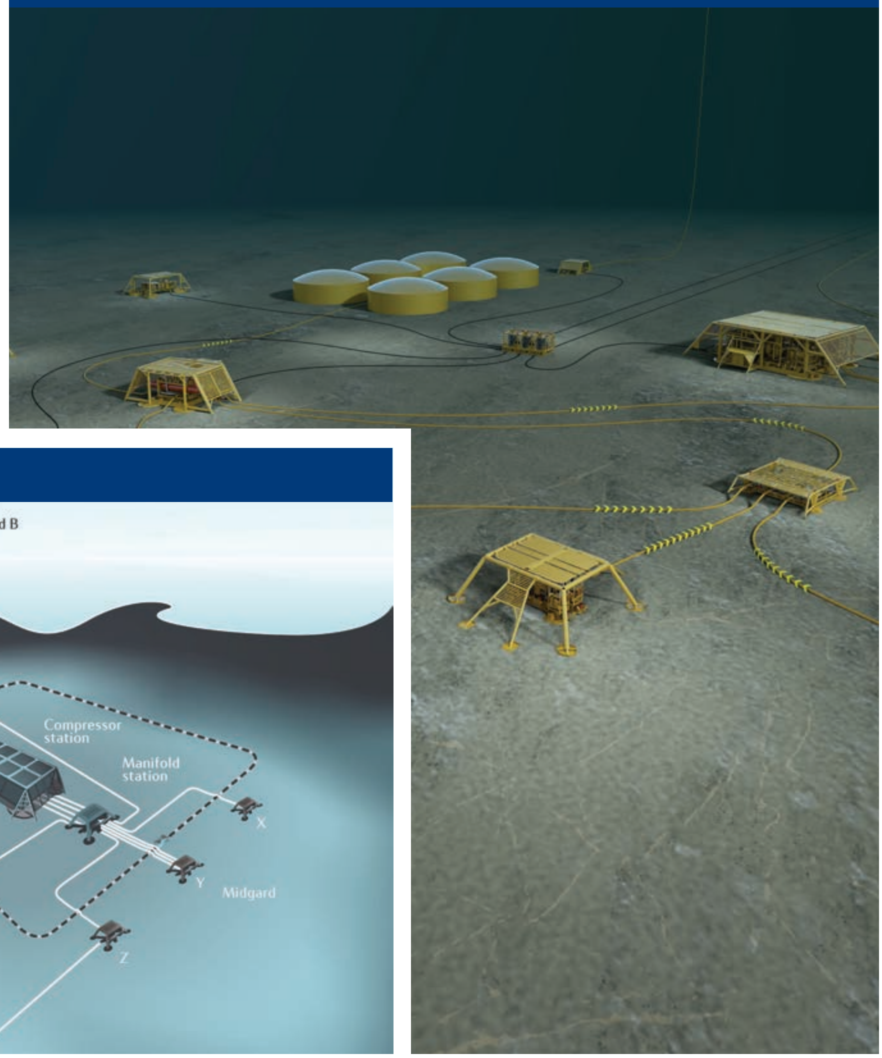
As well as changing their internal skills set, companies should look outside their traditional business areas for other "legs to stand on," says Owe Hagesæther, chief executive at GCE Ocean Technology, co-host of UTC, so that they're sustainable in the long term, both locally and in the global market place. "Contractors and suppliers need to prepare themselves for hard competition and try to establish new related markets for themselves, such as in offshore wind, so that they have more than one leg to stand on." Subsea mining is another area companies could look to, says Crome. In fact, TechnipFMC is a member of the Norwegian Forum for Marine Mining, alongside UTC co-host GCE Ocean Technology, Equinor, DNV GL, NTNU, the University of Bergen and Swire Seabed.

Companies could also look at alternative business models, as some such as CCB Subsea have already done, establishing service rental models, and working with smaller nimbler companies, such as Aker Solutions working with FSubsea, says Hagesæther.

