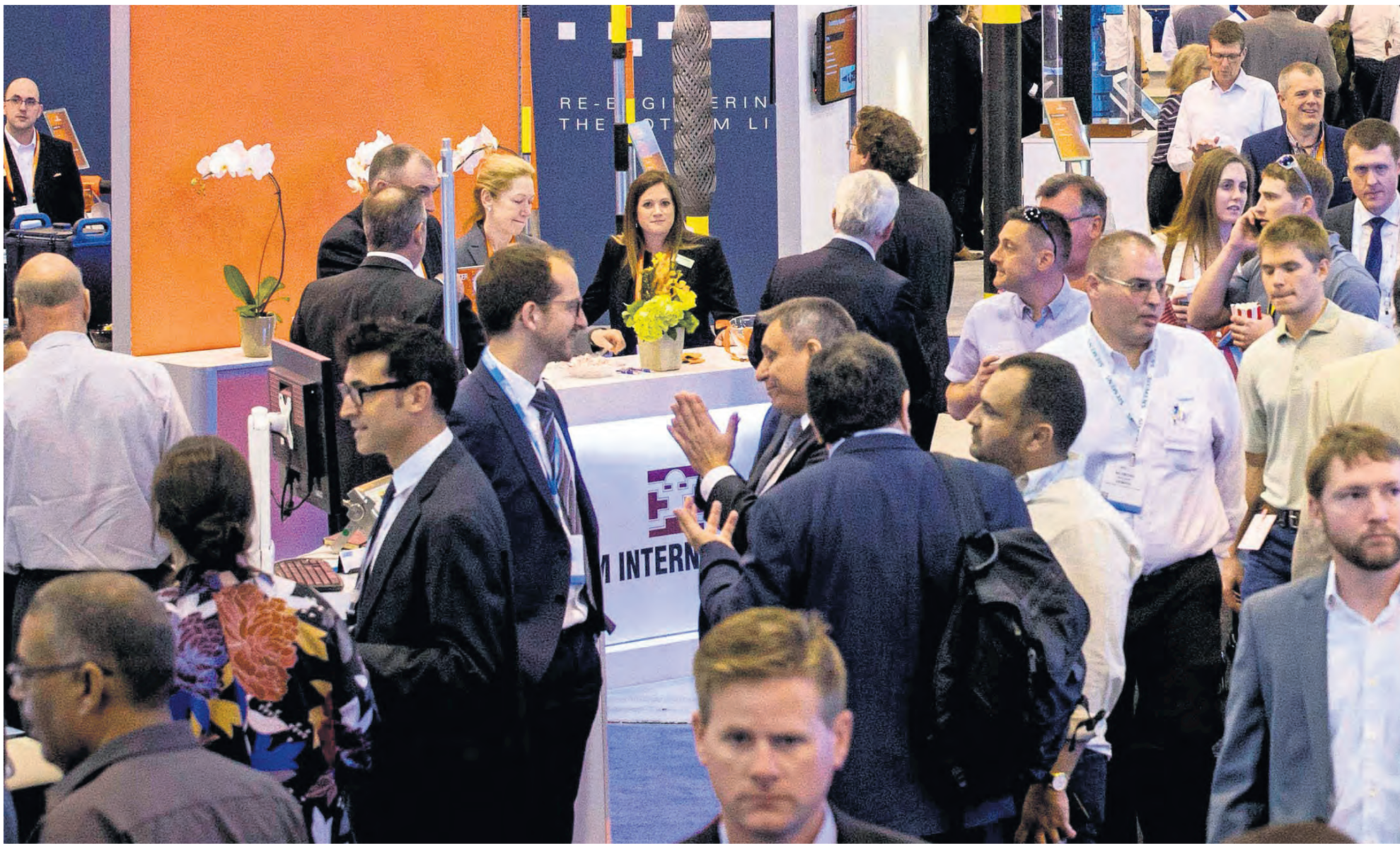
upstream technology

Finding the platform for oil and gas innovation

Swiss company ANYbiotics recently tested its ANYmal autonomous inspection robot on a North Sea process platform
Photo: ANYBIOTICS

OVERVIEW



Industry kits out for the future

Latest technological innovations and developments on show as oil and gas sector gathers in Houston for OTC

RUSSELL MCCULLEY
London

AS TENS of thousands of delegates from the international oil and gas industry gather in Houston for the Offshore Technology Conference, they will find themselves among friends and familiar faces on the exhibition floor.

But it would be a mistake to think that all is business as usual.

The offshore upstream industry is understandably cheered by what appears to be the end of an especially punishing stretch and there is a noticeable sense of optimism these days at events such as OTC.

But the pressures brought on by the downturn — chiefly to keep development and operating costs down — have not gone away and are unlikely to do so no matter how the oil price fluctuates.

Efficiency is the industry mantra and it influences every decision about what gets built, how day-to-day operations proceed and what technology projects get funded.

The industry is also under intense pressure to demonstrate that it is serious about reducing emissions of greenhouse gases such as carbon dioxide and methane.

A warming planet has focused public attention on climate change and, despite retrenchment in the US and elsewhere, the long-term trend is towards tougher emissions regulations and greater scrutiny of polluters.

Hitting the Paris Agreement targets is an enormous challenge — after flattening, CO_2 emissions began to climb again in 2017, according to the International Energy Agency.

The challenge is compounded by the fact that energy demand is rising and expected to grow for decades to come.

Cleaner production

Lean but safe upstream operations, cleaner energy production and efficient oil and gas recovery all rely on the sort of technology under discussion in OTC's technical sessions and on display in its exhibitors' booths.

These technologies show just how far the industry has come in the so-called energy transition.

As 2018-19 OTC chair Wafik Beydoun points out, a good 40% of the conference agenda this year concerns such non-traditional topics as renewable energy, alternative fuels, emissions reduction and the technologies enabled by digitalisation, including machine learning, robotics, predictive analytics and more.

Digitalisation is not new to the business — seismic and subsurface have long relied on high-power computing for analysis and interpretation.

However, big data is transforming aspects of the upstream industry where it may have had limited impact before.

Digital technologies are also bringing oil and gas more in line with the automated processes and connectivity associated with what has been dubbed the fourth industrial revolution.

This is evident in the way floating production systems are being designed and operated.

There is more emphasis on simplified designs that make use of standardised solutions where possible.

Digital twin technology is enabling more efficient monitoring and maintenance of offshore assets, both new and retrofits, while reducing the number of people needed onsite to run them.

Predictive analytics help operators make better decisions about making repairs, reducing costly downtime.

Service companies are doing their part, developing new tools and techniques to help keep production flowing as much as possible during maintenance and repair activities.

Much work is going on below the water line as well. The downturn hit the subsea business hard, with orders for subsea equipment and umbilicals, risers and flowlines falling 50% from 2014's record highs, according to Oslo-based oil and gas consultancy Rystad Energy.

Subsea is on the upswing, however, Rystad reports, and is expected to outperform other oilfield service segments over the next few years — good news for many of the companies that form the bedrock of OTC.

Resurgence

Spending on subsea equipment for ultra-deep-water is expected to lead the resurgence over the next five years, with activity picking up this year and intensifying in 2021 as a wave of floating production, storage and offloading systems gets under way in Brazil and development of the Stabroek block off Guyana picks up pace, Rystad says.

Operators are looking to longer and more challenging subsea tiebacks to access fields that they once might not have considered developing for technical and economic reasons.

The hurdles are coming down, thanks to innovative research and development in the subsea industry that addresses flow assurance challenges and seeks to improve recovery rates.

And as drones and autonomous systems are taking on more inspection duties on the platform, keeping workers out of harm's way, specialists in subsea robotics are developing underwater robots that reside on the seabed, continuously inspecting assets, gathering data and sending it back to the surface.

It is not much of a stretch to imagine these robots one day having the ability to interpret the data themselves and intervene if a problem is indicated.

The people behind such innovations are natural problem-solvers and innately curious about how things work — and how they could work better.

Those traits are welcome in the offshore oil and gas industry which, despite some remarkable achievements, still has much work to do as it addresses the world's growing energy demand and equally urgent calls for it to be cleaner and affordable.

OTC has long provided a platform for discussing the challenges, sharing ideas among peers and showing off the kit that keeps the industry humming.

As the event enters its sixth decade those objectives seem as relevant as ever.

On the floor: the exhibition hall at OTC
Photo: OTC/ RODNEY WHITE

The pressures brought on by the downturn — chiefly to keep development and operating costs down — have not gone away and are unlikely to do so no matter how the oil price fluctuates.

FLOATING PRODUCTION

SBM presses Fast4Ward for th

Company expects to cut first steel this summer on floater concept's **next unit**

RUSSELL MCCULLEY
Monaco

Under construction: the first Fast4Ward hull at the SWS yard in China

SBM Offshore expects to cut first steel this summer on the third floating production, storage and offloading hull to be built under its Fast4Ward programme.

The hull, which like its predecessors was ordered on spec, will be built in the China Merchant Heavy Industry (CMHI) yard in China.

The first hull in the series is "well advanced in the drydock" at Shanghai Waigaoqiao Shipbuilding (SWS) yard in China and is scheduled for delivery this year, says Bernard van Leggelo, SBM Offshore's managing director for China and Singapore.

The FPSO is destined for the Stabroek block off Guyana, where operator ExxonMobil is expected soon to make a final investment decision on the Liza 2 development.

About 100 blocks have been built for the second hull, which is also being built at SWS, van Leggelo says.

Rolling out

SBM rolled out the Fast4Ward design in early 2016. The concept is based on a standardised hull design and a "catalogue" of topsides plant and processing modules.

The company says starting with the standardised hull can shave six to 12 months off a project's development timeline.

The first three hulls to be built under the programme have storage capacity of up to 2 million barrels.

The generic Fast4Ward hull can support topsides weighing up to 35,000 tonnes and is designed for processing capacity of between 100,000 and 220,000 barrels per day of liquids and up to 400 million cubic feet per day of gas.

Van Leggelo says: "We clearly have hit a sweet spot and we are getting a lot of serious interest, so that's why we are ratcheting up the fabrication capacity for these hulls."

The concept fits the industry's post-downturn focus on efficiency — a necessity, given that it is operating with thinner ranks.

"There is limited capacity and I think it's recognised that the industry has to be cleverer about (design) selection, and also de-risking," he says.

"Building a standard hull is a de-risking exercise."

SBM has not discussed publicly a list of potential clients for the second and third Fast4Ward units but the company is apparently confident enough that the hulls will be snapped up to have secured slots in the fabrication yards.

Capacity constraints were an incentive to move ahead with the spec orders, van Leggelo says.

"That's one of the reasons we went to China Merchant — to make sure we don't get caught on the capacity side. This is a big hull. We don't want to corner ourselves into one area and (we want to) have multiple options from a cost and schedule perspective. It takes quite a big drydock" to build the hull, he says. "In China alone there are probably only three or four that can do it, probably half a dozen (worldwide).

"You also need to have the confidence in the yard's capability," he adds, noting that Chinese yards have made significant advances in recent years, not only on FPSO hull construction and conversions but topside module fabrication as well.

Topsides are "the next big piece" in the Fast4Ward programme, he says.

"That will be put to work shortly, where we will start manufacturing of standard catalogue topside modules.

"The standard hull works. And we have the catalogue of 70-odd modules in different stages of advancement," van Leggelo says.

"There, it's a case of hedging your capacity. Maybe you can do half your modules standard, or two-thirds.

"It's not going to be a case where all your modules are straight out of the catalogue — that would be too nice. But it significantly reduces your capacity requirements and improves your schedule."

Shaping processes

Richard Ella, SBM Offshore group technology director, says the Fast4Ward philosophy "has really evolved beyond the product — it's begun to start shaping the work processes within the company".

"Fast4Ward principles are being applied to other areas within the business," he says. That extends to the company's research and development efforts and its role in the future energy business, Ella says.

"I think the interesting challenge for the energy world right now is management of the energy transition — how we move from this traditional oil and gas world into the renewable world, and what will that renewable world look like. The landscape is evolving quite quickly."

SBM dedicates around 2% of its revenues to technology development, with about 30% of the R&D budget going to digitalisation, some 30% to 40% devoted to gas and renewables, and the remainder spent on the company's traditional floating production business, including mooring and swivel technology, he says. "We've

hird hull

Photo: SBM OFFSHORE

also been investing in swivel technology for the future market in terms of low-temperature applications – FLNG (floating liquefied natural gas) and hydrogen swivels, because we're starting to see a hydrogen economy become a talking point in the industry. That's a significant shift in the last 12 months."

The company is also doing work in shallow-water FPSO applications, Ella says: "There are some unique challenges as you try to moor large vessels in shallow-water environments."

There is also talk in the industry of an unmanned FPSO, which brings another set of challenges, he says.

"One of the key technology enablers for that is electrification. We have a high-voltage swivel in development that also fits the renewable energy environment."

Further R&D in digital technologies will be needed to fulfil the industry's vision of minimally staffed platforms with automated inspection, predictive maintenance and lower emissions, he says.

"These things are starting to move quite quickly in the industry."

FLNG sector on radar for floater concept

SBM Offshore is applying the Fast4Ward concept to floating liquefied natural gas, *writes Russell McCulley*.

The company is working on the design of a modular hull and topsides layout that could improve the economics of medium-scale FLNG projects, says SBM's China and Singapore managing director Bernard van Leggelo.

"We are removing a lot of the project risk around membrane technology and looking at modularising LNG layouts and coming up with standard modules there as well," he says.

