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# West of Shetland

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**Northwest Europe**
New Money, Finds & Field Starts

**Subsea Processing**
Gas Compression Headed for New Waters

**Drilling Efficiency**
"See" Ahead of the Bit

VOL. 44 / NO. 4

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# FEATURES


Source: Elaine Maslin



**ON THE COVER:** The Ocean Greatwhite, before it set off to drill Blackrock and Lyon (Source: Elaine Maslin)

# FEATURES

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# DEPARTMENTS



Source: Enpro

Source: Equinor

Source: Neptune Energy

Source: Aker BP

Source: Total

# BY THE NUMBERS

## RIGS

### Worldwide

| Rig Type | Available | Contracted | Total | Utilization |
|---|---|---|---|---|
| Drillship | 26 | 63 | 89 | 71% |
| Jackup | 121 | 314 | 435 | 72% |
| Semisub | 33 | 73 | 106 | 69% |

### Africa

| Rig Type | Available | Contracted | Total | Utilization |
|---|---|---|---|---|
| Drillship | 5 | 13 | 18 | 72% |
| Jackup | 11 | 23 | 34 | 68% |
| Semisub | 1 | 3 | 4 | 75% |

### Asia

| Rig Type | Available | Contracted | Total | Utilization |
|---|---|---|---|---|
| Drillship | 4 | 7 | 11 | 64% |
| Jackup | 45 | 90 | 135 | 67% |
| Semisub | 9 | 18 | 27 | 67% |

### Europe

| Rig Type | Available | Contracted | Total | Utilization |
|---|---|---|---|---|
| Drillship | 13 | 2 | 15 | 13% |
| Jackup | 9 | 42 | 51 | 82% |
| Semisub | 10 | 29 | 39 | 74% |

### Latin America & the Caribbean

| Rig Type | Available | Contracted | Total | Utilization |
|---|---|---|---|---|
| Drillship | 2 | 18 | 20 | 90% |
| 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 | 1 | 22 | 23 | 96% |
| Jackup | 24 | 30 | 54 | 56% |
| Semisub | 3 | 8 | 11 | 73% |

### Oceania

| Rig Type | Available | Contracted | Total | Utilization |
|---|---|---|---|---|
| Drillship | 1 | 0 | 1 | 0% |
| Jackup | 2 | 1 | 3 | 33% |
| Semisub | 0 | 6 | 6 | 100% |

### Russia & Caspian

| Rig Type | Available | Contracted | Total | Utilization |
|---|---|---|---|---|
| Jackup | 2 | 7 | 9 | 78% |
| Semisub | 2 | 4 | 6 | 67% |

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 August 7, 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 | 23590 | 66072 |
| Shallow water | 3214 | 108537 | 311216 |
| Ultra-deepwater | 330 | 34353 | 50041 |

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 | 738 | 29284 | 30561 |
| Asia | 1024 | 17094 | 39968 |
| Europe | 957 | 19854 | 24424 |
| Latin America & the Caribbean | 241 | 42727 | 11068 |
| Middle East | 141 | 145119 | 115263 |
| North America | 6232 | 25047 | 4987 |
| Oceania | 123 | 2828 | 25066 |
| Russia and the Caspian | 70 | 26753 | 23514 |

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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# OE WRITERS


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Pallanich


Paschoa


Smith


Stoichevski

# LOOK BACK, **FORGE AHEAD**

The world today is an increasingly contentious place, with rising amounts of geo-political conflict and economic uncertainties. The price of oil has been on a figurative rollercoaster ride for more than five years, and on August 1 Brent and WTI prices declined by more than 7% when the U.S. announced new tariffs on China. According to the recent *'Short Term Energy Outlook'* from the U.S. Energy Information Administration (EIA), "Energy high yield corporate bonds have increased for energy companies by more than those for the broader market," reflecting increased risk default and potentially higher borrowing costs for some oil producers. *That's the bad news.*

What's the good news? While there has been an influx of renewable sources to the energy mix, oil and gas remain the cornerstone of global energy for the coming generation. And according to that same EIA report, energy markets should remain stable in the short term through 2020, averaging $65/barrel through the end of next year. While I generally eschew clichés, *'When the going gets tough, the tough get going'* is apt in this instance as it applies to offshore energy leaders that have been forced to innovate to reduce the cost of extracting oil from under the world's seas. Reporting on the technologies that help offshore companies operate in a safer, more efficient and economical manner has been the province of *Offshore Engineer* since its founding in 1975, an editorial mandate that continues today.

In this edition, starting on page 8, **Jennifer Pallanich** reports on a technology launched by Schulmberger – the IriSphere look-ahead-while-drilling service – that uses electromagnetic technology to allow operators to 'see' ahead of the bit, helping to fill in the gaps when seismic data and reservoir modeling is not enough. On page 12, **Elaine Maslin** offers a look at a fresh take on a xmas tree which offers operators the ability to more quickly and easily change functions to suit needs, helping to reduce cost and schedule, which have historically been driven by imagining and engineering a system that was designed and built for the life of the field. Bigger picture, the digitalization and automation trends are undeniable as operators increasingly test, trust and tap next-generation tech to streamline operations and reduce costs. These trends are summarized in a number of features in this edition, from *"A Piece of the Puzzle"* starting on page 32; to our special report on *"Automation: Big Data, Security and Remote Ops"* starting on page 42; and finishing with an insightful look at the progress and future prospects of creating a *"Digital Twin"*, starting on page 46.

It was just 12 months ago that we were finalizing the deal to acquire this prestigious title and starting the process to relaunch *Offshore Engineer*, **OEDigital.com** and **AOGdigital.com**. This, like the market, has been an exhilarating rollercoaster ride.

Of all of the uncertainties in the world and in your business, one thing you can count on is that this venerable brand is in good hands. The wheels are in motion to add *Offshore Engineer* to our family of BPA-audited publications, as BPA is the undeniable 'Gold Standard' when it comes to B2B magazine circulation audits. This is part of our commitment and assurance to this industry to deliver insightful, timely and compelling articles, analytics and insights to a global, targeted, qualified audience. While we are new drivers of the *Offshore Engineer* brand, we are long-tenured publishers in the maritime, energy and subsea spaces, as this year our company celebrates its 80th anniversary. As we look back on eight decades and ahead to the next, we thank you for your interest and support, and we look forward to exploring an exciting new era of offshore energy discovery and recovery.

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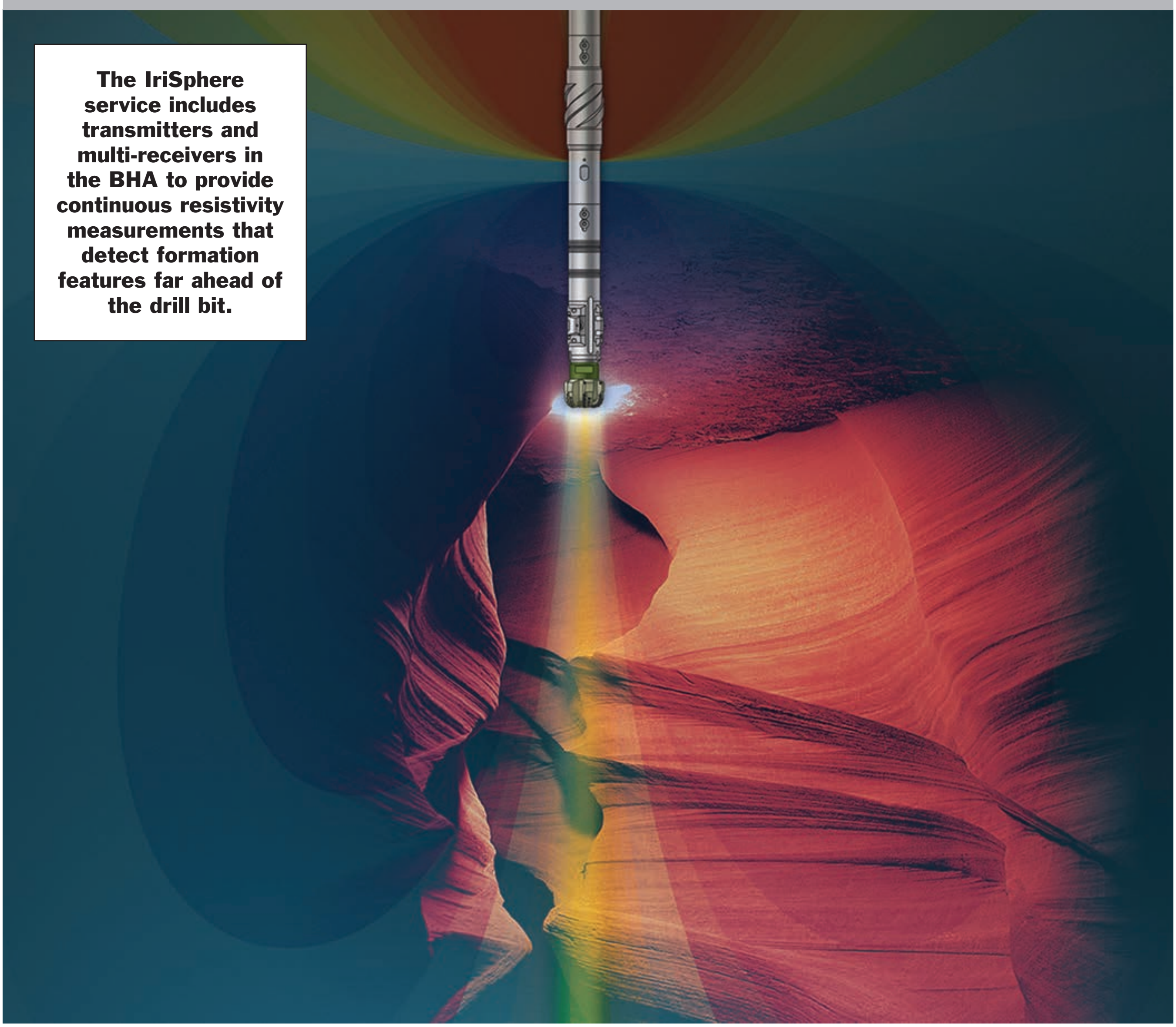
# "SEE" AHEAD OF THE BIT

By Jennifer Pallanich

Even with the best seismic data and reservoir modeling available, drillers have remained in the dark about what's in front of the drill bit. A new sensing tool has been designed to "see" ahead of the bit and can transmit data in real time to shift drilling operations from reactive to proactive.

In early May, Schlumberger launched the IriSphere look-ahead-while-drilling service, which uses deep directional electromagnetic (EM) technology to detect formation features as far as 100 feet ahead of the drill bit in real time, which allows drillers to adjust operations accordingly.

With this tool, drillers can identify the precise locations of



**The IriSphere service includes transmitters and multi-receivers in the BHA to provide continuous resistivity measurements that detect formation features far ahead of the drill bit.**

Source: Schlumberger

hazards like the bottom of a salt layer or the top of a depleted or over-pressured zone to avoid stuck pipe, mud losses and kicks, says Vera Krissetiawati Wibowo, Drilling & Measurements resistivity product champion, Schlumberger. Feedback from the launch of the technology has been "very positive," she says.

Schlumberger proposed the IriSphere service to an operator concerned about the potential for a high-pressure zone in a shallow water exploration field offshore China. This operator had previously penetrated the zone and experienced severe borehole instability issues which led them to need to redrill, she says.

For the new well, the operator believed the optimal casing zone was below a shale marker and above the high-pressure reservoir, Wibowo says.

"The shale marker was detected 20 meters ahead of the bit," she says. The casing was safely set at a depth that isolated the lower pore pressure and high fracture density formation from the high-pressure sand, and drilling resumed, she adds.

Avoiding the drilling hazards is not the only advantage, Wibowo says. Because the tool can sense up to 100 feet ahead of the drill bit, it can detect the top of reservoir, distinguish between thin laminates and true reservoirs, and provide intelligence on the depth of the reservoir, she says.

That capability saved an operator from needing to drill a sidetrack well offshore Western Australia. The operator had a complex reservoir environment with high seismic uncertainty on the position of the reservoir top. The field had a complex anticline and was composed of siltstones between discontinuous sand bodies and characterized by a lack of markers above the reservoir. In such situations, conventional drilling methods call for drilling a pilot hole to locate the top of the reservoir, then a sidetrack to determine the thickness.

Schlumberger's IriSphere service detected the top of sand 62 feet ahead of the bit and was able to detect the 82-foot thick sand. Subsequent coring operations were optimized based on data acquired while looking ahead of the drill bit.

"We eliminated the pilot hole," Wibowo says.

The IriSphere service's EM-based deep directional resistivity measurements are integrated with offset and other data to provide a resistivity profile ahead of the bit, delivering an accurate downrange representation of the forma-

Source: Schlumberger

"KNOWING THE CONDITIONS THAT LIE AHEAD IN REAL TIME AND CONTINUOUSLY ENABLES THE CUSTOMER TO REDUCE DRILLING UNCERTAINTIES."

VERA WIBOWO,
SCHLUMBERGER

tion while drilling.

The tool enables the customer to make proactive drilling decisions rather than reacting to measurements at or behind the bit, Wibowo says.

She emphasizes that pre-job modeling is crucial to understanding reservoir issues and sensitivities to determine how far ahead the customer has the ability to look. It's also key to properly space the transmitter and receivers when planning the bottom hole assembly (BHA) to obtain the desired sensitivity, she said.

"The further we space the transmitter and receivers, the further our signal propagates," she says.

To date, she says, the largest distance between the transmitter and receiver has been 160 feet along the drillstring, which made it possible to see 100 feet ahead of the drill bit.

The system uses one transmitter combined with one, two or three receivers. The system applies to hole sizes ranging from 5 5/8 inches to 16 inches.

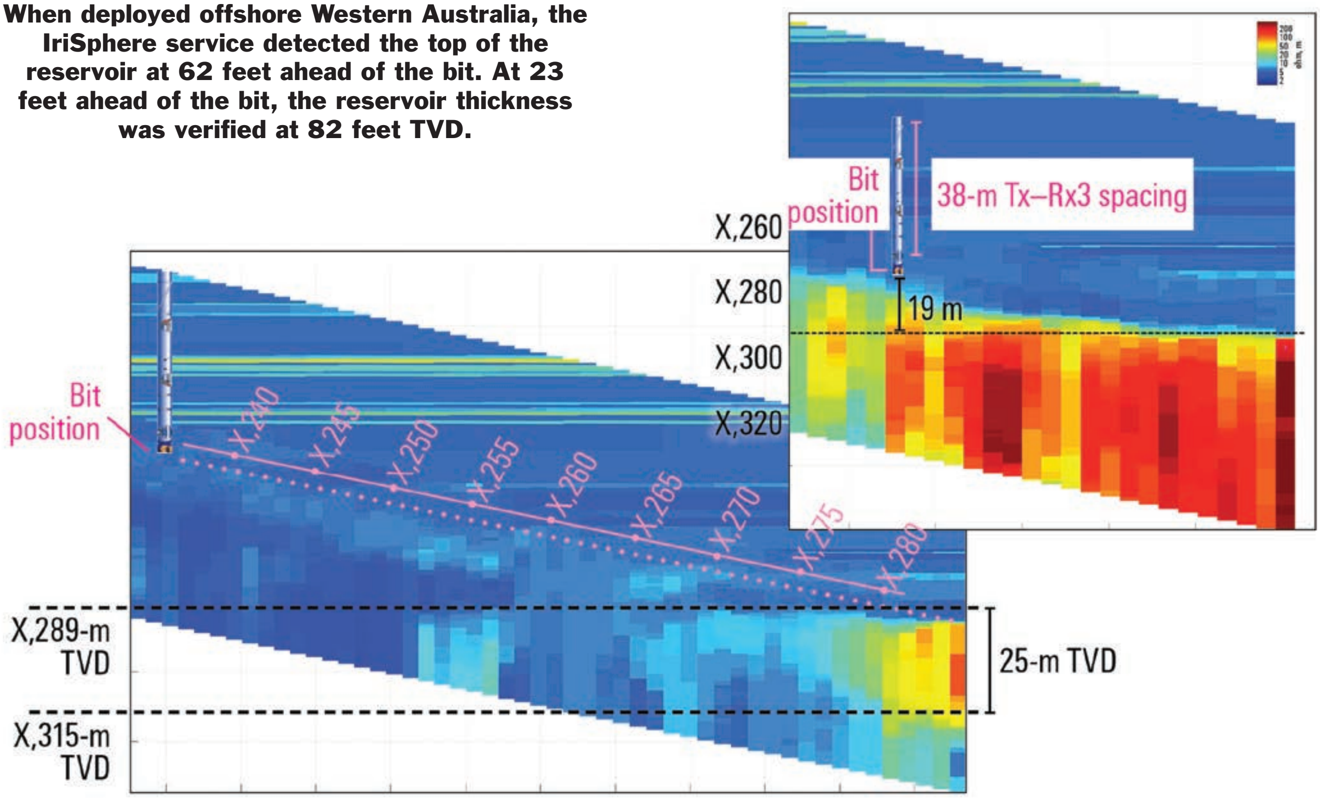
With more than 100 measurements available in real-time, IriSphere uses state-of-the-art inversion to invert for a high-resolution 1D formation profile in resistivity ahead of the bit, according to the company.

In developing the tool over the course of five years, Schlumberger conducted more than 25 field trials in Asia, Australia, Latin America, North America and Europe. These trials included successfully detecting reservoirs and salt boundaries, identifying thin layers and avoiding drilling hazards, such as high-pressure formations that can lead to wellbore stability issues. The tool has also been used onshore to detect a high-pressure environment.

The development team – which includes a number of experts in deep directional resistivity – engineered the system in response to customer requests to be able to look ahead of the drill bit in order to reduce drilling risks, improve efficiency and place casing in specific locations.

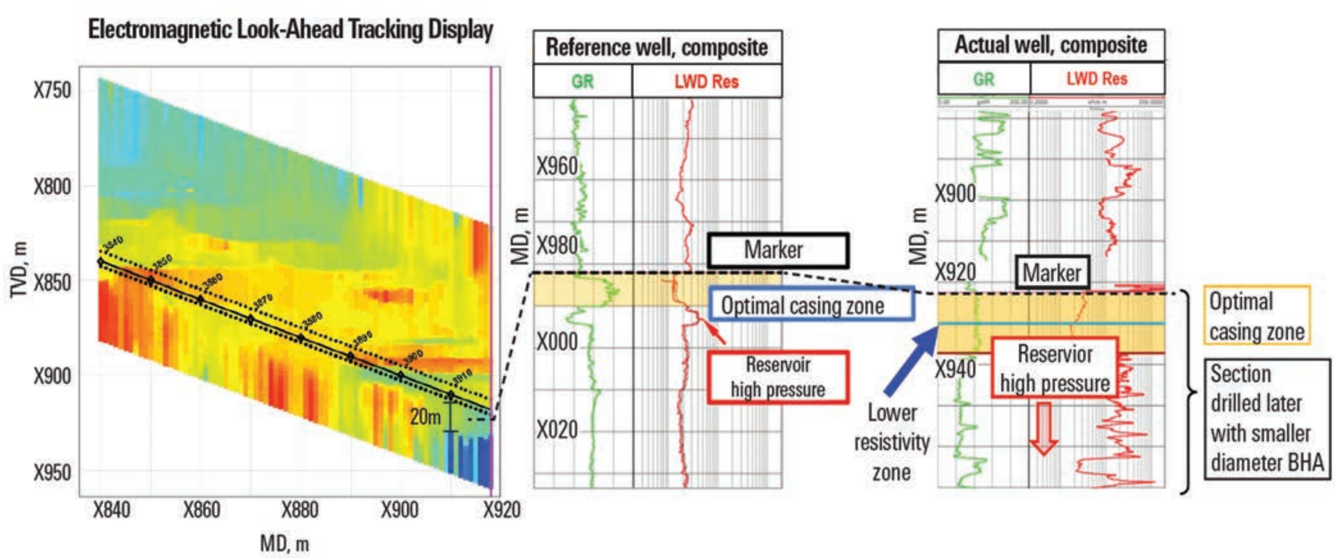
"Knowing the conditions that lie ahead in real time and continuously enables the customer to reduce drilling uncertainties," Wibowo says.

**When deployed offshore Western Australia, the IriSphere service detected the top of the reservoir at 62 feet ahead of the bit. At 23 feet ahead of the bit, the reservoir thickness was verified at 82 feet TVD.**




Source: Schlumberger

**Below: The Schlumberger team recommended the IriSphere service for a well offshore China. The service detected and accurately mapped the target shale marker 65 feet ahead of the bit. The use of IriSphere service offshore China averted previous hazards and is now the preferred technology in that specific field.**




Source: Schlumberger

# Welcome to the **App Store**

**By Elaine Maslin**

Imagine a kind of app store for subsea xmas trees; a plug-in platform into which a myriad of functionality can be added and changed to suit. It's a concept being pitched by UK subsea technology firm Enpro, except it's calling it a "process USB" port.

The idea is that operators can order stock xmas trees for their projects and then use a Flow Access Module (FAM) hub to augment its capabilities, as and when required, from intervention operations to flow metering or pigging.

The FAM sits within the jumper where it connects to the tree (or manifold) and provides a hub that is used for interchangeable FAM modules, from field commissioning to decommissioning.

Enpro's technology, which can interface with any original equipment manufacturer subsea production system, has been created by the same team that previously founded DES Operations which, along with the MARS (Multiple Application Reinjection System) technology they invented, was sold to Cameron in 2007.

Ian Donald, Enpro's CEO, says, "The old standardization method was to fit everything that the field might need throughout the life of field on the tree or manifold, which adds to cost and schedule. There's an alternative; use things you need when you need them," he says. "Have a tree and manifold off the shelf then use FAMs to get to first oil faster. Then you can have advanced functionality without needing a bespoke tree, you minimize the xmas tree footprint and you have future proofing. Put on what you need when you need it."