Technip and FMC's joint venture Forsys, which led to the two business' merger, and the iEPCI (integrated engineering, procurement, construction and installation) offering is another example. Crome says: "We launched iEPCI about three years ago through the Forsys joint venture, and it's taken off, in many

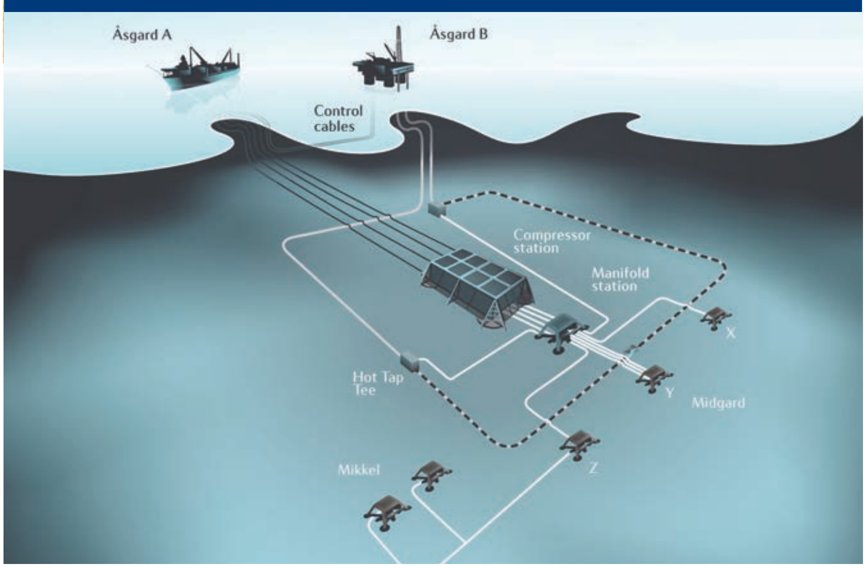
Source: Marit Hommedal

Subsea factory



Source: Equinor

Åsgard subsea compression



Source: Equinor

ways more than expected. It has its appeal to all different sizes of operator." It's an enabler for small operators, but it's also been popular with larger players he says, because it means they can retain smaller project teams when the upturn comes.

TechnipFMC also has its different legs to stand on, to ride out the bumps: an onshore and offshore division working on major platforms and facilities; shale through its surface division; and then also subsea, Crome points out.

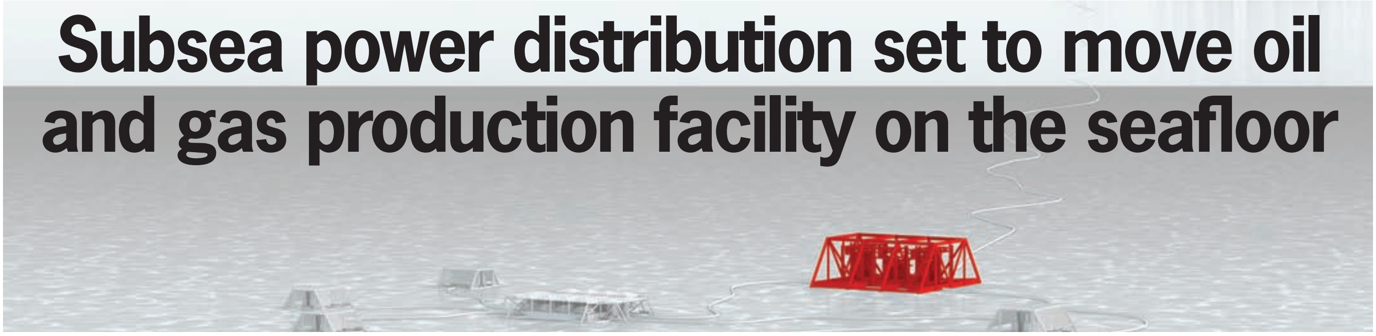
If companies can maintain their edge through new models and markets, their real strength – and UTC's core – subsea technology will have future markets. Indeed, while the NCS is on most of their doorsteps, there's are huge possibilities ahead in growing but also challenging markets such as Brazil, says Hagesæther. "There are new operators in Brazil, in addition to Petrobras, the market is opening up and it's being to be an exciting opportunity for the Norwegian supply chain," he says.

Program Committee Chairman Jon Arve Sværen challenges companies to question where they sit in this complex environment. "Where are you placed in the future energy mix? What can your company do in this perspective? What are you doing to promote the industry, to attract the best talent? These are the questions companies should be asking. We are not going to have all the answers, but we will have these topics on the UTC agenda and we will contribute to developing philosophies and strategies to help you find the answers."

Prominent speakers from companies including BP, Shell and Equinor, alongside Norwegian Prime Minister Erna Solberg, will be among those offering their perspectives and discussing these topics at this year's UTC, alongside the extensive parallel technical sessions, exhibition and networking opportunities.