As with the Fast4Ward floating production, storage and offloading design, the standardised FLNG hull could speed up the engineering and construction process, van Leggelo says.

"LNG has really suffered on projects — everything seems to be different and custom all the time. So, if we can apply some standardisation and certainty of outcome on the hull, and we can have maybe half the modules as reasonably standard, then I think we are way ahead of the pack."

SBM group technology director Richard Ella calls the project "a radical new hull concept" in that it uses spherical Moss LNG storage tanks — the type of tanks seen on most LNG carriers — rather than membrane storage tanks.

"It's the hull that governs the critical path for an FLNG project," he explains.

"The linings of membrane tanks are extremely sensitive, so you have to complete them once all other work on the hull has been done.

"This concept allows the LNG hull to be built on a modular basis so that it has flexible LNG storage capacity, LPG (liquid petroleum gas) storage capacity and condensate storage capacity. It takes the hull away from the critical path — these tanks are not sensitive in the same way membrane tanks are.

"We're looking at this as the future, a sort of Fast4Ward approach to an FLNG hull solution, which would be quite disruptive for the industry."

The Moss tanks, which are installed below deck in the design, could be configured to match production storage requirements and could be new or repurposed units.

Challenge: SBM Offshore group technology director Richard Ella
Photo: SBM OFFSHORE

"It really brings a kind of flexible modularity that's not available in LNG today," Ella says.

The concept, which has been in development "internally" for the past couple of years, could also help address the issue of associated gas at oil developments, he says.

"We can see a set-up where you'd have an FPSO at the field and an FLNG vessel taking the gas and processing it for the market."

The more standardised concept could speed time to first production, which now runs about 60 months for an FLNG vessel.

"Our technology challenge that we're trying to solve with this hull is to deliver an FLNG solution on a schedule similar to a traditional FPSO in the industry, closer to 36 to 40 months," Ella says.

Van Leggelo says SBM envisions FLNG processing capacity for the design of about 1.3 million tonnes per annum. "We think the up-to-1.3 million tpa mid-scale niche is quite suitable for these hull sizes and standard technology, so that is what we are pursuing," he says.

DOWNHOLE TECHNOLOGY

Clair Ridge in spotlight for BP's fibre optics

Use of **new technology** at West of Shetland project could be step change for real-time **well monitoring**

ROB WATTS
London

Optimal targets: BP's Clair Ridge facility in the UK West of Shetland area Photo: BP

BP'S massive twin-platform Clair Ridge development in the UK West of Shetland area could see later this year the first deployment of groundbreaking new distributed fibre optic technology for real-time monitoring of wells.

Distributed fibre optics is a growing technology that allows real-time monitoring of wells without the requirement for intervention, Lina Serpa, vice president wells, BP North Sea, tells Upstream.

At Clair Ridge, BP has been working closely with GE-controlled service company Baker Hughes (BHGE) to develop what is thought to be a world-first system.

BP says this will bring step-changes in surveillance data and well-performance functionality, as well as provide a stepping stone to introducing fibre optic data to subsea wells for the first time.

"The new system will have huge value in terms of how we optimise performance of our wells globally," says Serpa.

Data gathering

Fibre optic data-gathering systems have up to now been limited to a single line, limiting data gathering capability and options for well-completion design.

However, this new distributed fibre optic system will be able to infer, in real time, information about multiphase inflow performance, or how much oil, gas and water is coming from which parts of the well.

It will also be able to infer information about well integrity, sanding performance and gas lift performance of wells.

The technology works by shooting light down a fibre optic line that is deployed on the well completion. Thermal and acoustic effects in the well distort the light, which can be interpreted at the surface to show in real time how the well is performing downhole.

The technology therefore does not provide direct measurement of flow, hence why the information is "inferred".

Systems that rely on a single fibre give either distributed temperature or acoustic measurement, but not both simultaneously.

Existing distributed fibre optic technology can gather data during a well intervention.

However, this is not permanently installed, so it does not allow continuous monitoring, but only for the duration of a well intervention. Flow profiling is also limited, as the fibre is internal to the completion.

A real-time system with a number of fibre optic lines has been conceptually available for some time from BHGE.

The company has an "intelligent" wet-mate system that utilises a downhole wet-mate connector, a fibre-optic component with up to six contacts, together about the size of a human hair, which comes together to connect the upper and lower completion.

The modular wet-mate system also allows for electrical and hydraulic connections.

This makes possible a significant upgrade in data-gathering capability on the well and enables the inclusion of downhole pressure and temperature gauges in the reservoir.

BP says it has supported a rigorous re-engineering of the system in collaboration with BHGE over the past 18 months.

This has included design changes, reliability assessments, system testing and development of robust operational procedures.

Serpa says the challenge is heightened by the harsh well environment and the fact the tight tolerance, highly sensitive connection has to be made up to 3000 metres from the rig floor.

The system also has to perform reliably over the life of a well and be compatible with a number of additional well systems that are used to shut off zones and optimise production in response to the fibre optic data.

Optimising production

The completions on the Clair Ridge wells have been designed so they can respond to the data coming in, optimising production by shutting gas and water-dominant zones through the use of remotely actuated sliding sleeves and robust open hole zonal isolation.

In collaboration with Weatherford, sliding sleeve technology has been developed along with an open-hole zonal isolation anchoring system to improve reliability.

"Clair Ridge is a massive, naturally fractured field with generally poor matrix quality rock – good well performance relies on intersecting fractures," says Serpa.

"Our understanding of placement and long-term behaviour of fractures is poor. The fibre optic data will be used to understand the performance of the fractures in real time in parallel with conventional well surveillance data.

"This will allow for well-placement decisions in field development and well-operational decisions to be made via use of complementary sliding sleeve and zonal isolation technologies."

The technology also has a number of other functions. The lines can be used to monitor well integrity, sand performance and artificial lift performance in addition to giving in-situ reservoir pressure and temperature data.

It also reduces the requirement for conventional well intervention surveillance activities such as production logging, reducing operational expenditure and demands on platform activity.

If successful on Clair Ridge, the technology could be applied more globally in BP.

"The value of this is, as of yet, unrealised," says Serpa.

The $5.8 billion Clair Ridge project produced first oil in November.

It is the second phase of development at the giant field where the UK supermajor is already examining future phases.

BP, with partners Shell, Chevron and ConocoPhillips, is sitting on in-place resources of more than 7 billion barrels at the Clair field, discovered in 1977 and first exploited in 2005.

The initial Clair phase one development targeted recoverable resources of 300 million barrels, with BP aiming to produce about 640 million barrels from the larger Clair Ridge scheme.

MAINTENANCE AND REPAIR

Staying cold under pressure

Reinforcement technology eases safety risks and downtime during **corroded hull plating repairs**

GARETH CHETWYND
Rio de Janeiro

Bonding moment: ColdShield technicians prepare bonded composite reinforcements for the FPSO deck repair
Photo: COLD PAD

A TECHNOLOGY pioneered by French company Cold Pad as an alternative to welding is changing the way offshore repairs are carried out on floating production, storage and offloading vessels.

The ColdShield bonded structural reinforcement technology, jointly developed by Cold Pad, the French Institute of Petroleum and operator Total, allows "cold" repairs to be carried out on corroded hull plating on an FPSO, avoiding the potential safety risks and downtime involved in welding operations.

The seed for the technology was planted when Cold Pad founder Jean-Philippe Court was part of Total's team working on hook-up operations off Angola.

Court was struck by the disproportionate impact on production associated with welding offshore, along with the crewing demands.

Drawing on aeronautical industry practices, he began to search for a cold repair solution that could be performed on an FPSO while normal production operations continued.

The resulting ColdShield technology combines a top reinforcing plate of super duplex alloy with a layer of structural polymers.

Reinforcement

The internal polymers are surrounded by a compressed elastomeric peripheral seal bonded encapsulation, giving the assembly a lifetime of 10 to 20 years.

Class approval for Cold Pad's reinforcement methodology for hull structures was granted by Bureau Veritas and ABS in 2016 followed in 2018 by DNV GL and Lloyd's Register.

A breakthrough commercial application came in 2016 with the repair of a few corroded brackets in a void tank of an FPSO operated by SBM Offshore in West Africa.

"The value of the contract was less than €700,000 ($787,000) but we provided savings of about €3 million if you look at the associated costs that hot repair would have presented," says Christophe Paillusseau, vice president for sales and marketing at Cold Pad.

A second contract with an unidentified client offered savings of more than €100 million compared with hot works, Paillusseau claims. The application addressed a mid-ship deck repair where hull girder strength was to be considered.

Cold Pad had to prove the fatigue life of the reinforcement solution, an exercise that saw the company issue what it says are the first fatigue SN Curves for a bonded reinforcement. ColdShield pads can be formed to cover up to five square metres but can also be combined to cover larger areas.

For example, a large operator recently engaged Cold Pad to repair an area covering 100 square metres of deck under a contract worth between $5.6 million and $11.2 million.

The technology is proving popular with operators dealing with humid tropical regions that pose corrosion challenges to even the best-built vessels, many of which are permanently moored.

Cold Pad is also building up a backlog of orders for its C-Claw product, a heavy-duty fastening solution which uses bonded bases to dispense with the need for a hot repair environment.

These fasteners provide one-tonne tension-shear resistance and are typically used for steelwork on tertiary steel, such as modifications to pipe supports, skids, ladders and handrails.

Cold Pad is now deploying its technology in a growing number of countries and has contracts in the pipeline in Brazil.

Cold work can significantly reduce the size of repair crews, particularly when crude oil storage is in the picture. Hot work often requires crews to empty and enter tanks, for example when repainting the reverse side of repaired plates.

"Corrosion repair may require the emptying of several tanks, but cold repair can allow this... to be non-intrusive with no impact on operations," Paillusseau says.

A recently awarded contract for repairing leakage on weldments between tanks on a floating storage and offloading vessel working in South-East Asia will save the US company involved some $30 million compared with the production disruption that would have occurred with hot repair, according to Paillusseau.

"This kind of cold work technique with low (persons on board) requirements provides operators with extra operational flexibility. Operators shift some structural maintenance from planned shutdown to normal production time," he adds.

SEISMIC

Stepping up the OBN drive

Stage is set for increased activity in the market for **ocean bottom node surveys**

ANDREW MCBARNET
Vancouver

IT HAS been a long time since a seismic acquisition contract caused a stir. The script was rewritten last July when Abu Dhabi National Oil Company (Adnoc) awarded the world's largest-ever 3D seismic acquisition survey to BGP, the Chinese seismic services subsidiary of China National Petroleum Corporation.

Worth an eye-popping $1.6 billion, the work involves 23,000 square kilometres of onshore data collection and 35,000 square kilometres offshore.

The scale of the ocean bottom node (OBN) seismic portion of the offshore coverage, which will also involve towed-streamer operations, has vaulted BGP into a leading contender, just as it intended.

The company is on record as saying that it missed out on the towed-streamer acquisition market but will not let seabed seismic slip through its fingers.

In addition to the ongoing Adnoc project, it has work off Nigeria for Chevron and Shell, in Brunei for Shell and Azerbaijan later in the year for BP.

The immediate outlook for BGP and its rivals in the OBN space looks favourable.

Every market survey suggests that the percentage of the total marine seismic market for ocean bottom seismic (OBS) has grown from approximately 4% in 2006 to around 20% and is projected to rise further.

Norwegian consultancy Arkwright estimates the 2019 OBS market value at $1.2 billion to $1.4 billion.

OBS — now mainly nodal rather than cable-based — offers much better illumination of the subsurface in targeted areas.

This is exactly what oil companies are looking for, with the emphasis today on enhanced oil recovery from producing reservoirs and low-risk infield exploration for reserves that can be tied into existing offshore infrastructure.

Sustainability challenges

If there are dark clouds on the horizon, that could be due to over-capacity and sustainability challenges.

Stephan Midenet, chief executive of Seabed Geosolutions (SBGS), warns against repeating the "streamer story".

None of the current players, with the exception of BGP, has the safe haven of a larger parent company to protect them from a drop in seabed seismic survey demand.

SBGS itself is a 60:40 joint venture between Fugro and CGG with the longest history in the business, going back to the commercial introduction of the precursor of its current CASE Abyss node-deployment system in a Gulf of Mexico survey in 2005.

In action: automated node deployment on the Subsea Viking

Photo: SBGS

This is now complemented by the more versatile, automated Manta system, which is able to operate in all water depths with the same node.

A CASE crew recently completed a project in the deep-water Gulf of Mexico for Shell.

One Manta crew is in Brazil and another is due in the Red Sea for Saudi Aramco with partner ARGAS.

Both partners in SBGS have expressed the desire to divest the company, presumably in a straight sale or potentially floating it as a separate entity. On 16 April, Axxis Geo Solutions, rebranded recently as AGS, announced a merger with Songa Bulk, a listed Norwegian investment company, to enable the company to trade on the Oslo exchange with the opportunity to attract additional investment.

Node rents

The company has access to vessels but rents its nodes, currently provided by Geospace Technologies.

Magseis had to go to the market to raise funds to acquire the technology assets from Fairfield Seismic Technologies last year, as did SAExploration, to buy the assets of Geokinetics out of bankruptcy.

In the Magseis case, there was a nice, likely one-off sale of 17,000 nodes to BGP for its Middle East job, worth $150 million.