The first FAM was deployed in 2016, on BP's Nakika K3 (Keplar) satellite in the US Gulf of Mexico. There, a standard tree with a manifold tie-in was used. Normally, here, a flowloop would be used, says Donald, but this would have been uneconomical to reach the optimal tophole location. Instead, a spur line was used supported by a FAM with a multiphase flow meter, water cut meter and sand detector. To manage the flow at the other end of the spur, a flow assurance FAM module was deployed. According to BP, tens of millions of dol-

**Left:** An Enpro FIS Subsea Safety Module (SSM) on deck prior to deployment.

**Right:** An Enpro FAM flow assurance module during system integration test (SIT).

Source: Enpro

lars was saved on the project by using a stock tree, getting rid of the flow loop. "It's a potential model for tiebacks in the region," says Donald.

Since then FAMs have been used on more than 50 wells across 16 subsea fields, from the US Gulf of Mexico to West Africa and the North Sea, on projects from adding flow measurement capability to enabling multiple well tie-ins out to 10 kilometers.

Other projects have included retrofitting multiple FAMs on a field for Tullow, offshore West Africa. "They liked it so much they specified it for all new wells on the TEN field," says Donald. The dual bore flow-through hub can be fitted as a "placeholder" for any future requirements. Initially, this will be multiphase flow meters but then also hydraulic intervention capability. For injection wells, single meters are being used and the FAM hubs could also be used for pigging. "Having modules like meters independently retrievable saves cost," says Donald. "The flow-through hub can be replaced by metering or access for hydraulic intervention, at any point life of field."

In the US Gulf of Mexico, operator LLOG has used the technology on a number of fields. "It's meant they can use standard trees and standard manifolds, while simplifying the jumper design and making the modules retrievable," says Donald, "getting to first oil faster, and then configuring them."

FAM hubs have also been used for hydraulic intervention, alongside Enpro's other key technology, its patented Flow Intervention System (FIS), which includes pumping via a range of conduits from the vessel to the FAM in 2,000 meters water depth.

Donald says an early driver for the FIS concept was to open up easier subsea well intervention operations, by enabling hydraulic/fluid access to wells using smaller vessels and technologies including composite pipe, coil or tube.

To date, Enpro has deployed a 10,000 pounds per square inch (psi) FIS in Ghana. It's now working on a 15,000 psi system, for use down to 3,000 meters water depth. The system, which will include onboard lights and camera, so a second "eyeball" remotely operated vehicle (ROV) isn't needed on site, recently completed factory acceptance tests and is working toward API17G2.

Enpro is also working on development projects to add other 'apps' to the FAM offering including HIPPS (high integrity pressure protection system), FAM pump, based on positive displacement twin screw pump technology and an acid neutralization FAM.

# What About **Well Intervention?**

**By Elaine Maslin**

In a bid to maintain production rates but with less outlay, operators have been looking closer to home. Reducing costs and increasing efficiency have been high on the agenda. Should well intervention be higher?

Well intervention, which can help increase production or restore shut-in wells, might seem like a sensible option in a lower oil price and profit environment. But are operators doing as much as they could?

Restoring shut-in wells can add production at economic rates, Margaret Copland, senior wells and technical manager at the Oil & Gas Authority (OGA) told the Offshore Well Intervention Europe (OWIE) conference in Aberdeen earlier this year.

There have been 7,000 wells drilled on the UK continental shelf (UKCS). Some 2,700 of those are deemed active, and of that number about 600 were shut-in, according to the OGA's 2018 Wells Insight report. About 32% of the total are subsea wells.

According to the OGA's data, 22 million barrels of oil equivalent (boe) of production was added in 2017, through intervention operations, at an average well restoration of just $6.4/boe. "That's an amazing rate of return," Copland says. Yet, subsea well intervention was carried out on just 14% of wells in 2017, she said, compared with 54% of platform wells. "Given that 30% of wells are sitting shut-in – that's not wells

that are in cessation of production (COP), it's 30% of the active well stock – there is something wrong with a 14% intervention rate. We should be at 30%, trying to get these shut-in wells online, assuming facilities can handle it (e.g. water handling, etc.)."

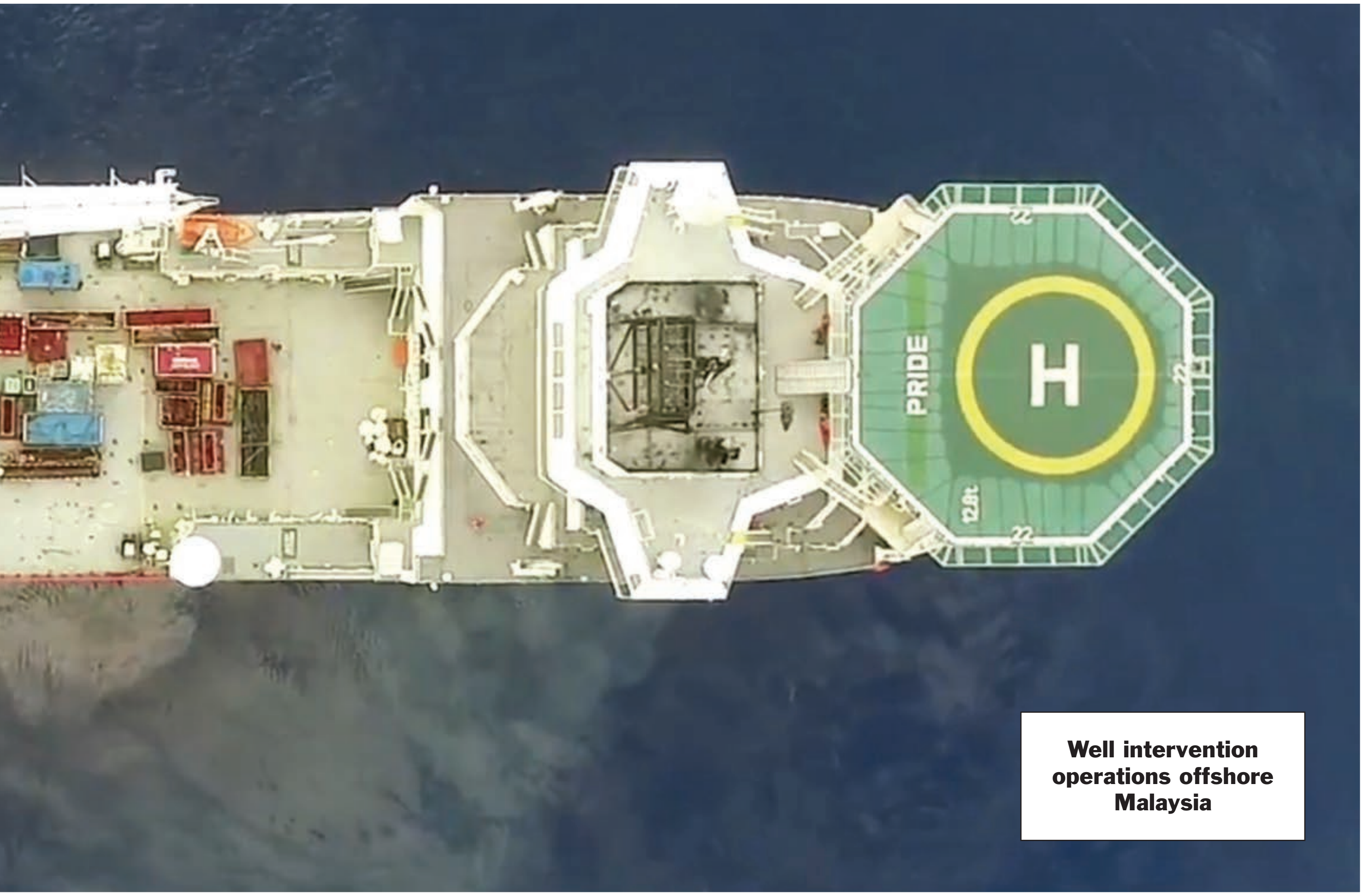
**Subsea challenge**

Cost could be a challenge. Subsea well intervention cost 54% of the total well intervention spend on the UKCS in 2017, according to the Wells Insight report. Another issue is lack of data about what is actually happening in wells, i.e. a lack of well surveillance. The rate of well surveillance work was just 8% of the active well stock in 2017 – and that rate is significantly less for subsea wells – despite a large prize that could be had by doing well intervention, Copland said.

Garry Fines, regional manager, at Baker Hughes, a GE company, agrees, saying that there is a "data gap". "That makes the task harder, finding out which wells to intervene on," he says. "By increasing surveillance and intervention rates, you increase opportunity to unlock these reserves."

Fines says that the number of shut-in wells is an opportunity, as is doing things differently. That may come, thanks to a change of the guard in the UK North Sea. Between 2014-2018, there's been a 23% change in ownership. "That's driven change," he says. Many of the new companies in the basin are independents and quite often private equity backed, which suggests a different finance dynamic – i.e. a push for faster payback on investment. "For me, intervention is a lower cost opportunity than drilling a new well. I'm a bit baffled why intervention isn't higher up the pecking order in what we can do," he says.

According to Fines, demand for well intervention in the North Sea – across Norway and the UK – totals about 1,000 days per year, with 726 of those days based on rig utilization (e.g. platform based) and the rest from light well intervention (LWI) vessels. In the UK, intervention activity is led by riserless LWI vessels (RLWI) in a more spot market type environment. In Norway, Equinor drives the agenda with long-term contracts for RLWI vessels. This work will increase as subsea tree installations increase, by about 200 by 2022, suggesting




**Well intervention operations offshore Malaysia**

Source: Malaysia Petroleum Management

Source: Oil & Gas Authority

> "GIVEN THAT 30% OF WELLS ARE SITTING SHUT-IN . . . **THERE IS SOMETHING WRONG WITH A 14% INTERVENTION RATE.** WE SHOULD BE AT 30%, TRYING TO GET THESE SHUT-IN WELLS ONLINE, ASSUMING FACILITIES CAN HANDLE IT."
>
> **MARGARET COPLAND**

6.2 intervention systems are needed in the market by that year, compared with 3.9 last year, Fines says.

**Operating models**

Offering a dedicated vessel that offers full contingencies and even dive support capability, should be an attractive model for operators, says Helix Energy Solutions, which has the most intervention vessels and longest track record, and is soon bringing its newbuild the Q7000 semisubmersible to the market. The firm also has LWI vessels with saturation diving capability that can help to de-risk operations, by performing well surveillance and doing simultaneous diving operations, says Neil Grieg, Deputy Project Manager, at Helix Well Ops, part of Helix Energy Solutions. These capabilities can help reduce subsea well plugging and abandonment costs by doing more of the work that rigs would do, he says.

TIOS, a joint venture between TechnipFMC and Island Offshore Subsea, which uses vessels managed by Island Offshore and services from Atlas Intervention, also says a dedicated service is more efficient. Yet, TIOS' Andrea Sbordone says, while cost is related to efficiency, often projects are evaluated based on spread rates – wrongly.

Fines suggests there's an opportunity to offer outcome-based contracts, i.e. a fee based on increased production rates, or deferred payment terms. He also suggests using vessels of opportunity. "Use vessels already on hire with lightweight modular intervention systems," he says. "There's a myriad of things we could do, without spending too much capital. I think market is under supplied, there are shut in wells we can exploit. The operator segment and ownership critical point could drive industry to more light well focused approach."

**Looking overseas**

In Malaysia, a campaign to increase well intervention rates has been paying off. In 2013, with declining production rates and 50% of the country's well inventory idle, Malaysia Petroleum Management (MPM), part of Petronas, decided to take charge. Following some success, the oil price collapse in 2014 called for a new strategy, Shahril Mokhtar, head of completions at MPM, told OWI. Costs had been too high and the success rates too low, at 65%. The new strategy, Integrated Idle Wells Restoration (IIWR), launched under the nationwide Cost Reduction Alliance (CORAL 2.0) program, set out to reduce those costs and increase the success rate.

By 2018, 10 operators were involved and 13 projects run, including Malaysia's first subsea well intervention and its first subsea well decommissioning operations. The subsea well intervention work on one three-well project was done at \$12 million under budget (final cost \$8 million) with a 100% success rate, says Mokhtar. New technologies for the region have as also been deployed, including perforate, wash and cement (PWC), cement packers and Ampelmann walk-to-work systems. In total, 22 projects have been run and 75% more production has been achieved under the project, which closed out earlier this year.

A large part of the success was based on using an integrated model, promoting collaboration and risk sharing, he says, while cost savings were made by just using the right operating model, i.e. using the right conveyance method (coiled tubing or wireline, etc.) and selecting the right equipment for the job, Mokhtar said.

The key was a "whole industry approach," says Mokhtar. "To get this whole industry approach was not easy," he says. "It meant getting operators and service companies to work together and then aggressively sharing the learnings, raising awareness and training."

Helix Well Ops' newbuild Q7000 semi-submersible

Source: Helix Well Ops.

# New Money, Finds & Field Starts

**By William Stoichevski**

Norway's government will earn around NOK 265 billion ($30 billion) taxing and taking up stakes in its oil and gas fields in 2019, and Norwegian production is on the rise. In contrast, Britain in 2019 will earn about GBP 1.1 billion ($1.34 billion), says the UK Office of Budget Responsibility. The nature of new offshore investment, however, augurs well for higher project counts and earnings across the North Sea.

The Norwegian continental shelf (NCS) and the UK continental shelf (UKCS) are being buoyed by higher commodity prices. Both have stable tax regimes. Both are seeing new projects, and for both asset swaps are back, as the majors rationalize field stakes.

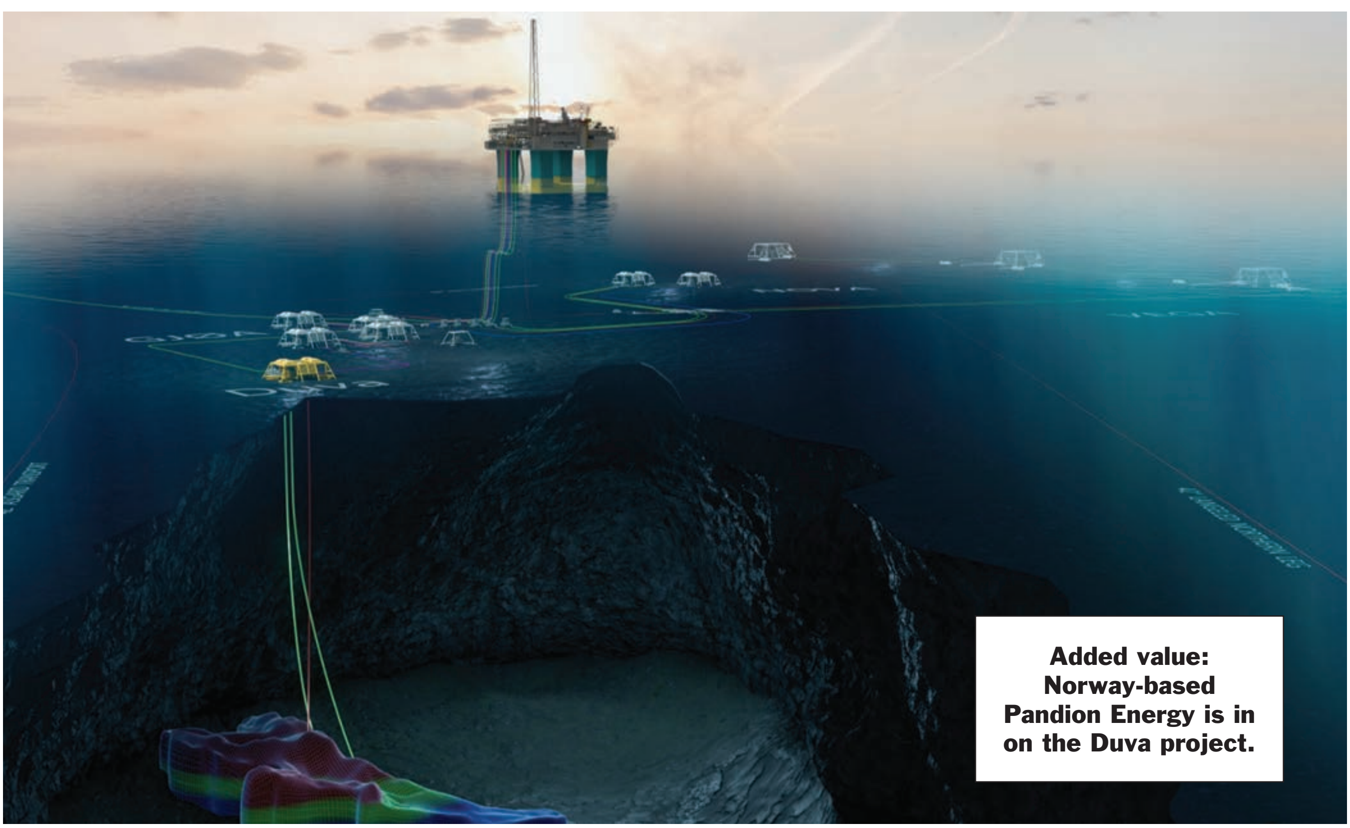
Now, too, both private and Norwegian capital are on the move forming asset-buying alliances across the North Sea. Newly made heavyweight pairings are shoring up project counts.

While Equinor is still fueling Norway's recovery, a host of new players and newly enlarged independents are taking up stakes: Wintershall Dea and Capricorn (at Nova); Neptune (at Duva, Norway and Seagull, UK); PGNiG (King Lear and Tommeliten Alpha). Older newcomers Lundin, OMV and Idemitsu are, meanwhile, leading forays into high-reward development, with new-builds and tie-ins to older infrastructure.

As in the UK's latest licensing round, Norway's most recent acreage awards saw a record 83 production licenses offered 33 companies. Awards in (mature) areas offered operators 90 blocks — five in the North Sea, 37 in the Norwegian Sea and 48 in the Barents Sea — with an August 2019 deadline.

Oslo sees investments offshore Norway "rising over the next years". Only a spell of dry wells this year and lingering low day rates for rigs and offshore vessels are dampening the mood. As of this writing, the well count in 2019 has reached 25 (53 in 2018).

Projects given the royal nod so far this year only add to 20 okayed and in the works by the end of 2018. Of 80-odd fields in production by the end of 2018, 64 were in the North Sea, 17



**Added value: Norway-based Pandion Energy is in on the Duva project.**

Source: Pandion Energy

in the Norwegian Sea and two in the Barents.

The field stakes of operator ExxonMobil — now for sale — look set to give impetus to one of Norway's larger operators. Buyup candidate Aker BP recently announced a large new discovery at the Noaka field, where up to 200 million barrels of oil equivalent (MMboe) are said to be in-place.

The real story in Norway lies in the 1 billion boe that lie in 15 named projects at various stages of development — and in about 30 discoveries over the past three years. Moreover, value in Norway, as in the UK, also revolves around new money creating opportunity out of older infrastructure.

**The two Johans**

Dominating the Norwegian offshore scene is the Johan Sverdrup field in the North Sea, with its planned 660,000 barrels per day (bpd) of oil. A quarter of Svedrup's size is Johan Castberg in the Barents Sea.

The NOK 42 billion ($4.7 billion) Sverdrup Phase II (approved in May 2019) is still yielding contracts, steel-cutting is ahead of schedule at contractor Aibel's fabrication yard in western Norway. Phase II means five new subsea templates for 18 production and water injection wells, although a 200-megawatt power hub linked to shore is planned at Sverdrup for an area of fields that includes Edvard Grieg, Ivar Aasen and Gina Krog. Phase 2 is also a new process platform and bridge connections to Phase 1's riser platform.

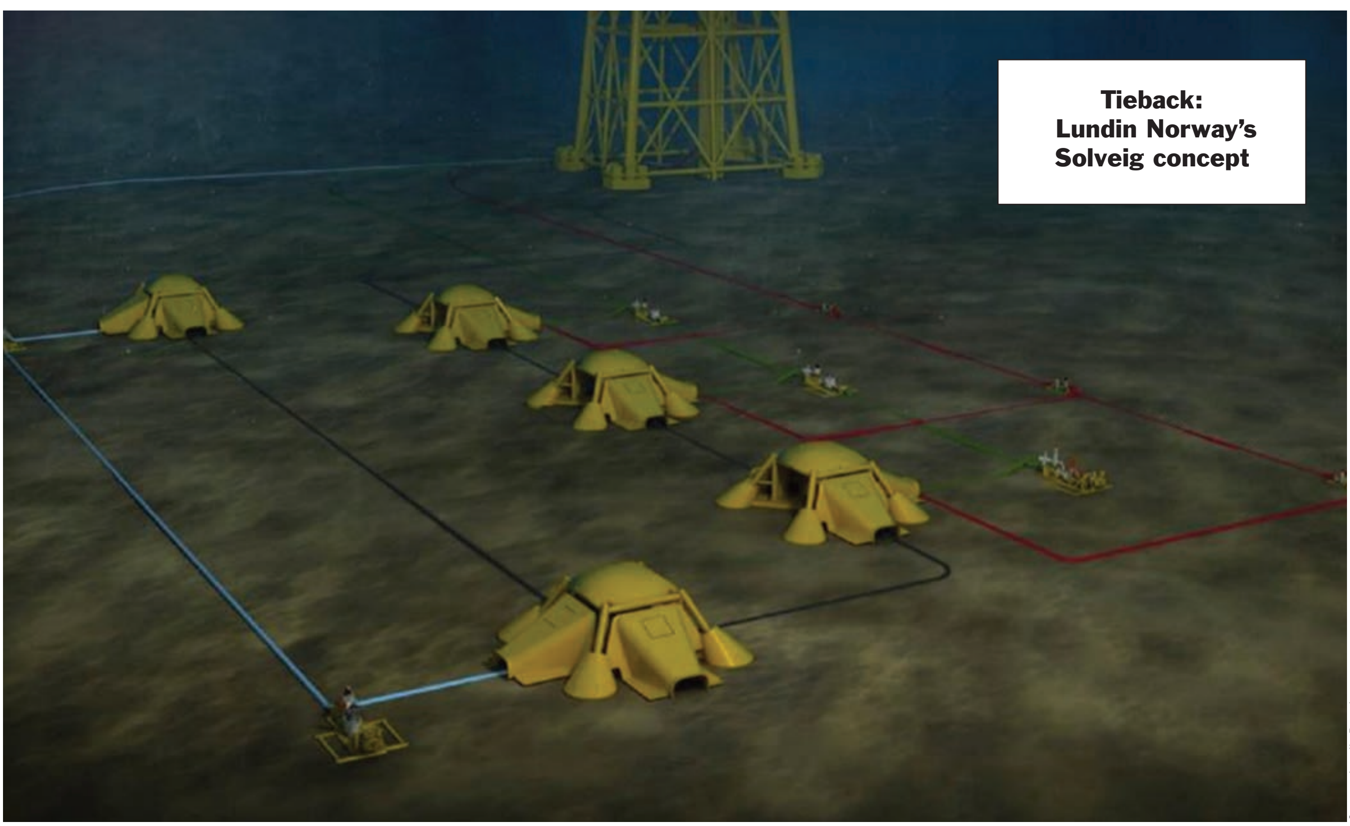
At 650 million boe, Castberg is the largest oilfield project in the Barents Sea and looks likely to be confined to an offshore floating production, storage and offloading unit (FPSO) delivering oil by shuttle tanker. It's scheduled for first oil by year-end 2022. The Castberg FPSO will weathervane as it produces from 30 wells in 10 subsea templates that'll also tap two satellites. SBM Offshore will build Castberg's production turret, and Dubai Drydocks will build the mooring system that'll anchor in 370 meters of water, while also tackling construction-related procurement.