UTC is co-hosted by the Underwater Technology Foundation (UTF) and GCE Ocean Technology, supported by the City of Bergen, with organizing partners the Society of Petroleum Engineering (SPE) and the Society of Underwater technology (SUT). To find out more about this year's program, visit https://www.utc.no/program

Subsea power distribution set to move oil and gas production facility on the seafloor



Source: ABB

By Svein Vatland, Vice President Subsea Technology Program at ABB

Subsea power distribution down to 3,000 meters depth will soon be a reality. This summer, a full-scale prototype will be running a 3,000-hour test. After that, assuming all goes as planned, it will be time for commercial launch, potentially with far reaching implications for production facilities worldwide. It may even eventually make the entire topside production platform a memory from the past.

A new design for power distribution infrastructure in offshore installations is currently taking shape in Norway. Here, ABB and a group of partners are developing equipment designed to sit on the ocean floor, at depths of up to 3,000 meters, operating for up to 30 years without maintenance. The subsea power distribution system can provide up to 100 megawatts (MW) and be supplied over a distance up to 600 kilometers. The joint industry project (JIP) is a collaborative venture between ABB and Equinor with its partners, Total and Chevron.

The project aims to improve recovery rates for new offshore installations and to extend the life of existing assets, using advanced modular subsea installations instead of traditional platforms and floating production systems.

The seeds of the project were sown in 2013, when ABB was tasked with improving the recovery rate at the Asgard field in the Norwegian sector of the North Sea. The operator, Equinor, had discovered that the pressure inside the well was dropping at an alarming rate, although the remaining reserves were considerable. ABB provided power for subsea gas compression equipment for artificial boost, the first of its kind.

In the absence of any power distribution on the seabed, each pump and compressor initially had a cable tied back to a floating production platform. This issue was subsequently addressed, and all process equipment is now located on the seabed, powered by a singular cable with modular power distribution.

NEW CONCEPT DEVELOPED

The JIP was formed to develop this concept further. With a power distribution infrastructure on the seabed, future offshore production may not require any topsides or floating production systems, offering significant cost and safety benefits. Power will be supplied with a single cable, instead of one for each load. All equipment for medium voltage distribution, power conversion, automation and auxiliary power will be fitted in subsea enclosures. A modular power distribution system on the seafloor will drive pumps, compressors and other process plant.

The potential savings are considerable. In a project with eight different loads, such as pumps or compressors, capex savings could be about $500 million. Efficiency will be significantly improved, as the loads are closer to the well. It should be possible to save as much as 30% on capex and opex over a 30-year lifetime.

With further development, the concept could eventually result in an autonomous subsea factory, using digital solutions to enable intelligent remote and unmanned operations. This would further reduce capex and opex, while increasing recovery rates, improving safety, enhancing reliability, raising productivity and minimizing environmental impact. The power can be supplied over a distance up to 600 kilometers. Using this concept, practically all of the world's known resources can be reached.

A TECHNICAL CHALLENGE

While there is a robust business case for placing power distribution equipment on the ocean floor, this is not the same as having a technical solution. Many hurdles had to be overcome to get to the launch of a full prototype test. Designing a power supply infrastructure that can operate at 3,000 meters depth for 30 years meant considerable technical challenges, as the operational conditions are extremely harsh and reliability requirements exacting. Nothing like this has ever been done before, and many new insights have been gained along the way.

The system consists of a subsea control system and low voltage distribution, subsea medium voltage switchgear, and subsea medium voltage variable speed drives. At the start of the project, most of this equipment did not exist. When a first shallow water test took place in 2017, this was the first time that a medium voltage variable speed drive had ever been operated under water.

This summer will see the beginning of a 3,000-hour test in shallow water with a full-scale prototype — medium voltage switchgear, control and low voltage distribution equipment and two parallel variable speed drives (VSD). The first commercial system is expected to be in operation by 2023.