As a result of the Fairfield purchase, valued at $233 million, the combined Magseis Fairfield entity has the challenge of operating two technologies, the Magseis Marine Autonomous Seismic System (MASS) and Fairfield's longer established range of ZNode technology for all depths.

Of the leading offshore contractors, only Shearwater GeoServices has any OBS capacity, having inherited the cable-based Q-Seabed technology from its acquisition in 2018 of the marine seismic acquisition business of Schlumberger's WesternGeco.

Shearwater's WG Tasman and WG Cook multi-purpose vessels will be working this summer in the North Sea for Aker BP and Equinor under a multi-year contract. It is also re-rigging the Vespucci with OBN surveys in mind, using OBX nodes from Geospace.

Polarcus is collaborating on a three-month combined towed-streamer/OBN project in the Middle East with SAExploration for Dubai Petroleum Establishment. It has no plans to invest in its own OBN capability.

Petroleum GeoServices has yet to show its hand but some future involvement seems inevitable.

Testing time: preparing the Wolfspar technology for deployment
Photo: BP

Multi-client scenario best hope as seismic players chase opportunities

OIL companies are increasingly spoiled for choice in any ocean-bottom node (OBN) strategy, with no obvious shortage of nodal capacity and operators in the market place, *writes Andrew McBarnet*.

iSeismic, a subsidiary of Norwegian survey and rig positioning company iSurvey, will soon add to the competition, and others may follow the perceived investment opportunity.

The level of demand and differentiating technology will therefore determine future operations.

The best future scenario is for a serious multi-client market to develop. TGS, which a few years ago was responsible for commissioning a third of all towed-streamer surveys on a multi-client basis, has been making moves in this direction.

It has launched the first phase of Amendment, a 2350-square kilometre seismic survey in the Mississippi Canyon and Atwater Valley areas of the deep-water US Gulf of Mexico, with Schlumberger as a partner.

Magseis Fairfield is carrying out the project with ZXPLR nodes and remotely operated vehicles.

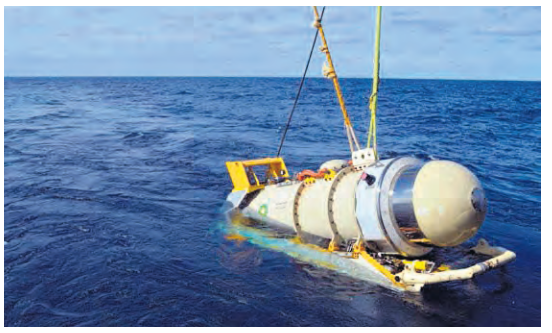
As Will Ashby, TGS senior vice president, North America, explains: "This is the first ultra-long offset, sparse node survey aimed at obtaining new velocity information to better image the subsalt.

"The data can then be processed by the latest full-wave imaging and other techniques. Owning the underlying data from previous surveys makes this particularly attractive for us."

UK supermajor BP for its part has developed the Wolfspar seismic source focused on capturing low-frequency seismic data.

The technology, along with the subsequent sophisticated processing of the data, has been credited for making possible BP's recent discovery of more than 1 billion additional barrels of oil in place at its Thunder Horse subsalt field in the Gulf of Mexico.

TGS is also co-investing with Axxis Geo Solutions on a first multi-client project in the North Sea, a 1500 square kilometre survey using node-on-a-rope technology.



Pushing ahead: BP has deployed its Wolfspar technology in the US Gulf
Photo: BP

Meanwhile, oil company customers will want to drive down the price of seabed surveys.

The leading players are all focused on speeding up surveys by automating the deployment and retrieval of nodes, but so far deployment at much more than 2 knots per hour is rare.

After six years in development, Norwegian node system supplier inApril is manufacturing the first nodes for its Venator OBN system, which it claims will produce significant improvements in speed and efficiency.

An interesting futuristic project is Saudi Aramco's Spicerack initiative being developed mainly by the company's EXPEC Advanced Research Centre and SBGS.

It envisions OBN surveys carried out by autonomous underwater vehicles with the promise of major efficiencies and lower costs. A second pilot feasibility test with 200 vehicles is due this summer.

Spicerack and remotely operated technology being researched by others would be genuinely transformative. Such developments, however, are a few years out.

SEISMIC

Charting a careful transition to OBN

SAExploration emerges as competitor in the **ocean bottom node** seismic business

ANDREW MCBARNET
Vancouver

Flying high: SAExploration chairman Jeff Hastings Photo: SAEXPLORATION

On location: AquabVib deployed at South Timbalier Block 52 in the Gulf of Mexico
Photo: SAEXPLORATION

SAEXPLORATION chairman Jeff Hastings likes the current opportunities in the seabed seismic survey business. But he has a word of caution.

"I have lived through two ocean bottom seismic bubbles, so we need to be very careful not to over-extend capacity in this market," he says.

The winners, according to Hastings, are going to be those operators that can speed up deployment and retrieval of nodes and bring the price down to a more competitive level.

That is exactly what his company is aiming to do. He expects to be announcing soon some developments in both source and receiver technology which will move the needle with regard to more cost-effective ocean bottom node (OBN) operations.

"Up to now we have not had our own nodes," Hastings says.

"However, we see that having an inventory of single nodes that can operate in all water depths is going to provide efficiencies. There are also improvements on the source side which we want to address."

SAExploration, based in Houston but with its North American headquarters in Calgary, Canada, has until now been something of an outlier in the OBN space.

One gets the impression that Hastings likes it that way — over the last five years the company has been quietly building up a track record with international surveys, including deep-water offshore Malaysia for Petronas and West Africa for Chevron.

It is currently busy on a contract using a node-on-a-rope system in India for ONG with Axxis Geo Solutions providing the vessels.

In Dubai, SAExploration is working with Polarcus, the towed-streamer marine geophysical contractor, on an "infill" project, which may well become more commonplace in the future.

In an infill project, the nodal seismic operation supplements the main survey by filling in the areas which towed streamer operations cannot reach, for example, coverage around existing production facilities. Later this year a deep-water project in Brazil is on the schedule, and Hastings says there is plenty of other work out for bid.

SAExploration in the past has mainly been thought of as a land and transition zone seismic acquisition company with its operations focused on South America, South-East Asia, Alaska and Canada.

The company began life in 2006 as South American Exploration, with its first project in Peru. It rebranded in 2011.

Last summer, SAExploration bought most of the assets of Geokinetics out of bankruptcy for a little less than $20 million.

The move was enabled by a capital restructure earlier in the year, plus establishment of a new credit facility and share issue.

The acquisition of a significant international land and seafloor geophysical company — on favourable terms — has changed SAExploration's perspective.

Complementary assets

At the time of the deal, Hastings spoke about the complementary assets, increased global reach, potential relationships with new clients and the reduction or elimination of the company's need to rent equipment.

A bonus has been the addition of some seismic processing computer power and technical support personnel.

"Up to now we have really only focused on infield (quality control) during survey acquisition," he says.

SAExploration also inherited AquaVib, a marine vibrator being pioneered by Geokinetics as an alternative to airguns as a seismic source in shallow-water environmentally sensitive coastal areas.

The sound pressure levels generated by the vibrator are a small fraction of those generated by airguns, and therefore potentially less harmful.

Of several marine vibrators under development, AquaVib is the closest to commercialisation.

Geokinetics carried out successful field tests during ocean bottom seismic surveys in 2015 and 2017. A further trial is due shortly off Malaysia during a survey for Petronas. "For data acquisition in particular transition zone environments, there is definitely going to be a place for marine vibrators, but they won't be replacing air guns any time soon," Hastings says.

In the meantime, he is not taking his eyes off the main seabed seismic market, in which he has been immersed one way or another since the early 1990s.

Hastings served as vice president at Denver-based Northern Geophysical, which deployed ocean bottom cables in Alaska, along the Arctic coast and in the Cook Inlet, developing techniques to counter the high current conditions.

Operations continued with the formation of Fairweather Geophysical, later acquired by Veritas (soon to become Veritas DGC), until the bottom dropped out of the market. "In the early 1990s, we thought there was plenty of space," Hastings recalls.

"Then everybody did exactly what they seem to be doing now, ramping up the amount of capital to build new equipment.

"The same thing happened again at the end of the 1990s when nodes began to make an impact along with cable.

"Now over-supply and commoditisation are again the danger if we are not disciplined and look to the long term."

In 2007, Hastings left Veritas-DGC, by then a CGG company. He and a number of management colleagues joined up with Brian Beatty, founder of SAExploration, focusing their attention mainly on South America, surveying in Peru, Colombia, Bolivia and Brazil. A major contract from Apache Corporation in 2010 had the company back in familiar territory, Alaska.

It launched the company's journey into seabed seismic with the deployment of 2000 Z700 nodes from Fairfield using a deployment method of its own.

"We were pretty isolated working in Alaska, so chose to adapt a node-handling system of our own based partly on the local long-line fishing industry," Hastings says.

Renting nodes from Geospace followed, and the company was soon offering international OBN seismic services using either node-on-a-rope or deep-water remotely operated vehicle-assisted techniques.

SAExploration has come in from the cold.

INSTALLATION

ALE loads up for heavy lift capacity boost

ALE to the chief: an artist's impression of ALE's SK10000 ultra-heavy-lift crane
Image: ALE

Company will use its land-based SK10000 crane to target FPSO and FLNG markets

RUSSELL MCCULLEY
London

HEAVY lift specialist ALE is rolling out what it claims will be the world's largest capacity land-based crane with a lifting capacity of 10,000 tonnes.

The UK-based company says the SK10000 will target the floating production, storage and offloading and floating liquefied natural gas vessel markets, which are using increasingly heavy topsides modules.

ALE currently has a 5300-tonne capacity crane built to its SK design, the SK350, which has been used to lift modules in Nigeria and Brazil.

Raising capacity to 10,000 tonnes essentially involves scaling up the company's current SK technology, says ALE global sales director Michael Birch.

"We're using the same basic design of the SK," Birch says, referring to a lattice boom crane that rotates around a static ballast.

Connections

The larger crane will use the same type of lattice boom as the SK350 but where the latter has one 130-metre-long boom, the SK10000 will have two of the lattice booms connected.

"Because of that we can make it bigger and smaller," he says, meaning that it can be scaled back down and redeployed after an ultra-heavy lift job.

"Our new design is a new crane based on the components we have used in the earlier cranes. It is 80% built — the crane is ready to be deployed when we secure the first contract for it", he says.

Birch says the move towards larger modules weighing up to 6000 tonnes for FPSOs and FLNG drove development of the crane.

"We saw there was an opportunity, in speaking to a lot of our clients, particularly on the design side rather than the fabricators," he says.

"They are interested in building 5000 to 6000-tonne modules. They can lift these modules at some of the yards in Korea, or they can lift them with floating cranes. But floating cranes are very expensive to mobilise."

He sees the increased lifting capacity as a way for clients to help fulfil local content requirements.

While FPSO and FLNG hulls are typically built in Asian yards, many modules can be assembled and installed in the oil-producing country.

"It allows them to perform the work in the local region. And we've done it already in Brazil and in Nigeria with the 5000-tonne crane," Birch says.

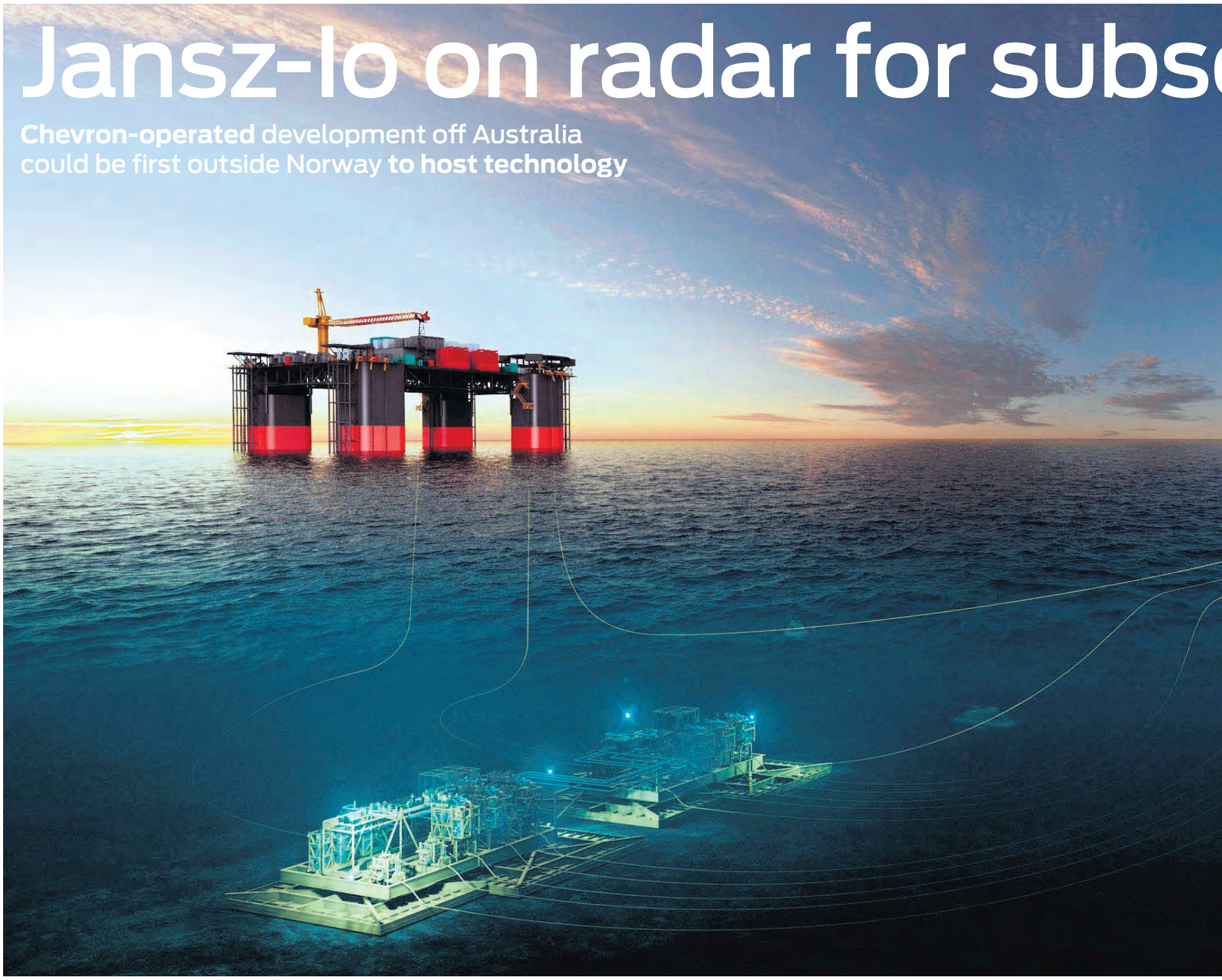
"One advantage is that the crane is containerised, so it can be shipped easily," he adds.

