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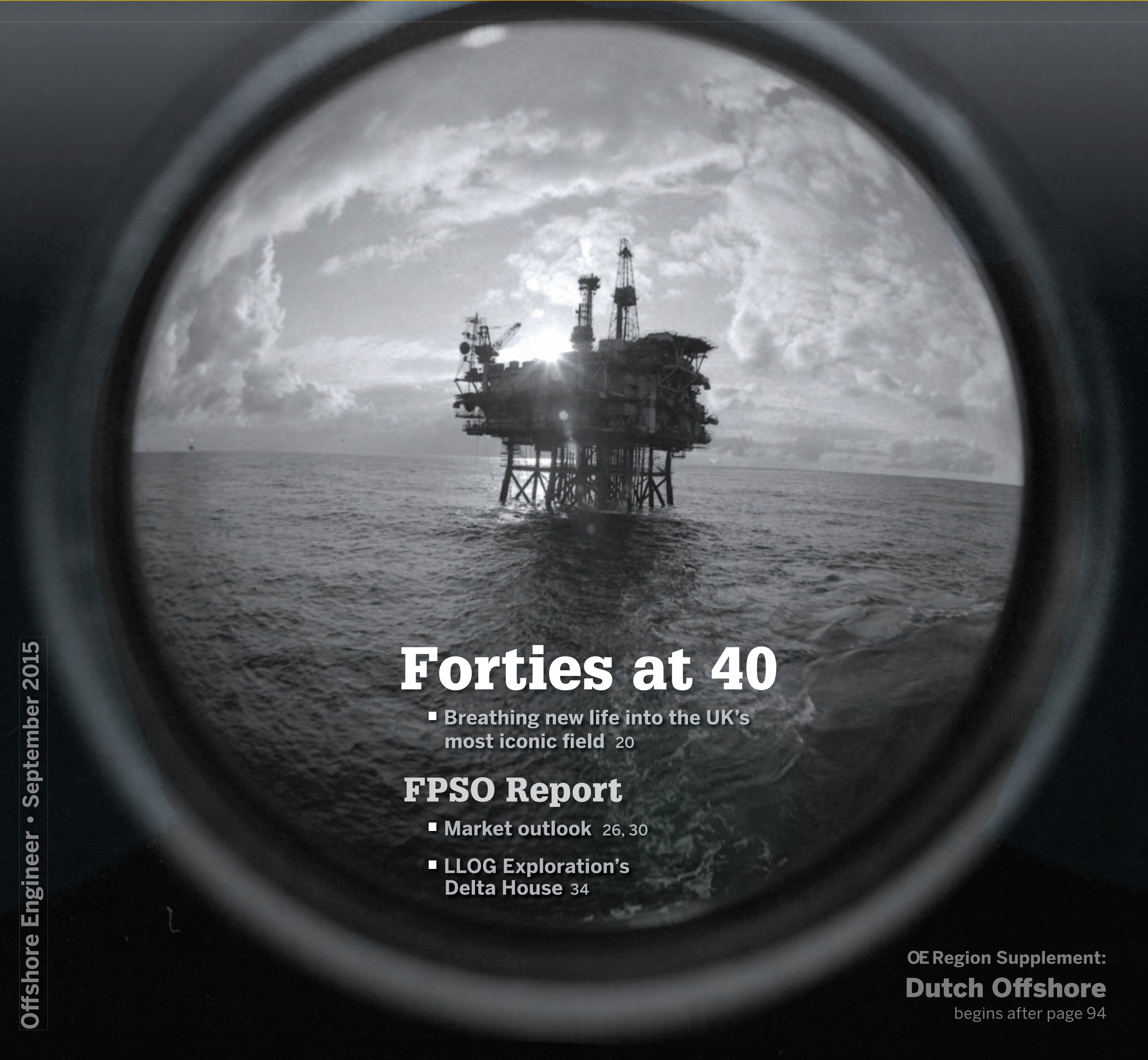

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Dutch Offshore
begins after page 94

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Photo from Petrobras

ON THE COVER

Through the looking glass. *OE* is not the only one celebrating its 40th birthday this year. The iconic Forties field in the UK North Sea, too, began production in 1975. We take a look back on the history of the field and its future. *Photo reproduced with permission of BP Archive.*

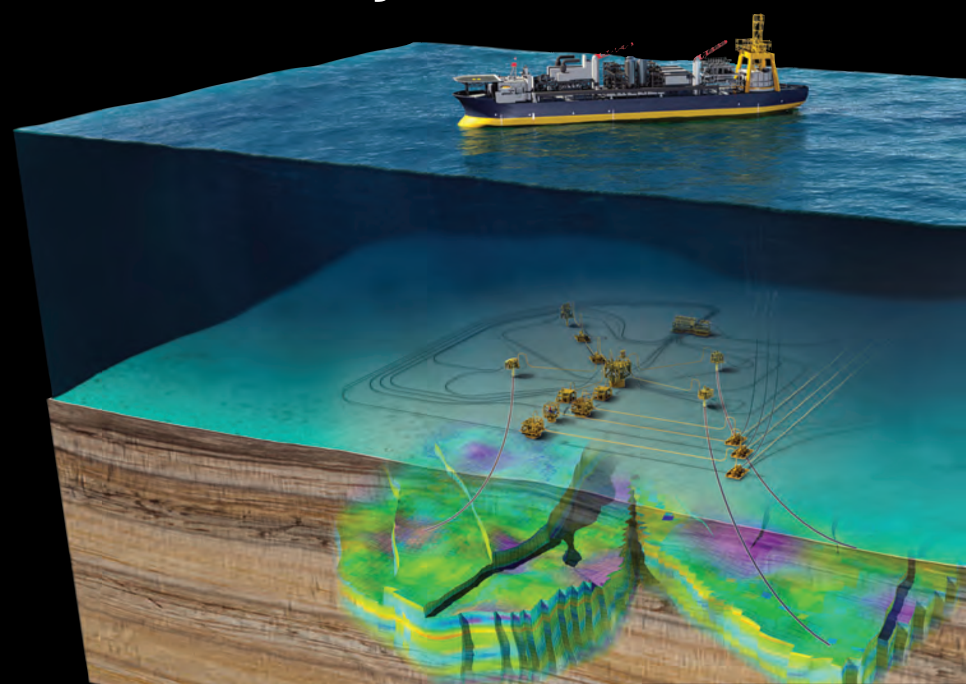

Photo from Dockwise.

OE Region: Dutch Offshore

Leveraging strength. The cover of ***OE***'s special report on the Dutch offshore sector features the *Dockwise Vanguard* carrying its first ever ship-shaped FPSO cargo, the *Armada Intrepid* – one of the largest cargoes ever transported. The *Dockwise Vanguard* successfully delivered the FPSO to Batam, Indonesia, on 8 July 2015, just two months after it set sail from Rotterdam's Caland Canal. ***OE*** Regions: Dutch Offshore begins after page 94.

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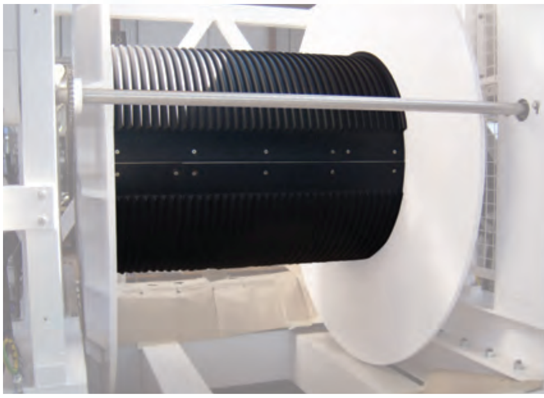
Departments & Columns

"Is the industry succeeding in its challenge to reduce costs and improve efficiency?"



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Online Exclusive

What's next for Mexico?

After Mexico's historic energy reform, many have high hopes for the country's oil and gas sector. But, the first offshore bid round was a disappointment with only two of 14 areas being awarded. Audrey Leon examines what the country has learned from its first auction and what can be done for future rounds.

What's Trending

Let the good times roll

- Steel jacket sets sail for Mariner field
- Israeli government approves Leviathan plan
- Jubilee back to full production

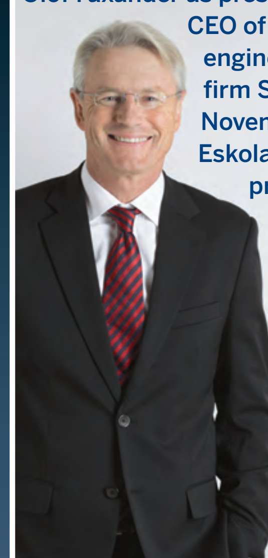
What's Trending

A guide to fixed and portable gas detection for shipbuilding and ship maintenance

SCOTT SAFETY

Based on the model of "universal truths," Scott Safety Gas and Flame Detection R & D Engineering Manager Dan Munson offers guidance on how to evaluate current systems, and project the impact of next-generation gas detection on companies' safety and productivity in a global economy. Munson discusses the evolution and benefits of designing, implementing, and maintaining a truly universal approach to gas detection.

People



Björn Rosengren, current president and CEO of Wärtsilä, will replace Olof Faxander as president and CEO of Swedish engineering firm Sandvik in November. Jaakko Eskola, current president of Wärtsilä Marine Solutions, will take the top spot vacated by Rosengren.

Archer

Q&A

How can you reduce offshore drilling costs while maintaining operational efficiency?

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Voices

Pain and gain. With quarterly reports bleeding red for most companies, OE asked:

Is the industry succeeding in its challenge to reduce costs and improve efficiency?

The need for increased efficiency to reduce costs per well is greater today than ever before. Today's market creates an ideal climate to leverage technologies that eliminate time waste to improve efficiency for reduced cost per well. Wired drill pipe is just one of the technologies that our industry has developed to drive down cost and improve performance.

Ted Christiansen, NOV Wellbore Technologies, IntelliServ president

Although individual organizations are making a concerted effort, greater collaboration across the industry is required to ensure we are truly tackling the challenge head on. Bold action is required and we must do everything we can to address areas were costs have spiraled. This is not only about efficiency and cost reduction, but tackling the behaviors behind these costs. We must also look to simplify and achieve pan-industry standardization. Promoting common good practice to maximize value is key to ensuring we have a safe, sustainable and competitive industry for years to come.

Bill Morrice, managing director, Technip UK

We are definitely on the road to success, but must review our early actions to ensure that short-term savings haven't just moved costs to the right.
Fabric maintenance deferred today may lead to higher future costs because degradation goes beyond the point of repair. Alternatively, failing to train people now will lead to future skills shortages at all levels.

It's good to see companies reviewing the cost benefit they provide, but some buyers may be confusing cost with value. Sustainable improved efficiency doesn't come from threats, it comes from true engagement.

Jon D'Arcy, managing director, Apollo Offshore Engineering

Current market challenges have forced a focus on reliability, risk-based maintenance, enterprise asset management (EAM) and asset integrity management (AIM), but companies struggle with execution in an environment of low budgets, reduced manpower and competing priorities.

This drives the need for a logical and sequenced EAM/AIM implementation plan, with each part of the plan justified based on ROI, prioritized according to impact and sequenced according to resource availability.

The industry needs cost-effective solutions that maximize efficiency. Having risk-based maintenance strategies that reduce unplanned downtime and maintenance spending is critical.

Rob MacArthur, senior vice president, Offshore at ABS Group of Companies, Inc.

The industry has seen in this challenge an opportunity to implement a business culture based on efficiency and cost reductions that in the long-term will allow companies to be much more profitable.

Companies are applying financial discipline, renegotiating contracts with providers and governments, and being more selective, deciding where to make investments, especially in the upstream projects, were costs are much higher. The positive effect of this is that even when crude prices rise again, the companies have gained efficiency thanks to the changes made in their business model.

Antonio Merion, director of business environment study & analysis, Repsol

The industry has responded quite quickly to the challenge of falling returns and oil prices. Many players have responded swiftly by focusing on the short-term task of managing capacity costs. However, this should not be confused with the more fundamental efficiency gains needed.
We see changes including simplification of concepts and solutions and technical requirements as well as some efficiency gains.
New partnerships are being forged to address inefficiencies and develop opportunities in the traditional field development interfaces. A good example is the collaboration between Aker Solutions and Baker Hughes.
We haven't yet seen oil company driven cross-industry collaboration on standardizing technical requirements and specifications or other similar initiatives that could significantly impact costs in the entire supply chain also longer term.
The industry needs to fundamentally change and adapt a culture of cost consciousness to reverse the longer-term trend of falling returns. Are we succeeding? The jury is still out!

Tore Sjursen, executive vice president for operational improvement and risk management at Aker Solutions

During good times, our industry tends to focus on getting the job done rather than on capital efficiency. In today's lean market, the industry responded rapidly with short-term cost-cutting measures, such as reductions in workforce and pricing pressure on suppliers. Through resourcefulness, we are progressing toward sustainable cost-reducing measures, such as better use of assets and inventory, improved operational efficiencies, and detailed root cause analysis to prevent wasteful activities. As we focus on better managing our day-to-day business, sustainable cost reductions become apparent. Moreover, new technologies are being developed to deliver greater operational efficiencies to our clients.

Doug Farley, global product line manager, Cementing Products, Weatherford

Every facet of the global oil and gas industry has experienced pressure to reduce costs in this challenging low-price environment. In the US, operators are renegotiating service contract terms, and the service sector is achieving synergetic cost reductions by merging with competitors and streamlining workforces. Overall, companies are focusing on doing more for less; optimizing production from active wells through lower cost interventions, identifying production sweet spots and improving completion and stimulation techniques to maximize the economic return of all wells. Enhanced recovery techniques, smart wells, geo-steering well placement, reservoir modeling and simulation all serve to increase production and recovery efficiencies. However, in order to secure future success, ultimately we need to see further improvements in production increases against the money invested to achieve those increases.

Allen Howard, president and CEO, NUTECH

Go to OEDIGITAL.COM and give us your opinion on this month's topic!

Undercurrents

Winds of change

What a difference two years make. The theme of any industry conference over the last few years has dealt with how to recruit the next generation to stave off the impending Great Crew change and perceived skills gaps.

However, this year, for many, the theme has been more about job cuts. Bloomberg recently described the latest round of job cuts as the "largest cost cuts in a generation." Cutbacks across the industry total US$180 billion so far this year, the most since the oil crash of 1986, analysts Rystad Energy told Bloomberg.

Despite all that, we're gearing up for this year's SPE Offshore Europe this month (8-11 September), with the conference theme: "Inspiring the next generation," chosen to underscore the importance of attracting new talent into the industry, even when most ***OE*** staffers have heard many times that firms simply aren't hiring right now.

Offshore Europe co-chairman Charles Woodburn told European editor Elaine Maslin last month that the show's theme is as relevant as ever. "We know the market will recover as supply and demand rebalance, and that is a matter of timing."

The worst thing the industry can do now is to cut off our noses to spite our faces. Yes, not all positions lost were either highly-skilled or what is considered core. However, companies need to make sure that they still recruit and train new blood so that the industry won't have the sort of shortages they saw back in the 1980s, and again just four years ago, when engineers with 10-20 years' experience were in short supply. And, also not let rates escalate again, an issue raised by Wood Group's Bob Keiller at SPE Offshore Europe in 2013.

"It's important that we take a long-term perspective and make an assessment not only of today's needs but of future skills needs," says Kevin Higgins, Petrofac, of developing talent in today's environment. "That includes making sure that funding of essential training is continued, and that we work hard to retain graduates. The same can be said for apprentices, and for other key and scarce skills disciplines."

Companies need to re-think how they run their businesses, weed out dead weight, get the good people to train the young, and be leaner.

One of those companies making the case for lean is Hess. In ***OE***'s May issue, Stan Bond, vice president of developments for offshore Americas, Hess, said the industry needs to embrace the principles of lean. "Lean is about transforming leadership, planning, learning and thinking. Ultimately, it's about creating value and eliminating waste," he wrote. "We need to become more efficient. Lean thinking is a lot like the drive to improve safety — you never really get there, but you're always striving to be better, safer, more efficient every day." **OE**

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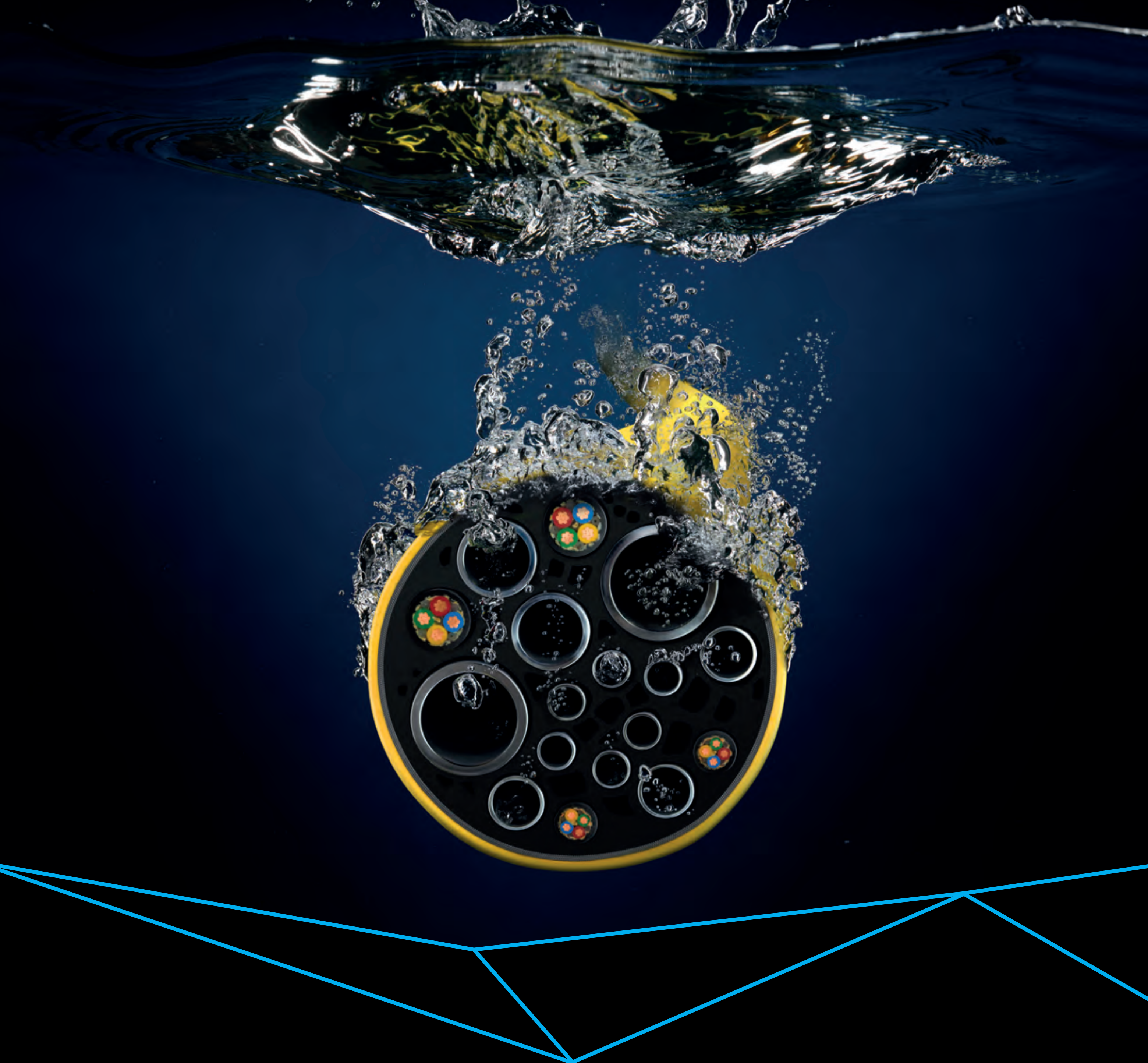

ThoughtStream

Andy Samuel, Chief Executive, Oil and Gas Authority

A new era

The sharp decline in oil prices over the past year has magnified the challenges that companies on the UK Continental Shelf (UKCS) have been grappling with for many years; increasing costs, falling exploration and aging infrastructure, coupled with commercial and legal complexity.

Sir Ian Wood's *UKCS Maximising Recovery Review* concluded that increased stewardship and more collaboration were essential for the industry, giving rise to the swift creation of the Oil and Gas Authority (OGA).

Given the challenging backdrop for our industry, now, more than ever, is the time to create a future of collaboration

We have a real opportunity to identify and remove behavioral barriers, set clearer expectations between organizations involved in the North Sea, learn from positive examples and secure leadership commitment to sustainable cultural change.

One of our first actions was the *Call to Action Report*, published February 2015, which identified two immediate risks resulting from the fall in oil price.

First, the risk of declining profitability in producing fields leading to the premature decommissioning of critical infrastructure. This has the potential to shut down whole areas of the UKCS, stranding valuable resources. To help avoid this, the OGA is working with infrastructure owners and partners to help find solutions in often challenging commercial situations.

Second, the risk that a lack of confidence could result in the failure to secure critical long-term investment in the basin. The US$2 billion (£1.3 billion) package of measures announced in the 2015 Budget provided a welcome boost to the industry and was well received by investors.

Alongside this it is now essential that the industry redoubles its efforts to create a more competitive cost base and increases efficiency.

With significantly fewer new wells planned in 2015, revitalizing exploration is another key priority. We are moving ahead with a $31.2 million (£20 million) government-funded seismic project, which will acquire new high-quality 2D data from the Rockall and Mid-North Sea High. Operations began mid-July, with three vessels in the field acquiring data over 220,000sq km.

"The OGA will be a catalyst for change but we don't have all the answers. We all need to lead the change. We all need to help secure the best possible future for our industry."

At the same time we've moved quickly to establish the OGA. It became an executive agency of the Department of Energy Climate Change (DECC) on 1 April 2015 and is on track to become a government company by summer 2016, subject to the will of Parliament.

The OGA has operational independence from DECC. The OGA's role is to regulate, influence and promote the UK oil and gas industry in order to maximize economic recovery. The energy bill will give us new regulatory powers, including the ability for us to participate in meetings with operators, have access to data, provide dispute resolution and introduce a range of sanctions, such as improvement notices and fines up to $1.56 million (£1 million). I don't expect to have to use these sanctions often; my preference is to work closely with industry to encourage collaboration and facilitate action.

Having already appointed a high-caliber leadership team, we will continue to develop the organization in the coming months, increasing our capability but remaining cost-conscious. I've set an overall headcount cap of 179 employees in order to avoid 'mission creep' and the latest wave of recruitment activity took place this summer.

Making the tripartite approach integral to how we work across the UKCS is the key ingredient in creating a positive future for our oil and gas industry, and I very much welcome the continued commitment of industry and government.

Maintaining a strong and constructive relationship with HM Treasury is critical. Alongside this, Oil and Gas UK and OGA are already working together effectively in a number of areas and I'm keen to build on this.

The OGA will be a catalyst for change but we don't have all the answers. We all need to lead the change. We all need to help secure the best possible future for our industry. We all need to turn commitment into action. OE

Andy Samuel, formerly of BG Group, began his role as chief executive of the UK's newly formed Oil and Gas Authority (OGA) on 1 January this year. The OGA, formed based on the recommendations of the Wood Review, was officially launched in April to instigate a new era of the mature North Sea focusing on maximizing recovery.