LONG-TERM TESTING

Since the 2017 shallow water test, components have been

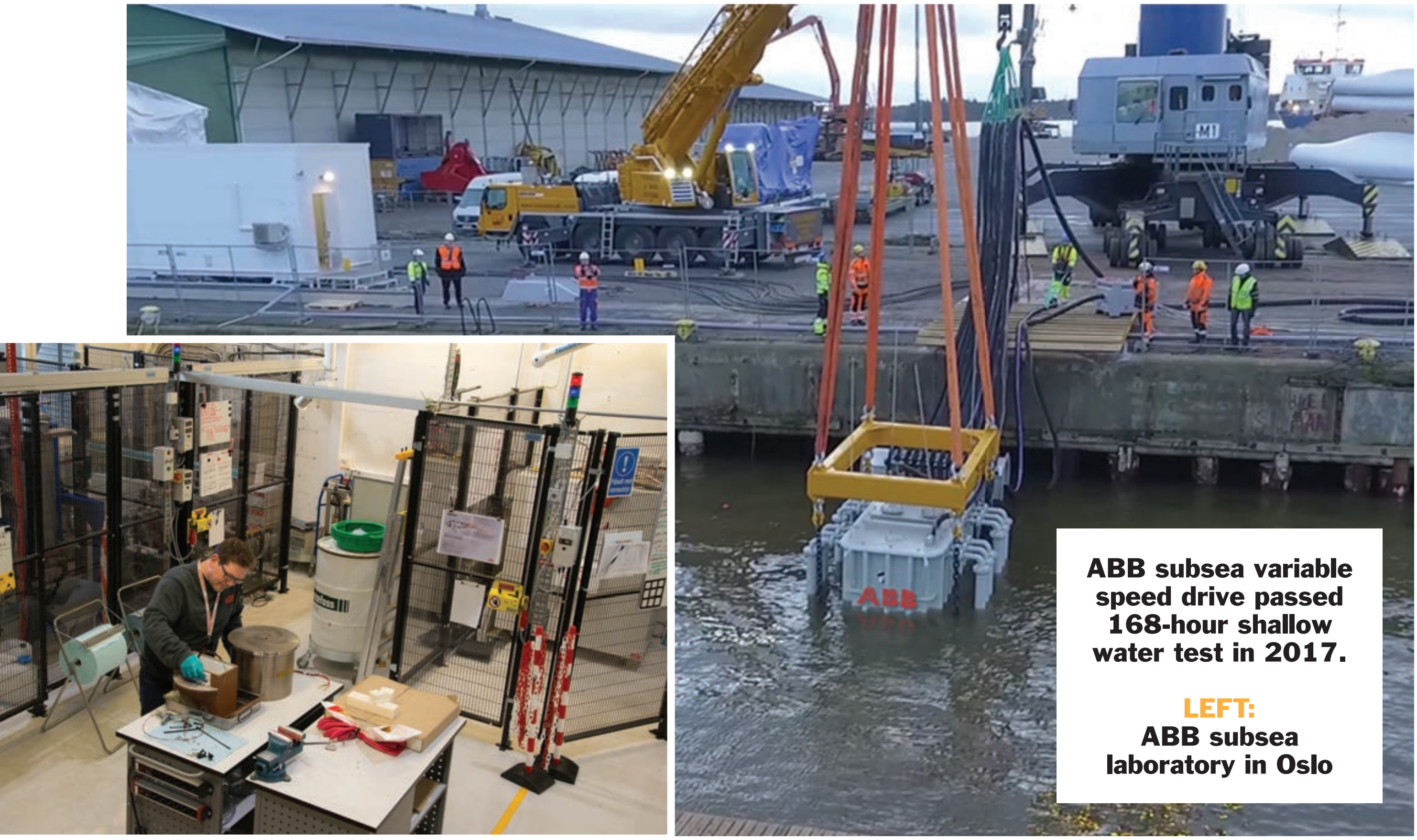


ABB subsea variable speed drive passed 168-hour shallow water test in 2017.

LEFT: ABB subsea laboratory in Oslo

Source: ABB

verified, redesigned and optimized. Long term testing has been ongoing on the component level.

A significant challenge during environmental development and test was to capture the precise conditions that would lead to a test deviation, a change in device behavior or component value, particularly when these deviations were intermittent and only apparent under the harshest of test conditions. This work was often carried out in specialist test facilities.

All components are based on existing equipment, adapted for subsea operation. The project aims to qualify the basic building blocks to work with the typical voltage and power ratings used in subsea processing, as well to operate in very demanding subsea conditions. All components are tested to API 17F. This includes tests for temperature, vibration and pressure, as well as accelerated lifetime testing.

The project activities follow the recommendations and technology readiness level (TRL) defined in the procedure DNV RP-A203. This provides a systematic approach to ensure the technology will function reliably within the specified limits. The progression to full scale prototype testing means the project is now moving from TRL3 to TRL4.

Existing requirements for topside equipment generally apply, as well as API17F Standard for Subsea Production Control Systems. Using these standards and methods, the project has developed packaging technologies to enable robust and cost-effective power distribution and conversion for subsea use. The goal is to provide the industry with proof that this technology is ready for use.