The new crane has an outreach of up to 200 metres and ground bearing pressure below 25 tonnes per square metre, ALE says.

SUBSEA TECHNOLOGY

Jansz-Io on radar for subs

Chevron-operated development off Australia could be first outside Norway **to host technology**



RUSSELL MCCULLEY
London

AKER Solutions has reached an agreement with US supermajor Chevron that could see the Norwegian company's pioneering subsea compression technology put to work at the Jansz-Io field off Australia.

The companies have signed a master contract to support delivery of the subsea compression system with the first service order under the agreement to include front-end engineering and design of the system, along with FEED for an unmanned power and control floating platform.

The agreement lays the groundwork for a potential engineering, procurement and construction contract that would make the project the first use of the subsea compression technology outside Norway.

Aker launched the first system in September 2015 at Equinor's Aasgard field.

A subsea compression system for wet gas delivered by OneSubsea came online at Equinor's Gullfaks South field a month later.

Knut Nyborg, head of front-end at Aker Solutions, says the agreement is a vote of confidence in the nascent technology.

"It is definitely an endorsement of the technology itself and the track record at Aasgard, as well as the team that delivered Aasgard and the facilities that were used to deliver it," he says.

The Aasgard unit "has been working fine now for three-and-a-half years", he adds.

Recovery rates

The company says that, by placing the compression equipment on the seabed near the wellheads, the technology improves recovery rates compared with traditional systems mounted on platforms.

Advocates say the technology, along with other subsea production systems, can also lower development and operating costs while reducing a project's carbon footprint. The system is part of a suite of technologies, some still in development, designed to move more oil and gas production, processing, power, inspection and storage capabilities to the seabed — what early on was being touted as the subsea factory.

Nyborg says that, in the current cost-containment and lower-emission climate, discussions now revolve around what combination of subsea technologies are best suited to a project and its operator.

"What we have come to realise is that, yes, there are a lot of technologies out there, but everything comes down to what is best for a specific field," he says. "There are some fields that require compression when the pressure has declined, and other fields that may require taking out (carbon dioxide) and reinjecting it."

The Jansz-Io field, part of the Chevron-operated Gorgon development, is about 200 kilometres off the north-west coast of Western Australia in water depths of around 1350 metres.

Greater depths

Production from the field runs to the Gorgon liquefied natural gas facility on Barrow Island via a 130-kilometre subsea pipeline.

The system installed at Aasgard is in comparatively shallow water depths of 345 metres but most of the equipment was qualified to greater depths, Nyborg says.

As the Aasgard system was getting up and running, Aker Solutions and project partners MAN Energy Solutions began working to bring down both the size and cost of the compressor module, with the aim to reduce the weight and size of future systems by half without compromising the functionality of the Aasgard sys-

FASTSubsea venture set to target multiphase

AKER Solutions and Norwegian compatriot FSubsea have teamed up to form a new entity, FASTSubsea, to jointly develop subsea multiphase pumping technology, *writes Russell McCulley*.

The new organisation will leverage technologies from both companies to qualify a system "for the medium-scale multiphase pump system market," says Knut Nyborg, head of front-end at Aker Solutions. The new venture will target a simplified subsea boosting system that reduces the space requirement and weight of topsides equipment needed to support current pumping systems.

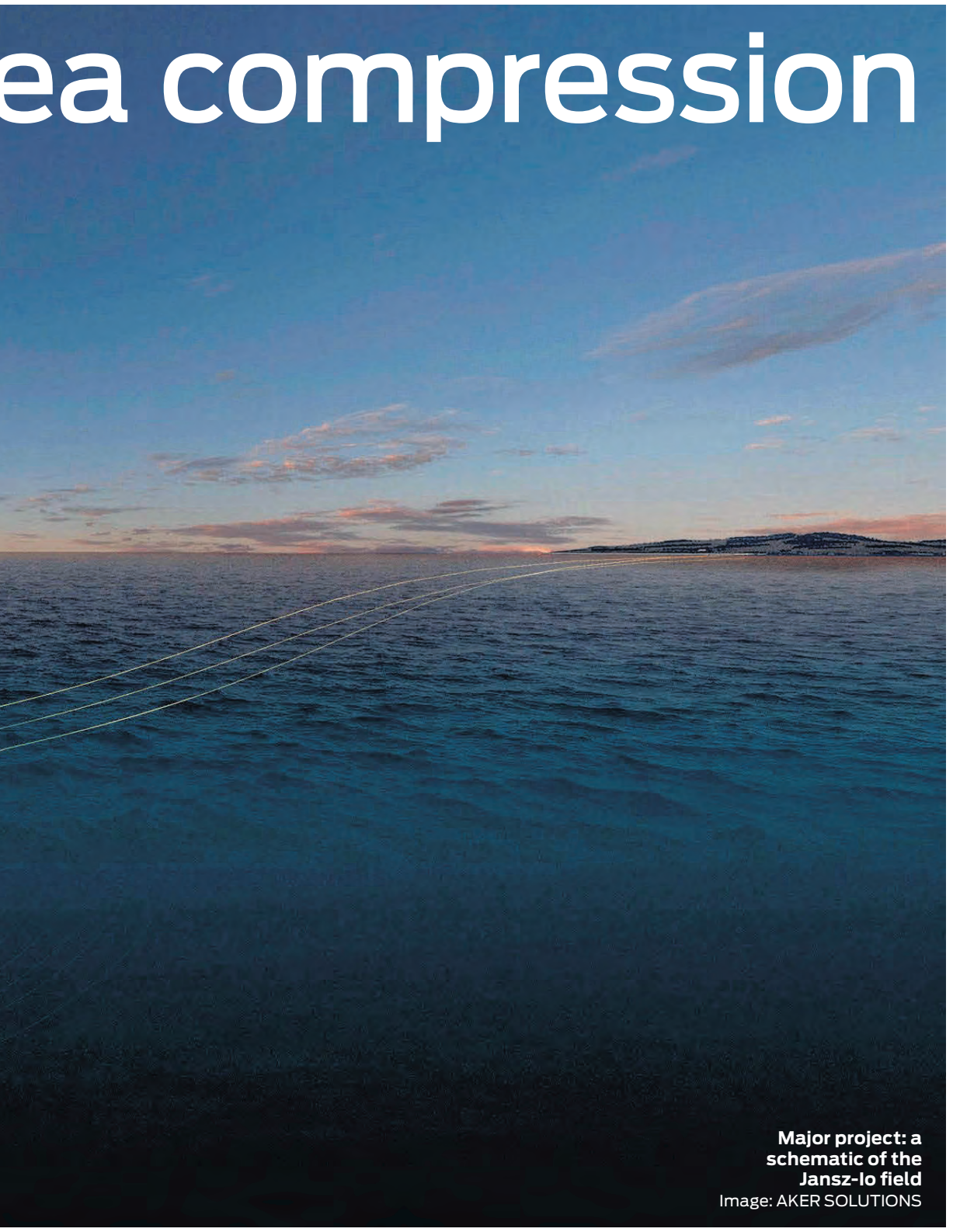
The companies say multiphase subsea pumping technology can increase oil recovery rates by more than 20% but uptake of the technology has been hampered by cost, space limitations and complexity.

Current systems can require topside modules weighing 800-900 tonnes for a dual pump installation, Nyborg says.

"This solution would reduce that and take down the cost and complexity for the operator," he says.

Of the 50:50 joint venture, Nyborg says: "We have been working on some of the same technology challenges and now we have opted to collaborate."

ea compression



Major project: a schematic of the Jansz-Io field
Image: AKER SOLUTIONS

Developments: Aker Solutions head of front-end Knut Nyborg
Photo: AKER SOLUTIONS

tem. The modules that compose Aasgard's twin trains, each driven by a MAN Energy Solutions 11.5 megawatt HOFIM compressor unit, are housed in a template structure 20 metres tall with a footprint of 75 metres by 45 metres and a total weight of about 4800 tonnes.

Nyborg said at the time that the size was necessary to meet the operator's schedule and to make sure the system functioned as planned.

Engineers designed a new configuration that fit all the compression system modules in a standard four-slot production template that could be installed without the need for a large heavy lift vessel.

The design reduced the number of modules per train from 13 to seven and greatly simplified the hydrate prevention system, optimised the process piping and cut the number of electrical jumpers from 155 to fewer than 50 for each train.

The Australian project will include many of the modifications, resulting in a simplified system that weighs much less without compromising functionality, Nyborg says.

"We have implemented quite a lot of those changes," he says.

"Working with MAN, we have had really significant weight and size reduction on this compression module."

Due to its significant volumes and flow rates, the Jansz-Io subsea compression project will require around three times higher compression duty compared to the Aasgard project.

"This will be really powerful stuff," says Nyborg.

Subsea gas compression and other seabed technologies are a good fit for Australia, which recently surpassed Qatar to become the world's top LNG exporter, Nyborg says.

"I think both the cost perspective and low carbon perspective would hopefully argue for some more of these subsea technologies in the future," he says.

"Most of them are inherently lower carbon, have less power consumption and have less materials in them."

The subsea factory, he says, "is not a goal in itself, as we see it, but means having the necessary tools to be able to develop a particular field in the most economical way and, more and more importantly, with the lowest carbon footprint."

Chevron operates the Gorgon project with a 47.3% interest and is partnered by ExxonMobil and Shell, each on 25%, Osaka Gas on 1.25%, Tokyo Gas on 1% and Jera on 0.417%.

ABB powering up for ultra-deep substation

A SEVEN-year joint industry project to develop subsea power technology is moving into a final phase this summer with full-scale prototype trials of a system that could enable up to 100 megawatts of power from shore to subsea developments in ultra-deepwater hundreds of kilometres offshore, *writes Russell McCulley*.

Electrification and automation giant ABB and JIP partners Equinor, Chevron and Total plan to carry out the 3000-hour shallow-water test of the subsea power substation in Vaasa, Finland, where ABB has a subsea transformer factory and where components of the prototype system were assembled.

Development of the subsea switchgear — a substation that can distribute power subsea — is key to the offshore oil and gas industry's quest for the so-called subsea factory, which could enable fully automated, all-electric developments controlled and powered from shore.

Proponents say such developments would take workers away from harsh and hazardous offshore work and put them in safer onshore control centres.

A subsea power substation could also enable substantial cuts in greenhouse gas emissions, reduce development costs and boost recovery, they say.

Svein Vatland, vice president at ABB and director of the subsea power JIP, says upcoming shallow-water tests will include two full-scale prototype variable speed drives (VSDs), switchgear and a control and protection system all running in tandem.

The technology "has never been done before — the subsea substation or subsea VSD — and these are big VSDs", he says.

"One VSD is capable of 9MVA (mega volt amp) — that's around 6 MW, so you can run all the large loads we know of today."

ABB built and tested a full-scale prototype of the VSD in 2017.

The trial was "very successful" and allowed the JIP to proceed to this summer's testing stage.

Electricity for the subsea power substation will be supplied via a single cable from shore or tied back to existing offshore infrastructure.

This is a much less costly option than multiple cables for each "load" or power demand source in a subsea production system such as a pump or compression system. ABB says the system could be used to power developments 600 kilometres from shore in depths up to 3000 metres.

"The general trend we see is that the easy oil has been discovered, so more discoveries are further out and deeper down. And that is a very strong driver for going (with a) subsea (development)," Vatland says.

Operators are also looking for ways to cut greenhouse gas emissions, he notes.

"Being able to have AC power supplied from shore — in Norway you can tap into the national grid, but in general you could generate power in a much more environmentally friendly way than if you have local generation from gas turbines on a facility," he says.

"That plays an important role on the emissions side of it."

Placing the distribution system on the seabed, closer to the reservoir, reduces the amount of power consumption required, the company says.

Vatland says that a 600-kilometere step-out may be extreme but not unfathomable. In any case, he says, "we have the ability to do it and the equipment is qualified for that" once the JIP completes its work.

The system is designed for a 30-year field life.

"Reliability issues and pressure issues had to be addressed," he says. At 3000-metre depths the components are subject to extreme pressure.