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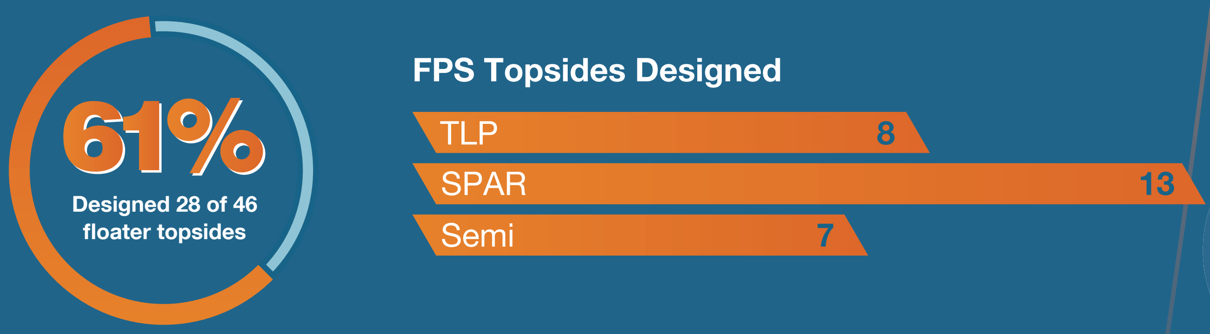

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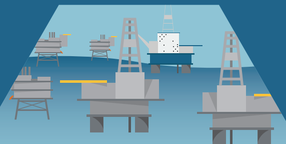

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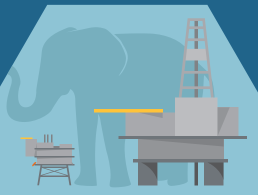

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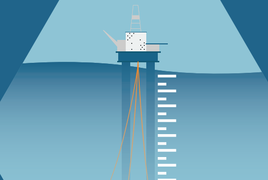

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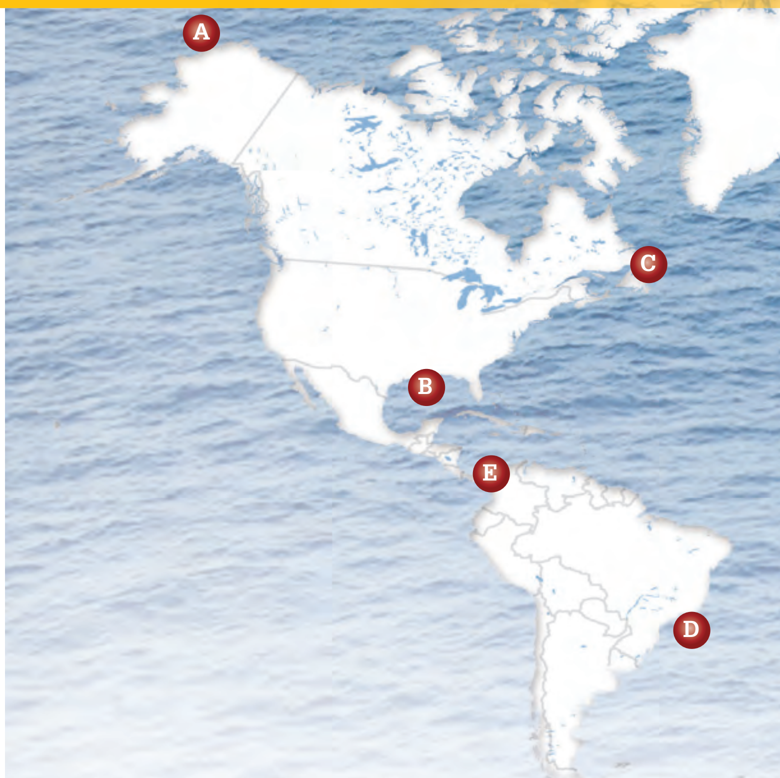


A Shell begins Arctic program

The US Bureau of Safety and Environmental Enforcement (BSEE) has given Shell final approval to drill into deeper into hydrocarbon-bearing zones at its Burger J prospect in the Chukchi Sea. Drilling operations began on 30 July with limited approval to only drill into the top sections of two wells on the Burger prospect, J and V. However, BSEE has not approved Shell to drill past the top sections at Burger V. The Burger prospect is 70mi northwest of the village of Wainwright, Alaska, at 140ft water depth. Shell is using the semisubmersible Transocean *Polar Pioneer.*

B Big Foot delayed

First production from the Big Foot development could be delayed up to 2018, Chevron announced in early August. Problems at the development began in June when work to install the Big Foot tension leg platform was suspended after nine of the 16 tendons lost buoyancy, in an incident that is still under investigation. Big Foot is located in the Walker Ridge area, about 360km south of New Orleans, Louisiana. Chevron operates the development with a 60% interest. Its partners are Statoil (27.5%) and Marubeni Oil & Gas (12.5%).

C West White Rose under assessment

Husky Energy is still assessing potential development options for its West White Rose extension in the Jeanne d'Arc basin, about 300km off the coast of Newfoundland and Labrador. One of two concepts being assessed, a fixed wellhead platform, has received regulatory approval from the Canada-Newfoundland and Labrador Offshore Petroleum Board. But, a subsea option to develop the field extension is also being evaluated. Originally expected to come on stream in 2015, the West White Rose final investment decision was deferred in December 2014.

D Iracema Norte begins production

Petrobras has begun production at the Iracema Norte development following the arrival of the FPSO *Cidade de Itaguaí* at the Lula field in the pre-salt Santos basin.

Petrobras says the 7-LL-36A-RJS well, the first to be connected to the platform, has a daily production potential of 32,000 bbl. The *Cidade de Itaguaí* FPSO will be connected to eight producing wells and nine injection wells. The unit is capable of processing 150,000 b/d of oil, 280 MMscf/d of gas. Petrobras expects to achieve peak production by early 2017.

E Anadarko hits Caribbean pay

Houston-based Anadarko Petroleum hit gas at the Kronos well, in 1584m water, off northwest Colombia. The *Bolette Dolphin* drillship drilled the Kronos-1 well, in the Fuerte Sur block, to 3720m deep, encountering 40-70m of net natural gas pay in the upper objective, and proving the presence of a working petroleum system, Anadarko said. Drilling will continue on Kronos-1 in order to meet a deeper objective. The drillship move next to the Calasu prospect in the Fuerte Norte block, about 100mi northeast of Kronos.

F BP invests in ETAP

BP has begun a US$1 billion investment at its Eastern Trough Area Project (ETAP), in blocks 22/24a and 22/24b, 240km east of Aberdeen in the central North Sea. The project is part of a platform renewal life extension project to see facilities continue through to 2030.

As part of the project, new wells will be drilled on Machar and Marnock fields, subsea infrastructure will be replaced, new technologies will be deployed, and new living quarters will be added to increase personnel on site from 117 to 143.

ETAP's first field was discovered in 1976 and has been producing since 1998.

G Chevron revives Rosebank

Chevron's Rosebank developments, 175km northwest of Shetland, seems to be moving forward once again following an EPCI contract awarded to Bluewater Energy Services by Hyundai Heavy Industries for Rosebank's FPSO turret and mooring system. The Rosebank project was on track until 2013, when partner OMV revealed operator Chevron was rethinking the project to reduce costs. The FPSO will be one of the largest ever designed and built at about 80m-high, with a process manifold/turntable of about 34m-diameter, says Bluewater. The FPSO is due to be competed in November 2016.

H Petronas' Irish probe tanks

Petronas subsidiary PSE Seven Heads' Midleton well offshore Ireland, in the Celtic Sea, has failed to discover commercial quantities of gas. Using Diamond Offshore Drilling's *Ocean Guardian* semisubmersible, the target depth was reached at 3393ft below sea level. Good quality reservoirs were encountered

in the Upper Wealden formations of the Lower Cretaceous, which was water wet, and in the Greensand, which found noncommercial quantities of gas. The well, in SEL 4/07, will be plugged and abandoned.

I Edvard Grieg is on track

Lundin Petroleum's Edvard Grieg field is on track for first oil in 4Q 2015 despite the topside modules installation delay earlier this year, which resulted in the firm revising down its full year production guidance to 32,000 boe/d.

Also, a successful appraisal well was drilled 2.4km from the platform, to help delineate the southeastern part of the field to optimize the drainage strategy and test potential incremental resource.

The field, with 185.8 MMboe gross reserves, is in Block 16/1 in the Norwegian sector of the North Sea and has a field lifetime of about 30 years.

J Israel approves Leviathan plan

The Israeli government entered into an agreement with Noble Energy and the Delek Group to move forward with development plans for the Leviathan field in addition to Karish, Tanin and the further development of Tamar. Noble said the new framework announced in August establishes a foundation for competition, and ensures that Israeli citizens pay a fair price for natural gas.

"The framework also promises a stable investment climate that will enable the continued exploration and production of Israel's offshore resources. Noble Energy welcomes the clarity this framework will bring."

Leviathan, which is one of the largest discoveries in the past decade, sits in the Mediterranean Sea about 130km off the coast of Israel at 1600m water depth.

K Aje edges toward first oil

The Aje 5 production well was spud in late July, in the Aje field offshore Nigeria in the OML 133 license, in the Dahomey basin.

The two Phase I development wells, Aje 5 and Aje 4, are being drilled using Saipem's Scarabeo 3 semisubmersible. Once Aje 5 is drilled, expected to be completed in September, the Scarabeo 3 will move on to re-enter and complete the Aje 4 well.

Peak gross production from the phase I development wells is expected to reach 11,000 b/d using Rubicon Offshore International's Front Puffin FPSO, with first oil targeted for December 2015, said partner MX Oil.

L Eni hits Egyptian gas

Eni encountered gas at the Nooros exploration prospect in the Abu Madi West license, in the Nile Delta, offshore Egypt. The Nidoco NW2 Dir NFW well, which sits 120km northeast of Alexandria, reached 3600m total depth. It encountered a 60m thick gas bearing sandstone interval of Messianian age with excellent petrophysical properties, further of other gas layers in the overlying Pliocene section.

Preliminary estimates show a potential 15 Bcm of gas in place, plus associated condensates.

Eni will be focused on a fast-track exploitation of this potential to fill up the processing capacity of Abu Madi Gas Plant.

M Majors bet on Mozambique

Three majors – Total, Eni, and ExxonMobil – are vying for the same block offshore Mozambique in its fifth licensing round. ExxonMobil, in partnership with Rosneft; Eni, with partners Sasol and Statoil; and Total, have all separately applied for area A5-A in the Angoche basin, offshore northern Mozambique. In total, some 15 areas were included in the round, within the offshore Rovuma, Angoche, and Zambezi areas, as well as onshore areas, together covering 74,402sq km. Rosneft had already revealed its application led by ExxonMobil for area A5-A/B in the Angoche basin and Z5-C/D in the Zambezi Delta late last week. Eni has also both applied for the A5-B area.

N Salman production ramps up

Crude oil production from Salman oil field, which Iran shares with the United Arab Emirates, in the Persian Gulf has increased.

Abbas Rajab-Khani, official in charge of the Iranian Offshore Oil Co.'s operations in Lavan region said that the production hike on Salman came after the company took steps for the development of the field. Five new wells have already been drilled in the field, increasing production by 7000 b/d, and three drilling rigs are currently in operation, drilling new wells or repairing wells that are not currently producing oil, Rajab-Khani said. The field has about 4.5 billion bbl in-place reserves, with 1.6 billion bbl recoverable.

O Hawkeye-1 disappoints

Otto Energy's Hawkeye-1 exploration well, in the Palawan basin, offshore Philippines, reached 2920m TD and will be plugged and abandoned. "The hydrocarbon size discovered is at the very low end of expectations and is not economic to develop," said Matthew Allen, Otto's MD and CEO. The well was thought to contain a best estimate STOIIP of about 480 MMbbl; and 65 MMbbl best estimate net prospective resource.

P Inpex to drill offshore Japan

Japan's Agency of Natural Resources and Energy has chosen Tokyo-based Inpex to drill an exploratory well in the Sea of Japan. Exploratory drilling will take place May-August 2016, 80-86mi (130-140km) from the Yamaguchi and Shimane prefectures. Inpex will undertake a site survey to map the subsea surface and observe currents at the location to prepare for the operation. The objective of the project is to determine the presence of hydrocarbon deposits and conduct geological studies.

Q Cue discovers Ironbark

Cue Energy discovered a new play type, Ironbark, in the WA-359-P permit offshore Western Australia, which the company believes is associated with the prolific gas-bearing Mungaroo Formation. Ironbark has multiple objectives and has been identified as a primary candidate for drilling, the operator Cue said. The company has applied to NOPTA to have the third year well commitment suspended to allow further time to mature the prospect and plan for drilling. A farm-out process is underway to find suitable joint venture partners to drill the well.

R Yolla-6 begins production

The Yolla-6 development well at the BassGas project offshore Australia has commenced production following the successfully tie-in to export facilities on the Yolla platform.

The early, unstablized production rate from the BassGas facilities has now increased to approximately 57 terajoules a day following the addition of the Yolla-6 well. The BassGas project consists of the Yolla offshore wellhead platform connected by pipeline to the gas processing facility at Lang Lang, Victoria. The Yolla platform is located in Bass Strait, some 140km offshore from Kilcunda, Victoria.

S Russia increases Arctic claims

Russia's Ministry of Foreign Affairs has submitted a revised bid claiming 1.2 million sq km of Arctic sea shelf to the UN Commission on the Limits of the Continental Shelf.

Under Article 76 of the UN Convention on the Law of the Sea, Russia argues it has a right to extend its control up to 350nm.

Canada, Norway, Denmark and the US are also attempting to claim territories in the Arctic. The sea shelf is believed to hold a large amount of oil and gas, which Russia estimates could be worth up to US$30 trillion. ▪

Contract Briefs

Sea Trucks in multiple wins

Sea Trucks Group has won two jobs that will commence in 3Q 2015. First, Sea Trucks will provide accommodation support services, lifting operations and installation work to Permaducto S.A. de C.V. using the *Jascon 31,* for works on the KMZ68/69 project from Pemex for 95 days plus options. The DP3 accommodation construction vessel will start sailing soon from West Africa to the Gulf of Mexico.

For the second contract, in Brazil, Sea Trucks will provide accommodation support services to Saipem for 300 personnel, including lifting operations, storage support and logistic support services for modifications works of an FPSO. The recently upgraded DP3 accommodation support vessel *Jascon 28* was selected for the work, with the contract set for a minimum period of four months.

DOF Subsea bags IMR contract

DOF Subsea North America has been awarded an inspection, maintenance, and repair contract from Freeport-McMoRan for a period of six months firm.

The operations will commence immediately and the vessel *Harvey Deep Sea* will be utilized under the contract. The *Harvey Deep Sea* is an ABS-classed DP2 multipurpose construction vessel. The vessel is under a long-term charter agreement between DOF Subsea and Harvey Gulf International Marine.

Keppel inks third GoFLNG conversion

Keppel Shipyard has signed its third contract with Golar LNG worth approximately US$684 million for a floating LNG conversion.

Keppel Shipyard will convert Golar's Moss type LNG carrier, the *Gandria*, into a Golar Floating LNG (GoFLNG) facility.

Notice to proceed with the conversion is expected in 2016 and will take about 31 months. The *Gandria* conversion is to be used by Ophir Energy on its Fortuna development in deepwater Equatorial Guinea, with delivery expected in 2019.

DONG signs up Maersk Giant

Denmark's Maersk Drilling has been awarded a new contract for the jackup rig Mærsk Giant with Danish energy utility DONG Energy.

The contract covers 150 days of work on the Nini and Siri field in the Danish part of the North Sea. The estimated contract value is US$16 million.

The contract is in direct continuation of the current contract with Talisman keeping Maersk Giant employed until March 2016.

OSBIT wins Helix contract

Helix Well Ops UK awarded OSBIT Power a contract to deliver new support structures and deck equipment for two of its new well-intervention vessels.

The contract will support Helix's well intervention operations on *Siem Helix 1* and *Siem Helix 2*.

Each vessel will be supplied with a collection of three systems, a maintenance and storage tower, BOP support stand and moveable deck.

The structures and equipment will be delivered to Helix in early 2016 ready for installation on the vessels. ■

Forty and still 'a beaut'

Photo by Paul Thomson.

40 years of OE

For OE, 2015 is a milestone year – it's our 40th anniversary. We share that milestone with one of the world's most iconic oil fields – the UK North Sea Forties field. Elaine Maslin charts the field's history and finds out what the future holds.

Forties is no ordinary oil field. In fact, for some, Forties is an individual – a field with character, personality and presence. For Apache operations director Bob Davenport, "she's a beaut" and, while she's 40 years old, she sits as the third largest oil producer on the UK Continental Shelf, with plenty of life left in her.

Concluding his presentation on the 40-year-old field at the DEVEX conference in Aberdeen earlier this year, Jeff Towart, Apache's North Sea region exploitation manager said, "In 10 years' time, someone will be presenting 'Forties hits 50,' and it will still be going strong."

A basin opener

Forties' reputation comes not just from its sheer size. The central North Sea field was discovered at a time when many had about given up on the North Sea. "Back in the 1960s, gas had been found in the southern gas basin," Towart says. "Then there was a push northwards [for oil]. But, by the end of the 1960s, the industry was getting a bit disheartened with some of the disappointing results up there."

Sea Quest's discovery was celebrated with a cake which took 700 hours to make. Photo from BP.

In fact, in 1969, renowned geologist Miles Bowen was quoted as saying all the worthwhile gas fields in the southern North Sea had been found, while the search for oil in the North was doomed for failure, Towart says. Bowen wasn't alone in holding that view and even Sir Eric Drake, BP's chairman and CEO, said in April 1970 "there won't be oil there."

Nevertheless, BP held out and in October 1970, the *Sea Quest* semisubmersible drilling rig discovered Forties, in the South Viking Graben, 110mi east of Aberdeen, in 350ft water depth, with some 4.2-5 billion bbl in place. "This was a huge boost to the UK at the time," Towart says. "Forties (named after the sea area it sits in) and some fields discovered shortly after squarely put the North Sea on the map as a major oil province. Forties really kicked off the offshore North Sea oil industry."

1975 start-up

After a frenzy of construction activity, production started in September 1975, from Forties Alpha (initially known as Graythorp I) platform, flowing to shore in November – an occasion marked by Queen Elizabeth II. Forties Alpha was the first oil platform installed on the UK Continental Shelf. Brown & Root was the main contractor, and by the end of 1975, the first four Forties platforms were installed: Alpha, Bravo (which was known at the time as Graythorp II), Charlie and Delta, (which were known as Highland I and II, respectively). The Graythorps were built

at Laing Offshore, near Hartlepool, and the Highlands at Highland Fabricators at Nigg Bay on the Cromarty Firth. In 1979, production peaked at 550,000 b/d, higher than initial predictions. In 1986, Forties Echo was installed, followed by the Unity riser platform in 1993.

Forties Alpha, Charlie and Delta are self-contained drilling, production and processing units, with Bravo no longer processing fluids, but directly exporting them to Charlie for processing. Echo, having no processing facilities, exports its production fluids for processing via the Alpha platform. Charlie acts as a gathering platform. Processed fluids are exported to Cruden Bay and onwards to Kinneil via the Forties Pipeline System.

When production started in 1975, it was predicted Forties would stop producing in the early 1990s. By 1990, that was moved forward to 2000. Projects like the Forties Artificial Lift Project in the early 1990s, with gas lift and electrical submersible pumps, helped extend the field's life, and, as of 2002, Forties had produced about 2.5 billion boe, somewhere a little more than 50% of its reserves.

Then, BP decided to sell the field, its "crown jewels," for US$683 million to Apache. At the time, Forties was producing 41,000 boe/d and the remaining reserves were estimated to be 144 MMboe, with field life expected to end in 2012.

A new start

What happened next was a huge success story. Apache has gone on to produce about 240 MMbo (120 MMbo from Apache drilled wells) from Forties and thinks there's another 100 MMbo to be had, Davenport said, speaking at SPE Annual Technology Conference and Exhibition last year.

Investment

A huge piece around Apache's success on Forties has been investment. Since 2003, Apache has spent some $5 billion on Forties' infrastructure and drilling, bringing four drill strings back into use, as well as investing in everything from the cranes through to the export pumps and a new gas and power ring main around the field – until then each facility was powered locally – with four new gas-powered turbines installed (20 older units could then be removed), and issues that beset the export system were also resolved. All of which has helped increase production efficiency and lifting costs.

The year after the field was scheduled to cease production, Apache installed a new platform, the Forties Alpha Satellite Platform (FASP), adding 18 new wells slots and increasing compression, power generation and processing capacity.

As a result, in 2012 through 2014, Forties ranked as the second highest producer in the North Sea, compared to 10^{th} in 2003. And the investment continues.

For Towart, the key drivers to the success of the field has been adding new barrels through the drill bit and ensuring they get produced efficiently while replenishing the target inventory and continuing steady capital investment.

Drilling

"Often people characterize the success at Forties around the aggressive drilling program," he says. "The drilling program has averaged about 13 wells per year over the last 10 years. Last year, we drilled 17 wells. We had five consecutive drill strings running in the field and that was a new record in Forties history." Some 75%

A BP Archive photo from Forties from the 1970s. Reproduced with permission from BP Archive

Forties Alpha and the FASP facility. Photo from Apache.

of current production is from Apache-drilled wells.

Apache has also broken flow rate records on the field. In 2009, Apache flowed the Charlie 6-3 well at an initial rate of 10,500 b/d, the highest initial rate from a Forties well since 1994. That record was broken again in 2011, with Charlie 4-3 reaching 12.567 b/d.

"What the drilling has allowed us to do is create a late-life production plateau of about 40-60,000 b/d," Davenport says, adding that many of these wells have been sidetracks, but Apache has also invested in downhole surveillance.

Drilling on Forties in the 1970s. Photo from BP.

This year Apache is drilling 14 wells, with 10 planned for next year. These will be drilled from the platforms and the Rowan Gorilla VII heavy-duty jackup rig drilling from the FASP.

Production efficiency

"It's not all been about drilling wells," Towart continues. "There's been a strategic focus on production efficiency from early on. In 2013, production efficiency was about 64% [around the current North Sea average]. That has been increased to more than 90%. In fact, in 2012-13, Apache ranked No. 1 for production efficiency in the North Sea, which is remarkable given that these are some of the oldest assets [in the basin]. That has really been done through huge brownfield investment from 2003-2009. To put it in perspective, if production capacity is 60,000 b/d and we increase efficiency from 65% to 90%, that's like adding 15,000 b/d to production. That's adding value." The investment has also helped reduce lifting costs to 45% less than the average in the basin.

Replenishing the inventory

But, Towart says if some of Forties' success can be characterized by aggressive drilling, really the field's story is around the portfolio growth, over time. When Apache bought the field, there were 38 targets in the portfolio, he says. During the redevelopment, 153 wells have been drilled, including sidetracks, and there are still 63 in the portfolio, he says – the target inventory keeps growing.

Key to the target replenishment is continued investment in seismic, Towart says. The first 3D seismic was shot over the field in 1988 – after 60% of the oil reserves had been produced. Apache shot more in 2005, 2010 and then 2013, with the next 4D shoot planned for next year.

Over the years, improvements in acquisition technology and processing and interpretation techniques, have helped build a clearer map of the field. "To make 4D successful we are continually trying to improve 4D processing and that's really about noise levels and repeatability," he says. The data had some 30-40% noise in 1998-2000. That's now been attenuated and is down to around 7%, he says, through better repeatability and matching. The better data is having results at the drill bit. "We are finding success rates in the field have climbed from about 78% to about 90% in the last year," Towart says, thanks to these improvements.