POWERFUL CONTROLLER

While the control system is based on existing products, the technology had to be significantly upgraded and modified. The system also needed a completely new enclosure design. Though there are already subsea electronic modules for well-control applications, the control system designed here will offer more advanced functionality compared to existing solutions. The system is much more powerful than any state-of-the-art system used for subsea today.

The subsea VSDs are designed to control the speed and the torque of the subsea pumps and compressors for seawater injection, boosting and compression applications. They are also instrumental for retrieving diagnostic data. It is often more useful to collect device data from the VSD than from the actual devices. This helps predict device behavior, optimize the operation and track performance indicators, building resilience.

The project is now in its final stages. As the shallow water test of the full-scale prototype begins, the industry can look forward to a new era in which subsea installations replace topside platforms, significantly reducing the costs and the risks associated with production.

Moving water treatment subsea

Source: NOV

Verification of the Seabox ability to treat water for increased oil recovery

BY ASTRID NYGAARD ENGESLAND, NOV

Unlocking full oil recovery potential is key for operators and a determining factor for field developments. Maximizing recovery rates is even more important in the current environment, as operators need to produce at a lower commodity breakeven price to make new marginal discoveries profitable. In the North Sea alone, there are approximately 400 potential tiebacks awaiting development. This, combined with the industry's environmental discharge focus, necessitates new and innovative solutions.

Using secondary recovery methods to provide pressure maintenance and sweep efficiency is one way of maximizing recovery. Commonly used methods include injection of water, gas or water alternating gas. The reservoir properties determine the preferred technical solution. Not fully understanding the reservoir characteristics can lead to injectivity problems if an incompatible solution is injected into the reservoir. Injectivity can decline due to bio fouling and impairment by suspended solid in the water. Marginal developments face yet another challenge—maximizing recovery potential while achieving profitability. This is possible through a tieback to host facilities or even moving into unmanned platforms.

National Oilwell Varco (NOV) offers a new, standalone, subsea system for water treatment that can provide clean water and increase recovery potential for marginal developments as well as for aging fields, long tiebacks, greenfield developments and small wellhead platforms. The Seabox subsea water treatment system provides disinfection of raw seawater and reduces the number of suspended solids, decoupled from topside water treatment processes. This eliminates the need to push water from the host facility to the injector. Water treatment and injection can now, with this new solution, be provided where and when required. Water injection and voidage replacement becomes a realistic and affordable alternative to production by depletion only or by transporting the water from a potentially constrained host, to increase the recovery potential of marginal developments.

Seabox

The subsea water treatment module technology aims to provides high-quality water treatment subsea without compromising safety, operability or reliability. NOV has made two operational and qualified the system to technology teadiness level (TRL) 6.