"All the equipment is oil-filled for pressure compensation," Vatland says.

"All the components that go into the system have to be able to operate under extremely high pressure, in oil. So that was one of the big challenges we had to solve."

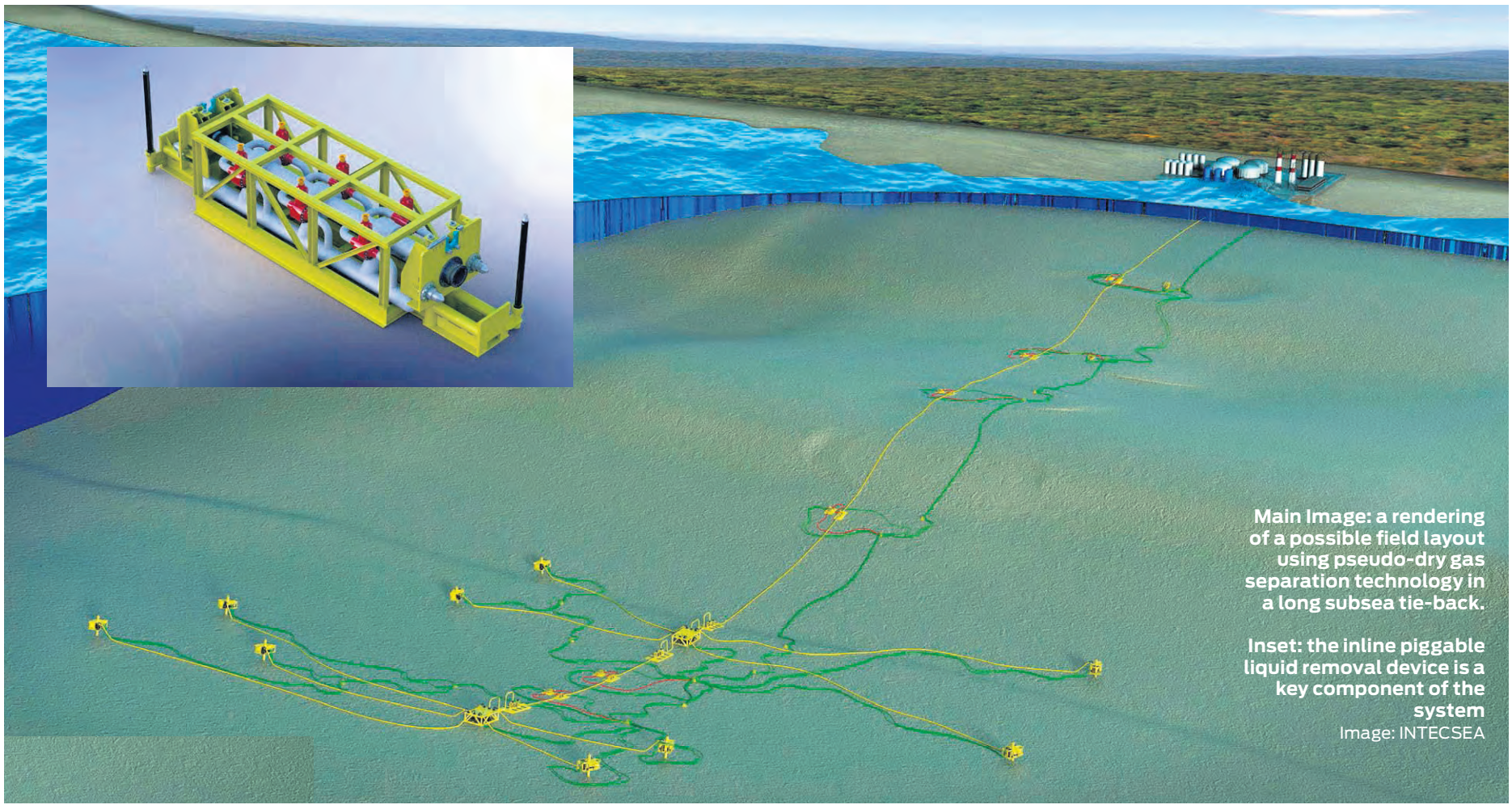
Launched in 2013, the JIP coincided with one of the worst industry downturns in recent memory. But Vatland says the partners remained committed to the project.

"There were never any discussions about backing out, and that was really good," he says.

"It also shows the need for it. This is really something that the industry wants. It's a game-changer — it enables the development of fields that before were not economically or technically viable."

Phasing in: the subsea power station under development
Photo: ABB

SUBSEA TECHNOLOGY



Main Image: a rendering of a possible field layout using pseudo-dry gas separation technology in a long subsea tie-back.

Inset: the inline piggable liquid removal device is a key component of the system
Image: INTECSEA

A dry path to production

Intecsea's pseudo-dry gas separation system aims to use natural reservoir energy to move gas **without the need for compression**

RUSSELL MCCULLEY
London

FINDING gas is the relatively easy part of the exploration and production equation, as the many significant offshore gas discoveries around the world in recent years attest.

However, it can be challenging for operators to justify the development of a deep-water gas field far from shore and existing facilities.

They have the technological solutions to get stranded gas to market, including subsea compression, floating topside compression and floating liquefied natural gas.

But each involves a considerable capital outlay that must be weighed against the ultimate value of the gas.

UK-based offshore engineering company Intecsea, part of the Worley group of companies, has, with funding from its internal Innovation Hub programme, spent the past couple of years developing a technology that it says will enable subsea tie-backs for gas reservoirs located more than 200 kilometres from shore, without the need for compression to propel the gas.

Intecsea says this can be achieved by creating pseudo-dry gas conditions through intermittent in-line equipment that removes associated liquids and transfers the liquids to a separate line for transport.

Creating near-dry gas conditions in the main production pipeline removes the hydraulic constraints that can rule out long distance tiebacks, according to the company.

Intecsea senior project engineer Lee Thomas explains: "I often say that everyone thinks the problem with a long subsea gas pipe is that there's not enough energy in the gas — that there's not enough pressure.

"That's not the problem. That's a symptom of a problem. The true problem is the liquid caused by gas transportation."

The idea sprang from Thomas' experience working with coal seam gas in Brisbane, Australia, as a pipeline engineer in collaboration with longtime work colleague Laura Liebana, a flow assurance engineer.

Two concepts

The pseudo-dry gas (PDG) technology involves marinisation of two main technology concepts — the drains along gathering networks in the onshore coal seam gas industry and the piggable liquid knock-out drums from onshore flare piping, he says.

Liquid generated by gas during transportation leads to excessive pressure drop, high turn-down and reduced gas recovery, Thomas says.

The PDG system aims to remove liquid at accumulation points to minimise gravitational pressure loss and allow the use of larger pipelines to negate frictional pressure drop. Of the technology's unusual name, Thomas says: "We call it pseudo-dry gas because it's not totally dry gas, just dry enough gas to emulate dry gas hydraulics.

"It wouldn't sound very good if we called it 'dry enough' gas," he adds.

In the year since it rolled out the concept at the 2018 Offshore Technology Conference in Houston, Intecsea's PDG separator team has carried out a technical and economic study for the UK's Oil & Gas Technology Centre that used field data from known stranded gas pools in the West of Shetland area.

The West of Shetland study, drawing on data provided by the UK Oil & Gas Authority, looked at a known basin of widely dispersed stranded gas fields in 1700-metre water depths around 200 kilometres from shore.

The study used a base case resource potential of 2.5 trillion cubic feet of gas with a liquid-to-gas ratio of six barrels liquid — water, condensate and monoethylene glycol (MEG) — per million standard cubic feet of gas.

The PDG option incorporating four liquid-removal units was compared with other potential development plans, including an FPSO, single-flowline and dual-flowline subsea tie-backs, and wet gas compression using both platform-mounted and subsea compression equipment.

PDG performed well on several metrics, including cost, coming out ahead of all other options except the dual-flowline tie-back, which was deemed slightly less expensive to develop.

The results, which were reviewed by representatives from operators and service companies, also showed a significant reduction in back pressure on the wells using PDG.

Recovery rates using PDG were notably higher and carbon dioxide emissions markedly lower than the other development options.

"Everybody is just throwing energy at the problem," Thomas says, insisting that engineers should look at the gas transport challenge not through the pressure lens but rather as a flow assurance issue.

"We're using the natural energy in the reservoir more efficiently to move the gas farther," he says.

Field proven

Thomas and his colleagues are now building a prototype system to test on flow loops at Cranfield University north-west of London.

"All the pumps, power systems and equipment needed to make this work are already field proven," he says.

"The industry has already developed the complicated technology."

The Cranfield test will focus on the piggable liquid removal device, using a prototype scaled down in diameter from the system design's 30 inches to six inches. This development stage is also being supported by The Oil & Gas Technology Centre.

If the tests go as planned, Thomas says, Intecsea will use the data to create a full-scale prototype for a pilot programme around 2022 with hopes that an operator will step forward to collaborate.

The research and development programme has revealed a few unintended benefits of the PDG technology.

Recent studies have shown that by simultaneously lowering the back pressures and the velocities of the gas, a PDG system has a much greater tolerance to hydrogen sulphide from the well stream, Thomas says.

And as producers of small oil pools are being discouraged from flaring associated gas, the technology provides a cost-effective alternative.

"Also, on oilfields, as soon as you get breakthrough on gas wells, you have to shut them down because of MEG constraints," he says.

"But if you use this system you can keep those wells flowing - you can separate the water and the gas very efficiently at the wellhead, and then just run the liquids back in the umbilical core.

"Instead of re-injecting MEG at the trees, you can inject it downstream."

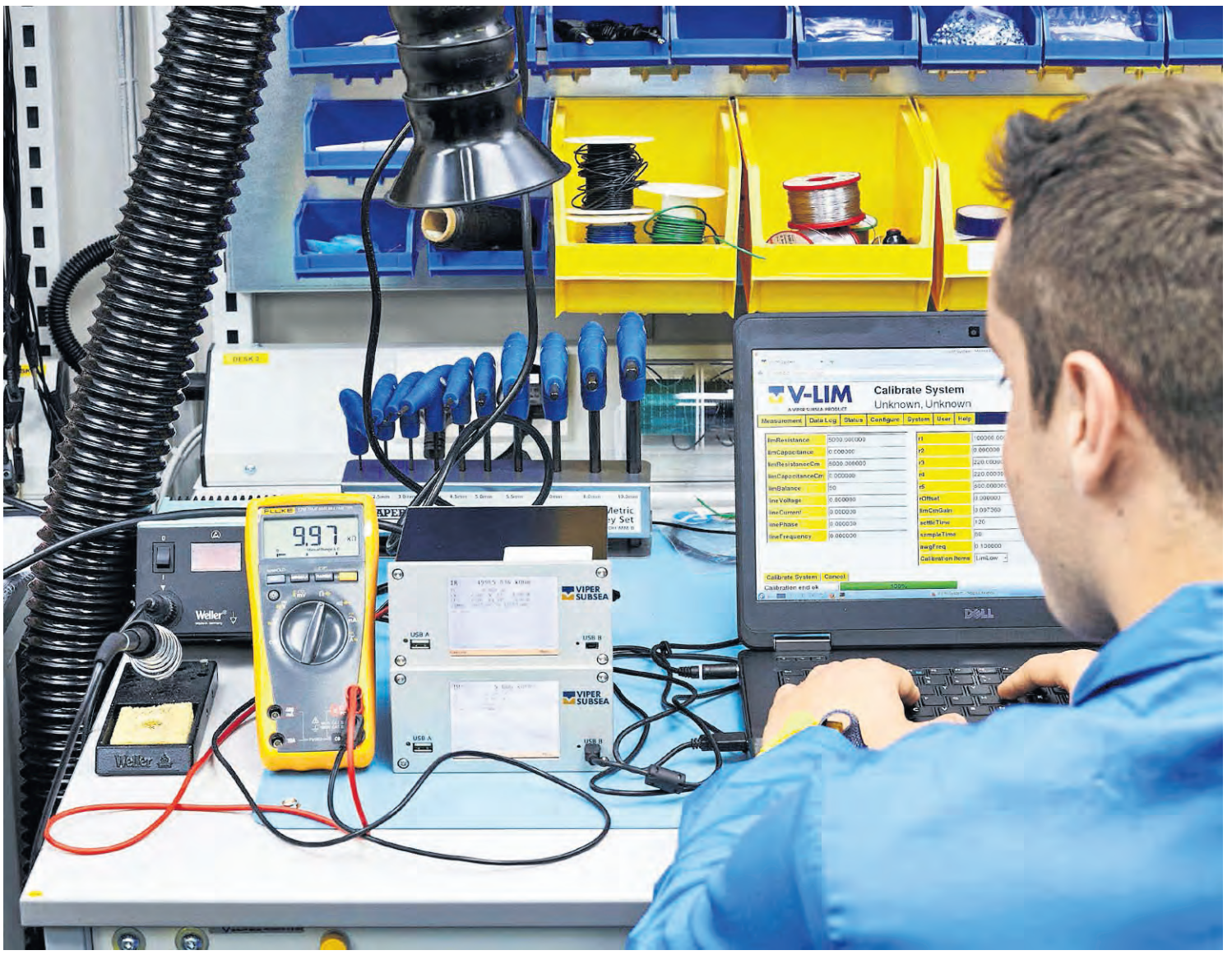
Thomas adds: "What we didn't realise at the start is that there are multiple applications for this concept. It's as much a new concept as a new technology."