**Redevelopment**

In March, 2019, Norway officially gave the nod to close the Gullfaks C platform in the North Sea (as infrastructure). It had, a month earlier, okayed the Norne FPSO's life-extension, by default extending the Norne, Urd and Skuld fields in the Norwegian Sea.

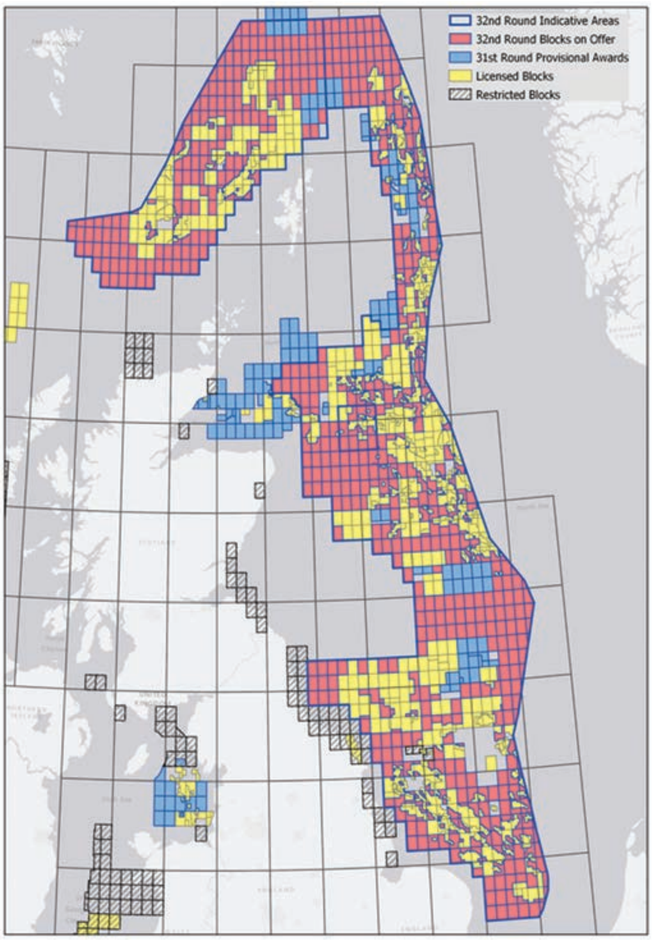
In June, a plan to lift 17 MMboe more from the Gullfaks field was given the royal nod, four years after its Phase 1 was approved. One of Norway's largest oil and gas fields, its three platforms were scheduled to be closed. A NOK 2.2 billion ($247 million) plan will keep the Gullfaks area producing to 2030 from beneath its Shetland chalk cap.

July saw ConocoPhillips submit a plan to redevelop the southern North Sea Tor II field northeast of Ekofisk, aiming at an extra 60 MMboe for NOK 6 billion ($673 million). Two



**Tieback: Lundin Norway's Solveig concept**

Source: Lundin Petroleum




Source: UK Oil & Gas Authority

**General interest: the UK's 32 Licensing Round acreage offering**

subsea templates will produce into a new 14-kilometer pipeline fed to the historical Ekofisk platforms for processing.

July also brought approval for the NOK 1.4 billion ($157 million) Vigdis Boosting Station, where another of Norway's impressive subsea pumps will yield 11 MMbbls of timely increased oil recovery (IOR) from seven subsea templates that produce to the Equinor-operated Snorre field. This 22-year-old field is on-trend for Norway, where "fast track" and IOR increasingly imply "life extension" at Oslo's urging. The Snorre A and B platforms and their infield pipes will be modified for Vigdis and a new power cable connected at Snorre B.

**New finds, new projects**

As July rolled on, parliamentarians approved Lundin Norway's plan for the Solveig development (four months after submission) — a NOK 6.5 billion ($730 million) subsea tieback to the Grieg platform that takes aim at 60 MMboe via three producers and a water injector by 2021. In all, seven satellite wells will need to be drilled.

Already, TechnipFMC's fabrication and spool base in Orkanger and its rental tool and subsea base in Bergen are tagged for work on the Solveig tieback. Others include ASCO and Rosenberg Worley. TechnipFMC at Oslo and Kongsberg will handle the subsea project execution.

Lundin, meanwhile, has run a "trial extraction" from an old appraisal well of the Rolvsnes fractured granite bedrock formation. Production from this tight species is understood to have been a first for the NCS and could open new areas.

Rolvsnes, like Solveig, appear to extend the Grieg field in the North Sea by some 4 kilometers to the northwest. Once believed to hold about 320 MMboe, drilling into granite yielded what could be another 18 MMboe.

**Operating models**

In February, Neptune Energy — a company actively seeking help from the UK subsea supply chain — gained royal assent for NOK 10 billion designs on the Duva and P1 projects in the Gjoea field area. Some 54,000 boepd are the goal, in-sum.

On-trend for Norway, Duva will see an existing platform produce for a subsea template of three wells. Ditto for Gjoa P1: a template of three wells. Year-end 2020 should see first oil (or gas, check) for these parallel projects 12 kilometers from the Gjoa platform in the North Sea.

Operator Neptune leads partners Idemitsu and Pandion Energy (the bought-out Tullow Oil Norway, backed by private equity partner, Kerogen Capital) and Wellesley Petroleum to a field it took 30 years to find a drainage strategy for (P1).

**A gas outlet**

Spurring on gas investment are Norwegian belief in and support for the still thinly developed northern Norwegian Sea gas province and its associate infrastructure.

The new Polarled pipeline and Nyhamna plant changes will bring northern gas from the newly opened Aasta Hansted gas spar — now tantalizingly close to arctic deposits — south to export lines — especially a newly agreed branch line for Norwegian gas throughput through Denmark and on to the Baltic States via Baltic Pipe. The idea has spurred the Poles, and PGiNG has been active buying field stakes.

Baltic Pipe, however, lays bare Danish resistance on "environmental grounds" to the Russian-German Nord Stream II trunk line.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**The UK**

Norwegian private equity investor HiTec Vision, in joint venture with Petrogas, is buying French major Total's stakes in 10 UK North Sea fields for $635 million. The news is nearly as significant as the discovery of the UK's largest gas find in a decade at CNOOC's and Total's Glengorm, a 250 MMboe giant.

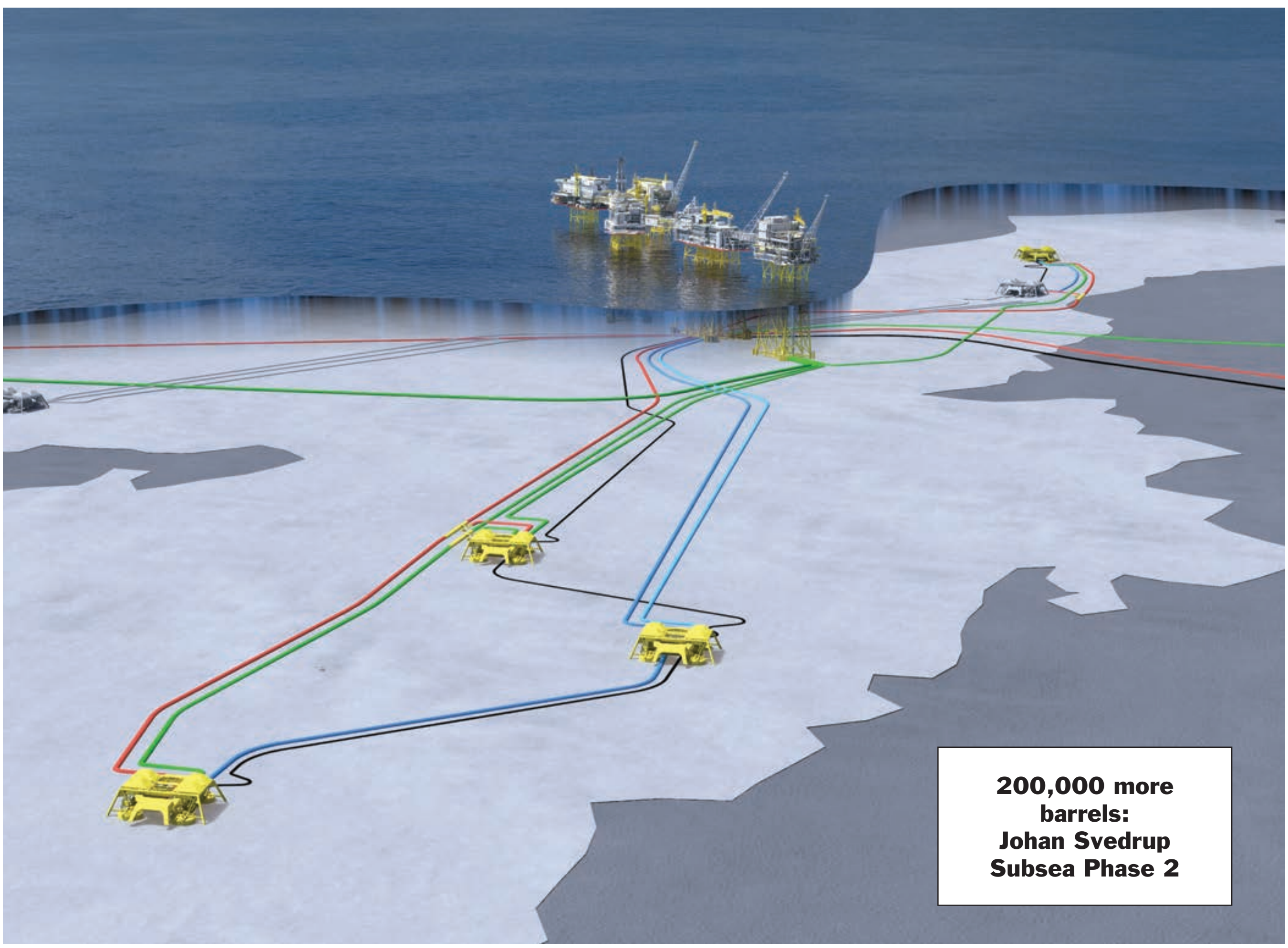
As with ExxonMobil's sale of Norwegian field stakes (and ConocoPhillips's UK asset sale in April), Total's reserves cache in the UK is considerable. The HiTec pact means Chinese operator CNOOC's Golden Eagle field, with its 13,000 bpd, has new Omani-Norwegian owners. Wood Mackenzie suggests several decommissioning opportunities might also become life-extension and modifications projects under those new owners. Total, meanwhile, is seen continuing on at Elgin-Franklin, Laggan-Tormore and Culzean.

Petrogas, Wood Mackenzie points out, "is the upstream arm of MB Holdings, a family-run Omani company specializing in drilling and oilfield services … alongside exploration and production of oil and gas." Wood Mackenzie's Middle East expert says the Petrogas focus is mature, producing assets. HitecVision, which has a stake in Norwegian Vår Energi with Eni, already owns UK offshore stakes via shares in Verus Petroleum.

Meanwhile, Shell's high-pressure, high-temperature (HPHT) Jackdaw wellhead platform project in the North Sea is still on and drawing a who's who of engineering heavyweights. Importantly, too, Equinor after the last licensing round is newly established West of Shetland and in the Moray Firth, while still looking for Mariner and Rosebank (FPSO) suppliers.

Apart from the dozen "fast-tracked" subsea tiebacks in the offing offshore Norway, there were 10 development plans submitted in 2017 and 2018 (including Sverdrup). Names like Troll Phase 3, Nova, Utgard, Dvalion, Byrding, Trestakk, Oda, Njord, Bauge, Ekofisk 2/4 VC add to a burgeoning number of Norway projects.

Oslo, too, is investing NOK 27 billion ($3 billion) in its direct field stakes while also absorbing NOK 57 billion ($6.4 billion) in partner expenses for a total of NOK 105.9 billion ($11.9 billion), plus ownership in Equinor.



**200,000 more barrels: Johan Svedrup Subsea Phase 2**

Source: Equinor

# Deepwater ... in the North Sea?

*Once upon a time, many a year ago, the North Sea was seen as a new deepwater exploration frontier. Some may be surprised that it still is.* **Elaine Maslin reports.**

Back in the 1960s, compared with the shallow waters of the Gulf of Mexico where drillers first got their feet wet, the North Sea was seen as a deepwater province. These days, with operators drilling beyond 3,600 meters water depth (OE: March/April 2019), and production established in waters close to 3,000 meters deep, the water depths here are now taken more for granted. Few developments go deeper than 500 meters in the UK North Sea, with only Total's Laggan Tormore development – a subsea tieback to shore – close to the 600 meters mark.

So, it may surprise some that the industry has been drilling in water depths well above 1,000 meters, and reaching close to 2,000 meters, for quite some time. In fact, the 10 deepest wells drilled on the UK continental shelf (UKCS) to date, according to data from the Oil & Gas Authority (OGA), are all in waters deeper than 1,185 meters (see chart).

They're all out on the Atlantic frontier, on the Rockall Trough or in the Faroes-Shetland Trough, west of Shetland. To date, every single discovery made at these depths remains untapped. The problem is these discoveries are in environmental conditions – including the weather, the waves and currents – that are on another level to even the northern North Sea, and the subsurface has proved hard to get to grips with, both in terms of imaging it and drilling through it.

**New developments**

While the environmental conditions are unlikely to change, the prospects for new developments out here are. Equinor, which took over operatorship of Rosebank, the UKCS' largest undeveloped discovery, with an estimated 300 million barrels (MMbbl), says it plans to reach a final investment decision on the field in May 2020. It's been a long time coming – Chevron

| | WD | Region | Spud date | Operator | Prospect/ Discovery | Well |
|---|---|---|---|---|---|---|
| 1 | 1886 | Rockall Trough | May 2001 | ConocoPhillips | Dry well | 132/06- 1 |
| 2 | 1621 | Faroe-Shetland Trough | April 1999 | Mobil (now Total) | Tobermory | 214/04- 1 |
| 3 | 1567 | Faroes Platform | October 2010 | Chevron | Lagavulin | 217/15- 1 |
| 4 | 1556 | Faroe-Shetland Trough | July 2000 | ExxonMobil (now Total) | Bunnehaven | 214/09- 1 |
| 5 | 1452 | Faroe-Shetland Trough | May 2019 | Siccar Point Energy | Lyon | 208/02-1 |
| 6 | 1373 | Rockall Trough | May 1980 | BNOC | (Rosemary Bank) | 163/06- 1 |
| 7 | 1288 | Faroe-Shetland Trough | March 2012 | BP | North Uist | 213/25c- 1 |
| 8 | 1259 | Rockall Trough | April 2000 | Marathon Oil | n/a | 153/05- 1 |
| 9 | 1238 | Rockall Trough | June 2006 | Shell (now Siccar Point) | Benbecula North | 154/01- 2 |
| 10 | 1215 | Faroe-Shetland Trough | July 1998 | Mobil (now Total) | Eribol | 213/23- 1 |
| 11 | 1185 | Faroe-Shetland Trough | June 2009 | Chevron (now Equinor) | Rosebank | 213/27- 4 |

discovered Rosebank, in 1,110 meters water depth, in 2004.

There's also been a resurgence in exploration activity in the area – above 1,000 meters water depth. Siccar Point Energy's Cambo appraisal well, in 1,110 meters water depth, confirmed a high-quality reservoir and sustained flow. Siccar Point is now planning a phased development with the first phase targeting more than 100 MMbbl.

Earlier this year, Siccar Point Energy successfully drilled Blackrock, which sits between Cambo and Rosebank, in 1,115 meters water depth using Diamond Offshore's Ocean Greatwhite semisubmersible. Investment research firm Edison says Blackrock could hold 200 MMbbl in reservoirs similar to Cambo and Rosebank. Then Siccar Point moved on to the Lyon prospect. As your correspondent completes this article, Siccar Point had completed drilling on Lyon, in 1,452 meters water depth (putting it in fifth place in our deepest water UKCS wells rankings), using the same rig. Results there were not so positive, with Siccar Point announcing on June 28 that the well had not encountered reservoir quality sandstone.

Many were watching Lyon closely. If successful, it could be what's needed to create a new gas hub in the region, allowing existing smaller discoveries, including Tobermory and Bunnehaven, plus Cragganmore, to be developed, says Edison, which had estimated mean recoverable resource of 1.4 trillion cubic feet (Tcf) at Lyon – had it been a success. Andy Alexander, Chief Geophysicist and Subsurface Manager at Siccar Point, told the Devex conference in Aberdeen earlier this year, "West of Shetland is a key area for extending the basin's future. If you look at West of Shetland and the yet to find resources, there's 6.3 billion boe, a third of the total yet to find on the UKCS. If you include the Rockall it's up to 50%."

**We've been here before**

Exploration in the deepest waters West of Shetland isn't that new. BNOC drilled in 1,373 meters water depth in 1980. But, some areas were under a territorial dispute for some time and that was only resolved in 1999, says Alexander. "That's just 19 years ago, compared with more than 50 years since the rest of the North Sea was opened for exploration. Compared with the central North Sea or northern North Sea, there's still lots of room to grow."

Some of the technical challenges are being resolved. Brenda Wyllie, Northern North Sea and West of Shetland Area Manager, at the OGA, points out that there's been production West of Shetland since the 1990s, such as Foinhaven and Schiehallion, in up to 500 meters water depth. Technologies to operate subsea infrastructure 100% with remotely operated underwater vehicles (ROV) has been developed and for even deeper waters, in 1,000+ meters. Drilling technologies have also evolved, as have seismic data acquisition techniques.

**Subsurface, subsea and surface challenges**

Still, it's not an easy area to work in. The West of Shetland area forms part of a series of rift and volcanic passive margin basins which extend along the length of the Northwest European Atlantic Margin. This area has been hard to image due to intrusive and extrusive Tertiary volcanics, says Matt Dack, senior geoscientist, CGG Multi-Client & New Ventures.

Weather and metocean conditions also factor significantly, especially when it comes to designing surface and subsea facilities for these parts. Some of the issues for the environment Rosebank sits in were outlined by Chevron's Peter Blake, back in 2013 (while oil prices were still high).

At that time, Chevron was working on a floating production, storage and offloading unit (FPSO) development with subsea wells, supported by gas lift and water injection, as well as dual production flowlines and chemical injection to control wax and hydrates, to tap the oil and gas condensate reservoirs at Rosebank. The design was moving toward what would have

## MAKING PLANS FOR CAMBO

Cambo is 125 kilometers northwest of the Shetland Islands, 30 kilometers southwest of Rosebank and 50 kilometers north of Schiehallion. Discovered in 2002, Siccar Point acquired the field license in its takeover of OMV (UK) in January 2017. Shell UK joined as a partner in May 2018. Siccar Point has said the field has 800 MMbbl stock tank oil initially in place with an estimated recovery factor of 30-35%. The development concept will be focused on a two-phased approach with Phase 1 targeting circa 150 MMboe. Baker Hughes, a GE company, was selected as the exclusive supplier to support the appraisal and early production phases of the project, with the ability to extend into the full field development. Installation of subsea production equipment and flexible pipes will be in partnership with Ocean Installer, for the early development phase. Crondall Energy secured a frame agreement contract to provide support identification and evaluation of FPSO options for the development and pre-front end engineering design (FEED) technical assurance of the subsea design. Wood Mackenzie has said it expects the field to be developed with a new leased FPSO, five subsea production wells and two injectors.

been the largest turret built for any FPSO, moored with 20 mooring lines. "It's really pushing the envelope as far as technology is concerned," Blake said in 2013. Part of the reason is the water depth and the number of lines coming into the turret, but also the conditions, which make riser clashing a concern.

The design wave height for the area was 108 feet, with a 140-foot survival wave weight.

In addition, there's current shear, through the water column, in multiple directions (which the installed risers and flowlines would need to live with), and even current (1 meter per second) on the bottom. Blake said wave heights run at more than 3 meters more than 50% of the time, West of Shetland (compared with the Gulf of Mexico seeing less than 2 meters almost 90% of the time). A multi-year installation window would have also been needed in these conditions – Blake was estimating four years – where weather windows are limited.

These issues push up costs. According the Wood Mackenzie, the likes of Rosebank and Cambo come in at $40-50/bbl. "That's pretty high," says Kevin Swann, Research analyst, Wood Mackenzie. "Globally, for all projects sanctioned in the last three years, it's below $35/bbl. In the North Sea some of the infill developments have been below $30/bbl. There's a premium West of Shetland."