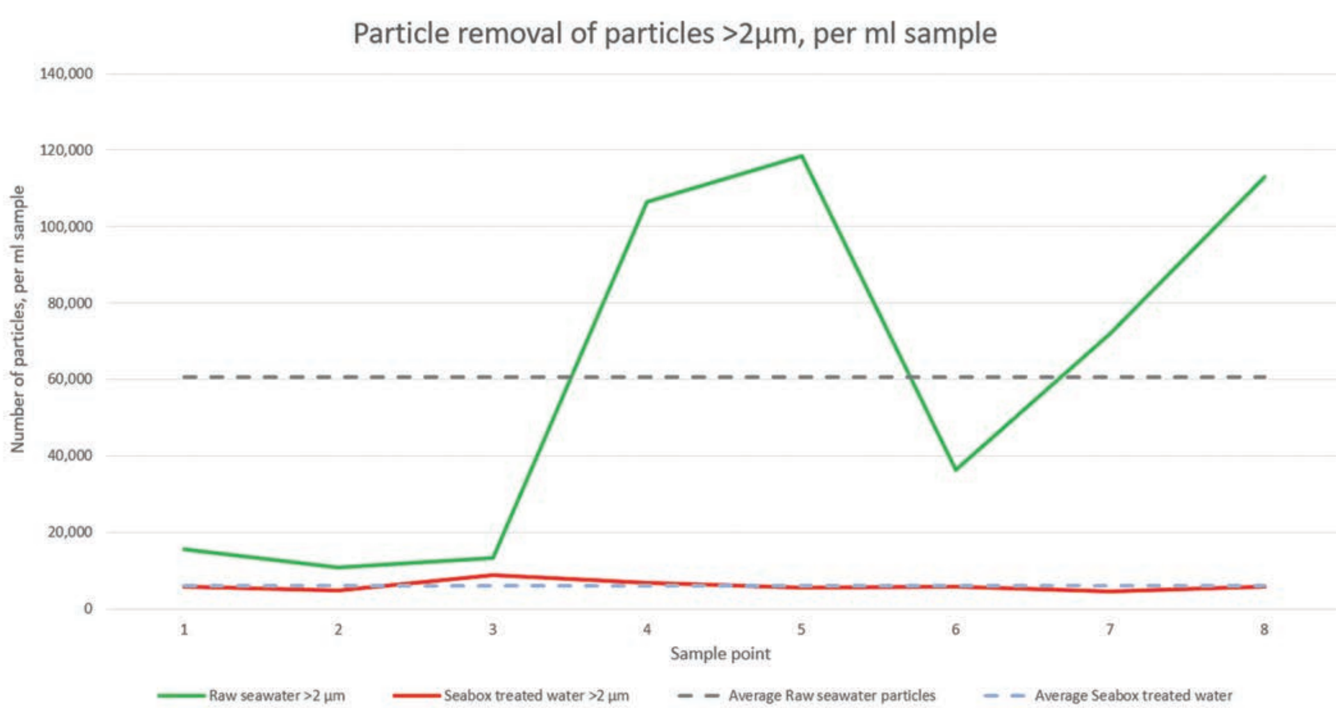
The Seabox module is made of glass reinforced polymer (GRP) and consists of three major parts: a tray, a still room and a treatment unit. It is designed to have all interchangeable parts located inside the easily retrievable treatment unit to make intervention easy. The module utilizes known methods toward disinfection of the water and to settle solids. The disinfection of water is performed via two in-situ electrolysis processes. First, electrochlorination cells at the inlet of the module produce sodium hypochlorite, and then a secondary oxidizing step where higher order oxidizing agents are generated to further decompose dead organic matter. This, combined with the large volume of the module, will secure enough time for the chlorine to react with the organics in the seawater. The solid settling is provided by sedimentation (gravity), and due to the proprietary internal design of the still room module resulting in laminar flow, causing particles with a higher density than water to settle. Standardization is key to the Seabox module design. The module is designed with a treatment capacity between 20,000 and 60,000 barrels of water per day and can be installed at water depths down to 3,000 meters.

Test setup

NOV installed a Seabox module off the coast of Stavanger, Norway, as part of a verification project in February 2018. The objective was to verify the performance of the full-scale module in a representative subsea environment. The project was backed by three operators and had a test period of three months. During this period the module's disinfection and particulate settlement capabilities were analyzed. The unit was installed at 220 meters water depth, 550 meters off the shore from the control station, which supplied power and communication. The subsea pump was installed near the shore and drew water through the Seabox, where a sample line downstream the pump guided a fraction of the treated water to an onshore facility for water quality analysis. A raw seawater sample line near the module offered comparison sampling

Sampling results

The scope of work, to meet the objective of the verification program, set out an extensive sampling program to verify the module's disinfection and sedimentation capabilities. The sampling program was divided into these two major categories. Together with the project sponsors, NOV created a sampling program that involved a total of 13 different types of



Source: NOV

analyses, all performed by an independent third-party lab that specializes in services for the upstream oil and gas industry.

To verify the water disinfection capabilities of the module, e.g. the abilities of the module to remove, deactivate or kill microorganisms in the seawater, planktonic and sessile general heterotrophic bacteria (GHB) and sulphate reducing bacteria (SRB), adenosine triphosphate (ATP) and quantitative polymerase chain reaction (qPCR) was measured throughout the verification program. The general results through these samples showed that both the planktonic and sessile levels in the treated water were below detectable levels. The results are further supported by the ATP and qPCR samples. Comparing ATP levels from the raw seawater and treated seawater, on average a total 98.6% of all microorganisms were inactivated by the disinfection process within the module. The qPCR showed a total decrease in bacteria level with 99.8% and 100% for the SRB count. The results confirmed the module's ability to provide disinfected water through the electrolysis process and use of residence time.