SUBSEA TECHNOLOGY

Viper kits up at the double

Company combines two technologies to boost protection against electrical **circuit failure**

RUSSELL MCCULLEY
London



Innovation: integration testing of the V-LIM hardware and software

Photo: VIPER INNOVATIONS

THERE are many benefits to be found in the increasing electrification of subsea developments, but the trend also presents some challenges in guarding against electrical failures.

Water ingress to subsea electrical cables is the main cause of electrical faults, which can lead to low insulation resistance (IR) and eventual circuit failure.

Neil Douglas, managing director of UK-based Viper Innovations, says: "The biggest challenge operators have with their subsea control systems is electrical failures. Water and electricity don't mix very well.

"The kit is designed to be on the seabed 15 to 30 years and most operators take the view, when, not if, they will have electrical failures."

In the North Sea, Douglas notes, electrical cable failures after 10 to 15 years in the water are common, adding that failures occur much more frequently in the Australasia region although the reason is not fully understood.

Viper Innovations, formerly Viper Subsea, built its reputation on a suite of subsea monitoring electronics and integrity management tools including V-LIFE, a technology that can rejuvenate and increase insulation resistance on umbilicals and subsea electrical cables that have been compromised by water ingress.

Monitoring

The company has combined two of its technologies — the electrical line integrity monitoring system branded V-LIM and a subsea-deployed system that detects and locates electrical faults, V-SLIM — in a system that can continuously monitor a subsea distribution network and give a precise location of a fault.

That information is valuable because existing topsides line insulation monitors can only tell that there is a problem somewhere in the subsea system, not the number of faults or where they are.

A campaign to find the problem is not only costly but can create new vulnerabilities in the system as electrical components are disconnected and reconnected during a fault-finding intervention.

Viper's fault-locating system, dubbed V-IR, uses electronic monitoring devices placed at intervals along a subsea electrical distribution system that can indicate the direction of a fault and isolate it.

V-IR research and development got under way in 2013 with a joint venture assisted by the trade organisation Industry Technology Facilitator.

The joint industry project included Viper and five oil and gas majors, Douglas says.

A qualification programme wrapped up in February last year and in November the company was awarded a contract to provide technology to Aker Solutions for the Norwegian company's work on Equinor's Askeladd project in the Barents Sea.

Equinor early last year awarded an engineering, procurement and construction contract to Aker Solutions for delivery of a subsea production system at Askeladd, the second development phase at the operator's Snohvit liquefied natural gas project.

Viper has deployed "hundreds" of the topside V-LIM systems but Askeladd will mark the first commercial application of the new subsea electronic monitoring system, which incorporates the topsides kit.

Investments

Under the terms of the joint industry project, he says, the V-IR development costs have been divided six ways.

The operators hope to recoup their investments through discounts of the product or royalties from sales.

Douglas says the operators requested that the technology be made available to all service companies.

It was designed so that it can be incorporated into any equipment manufacturer's system and can be deployed on new developments or on brownfields by replacing electrical flying leads.

The company is working now on artificial intelligence solutions to predict electrical failures in a knowledge transfer partnership organised through Innovate UK.

It is also applying its insulation resistance monitoring and fault locating expertise to live low-voltage above-ground electronic cable systems such as those running alongside rail tracks in the UK.

Douglas says: "We have taken this technology and are now delivering it to Network Rail," which like subsea takes a significant financial hit when an electrical failure disrupts operations.

Viper calls the service, CableGuardian, "the first platform to offer proactive monitoring, detection and location of both insulator and conductor faults on live signalling power distribution systems".

In 2016, the company acquired a 33% equity stake in US company LiveWire Innovation, which markets a technology that transmits small signals along electrical cables and uses data collected to detect anomalies that might indicate short-circuit or open-circuit faults.

The acquisition was a move to diversify the company during the oil and gas downturn.

"But what we're looking at in other industries, hopefully we can pull back into the subsea industry," Douglas says.

RENEWABLES

Floating wind readies for next

Pioneering technologies set to make sector competitive with **bottom-fixed offshore scene**

RECHARGE

DARIUS SNIECKUS
London

The pioneering floating wind technologies being readied for the first wave of utility-scale projects taking shape for construction off Europe, Asia and the US are betting on economies of scale to get to a levelised cost of energy below €50 ($56) per megawatt hour before 2030, competitive with conventional, bottom-fixed offshore wind.

But Norway's Equinor, US outfit Principle Power and France's Ideol — all with sea-trialled units and multi-gigawatt international order pipelines waiting to be uncorked — could yet be beaten to that target by next-generation concepts bound for market.

Designs from start-ups including Spanish trio X1 Wind, Saitec Offshore and EnerOcean — fashioned from the first for mass production and installation, rather than adapted from offshore oil platforms — are now in prototype testing.

"Many of these new concepts — X1 Wind's, Saitec's, EnerOcean's and others — have this potential to either solve some of the technical problems and/or reduce some of the cost when compared to the earlier designs, which, of course, they have benefited from studying over the past decade," says Giles Hundleby, director at UK consultancy BVG Associates.

Killer apps

"It is very positive these new designs are coming. Whether some of the innovations they are adding (to the engineering) are 'killer apps' which could be adaptable by other platform concepts too, it is still a little too early to say," Hundleby adds.

"Certainly, they could have an important role for the sector by showing in which new areas of technology or manufacturability costs could be further driven down."

Even by the precocious standards of the rapidly evolving sector, these new designs have made impressive strides to market in the opening months of 2019.

X1 Wind and Saitec both announced in April that they had each pulled in almost €6 million ($6.8 million) in European Union funding to help advance their technologies, known respectively as PivotBuoy and SATH (Swing Around Twin Hull) in part-scale versions.

And both companies are in discussion with developers to deploy 10 megawatt-plus models as part of multi-hundred megawatt projects in the coming years.

The prototype of the PivotBuoy, which will be topped with an adapted 225 kilowatt Vestas turbine, combines a jointed-steel tension-leg platform and single-point mooring (SPM) system in a downwind design that weathervanes with the prevailing wind, in order to better capture the resource.

The SATH, though it also weathervanes on an SPM, is a different animal, based on a joined pair of cylindrical pre-stressed concrete hulls.

"In the last decade, a number of prototypes have successfully proven floating wind is technically feasible, but costs need to be reduced by at least 50% to start," stresses X1 Wind chief executive Alex Raventos. "Technology disruption is required to achieve large-scale cost-competitive floating wind.

"We are already seeing significant cost reduction when scaling up to 8 MW to 10 MW rotors as well as with serial production of platforms. We expect to bring another step change to make floating wind competitive against current energy technologies."

Saitec chief technology officer David Carrascosa echoes the view: "The first thing to us is scale up. That makes the (economics) for everyone much better. But yes, (mass production) of this new generation of technology gives us a new opportunity of reducing the cost."

The X1 Wind and Saitec prototypes — which have undergone a battery of tests in various R&D centres' wave tanks and wind tunnels — are set for installation off the Canary Islands next year.

Another weathervaning Spanish-built concept, EnerOcean's W2Power — the world's first twin-rotored floating wind power platform — is about to start a trial as a part-scale unit off the Canaries.

Maiden-unit project

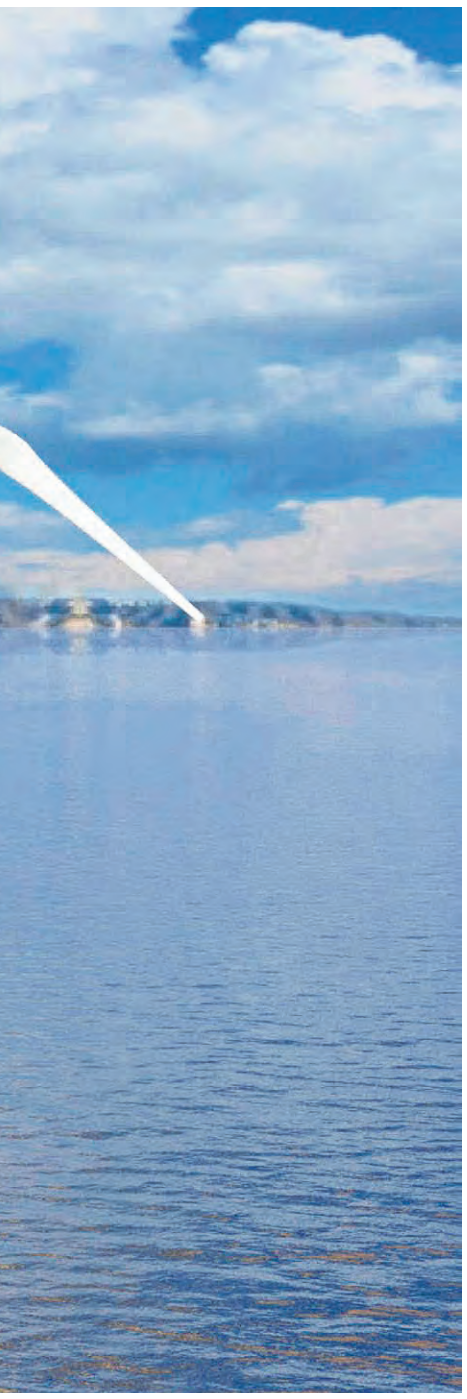
EnerOcean's design — a triangular steel semi-submersible with angled turbines — will be put through a fast-track testing programme with 100 kW turbines off the island of Gran Canaria, as the developer ramps up plans for a maiden multi-unit project dubbed CanArray.

This 60 MW project would see five units each flying two "off the shelf" 6 MW turbines. "We want to show that our concept, with its two turbines, can be built on a light, robust platform... (and that) there is high value in generating high power from this design, which includes some real innovations in terms of the weathervaning and the leaning towers that allow (the rotors) to reach out beyond the base of the platform," says EnerOcean president Pedro Mayorga.

The next few years will be a crucible for these new concepts, challenging the wisdom gleaned from exhaustive computer modelling and tank-trial engineering with the harsh realities of life at sea.

"Next-gen floating wind may help solve the issues behind mass scale production, but proving these technologies actually work in marine environments is the

t wave



Above: an illustration of EnerOcean's W2Power floating wind concept
Image: ENEROCEAN

Far left: X1 Wind's PivotBuoy floating wind concept
Image: X1 WIND

Left: Saitec's SATH (Swing Around Twin Hull) floating wind concept
Image: SAITEC

first hurdle," stresses Bloomberg NEF analyst Imogen Brown.

"Meanwhile, the more mature technology players are adapting pre-fabrication techniques to facilitate mass scale production (to hone their cost-competitiveness)," she adds.

De-risking technology

Carrascosa speaks for floating wind platform developers in general when he says of the SATH demonstrator: "We want to de-risk (the technology) and get a unit in the water, test assemblies and (the hull) but also to accelerate the commercialisation process of the 10 MW-plus model, as a way of tackling the past and the future at the same time, to truly industrialise the concept and help do the same for the industry."

15 GW global fleet on horizon for market by 2030

AS FLOATING wind power surges toward the energy mainstream, analysts have regularly revised future market forecasts upward, with the consensus anticipating a 15 gigawatt fleet turning around the world by 2030.

However, as projects and prototypes are rapidly built out, and the expected cost reductions are achieved, that figure could prove to be conservative.

"A lot is dependent on the speed and the volume ramp-up by the sector," says BVG Associates director Giles Hundleby.

"We will definitely see a sub-€50 ($56) per megwatt hour (levelised cost of energy) when we see the first 1 GW project switched on – and to be clear, we couldn't do this tomorrow, it will require 200 MW and 500 MW projects first.

"And if we can get to 15 GW installed by 2030 – or beyond – then that low an LCOE is achievable.

"You only need to have a few substantial successes in the next couple years – off Japan, France, Scotland, Norway and the US, totalling 6 to 8 GW – and you can start to see how this all takes off."

As turbine designer Henrik Stiesdal, who is developing a new-look, "industrialisation-minded" floating platform, recently remarked: "At a point, a forecast is just that. Maybe it is good to motivate (the sector) right now, but we certainly shouldn't let it hold us back from achieving a much bigger (build-out of floating wind) around the world by then."

Luis Gonzalez-Pinto Barrenetxea, head of renewable energy at Saitec, agrees, adding: "Once you get a first commercial floating wind farm, the next 10 years are going to be crazy in how many projects will move forward."

EMISSIONS

Measuring up to cut methane

Oil and gas companies turning to technology to help reduce industry's **greenhouse gas emissions**

RUSSELL MCCULLEY
London

THE upstream oil and gas industry, under pressure to cut greenhouse gas emissions, is increasingly looking for technical solutions to help it reduce and offset its carbon footprint.

While effective and affordable carbon capture, utilisation and storage technology may be some years away, the industry has opted for now to focus largely on cutting emissions of methane, which has a shorter life in the atmosphere than carbon dioxide but is far more destructive in the short term.

Many in the industry see methane as the easiest challenge to address and the one where results can be seen quickly.

Some companies have taken steps to reduce flaring and to replace high-emission oilfield equipment with up-to-date technology.

Gordon Birrell, BP's chief operating officer for production, transformation and carbon, ticks off several initiatives the UK supermajor has under way to bring its emissions down.

The company recently commissioned its first "green" completion in Oman, a technique long used in the US Lower 48 to complete wells without flaring gas, he says.

BP is using drones in the US and elsewhere to look for leaks and is well into a campaign to replace high-bleed controllers with more efficient equipment in remote areas with no electricity.

About 10,000 controllers have been upgraded so far, Birrell says.