But, it also helps having a world-class reservoir, he says. Forties is a Late Paleocene-aged turbidite channel complex deposited in a proximal submarine fan location, with a high degree of complexity

Quick stats

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

New discoveries announced

Depth range	2012	2013	2014	2015
Shallow (<500m)	74	72	70	26
Deep (500-1500m)	23	19	27	10
Ultradeep (>1500m)	37	35	13	8
Total	134	126	110	44
Start of 2015	135	125	90	-
date comparison	-1	1	20	44

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

Reserves in the Golden Triangle

by water depth 2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	7	27.75	333.28
Deep	12	941.00	2195.00
Ultradeep	40	10,923.75	12,450.00
United States			
Shallow	15	86.30	234.00
Deep	17	984.27	980.48
Ultradeep	24	2746.50	3380.00
West Africa			
Shallow	115	3762.45	15,969.22
Deep	37	4622.50	5540.00
Ultradeep	13	1635.00	2160.00
Total	273	25,701.77	42,908.70
(last month)	(282)	(25,614.52)	(46,991.98)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	909	38,925.88	561,960.78
(last month)	(923)	39,108.06)	(569,033.78)
Deep	120	7625.58	71,715.91
(last month)	(125)	(7504.58)	(109,705.91)
Ultradeep	81	15,333.25	30,957.00
(last month)	(81)	(15,333.25)	(31,257.00)
Total	1110	61,884.71	664,633.69

Pipelines

(operational and 2015 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,385	(41,141)
Planned/ possible	24,891	(25,103)
	66,276	(66,244)
8-16in.		
Operational/ installed	81,917	(81,883)
Planned/ possible	50,024	(49,837)
	131,941	(131,720)
>16in.		
Operational/ installed	92,612	(92,612)
Planned/ possible	44,140	(44,140)
	136,752	(136,752)

Production systems worldwide

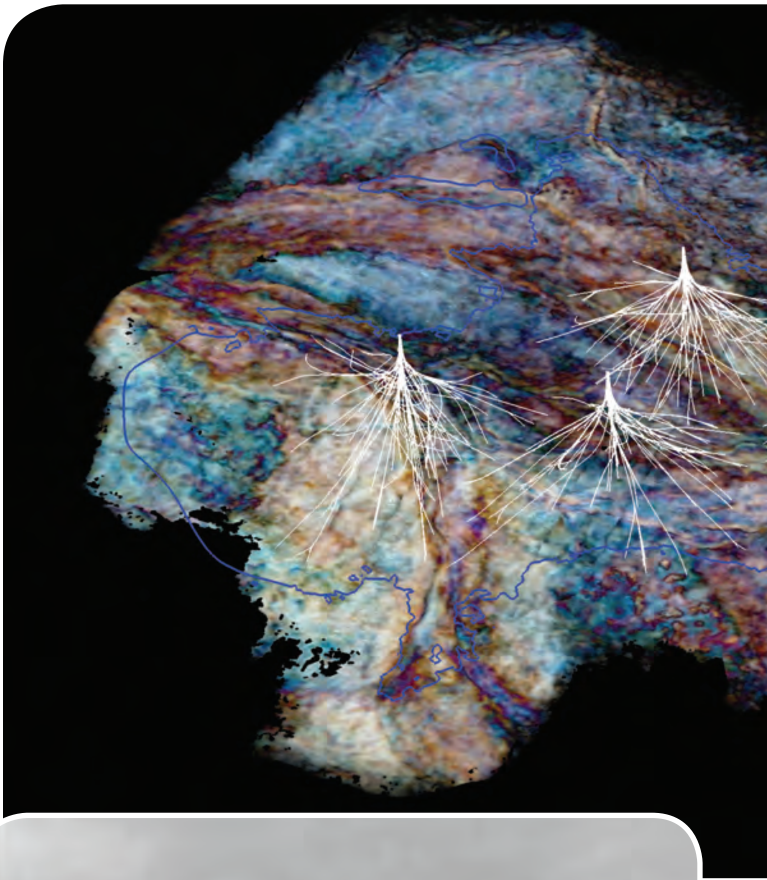
(operational and 2015 onwards)

Floaters		(last month)
Operational	273	(273)
Under development	47	(47)
Planned/possible	320	(320)
	640	(640)
Fixed platforms		
Operational	9241	(9232)
Under development	92	(94)
Planned/possible	1378	(1387)
	10,711	(10,713)
Subsea wells		
Operational	4744	(4775)
Under development	467	(445)
Planned/possible	6471	(6474)
	11,682	(11,694)

Global offshore reserves (mmboe) onstream by water depth

	2013	2014	2015	2016	2017	2018	2019
Shallow	42,232.00	14,492.13	39,896.31	28,928.21	17,910.82	25,877.08	25,385.13
(last month)	(22,904)	(14,233.51)	(40,181.52)	(29,444.97)	(18,549.54)	(25,954.66)	(25,295.93)
Deep	480.55	4469.26	4340.71	2371.84	2150.66	4921.92	6484.04
(last month)	(481.00)	(4,469.26)	(4,340.71)	(2,371.84)	(2160.95)	(4836.00)	(13,133.29)
Ultradeep	2928.44	2342.81	1929.58	3034.17	3287.44	5221.54	7318.54
(last month)	(2928.00)	(2342.81)	(1929.58)	(3257.38)	(3812.64)	(4473.13)	(8519.40)
Total	45,640.99	21,304.20	46,166.60	34,334.22	23,348.92	36,020.54	39,187.71

10 August 2015



A BP Archive photo from Forties from the 1970s. Reproduced with permission from BP Archive .

influencing the flow behavior but also providing traps of by-passed oil accumulations that remain unswept.

Nearfield development

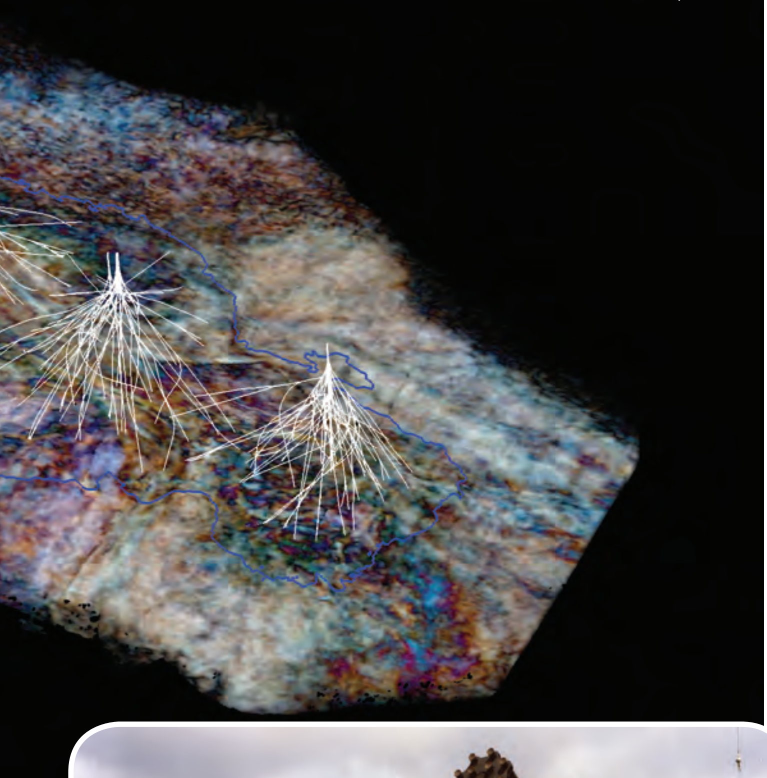
Other ways Apache has been adding value is through near field development. The Maule field came onstream in 2010, Bacchus, the first subsea tieback to Forties, came on in 2012, Tonto in 2013 and the latest, Aviat, is due on stream in 2016.

Aviat will be a bit different. It is a two-well, 23km tieback fuel gas supply project for Forties – and yet another project to maintain field-wide efficiency. Many North Sea facilities are finding, as they age and gas supplies deplete, they require diesel as a fuel supply. Having installed the ring main around the Forties platforms early in its operation of the field, Apache has been looking for a new source of gas, which Aviat will provide, providing up to 19 MMscf/d of fuel gas.

Culture

For Apache, the success at Forties isn't just about technology or

Beneath the surface on Forties. Photo from Apache.



A BP Archive photo from Forties from the 1970s. Reproduced with permission from BP Archive .

investment. For Projects Group Manager Mark Richardson, what sets Apache's Forties business apart is the firm's approach to leadership, culture and behavior: "Our ability and flexibility to understand the opportunities available is central to this culture. So, we encourage risk taking, not safety risk, but around commercial, contractual, technical, reservoir, subsurface and project opportunities, because where you take risk, there is often reward."

Towart says: "It is about nimble decision-making and pushing the decision-making process down through the organization, focusing on the right projects, risk-taking, personal initiative, and a sense of urgency."

A healthy future

Forties, a field that had been scheduled to cease production in 2013, is a prime example of big fields that get bigger. Drilling and investment in the field, a core and profitable asset for Apache, even in today's tough oil price environment, continues.

In the right hands, "Forties has hit 40 and it still has a lot of value to be gained," Towart says. **OE**

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	111	91	20	81%
Jackup	406	308	98	75%
Semisub	157	119	38	75%
Tenders	31	20	11	64%
Total	705	538	167	76%

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	37	35	2	94%
Jackup	71	51	20	71%
Semisub	20	16	4	80%
Tenders	N/A	N/A	N/A	N/A
Total	128	102	26	79%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	15	8	7	53%
Jackup	118	79	39	66%
Semisub	34	18	16	52%
Tenders	19	12	7	63%
Total	186	117	69	62%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	29	24	5	82%
Jackup	9	7	2	77%
Semisub	30	26	4	86%
Tenders	2	1	1	50%
Total	70	58	12	82%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	50	43	7	86%
Semisub	44	38	6	86%
Tenders	N/A	N/A	N/A	N/A
Total	94	81	13	86%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	109	95	14	87%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	114	98	16	85%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	22	19	3	86%
Jackup	23	17	6	73%
Semisub	13	9	4	69%
Tenders	10	7	3	70%
Total	68	52	16	76%

Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	6	4	2	66%
Jackup	26	16	10	61%
Semisub	12	9	3	75%
Tenders	N/A	N/A	N/A	N/A
Total	44	29	15	65%

Source: InfieldRigs

11 August 2015

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

FPS market expected to rise

Spending on floating production systems is expected to increase 73% in 2015-2019, with US$81 billion due to be spent over that period. Douglas Westwood analyst Ben Wilby sets the scene.

Douglas-Westwood (DW) forecasts that between 2015 and 2019, $81 billion will be spent on floating production systems (FPS) – an increase of 73% over the preceding five-year period. A total of 110 floating production units are forecast to be installed – a 41% increase.

A continuing trend towards newbuilds and conversions compared to redeployments as well as projects that have already been sanctioned will ensure that spending in the sector will remain high over the forecast period.

While the FPS market will still grow, this growth is significantly less than expected due to the collapse in oil prices and installations in 2018 will decline significantly as a result (i.e. there is a dip in orders expected in 2015 and we anticipate that this will last well into 2016 with the impact on installations being seen in 2018.

Market forecast

Floating production, storage, and offloading (FPSO) units represent by far the largest segment of the market in terms of numbers (87 installations) and account for 81% of the forecast capex. Tension leg platforms (TLP) account for the second largest segment of capex (9%) with FPSs third (7%). The smallest segment, spars, has a forecast capex of $2.9 billion (2% of the total forecast capex).

The forecast period highlights the continued increase in TLP installations and capex, continuing on from 2014, which saw two TLPs, the Olympus and P-61 units, installed. While no units were installed from 2010-2013, 10 TLPs with a total capex of $7.6 billion are expected to be installed over the period.

Latin America

Latin America accounts for 28% of the 110 installations forecast and 32% of the projected capex, with the majority of these units

BG Group's *Knarr FPSO*, moored offshore Norway. Photo from Teekay.

being FPSOs. The disparity between the two figures is from Latin America having higher than average capital costs compared to other regions due to Brazil's higher proportion of expensive deepwater projects and high local content requirements. While the region is expected to have the highest capex, it is unclear whether this will continue into the 2020's with the low oil price adding to ongoing problems faced by Brazilian operator Petrobras. These include a status as the world's most indebted company and a corruption scandal that has engulfed much of the oil and gas industry in the country. All of these issues are likely to have an impact on the capital the company can assign to new units, but are unlikely to affect the numerous sanctioned projects due to Petrobras having plans in place that ensures units are ordered many years before they are required.

Shell's Bonga North West deepwater project. Photo from Shell.

FPS expenditure to total $81 billion over 2015-2019 period

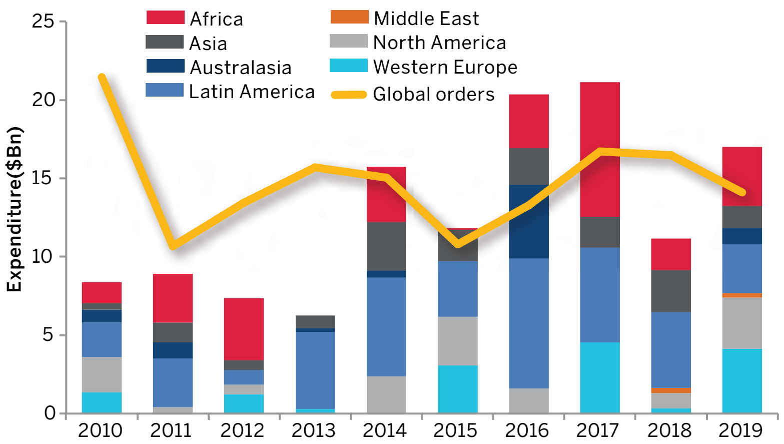


Figure 1: Global FPS Installation Capex by Region 2010-2019
Source: Douglas-Westwood, World Floating Production Market Forecast 2015-2019

Africa

Africa will be the second largest region for spending over the forecast period with a capex of $17.8 billion (22%). Like Latin America, a large proportion of installations will take place in deepwater and this will continue to drive spend in the region. The impact of deepwater will be particularly prevalent in 2015-2017 when a number of >1000m water depth fields are anticipated to come onstream. After this there will be a drop in capex as the impact of a low oil price impacts the market. This will hit the frontier area of East Africa hardest due to the unknown nature of developments in the area, and as a result, East Africa will have extremely limited deepwater production over the forecast period. If it was not for this East African-led drop in capex, Africa would likely have been close to Latin America in spend and possibly overtake it as the region with the highest FPS capex.

Asia & Western Europe

Although Asia has more installations (25) forecasted than Africa (20), it will account for only $10.4 billion (13%) of global capex. This is due to the majority of units being located in relatively shallow water and benign environments, requiring more straightforward FPS designs and hulls sourced from converted vessels, which are usually cheaper than newbuilds. This is unlikely to change over the forecast period with major deepwater developments such as Chevron's IDD project seeing delays.

Although a predominantly shallow water region where fixed platforms are utilized, Western Europe is expected to see a respectable number (19) of FPS installations over the next five years. Some of these projects revolve around the rejuvenation of mature producing areas.

Key demand drivers

Three main factors are driving the sustained FPS sector growth:

- Move to deepwater;
- Development of complimentary production technologies;
- Marginal field development and early production systems.

As shallow water opportunities become increasingly scarce, the development of deepwater reserves will accelerate rapidly. For a field in deepwater, FPS is the development method of choice, since fixed platforms are often ruled out on technical and/or economic grounds.

As a result, floating production expenditure in deepwater is expected to total $55 billion over the 2015-2019 period, 68% of the value of the global FPS market. Deepwater capex would likely have been more significant if the oil price had remained high, but since deepwater developments generally cost more they are more likely to be deferred until there is a favorable oil price. As a result, much of the capex in deepwater will come from projects that have already been sanctioned.

Considerable versatility enables FPSs to be used for a variety of different applications besides conventional life-of-field production. These include extended well testing (EWT), early production systems (EPSs) and rejuvenation projects.

FPSOs are also an attractive solution for marginal field developments, particularly where an existing unit can be renovated,

The FPSO *Cidade de Ilhabela* is producing the Petrobra-operated Sapinhoá field. Photo from BG Group.

modified and redeployed at a significantly lower cost than a newbuild. This is something that can be seen in a number of projects in Western Europe and this trend will likely increase in the future as frontier areas such as East Africa or the Arctic are developed.

Lease versus own

Three main factors will affect the supply of units in the FPS sector:

- Financing;
- Local content;
- Leasing.

Financing remains a challenge for leasing contractors and smaller exploration and production companies, as a result of the lower oil prices which have placed additional strain on company budgets and greater efforts are being made to ensure delays and cost over-runs are avoided to maintain project economics. At the same time local content requirements are pushing up prices and extending lead times, particularly in Brazil.

For the oil company field operator, FPS ownership becomes the more cost-effective option where production extends over a long period. However, given the current macroeconomic environment, such capex commitments may be deferred. Therefore, the decision to lease an FPS can be seen as a trade-off between the lower upfront capex and the increased operational expenditures as a result of the leasing charges. However, leasing also brings advantages in terms of the cost of field abandonment.

The top three leasing contractors are SBM Offshore, MODEC and BW Offshore, which collectively account for 35% of the leased fleet. The FPSO leasing sector has seen slight improvements with 87% utilization at present. However, the sector continues to be affected by severe project delays and cost over-runs, with contractors still reporting write-downs on new projects.

Dealing with delays

The FPS supply chain is causing concern amongst investors and exploration and production companies. The challenges in delivering large and complex production systems on time and on budget are such that cost over-runs have become the norm and delays in both project sanctioning and project execution are more common than delivery on time. The industry is looking at ways of approaching FPSO projects differently, perhaps through a standardized approach to FPSO engineering.

Local content requirements are also causing delays in project execution and cost overruns. The ambition of creating value and employment locally will need to be balanced with the need to have an efficient, competitive and competent supply chain. These ambitions may continue to prove to be mutually exclusive. Political risk often compounds the challenges of local content requirements, with issues such as unstable fiscal regimes, changes of government and regional conflict present in a number of upstream environments worldwide.

Conclusions

The oil price collapse will have a significant effect over the forecast period, leading to significantly less spending than would have been expected if oil had stayed at a high price. Orders in 2015-2016 will be the most affected, with a knock-on effect on 2018 installations. Up until the oil price collapse, the FPS sector recovery following the 2008-2009 downturn had continued steadily. A total of 68 units were ordered in 2011-2014 compared to 23 units during the downturn.

According to DW, there are 51 units in-build at present – a slight decrease compared to DW's last edition of the report. With fewer units expected to be ordered, a downward trend may be seen for the next few years.

Marginal, deepwater and remote fields will continue to be areas of focus for the exploration and production industry and FPS units are a key enabler for production. Growth in these areas will however be tempered by the low oil price.

There is upside potential, if the supply chain can deliver and if the operators are willing to move ahead. DW are tracking more than 160 FPS deployment opportunities and have taken a realistic appraisal of these projects to arrive at our forecast of 110 installations. Ultimately, FPSs are likely to remain the only option for deepwater oil developments for the foreseeable future and an attractive proposition for marginal and remote fields. Given the increasing reliance upon reserves in these areas, we have confidence in the long-term proposition of the FPS sector, despite the current risks and disruption that are evident.

Ben Wilby joined Douglas Westwood as a researcher and primarily works on the continual updating of the Offshore Oil and Gas Database and is one of the authors of The World Floating Production Market Forecast 2015-2019. Ben graduated from the University of Chichester with a degree in History.

FPSOs shine bright in down market

In advance of OE's 2015 Global FPSO Forum, in Galveston, Texas, Audrey Leon speaks with the event's co-chairs – SBM Offshore's Jim Wodehouse and Endeavor Management's Bruce Crager – to discuss topics affecting the FPSO sector.

While most news these days concerning the oil and gas industry is gloomy, one sector looking past the clouds is the FPSO market.

In June, Consultancy Visiongain reported it expected global capital spending on newbuild and converted FPSO vessels to reach US$8.65 billion this year, with the largest spend focused on South America and West Africa. Even Brazil – despite much uncertainty due to recent scandals – continues to be one of the hottest players in the market.

At the end of July, production began at the FPSO *Cidade de Itaguaí* on Petrobras' Iracema Norte development. Investment firm Simmons & Co. said in a report early August that the Iracema Norte project was originally expected to be completed in 4Q 2015, but was completed ahead of schedule. Additionally, Simmons reports there are three additional FPSOs that are in the integration process and expect to see first oil in 2016. The firm puts the Lula Alto development (Petrobras 65%, BG 25%) at a 1Q 2016 start, followed by Lula Central in 2Q, and Lapa in 4Q 2016.

Cidade de Itaguaí, converted by MODEC in consortium with Schahin, is 332m-long, 31m-high, and 58m-wide, and weighs 82,000-tonne. The FPSO is capable of processing 150,000 bo/d, 280 MMscf/d of gas. It is able to store 1.6 MMbbl of fluids, and inject 264,000 b/d of water.

Also in June, research analysts Douglas-Westwood said they still expect FPSOs with a total value of $60 billion to be installed from 2015-2019. However, the firm noted the effect of the downturn on the FPSO market in 2015, citing at the time that only three contracts have been awarded. However, those three contracts accounted for some $1.5 billion in spending. Douglas-Westwood forecasts that four more awards are likely this year while a further five could potentially be awarded if there is an improvement in the oil price.

OE: Despite the downturn in oil prices, many reports suggest a promising future for the FPSO market. What is your take on the current market?

Jim Wodehouse, strategy development manager, SBM Offshore: The fundamental benefits of the FPSO, such as; deepwater and ultra-deepwater mooring capability, large riser capacity for complex subsea configurations and subsea tiebacks, suitable hull size for large topsides to accommodate complex processing requirements, and large oil storage capacity for remote regions, are all features which will ensure a promising future for the FPSO. Of course, the near-term demand for new FPSOs is depressed due to the low oil price, but I am confident that the inherent flexibility of the FPSO concept will enable the industry to adapt to the new market conditions.

Bruce Crager, executive vice president, Endeavor Management: Although the current supply and demand for oil and gas is out of balance, the world will continue to need fossil fuels for many years to come. Everyone in the world who has cars, electricity, and other basic services want to keep them. Therefore, growth in the world's population ensures increased energy needs in the future. FPSOs are a very practical way to meet the long term need for energy. I believe the FPSO market will grow independent of oil price, although some projects may be

Shell and partner Esso Exploration agreed to sell their 50-50 stakes in the Anasuria Cluster, including the *Anasuria* FPSO, in the UK Central North Sea, to a Malaysian joint venture consisting Ping Petroleum and Hibiscus Petroleum in August. Photo from Shell.

Bruce Crager

delayed in the near-term. FPSOs can be used anywhere in the world and in any water depth beyond 50ft. They are used in marginal fields as well as large fields producing over 200,000 b/d. In addition, they are more easily relocated and reused than other types of offshore facilities. Therefore, the longer term future for FPSOs is very positive.

OE: Are there any new innovations that the market can expect to see over the next few years?

Wodehouse: In order to adapt the FPSO concept to the new market conditions, there will need to be changes to the contracting and business models, as well as new technology innovations. Strategic frame agreements, standardization of technical requirements, and consistent contractual terms, between the oil companies and the main FPSO contractors, and between the main FPSO contractors and their main suppliers, will be key to reducing costs, schedule and risks in future projects. New technology innovations will include greater use of steel risers to meet the challenges of the HPHT wells, application of enhanced oil recovery (EOR) technology to increase oil recovery from the reservoir, and increased use of onshore gas processing technology "marinized" for gas FPSOs, LNG FPSOs and challenging gas compositions on large oil FPSOs.

The *Cidade de Itaguaí* FPSO is the latest vessel to come onstream at Petrobras and BG Group's Iracema Norte development. Anchored 240km off the coast of Rio de Janeiro, in about 2240m water depth, the FPSO is connected to eight production wells and nine injection wells. Photo from BG Group.

Crager: Technology related to FPSOs continues to be developed in several areas. These include a) mooring and turret improvements, such as higher pressures, deeper water moorings, and improved disconnectable designs for difficult areas, such as those with hurricanes and ice; b) improved process systems for heavy oil and crudes with H_2S and CO_2; and c) improved methods to evaluate the condition of FPSOs and extend their life in the field. "Stranded gas" is still an issue in many fields and improvement in FLNG and more reasonably priced gas to liquids technology should help solve this problem

OE: What's the greatest challenge facing FPSOs?

Wodehouse: Ensuring that, even with the pressure to reduce costs, the increasingly complex FPSOs of the future are delivered on time and on budge, and are capable of being operated in a safe, reliable manner.

Crager: Cost overruns and delayed delivery are clearly issues in the industry and many FPSO projects have suffered from these type of problems. Operators and FPSO leasing companies have tried various commercial and delivery models to overcome these issues. Unfortunately, there have been a number of companies who have converted FPSOs but had no prior experience so they are more likely to have problems than the more experienced contractors.

The basic practices of large projects still apply to FPSO projects and when followed, will help avoid cost and delivery problems. These basic principles include rigorous engineering before starting construction, 3D modeling, minimizing changes, ordering long lead items as soon as possible, and working with experienced contractors. Functional vs. company-generated specifications can also help minimize cost and delivery problems. Standardization is being promoted, but the industry, particularly the larger operators, often stay with their own specifications and practices as opposed to more standardized industry guidelines/requirements.

OE: With the opening of Mexico's energy market, what is the outlook for FPSOs in this sector? At last year's Global FPSO forum, Crager said with regards to deepwater development that there is a need for this technology. What's your take now? Will Mexico be the next big area for FPSOs?