To verify the solid removal capabilities, NOV used Coulter Counter, turbidity and silt density index (SDI) as sampling methods. The Coulter Counter provides a measurement of the particle count and size distribution. The comparison of the raw seawater samples and the Seabox-treated water showed a significant effect on the sedimentation ability for the module. On average, the particle count for the raw seawater was about 10 times higher compared to the Seabox treated water for particles larger than 2µm. Through turbidity measurement it was possible to measure the concentration of suspended particles in the water. The turbidity of the Seabox measured around 1 FTU, which is within the range of turbidity measurements in potable water. The SDI is used as a measurement for fouling or plugging potential. During the eight samples taken, the Seabox provided SDI levels ranging between three and four, which is acceptable to potential downstream nanofiltration applications, should this be required. By comparison, five out of eight raw seawater samples had an SDI above its measurement range at SDI of 6.

Future potential

This verification of the Seabox capabilities to disinfect and remove particles from the seawater, and the installation flexibility, provides a new ability to add waterflooding to marginal field developments. When located on the seabed next to a water injector, the module can provide an improved flooding regime to ensure necessary pressure support and sweep efficiency. This can increase the oil recovery rate potential as the reservoir is exploited to its full capacity. The system is believed to be a strong contender for improving waterflooding for both green- and brownfields. Not only has NOV demonstrated its performance through an extensive verification program, the Seabox module has also been in continuous operation at the Ekofisk field in the North Sea since autumn 2018 with 100% uptime to date.

This technology is a competitive solution to provide increased water treatment capacity to mature brownfields or to provide high quality water to marginal developments. It can also be used as a hybrid solution where the subsea water treatment system is used as a pretreatment step upstream existing topside water treatment facilities to face well-known challenges like biofouling. This can reduce operational expenditures and increase availability of the overall water treatment system.

The Seabox subsea water treatment system, located on the seabed.

Source: NOV

Oceaneering

Ocean Evolution

Oceaneering has taken delivery of a new DP2 subsea construction support vessel built by BAE Systems in the US.

The 108-meter Ocean Evolution is equipped to provide services for subsea tiebacks installations, subsea maintenance, repair and decommissioning as well as stimulation and light well intervention. It is equipped with a 250-metric-ton active heave compensated (AHC) crane, two work-class remotely operated underwater vehicles (ROV) with AHC launch systems, survey systems and subsea tooling, all built for work in up to 4,000-meter water depths.

The newbuild is powered by five low-emission EPA Tier 4 diesel engines and features accommodations for 110 persons, helideck and a working moonpool.

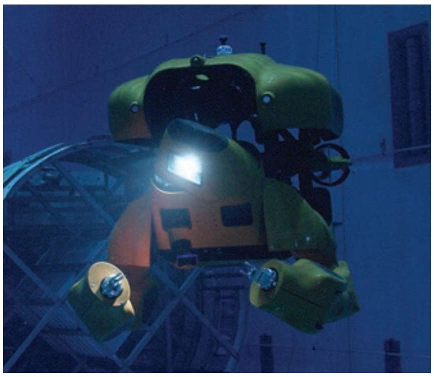
At press time, the recently christened vessel was slated for project work to begin in June.

The new vessel is designed to aid in a number of subsea tasks.

Source: Oceaneering

Houston Mechatronics

AI-powered Manipulator Hands



Source: Houston Mechatronics

Aquanaut AUV/ROV

Despite many technological advances for underwater vehicles over recent years, robots in the ocean typically do not have the manipulation dexterity of their land-based counterparts.

Under an award from the Office of Naval Research, subsea robotics firm Houston Mechatronics is developing highly dexterous robotic hands for subsea manipulators that use artificial intelligence (AI) grasping behaviors.

The hardware will be coupled with AI-powered software to enable higher performance, and it will be demonstrated with Houston Mechatronics' Aquanaut, a shape-shifting robot that can can change its morphology from a long-range autonomous underwater vehicle (AUV) to an untethered remotely operated underwater vehicle (ROV) for stable, seabed or water column manipulation tasks.

OWLC

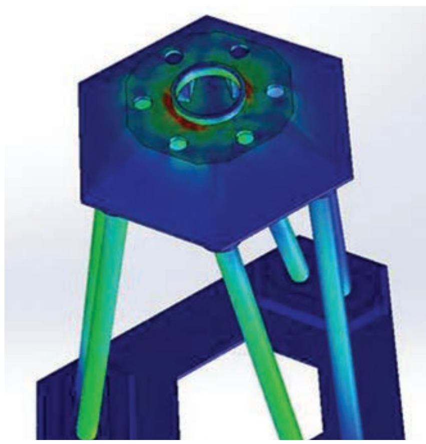
Offshore Wind Foundation

Hydraulic engineering and offshore renewable energy specialist HR Wallingford says it is working with partners Offshore Design Engineering (ODE), DNV GL, Cambridge University and the Offshore Renewable Energy (ORE) Catapult to test and certify the Gravity Tripod, a "potentially revolutionary" new offshore wind foundation concept designed by Offshore Wind Logistics and Construction (OWLC).