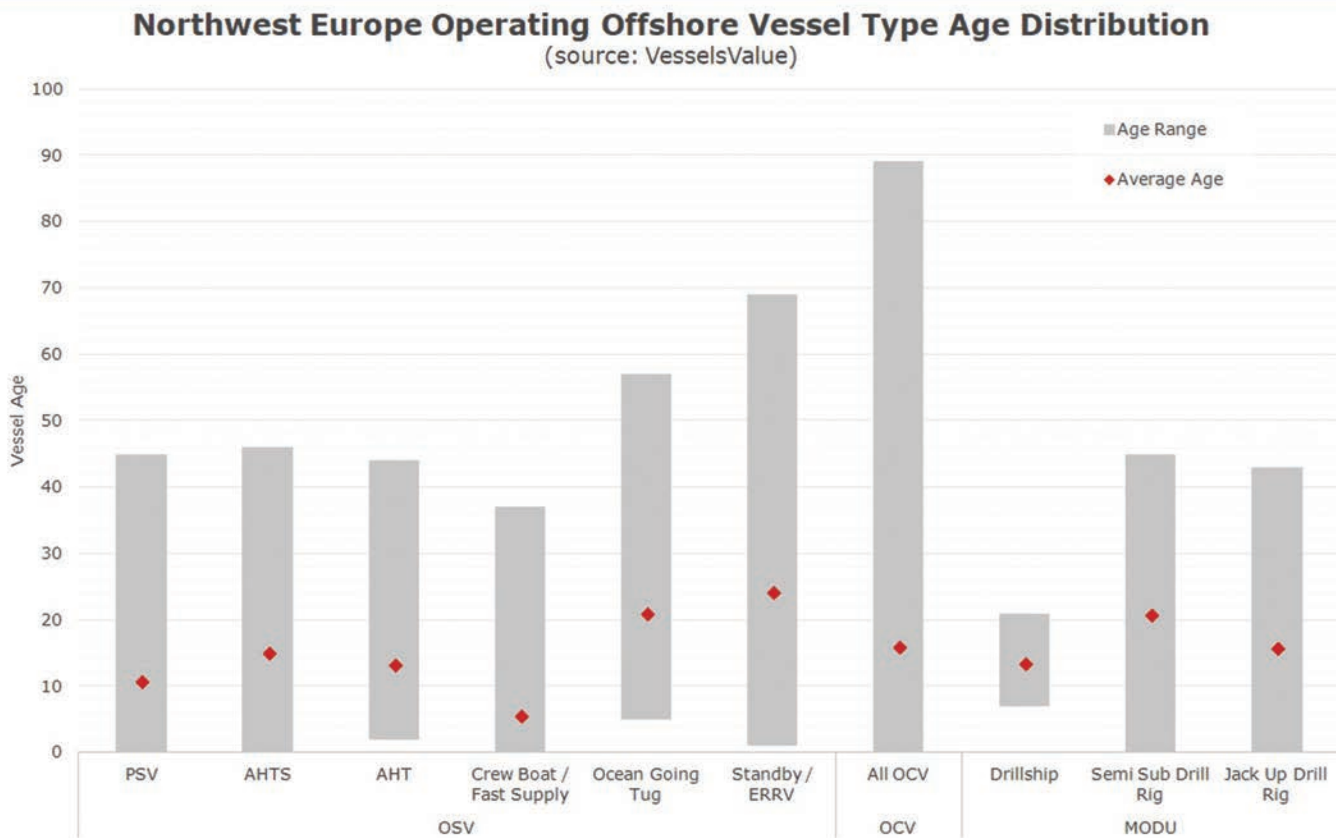
**Access to infrastructure**

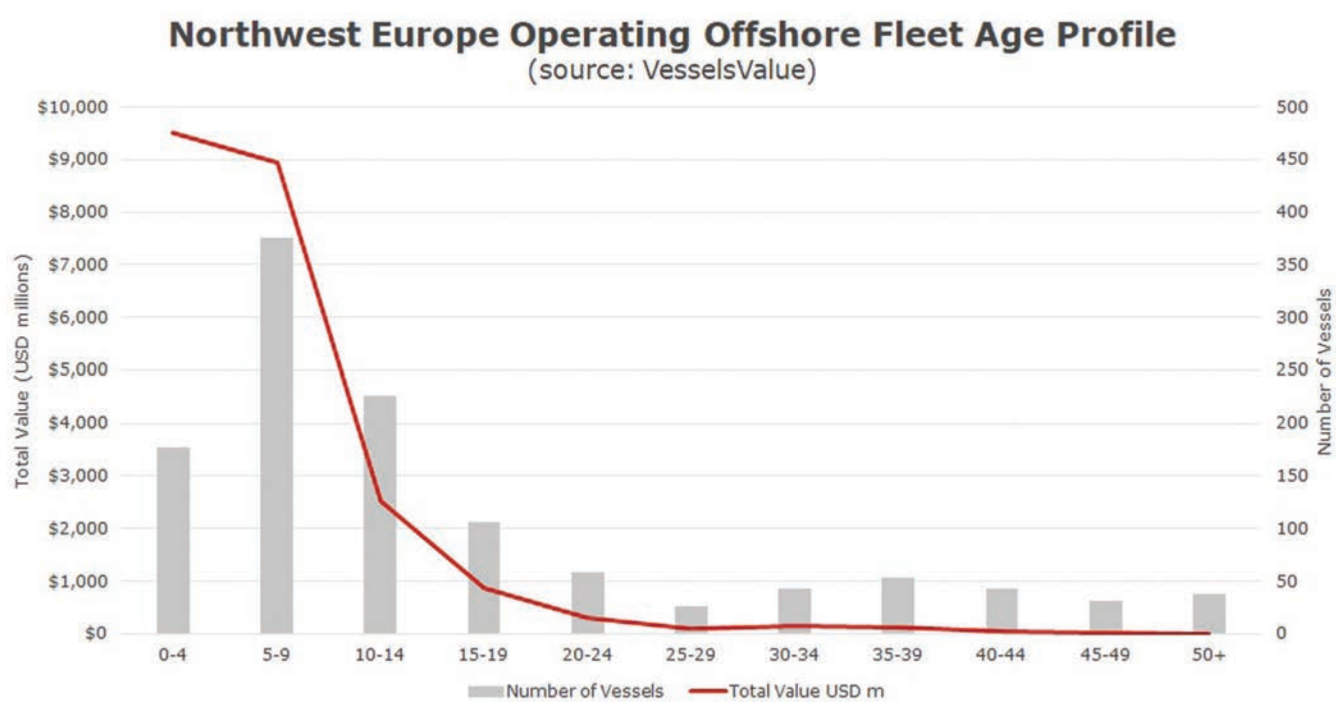
One of the big problems is gas export, says Swann. "This is something companies have been trying to look at and work out. Existing developments, Foinhaven and Schiehallion (now Quad 204) export through the West of Shetland Pipeline System (WASP), which has limited capacity. When you get things like Cambo and Rosebank, you need an export solution for the gas. You can't flare it forever. So, it's a challenge, how to get the gas to market."

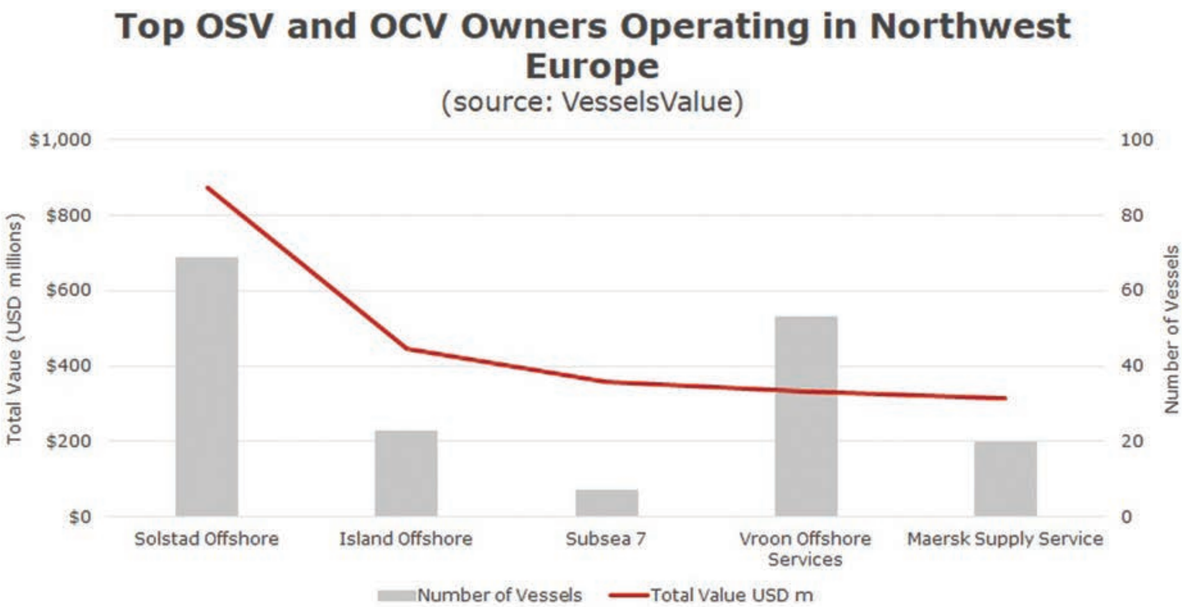
The OGA has an area development plan to try and address the problem and that's for discoveries already known about, but few details were available.

Even further down the line, there's another big challenge. Current exploration bits are focusing on the Faroes-Shetland Trough area, while pre-drill work has focused on the Rockall Trough – including £40 million ($48.6 million) of government funded seismic data acquisition and frontier focused licensing rounds. But that's a story for another day.

Powered by VesselsValue




Top OSV and OCV Owners Operating in Northwest Europe
(source: VesselsValue)
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$400
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Subsea 7
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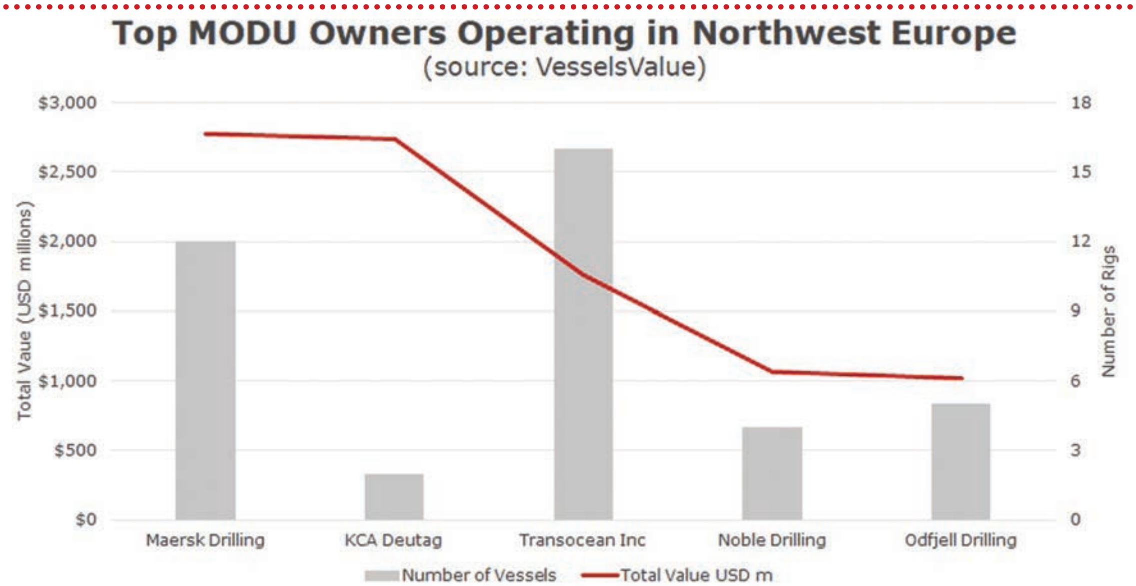
Number of Vessels
Total Value USD m


Top MODU Owners Operating in Northwest Europe
(source: VesselsValue)
Total Value (USD millions)
Number of Rigs
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$2,500
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$1,000
$500
$0
18
15
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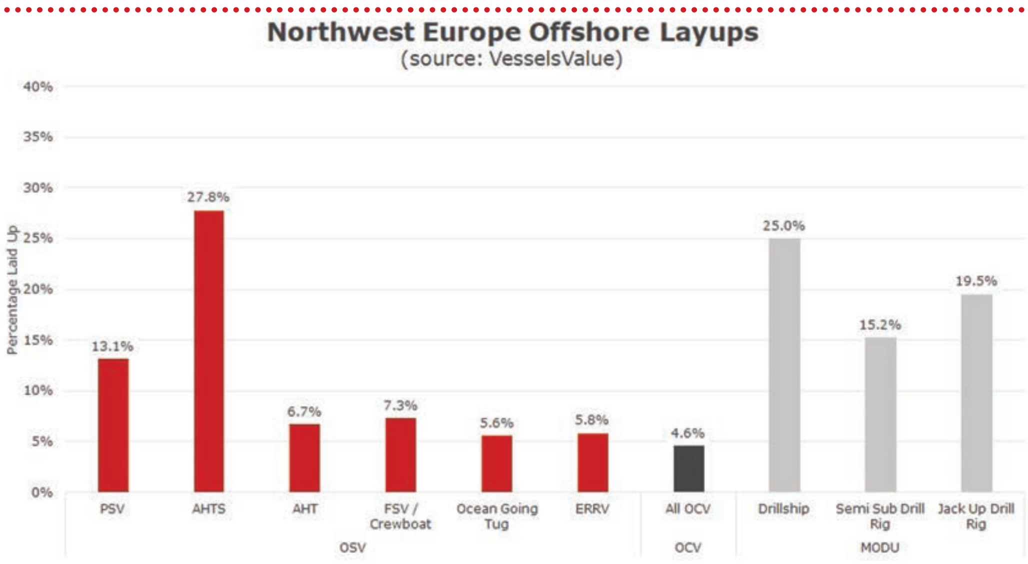
Number of Vessels
Total Value USD m


Northwest Europe Offshore Layups
(source: VesselsValue)
Percentage Laid Up
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35%
30%
25%
20%
15%
10%
5%
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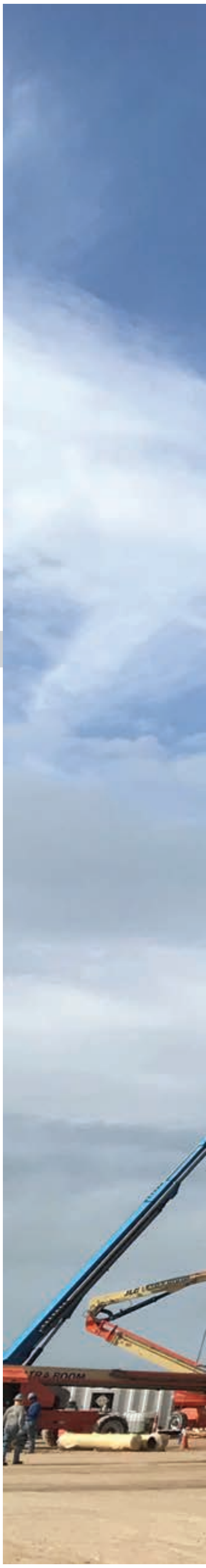
27.8%
6.7%
7.3%
5.6%
5.8%
4.6%
25.0%
15.2%
19.5%
PSV
AHTS
AHT
FSV / Crewboat
Ocean Going Tug
ERRV
All OCV
Drillship
Semi Sub Drill Rig
Jack Up Drill Rig
OSV
OCV
MODU

# The Gulf of Mexico Way

BY JENNIFER PALLANICH



Following a "Gulf of Mexico way" of project execution strategy, standardizing equipment, opting for subsea solutions where possible and focusing on efficient drilling methods is saving $1.3 billion on the Equinor-operated Peregrino Phase 2 heavy oil project offshore Brazil. The wellhead platform topsides are due to leave the Kiewit yard at Ingleside, Texas, later this year.

Peregrino Phase 2, in 120 meters water depth, is adding 273 million barrels of recoverable reserves to the Peregrino area and expected to achieve first oil at the end of 2020. The Peregrino field, originally known as Chinook when discovered in 2004, holds an estimated 2.3 billion barrels of oil in place and has been producing 14º API oil to the Peregrino floating production, storage and offloading unit (FPSO) since 2011.

Two fixed wellhead platforms and the FPSO currently serve the field. Phase 2 will see the installation of a third fixed wellhead platform, known as WHP-C, which will be tied back to the FPSO. It will drill a series of 15 production and seven injection wells in the southwest area of the field, which is not accessible from the existing WHP-A or WHP-B units.

The WHP-C includes components designed and manufactured in Texas, the Netherlands and Norway and brought together at the field in Brazil. While much of the topsides will be joined together onshore, some of it will be taken apart prior to sailaway for Brazil. The main support frame is slated to leave Kiewit in late autumn on a barge while the drilling modules are to depart in November on a heavy transport vessel.

"At the moment, we are testing the different equipment parts and the systems," Frode Haldorsen, Equinor's facility manager for Peregrino Phase 2, said in late June. "All is working as planned."

Heerema Fabrication Group in the Netherlands is fabricating the eight-legged jacket. Leirvik in Norway is manufacturing the 120-person living quarters. Cameron and Nymo in Norway provided the drilling facilities. The WHP-C also includes utilities and a helideck as well as standalone power generation, which will be able to export power to WHP-A.

Phase 2 features horizontal production wells with subsurface downhole electric submersible pumps (ESP) providing artificial lift. Three multiphase export booster pumps will be installed to pump oil, gas and water that will be carried by export pipelines to the Peregrino FPSO, which has a production capacity of 100,000 b/d, while produced water will be separated out and returned to WHP-C for reinjection.

Haldorsen said Equinor is leveraging lessons learned from the original Peregrino project along with understandings from how projects are executed in the Gulf of Mexico and other regions.

"We're taking learnings from Peregrino and from this yard and how they construct and execute here in the Gulf

The Peregrino WHP-C platform at Kiewit's yard in Ingleside, Texas.
It is slated to arrive in Brazil late this year and begin operations in late 2020.

Source: Oscar Ayala/Equinor

of Mexico and mixing that together," he says. "It's a big element in how we were able to reduce costs on the project."

As originally designed, Peregrino Phase 2 was projected to cost $4.3 billion. But by applying strategies that included embracing the "Gulf of Mexico way" of executing projects, including standardization of equipment, using tie-in concepts to existing Peregrino facilities and subsea solutions causing fewer topside modifications, and efficient drilling methods and new contracts for drilling and management services in Brazil, the team was able to shear $1.3 billion off the project, resulting in project sanction in February 2016.

Haldorsen says the ability to "adapt to the yard" and understand the local work processes is necessary for succeeding with a big project. "Whether we go east or west, that's what we need to know. What is the Gulf of Mexico way of doing things? And that way you can succeed," he says.

One sign of success is weight control, and by avoiding weight increases, the project was able to move offshore lifts onshore to minimize the number of offshore lifts required, the company said.

"When we reduce the offshore scope, we reduce the offshore work, as well as the potential for things that could be an HSE trigger," Haldorsen says.

As a result, two of the drilling modules will be lifted onto the topsides onshore at the Kiewit facility, rather than as offshore lifts. Onshore lifts will place a 377-metric-ton module and a 228-metric-ton module on the topsides.

"We tried to maximize the things we could do here at Kiewit," Haldorsen says.

The topsides itself is 95 meters long, 57 meters wide, and 49 meters high. The main support frame for the WHP-C topsides weighs 10,500 metric tons while the completed topsides gross operating weight is 23,000 metric tons.

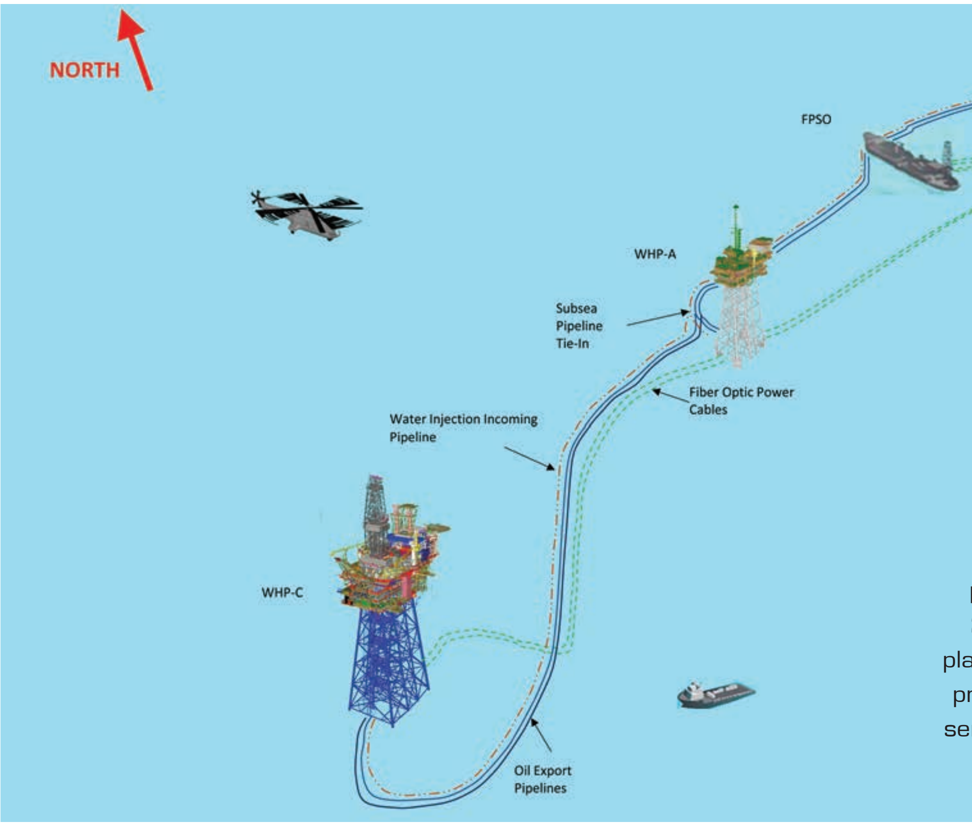
It is always critical to keep the weight of the topsides from creeping up, he notes.

"A benchmark of a lot of projects is you see weight going up and up. You have to buy more steel and fabricate that steel and move that steel," he says.

Controlling the weight was one method of keeping costs down, he adds.

"We are in the last phase of our schedule, and the good news is we are on track to milestones and the budget," he says, noting a focus on health, safety and environment (HSE) has been a cornerstone of the development. As of late June, the job in Kiewit had tallied 3.5 million manhours with no lost time incidents. Another part of the focus has remained on using new as well as proven technology and adapting digital solutions to keep operational and maintenance costs down once the unit is operational, he says. As such, the designers looked at how to reduce the number of people required for operations without compromising HSE.