Jim Wodehouse

Wodehouse: The opportunity for the use of FPSOs in the deepwater offshore Mexico is tremendous, and although that market has been slower to develop than we all hoped for, the resource appears to be there and the FPSO industry has the capability to meet the challenges, so it will happen, the question is how soon.

Crager: I presented an overview of FPSOs in Mexico at last year's Global FPSO Forum based on the current and planned FPSO activities at that time. Little has changed. There are still several FPSO projects under consideration by Pemex, such as the large FPSO and the extended well test FPSO for the Ayatsil Tekel field. In addition, the deepwater lease areas that are expected to be offered later this year should be logical locations for FPSOs if they are found to be of commercial interest.

The technology issues I mentioned above will be important to FPSO development in Mexico, including heavy oil processing, dealing with H_2S and CO_2, and disconnectable moorings due to hurricanes. Mexico could be a major area for FPSOs, but having other operators come into Mexico under the new leasing program will be an important step. These new operators will bring funding, active exploration programs, and are likely to have experience with FPSOs from other parts of the world. OE

The Global FPSO Forum returns to Galveston, 15-17 September 2015. Visit globalfpso.com to find a list of speakers and conference agenda.

A stabilizing design

Audubon Companies' Denis Taylor and LLOG Exploration's Craig Mullett discuss changing design considerations for condensate stabilization on the Delta House FPS in the Gulf of Mexico.

Coping with unexpected engineering challenges during the design and development of infrastructure is something that is inherent in the deepwater offshore oil and gas industry.

Case in point: LLOG Exploration's Delta House floating production system (FPS) in the Gulf of Mexico (GoM).

Delta House, in Mississippi Canyon Block 254, was built under a rather unique set of circumstances. Unlike the conventional approach taken by most offshore operators, which involves delineating wells and studying reservoir composition before detailed design and construction begins, work on Delta House started

Delta House. Image from LLOG Exploration Co.

before a discovery was even made. Part of this was due to the fact that the 20 or so deepwater leases acquired for production by LLOG in 2010 were set to expire in early 2014 – requiring expedition of the entire construction process so that the FPS could be brought online and wells could be drilled within 36 months.

In order to achieve this milestone and keep pace with the highly aggressive production schedule, topsides engineering contractor Audubon Engineering Solutions had to begin front-end engineering design (FEED) efforts before reservoir characteristics were defined.

Assuming a reservoir composition similar to a nearby analogous field (GOR of ~2000 scf/bbl and 28-32°API), the initial design included routing liquids from compressor scrubbers to production separators with lower operating pressures – a method commonly used on offshore facilities to reduce liquid recycle and minimize compression requirements.

During this initial design process, however, a well sample phase behavior (pressure, volume, temperature or PVT) analysis conducted by a third-party laboratory revealed that the reservoir contained a stock GOR of approximately 2300 scf/bbl and a crude oil gravity of 38°API – a substantial deviation from the previously assumed composition. The analysis also indicated that reservoir fluid was rich in condensates, including propane (C3), butane (C4), and pentane (C5), resulting in a much larger liquid recycle and higher compression requirements in order to meet oil pipeline Reid vapor pressure (RVP) specifications. Although Audubon Engineering Solutions and LLOG were suspicious whether this data was entirely accurate, given the unusual numbers, they proceeded under that assumption that if it were even remotely indicative of the reservoir's composition, a conventional liquids handling philosophy would be impractical and other options would need to be explored.

Liquid handling options

When considering a new liquid handling design approach, two options were examined. The first option was to retain much of the equipment used in the original design and add a condensate processing train in order to dehydrate the condensate from the scrubbers before pumping it into the gas export pipeline. This approach would effectively eliminate the recycle loop and reduce compression requirements, but a lower volume of sales oil would be produced.

The second option included a complete overhaul of the original design by replacing much of the topsides equipment with a crude stabilizer. This would enhance separation of the condensates, reduce compression, and allow RVP specifications to be met. The process itself, however, was overly complex and required a great deal of heat in order to operate. The necessary equipment presented structural concern due to its weight as well.

During the process of evaluating these options, efforts were made to replicate the data from the initial PVT analysis in a process simulator. When it could not be done, a second analysis was ordered to confirm the suspicion that the data was incorrect. As expected, the second analysis revealed that the reservoir composition was in fact much closer to what was originally assumed (stock GOR and specific gravity were calculated to be ~2100 scf/bbl and 37°, respectively). This data was more favorable from a processing standpoint, but with relatively high amounts of condensate still detected, the large recycle loop remained.

After the new PVT data was verified in a process simulator, the total overhaul of topsides equipment and addition of a crude stabilizer was taken off the table. The option of adding a condensate processing train by itself was also reconsidered due to its inability to provide adequate separation. After examining different seasonal and environmental conditions in order to better understand how the facility would operate throughout the year, it was determined by LLOG and Audubon Engineering Solutions that a hybrid of these two options would be most appropriate given the unique composition of the field.

The solution: condensate stabilization

The new hybrid design for liquid handling at Delta House included keeping most of the equipment from the initial FEED phase – along with the condensate processing train – and adding a stabilizer with overhead cooling and two-phase separation of

Fig. 1: Simplified flow diagram of the condensate stabilization system

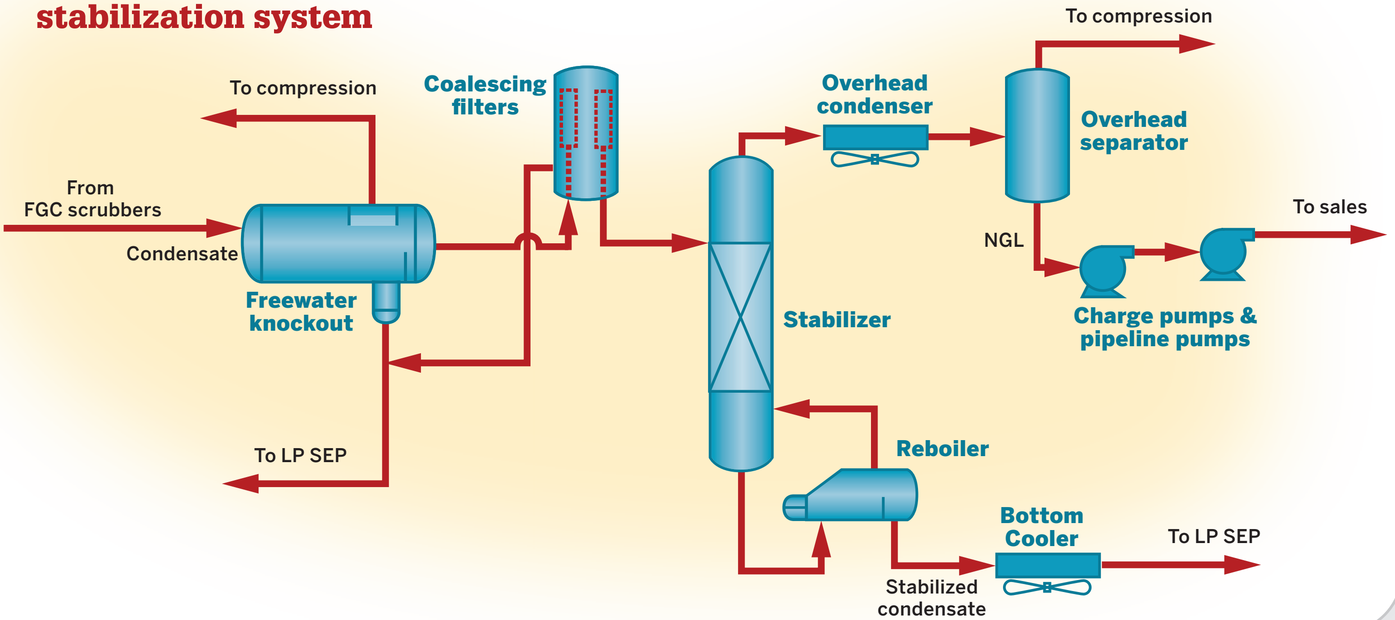


Fig. 2: Summary of early life operating conditions

Parameter	Normal		Sensitivity	
	Summer	Winter	Summer	Winter
RVP [psia]	8.6	9.6	8.6	9.6
Cooler operationg temp [°F]	120	120	100	100
Advised reboiler operating temp [°F]	315	250	315	260
Freewater knockout feed ratio [BBL/1000 BBL crude] (Note 1)	32	39	33.5	44.5
NGL production ratio [BBL NGL/1000 BBL crude]	10	1.5	18	8.5
Stabilized condensate production ratio [BBL stab cond/1000 cond/BBL crude]	10	16.5	10	17.5

Note 1: Ratio reflects total liquids (water and hydrocarbons) feeding the freewater knockout.

the overhead product. After receiving condensate from a freewater knockout and coalescing filters, bottoms product from the stabilizer would feed into the low-pressure separator. This design would ultimately improve compression capabilities and increase the volume of sales oil that could be recovered. A flow diagram of the condensate stabilization system used at Delta House is outlined in Figure 1.

Meeting seasonal RVP specifications

Due to the seasonal changes in oil pipeline RVP specifications, the stabilization system design had to be flexible enough to meet requirements under various operating conditions. In the winter (April to September), the system would have to meet an RVP specification of 9.6psi absolute (psia). During these months, a higher concentration of C3, C4, and C5 could be present in the sales oil and the temperature setpoint for the reboiler could be relatively low (250°F) – resulting in higher oil production rates and a lower volume of natural gas liquids (NGL). It was estimated that approximately 16.5 bbl of stabilized condensate would be produced per every 1000 bbl of crude oil.

In the summer months (April to September), a crude oil RVP specification of 8.6psia would have to be met. The stabilizer reboiler would operate at 315°F, which would allow for the maximum volume of stabilized condensate to be recombined with the crude before entering the sales line. In these conditions, the system would produce approximately 10 bbl of stabilized condensate per every 1000 bbl of crude oil.

Additional design considerations

Ambient temperatures also had to be considered when implementing the condensate stabilization system on Delta House. Outside temperature has a direct impact on aerial cooler outlet temperature, which in turn has an impact on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the amount of condensate that feeds into the stabilizer, as well as the volume of NGL that's produced. Although the aerial process coolers on Delta House were designed to operate with 120°F outlet temperatures, LLOG and Audubon Engineering Solutions had to ensure that this setpoint could be maintained in the colder months of the year. Figure 2 shows early life system operation parameters during the summer and winter months.

Because excessive volumes of water entering into the stabilizer could result in a number of costly issues, including the formation of a hydrate plug in the gas sales line, which can potentially force a total shutdown, freewater knock-out and coalescence filters on Delta House were designed to remove as much water from the crude as possible. This was achieved by implementing a number of safeguards, including installing a water drain in the condensate stabilizer. Determining the presence of water was achieved by installing a sample location on the drain line, along with an interface level gauge and transmitter in the stabilizer overhead separator to alert operators in the event that water begins to accumulate.

Making Delta House a success

The Delta House FPS achieved first oil in April 2015 – roughly two and a half years after construction on it officially began and two full years earlier than similar platforms around the globe. It has a capacity of 80,000 b/d of oil and 5.7 MMcm/d (200 MMcf/d) of gas and hosts production from multiple fields.

The condensate stabilization system implemented by LLOG and Audubon Engineering Solutions on the FPS is just one example of the types of innovative methodologies that offshore producers are using to keep pace with the ever-present demand to optimize production facilities.

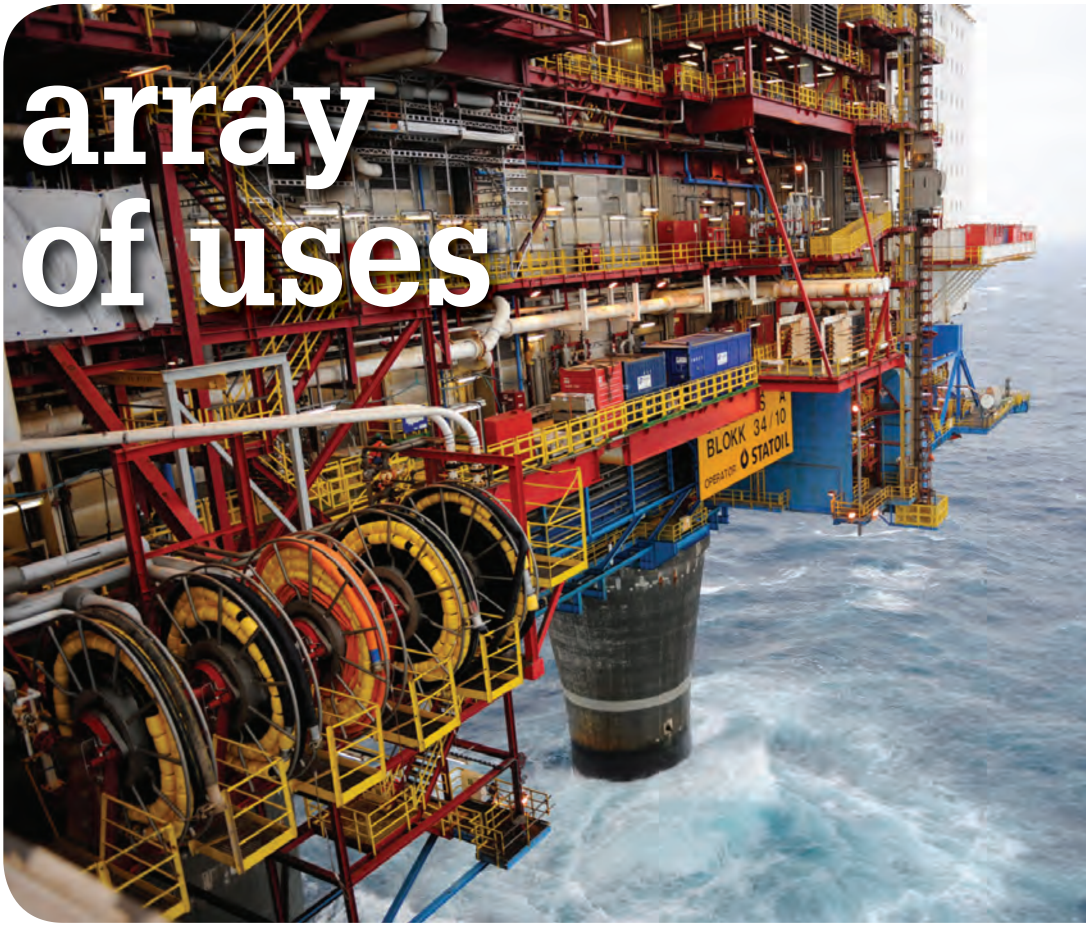
With relatively modest space and weight requirements (75-80 metric tons, 22ft x 24ft x 47ft), the use of similar equipment on offshore platforms could become more prevalent as operators look for cost-effective ways to improve yields and ensure that their product meets pipeline owner specifications – especially in fields where reservoir studies indicate higher levels of condensate. OE

Denis Taylor *is a founder and managing partner at Audubon Companies. Taylor has over 25 years of engineering and project management experience in the oil and gas industry, including mechanical systems design and upstream and midstream consulting. His experience in the upstream industry includes the design and installation of floating deepwater facilities and production platforms in coastal Louisiana and on the Gulf of Mexico's Outer Continental Shelf.*

Craig Mullett *serves as offshore construction manager for LLOG Exploration. Mullett has 35 years of experience in the engineering, construction, and commissioning of offshore oil and gas facilities.*

the heart of the matter

An array of uses



There is more to 4D technology than just exploring for oil and gas. It can also be used to monitor the storage of carbon dioxide and methane in offshore reservoirs in the North Sea. Heather Saucier finds out more.

More than three decades ago, 4D seismic technology was merely an academic research topic. Today, it has become one of the most effective technologies – not only for identifying an offshore reservoir's remaining oil and boosting recovery rates, but also for monitoring the storage of gases, such as carbon dioxide and methane, in the seabed.

The success of 4D seismic is most notable in the North Sea, an area which has been a natural laboratory for testing and advancing the technology to the point of worldwide recognition.

"The recovery efficiency in many fields in the North Sea was running in the earlier days at 30-35%. Now, we are starting to get 50-60% recovery rates," notes John Underhill, Shell Centre for Exploration Geoscience at Heriot-Watt University in Edinburgh, Scotland.

Statoil, which has used 4D seismic technology for roughly 25 years, recently placed an estimated net value of US$4 billion on the assets it monitors in the North Sea.

"Given the huge net value that can be directly attributed to applying 4D seismic and the growing need to monitor carbon dioxide storage projects, the demand for 4D seismic will undoubtedly grow," says Paul Brettwood, vice president of technology at ION Geophysical.

The fourth dimension

Also known as "time-lapse technology," 4D seismic involves the acquisition, processing and interpretation of multiple 3D seismic surveys taken at different points in time – which adds the fourth dimension to the process.

Each 3D survey is taken over the same area of a producing field to monitor changes caused by reservoir production in the subsurface.

The first step in the process requires shooting a 3D baseline survey, Underhill explains. After a period of time, an identical survey is shot using the same acquisition and processing parameters. By subtracting the second survey from the first, one can see changes in fluid saturation and pressure caused by the depletion of a reservoir over time.


Paul Brettwood

These changes can help operators detect missed pockets of oil or water encroaching toward a well. Based on that information, choices can be made to drill infill wells or shut in wells, resulting in more effective reservoir management, Underhill says.

"You can actually see from one 'moment' to the next," Underhill adds, explaining that "moments" are often years apart.

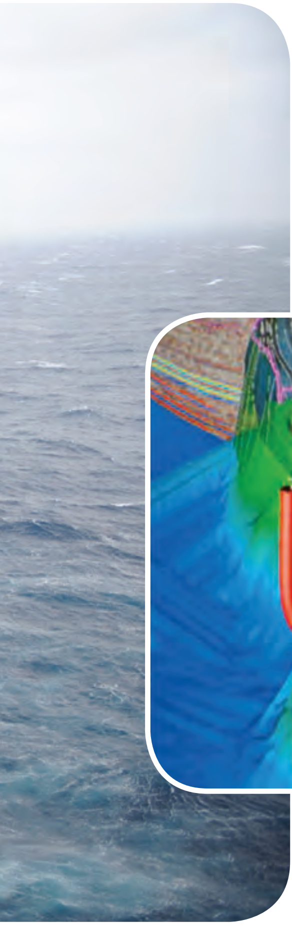
Five years seems to be the ideal length of time in terms of cost-benefit analysis, Underhill says. Over a 20-year period, four 3D surveys should be sufficient – depending on the reservoir, of course. The amount of change one might see in one year does not justify shooting frequently, as 3D surveys are multi-million dollar operations, he explains.

"However, the expense of this technology more than justifies itself because you are managing fields far better," he says. "You get more oil out of the ground in the long run."

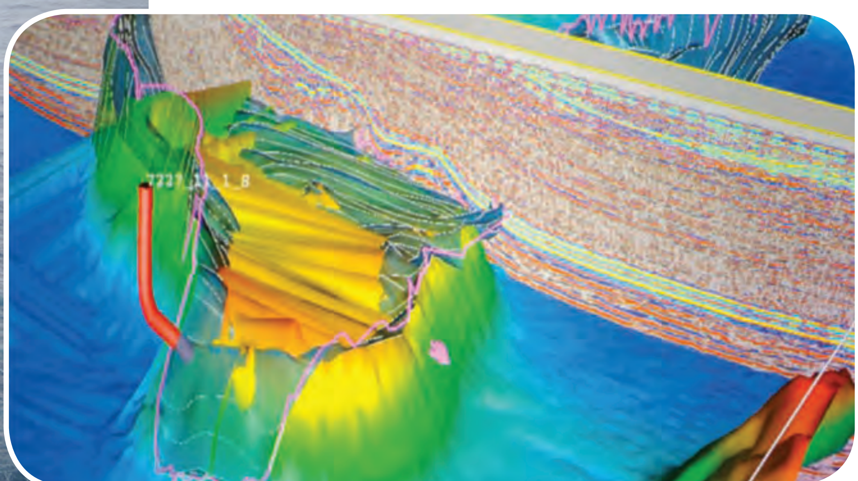
Qualitative to quantitative

In 4D seismic technology's early stages, its accuracy was limited, keeping it a qualitative tool, primarily used to interpret internal reservoir structures and to identify depleted or "unswept" zones, according to CGG, a French seismic and data processing firm.

However, advances in 4D processing, in particular, have turned the technology into a quantitative reservoir management tool, with the ability to make more



Statoil boasts a 59% recovery rate at the Gullfaks field in the Norwegian sector of the North Sea. The first 4D seismic was shot there in 1995. Photo: Harald Pettersen – Statoil.



On Gullfaks alone, 4D seismic surveys have contributed to 62 MMbbl of additional production. The technique is based on comparative results of 3D seismic surveys, providing quantitative imaging for production of oil saturation maps. Photo from Statoil.

accurate assessments about fluid saturation and pressure.

"This technology has contributed to increased hydrocarbons at the Statoil-operated Gullfaks field [in the Norwegian sector of the North Sea] valued at $950 million (net present value)," according to Statoil's website. The North Sea's Brage field off the coast of Norway has been in production since 1993 – its life extended with the help of 4D seismic's ability to assess remaining hydrocarbon volumes and optimize a recovery strategy, CGG reports.

The company adds that time-lapse technology has "very real" budgetary consequences and "significant" revenue implications.

John Underhill

When appropriately used in the right reservoirs, the cost of the additional oil recovered has been reported to be as low as $1/bbl, Brettwood says.

Not only can time-lapse technology optimize production in terms of recovery and cost, it can help increase safety and reduce environmental impacts, he adds. For example, in the event of an internal blowout, 4D seismic can provide information on where reservoir fluids are moving and where relief wells might best be placed. Similarly, in a carbon dioxide or methane storage situation, 4D seismic allows the user to track fluid movement through the storage formations and therefore be in a position to prevent the potential breaching of seals.

Underground storage

Many of the oil fields in the North Sea are mature and in relatively shallow water, making them ideal for detecting residual oil, unlike deepwater locations that can weaken and distort seismic signals, Underhill says.

Furthermore, the soft and clastic fields of the North Sea are more conducive to analyzing changes in fluid saturation, pressure, porosity and stress than in the hard carbonate reservoirs of the Middle East, for example, Brettwood explains.

An abundance of mature oil fields also have made the North Sea an ideal testing ground for subsurface storage projects, such as using depleted reservoirs to store carbon dioxide and methane.

"One of the earliest and most successful carbon dioxide storage examples is at the Sleipner field in the North Sea," Brettwood says. "The monitoring there has confirmed that the carbon dioxide remains in the sand unit into which it is injected."

Combining 4D seismic results with other monitoring methods, such as time-lapse gravity and electromagnetics, should also provide the data needed to verify the amount of carbon dioxide stored, as well as its areal extent," Brettwood adds.

What's next?

While 4D seismic technology has been successfully proven in shallow fields, acoustic signals often get weak or distorted in deepwater.

Efforts are being made to improve 4D signal-to-noise ratios to detect weaker 4D signals, Brettwood says. Improvements are being made in areas including acquisition, processing and inversion of 4D seismic data.

In terms of acquisition, more accurate positioning of the seismic sources and receivers will allow for better repeatability of the survey by reducing the level of 4D noise (the sum of all non-repeatable effects not linked to production- or injection-induced effects).

A new approach to data processing includes addressing all 3D datasets simultaneously – in a "global optimization approach" – rather than as a series of separate sets that are processed using the same flows and parameters.

In terms of offshore subsurface storage, technology is advancing in that field as well. Areas of advancement range from improved particle motion sensors and more accurate algorithms to innovative ideas. These ideas include the work on muon tomography (a technique that uses cosmic ray muons – or small, charged particles – to generate 3D images of volumes) by Professor Jon Gluyas at Durham University in England, Brettwood says.

Other areas aim to provide an inexpensive, continuous and passive monitoring methodology that is directly sensitive to carbon dioxide density.

"The injection of carbon dioxide into a reservoir can create a very complex wavefield that requires sophisticated imaging and velocity-model building techniques, such as full waveform inversion or 4D elastic imaging," Brettwood says.

All of these acquisition and processing technologies are improving and maturing and allowing finer details and smaller changes in the reservoir to be seen.