The solution, which is currently being subjected to extensive physical model testing, is intended to help keep costs down as offshore wind projects move into deep waters.

The Gravity Tripod is designed to accommodate turbines from 3 to 16 megawatts (MW), and it requires no piling, is low drag, low scour and installed with minimal seabed intervention, according to its developers.

The Gravity Tripod would require no piling and could be installed with minimal seabed intervention.



Source: HR Wallingford

James Fisher Offshore

Cutting Tool

UK based equipment and services company James Fisher Offshore has developed a new internal abrasive cutting system designed to provide higher performance, cost savings and operational efficiency for underwater decommissioning activities.

The abrasive cutting technology offers an innovative method for the internal cutting and removal of subsea tubular structures, ranging from piles and jacket legs through to well casings and well heads. The system is capable of severing double-plated hull sections greater than 84 millimeters in one pass, and offers performance enhancements such as real-time cut verification, visual external cut monitoring and increased flexibility. The unique airflow system negates the need to de-water and reduces the amount of operations in the task, minimizes the equipment required, and a leads to a 60% reduction in the overall cutting time, the manufacturer said. .

Source: James Fisher Offshore

The new system is designed for the growing decom market.

WFS Technologies

Riser Monitoring

WFS Technologies, a specialist in Subsea Internet of Things devices, has introduced new solutions for monitoring offshore risers both above and below surface, on fixed structures including jackets and braces, in real time. The new products allow for the measurement of 9-axis motion (vibration, orientation), local analytics and the reporting of real-time information through the water-air boundary with WFS' patented Seatooth technology, which removes the need for dunkers. .

The WFS sensors are enabled with edge computing that can be used to validate the model in subsea conditions, and report data in real time. Edge computing enables the fatigue model to be uploaded to each sensor. Analysis is undertaken locally, with the relevant data logged on the sensor and any deviation from the model communicated wirelessly by exception.

Source: WFS Technologies

Operators can gain real time, actionable information on riser condition in any environment.

Schlumberger

Digital Exploration Platform

A new digital platform is designed to help exploration teams rapidly discover and access basin-scale data and manage exploration opportunities.

Schlumberger's GAIA platform uses the power of the DELFI E&P cognitive environment to access data available from E&P industry data providers, enabling users to discover, visualize and interact with all available data in a region or basin without compromising resolution and scale.

More than 3 million square kilometers of 3D seismic surveys, 3 million kilometers of 2D seismic lines, and other exploration data types from Schlumbergers' partner network of seismic and well data providers will be available through the platform.

The platform combines the use of a high-performance digital map for global data discovery and 3D visualization with streaming of basin-scale subsurface data.

Source: Schlumberger

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Data Driven Drilling & Prod. Conf.
June 11-12
Houston, USA
www.upstreamintel.com/data

Underwater Technology Conf.
June 11-13
Bergen, Norway
www.utc.no

Global Petroleum Show
June 11-13
Calgary, Canada
https://globalpetroleumshow.com

Brasil Offshore Conf. & Expo
June 28-28
Macae, Brazil
www.brasiloffshore.com/en

Subsea Well Intervention Symp.
August 13-15
Galveston, USA
www.spe.org/events

Offshore Europe Conf. & Exhibition
September 3-6
Aberdeen, UK
www.offshore-europe.co.uk

Gastech Exhibition and Conf.
September 17-19
Houston, USA
www.gastechevent.com

Asia Offshore Energy Conf.
September 26-28
Jimbaran, Indonesia
www.asiaoec.com/

ATCE
September 30-October 2
Calgary, Canada
www.atce.org/cfp2019

OilComm and FleetComm
October 2-3
Houston, USA
www.atce.org/welcome

OTC Brazil
October 29-31
Rio de Janeiro, Brazil
www.otcnet.org/brasil

APOGCE
October 29-31
Bali, Indonesia
www.spe.org/events

Ocean Energy Conf & Exhibition
October 30-31
Edinburgh, Scotland

APOGCE Africa Oil Week
November 4-8
Cape Town, South Africa
www.africa-oilweek.com

ADIPEC
November 11-14, 2019
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