Part of keeping maintenance costs down includes high-




Peregrino Phase 2 opens up the southwest extension of the Peregrino field and makes it possible to recover an additional 273 million barrels. The WHP-C platform, which will drill a series of production and injection wells, will send the production stream to the Peregrino FPSO and will receive treated water for injection.

Source: Equinor

Frode Haldorsen (left), Equinor's facility manager for Peregrino Phase 2, and John Erling Nordbø, construction & completion manager Peregrino Phase 2 project.

Source: Roar Lindefjeld/Equinor

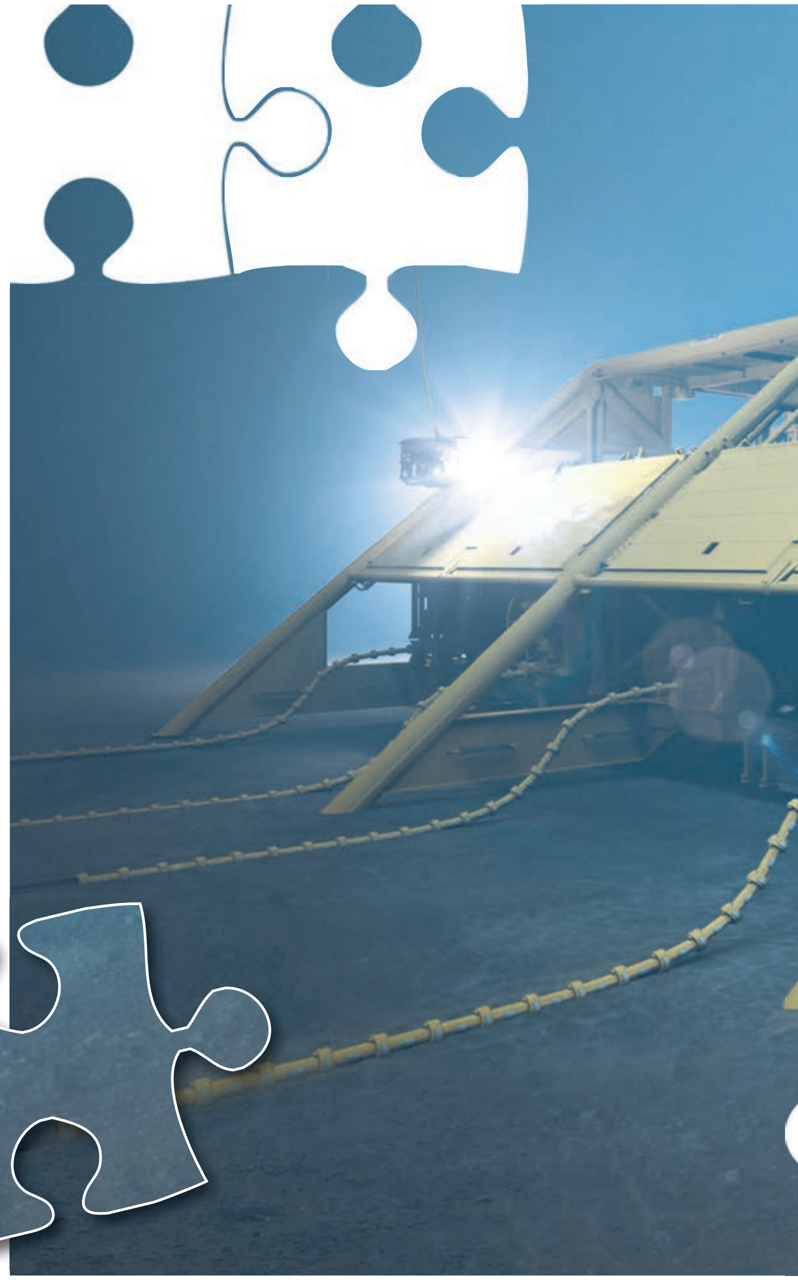
quality painting to protect the steel and decrease the required re-applications of coatings because Peregrino is in a very corrosive environment, Haldorsen says, noting the paint expert was consulted to ensure the right specifications for the paint job and that it was done in accordance with those specifications.

TechnipFMC Brazil won the subsea umbilicals, risers and flowlines (SURF) engineering, procurement, construction and installation (EPCI) contract. Schlumberger Brazil has the contract for drilling (Total Well Delivery). Gran Energia (Brazil) is handling hook up and supplying the floatel.

Even though the platform has been built in Texas, Norway and the Netherlands, the project also creates jobs in Brazil. In operations, WHP-C creates about 200 long-term offshore jobs.

The Peregrino oil field is located in licenses BM-C-7 and BM-C-47 in the Campos basin. Equinor operates the field with 60% interest on behalf of partner Sinochem.

# A Piece of the Puzzle



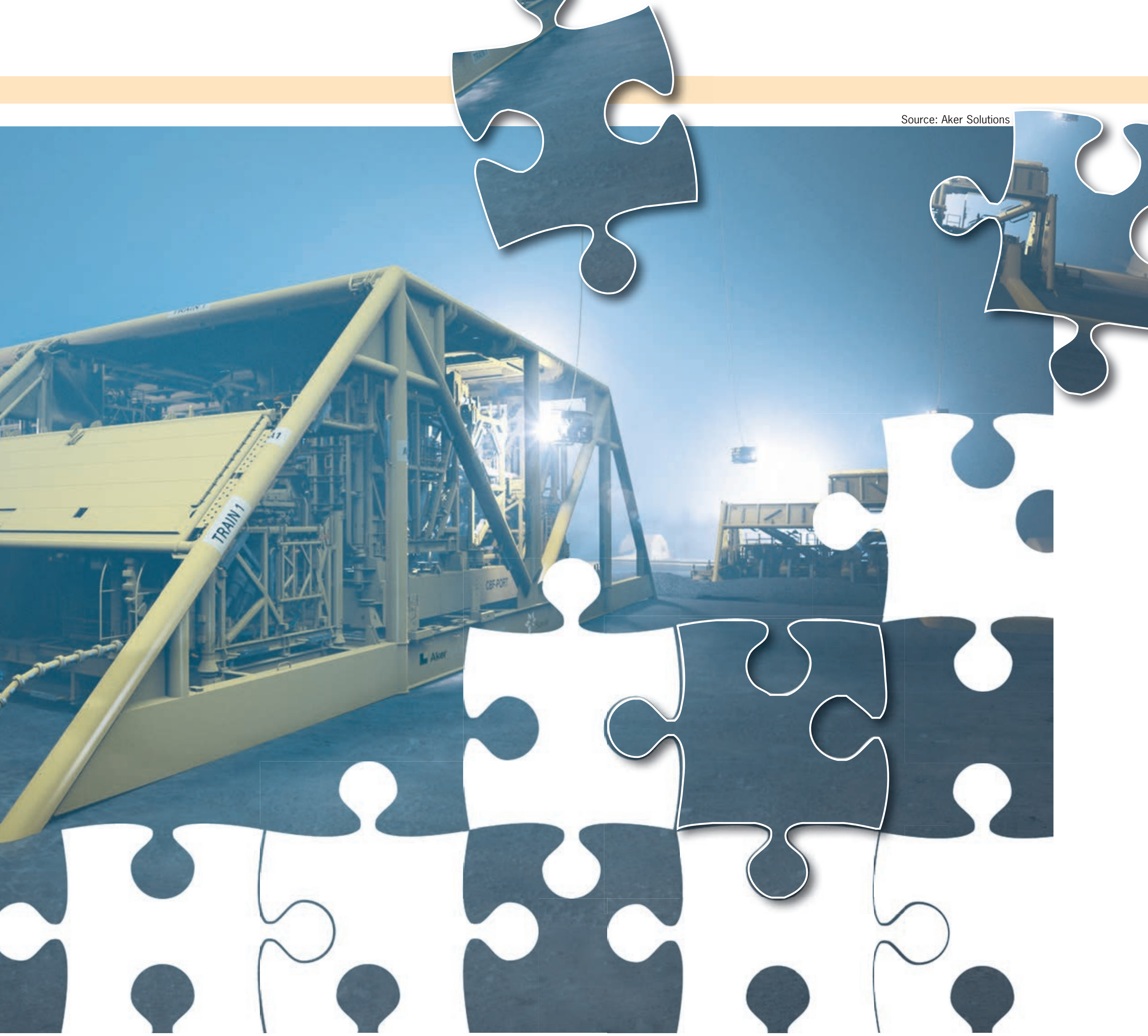
BY ERIC HAUN

As technological advancements continue, subsea processing equipment such as gas compression – now moving beyond Norwegian waters for the first time – may prove to be an increasingly important piece of the offshore production puzzle.

"The overall subsea landscape is changing radically," said Knut Nyborg, EVP and head of front end at Aker Solutions. "There is a move toward smaller, lower cost, flexible and digitally enabled system solutions that focus on enhancing recovery and minimizing environmental impact. In that context, subsea compression has a very important role to play and a very positive market outlook."

Compressors that help maintain plateau gas production rates as offshore reservoir pressures drop over time have typically been installed on platforms above sea level, but placing this equipment on the seabed closer to the wellhead can improve recovery rates and reduce capital and operating costs. Placing the compressor closer to the wellhead increases production and the possibility to extend field life thanks to a lower pressure drop in the pipeline downstream, Nyborg explained.

Subsea compression has a long list of merits, he said: "It provides a better business case by cutting costs and increas-




ing production, it is safer, being remotely operated, and the environmental footprint of a subsea compression installation is significantly lower, offering advantages over topside-based solutions."

But it's been a long road from when the subsea compression concept was first conceived in the mid-1980s to the first commercial use a few short years ago.

An important milestone along the way, Nyborg said, is when Statoil (now Equinor) awarded Aker Solutions a contract in December 2010 to supply subsea compression for the Åsgard project in the Norwegian Sea. "Apart from showcasing the successful developments of new subsea processing technologies, subsea compression also proved itself a viable alternative field development solution," he said.

When the Åsgard subsea compression station started up in September 2015, it effectively completed the final step for technology qualification and demonstrated the system benefits and performance in operation, Nyborg said.

The system uses a MAN High-Speed Oil-Free Integrated Motor (HOFIM) compressor with 11.5 megawatts (MW) compression power. Depending on flow rates and pressure, the system is able to provide a pressure ratio up to 3.5, and


The subsea compression system in Egersund, Norway before sail away to the Åsgard feld.

Source: Aker Solutions

flow rates up to 18,000 cubic meters per hour, per compressor. The topside electrical variable speed drives and the subsea transformers for both the compressors and the pumps were provided by ABB. Aker Solutions also delivered the topside power and control module for the Åsgard A floating production, storage and offloading unit (FPSO) to power the compressors and pumps.

To date, the Åsgard subsea compressors have run for more than 60,000 hours with close to 100% reliability, and it is estimated that the solution will enable more than 300 million barrels of oil equivalent to be recovered from the field.

## New fields

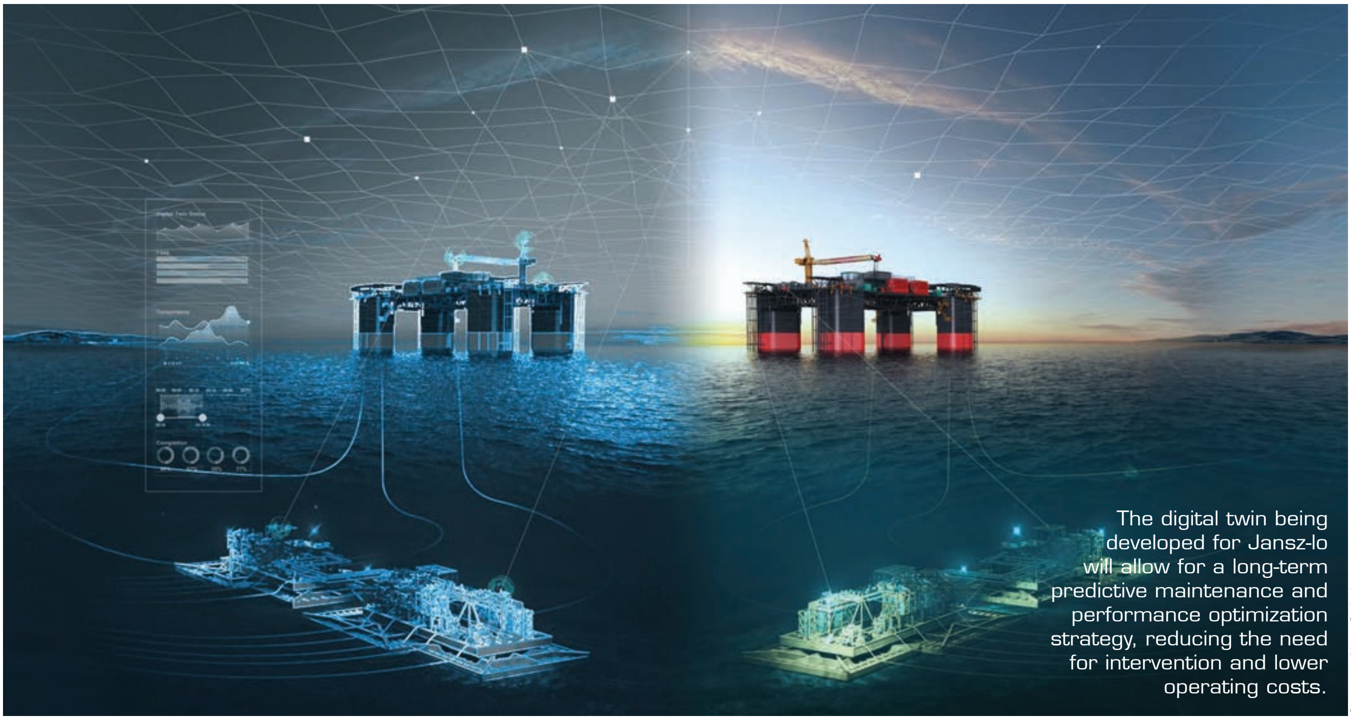
Now Aker Solutions and its partners are working to advance the technology even further as they look to take subsea compression projects into new waters.

Located around 200 kilometers off the Australian northwest coast in approximately 1,350 meters water depth, Jansz-Io, part of the Gorgon project – one of the world's largest natural gas developments – will mark the first use of subsea compression technology outside of Norway. The project, led by operator Chevron with partners ExxonMobil and Shell, is currently in the FEED phase and going "full steam ahead", Nyborg said.

After delivering Åsgard, Aker Solutions' lead engineers from the project, together with help from separate alliance agreements with MAN Energy Solutions and ABB, employed their experience and lessons learned to develop a next generation subsea compression system, SCS 2.0, for new field developments, including Jansz-Io. The companies managed to maintain their core teams and competencies through the downturn, already underway when Åsgard went on stream.

According to Nyborg, "The main objective of the SCS 2.0 program has been to reduce cost, size, weight, complexity, delivery time and also the need for heavy lift operation, while keeping the core functionality and robustness in design." He said, "The engineering work performed indicated that the SCS 2.0 system is able to realize more than 50% reduction in terms of total size and weight."

"Take the compressor module for example, utilizing the lesson learned – the module size and weight were reduced from 294 tons to 180 tons. One way this was done was by simplifying the module pipe routing and by moving the anti-surge function out of the compressor module. Compared to Åsgard the number of modules has been reduced from 13 to seven per



The digital twin being developed for Jansz-Io will allow for a long-term predictive maintenance and performance optimization strategy, reducing the need for intervention and lower operating costs.

Source: Aker Solutions

train in the SCS 2.0 system."

Building upon the Åsgard experience, the Aker Solutions and MAN Energy Solutions alliance aims to deliver a true well stream compression system boosting the liquid and gas mixture that arrive from subsea wells without the use of scrubber and pump. "This will further reduce the size, weight and cost and thus make the high capacity centrifugal subsea compression system even more attractive," Nyborg said.

"The well stream system will include a flow conditioning unit, a subsea compressor with auxiliary systems, a cooler and associated controls and high voltage equipment. The need for a separate liquid pump, with its high voltage power supply, is removed as all liquid is routed through the compressor. There are tremendous savings in reducing the umbilical scope and high voltage power supply accordingly, in particular on long distance step outs at deep waters."

The flow rates for Jansz-Io are up to three times those at Åsgard, requiring three compressors operating in parallel from one scrubber in one train. Aker Solutions was not able to share details on the subsea footprint, but said the power requirement per train is three times the 11.5 MW Åsgard train. The Jansz-Io compression station is located approximately 140 kilometers northwest of the onshore terminal at Barrow Island (the step out for Åsgard was around 40 kilometers).

Early execution of a technology qualification program for the water depth (1,400 meters) and increased design pressure (285 bar) has been ongoing since 2017.

Nyborg said the proven Åsgard technology is applied for Jansz-Io but with added lessons learned from commissioning and feedback from operation to support further optimization, including reduced equipment costs, better delivery time, minimized heavy lift operations and design robustness to limit maintenance operations.

"Åsgard subsea compression was the first subsea compression delivery anywhere. The modularization philosophy for Åsgard was to keep all main process equipment individual retrievable from the station, and the consequence of this was separate modules for each of the main process units, in addition to a spool interface module. This gave us a robust design, but also substantial weight and size," he said.

Since Åsgard, the lead engineers have been focusing on implementing the low/no risk opportunities that are spotted in the project execution and design, Nyborg said: "For example, the reduction of the process modules from seven to three results in a significantly reduced footprint of the compressor train. Heavy lift operations are minimized by reducing the weight of the modules."

"Delivery time is improved by the fact that we have done this before. It is all about the knowhow and experience of the team, as well as the strength of the alliances we have with ABB and MAN Energy Systems. We have also been focusing on critical sub-suppliers as a continuous process, not just for specific projects," Nyborg said.

In addition to performance gains, another benefit of subsea compression at Jansz-Io is improved environmental footprint over the life of the field. Nyborg said, "Getting the compressor closer to the well offers big advantages compared with alternative solutions (compression platform or onshore compression). Our updated subsea compression system can offer increased recovery, less power consumption, offshore logistics elimination, no discharge or emissions, with less material used. The weight of the Jansz-Io system will be significantly lower per MW compression compared with Åsgard."

Nyborg said Aker Solutions has developed a set of performance indicators that will be used to measure the environmental impact of products and system solutions in a project or product development. Due to launch this year, the indicators will be incorporated in the Jansz-Io project to measure the efficiency of boosting, material consumption and intervention frequency.

# Standardized Subsea Processing

When used under the right circumstances, subsea processing technologies have clear and obvious benefits as an enabler for increased oil recovery and even as a more environmentally friendly alternative to conventional processing equipment.

In many instances, however, operators have found these solutions to be too expensive to implement. The number of projects with subsea processing that have been sanctioned to date are far fewer than what operators would like, because of the cost level, said Kristin Nergaard Berg, a principal engineer at DNV GL.

With this in mind, DNV GL, working alongside suppliers Aker Solutions, Baker Hughes GE, OneSubsea and TechnipFMC and operators Petrobras, Shell, Equinor and Woodside, kicked off a joint industry project (JIP) in 2015 aiming to use standardization as a means to reduce the lifetime cost of subsea processing equipment for use globally.

Berg, the JIP project manager, said the partners initially looked at the "big scope" of subsea processing technologies, including pumping, compression, seabed separation and injection, but decided to focus on pumping because it's the one technology most operators were interested in and it's by far the most mature of the group – meaning more experience to draw from.

The JIP's first phase outlined the plan for standardization, and now, after several years, the partners have completed phase two, resulting in guidelines converted to DNV GL recommended practice (RP) and shared with the broader industry outside of the JIP group for comments ahead of publication in early autumn 2019.

The goal is to make subsea pumping a more competitive option through standardization and alignment of technical requirements, definitions, work processes and documentation. The RP examines standards, functional requirements and specifications; system design; pump modules and pressure containing equipment; control system and instrumentation; power systems; materials and welding; and qualification work processes and test requirements. "The key is that we have looked into the whole subsea pumping system, including several disciplines trying to find ways to lower the cost in each and every discipline," said DNV GL's Sofia Wilhelmsson.

What kind of cost and time savings can be achieved? It's still a hard question to answer. "The real benefits will first be seen when the document is taken into use. There's no benefits or cost savings in a piece of paper," Wilhelmsson said. The hard numbers will come through implementation and experience after the RP guidelines are put to use.

# Another Piece of the Puzzle

Source: NOV

BY ELAINE MASLIN

One of the missing links for some fully subsea production systems has been subsea storage, either for production fluids, later periodic offtake or production chemicals.

NOV has been working on a gravity-based subsea storage unit (SSU), based on a design initially developed by Kongsberg. The design, which would compete with a floating storage unit (FSU), has now gone through testing and looks set for large scale verification testing, likely in Norway.