"There are definitely people investing time and energy into improving time-lapse seismic," Underhill says. "In the North Sea especially, the environment is very conducive to this type of analysis as well as a large prize." OE

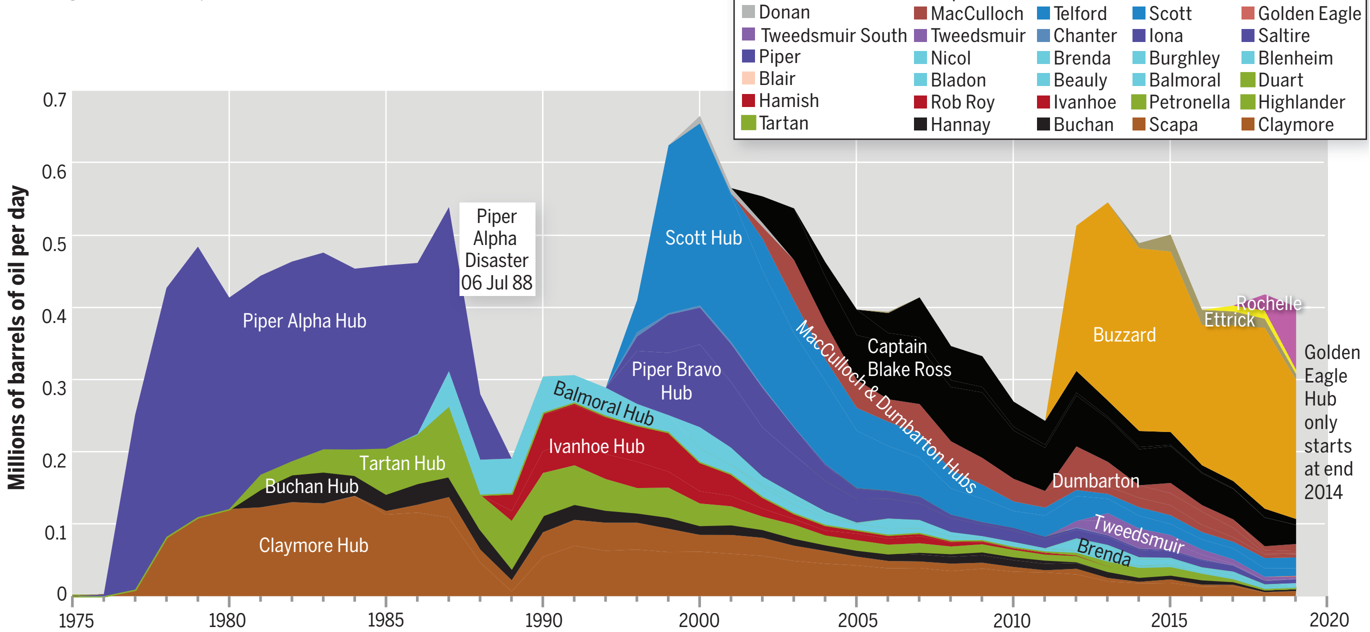


Figure 1 – Oil production in the Outer Moray Firth, UK North Sea.
Image from Mike Cooper. Data from DECC website.

Unlocking potential

A team of subsurface and facilities engineers have been working together to create a viable, small footprint solution for a string of sour fields in the UK's Outer Moray Firth. Mike Cooper explains.

For almost 40 years the Outer Moray Firth has been one of the most prolific producing areas on the UK Continental Shelf. From the early giant fields at Piper, Tartan and Claymore, through the major Scott and Buzzard finds in the 1980s and 1990s to new developments at Ettrick, Athena, Rochelle and Balloch, the basin has yielded over 6 billion bbl of oil to date, with more to come in the years ahead.

Indeed the production profile shown in Figure 1, which does not include the impact of the Golden Eagle hub, on stream in November 2014, attests to both innovation and rejuvenation in this area, despite the tragedy that impacted this area in 1988 at Piper Alpha.

There are two other important trends in the Outer Moray Firth basin, which are clear:

- The mature oilfields (including Claymore, Buchan, Tartan, Ivanhoe (abandoned), Balmoral and Piper hubs), which have been in production for over 30 years, are now contributing less than 30,000 b/d collectively. Without major new investment, much of the aging infrastructure is predicted to cease production in the coming decade.
- "New" oilfields (e.g. Buzzard) generally exhibit steep production declines within a few years of start-up and, once these are stacked on the underlying decline curve from older fields, the decline curve steepens.

This is a major issue for the new government and becomes of greater concern when commodity prices are low. Some older fields barely cover the costs of operation and at US$45-65/bbl many will be losing money.

The current infrastructure in the eastern part of the Outer Moray Firth is shown in Figure 2.

By contrast, Figure 3 illustrates this same area in 2025, based on predictions of natural declining production (courtesy of Wood Mackenzie January 2015 model). It is predicted that all but three fields are currently anticipated to be operational in 10 years' time. Time will tell if this prediction is realized.

There is some hope for the area. Three companies – UK independents Parkmead Group, Faroe Petroleum and Atlantic Petroleum – are actively working to deliver the next phase of oil production in Outer Moray Firth region.

The Perth, Dolphin and Lowlander (PDL) oilfields, jointly containing about 80-90 MMbbl reserves were discovered in the 1980s, but have been overlooked for development for over 30 years. The oil is reservoired in Upper Jurassic sandstones in large stratigraphic traps in the 10,500-13,500ft subsurface depth range. Water depths are 130-140m.

One of the primary reasons these fields have not been developed before is that the existing platforms and floating production, storage and offloading (FPSO) developments in the area are not designed to handle the sour gas, or gas containing hydrogen sulfide (H_2S) at these fields.

Parkmead, Faroe and Atlantic have been working on a design to handle these fluids, which would allow safe and efficient processing of the oil and gas and

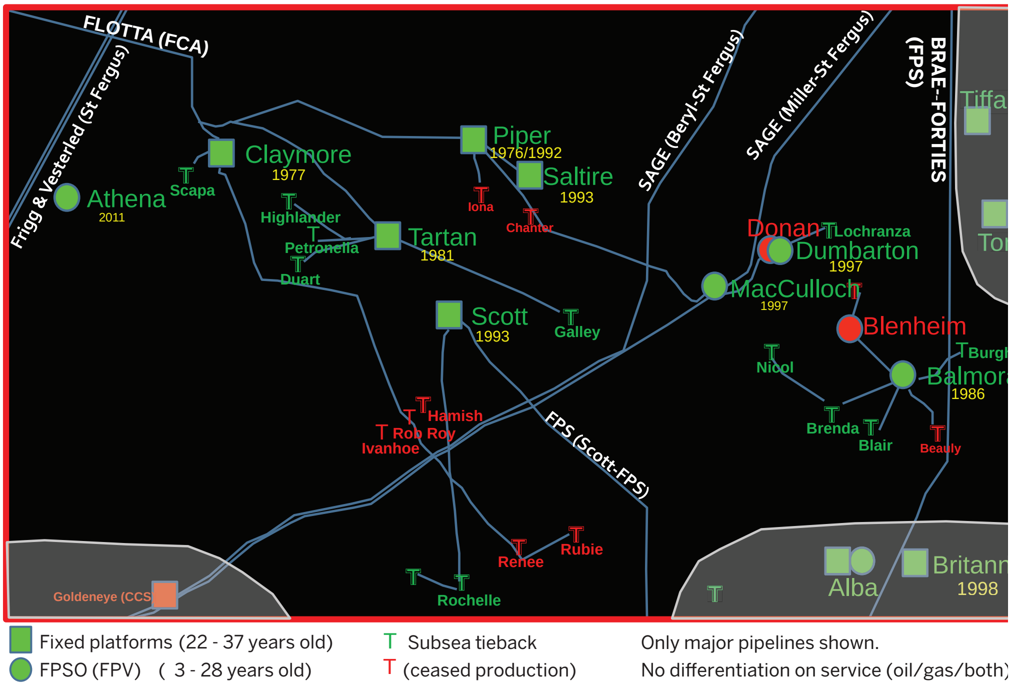


Figure 2 – Eastern Outer Moray Firth area. Current infrastructure map. Image from Mike Cooper.

minimize the environmental footprint. It would also be the first dedicated floating facility that can handle sour fluids in the North Sea.

The current plan is to use a ship-shaped FPSO moored near the Perth oil field in block 15/21c and tieback the Dolphin (8km to the southeast) and Lowlander (16km north) oil fields to this facility.

In total, eight producing and four water injection wells need to be drilled to deliver the 80-90 MMbbl reserves. The FPSO will be designed for a 20-year field life, with capacity to produce up to 50,000 b/d. All the producing wells will be fitted with gas-lift equipment to maximize production rates and reserves recovery.

Key considerations on the design include all materials have to be H_2S-resistant including the risers, in-field flowlines, tree lining and production tubulars. Processing onboard this new-build vessel has been designed with an amine process with stabilized offshore loading to DP tankers and excess sweetened gas exported to nearby infrastructure. A two-stage separation train, is followed by a stripping column for removal of H_2S and volatile mercaptans from the oil. Sweetened associated gas will be used as the stripping medium.

What's more, it is envisioned that the facility would be able to handle other liquids in the broader PDL area, estimated to contain more than 1 billion bbl of oil in place, creating the potential for a significant hub development.

"The PDL project represents one of the largest undeveloped oil projects in the UK North Sea," says Tom Cross, Parkmead's executive chairman. "The engineered solution enables us to produce the oil safely, efficiently and with minimal environmental impact from three new fields. A collaborative effort to equalize the interests in these three oilfields and develop a new hub has been fundamental in unlocking this resource," Cross continues.

"Older, existing oilfields where seawater has been pumped into the reservoirs for pressure support for decades have a tendency to become 'sour' underground over time. The PDL facilities will be able to handle such sour fluids in addition to those from the Perth, Dolphin and Lowlander oilfields and other currently stranded sour crude discoveries," Cross says.

The project has also overcome another hurdle. Historically, misalignments in field ownership has contributed to delays in developing oilfields. PDL now has a common ownership, which means for the first time in decades there is the opportunity to focus on an optimal development plan for all three fields combined in one hub development.

To date, 13 wells have been drilled across the three PDL fields, and Parkmead believes they are adequately appraised to sanction an economic development in the near future.

The fields contain up to 12,000ppm H_2S, contrasting with the 190,000ppm on the giant Kashagan project offshore Kazakhstan. Worldwide there are numerous examples of oil fields producing safely despite having sour gas concentrations an order of magnitude higher or more than we see at PDL.

A team of subsurface and facilities engineers have been working on behalf of the PDL partners to optimize the economic development of the three oilfields and it is expected the PDL facility would become one of the key strategic infrastructure resources in the Outer Moray Firth for decades to come.

PDL is one of the largest and most robust remaining conventional oil field projects in the UK North Sea. Collaboration and innovation have allowed the important resource in three fields to be unlocked through one facility with the smallest environmental footprint. **OE**

Mike Cooper *has over 30 years' experience in the oil and gas industry. Cooper has held senior subsurface roles with Lundin, Centrica, DEO Petroleum, Black Star Petroleum, EnQuest and Maersk. He is co-founder and CEO of Arenite Petroleum, a new company set up to explore conventional and hybrid UK plays onshore and offshore. Cooper was founder and former chairman of the annual Devex Conference and is a former director of the PESGB, and technical director at 1st Subsurface Oilfield Management. He holds an MSc in petroleum geochemistry from Newcastle University and a BSc (Hons) geological sciences from Leeds University.*

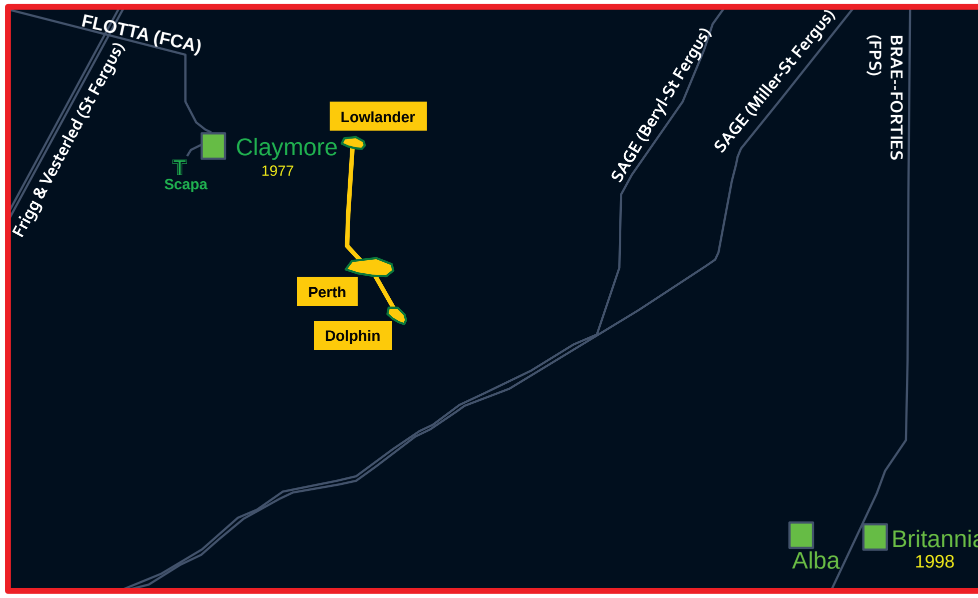


Figure 3 – Eastern Outer Moray Firth area. Forecast infrastructure map in 2025.

Factory drilling

Drilling on Statoil's Mariner will be a mega project – but Statoil is looking to lighten the load in ways that could only be done on such a large project. Elaine Maslin found out more.

When drilling starts on the Mariner heavy oil field, it will become one of the biggest offshore factories constructed in the North Sea.

In the first production phase, at least 130 well targets are to be drilled over 11 years, at a rate of about 10-12 per year in the initial years, from a platform rig and jackup alongside, supported by an intervention and completion unit.

It's going to be quite some task, costing more than US$7 billion in total. But, because of the scale of the task, operator Statoil has been able to make some upfront decisions on its approach to drilling and completions on the field, from which it stands to reap benefits during the field's 30+ year long life.

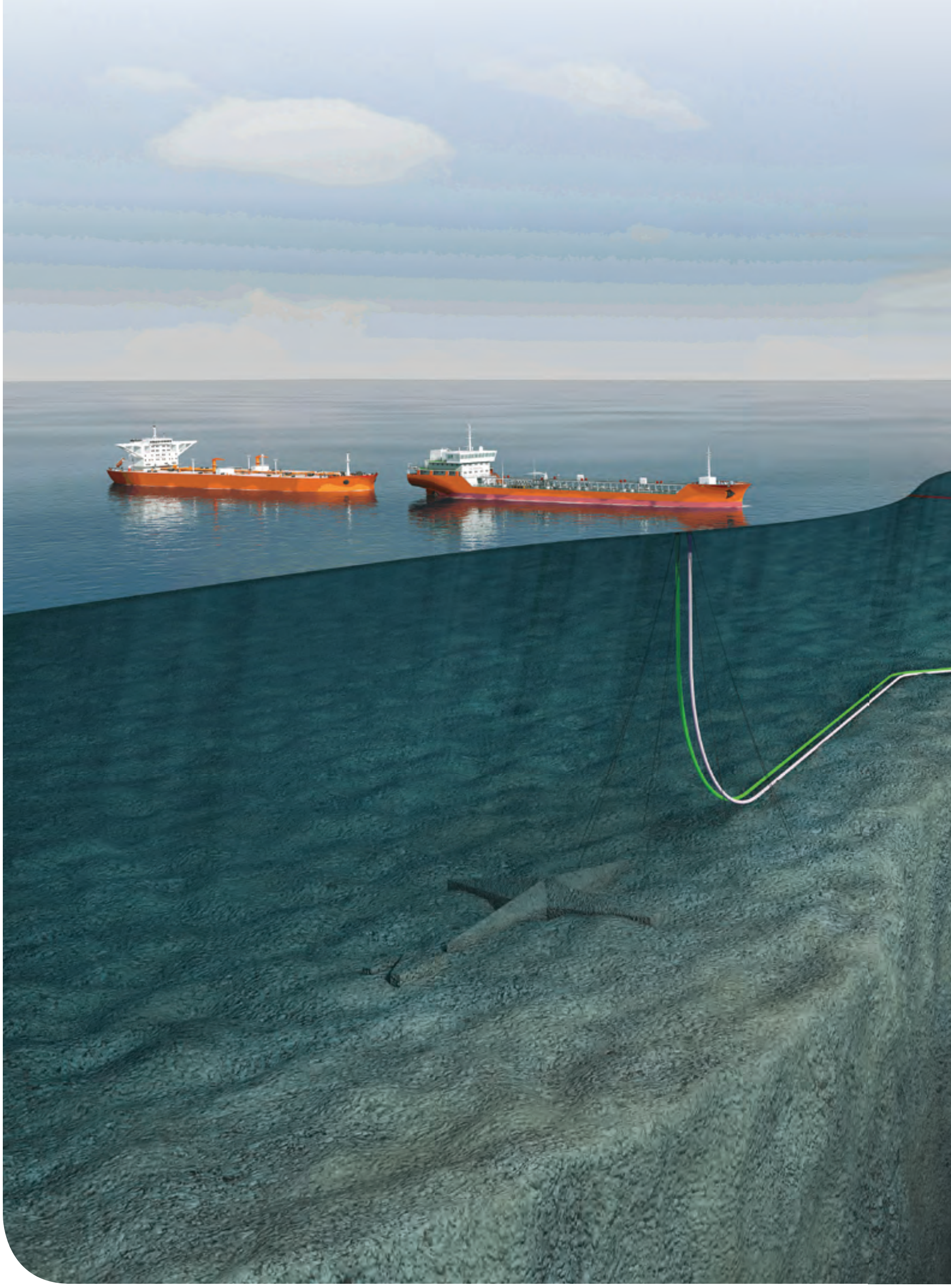
The field

Mariner, a heavy oil field in relatively shallow Maureen and Heimdal sands, was discovered by Union Oil on the East Shetland Platform in Block 9/11, 150km east of the Shetland Islands, in 1981.

Some five seismic surveys have been shot over the license since it was first awarded in 1980, and 18 wells have been drilled by four different operators (*OE: March 2015*), proving up an estimated 1 billion boe in place, and 250 MMbbl recoverable oil, ranging from 67-508 centipoise viscosity.

As with a number of other heavy oilfields in the area, and despite a string of development studies and concepts, the field was left undeveloped because of the difficulties around extracting heavy oil. These difficulties are being overcome.

Statoil's plan is a production, drilling and living quarters platform, currently being built in Korea, on a steel jacket, being completed in Spain, with a floating storage unit, supported by a jackup, with startup planned for 2017 and a 30+ year



The Mariner field concept artists' illustration. Images from Statoil.

field life.

The key challenges on Mariner are the viscosity of the oil, which requires intensive drilling and therefore complex well placing, as well as artificial lift technologies, and shallow reservoirs, which make the intensive drilling all the more challenging.

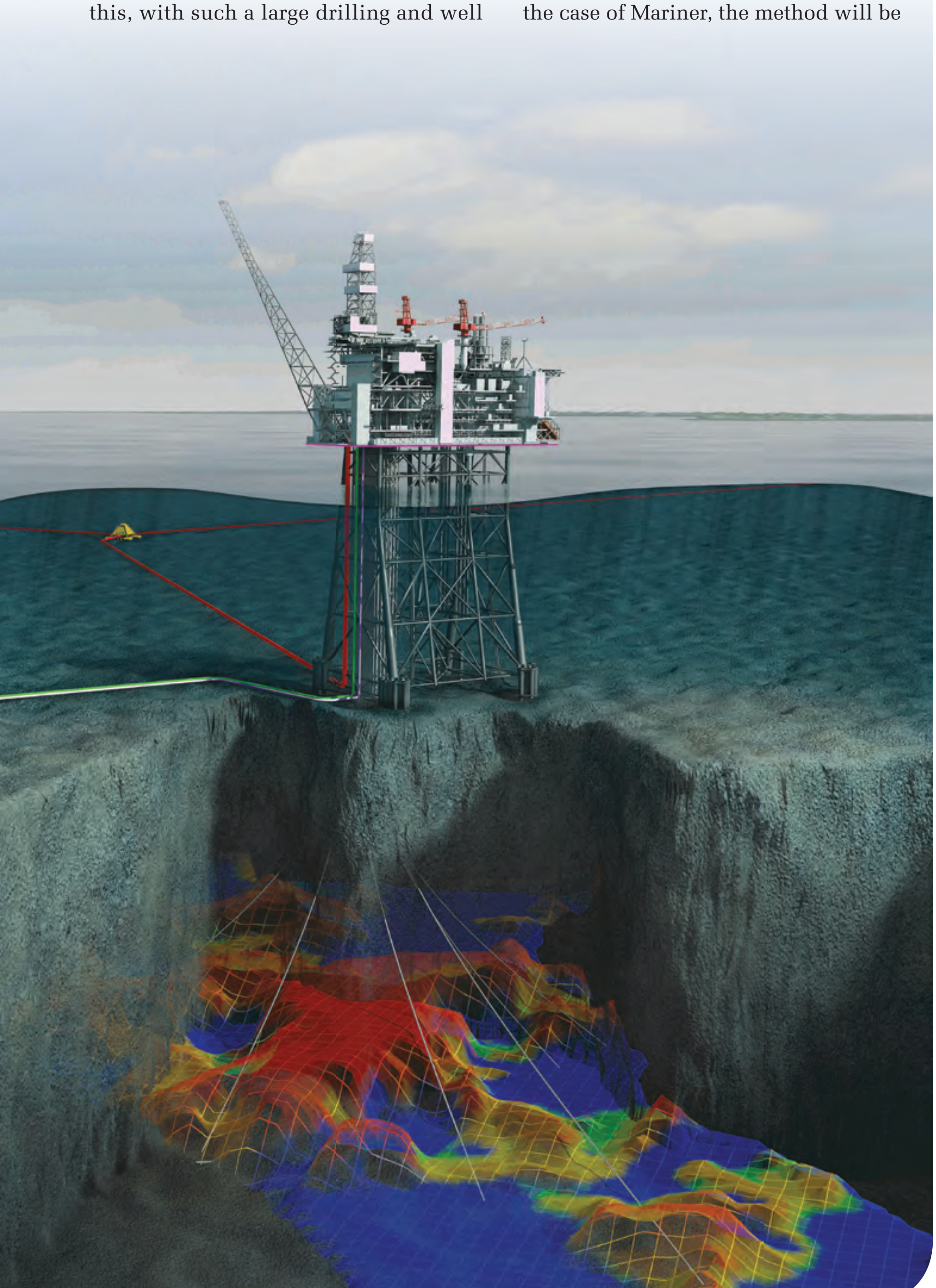
In total, Statoil has identified some 147 reservoir targets, to be reached using lateral wells, and some multilaterals, from a total 98 wells from the surface. With 50 slots on the Mariner platform, that means many wells will have to be side-tracked.

"Statoil hasn't done anything like this, with such a large drilling and well scope, and it is probably unique in the whole world," says Rolf Arne Thom, Manager Drilling and Wells, Mariner & Bressay, for Statoil. "We are going to be drilling for 11 years full time and, for a primary drilling program, that is very large."

Drill, drill, drill

In an onshore-heavy oil environment, wells would be drilled every 20-30m with steam injection wells, to help heat and move the oil, at every other well, Thom says.

This is less easy to replicate offshore, so alternative methods are required. In the case of Mariner, the method will be intensive simultaneous operations, or SIMOPS.



Statoil will have two rigs drilling full time at Mariner, on the platform and from a jackup for at least the first 4-5 years, from 2017, with Statoil considering starting pre-drilling late 2016, as well as an intervention and completion unit (ICU), to support the rig operations. The platform rig on the Mariner platform will run throughout the 11-year drilling period. Odfjell is Statoil's contractor for the platform drilling. The jackup, operated by Noble Drilling and currently being built to Statoil's Cat J design in Singapore, is on contract for four years, with extension options.

Because of the height of the Mariner platform, the Cat J jackup had to be designed specifically to be able to reach the Mariner well slots. This meant its deck is some 80m from the sea surface, which had knock-on effects on the evacuation facilities on the rig – lifeboats wouldn't just be able to free fall from that height, so they are on davits that can be lowered. Much of the design considering went into the legs, however, so that they could be tall enough and strong enough to cope with a 10,000 year wave.