Accurate measures

However, it has traditionally been difficult to quantify the size of leaks and to get an accurate measure of emissions from activities such as routine flaring.

"We deeply believe, along with many others in the industry, that you've got to be able to measure methane in order to control the leakage," he says.

"It's good for meeting the climate change goals of the Paris Agreement, but it's also good for business. Methane is a large part of natural gas, and if we can keep it in the pipe and sell it as a lower-carbon fuel relative to coal, then it's good for business.

"There's a virtuous cycle here," Birrell says.

While the company says it has reduced flaring — and that green completions and gas recovery and reinjection technology will help it make additional reductions on future projects — safety dictates that legacy projects will include routine gas flaring.

Incomplete combustion means a measure of methane escapes during flaring operations. The industry has assumed flaring efficiency of 98% — that is, about 2% of the gas, predominately methane, is not combusted and escapes into the atmosphere.

Until now, the industry has had no practical means to assure that figure other than tests carried out at the time of commissioning.

However, "a lot has been happening on the detection side in last 18 months," Birrell says.

The company has been working with Providence Photonics, a Baton Rouge, Louisiana-based company that has long provided cameras for leak detection.

BP is using a handheld camera system and software developed by Providence Photonics that detects and quantifies leaks.

The operator uses that information to determine how to prioritise remediation efforts.

"We now have these cameras deployed at every major site in BP upstream and the quantification software is also being deployed around BP as we speak," he says.

Recently deployed

Providence Photonics has also developed a camera system that uses video imaging spectro-radiometry (VISR) which BP recently deployed for the first time.

"This is really exciting technology," Birrell says. "We can use this to look at flare systems around our industry, not just in upstream but in the downstream as well."

Accurate measurements can help operators optimise flaring operations.

"We can adjust the amount of steam that's going up the flare, the amount of air that's going up the flare, the mixture of gases going up the flare and, based on the measurement, optimise the parameters of the flare to get the best possible combustion at the flare tip. And that reduces the amount of methane that goes into the atmosphere," he says.

"We have deployed that in Angola and Alaska and we are getting pretty positive results – our flares appear to be more efficient than we generally assumed."

BP is also working with Houston-based Rebellion Photonics on fixed gas cloud imaging cameras for around-the-clock monitoring.

"It's a bit like a sentinel watching your facilities 24/7, and they can detect and quantify methane that's being emitted from a site," Birrell says.

"We have now deployed fixed gas cloud image detectors in Oman, in Alaska, and we are about to (deploy them) in Trinidad.

"The detection technology really has moved ahead in the last 18 months and we are hopefully at the forefront of deploying the new technology around our facilities," he adds. The company is addressing emissions through automation, field design and renewable energy to provide power at remote assets, he says.

The company has worked with its peers in the Methane Guiding Principles group to develop a set of rules for reducing emissions that is being rolled out to industry, and in March signed a three-year strategic commitment with the conservation group Environmental Defense Fund (EDF) to advance methane emission reduction technologies and practices in the oil and gas industry.

"We're pretty excited about that," Birrell says. "We see EDF as a progressive NGO who want to work to make the industry better.

"And we want to make ourselves and the industry better," he adds.

Field work: BP using VISR technology to monitor flaring at the PSVM facility in Angola
Photo: PROVIDENCE PHOTONICS

Providence puts emissions in picture

NEW imaging techniques are helping oil and gas operators get a clearer picture of just how much greenhouse gases such as methane they are emitting — an important calculation for correctly assessing an emissions "inventory" but one that has traditionally been difficult to gauge.

US company Providence Photonics is working with companies including several oil and gas operators to develop more accurate methods for monitoring and measuring methane emissions in activities such as flaring.

The Baton Rouge, Louisiana-based company has developed a leak detection and measurement system, QL320, based on software designed to be used with handheld cameras manufactured by US thermal imaging company FLIR Systems.

More recently Providence Photonics has rolled out a system to monitor the combustion efficiency of flares based on video imaging spectro-radiometry (VISR).

The method is being used to accurately measure flare efficiency in real time, providing data that can help operators optimise flaring and cut back on unnecessary fuel or steam usage.

The company says the technology "offers the first and only practical mechanism for flare operators to achieve the operation mode known as the 'incipient smoke point', which typically has the highest combustion efficiency without causing visible emissions".

The VISR programme began with a grant from the US Environmental Protection Agency (EPA), says Providence Photonics chief technical officer Jon Morris.

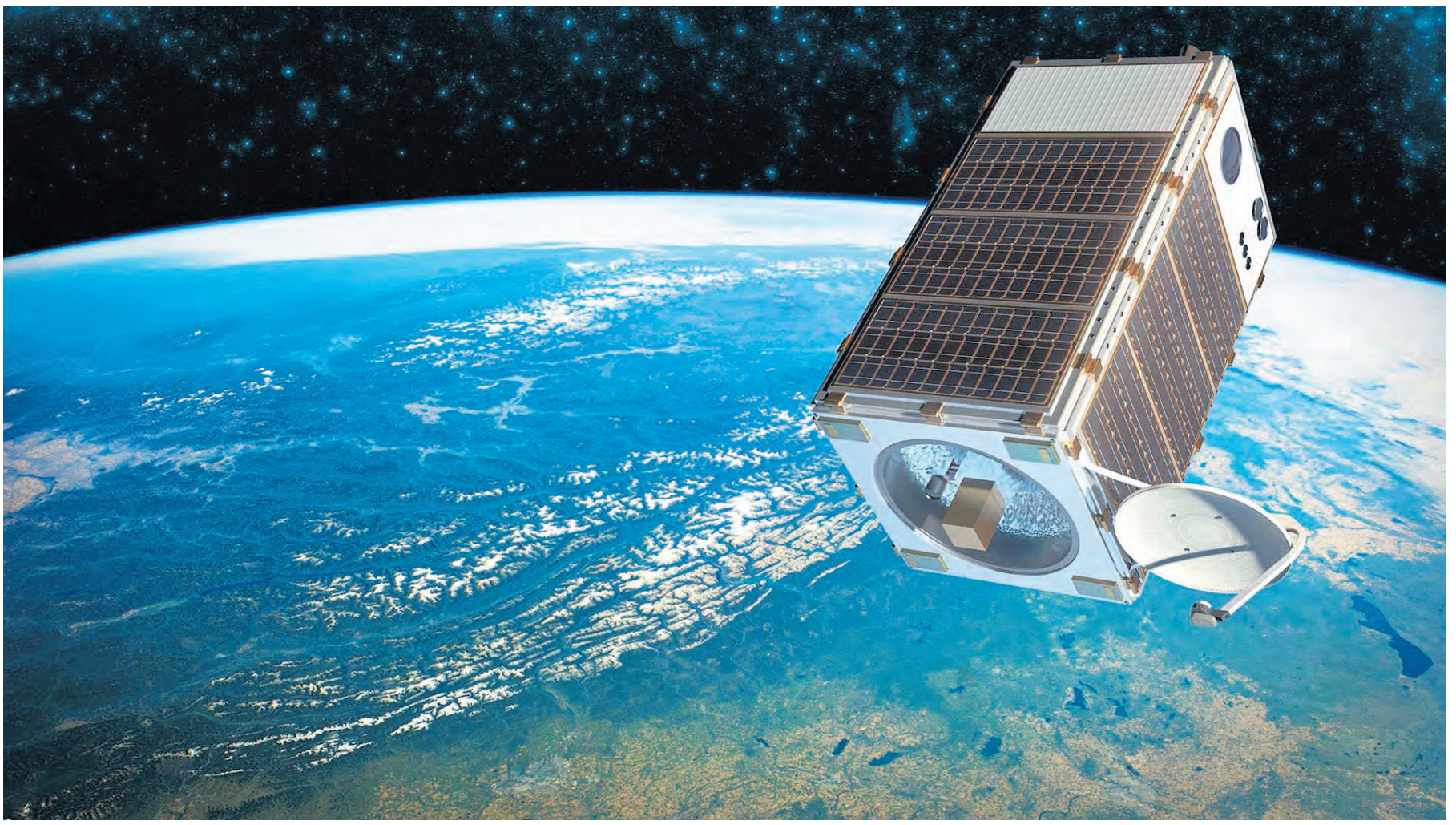
"We've been working closely with the US EPA to develop this method, and it is the only practical method I'm aware of to measure the combustion efficiency of an elevated flare," he says.

BP was an early sponsor of the technology, he adds: "They were one of eight companies — BP, ExxonMobil, Chevron, Chevron Phillips Chemical Company, Eastman Chemical Company, Phillips 66, Saudi Aramco and Shell — which funded a two-week blind test through the Petroleum Environmental Research Forum (PERF) in 2016 to validate the VISR method.

"They are now leading the application of this technology in the field to measure the performance of their flares," Morris says.

VISR is described as a multi-spectral imager that can directly measure relative concentrations of combustion product, carbon dioxide and unburned hydrocarbon, and calculate flare combustion efficiency in real time.

Global outlook



US-based conservation group Environmental Defense Fund is expected this month to award a final design and manufacturing contract for the MethaneSAT, a small satellite specifically designed to produce high-resolution images of methane emissions and make the information available to the public. Set to launch in 2021, the orbiter will be designed to measure methane emissions worldwide including the regions that account for more than 80% of oil and gas production.

Image: EDF

CAREERS

Sector's image hits new oil and

Recruiters look to appeal of **digitalisation** and energy **transition** challenges

ANAMARIA DEDULEASA
London

On course: students compete during a cybersecurity event

INDUSTRY observers have been warning of an upcoming skills shortage in the oil and gas business, the result of significant job cuts during the oil price downturn that pushed many industry professionals and their expertise towards other sectors.

This expected skills gap is nothing new to the industry, as historically the flow of talent in and out of the sector has corresponded with the economic cycle.

During a downturn, companies would pull back on university recruitment, graduate schemes and apprenticeships, so the influx of young talent would slow.

Once the oil price would recover, companies would poor resources back into their recruitment programmes.

However, what is new this time around is the generation the industry is now dealing with, as the skills gap may now be exacerbated by the fact that fewer young people are interested in joining the industry.

This is due in part to a perception of the oil and gas industry as dangerous, environmentally damaging and plagued by volatile spending cycles.

Nonetheless, experts are expressing confidence that digitalisation can help the industry address the skills challenge by bringing new jobs to the sector that focus on sustainability, embrace safety, push for diversity and keep costs under control.

Confidence

According to a survey from consultancy DNV GL, 34% of the industry professionals polled expect headcount to rise this year, which is a sharp increase from 20% in 2018 and 10% in 2015, at the lowest point of the downturn.

But while a return to hiring is a welcome sign of industry confidence, there will be clear challenges associated with growing headcount after a period of significant cuts, analysts say.

"Skills pressures are now firmly back on the agenda, rising sharply in our survey to take joint second place in the industry's barriers to growth. This comes alongside concerns about the oil price and the state of the global economy, and just behind the challenge of competitive pressures," DNV GL says.

"This skills gap hits hardest in Europe and North America (both 25%). In the UK, 39% see this issue as the greatest barrier to growth for 2019, the highest of any country.

"By contrast, concern is lowest in Latin America (10%), and the Middle East and North Africa (15%), despite having local content restrictions in place, while nearly one in five (18%) in Asia-Pacific is feeling the squeeze," it said.

Liv Hovem, chief executive of DNV GL Oil & Gas, says: "We need to ask ourselves how we expect to attract the talent that will be required to deliver as activity picks up again. Who would like to join our industry so soon after it dramatically cut so many people?"

Millennials are much more digitally savvy than previous generations, and the so-called Generation Z — those born in this century — are even more so.

This generation did not need to adapt to the "internet revolution" and digitalisation of things — they were part of it.

Therefore, as a generation that takes the latest technological advances for granted, they should be racing towards the industry.

Perception

However, according to a report from consultancy EY, the industry suffers from perception issues in relation to young people, who are "disincentivised to pursue careers in oil and gas by concerns about the longevity of the industry and a perceived harmfulness to society".

According to EY's survey, 62% of Generation Z (ages 16-19) found the prospect of a career in oil and gas "unappealing," while 44% of millennials (ages 20-35) said careers in the industry do not appeal to them.

> *The Millennial generation needs to feel that they are impacting the world.*
>
> Airswift chief executive Janette Marx

The younger generation appears to be snubbing the industry, more so than the previous generation before them, because they want their work to have a positive contribution on society and the world.

Also, millennials seek different job perks than previous generation sought.

The EY survey revealed that while salary is the top driver for young people at 56%, work-life balance is a close second at 49%, and job stability and on-the-job happiness matters for over 30% of EY's respondents.

Therefore, Hovem says, it is "vital" for the industry to help

d gas recruits

Photo: AFP/SCANPIX

young engineers understand the role that the oil and gas industry will play in decarbonising the world's energy system and the contributions they could make to changing the way the sector operates.

"Decarbonisation will become a prevailing theme of the oil and gas industry over the coming decades. Those working in our industry will have an incredible opportunity to influence that trend," she says.

Janette Marx, chief executive of staffing company Airswift, says: "The Millennial generation needs to feel that they are impacting the world, that they are doing something that makes them better. They also want to grow and continue their development throughout their careers. They don't want to be in the same role for years and years. They want to develop a lot of different skills, and want to be challenged in different ways."

According to Marx, rotation programmes have proven to help with retention, as well as providing workers with a better understanding of the company and the necessary work required.

"These generations change jobs quite rapidly compared to the previous generations because they want to know that they are constantly challenged. When they are not, they move on," she says.