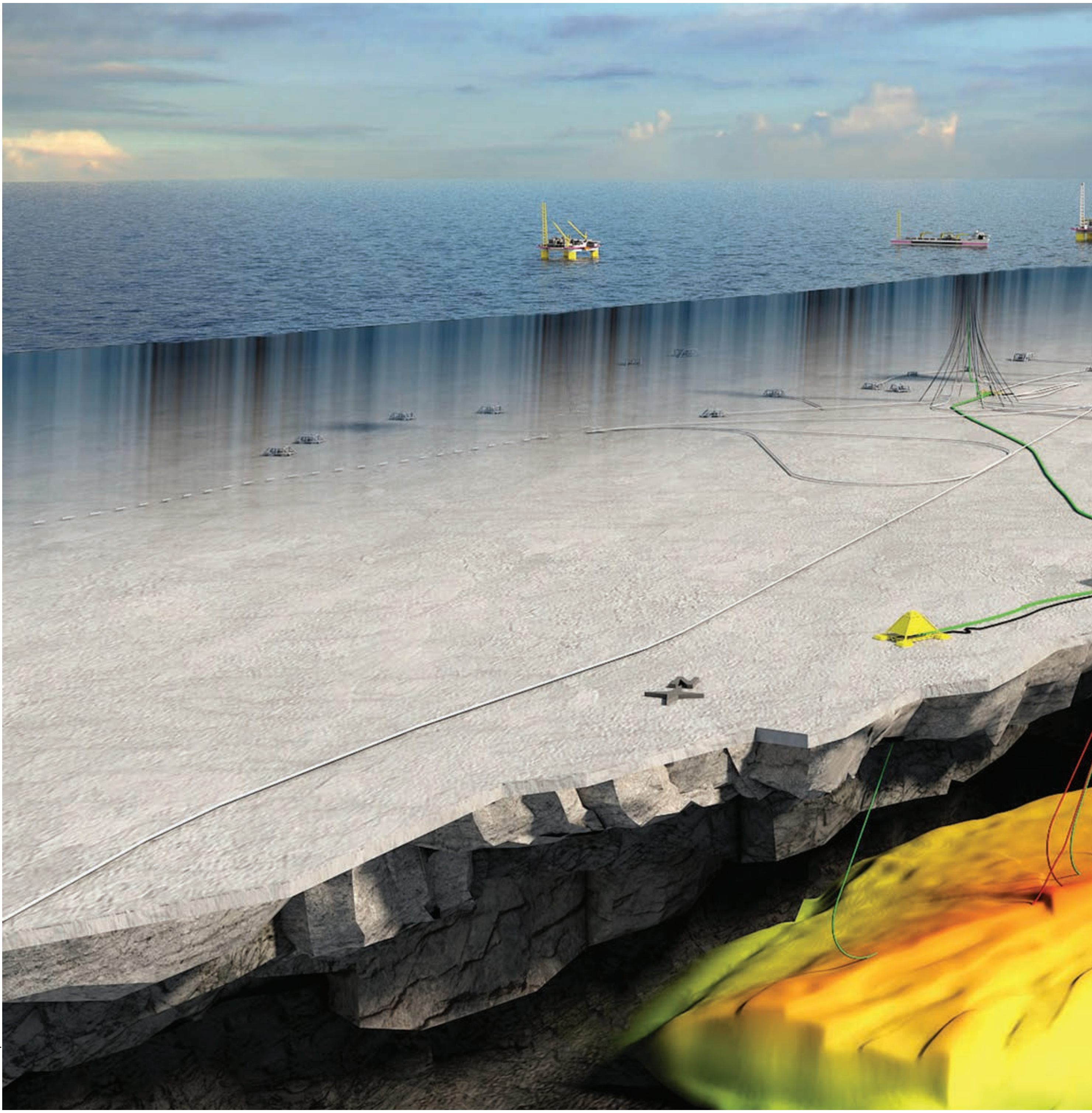
The design is based on using a flexible membrane for oil storage, which is contained within a glass reinforced plastic (GRP) protection structure, that also provides a secondary barrier, in case of a leak. Water is allowed inside the structure, so the surrounding seawater is the same pressure as the stored oil behind the membrane. A center pipe is used for filling and emptying, from the bottom of the structure, via a standard flowline. Should there be a leak, a leak detection system would alert the operator and leaked oil would be trapped under the dome.

The units can be deployed in clusters that operate together as a hydraulic single unit, but can also be isolated, so that the whole storage farm doesn't fail if a single unit fails, Julie Lund, subsea engineer and product manager for Subsea Storage Systems at NOV, told the Underwater Technology Conference (UTC) in Bergen earlier this year.

Lund says that subsea storage could offer lower capex and opex than an FSU, as well as a lower environmental footprint. NOV is pitching 20-year design life units at sizes between 10,000 cubic meters (cu m) to 25,000 cu m for water depth above 100 meters. A 10,000 cu m unit – the base case size – could typically take 40-875 cu m an hour of production and offload at 1,000-5,000 cu m an hour, she said. The company has also been working on chemical and produced water storage systems, which could also be needed during field life.

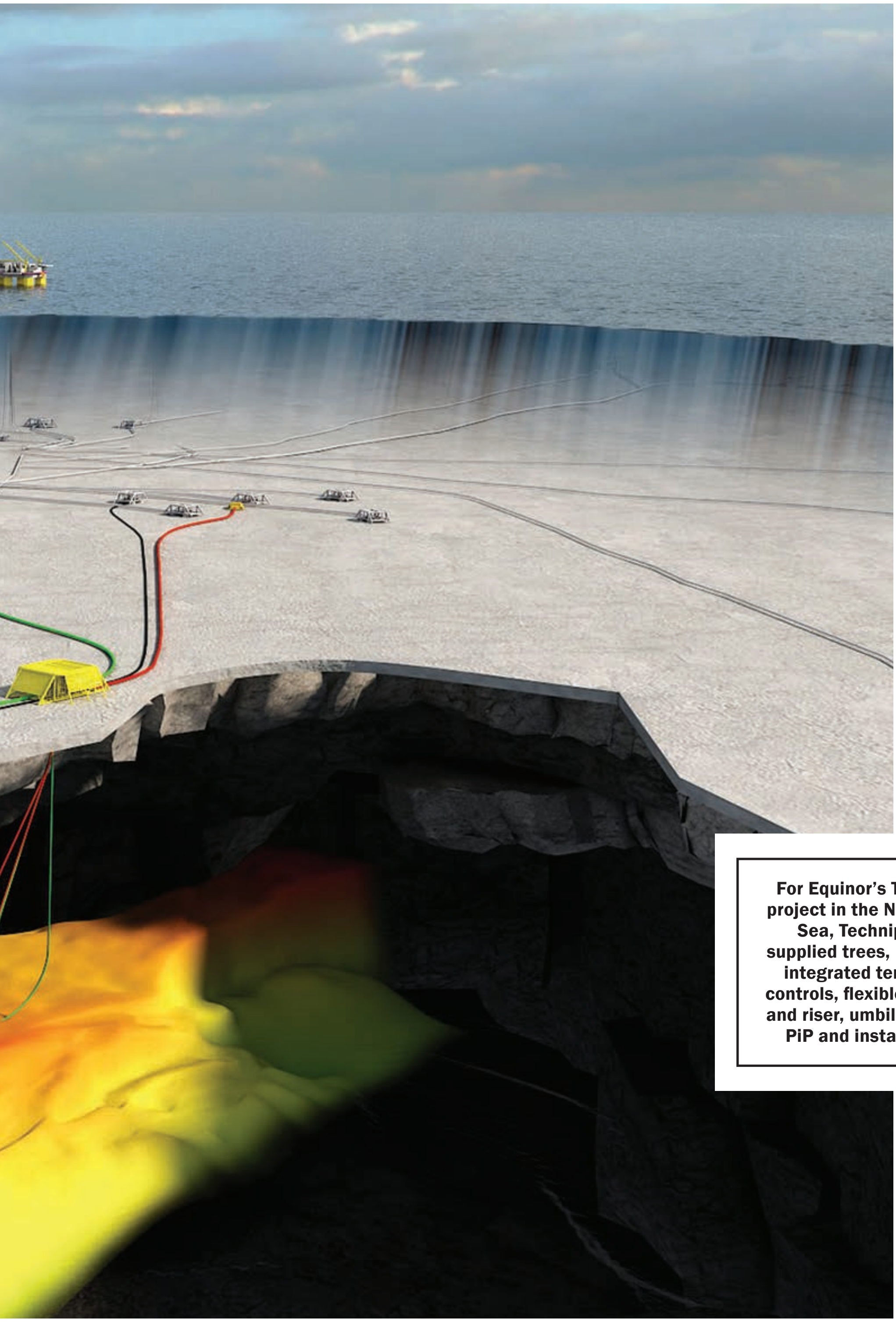
A lot of focus has gone into verifying the membrane that would be used. Following feasibility studies, NOV's work has most recently focused on parameter testing using air and then oil in scale tank models, which completed in early June at the Institute for Energy Technology (IFE) near Lillestrøm, Norway. This verified the behavior of different membranes and geometries and how oil filled and drained from the scale model tanks. NOV now plans to do a large-scale verification test working with Equinor and The Oil & Gas Technology Center in the UK.

# TechnipFMC's iEPCI



Source: Equinor

By Eric Haun



For Equinor's Trestakk project in the Norwegian Sea, TechnipFMC supplied trees, manifold, integrated template, controls, flexible flowline and riser, umbilical, rigid PiP and installation.

An integrated contract model combining the supply of subsea production systems (SPS) with the design and installation of subsea umbilical, risers and flowlines (SURF) has emerged as a top project-getter for services company TechnipFMC.

The London-headquartered company, with operational headquarters in Houston and Paris, officially began operating under the TechnipFMC name in January 2017 following the merger of SURF company Technip and SPS supplier FMC Technologies. It calls its offering iEPCI (integrated engineering, procurement, construction and installation).

Pre-industry-downturn and pre-merger, Technip and FMC had offered integrated solutions through an alliance agreement, and then later through the joint venture Forsys Subsea from 2015.

"Well before the oil price fall, we saw various indications that something needed to be done to keep the subsea market competitive with other development solutions for our customers," said Arild Selvig, TechnipFMC's VP Subsea Commercial, Norway & Russia. "As a driver of industry change, we saw an opportunity to transform our clients' project economics with our integrated expertise and solutions."

To date, the company has announced 16 integrated EPCI projects globally, including eight in the first half of 2019 alone, as it sees demand for its integrated solutions continue gaining market traction.

TechnipFMC is "by far the biggest player" within the integrated SPS and SURF segment, according to Rystad Energy analyst Henning Bjørvik, who says the UK based firm has pulled in more than half of integrated subsea con-

Source: TechnipFMC

> [Operators] see the value of our proven suite of technological capabilities from SPS to the SURF side, and we can mitigate risk on the schedule for interfaces that we can handle internally and also improve time to first oil.
>
> – **ARILD SELVIG,** VP SUBSEA COMMERCIAL, NORWAY & RUSSIA, TECHNIPFMC

tracts over the past three years.

Doug Pferdehirt, Chairman and CEO of TechnipFMC, said in a statement announcing the company's second quarter earnings, "In the subsea industry, iEPCI is a structural transformation that is occurring as a result of the creation of TechnipFMC, and this paradigm shift is accelerating.

"Integrated project awards have exceeded $3 billion for the first half of the year, and we have secured 100% of these awards. Importantly, integrated awards have accounted for more than 50 percent of our inbound orders in 2019. iEPCI has clearly proven to be a unique growth engine for TechnipFMC," Pferdehirt said.

Bjørvik said Norway and the UK is the region with the most integrated projects, with operators including Equinor, Neptune Energy, Lundin Petroleum, Hurricane Energy, Taqa and ConocoPhillips having each opted for at least one integrated contract with one of the several alliance partner groups marketing the approach today.

For TechnipFMC, who has also secured integrated work in other areas such as the Mediterranean, Gulf of Mexico, Malaysia and Indonesia, at least half of its iEPCI projects to date are in Norway and the UK.

Selvig said the market for iEPCI projects should be divided into two camps: majors and independents.

Independent companies see the value of long-term partnership and early engagement support during the study phase moving into a direct negotiated integrated contract, he said, adding iEPCI fits very well with their overall business model and taps into the contractor's competence base. "They see the value of our proven suite of technological capabilities from SPS to the SURF side, and we can mitigate risk on the schedule for interfaces that we can handle internally and also improve time to first oil," Selvig said.

Majors, too, have seen the value of integrated contracts, Selvig said: "We see that the majors are moving in an integrated contract model thinking. However, they see more that iEPCI is one important contract model in their toolbox, and in some cases, it fits their agenda and what they are after regarding, for example, accelerated schedule or new business environment."

According to Bjørvik, majors BP and Eni have arguably been the most active operators globally when it comes to awarding integrated contracts. Among its iEPCI awards in 2019, TechnipFMC has won two contracts from BP in the US Gulf of Mexico (Atlantis Phase 3 and Thunder Horse South Expansion 2), as well as a large contract from Eni worth upwards of $500 million for the Merakes project offshore Indonesia.

Another major, ConocoPhillips, this year awarded TechnipFMC an integrated contract for the Tor II project, an extension of the long-producing Tor field in the Greater Ekofisk Area of the Norwegian North Sea, representing the first time the operator has gone with subsea production and an integrated contract model, Selvig said.

TechnipFMC completed an integrated front-end engineering and design study (iFEED) for the project in autumn 2018, leading to discussions on the SPS and SURF portions, which TechnipFMC won. Delivered as an iEPCI project, the company will execute and install an integrated SPS and SURF solution. Tor II will include eight new production wells and a two-by-four slot SPS planned to be connected to the Ekofisk Complex by multiphase production and lift gas pipelines to existing risers at the Ekofisk 2/4 M platform.

Selvig said that the Tor II iEPCI project has the potential to be a springboard for a long-term relationship with the operator in Norway and the UK. Long-term partnerships are "very important", he said. "TechnipFMC would like to be perceived in the market as a long-term, trusted partner delivering value to our clients for integrated projects."

| Award date | Operator | Project | Location |
|---|---|---|---|
| November 2016 | Equinor | Trestakk | Norwegian Sea |
| June 2017 | Equinor | Visund Nord | Norwegian Sea |
| September 2017 | Hurricane Energy | Lancaster | UK North Sea |
| December 2017 | VNG (acquired by Neptune Energy) | Fenja | Norwegian Sea |
| January 2019 | Lundin Petroleum | Solveig and Rolvsnes (combined as one project) | Norwegian North Sea |
| April 2019 | Neptune Energy | Duva and Gjøa P1 (combined as one project) | Norwegian North Sea |
| April 2019 | ConocoPhillips | TOR II | Norwegian North Sea |
| July 2019 | Neptune Energy | Seagull | Central North Sea |

TechnipFMC has several long-term alliance partners, including Lundin, Neptune and Wintershall DEA. In its fifth iEPCI alliance partner, TechnipFMC's existing partnership with Wintershall was announced in July 2019 to be expanded to create additional value through integrated FEED, integrated EPCI and integrated life of field services.

The firm's alliance agreement with Neptune has been signed for an initial five-year term with options for further extensions, and covers the full project lifecycle from early concept work, through engineering, procurement, delivery of SPS and installation of subsea equipment and infrastructure, and continues into life of field support (TechnipFMC also offers integrated life of field services, or iLOF).

The first projects to be executed under the alliance agreement, Duva and Gjøa P1, are being developed under one iEPCI award, which TechnipFMC says is worth between $250 million and $500 million, as fast-track subsea tiebacks to the Neptune operated Gjøa facilities in the Norwegian North Sea.

TechnipFMC will supply the subsea equipment from the wellheads to the riser hang-off at Gjøa, including subsea templates, xmas trees, manifolds, production and gas lift pipelines, umbilicals, subsea structures and control systems, plus installation activities. The first template is expected to be installed on the Duva field during the second half of 2019 ahead of first oil targeted for the first half of 2020.

The alliance agreement and Duva and Gjøa P1 call-off follow on another Neptune integrated project currently underway. In late 2017 VNG Norge – acquired by Neptune in June 2018 – awarded TechnipFMC an iEPCI contract worth more than $250 million including trees, manifold, controls, riser bases, the world's longest electrically trace heated pipe-in-pipe (ETH-PiP), rigid flowlines, flexible risers, umbilical and installation for Fenja (previously known as Pil & Bue), a long 42-kiliometer tieback to the Equinor-operated Njord platform.

The electrically trace heated technology will help to avoid flow assurance issues for the flowline, Selvig said. "We are in the midst of execution," he said, with first equipment deliveries ongoing and good progress being made within the technology qualification program.

In addition, the company announced a new iEPCI award from Neptune Energy in late July. Under the terms of the contract, which TechnipFMC says is between $75 and $250 million, the company will manufacture, deliver and install subsea equipment including production and water wash pipelines, umbilicals, subsea structures and control systems for the Seagull project in the Central North Sea.

## "Lessons learned"

Commenting on the iEPCI work performed to date, Selvig said, "There's a couple of lessons learned from what we have done. If you take the Lundin case where we are currently executing, it was stated by the Lundin Norway CEO that because of this contract model they have saved at least one year to first oil."

The project he's referencing involves two fields combined under one iEPCI award: Solveig (formerly Luna II) and Rolvsnes, for tieback to the Edvard Grieg platform in the Norwegian North Sea. The iEPCI contract follows on previous iFEED work and continues on a long-term alliance agreement formed in 2017. For Lundin, the goal of the cooperation is to involve the supplier TechnipFMC earlier on to accelerate and simplify project developments.

Selvig also pointed to advantages recognized through its work with Equinor, specifically mentioning the Trestakk project, a Norwegian Sea tieback to the Åsgard A floating production vessel.

"When it comes to Equinor and the [integrated] projects we have run with them, they see that there is low variation orders, so they save contingency on the project on their side. We are able to deliver much quicker, and actually the Trestakk project we delivered and installed on the seabed in 22 months – which has never been done before," he said.

Trestakk, which consists of three production wells and two gas injection wells, had originally been seen as too expensive to develop, but simplification and streamlining achieved thanks in part to iFEED and iEPCI helped to drive down costs.

Anders Opedal, Equinor executive vice president for technology, projects and drilling, said in Equinor's July statement announcing first production from Trestakk that development costs nearly halved before the final investment decision (FID) was made, and then again even further from FID to start-up thanks in part to TechnipFMC.

Under its iEPCI award, TechnipFMC supplied and installed the flexible riser, production flowline, gas injection line, flexible jumpers, umbilicals and SPS with subsea trees and completion system, a manifold, wellheads, subsea and topside control systems and tie-in hardware and tools. "We were able to bring down cost of our scope close to 20%," Selvig said.

Additionally, Equinor has stated during their lessons learned seminars that they have had significant savings on their side outside of its contract scope with TechnipFMC during execution and follow up, he said.

In addition to better time to first oil and reduced cost on the seabed (including capex and install-ex), Selvig said risk mitigation during the execution schedule rounds out the list of "top three" benefits for iEPCI. TechnipFMC is able to handle all of the interfaces between the SPS and SURF packages internally. According to Selvig, this offers benefits such as better planning control, no variation orders and adjusted terms and conditions in the contract that are in favor of the client (the same warranty period for SPS and SURF, for example).

"[iEPCI] is a clear trend that is increasing. If you look at larger contracts over the past three years, close to 40% have been iEPCI globally, and for Norway it's the same figure; we have been awarded approximately half of these contracts," Selvig said.

"The interest for iEPCI continues to increase, so we should expect that we will see an increasing percentage of the total market being integrated," Selvig said.

# **Automation:** Big Data,

Offshore oil and gas is among the many industries in the midst of a vast technological shift being driven by rapid advances in new digital technologies and methodologies. Big data, artificial intelligence (AI), digitalization . . . The list goes on and on. But, how are these technologies being used across the offshore industry today – from exploration to design and all the way through production operations – to boost safety, security and efficiency?

**AI takes paper to digital**

In the engineering world, a large amount of data used for design and maintenance activities in both greenfield and brownfield projects exists only in the form of paper drawings. Compared to digital drawings, paper are difficult to extract information from, and converting these drawings – which often contain between 10,000 and 200,000 documents, depending of the size of the project – to digital formats can be extremely time intensive and costly.

# Security & Remote Ops

In an effort to get the paper drawings digitalized in a more efficient manner, Australian engineering company Worley is using AI to process scanned drawings and automatically redraw them on a digital platform.

According to Kalicharan Mahasivabhattu, a global data-science manager at Worley, human cognitive abilities are no longer needed to process information from drawings thanks to the emergence of technologies such as computer vision, optical character recognition (OCR) and natural language processing (NLP). He said AI can adapt the concepts of pattern recognition, text recognition and line segment recognition to develop a model that learns to recognize components of an engineering drawing, even hand-written notes and sketch markups.

AI systems can be trained to recognize drawings' visual content and provide a simplified context. AI-based algorithms can then read a scanned process and instrumentation diagram to recognize graphical content such as instruments,

**Ivar Aasen, operated by Aker BP, is the first manned platform on the Norwegian continental shelf to be controlled from land.**

Source: Aker BP

tags, pipelines, text, etc., and the information extract that AI generates from a paper drawing can later be passed to an automation script to create a new digital version. By Worley's estimate, it takes an average of 25 hours to convert a single drawing manually. By reducing the manhours by 50% at $25 per hour, the savings for a project with 3,000 drawings could be $900,000.

**Sensia**

The market for digital oilfield solutions is growing rapidly, as many of the industry's top players are making moves to enhance their portfolios of automation and digital solutions offerings.

Recognizing a need in the market, oilfield services company Schlumberger and industrial automation company Rockwell Automation teamed up earlier this year to launch a new joint venture (JV) company being marketed as "the first fully integrated digital oilfield automation solutions provider". Sensia, based in Houston, will operate as an independent entity, with Rockwell Automation owning 53% and Schlumberger owning 47% of the joint venture.

"Oilfield operators strive to maximize the value of their investments by safely reducing the time from drilling to production, optimizing output of conventional and unconventional wells and extending well life," said Blake Moret, chairman and CEO, Rockwell Automation said in a statement announcing the JV in March. "Currently, no single provider exists that offers the end-to-end solutions and technology platform that address these challenges."

Drawing upon the technology and expertise of each JV partner, Sensia will specialize in sensors and measurement technology with intelligent automation across the complete lifecycle from well to terminal. The company will be "uniquely positioned to connect disparate assets and reduce manual processes with secure, scalable solutions that are integrated into one technology platform," Moret said.

Paal Kibsgaard, Schlumberger's chairman and CEO at the time of the announcement, said Sensia will provide technology aiming to further drive optimization of exploration and production assets. For Schlumberger, he said, the joint venture is part of its strategy to offer smart, connected devices with rich diagnostic capabilities, coupled with measurement, automation and analytics that improve oilfield operations, facilitate business decisions and reduce total cost of ownership throughout the life of a field.

**Ivar Aasen: Manned controlled from land**

An announcement from Aker BP earlier this year signaled a first for the offshore oil and gas industry. In January, the Norwegian oil and gas company said it had shifted control of its Ivar Aasen production platform in the northern North Sea to onshore facilities in Norway, meaning the platform became the first manned offshore facility on the Norwegian continental shelf to be controlled from land.