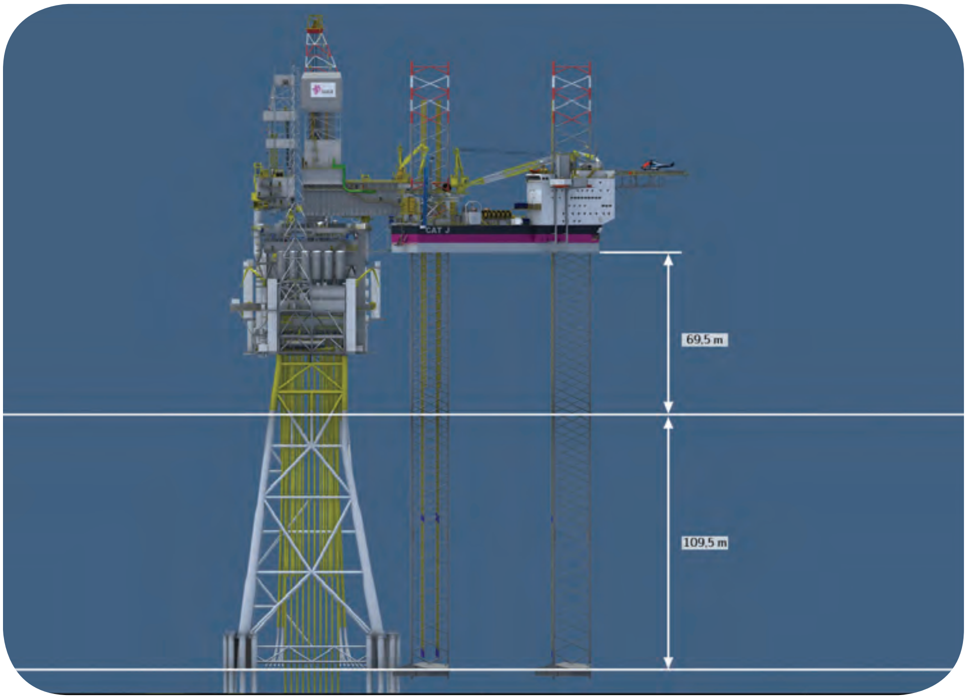
An ICU, offshore

The ICU was a novel decision and something Statoil hasn't done before and hasn't seen others do before on this scale. Usually, a wireline, snubbing or coiled tubing unit would be brought in to help perform intervention work, but not from day one, Thom says. Because of the huge scope of work on Mariner, Statoil was able to take a decision to have capability from day one, lightening the completions load as a bonus.

It will sit in the 23m-high so-called cathedral deck, between the BOPs and the Xmas trees. It will be used to install upper completions and electric submersible pumps (ESPs) as well as for interventions and changing out ESPs.

"We need to be producing wells all the time and these heavy oil wells can get water wet very quickly. Traditionally, on older fields, your rig has to be used to maintain older wells, which means you cannot use it for drilling," Thom says. "On this platform, we will be able to keep the drilling rigs doing what they are supposed to do and the ICU will take care of the completions and interventions."

The ESPs, which are known to fail,



The Cat J jackup design to be used on Mariner.

across industry, on average every 2-3 years, are likely to require a lot of work. But, Statoil has created another novel solution to make the ICU's work replacing ESPs easier, too. It has designed the Mariner wells so that the ESPs will be run on a separate 2 1/8in tubing within the 7 5/8in production tubing, which means when one fails, only that tubing string has to be pulled out by the ICU. "Traditionally, it is an integrated part of the tubing so you have to pull out the whole completion to change the ESP," Thom says.

Otherwise, the well design will largely be traditional, Thom says. Most will be long horizontals, up to 1700m-long, and possibly longer in the future, in order to bring enough flow into the well. But, Statoil will use sand screens and gravel packs in some of the first wells. They will also deploy autonomous inflow control devices (AICD), to control water ingress into the well; as water cut increases, the AICD will gradually close off the flow from that section.

To give the viscous oil a further helping hand at reaching the topside process equipment, Statoil is also using diluent, which will be pumped down the annulus between the production tubing and the 2 1/8in tubing, joining the production flow as it enters the ESP, to thin the oil, making it easier to handle topside.

One of the challenges with having the two rigs and the ICU operating simultaneously, will be being able to move equipment between well slots without disturbing the different activities. To do this, Statoil is looking at a building a 3D "plug and play" model, into which it can plug planned moves, so that it will be able to suggest the best option for any particular move or operation. Also, because of the intensive SIMOPS on board Mariner, the platform has been designed so that the decks are closed and fluid tight, to avoid any dropped objects or environmental leakage.

Another challenge will be placing the wells. "It is going to be challenging to place well number 130," Thom says, especially when the Mariner reservoirs are at 1200m and 1500m. "You do not have much room to build the angle and hit the target," he says. "It is a quite unconsolidated formation. The interaction between the wells is not so much a risk, it is going to be to achieve the angle you need in this loose sand and that's not easy. But there is quite a lot of experience in the area, such as on the Captain and Alba fields, which have similar formations types."

A $65/bbl business case

Statoil made its decision to move forward with Mariner in a $100/bbl environment, so the firm has looked for ways to make the project more viable at today's prices. One has been through assessing the seismic. From its latest seismic data from the field, Statoil has decided that it would be able to reduce the amount of drilling required to reach the targets it wants to, saving the limited cash there is in the current environment. The scope had been 140, but that has so far been reduced to 130, with prolonging the horizontal wells and geosteering, to target the sands, helping to more efficiently drain reservoir targets.

Statoil also selected Schlumberger as the integrated drilling services contract provider on Mariner. Thom says this has reduced the number of contractor interfaces from more than 30 to just one.

"For us now, the focus is to standardize and not to change our plans," Thom says. "We have frozen the well design, the casing program, completion design etc., and they will be kept until we get good at them. We want to learn, and we will have a lot of monitoring, looking at weight on bit and the stability of the drill string and combine that with mud logging, and industrialize."

The interface between onshore and offshore will also be strong, with teams monitoring drilling, well, ESP and production performance onshore, as well as offshore. When it moves into its new purpose built offices near Aberdeen next year, the firm will have a control room which connects directly offshore.

It's a mighty undertaking, but one which is only possible thanks to technology developments over the last 20 years, Thom says. "Long horizontal multilateral wells, ESP pump reliability – and we are banking on it getting better as we go – using diluent, combined with the AICDs and the ICU, as well as subsurface work, has meant we were able to build a business for Mariner. For me, the most exciting part is the SIMOPs and the ICU, which is new."

Statoil is the operator of the field with 65.11% equity. Other partners include JX Nippon Exploration and Production (U.K.) Limited (28.89%) and Dyas Mariner Ltd. (6%). **OE**

MORE **INFO**

Watch Dragados Offshore's video about the Mariner jacket construction, roll-up and load out: www.oedigital.com/oe-media/oe-videos/item/9944-mariner-marches-on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Designer mud

The West Franklin well head platform installation last year. Photos from Total.

Designer mud is helping Total tap pressure depleted HPHT reservoirs in the UK North Sea. Elaine Maslin takes a look.

For most, designer clothes are a luxury you could do without. Not so with designer mud, especially for Total's high-pressure, high-temperature (HPHT) fields in the UK North Sea.

Designer mud, sometimes also called intelligent mud or stress caged mud, has been a key enabler on the firm's assets in the Elgin Franklin area, specifically around drilling infill wells, in depleted reservoir zones, where steep and rapid changes in pressure could otherwise prove very difficult to drill.

"It [designer mud] really is key. These formations – sand and chalk – we know how to drill them and we know how to efficiently manage the rock formation," says Tom Brian, senior drilling engineer, Total E&P UK. "We understand what tools we can run. The challenging piece is the pore pressure and to manage the change in pore pressure."

Elgin Franklin

Total E&P UK has been a front-runner in HPHT field development in the UK, with its Elgin Franklin HPHT development in the central North Sea, producing since 2001. It was challenged with pressures up to 15,500psi and temperatures up to 350°F on the fields.

Franklin was discovered in 1986 and Elgin in 1991. It took 15 years and £20 million of research investment, before both could be produced. Initial development challenges included 3-4% carbon dioxide, 30-50ppm hydrogen sulphide, and a 1100 bar, 190°C temperature reservoir. There are also 175 g/L formation chlorides.

The next challenge was one the company initially thought may not be possible – drilling infill wells – due to pressure depletion in the reservoir. However, Total did it. In 2008, Total drilled its first infill well on Franklin, "opening a new horizon," says Total E&P UK managing director Phillippe Guys.

Thanks to the success in this area, Total has brought on stream two new platforms at the Elgin Franklin complex – Elgin B and West Franklin, extending the development's life from 22 years, as initially anticipated, to more than 32 years.

Pressure depletion

The concern over drilling these wells had been around pressure depletion. Drilling at virgin pressure, while still providing a HPHT challenge, is simpler, due to having a consistent pressure. It is a different story once the reservoir has started to be depleted.

"At the reservoir, you have got a reduction in pore pressure, which reduces fracture gradient and weakens the formation, which creates difficulty drilling, because you still need a mud weight heavy enough to balance the higher pressure formation still exposed above," Brian says. While in theory, reservoir zones should deplete at the same rate, they don't, creating complex systems that have to be navigated. "You have to find a balance to stop any fluids coming in, but not so that it is so overbalanced above the pore pressure or fracture gradient that you can fracture the formation, induce losses or become differentially stuck."

The alternative is to isolate the depleted zones, with liners, and carry on drilling with a different mud weight, but because of the number liners required for the multiple zones drilled through, you would run out of hole sizes to continue, Brian says.

Wells have been lost by not getting this right, resulting in geo-mechanical deformation, which also potentially results in resources which can no longer be reached unless another way can be found to access them.

Mud, glorious mud

Total uses managed pressure drilling and expandable liners, but, Brian says, the key is the designer, or stress caging

Walk to work on the West Franklin well head platform.

mud. The mud contains particles that plug any micro fractures as soon as it reaches them, strengthening the formation. The most common particles are made from graphite and calcium carbonate.

The important part is the work done to determine the size of particles necessary for each reservoir according to the different pore pressures, fracture gradients and which zones will be exposed during drilling. Total has a geo-mechanics team tasked with this job. Brian says they have become good at predicting the reservoir characteristics. By interpreting logging data from existing wells and then providing the data required to design the mud needed, which is then procured from Halliburton Baroid. Total has been using Halliburton Baroid's Steelseal and Baracarb, made from graphite and calcium carbonate, respectively.

The particles range from 5 microns, looking like powder, to 1500 microns – currently the largest used by Total – which looks like coarse salt granules. Reaching this size has only been achieved by the firm using the mud over the years and increasing its understanding of what it can do. But it's not as simple as using mud with one particle size in it – as fractures will not form uniformly – a particle size distribution has to be calculated so that the different sized fractures that develop can be plugged. In addition, using managed pressure drilling allows the firm to more closely navigate the bottom hole pressure.

While using designer mud enables Total to drill through these sections, because it means there are specifically sized particles in the mud, it cannot just be recycled after the drilled cuttings are removed. The mud has to be constantly treated before being recirculated back into the well in order to maintain the proper and designed particle size distribution.

The latest well drilled using designer mud was West Franklin D, and another is due to be drilled this summer. West Franklin D was the second well drilled on West Franklin, to a vertical depth of 5600m, to the top of the reservoir. It had to go through a heterogeneously depleted Fulmar interval reservoir, which meant encountering changes in pressure from 1100 bar to 600-700 bar, over the space of a few meters.

"We have been increasing our understanding, over the years, of just how much we can do with the designer mud," Brian says. "We don't think we're yet at the limit [of particle size that can be used] and work to understand what we can achieve continues. It is all part of the infill drilling problematic." OE

Drilling with liner goes deep

Weatherford's Steve Rosenberg and Ming Zo Tan demonstrate how drilling-with-liner technology isolated a depleted sand section in deepwater Gulf of Mexico well in one trip.

The Weatherford Defyer casing bit seen here was drilled out in 19 minutes with no damage to the drill out bit.
Images from Weatherford.

Working in an area that leaves no room for error, an operator sought to mitigate risks when drilling and isolating a 6.5ppg depleted-sand formation.

The well, in the deepwater Mississippi Canyon section of the Gulf of Mexico at 5743ft water depth, featured a 60ft shale interval with a high risk of catastrophic fluid loss during drilling and cementing. A Weatherford drilling team collaborated with the operator in the early development stages and planned a drilling-with-liner (DwL) operation.

The team would drill below existing 13 5/8in, 88.20lb/ft x 14in 113lb/ft casing and execute a 9 7/8in, 62.80lb/ft Q-125 DwL operation from a measured depth (MD) of approximately 13,000-13,400ft at a deviation of 38°.

The operational objective was to isolate the depleted sand formation, drill a sufficient interval of shale, accomplish the operator's cementing objectives, and obtain an acceptable formation integrity test (FIT).

Mitigating risks with one-trip

Because of the early collaboration between Weatherford and the operator, the team was able to select a technology that not only met the drilling objectives, but did so in one trip. The single-trip focus would help to mitigate risks associated with fluid loss and wellbore exposure.

Drilling through depleted sands is among the hazardous conditions in which the stakes increase with every trip. Conventional drilling—running pipe, setting liners, and then cementing them in place can damage the borehole before the first joint of liner goes in the hole. Tripping in and out of the hole, wiper trips, and extra circulation can often create other problems in addition to the trouble zones.

The DwL technology simultaneously runs liner during drilling and allows for immediate cementing, which seals off the trouble zones and eliminates the need for wiper trips. The technology also allows for the use of a reduced mud weight and reduces the likelihood of well integrity failure as a result of poor cementing.

Planning for error-free drilling

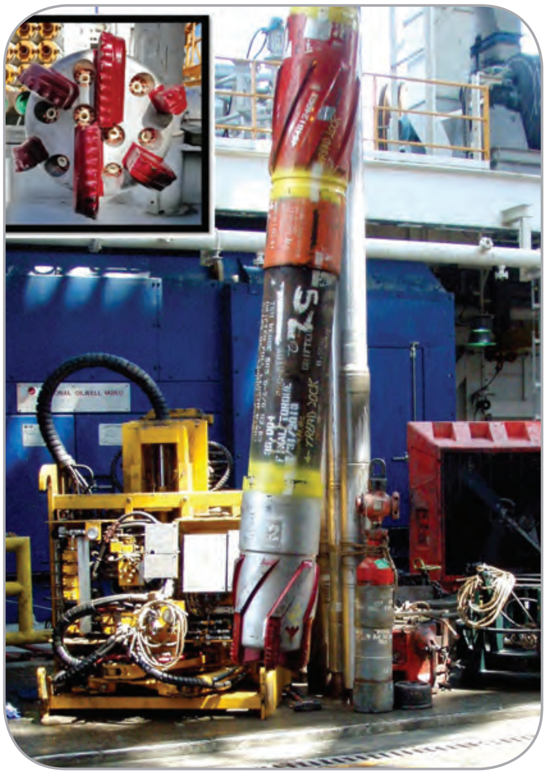
Weatherford and the operator collaborated for a comprehensive planning stage. This included torque, drag, and hydraulics modeling of the liner running and drilling operation; connection cyclic fatigue analysis, bottomhole assembly (BHA) and directional tendency modeling; cementation and centralization; and plastering effect evaluation.

Combing operator data, case histories, modeling, and simulations, the team identified a number of risks. Among the potential issues were induced losses resulting from surge effects; lost circulation below the 14in casing shoe; inability to re-establish circulation after drilling, which could necessitate cementing the liner higher than desired; cement failing to circulate to the top of the liner, which would require a remedial top-of-liner squeeze; differential sticking caused by the 3500 psi pressure differential between the mud and formation pressures; and helical buckling during liner-top packer setting.

Setting drilling procedures

Seeking to mitigate the risks identified during the assessment phase, the team set drilling procedures and recommendations. The team would use a flow rate of 100-300gpm to ream below the existing 13 5/8in x 14in casing shoe. Once drilling commenced, the operation would maintain a flow rate of 300l/min, which would provide a 70.6% cuttings-transport ratio. The differential pressure across the liner top would be 135 psi. Calculations show the standpipe pressure will not exceed 500 psi at 300gpm, with 11.8ppg mud and a 50ft/hr rate of penetration (ROP).

The minimum allowable flow rate to



Weatherford drilling-with-casing (DwC) technology increases drilling efficiency and reduces risk exposure by removing the need to trip pipe and bottomhole-assembly (BHA) components while constructing leaner wellbores.

evacuate cuttings is 190gpm in the riser and 90gpm in the 13 5/8in x 14in casing. In the event that flow rate needs to be lowered to between 90-190gpm, the riser booster can raise the flow rate to 190gpm.

According to calculations, doubling the rate of penetration (ROP) from 40 to 80ft/hr would increase equivalent circulating density (ECD) by 0.16ppg. However, the team could double the revolutions per minute (RPM) from 50 to 100rpm and show a negligible ECD effect of <0.003ppg. At this high RPM, the standpipe pressure is also not expected to exceed 500 psi at 300gpm, with 11.8ppg mud and 50ft/hr ROP.

Drilling through the depleted sand

Operational execution began after setting the 13 5/8in x 14in casing. The drilling team picked up the 649ft liner BHA string, torqued to 36,000ft-lb, and ran to a depth of 12,900ft. The team periodically stopped running the liner to function test the blowout preventer (BOP) and diverter and to verify that the well remained static.

As planned, circulation started at 100gpm and background rotary torque readings were established at 12,900ft, just above the 13-5/8in x 14in casing shoe. The team added LCM consisting of 12ppb calcium carbonate and 3ppb graphite to the mud system. The rat hole was cleaned out to 12,950ft with lost circulation.

Drilling commenced with a 170-300gpm pump rate, 300 psi surface pressure, 10,000-20,000lb weight-on-bit (WOB), 70-90 rpm, and 15,000-20,000ft-lb of torque. Although the team experienced total fluid losses, the annulus remained full during connections while pumping 300gpm with the riser booster pump.

The team reached a total depth of 13,256ft in 20 hours with a controlled on-bottom ROP of 16.7ft/hr while incurring total fluid losses during the entire DwL operation. Measured fluid losses during the DwL operation were 5850 bbl, and the Defyer casing bit was drilled out in 19 min.

Cementing through the depleted sand

The team shut down the pumps and

rigged up the cement head. They pumped a 2 1/8in liner-setting ball downhole to the mechanical ball seat, but several attempts to pressure up and set the hanger were unsuccessful. The hanger was sliding downhole as the slips were trying to bite into the casing wall, probably because of the large amount of LCM in the system. The team slacked off and set the liner on bottom at 13,256ft.

The team picked up the string to neutral weight, freely rotated at 8000-10,000 ft/lb of torque, and released from the hanger with 585,000-lb pick-up weight. They pressured the string to shear the ball seat at 3684 psi and then circulated 3 bbl of mud at 225 psi to ensure that the string was not plugged.

They performed the liner cement job by pumping 100 bbl of 12.5ppg spacer and 3 bbl of 13.7ppg cement along with the bottom dart. Then they pumped another 54 bbl of cement along with the top dart and 20 bbl of spacer. This was displaced with 11.6ppg oil-base mud (OBM) until the bottom dart latched into the bottom plug, which required 295 bbl.

The team then launched the bottom plug with 1150 psi of pressure and continued pumping until it landed on the float collar, which required 326 bbl. The rupture disc was blown at 1030 psi, and the top dart latched into the top plug at 351 bbl. The plug was bumped with 1300 psi of pressure, held for 3 minutes, and then bled off to check that the floats were holding.

Next, the team performed a liner-top cement job by bullheading 50 bbl of spacer, 75 bbl of 13.7ppg cement, and a further 20 bbl of spacer. They displaced with 359 bbl OBM at a maximum pressure of 710 psi. Total mud losses during both cement jobs was 1139 bbl.

Finally, the team applied 130,000lb of set-down weight to set the liner top packer and successfully tested the liner-top packer to 1135 psi for 5min.

Conclusion

Weatherford DwL technology isolated the depleted-sand formation and avoided potential contingency liners, sticking, and other delays that would have occurred if conventional drilling means had been deployed. The operation mitigated the expected catastrophic fluid losses and enabled the client to meet its well construction objectives. The DwL operation, was completed in 21 hours and ahead of schedule. OE

***Steve Rosenberg** is the global drilling reliability manager for Weatherford's Well Engineering and Project Management Team with over 30 years' experience in the oil and gas industry. He has previously worked with Diamond Offshore and Conoco. He holds BS degrees in petroleum engineering from Mississippi State University and biology from St. Lawrence University.*

***Ming Zo Tan** is the global product champion for Weatherford Drilling with Casing Product Line. He joined Weatherford 12 years ago as a DwC Product Line Manager and held the position of Global Application Engineering Manager prior to current position. Prior to Weatherford, Tan held various positions within Halliburton. He holds a BS degree in petroleum engineering.*

Modeling in the deep

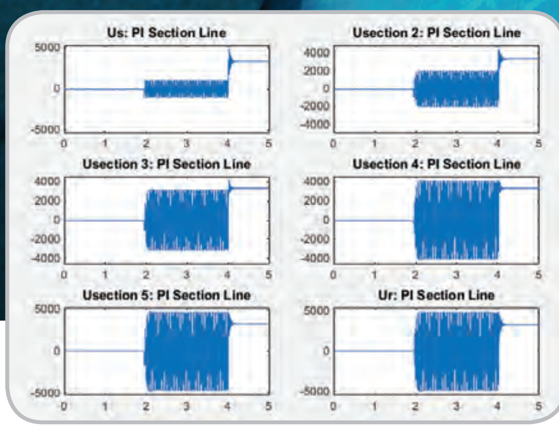
An approach to modeling and simulation combining subsea electrical and fluid systems can facilitate a better understanding of the interaction of long-distance tiebacks supplied by step-outs. ABS' Milton Korn explains.

The great distances and difficulties in placing equipment and systems associated with subsea production exert extraordinary pressures on equipment/system installation and commissioning to "get it right" the first time.

The cost of rework and lost production can be compounded by environmental and economic extremes, which pose major challenges as evolving subsea concepts transition into the field. Failed installation can be fixed, but a failed design places additional impediments in the way of successful operation.

Several years ago, ABS started developing simulation capabilities as part of its technology program. The resulting modeling and simulation proficiencies provide insight into equipment/system design and operation, including subsea power systems.

Applying simulation in the electrical and thermal fluid domain provides a means of exploring aspects of equipment and system that were not possible previously – until a system had been installed and commissioned. These simulation capabilities can be used for subsea operations as well as operations on marine and offshore assets that deploy sophisticated and complicated power systems that were not imagined a few short years ago.



Voltage variation along the length of an unloaded transmission line at fixed frequency. Images from ABS.

Advanced power systems

Subsea power system requirements are challenging the functional limits of traditional equipment and systems. The velocity and magnitude of change to equipment and systems have raised concerns about the reliability of power systems that incorporate these new technologies and the adequacy of the analysis techniques used to predict equipment and system performance.

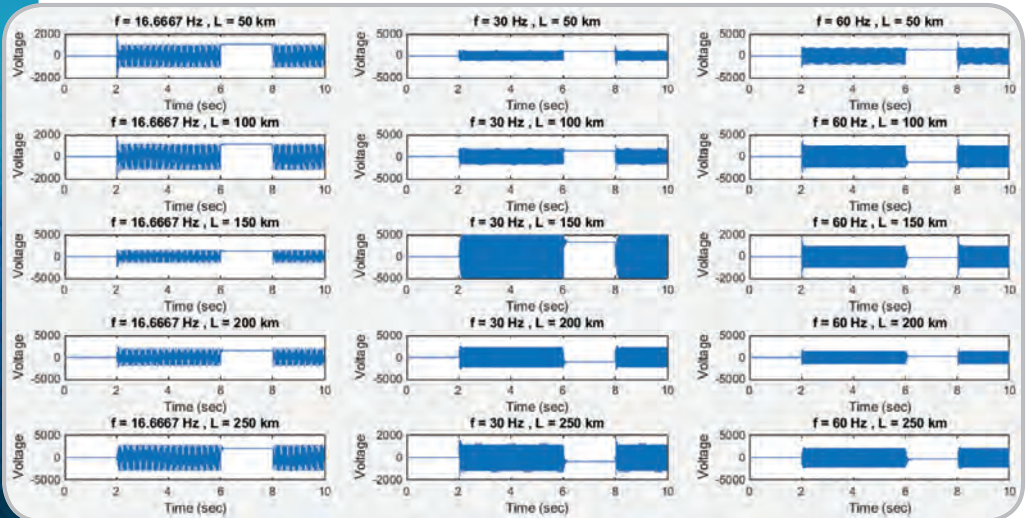
ABS models are being developed to study equipment and system performance under a variety of normal and fault operating conditions. These same models will also allow engineers to study the optimal coupling point of energy storage systems. Optimizing the coupling point of energy storage systems offers the opportunity to reduce capex by providing the potential to justify reduction in the size and number of onboard generators. Opex and emissions can be reduced using this approach because it provides the opportunity to run the minimal set generators at their lowest cost/emissions point.