"Once (millennials) get down one part of their job they are ready to move on to another section."

Industry needs to move fast to attract workers with new skill sets

THE challenges facing the industry today — produce greater quantities of oil and gas from more complex geologies all while increasing environmental stewardship — are technologically robust, *writes Anamaria Deduleasa*.

It will require people who are skilled in the use of robotics, 3D printing, artificial intelligence, supercomputing and blockchain.

These skill sets are somewhat new to the industry, despite it being historically technology-driven.

Data scientists — much sought-after due to the industry's increased focus on digitalisation — are often drawn to technology companies and other digitally-driven players, but in a world where every oil and gas company is pushing towards digitalisation to better perform, skills in this department are increasingly important.

"Automation and digitalisation will improve efficiency, but if companies don't move fast enough to implement new technologies and grow their talent pool, the consequences could be painful," says Airswift chief executive Janette Marx.

Airswift, which provides energy workforce staffing services, also tracks job losses in the oil and gas industry together with job site Energy Jobline.

The companies say the current recruitment challenge is down to a wave of imminent retirements and fewer young people entering the field. In their most recent annual Global Energy Talent Index, with 17,000 respondents from 162 countries, the companies say attracting talent lies in highlighting the vast scale of the technological and engineering challenges to be overcome.

"Automation promises to free up professionals from tedious tasks, enabling them to shift their skills to other areas of importance," according to the report.

This, however, does not mean the current workforce will be replaced in its entirety.

A world where robots, artificial intelligence and "smart technology" will take over certain tasks from workers in the sector but will not necessarily lead to job cuts. Instead, the job market will grow and adapt, digital specialists argue.

Chris Rivinus, programme leader, digital transformation at Tullow Oil, recently said at a conference: "The idea AI machine learning will eclipse the need for human work is premature. Maybe we will have this conversation in 30 years, but definitely not now.

"Take for example the use of robot dogs offshore," he said in an apparent reference to the four-legged inspection device the Swiss company ANYbiotics has declared the world's first autonomous offshore robot.

"This will replace a role or two in terms of people going to do offshore jobs which are dangerous. But this does not mean a replacement of personnel because you will still need an army of people behind that dog," Rivinus said.

FINANCE

On show: a conveyer belt with objects is used to demonstrate blockchain technology during a recent technology event Photo: AFP/SCANPIX

Joining the blockchain gang

Private networks offering transparency on transactions and monitoring **production and supply chains**

ANAMARIA DEDULEASA
London

BLOCKCHAIN technology, which creates secure ledgers for digital transactions and rapidly accelerates the pace at which transactions can be made, has the potential to disrupt every major industry, including oil and gas.

And as the industry pushes ahead with its digitalisation ambitions, it is beginning to adopt this technology, which first emerged as the architecture underpinning the cryptocurrency Bitcoin.

The irony of simplifying oil and gas operations with a complicated technological concept like blockchain is difficult to ignore, but if they are to be believed, digital innovators expect it will cut down on operational time and costs while also introducing more transparency to the industry — a powerful idea.

Applying blockchain technology to the oil and gas industry is different than applying it to create cryptocurrency.

Oil and gas companies usually use a private blockchain network, which only allows invited parties to view the data on transactions.

Conversely, public blockchains such as Bitcoin allow anyone with an internet connection to view transactional information. This means that a private blockchain can boost trust among various parties within the industry from suppliers to shippers, while still being secure from outside parties, according to tech giant IBM.

In addition, because all trading parties, including the buyer and the seller, along with their respective banks, are on the same distributed ledger, all details of the transaction are simultaneously visible to everyone, increasing transparency in the process.

Reducing threats

This step could also reduce the threat of fraud and cybercrime thanks to the distributed nature of blockchain while reducing overhead costs, cash cycle times, and cost intermediaries, IBM says.

"In the future, as blockchain-enabled business transactions become more sophisticated, business and industry networks could evolve into self-governing cognitive business networks and reduce the cost of payment transactions by an estimated 30%," the company says.

Vakt Global, a consortium led by supermajors BP and Shell, launched at the end of last year a blockchain-based digital trading platform in an effort to bring about new efficiencies to the way oil is bought and sold. Other members of the consortium include Norway's Equinor, trading houses Gunvor, Koch Supply & Trading, and Mercuria, as well as banks ABM Amro, ING and Societe Generale.

Other investors recently have joined, including French player Total, India's Reliance Industries and US giant Chevron.

According to its creators, the Vakt Global tool is meant to facilitate the trade in crude oil between commodity firms, claiming to be the "first enterprise grade" blockchain solution within the oil and gas market.

It is designed to help trading companies replace paper-based documentation with smart contracts.

By automating parts of the process, the move is expected "to help companies cut costs, reduce errors and make post-trade processes more efficient".

So far, the tool is used to trade two thirds of North Sea crude, but further expansion plans are due to be announced this year.

While the supermajors are focused on trading, others in the industry are looking to blockchain technology for far more creative endeavours.

Smaller players such as Canada's Petroteq, in collaboration with Mexican giant Pemex, launched Petrobloq — a blockchain consortium designed to track, monitor, and account for every drop of petroleum on a transparent, immutable and secure platform.

Rethinking supply chains

Petrobloq is looking to "rethink traditional supply chains for the industry", monitoring everything from drilling to a finished petroleum-based product and all points in between.

The goal of the platform is to minimise production losses, and implicitly profit losses, at every level of the oil and gas production cycle by "seamlessly" sharing data between users, Petrobloq claims.

"The time it takes to cut a deal will be reduced significantly, and the middleman essentially disappears, reducing costs for every sub-section of the industry", it says.

WHAT IS BLOCKCHAIN?

- Blockchain technology, which first emerged as the architecture underpinning cryptocurrency Bitcoin, uses a shared database that updates itself in real time and can process and settle transactions in minutes using computer algorithms, with no need for third party verification.
- Essentially a linear transaction log, it is typically replicated by computers whose owners (called miners) are rewarded for logging new transactions.
- According to experts, there are two things that this technology is based on: one is that a change in any block invalidates every block after it, which means that you cannot tamper with historical transactions.
- The second is that you only get rewarded if you are working on the same chain as everyone else, so each participant has an incentive to go with the consensus.
- Essentially, the end result of using blockchain in a business is a shared definitive historical record in which you only get paid if and when you play your part.
- Therefore, following the rules is mathematically enforced, and bribery or bullying would be eliminated.

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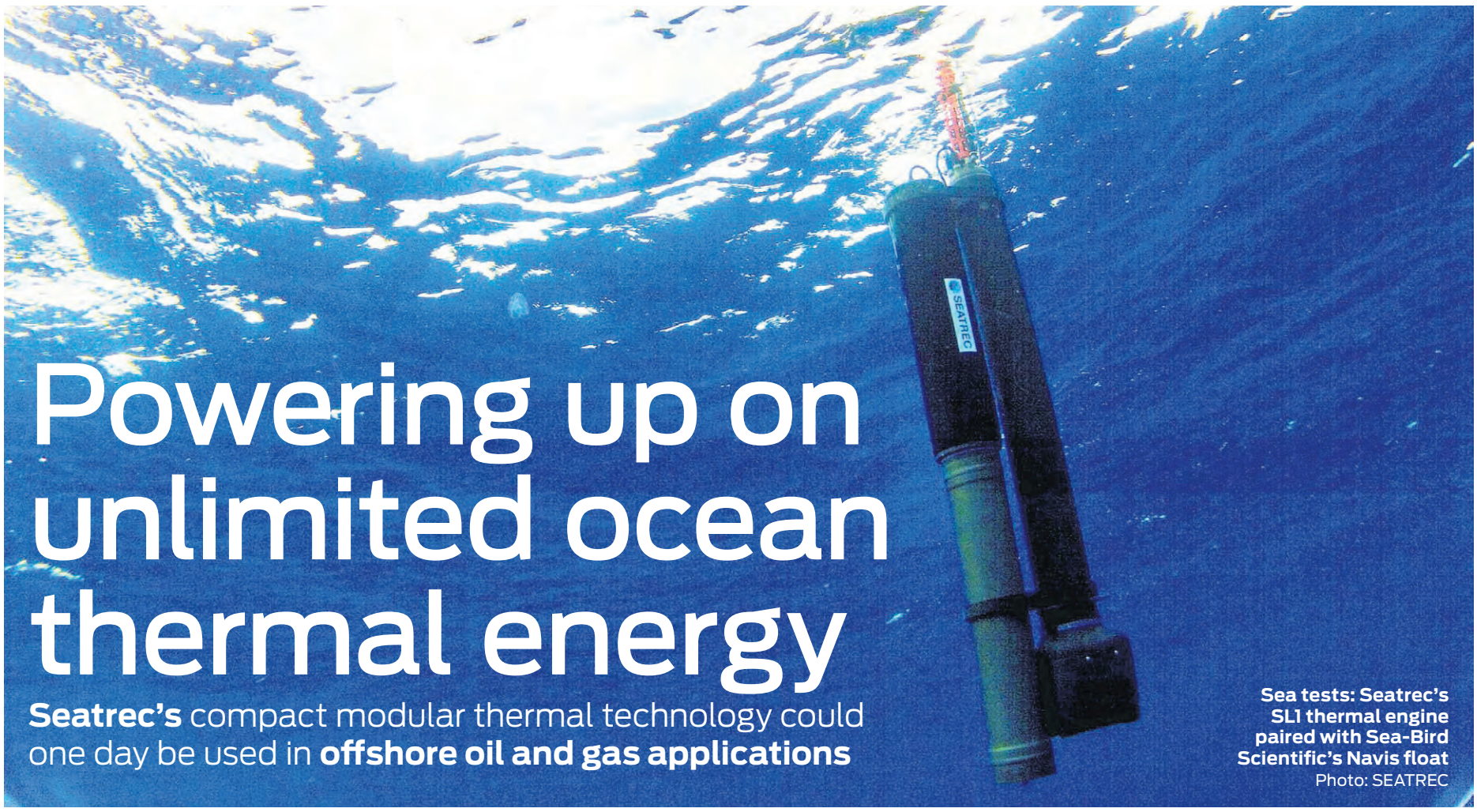
RENEWABLES



Powering up on unlimited ocean thermal energy

Seatrec's compact modular thermal technology could one day be used in **offshore oil and gas applications**

Sea tests: Seatrec's SL1 thermal engine paired with Sea-Bird Scientific's Navis float
Photo: SEATREC

RUSSELL MCCULLEY
London

A promising thermal engine technology that generates energy from temperature differentials in the ocean and converts it to stored electrical power could provide an environmentally friendly alternative to lithium batteries in unmanned subsea drones.

California-based Seatrec is developing the compact modular thermal engine for use in the oceanographic research and defence markets and says the technology could one day find wider use in offshore oil and gas applications.

The company recently carried out successful ocean tests in Hawaii pairing its SL1 thermal engine with a Navis float from Sea-Bird Scientific, an autonomous profiling device that can be outfitted with sensors to measure ocean conditions such as temperature, salinity and water chemistry.

This type of drone freely drifts on ocean currents but requires battery packs to propel it up and down and to power sensors and satellite communications. Replacing the drained batteries at sea is costly, and their eventual disposal — often at sea — is environmentally unsustainable, says Seatrec founder and chief executive Yin Chao.

"Power for drones is one of the biggest problems for underwater applications," Chao says.

"Oceans have an unlimited amount of thermal energy associated with temperature differences, so we have been putting together a team to find an innovative way to harvest energy from a really small temperature differential in the water — typically 10 degrees Celsius between warm water at the surface and cold water at depths."

Origins

The origins of the thermal energy project go back about 10 years, when Chao was working in NASA's jet propulsion lab at the California Institute of Technology, or Caltech.

The technology uses the water temperature differential to convert a solid material to a liquid state. The material expands as it melts, creating enough hydraulic pressure to generate electricity which can then be stored for future use.

On board: the team prepares to test the SL1 thermal engine and Navis float

Photo: SEATREC

Seatrec's SL1 thermal engine is compatible with relatively simple floats — vertically-moving robotic probes that are widely deployed as part of a global ocean observation network — and multiple units can be attached to increase power generation.

The company is working on a compact system that will be operable at depths up to 2000 metres as well as a thermal engine for autonomous underwater gliders.

Both systems can be used to retrofit existing fleets of battery-powered drones, Chao says.

In the Hawaii trials, the Navis float outfitted with the thermal engine completed 42 operations over a three-week period in water depths ranging from 500 to 750 metres.

"The field effort was successful in confirming the ability of the combined Navis-SL1 float to operate autonomously in the ocean with energy generation performance exceeding expectations," Seatrec says.

Chao says the next sea trials, due to take place in June, will feature a Navis float "scaled-up" with a second thermal engine to enable more data-gathering sensors, while noting that underwater systems such as the Navis float have relatively low power demands.

"The underwater applications people have been trying very hard to optimise energy budgets, so a lot of the sensors don't really require a lot of energy," Chao says.

Seatrec's longer-term plans include development of an underwater platform that generates enough electricity from thermal energy to serve as "a kind of underwater charging station", he says.

Such a platform could one day be used to keep a fleet of autonomous underwater vehicles charged during remote oil and gas site surveys and inspections.

"The energy industry needs to collect quite a bit of environmental information using different sensors, either near a platform or farther afield, to anticipate situations and make better decisions," Chao says.

"I can see how a system like ours could support that data collection in a much more cost-effective manner."