The Ivar Aasen platform features data-driven condition monitoring from Siemens and was constructed with two identical control rooms – one on the platform and the other in Trondheim – and the Norwegian operator said the plan has always been to move the controls to land. Doing so unlocks considerable potential for increased revenues because subsurface experts are closer to the control room and trips to the platform are reduced.

Using Siemens' Topsides 4.0 service, Aker BP was able to reduce the platform's physical manpower and optimize equipment maintenance schedules. The companies have a strategic long-term partnership in place to implement digital lifecycle automation and performance analytics for future field development projects.

Aker BP received the green light from Norway's Petroleum Safety Authority in November, and in January started using its onshore site to monitor facilities, production, equipment and follow up everything that takes place on the field. The control room also plays a role in activating work permits, and for the arrival of vessels and helicopters within the 500-meter zone, the company said.

Even with controls moved to shore, the staff of about 70 people working on Ivar Aasen, 175 kilometers off Norway's west coast, will remain as before, Aker BP said.

**Woodside invests to protect**

Like in many industries, companies in oil and gas are finding that they need to boost their effort to safeguard digital networks and systems to ensure their critical assets remain protected against threat of increasingly sophisticated cyber criminals. Australia's largest oil and gas exploration and production company, Woodside, is among those investing to ensure its operating assets remain cyber secure.

In March, the company announced it would take a 10% shareholding in Sapien Cyber, a Western Australian company specializing in the protection and security of critical infrastructure.

Sapien Cyber was launched by the cyber security research team at Edith Cowan University, commercialized in partnership with Jindalee Partners, and refined in collaboration with Woodside. It is a 100% Australian-owned technology platform that provides clients network visibility, dynamic real-time monitoring and actionable intelligence to dramatically reduce the vulnerability of digital systems to cyber attack.

"Solutions need to evolve faster than the threats. Our unique approach offers unparalleled, real-time visibility to the client's network, detecting operational technology cyber threats before they can wreak havoc," Sapien Cyber chairman John Poynton said in a statement.

"The sophistication of Sapien Cyber's technology platform has the potential to deliver a comprehensive and multi-dimensional cyber security solution to protect Woodside's operating assets," said Woodside's chief technology officer Shaun Gregory, who has also joined the Sapien advisory board.

"Around the world, and across industries, operational technology of critical infrastructure has become a specific, high-priority target of state-sponsored actors in recent years. The emphasis on data-led decision making is challenging the industry to make operational data more accessible to employees in a variety of locations. Along with the benefits of doing this come additional risks of cyber attack," a Woodside spokesperson told *Offshore Engineer*.

"Technology solutions like those being developed with Sapien Cyber assist, and need to be paired with effective workforce engagement to build the awareness, behaviors and capabilities that support the technologies."

"Our goal is to have equal detection and response capabilities in both information technology and operational technology," the spokesperson continued. "Sapien's solution focuses on monitoring and response in operational technology. We are working collaboratively with them to deliver improved operational technology cyber threat detection and response, to protect Woodside's operating assets."

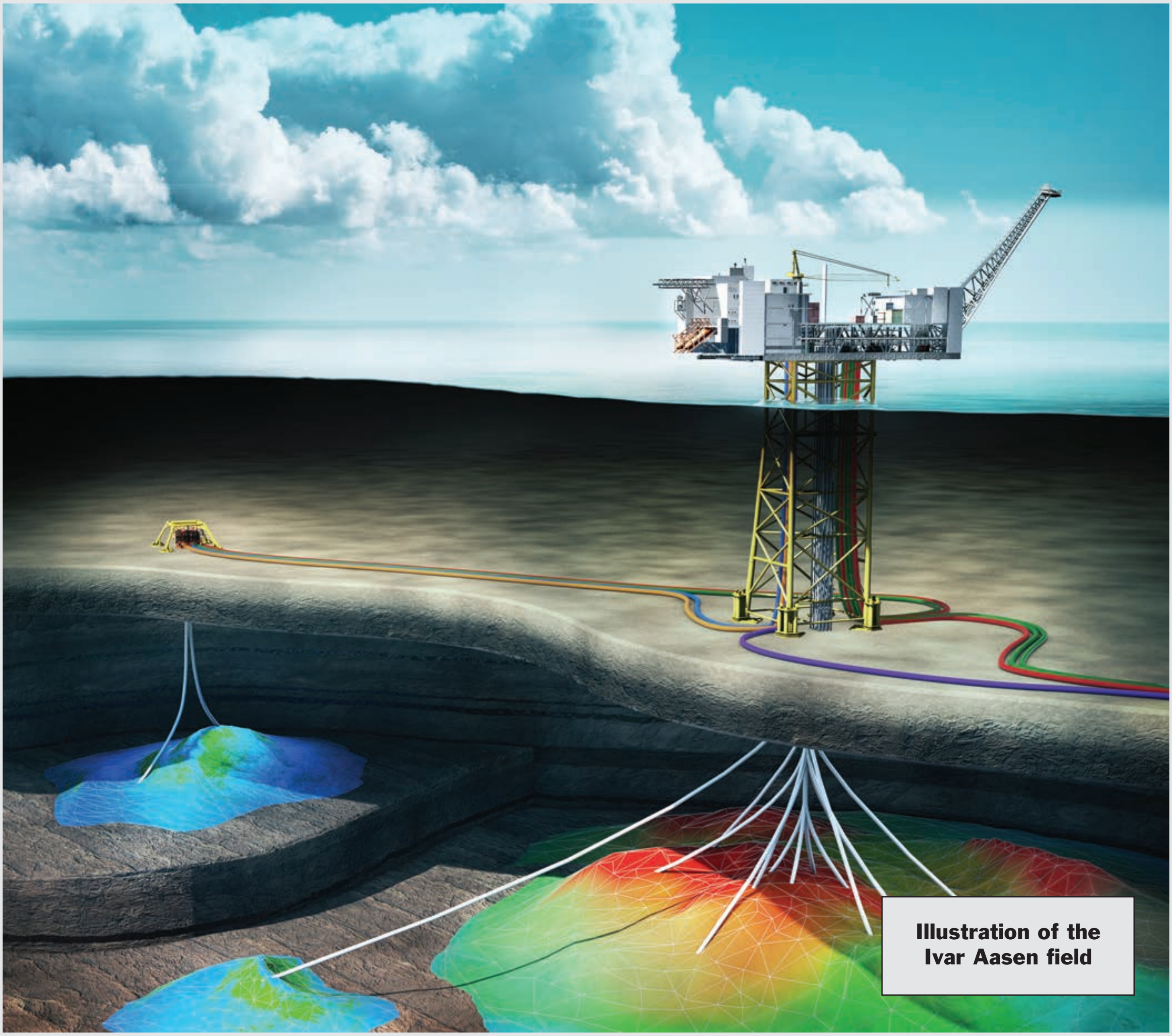


**Illustration of the Ivar Aasen field**

Source: Aker BP

Source: ABS

# DIGITAL TWIN: Taking Shape of the Offshore Ecosystem

The offshore industry is going through an unprecedented digital disruption that transcends asset classes and is creating a roadmap to safer and more cost-effective operations.

The current face of that transition is the ‘digital twin’, a virtual replica of physical assets, processes and systems that ultimately will be used by owners to predict failures before they happen and make production more reliable.

The technologies that enable advanced data analytics – such as artificial intelligence, machine learning, streaming analytics and parallel processing power – have matured to the point that huge volumes of data now can be cleaned and analyzed in near real-time, rather than days. The offshore industry has always produced a lot of data; simply put, processing it has become a far more time- and cost-effective process.

Ongoing pilot projects – with rig and platform builders and operators, offshore supply companies and the floating production, storage and offloading unit (FPSO) community – are currently performing the type of real-time data analyses that improve asset reliability, safety, drilling efficiency and well production. They are proving that asset downtime can be reliably reduced.

It’s a common joke among data specialists working in the offshore sector that you can ask 10 people in a room to describe a digital twin and you will get 20 definitions. That may be because the elements that make up a digital twin are bespoke to why it is being built – i.e., the purpose for which the asset owner is building it.

At its heart, a digital twin is a virtual condition model of an asset on which simulations can be run to improve/predict operational characteristics without having to physically affect the asset.

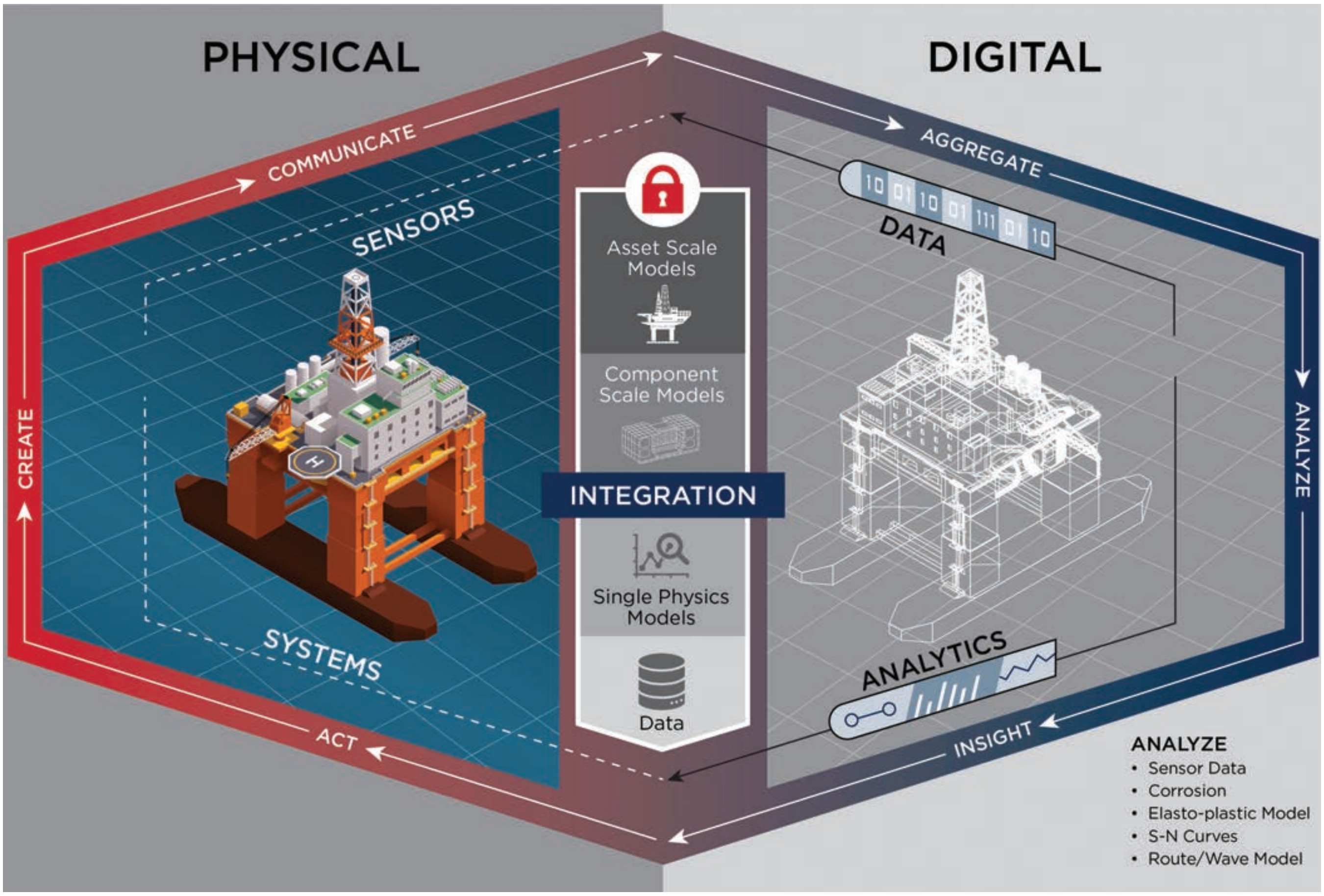
The virtual asset’s scale – whether it represents a simple component or complex marine ecosystem – detail (will every bracket on the rig be modeled and its condition tracked?) and the frequency at which it is to be updated determines the complexity of the model.

Once the scale is decided, the owner then defines the analytical capabilities of the condition model; will operational decision-making be improved by real-time data-based analytics, predictive analytics, physics-based analytics, finite element analysis, etc.

To some degree, classification societies have been working with their clients on basic digital twins for some time. But rapid recent advances in computational power have allowed the scope of those models to be aggressively expanded.

Progressive owners now have the power to expand the scope of the assets they choose to model from equipment and subsystems to an entire rig, platform or floating production system and their wider ecosystems.

This is a significant step forward. Why? Because an asset’s




Source: ABS

performance is less determined by how well its pumps or top-drives working in silo than by how the equipment and components collectively perform within their environment, and how that impacts overall operations.

As the technologies advance, the scope of digital twins is taking on the shape of the entire ecosystem, including the human element; it is now possible to calculate models to determine what the impact of the performance of a component will be on the people operating on a rig, FPSO or platform.

When that becomes a reality, owners will be able to virtually represent what will happen to the performance of their assets in various operating environments. Adjusting the performance of complex assets in real time requires engineering, physics and machine-learning elements to be fully instrumented, and the data-processing power to support live analyses. Now that is possible.

Most of the findings from the offshore pilots currently exploring the industry applications for digital twins have yet to be released. But first-mover marine applications are already showing great promise.

ABS recently released the preliminary findings from a project with Military Sealift Command (MSC), a division of the U.S. Navy, in which MSC implemented digital-twin technology to improve operational readiness, optimize maintenance and minimize unplanned failures for the ships involved in the pilot.

Class societies such as ABS have been building the capabilities to help their clients capitalize on the digital revolution – including the opportunities that arise from disruption – for some time. On the human level, the traditional class workforce of engineers and naval architects has gradually been blended with systems engineers, cyber engineers, risk engineers, data analysts and data scientists.

As the current projects suggest, class now has the capability to ingest unprecedented amounts of raw structured and unstructured data – improving the data quality as it comes in – to undertake not only performance analyses, but also the anomaly detection that is at the heart of predictive analytics.

ABS is now transforming this experience into models that can be dropped onto a digital twin of any scale and ultimately help offshore owners to improve the performance of their assets by better predicting and mitigating potential safety issues.

Condition-based monitoring is a prerequisite to condition-based maintenance. Aside from fulfilling a mandate to provide independent technical advice to asset owners in the offshore industry, a transition to condition-based maintenance will simultaneously reduce the intrusiveness of class by uncoupling its requirements from rigid calendar-based regimes.

# 3D Printing *Brings New Dimensions to Field Commissioning*

**BY ELAINE MASLIN**

Access to and use of additive manufacturing (AM), also known as 3D printing, has increased in recent years due to the expiring of patents on techniques and technologies, says Hugues Greder, Lead Petroleum Engineer at Total.

Computing power is much more powerful and there's also been an increase in the power of the lasers used in the AM process. While a large proportion of AM today is still for prototyping and tooling, about a third is for end uses, i.e. parts, he told the Underwater Technology Conference (UTC) in Bergen, Norway, earlier this year. And more is likely to come.

Total is keen to talk about AM after some recent success stories, including solving a problem during deepwater subsea pipeline commissioning that would have otherwise cost more than €10 million ($11.2 million) to rectify. The problem was found during the Egina field commissioning in 2018.

Discovered in 2003, the Egina field sits in 1,600 meters water depth, about 200 kilometers south of Port Harcourt, offshore Nigeria. Because it has a fairly shallow reservoir, at 1,400 meters below the mud-line, about 40-50 extended reach wells are being drilled on the field. These produce up to a 330-meter-long floating production, storage and offloading (FPSO) vessel – Total's biggest – which came on stream last year, producing about 200,000 barrels of oil equivalent per day (boe/d), or about 10% of Nigerian production.

During commissioning, a problem arose. "When we wanted to connect the Egina gas export line to the Akpo gas export line, we couldn't remove the pressure cap on the in-line tee assembly," says Greder. "We tried several times and it didn't work." The pressure cap, sitting in 1,300 meters water depth, has a plunger flange and bolts. "When we looked, we saw traces of gas hydrates so we were thinking the blockage was due to gas hydrates inside." Delay could have meant that the Egina FPSO was not commissioned on schedule.

The conventional way of dealing with this would be subsea intervention – and replacing the in-line tee. This would have cost in both time and money and would have meant shutting in Akpo. "A Nigerian colleague analyzed the situation and thought out of the box," says Greder. "The idea was to remove the plunger and force methanol to the location." The shape of a tool needed to do this was drawn up and then adapted with a view to using additive manufacturing to "print" it. AM meant the geometry could be more complex than if traditional manufacturing methods were used – and manufacturing time could be faster.

"We're not constrained by tooling and you don't need to have a solid part," it can be hollow, which saves printing time and materials, Greder says. In fact, by printing it, the tool weight was reduced by 50%. The part, measuring 32 centimeters in diameter and 35 centimeters high, was printed in 36 hours, layer by layer, at Total group company Hutchinson (founded by an American businessman in France in 1853) in Paris. It was made using Polyamide 12 powder, which is laser sintered into the form required.

Using this method creates, initially, a large cube. With the non-sintered polyamide powder removed, the tool was


Source: Total

revealed then shipped to Port Harcourt within 48-hours and then sent offshore. Using a remotely operated underwater vehicle (ROV), the plunger was unbolted and then the tool used to inject methanol, dissolving the hydrates in the pipe and successfully allowing the pressurized plug to be removed within four hours.

"It was 10 days from design to delivery, 50% lighter than expected, and the cost was reduced by a factor of 10 compared with a conventional subsea operation for this kind of problem, that would have cost more than €10 million," says Greder. Akpo production also didn't have to be halted and the gas export line was connected on schedule.

"Using additive printing means it's topologically optimized. You can have shapes close to what nature can offer us, like a bee nest," Greder says. By using this approach more, lead times, nonproductive time and production short-falls can be reduced. "In future, I can imagine a printer in Aberdeen, Stavanger, Bergen, where you can send a file and they print a tool you need and send it offshore. If you can do it on demand, you can also save storage cost.

"Another advantage is that compact sophisticated parts with more functions, lighter weight and easier to instrument, can be made," he continues. "Tiny holes can be made to measure pressure at specific locations. These holes you cannot machine. But you can embed them precisely to allow you to do monitoring and pressure monitoring of a part. Third, you can do in-situ repairs to parts."

Greder says that, for Total, this is something new and valuable in the field, and it's happening more. "Several impellers have been made and put in refineries in France," he says. "On the Culzean production facility in the UK North Sea, we 3D printed some titanium alloy inducers for installation on transfer pumps." The modified impellors helped to counteract cavitation and could be produced quickly, instead of taking 24 weeks, using traditional methods.

"This will grow," concludes Greder. "AM will certainly disrupt the oil and gas supply chain. More work needs to be done on quality of the material; you're creating a part at the same time as creating the shape. Before, you were working on material that was created then the shape was certified. So there's work to be done around certification of material and repeatability. There's also intellectual property, if you want a copy of a part. For the time being, we have started using it on non-critical parts. But it will come."

# Smart subsea strategies avoid obsolete equipment risks

**Iain Smith, President, Subsea Controls, Proserv**

In the oil and gas industry, cold, hard data greatly informs an upstream operator when it looks to predict the future direction of the market and chart the course of its business strategy.

A substantial rise in the price of oil might mean previously shelved, investment intensive projects are dusted off and reignited. A spike in the price of other commodities, such as steel or aluminum, could mean original equipment manufacturers (OEM) will bump up the prices of manifolds or subsea trees, thus impacting cost projections.

But some key benchmarks are harder to quantify. Reliability of equipment is not so easy to measure but it is nonetheless essential, no matter where that operator is pumping oil or gas. In the harsh, often challenging environments encountered in the subsea segment, shutdowns and failures are a particularly major headache and are not easily rectified.

**The obsolescence factor**

The risk of equipment becoming obsolete is a perennial problem, which impacts the reliability of subsea control systems. The common scenario is that an operator will acquire a system from an OEM and then utilize it, with no major hassles, for a period of time.

But invariably, sometimes as soon as five years after deployment, the system will begin to falter as components break down and gradually the reliability of the operation will be increasingly compromised. In our experience, the one piece of kit that so often seems to be the root of the failure – is the electronics in the control system itself.

Faced with regular outages, the operator will naturally turn again to the OEM and seek new circuit boards to replace the broken parts, only to find the latest generation of the control system no longer co-exists with the previous technology and the desired hardware simply isn't available.

Typically, when a control system develops regular failures and the supplier cannot offer tangible support, an operator feels compelled to upgrade everything – adding to capital expenditure (capex) and requiring a convenient production shutdown period when the replacement can be installed.

When the oil price is sky high, then spending $20 million on a full upgrade because a couple of relatively minor parts have failed, might be easier to swallow, but it still doesn't make commercial sense if such an outlay is being committed when there are clear alternatives available.

**Opting for coexistence**

As the industry has steadily risen from the nadir of the downturn in 2016, the "lower for longer" philosophy around oil prices is still very much on the boardroom table when it comes to corporate strategy. It is surely counterintuitive for an operator to seek to extend the life of assets and ramp up efficiencies when it is missing a big trick regarding resolving the issue of obsolete control systems.

The subsea product development strategy at Proserv is attuned to addressing the inherent obsolescence challenges faced by operators, by providing technology solutions that actually coexist with the OEM's original control system.

Our Augmented Controls Technology (ACT), for instance, enables additional technologies, such as flow meters, to be deployed to support, or 'augment', any existing control system, removing or replacing defective components as required. So, this effectively means a full system upgrade, and its hefty associated costs and time implications, can be avoided.

At a time of ongoing capex caution, a feasible alternative option to committing tens of millions of dollars towards major upgrades could transform a business plan.

**Making commercial sense**

Over and above the cost benefits, there are additional gains from preferring a coexistence approach to the replacement of a whole control system.

Presently, an operator that can see further potential in a field, and who may want to add a couple of new tiebacks to it, might be constrained by the misguided belief its unreliable and ageing controls system would have to be completely replaced in order to undertake the expansion – and so access


**A Proserv technician carrying out an equipment inspection**

the additional oil and financial returns. So, the project simply wouldn't add up.

But by choosing to augment and improve its existing control system at an affordable cost, rather than make a big investment on a full upgrade, the opportunity to add in those tiebacks suddenly becomes commercially viable.