Subsea power systems research

Pumping stations and compression stations are located along the tieback to achieve the desired flow for the piping system. Linear step-outs supplied from shore are coupled to the tieback at multiple points along its length to deliver electrical energy at the required rate and appropriate quality for pumping and compression stations.

Subsea modeling gives engineers a way to individually and collectively evaluate the operation of the electrical power systems, tieback and the pumping/compression stations during normal operation scenarios such as startup, acceleration, production and shutdown as well as during transient events. This approach also allows for examination of anticipated system performance during fault events and allows for correction and optimization prior to deployment. Correction prior to deployment provides the opportunity to reduce the risk of catastrophic failures such as an environmental incident, personal injury, damage to equipment or loss of production.

The ABS Modeling and Simulation team explored the transient nature of energizing subsea transmission systems, including capacitive charging current, the Ferranti effect and the dependence of transmission line voltage on both time and position along the line. Working from the



The dependence of transmission line voltage on both time, position along the transmission line and frequency.

basic performance criteria of the coupled electrical and fluid system, engineers used the characteristics of the fluid being transported (specific gravity, viscosity and temperature) to size the tieback to achieve the required mass flow rate with acceptable flow velocity, maximum pressure and pressure drop. The hydraulic power required to achieve the desired flow rate was calculated and with it an approximation of the overall electrical power required.

Distributing the pumping stations and hydraulic power along the length of the tieback facilitates maintenance of fluid parameters within the parametric bounds of maximum pressure, pressure drop and fluid velocity. Using a cost function, the selection process also can be optimized for capex and opex.

If the pumping system is to be designed for N+1 operational criteria, further iterations of the process must be performed to facilitate locating and sizing pumping stations so sufficient energy is present for the fluid to bypass a pump station and remain within the parametric bounds of maximum pressure, pressure drop and fluid velocity.

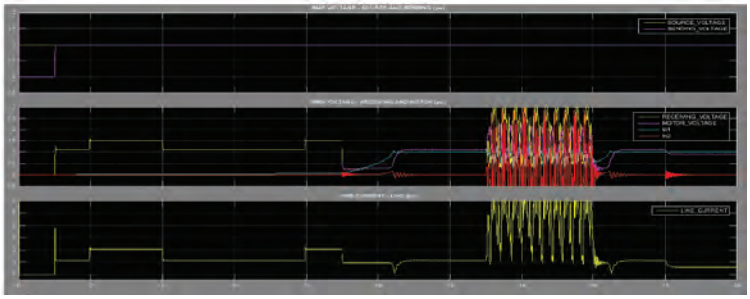
Fixing required hydraulic power at various points along the tieback allows pumps, motors and drives to be selected and defines the electrical power required at each pumping station as well as the overall electrical power required from the step-out.

The length of the step-out and the unit cost of the cable itself make it unlikely that a uniform cable will be selected along the step-out length. At the source (shore) end, the cable will be sized to deliver the full electrical load of the system. Downstream of the first pumping station, the cable will be tapered to supply the remaining pumping load during both normal and N+1 operations.

Step-out cable development cannot take place in a vacuum. Engineers must consider the influence of the other elements of the subsea pumping system. Cable design must take into account the desired nominal operational values of voltage and frequency as well as behavior during the transient energizing period, the capacitive charging current and the operating loads.

Subsea pumping system operation

During operation, power quality at each tap point is dependent on the total system load as well as the specific loading of individual pumping stations. Pumping stations interact with one another. Variations in discharge pressure of upstream units influence the suction pressure of downstream units. Separating pump stations with subsea pipeline segments of varying lengths complicates pumping station control where hydraulic signal propagation speed is limited to the speed of sound in the pipeline fluid. Overall pipeline flow may be set by a master or supervisory control system. At each pump station, local controls work with the master set point to achieve the desired flow while working with pump specific limits for suction and discharge pressure control.



Transient response and resonance at the receiving end of transmission line during switching events.

The transfer of pumping/compression load from one station to another can impact not only the total system load, but can result in the potential excursion of power quality outside acceptable values. The effects of excursions can be mitigated by installing equipment that can operate in a diverse power quality environment or by using line compensation equipment to actively stabilize power quality.

Moving from concept to reality

The ABS Modeling and Simulation project, which incorporates model-based design, is part of ongoing multiyear research targeting subsea power systems, power systems associated with dynamic positioning vessels, and other innovative technologies that are rapidly being rationalized and introduced into the offshore sector.

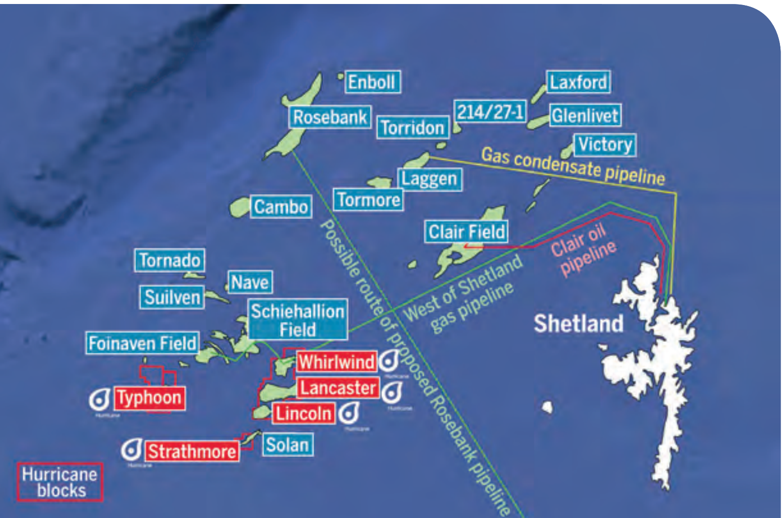
The results of ongoing ABS efforts can be used to optimize the subsea pumping system cost function and deliver insight into the complexities of maintaining control of both the hydraulic and electrical domain to provide reliable pumping system operation.

Refined models include more of the hydraulic, thermal and electrical characteristics of the coupled systems to increase simulation fidelity. ABS hopes to further these efforts through the formation of a joint industry project that will focus on practical simulation technology for marine and offshore applications. OE

***Milton Korn** is ABS Managing Senior Principal Engineer. Korn leads the Electrical & Controls Group within the Offshore Technology Division and manages research on advanced techniques for structural health monitoring and wireless subsea sensor networks. Korn holds a BE in electrical engineering and a BS in computer science/mathematics from the SUNY Maritime College. He received his MS in electrical engineering from the Polytechnic Institute of New York.*

Making it simple

Hurricane Energy has proven commercial oil can flow from its fractured basement oil reservoirs West of Shetland – it's next job is finding an economical solution to get it to market. Elaine Maslin reports.



Existing pipeline infrastructure and fields West of Shetland. Images from Hurricane Energy.

Imagine there is proven oil in the ground, but not enough cash to fund the initial preferred development option, which would capture long-term production data from a number of wells to optimize the full field concept.

What do you do? This was Hurricane Energy's conundrum for its Lancaster fractured basement reservoir development West of Shetland, until it successfully drilled and tested a 1km horizontal well on the Lancaster field in 2014.

The results of the well test enabled Hurricane to completely review its first phase of development on the field.

The firm, which had been considering a multi-well, floating production, storage and offloading (FPSO) concept, is now looking at a simple, one-well, first phase early production system (EPS), using a DP FPSO with a disconnectable turret and minimal subsea and process infrastructure.

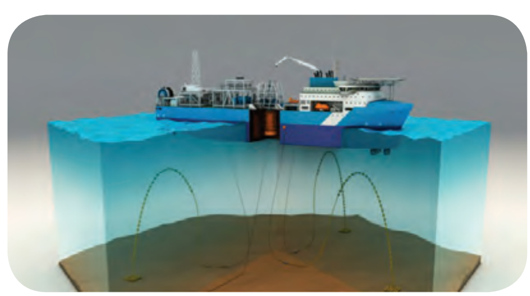
Hurricane hopes that, ultimately, this concept will lead to an enhanced full field development, potentially stimulating a new hub in what has been up to now an area with limited infrastructure.

Early concepts

Hurricane Energy was formed in 2004, to focus on naturally fractured basement West of Shetland. It was awarded its first license, P1368, containing the Lancaster field, in 2005. It now has three licenses, with the second two containing the Typhoon and Tempest prospects. The area sits on the Rona Ridge, in about 150m deep water, with Typhoon and Tempest in slightly deeper water, at about 490m.

Lancaster has had four wells drilled on it, the first by Shell in 1974 and then three by Hurricane, in 2009-2014, proving up 207 MMbbl of 2C contingent resource. A further 200 MMbbl has been found on the nearby Whirlwind field, plus 400 MMbbl P50 prospective resources across its other assets, Neil Platt, Hurricane's chief operations officer, told the Devex conference in Aberdeen earlier this year.

But, development options for the field and neighboring Whirlwind and Lincoln discoveries, have not been obvious. "The location and environment are a challenge, as is the lack of infrastructure" Platt says. "However, not a challenge that Hurricane believes cannot be overcome with the right mindset."



Artist's illustration showing a minimal facilities DP production vessel.

Hurricane worked with EPC Offshore, now part of Costain Upstream, on a series of conceptual reviews from 2012-2013. More than 45 concepts were assessed, based on 4-5 fundamental principles, with 10 short-listed for further evaluation.

"The main considerations were; platform versus FPSO, phased versus pre-invested 'all in one go,' hub versus third-party host and different options for oil export etc.," Platt says. One solution was broadly favored, a two-phase project based on an FPSO, which would be designed to either have the facility to be upgraded at a future time or be replaced by a larger vessel.

The first phase of this concept is constrained by Hurricane's primary objectives of better understanding the reservoir performance as well as providing an economic return on the capital expended.

"From our analysis of our 2014 well test results, we don't believe we can learn much more from drilling further wells, rather we need to put the field on a long-term production test, which we refer to as an early production system, to really understand the performance of the reservoir, whilst at the same time delivering an economic return on the capital invested," Platt says. "As the reservoir is also near bubble point and there remains uncertainty over the effective aquifer pressure, the prolonged period of production will also be designed to monitor these variables to assist with and augment long-term planning."

Within the company's latest Competent Persons Report (CPR) dated 2013, the reservoir evaluation phase, or phase 1 would involve a leased FPSO, capped at 37,500 b/d, from six wells; using the 2010 suspended appraisal well, the 2014 horizontal well, a further three horizontal wells and a crestal surveillance well. The project would run for 2-5 years, with two years to provide production data, followed by a further approximate three years while the optimum full field facilities are installed for the commencement of production from phase 2.

With the nearest oil export line from West of Shetland c.85km away at the BP-operated Clair field, Hurricane went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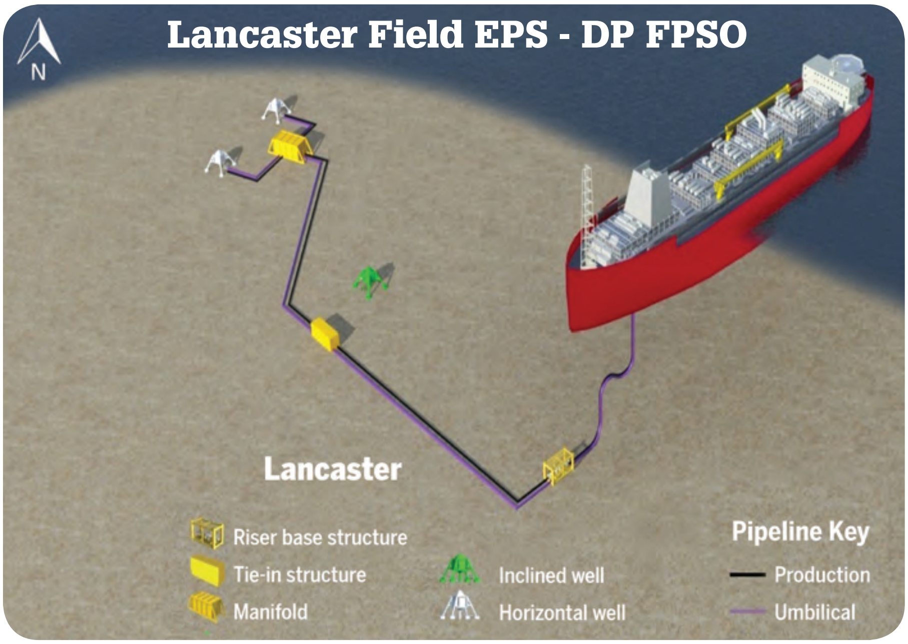
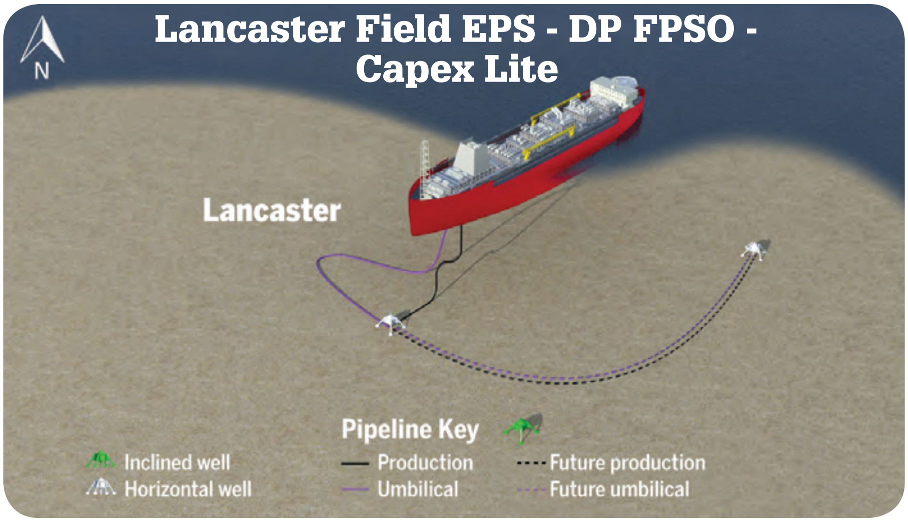


The EPS reference case.



The EPS capex lite option.

for oil offtake by shuttle tanker.

For phase 2, a further five wells would be added, increasing capacity to a total 80,000 b/d with the concept designed to handle both upside Lancaster volumes and potentially other nearby assets. The CPR states that Lancaster upside volumes could be in excess of 400 MMbbl in the 3C case.

Flow assurance and artificial lift methods – electrical submersible pumps (ESPs) vs. gas lift – were considerations for both phases, as were the implications of future produced water on flowline design, (heated or not) and chemical injection requirements.

Price changes everything

At the time of the CPR, oil was trading at a steady US$100/bbl. The phase 1 development was estimated to cost about $1 billion, with a letter of assurance required for the leased FPSO of c.$750,000. Total project cost, including phase 2, was closing in on $3 billion. With the declining oil price, Hurricane needed to look at alternative solutions to achieve phase 1's primary objectives.

It came up with a DP2/3 EPS, which it called the EPS reference case. This would involve turning the existing horizontal well 205/21a-6 into a producer, and adding a new horizontal well at the same drill center, with both tied back to a small leased FPSO, about 3km away. The 4Z well would remain suspended initially with the option to either tie back or run gauges for reservoir performance analysis at some time post first oil depending on field requirements and the constraints on the vessel.

The reduced level of subsea infrastructure meant a smaller FPSO and therefore lower capex and potentially a faster route to first oil. The vessel could also then be used as a facilitator for EPSs on the company's other assets as Lancaster moved into phase 2.

Well test changes all that

Then, last year, Hurricane flowed better than expected commercial rates of oil from Lancaster, at 9800 b/d, with an ESP down the well, constrained by surface equipment. "This enabled us to further optimize our thinking on how to progress and accelerate the Lancaster hub and how we can move forward with a phased development," Platt says.

The company's original phase 1 development was based on its CPR, which predicted 2km-long horizontals would be needed to achieve a starting well rate of 10,000 b/d. "Last year, we achieved nearly 10,000 b/d from just 1km," Platt says.

Hurricane reviewed its EPS reference case plans – and came up with "EPS Capex Lite" based on a single well at first oil. "This is a step change, which has enabled us to also critically look at its subsea infrastructure work scopes and costs," Platt says. "We believe the outcome will still deliver the full evaluation and optimization data we need, but it now has the potential to allow us to drill the second well, funded from cash flow, at a timing of our choice during the initial five years and to place it optimally, based on the first few years' production from the single well."

The relatively simple DP FPSO would be 300m from the well, on a disconnectable buoy, using flexible flowlines, effectively tied to a small riser-based structure adjacent to the well. It would have a 20,000 b/d gross fluid handling name plate capacity, 10,000 b/d produced water capacity, and one separation train. The infrastructure would have the ability to "daisy chain" a second well using the umbilical and flowlines that go down to the riser based structure from the FPSO post-first oil.

"Normal oil offtake would be via shuttle tankers, but, in bad weather, the FPSO could disconnect and sail away to discharge the oil cargo itself," Platt says. Because of the shorter umbilical length, initial investigations suggest flowline heating would not be required and chemical injection would suffice. Instead of gas lift, ESPs, or potential hydraulic submersible pumps, would be used to minimize flaring through maximizing the use of produced gas for power generation and in marine systems.

"Process-wise; it's a turret and a buoy, with a simple oil processing and water clean-up system," Platt says. Hurricane hopes to be able to discharge any produced water over the side.

"Hurricane has also started discussions with a number of FPSO providers for a financial solution, which would not rely on traditional bank financing routes to help solve its conundrum of having to collateralize a letter of assurance to the FPSO provider," Platt says.

Phase 2, "Post-EPS Capex Lite"

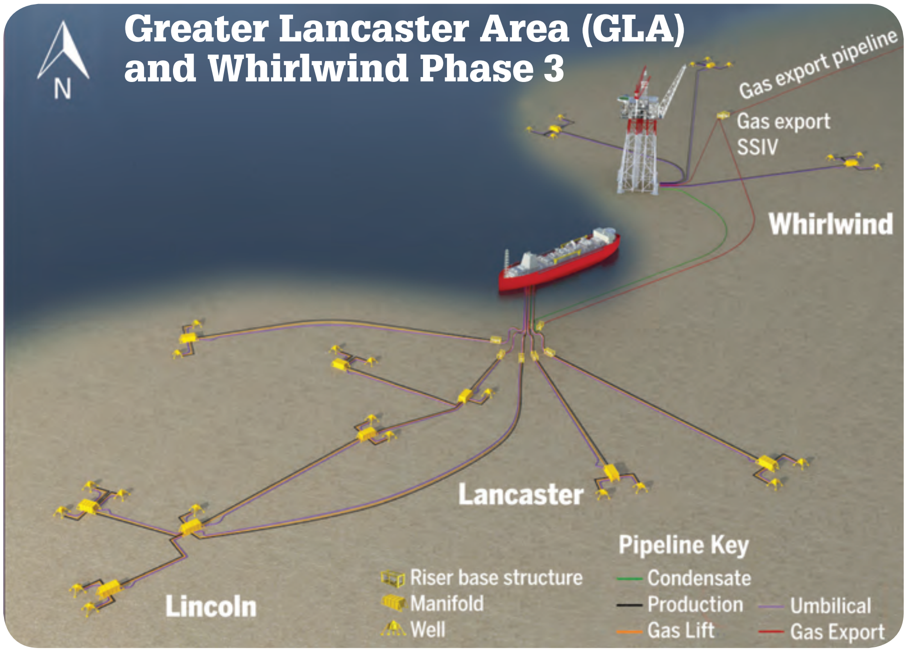
What the new phase 2 would look like is still undecided. "It could be that Hurricane goes direct from the "EPS Capex Lite" to a full field development in one go, or via the CPR concept of phase 1 through to a full field development," Platt says.

Hurricane also has more than the Lancaster field to consider. The nearby Lincoln field has a P50 prospective resource of 150 MMbbl, which could pave the way for a Greater Lancaster Area (GLA) hub development.

There is also Whirlwind, with a 200 MMbbl 2C contingent resource in the oil case. However, Whirlwind might require a platform-based solution to host compression supported by the GLA hub FPSO, as analysis of the Whirlwind discovery well suggests the hydrocarbon type may be either a light condensate or volatile oil.

Then, there is also Strathmore, Typhoon and Tempest. As *OE* went to press, Hurricane announced it had been awarded two further blocks in the area, 204/30b and 205/26d, which contain a new basement prospect provisionally named Warwick, considered to be analogous to the Lancaster discovery. Lincoln is also thought to extend into 204/30b.

"There's significant potential West of Shetland, not just for us, but for everyone," says Platt, who is keen to emphasize the opportunities for collaboration and shared facilities in this area. OE



What a Greater Lancaster Area and Whirlwind development might look like.

Making waves

Assumptions around tidal arrays need to be rethought, according to Professor Stephen Salter. Emma Gordon reports.

The renewables industry needs to contest the assumption that turbines operating in arrays in tidal streams should behave like underwater wind turbines, a leading expert in the field says.

Stephen Salter, emeritus professor of engineering design at the University of Edinburgh, is often credited with being the founding father of the UK's wave and tidal industry, having pioneered the development of wave energy in the 1970s.

Speaking at the All Energy Conference and Exhibition in Glasgow, UK, early May, Salter says if tidal energy is to realize the full potential from restricted flow channels like Scotland's Pentland Firth, different assumptions need to be made, which would imply different turbine designs should be assessed.

Salter has been working on an alternative design to the traditional three-blade horizontal axis turbine design, a vertical-axis, variable pitch rotor design, comprising multiple vertical, pitch-variable blades supported on horizontal rings, which would occupy a large cross section of a restricted flow channel.

As part of an array of 200m diameter, 50m deep versions of these machines, in a restricted flow channel such as the Pentland Firth, Salter says each pair of devices could generate a staggering 400MW.

The figure is based on research by Ross McAdam at the University of Oxford, which has reinforced Salter's questioning the accepted assumptions for restricted flow channel turbine design for areas such as the Pentland Firth.

He says the equation for hydraulic machines in a closed duct, which calculates power based on the head and flow rate, should be used when designing turbines in large, close-packed tidal stream arrays. And, to pinpoint the size of the resource, Salter adds that the head, which would increase as more turbines were installed, needs to be accurately measured.

Salter says it is important to find out how much energy is currently being wasted; adding that, if this dissipation is high, installing more turbines will not substantially reduce flow capacity. The official estimate, which uses a bed friction coefficient appropriate for fighter aircraft and does not take certain factors, such as channel obstructions, into account, is conservative, Salter says.

The effectiveness of this approach has been confirmed in tests carried out by McAdam at Oxford, Salter says. McAdam measured double the Betz limit with a "sweepage" fraction of 0.59.

Salter's vertical-axis, variable pitch rotor design increases the resistance for the water to flow through its openings. Because the water has to exit through a smaller flow area, it will go faster, giving performance well above the Betz limit: the maximum coefficient of power for wind turbines, Salter says.

Further, the design achieves an even pressure drop across 95% of the rotor diameter, decreasing turbulence and improving the performance of successive rows of blades, he adds.

"What I want to do is have the wake much cleaner than what came in, and a pressure drop across rotors that is even," Salter says. "You do this by having a vertical-axis rotor with blades at varying pitch, with two contra-rotating rotors. These pitch angles deliver nearly constant pressure."