Indeed, industry analysts have identified a notable uptick in tieback activity around the globe.

Rystad Energy has forecast that in North America alone subsea tieback expenditure will more than double from 2020 to 2025, with a compound annual growth rate of 16.5% over the next six years.

Tiebacks offer a relatively low capex means of extending output from a field with a quick turnaround to production and minus the tens of millions of dollars of outlay, and development time, required for a new greenfield site.

So, as they seek to embrace projects that reduce time, cost and risk, a smart operator will also realize it can further reduce its overheads by acquiring, in its initial investment, a subsea control system solution that has the flexibility and capability to coexist with other equipment, and thus has little threat of becoming obsolete.

Such an approach fits much more appropriately with the current thinking of maximizing returns, improving efficiencies and extending the life of brownfield sites than the break/replace philosophy does.

At Proserv, we have seen a number of independent operators wise up to the benefits and value presented by breaking out of the old model. Their more limited footprint and capacity means that, especially when they are working smaller fields and seeking to gain more for less, the ability to avoid system upgrades when equipment fails, or has become obsolete, has been highly attractive.

But more of the international majors should follow suit. Many of these believe that buying their subsea production systems from one contractor offers them security and convenience. But that procurement strategy is likely to fall down when some of the system becomes obsolete five years later.

Irrespective of where the oil price sits and how deep an operator's pockets might be, it makes little strategic sense to accept poor reliability and the likelihood of obsolete electronics hardware.

Data analysis alone cannot tell the whole story but when subsea tiebacks are widely predicted to spike and the age of operational equipment is expected to keep increasing, a viable and cost-effective means of avoiding expensive control system replacements will undoubtedly play a vital role in the years ahead.

# Safe Commuting Offshore

The inherent risk associated with working in an offshore environment for oil, gas and wind energy production means transfer methods must fully consider and overcome challenges such as wind speed, sea state, visibility, temperature and vessel movement to achieve the safe and smooth transfer of personnel. In particular, operators and vessel owners are realizing the crucial safety and efficiency benefits that gangway systems, which connect a vessel to an asset, provide. When compared to conventional methods such as rope swings, it can deliver significantly better safety, operating and cost benefits, says offshore access solutions provider Ampelmann.

For the past decade, the Netherlands-based company has helped to enable the walk-to-work (W2W) movement through its fully motion-compensated gangway systems. Inspired by aerospace technology, the unique hexapod technology was conceived based on the idea of a flight simulator turned upside down. This is capable of measuring and compensating all six degrees of freedom of a moving vessel: surge, sway, heave, roll, pitch and yaw.

**Confronting extreme environments**

Gangway systems are now widely used offshore in regions including the North Sea, West Africa, Gulf of Mexico and the Middle East. This is due to their cost-effectiveness, wider operating window, and generally higher safety standards. In April, the Dutch offshore service provider announced it had enabled the safe transfer of five million people and 10 million kilograms of cargo worldwide.

The gangway technology employs six hydraulic cylinders on a hexapod to measure and compensate for any vessel motion. It then quickly corrects mobility to ensure the system has zero movement meaning smooth and comfortable journey to and from the workplace.

High sea states and extreme weather conditions and environments can often cause costly delays for offshore personnel traveling by helicopter or rope and basket methods. The innovative motion compensation means the systems can be used in the harshest of environments.

The original A-type gangway can compensate up to 3 me-


**Ampelmann's gangway systems can be used for transfers to both fixed and floating installations.**

Source: Ampelmann

ters significant wave height and transfer 20 people in under five minutes from a vessel to a fixed or floating object. It is suited to a wide range of applications and was recently mobilized on a Micoperi multipurpose support vessel (MPSV) Ocean Star, to enable the hook-up and commissioning of an oil and gas platform. The project, which marked Ampelmann's first contract in Mexico, enabled the safe transfer of more than 9,000 people over the duration of 110 days. The campaign experienced no technical downtime, resulting in maximum efficiency of operations.

The E-type gangway system is 1.5 times larger than the A-type. Its robust design is able to withstand harsh weather conditions which other W2W methods cannot. It can operate in 4.5 meters significant wave height and transfer a full shift of up to 40 people in 15 to 20 minutes.

The system was installed last year on the Olympic Orion vessel in the North Sea to support a decommissioning campaign for end client Spirit Energy. An E-type was also mobilized in Norway this year for DeepOcean to support the hook-up and commissioning of the Valhall Flank West (VFW) project, operated by Aker BP. This marked the company's first project in Norway. It is currently supporting the Normand Jarstein vessel enabling the transfer of key personnel to the normally unmanned installation. Around 100 workers have been safely transferred from the vessel to the platform, with more than 1,300 crossing successfully completed during the first hook-up phase, which lasted nine days.

### Driving efficiencies

While safety remains the highest priority, efficiency gains are continuously sought as operators aim to reduce operational time and risk, and improve flexibility. The E1000, which can transform from a gangway into a crane boom for cargo transportation, employs remote-controlled hydraulic pin pushers to fixate the gangway booms in less than one minute with a single button and can operate in wave heights up to 4.5 meters.

### The W2W market steps up

At a time when the oil and gas industry is being pushed to find new and innovative ways of working, Ampelmann's W2W solutions continue to create greater cost and safety benefits for operators which can then be passed down the supply chain. The hexapod technology has unlocked the full freedom in motion compensation to ensure the safe transfer of personnel and cargo anywhere in the world.

**The E1000 system in cargo transfer mode**

Source: Ampelmann

# Tackling Complex Reservoirs

**By Jennifer Pallanich**

Halliburton leveraged technology from the mining industry to reveal subsurface structures in a way that improves geosteering, geomapping and geostopping in complex reservoirs.

The service company has recently introduced EarthStar 3D Inversion, a 3D reservoir mapping process that, when used in geosteering applications, can maximize contact with oil and gas zones while mapping the surrounding formation to identify bypassed oil, avoid drilling hazards and plan for future development.

Derick Zurcher, Halliburton's strategic business manager for measurement-while-drilling (MWD)/logging-while-drilling (LWD), says the service company worked with mining software specialists Computational Geosciences, based in Vancouver, to "break down this large mathematical problem" of how to process the large number of measurements into a fully resolved 3D volume that could be useful in geosteering applications.

"They were looking at where the ore distribution is in the subsurface. We're trying to do the same thing, where is the distribution of oil and gas?" Zurcher says.

Currently, reservoir data used for geosteering typically comes from seismic, which may not "see" features smaller than 150 feet, and while-drilling tools that take measurements near the wellbore. This leaves "a big gap" between the two, Zurcher says. "For the first time, we have a service which can resolve that intermediate scale."

The 3D inversion capability uses Halliburton's existing EarthStar ultra-deep resistivity service, an LWD technology that identifies reservoir and fluid boundaries up to 68 meters from the wellbore. EarthStar 3D Inversion reveals features such as faults, water zones or local structural variations such as injectities, which could alter the optimal landing trajectory of a well, according to Halliburton.

"The industry now has a solution to understand the hydrocarbon distribution in the reservoir that wasn't there before," Zurcher says.

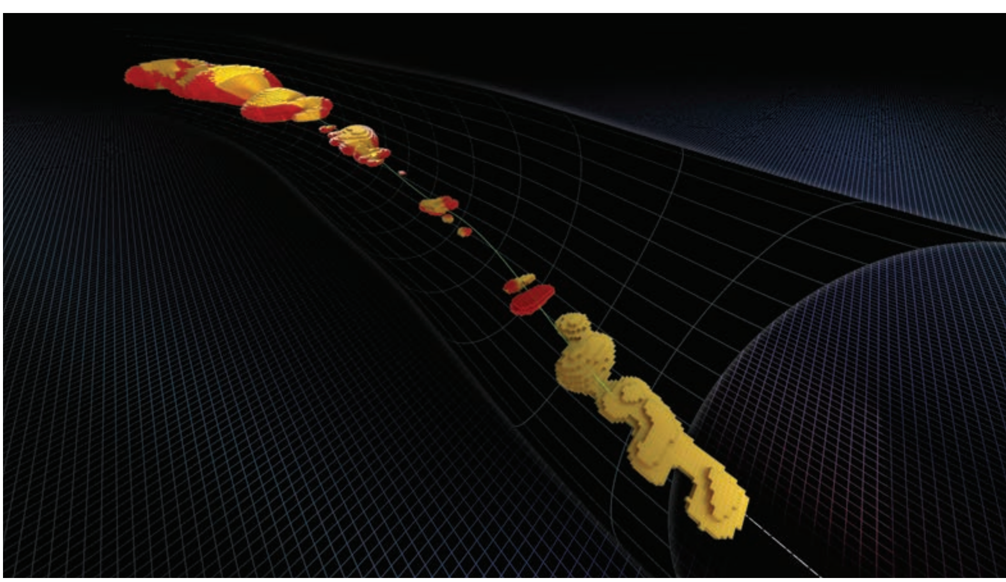
The new capability has been run in about a dozen wells offshore, including the North Sea and in the Americas.

In one run for Aker BP offshore Norway in late 2018, the operator was aware of complex geology involving turbidite channels and wanted to be able to optimally land the wellbore in the reservoir.

1D inversion showed isolated sand bodies, Zurcher says, but 3D inversion "showed the true shape and extent of these channels and whether they're connected, which was important for completion design and production."

The service could be useful beyond real-time geosteering applications, he says, including use in mapping the water front in a reservoir.

"We believe this isn't just a formation evaluation service. It goes beyond that," he says, adding that it provides important input for the completion and production phases of reservoir development.



(Source: Halliburton)

**3D inversion delivers a true representation of the reservoir for accurate well placement.**

# Radiography for NDT

By Jennifer Pallanich

A technology used in security and drug enforcement was modified to solve the age-old problem of how to use radiography for nondestructive testing of pipelines on rigs without affecting nucleonic measurement associated with pressure vessels.

The adapted technology doesn't skew nucleonics on high-pressure vessels such as oil-gas-water separators or force a shutdown, and it's allowing operators in the North Sea to rapidly carry out deferred pipeline inspections without waiting for a planned turnaround or shutdown.

In an industry with aging infrastructure, nondestructive testing (NDT) is vital for determining whether a material or component remains fit for purpose. Radiography has long been used to seek corrosion, cracks and other problems in equipment like pipelines, particularly those that are insulated. But sometimes NDT methods like radiography interfere with other nucleonic instrumentation and sensing programs.

Nucleonic sensors are used on the high-pressure units that separate the production stream into oil, gas and water because such vessels can present a safety issue if they become too full or too empty. A nucleonic detector on one side of the vessel can sense an isotope on the other side. As the fluid level within the separator falls, the detector can sense the radiation from the other side, while a rising level of fluid blocks the signal.

When radiography is used, there is a high risk the radiation can "confuse" the nucleonic detector, says Jim McNab, NDT subject matter expert at Oceaneering. "When the nucleonic detector sees the radiation from an exposed NDT isotope, it thinks it's seeing the radiation from its own isotope. It confuses it, and it thinks there's been a major production process issue and even shutdown of production. It's a false alarm," that often leads the control room to shut the rig down, he says.

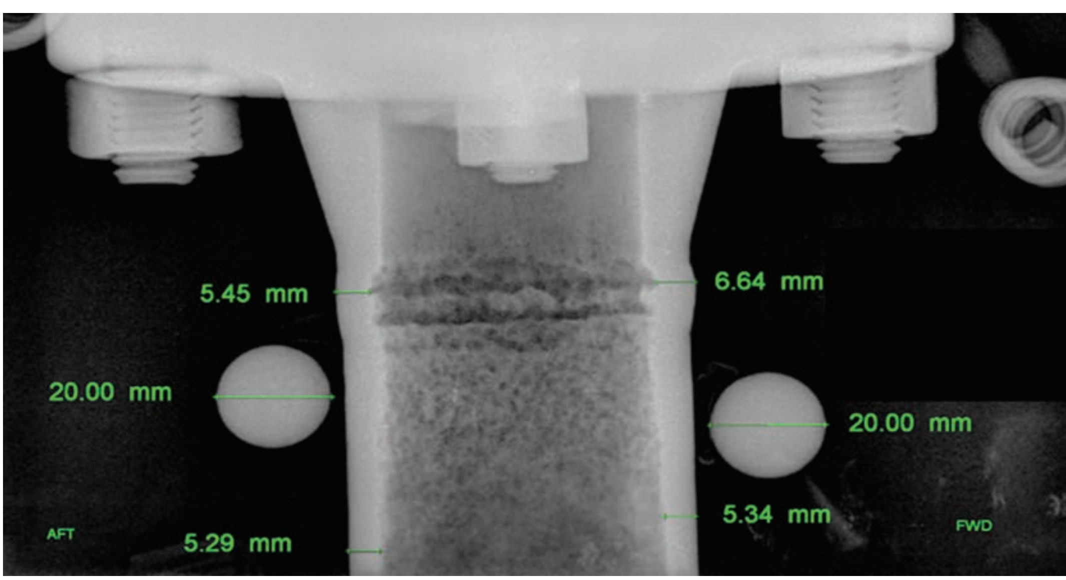
Oceaneering worked with manufacturers of specialist "pulsed" x-ray systems and nucleonic instrumentation to design a procedure that makes it possible to carry out NDT inspections while the plant is in-service by eliminating the effects of radiography operations on nucleonics. Oceaneering calls the offering Trip Avoidance X-ray Inspection (TAXI).

TAXI uses an x-ray camera that uses short radiation pulses rather than a constant source of radiation, typical of radio isotope. "The nucleonic detector can't see the short bursts, but we still get good x-ray images of the process piping and equipment," McNab says.

Ahead of an inspection, McNab says, the inspection team reviews sources of data that may influence what effect TAXI will have on the existing nucleonics.

Oceaneering has deployed TAXI in the North Sea over the course of the last year. One operator had planned pipeline integrity inspections over the course of three years to coincide with shutdowns. Oceaneering's TAXI service was able to carry out the inspections while the plant was in continuous production in three weeks without requiring a shutdown, he says.

"What we're doing now is enabling operators to inspect piping and equipment they wouldn't have been able to do previously, during production operations," McNab says. "In essence, we're able to find the leaks before leaks find us."




Source: Oceaneering

**Separator nozzle stub shows weld and pipe corrosion after seven seconds of exposure time with the TAXI service. The green numbers are the measurements of remaining wall thickness on a pipe. All the darker areas within the center of the pipe illustrates evidence of pitting type and weld root corrosion.**

NOV

# 'World's Largest Drawworks'

NOV claims it recently built 'the world's largest and strongest' drawworks, the AHD-1700. The new unit will help operators handle the increased casing weights and longer wells of the 20,000-psi (20K) high-pressure, high-temperature (HPHT) frontier. The 1,700-ton unit is will be installed on a Transocean deepwater drillship, scheduled for delivery in the first quarter of 2020. The AHD-1700 design came about after NOV took a holistic approach to its 20K initiative. The company said it saw a need for an AHD drawworks that could handle increased hookload and heave capacities.

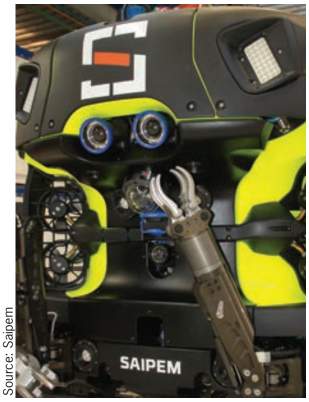
The AHD-1700, powered by seven motors, features a maximum hookload of 1,700 tons and full heave compensation. The unit's fast line pull comes in at 240,601 pounds, while it has a maximum continuous power of 10,500 horsepower.

**NOV says its new drawworks is the world's largest and strongest.**

Source: NOV

Saipem

# Hydrone-R: Resident underwater vehicle




Source: Saipem

Saipem said it has started functional testing on its Hydrone-R underwater resident vehicle at Sonsub facilities in Venice. The advanced underwater intervention drone was launched in water in July to start a comprehensive qualification campaign that aims to test all components and subsystems, including the subsea docking base in a real subsea scenario. Endurance and qualification tests will be carried over several months in open sea, offshore Trieste

Hydrone-R, which can operate as a ROV, tetherless ROV and AUV and is able to work down to 3,000 meters water depth, is part of the Hydrone fleet of vehicles, designed to perform life of field subsea services.

They will use subsea docking stations, called ByBase (for permanent deployment) and HyBuoy (a power and communication buoy for temporary/permanent deployment), and can also launch from a vessel when required.

Heerema Marine Contractors

# Sleipnir: World's Largest Crane Vessel

The world's largest crane vessel, Sleipnir, has started its maiden voyage from Singapore to Spain ahead of its first project in the Mediterranean, the vessel's owner Heerema Marine Contractors announced. The $1.5 billion semi-submersible was built by Sembcorp Marine and is reportedly the world's first construction vessel powered by liquefied natural gas (LNG).

During sea trials, when deploying all eight thrusters, the vessel reached a speed of 12.2 knots, which will help reduce transit times. Sleipnir's two 10,000-metric-ton revolving cranes, which can lift loads of up to 20,000 metric tons in tandem, lifted loads of 11,000 metric tons per crane. The dynamic positioning (DP) system kept Sleipnir stationary within the footprint of 30 x 30 centimeters during operational work.


Source: Heerema Marine Contractors

Deep Ocean Engineering

# Phantom X8

Deep Ocean Engineering unveiled Phantom X8, an electric, light work class remotely operated underwater vehicle (ROV) designed to be adaptable for various underwater tasks, such as light intervention work, pipeline inspection/routing, offshore wind farm maintenance, infrastructure repair and survey research, among others.

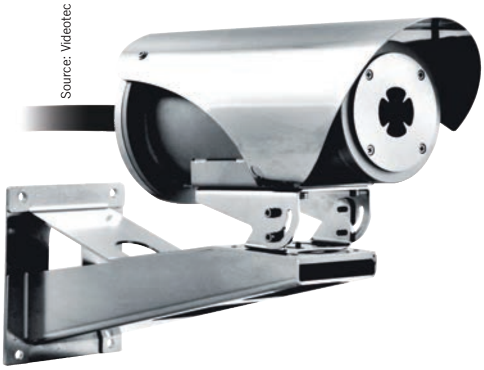
The 1,000-meter rated Phantom X8 ROV is configured with six vectored horizontal and two vertical 2.2-kilowatt Tecnadyne brushless thrusters. For clarity underwater, the Phantom X8 boasts high definition (1080 p) front (+/-90°) (pan optional) and rear (low light) cameras with three LED lights emitting 30,000 total lumens with adjustable brightness controlled by the pilot control box or GUI. The vehicle can be guided and controlled via auto functions for heading, altitude and depth.

**The Phantom X8 ROV**


Source: Deep Ocean Engineering

Videotec

# MAXIMUS MVXT camera



Source: Videotec

Videotec's new camera is designed for hazardous environments.

Videotec's MAXIMUS MVXT explosion-proof IP-based thermal camera features radiometric functions to provide a preventative surveillance system in hazardous areas and critical settings. The camera offers temperature detection and the option to send alarms based on temperature rules – key for monitoring processes or equipment when the ability to identify issues quickly and accurately can help prevent failures and reduce intervention times.

Impervious to rusting and corrosion, the stainless-steel camera is suited for harsh settings and potentially explosive environments, and it ensures full compliance with strict standards for classified environments, the manufacturer said.

T-Mobile, RigNet

# LTE in the Gulf of Mexico

T-Mobile and RigNet are bringing LTE coverage to more than 60,000 square miles of the Gulf of Mexico – in areas where connectivity has long been limited or nonexistent, according to the wireless provider. "We're putting an end to the pain that businesses and consumers in the Gulf have felt for years with limited connectivity – and in some cases, none at all," said Neville Ray, Chief Technology Officer at T-Mobile. Not just for smartphones, the coverage enables businesses to connect critical infrastructure with Internet of Things (IoT) technology and monitor remote equipment in real time for increased productivity and safety, it said. The new coverage leverages T-Mobile's 600 MHz and RigNet's 700 MHz spectrum to provide an enhanced experience for customers using RigNet's current Gulf of Mexico digital microwave infrastructure. T-Mobile said it is the first major wireless provider to "light up" the Gulf of Mexico with LTE, and noted that it used 5G-ready equipment, so offshore consumers and businesses will have access to the next generation of wireless technology in the future.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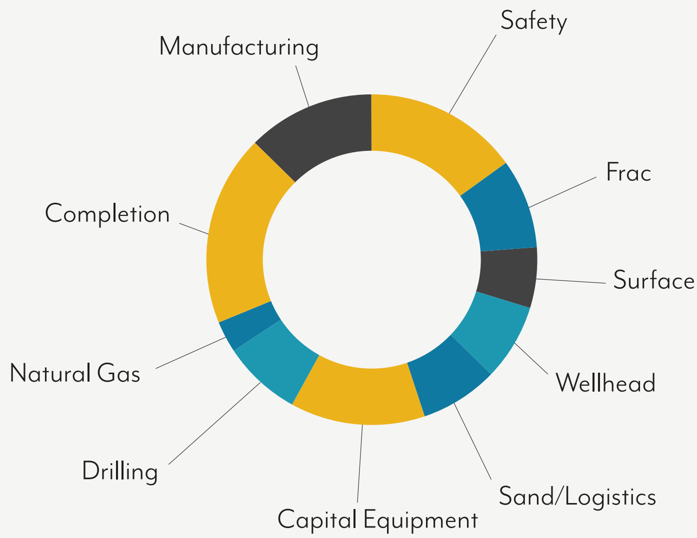


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www.spe.org/events

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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

**LAGCOE**
October 9-11
New Orleans, USA
www.lagcoe.com

**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
www.oceanenergy-europe.eu

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

**ADIPEC**
November 11-14, 2019
Abu Dhabi, UAE
www.adipec.com

**OWI Gulf of Mexico**
November 20-21, 2019
Houston, USA
interventiongom.offsnetevents.com

**Supsea Expo**
February 11-13, 2020
Aberdeen, UK
www.subseaexpo.com

**FPSO Europe Congress**
February 18-19, 2020
London, UK
www.fpsonetwork.com

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## A-E



## F-J



## K-Q



## R-U



## V-Z

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