Delegates also heard the vertical-axis design allows for better blade mounting, with rotors supported at both ends: reducing pressure differences across the blades.

Salter adds that supporting the beam (or blade) at both ends reduces the bending moment by a factor of four, compared with a cantilever blade seen on traditional three-blade horizontal axis turbines, which are only supported at one end. Salter's design also reduces the vortexes in the water created by traditional blades, which lead to energy loss and turbulence.

Salter also says contra-rotating rotors, using pitch control blades, mean the turbines could also be installed close together, canceling out each other's cross-force. In addition, due to the number of blades on an individual machine, having some blades fail would not impact performance, adding redundancy.

To ensure sufficient stability in pitch and roll, the (horizontally orientated) diameter of the rotor needs to be around three times the water depth. Many areas of the Pentland Firth have depths of around 70m. OE

Systematic evaluation of platform life

Getting to grips with the condition of older assets can be a difficult task. Stefano Copello outlines RINA's approach to revitalization.

The re-used jacket of the Nenè platform, owned by Eni Congo, during transportation from the US Louisiana yard to offshore Congo. Images from RINA Services.

There are a lot of aging oil platforms around the world, many of them reaching the end of their design life.

But, the fields beneath them still contain viable reserves. And, there are new fields to be exploited where an existing platform from another field could be reused economically. With the squeeze on capital expenditures, there is now incentive to find economical ways to extend the life of existing platforms, either in situ or for reuse in a new location.

Each case is different and each platform different, but it is important that the system-approach to assessment of residual platform life is the same, so that operators and regulators can have confidence in the asset in its new location or extended life.

The system approach

The starting point is to create an adequate picture of the platform in its current state, which captures the design strength and possible reductions in strength due to corrosion and fatigue. This has to be set against the site-specific conditions and operational requirements, which may not be the same ones against which the platform was originally designed. Next, determine the risk of structural failure, which could lead to unacceptable consequences. Then, determine the acceptable level of risk and set the safety target.

In simple terms, newbuilds are made to withstand a 100-year event at the original work site. For reuse or life extension projects, engineers must work backwards. Measure what you have, figure out the maximum event that the structure can withstand, then figure out how long you have left by taking into account the likelihood of an extreme event.

The Vega platform, operated by Edison, about 12mi from the southern Coast of Sicily, Italy.

Setting the standard

In the 1990s, the American Petroleum Institute developed standards for the Assessment of Existing Platforms to evaluate the fitness-for-purpose of old existing fixed offshore platforms. These rules were updated in 2005. The International Standard Organization developed the 19900 suite of guidelines to address design requirements and assessment of all types of offshore structures, including fixed steel structures, covered by the issuance of ISO 19902 Standard in 2007.

These standards are important. In the last 10 years, there have been more engineering works related to fitness-for-purpose assessments of existing platforms than design of new platforms in the Gulf of Mexico. RINA Services has built these standards into the updated Rules for the Classification of Fixed Offshore Platforms, which provides a cradle-to-grave framework for the structural and process safety of the entire platform. They build on RINA's experience with offshore platforms in the Mediterranean, Red, and Caspian Seas, as well as the Indian and Atlantic oceans. The rules facilitate life extension while giving owners more choice and control over their design, operation and maintenance strategies.

Environmental protection is central to the new rules, which have been developed with the aim of significantly reducing the risk of accidents and environmental damage. Platform operators can choose from and mix three approaches: classification, certification and verification.

Under each of the approaches RINA's rules now allow for load and resistance factor design, a semi-probabilistic approach to structural assessment. The rules set out clear guidelines and requirements for assessing fatigue and corrosion issues to determine what must be done to allow platforms to continue to operate beyond their design life. The life extension approach incorporates risk based inspection (RBI) and risk-based maintenance planning.

Screen shot of Nenè platform 3D model used for system approach.

Reassessment

All these standards start with a requirement to assess the platform so that the actual present condition is properly known. Every reassessment starts with data gathering, including general information such as date of installation, original and current platform use and function, location, orientation, water depth, number of wells and manning level. Original design data, including design drawings and material specifications, environmental data, operational criteria, soil foundation data, equipment and appurtenances, must be collated and if needed transferred into a digital format.

Construction and fabrication data including as-built drawings, fabrication, welding and construction procedures, etc., are needed, as is the platform history data, including environmental loading history and performance of the platform during past extreme environmental storms, changes in topside layout and weight, collisions or other accidental events and possible damages reported, survey and maintenance records and a list of any repairs and modifications.

Next, conduct the platform as-is survey, above and below the water, and include actual deck size and geometry, existing deck loading condition and equipment arrangement, field measured deck clearance elevation and layout of wells, with visual and non-destructive examination. All the data and survey information is used to build the platform model, which shows what you have, but it doesn't tell you the loads the platform may face. It is important to use current methods of environmental calculations described in the updated design codes, rather than the original design loads, and this may produce surprises. There is also a good argument for using meteo-marine data collected on site during the life of the platform if the platform is to continue on the same site. RINA used this approach in the life extension of the Vega A platform with some success. In the cases where this approach was used, RINA showed that actual loads in service varied by 15% less than the design loads (particularly for extreme wave loading), which has a major impact on the expected life ahead of the platform.

The structural safety of the as-is model now needs to be assessed relevant to the expected loads. What is peculiar in the strength assessment of existing platforms is that it is permissible to have predicted limited individual component failures, provided the reserve against overall system failure remains acceptable.

Sometimes strengthening to meet the applicable standards is not a viable option, in which case decreased reliability of the overall system could be acceptable, provided that the consequences of failure are acceptable for both the life and the environment, e.g. de-manning the platform to prevent loss of life, or providing evacuation in relation to forecast of

LAM 28 platform, operated by DOTL, located in the Caspian Sea, approx. 25-35km west offshore Cheleken peninsula, Turkmenistan.

environmental conditions exceeding the one the platform is actually capable of withstanding.

We get to those probabilities by the required safety target, which can be related to the actual system capacity of the platform, measured by the residual strength reserve of the whole jacket. That is evaluated in the simplified system reliability assessment introduced by RINA for the certification of the life extension of many offshore platforms in different offshore areas.

RINA uses elasto-plastic analysis linked to statistical evaluation. The structural model is subject to environmental loads, which increase up to the whole system collapse. The statistics then take into account strength and the environmental load, in order to finally evaluate the yearly probability of collapse in storm conditions.

A notional yearly probability of collapse of the platform may be evaluated by a simplified procedure, starting from the evaluation of the environmental forces acting on the structure, corresponding to wave, current and wind conditions with return period of one-year and 100 years, which may be represented by one-year and 100 years base shear global values determined by the quasi-static analysis normally carried out for the in-place conditions of the platform.

Then, for steel truss offshore structures, where the hydrodynamic load in storm conditions is dominated by the drag contribution, it is accepted that the maximum yearly load is reached in relation to the maximum annual wave height. It is assumed that the calculated values of the environmental forces are characterized by a yearly probability of exceeding equal to those of the associated wave height.

In order to solve the reliability evaluation, it is useful to evaluate the statistical distribution of the environmental load extremes according to a lognormal distribution, since it allows solving of the reliability evaluation in a simple closed form. An evaluation of the approximation introduced in relation to this assumption has been made in a joint industry project carried out by Italian offshore operators relevant to the life extension of existing offshore structures in the Adriatic Sea and it has been shown as negligible for the final result.

The reserve strength ratio and its relationship to the target values of notional yearly probability of failure can then be calculated. Note that there are guidelines on what this ratio should be in the ISO standards for new platforms, but these can be reduced for life extension so there is no set acceptable answer.

RINA used this approach for the LAM 28 platform offshore Turkmenistan in 27m water depth, consisting of different simple jacket modules joined at their topside by a latticed module support frame. This platform was subject to a reassessment analysis in 2013 with a target life extension of 10 years. The reassessment showed that the platform was compliant with the required safety level for the desired extension life target, provided that the platform shall be evacuated, and subsequently subject to a special survey, in case that a sea state characterized by maximum wave height greater than or equal to about 10m happens.

We used the same system to determine the expected life of the Nenè platform that had been used in the Gulf of Mexico for 10 years and was then to be modified and installed on a new site off Congo. The analysis with the structural modifications and new site conditions showed that an in-service life with acceptable safety levels of 10 years was obtainable without strengthening.

***Stefano Copello** is product development manager at RINA Services. He graduated with first class honors in civil engineering at Università degli Studi di Genova. At RINA since 1991, he has worked on technical activities inherent to the design, construction and installation of offshore structures, with particular reference to safety, reliability and maintenance problems of fixed offshore platforms and the development of reliability tools.*

Carbon sense

Flow visualization in horizontal wells is being improved thanks to carbon composite rods. Elaine Maslin takes a look.

Running wireline production logging (PL) tools into horizontal wells has never been that easy. The tool strings with the PL sensors have to either be run on the end of coiled tubing or pulled along the horizontal sections with a well tractor, both methods having operational drawbacks (time and cost) as well as frequent difficulties in acquiring good quality, valid data sets.

Even when a wireline tool acquires good data, the sensor is only able to make a measurement at one depth point at any given time. Ziebel employs its composite carbon technology conveyance systems to make distributed temperature sensing (DTS) and distributed acoustic sensing (DAS) measurements simultaneously across the entire interval of interest in an easier and faster manner, with the high strength of carbon fiber reducing the risk of not being able to retrieve the fiber optics from the well.

The Norwegian firm's new 4.8mm-diameter Z-Line system has seen its first commercial operational use on Statoil's Huldra platform in the Norwegian North Sea earlier this year as part of a project to assess well conditions ahead of a plugging and abandonment (P&A) campaign next year. It was the first time Statoil has commissioned a distributed fiber optic (DFO) well intervention and it was also Ziebel's first operation for Statoil.

The next step could be leaving a composite carbon rod or line downhole permanently in a well that is being P&A'd, says Neil Gardner, global sales and business development director for Ziebel.

The yellow wireline mast suspends the top sheave and the pressure control equipment. To gather DFO data, the Z-Line runs into the well through the pressure control equipment, at the top of which is the brass-colored bend restrictor funnel.

Photos from Ziebel.

Z-System

Ziebel's first DFO sensing system was the Z-System, which deploys fiber optic cables via a 15mm diameter semi-stiff carbon composite rod, using a unit very similar to a light coiled tubing (CT) unit. Once "parked" stationary in the well, the system acquires DTS and DAS along the full length of the rod. The concept for the technology was initially developed in the early 2000s, with a patent eventually being granted in 2006.

"The idea was patented to use a carbon composite rod with fiber optics inside to enter a well in order to measure parameters like temperature, pressure and others," Gardner says.

Since then, a lot of work was done refining the product, particularly experimenting with different sizes and configurations of the rod, as well as the chemistry of the composite rod material, with the University of Aberdeen providing mathematical modeling for different composite behavior, so that it would be able to perform the tasks required of it and withstand downhole conditions.

"The idea was to be able to push the semi-stiff rod out into horizontal well sections," Gardner says. "The horizontal well stock is increasing and will continue to do so. The difficulty with current technologies is that the sensors have to be either on the end of pipe or tractored in on a wireline. If you can do it with a carbon rod you can do away with the tractor or the coiled tubing."

For distributed measurements, the system has to be stationary. Unlike traditional sensors, which have to be moved across the entire zone of interest in order to get a full data set, the Z-System senses along the whole length of the rod while stationary. "We can also manipulate parameters in a producing well to see how it behaves and responds, such as adjusting the choke at surface or increasing the gas injection rate, and then instantly start to see the impact of these adjustments across the whole well," Gardner says.

Z-Line

However, Ziebel saw the opportunity to develop a smaller footprint system, which could be deployed on smaller platforms, such as in the southern North Sea, where a CT-like Z-System unit might not fit.

The result was the development of the Z-Line, a smaller 4.8mm-diameter carbon composite line, with a 6600lb/3000kg breaking strength, containing up to six fiber optic cables encased in a central steel tube. It comes mounted on a 1m-diameter drum, which can run on a standard wireline type set-up, and includes point pressure and temperature sensors on the bottom hole assembly. "It is smaller and more modular, which opens up many more wells to be investigated using fiber optics," Gardner says. "Because it is 4.8mm, it is much more flexible and can be deployed like a mechanical wireline or slick-line."

The system does preclude use on horizontal wells because you cannot push it in – it requires sinker bars and gravity to move it down into the well. But, it will go into relatively high-deviation wells, Gardner says – up to 75-80° deviation, depending on the well geometry, according to the company's calculations.

Z-Lines could be built as long as required by well depths, but the main application of interest (well integrity surveys) are in the shallower vertical section of most wells. The length is only limited by the space available on the drum and the ability to properly control the manufacturing process, Gardner says. The firm has built a 4000m-long version and it is aiming to build the next systems to at least 6000m length. The 3-4-tonne drum of Z-Line is shipped offshore inside an add-on-drum skid, with two sheave wheels, a Ziebel sensing cabin, and the dynamic seal pressure control section.

Working from the Huldra platform, Ziebel ran the Z-Line in two wellbores to measure temperature and acoustic profiles. Work was carried out by Ziebel over two, three-day periods in April and May 2015. Each operation was completed as planned, providing data that displays the conditions of each well in its entirety, during each intervention. It allowed Statoil to observe fluid movements, confirm the integrity of the wells, and plan the final abandonment, enabling the optimization of the forthcoming P&A campaign.

"We were looking for possible unwanted fluid migrations, particular in the annular space outside the main bore," Gardner says. "We have the ability to detect and visualize fluid travelling up or down versus time outside the central tubing, through one, two, and maybe three strings of pipe in the well. If you are trying to design a P&A program you need to know what is moving down hole. If there are undesirable fluid movements we can detect them and show the operator which sections in the well need sealing to prevent fluids migrating and pressure build-ups."

During the operation offshore Norway, the winchman used this panel to monitor the line depth, speed and tension, and the video monitor to verify that the spooling was running properly on the drum. The panel pictured indicates that a line depth of 9684ft has been reached in the well.

Pictured on the deck is the wireline unit, as it spools the Z-Line out towards the well. It runs under a lower sheave, up and over an upper sheave (not pictured) and down through the brass-colored bend restrictor funnel into the pressure control equipment, and then into the well.

More frequent monitoring?

Rather than permanent monitoring requiring fibers to be installed in every well, an operator can choose to run frequent Z-Line runs in wells with this intervention methodology. In this future vision the Z-Line would be kept permanently on board the platform, Gardner says. "Z-Line is light and can run in a well with a wireline unit. You would just have to drop in the drum, which is compatible with standard wireline units," he says. The sheave wheels, the instrumentation and some other ancillary equipment is also needed, but the rest is standard, Gardner says.

Can subsea wells be accessed?

To use the system on a subsea well, a rig and a high-pressure riser are required. But, in the future, it could be done from light weight intervention vessels, Gardner says. A development would be to run pressure control equipment to the seabed, which the line can go to through open water from the boat.

"There's quite a bit of interest in the bigger 15mm rod system for subsea applications, because it is stronger than a wireline," Gardner says. "Today, if you do light well intervention and you are running wireline tools into a long subsea well, there's a high degree of risk because if your tool string gets stuck or the well tractor fails, you have limited overpull strength in your wireline to pull it free. The only option is to electrically release the tool string from the cable and accept to have a large blockage negatively impacting production in the well until a rig can be brought in at a later date to retrieve it."

Ziebel is further developing the Z-System by embedding electrical conductors within their carbon rods to enable reach into extreme horizontal sections by connecting a well tractor to the end of the rod. This development will also provide the capability to run electrical well service tools, such as the new milling or cleaning tools available today, all of which would be additional to an undiminished ability to provide the DFO measurements, Gardner says. OE

Life extension or Decommissioning?

Understanding your asset is vital before making the big decision. Clarus Subsea's Vinayak Patil and John MacDonald explain the key challenges of subsea integrity management in the Gulf of Mexico.

Operators in the Gulf of Mexico (GoM) must remain as proactive in the approach to subsea integrity as they have been in pioneering deepwater. Many of the early deepwater facilities are nearing the end of their design life, bringing to light the decision of what is next. However, making confident decisions in terms of life extension or decommissioning requires a thorough understanding of the asset history. For example, events such as high eddy current speeds are often not the priority during operations but may become a driver of life extension. Also while pushing designs for deepwater requires bespoke systems and flexible regulations, there are few prescriptive requirements to guide best practice. These leave operators and subsea integrity management (IM) contractors to determine the best practices for their asset IM.

Loop currents

Loop currents are a unique feature to the Gulf of Mexico and have recently exceeded 4.3 knots (Eddy Lazarus), which approaches a 100-year return period event in accordance with the new metocean guidelines (API-RP-2MET). An image depicting the typical movement of loop currents and associated eddies is shown in Figure 1. Combined with these loop currents is the largest concentration of deepwater steel catenary risers (SCRs), which are subject to vortex induced vibrations (VIV) that can reduce the riser fatigue life and increase the potential for fatigue failure.

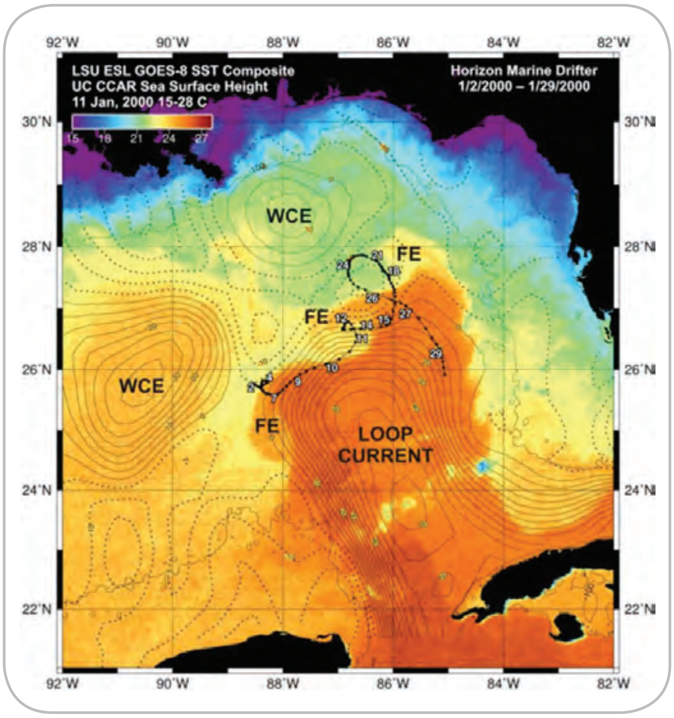


Figure 1: Loop current frontal eddies (Coastal Marine Institute (LSU) – MMS Contract 1435-01-99-CA-30951-85247)

State-of-the-art subsea IM programs can take a stepwise approach to managing accumulated fatigue due to high currents and VIV: 1) design, 2) monitor and 3) response measurement. The first, design, is beyond the scope of this article, but what is relevant is that design predicts a baseline fatigue life in response to current profiles (including loop currents).

As a leading indicator of fatigue performance, fatigue can be analyzed indirectly through accumulation of measured current speeds. Response limits are derived based upon the design analysis predictions and measured values. The measured current speed compared to design becomes a cheap and easy key performance indicator (KPI) of both short- and long-term riser fatigue accumulation. The objective is to signal an alarm well before the design life is compromised and to allow time to respond economically with retrofit strakes or vessel repositioning.

Where measured data or life extension targets show the design to be un-conservative, riser response, including strain and motion, can be directly monitored by installing subsea data loggers on the SCR. By measuring the SCR response for a period of time, some conservatisms and assumptions can be replaced in the design models and a new fatigue life estimated. This is particularly valuable if the monitored data includes extreme events, such as a hurricane or the recent high loop currents. However, this is a two-way street particularly for older designs where newer methods and metocean data may actually show the original analysis to be un-conservative, but a mature IM program in a frontier region such as the deepwater GoM will look for opportunities to reduce long-term risk by increasing confidence in the system. Preventing incidents has proven to be significantly cheaper than responding to them.

Bureau of Safety and Environmental Enforcement regulations for integrity management

US Bureau of Safety and Environmental Enforcement (BSEE) regulations require operators to manage integrity of the outer continental shelf (OCS) facilities in accordance with the safety and environmental management systems (SEMS) rule (30 CFR 250, Subpart S). The SEMS rule, based on the API-RP-75, is not prescriptive in terms of subsea IM. This allows operators latitude in development of their

IM programs, leaving a gap in what is commonly accepted as "best practice." The SEMS program is required to be audited within two years of the initial implementation and at least once every three years thereafter. The benefit of an open specification is that it allows the operator to set their own IM plans and priorities based on risks relevant to their system. There are many serial number one designed equipment in use in the GoM. The challenge is passing the required audit with little direction from the auditor.

Clarus has supported audits on behalf of operators and can confirm that the expectation is to identify and determine, in writing, an IM plan and then to implement/execute phases to resolve elements addressed within said plan. Subsea IM plans typically address the six elements shown in Figure 2 as a minimum, but Clarus has identified three key components that are adopted in more mature and efficient programs.

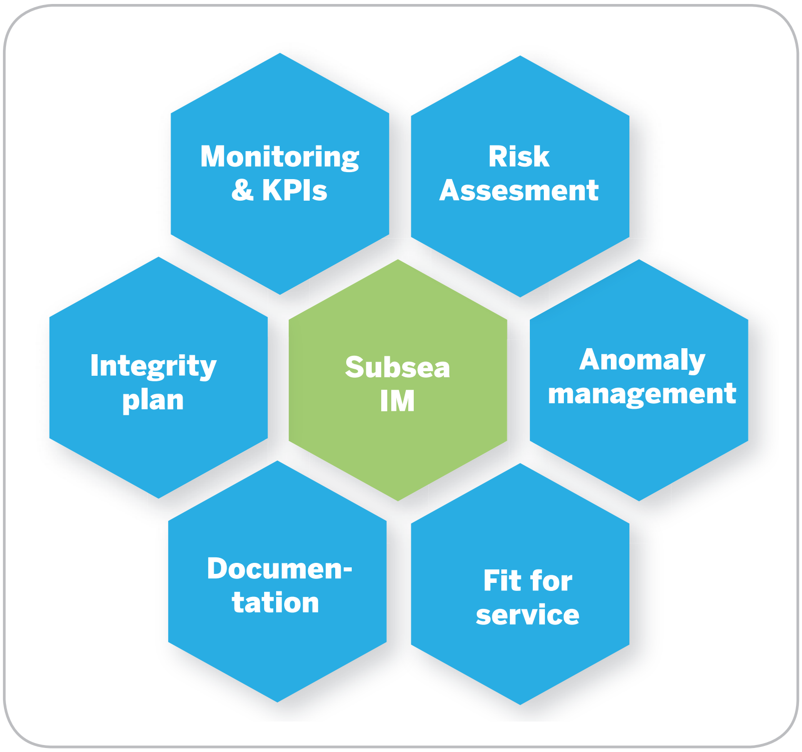


Figure 2: Subsea integrity management elements

1. Develop and write down an IM plan specific to your assets and associated threats. This can be a multi-page strategy complete with RACI charts and action metrics or a one page table listing the items to inspect and data to gather on a regular basis. First, this gives BSEE something concrete to audit against, but more importantly, Clarus has found that writing down a plan and sharing it between operations and engineering brings about many efficiencies. For instance, operations may have a remotely operated vehicle (ROV) in the field for many reasons in the near future and, once they are aware that engineering wants to conduct inspections, they can save on mobilization costs by combining efforts.

2. Look beyond ROV inspection for subsea equipment. When it comes to subsea equipment, there is more to be gained from gathered data than from ROV inspection alone. Examples include the current fatigue KPI discussed above, but can extend to acoustic signature monitoring of subsea pumps and valves to cutting edge nondestructive examination (NDE) technology for unpiggable pipelines. The data often adds confidence to the assessment, thus facilitating better long-term decision making.

3. Do not just go through the motions. Have an engineering expert review and write a technical assessment for all data gathered and inspections completed. In many cases, anomalies identified will need to be prioritized against other operational goals, but having the anomaly written up by the engineer will better equip the operations to evaluate the priority and resolve it in due course.

DNV GL has released recommended practices in the past few years covering both riser and subsea equipment integrity management. Both have good recommendations and considerations to get the most of an IM program. In the end, an efficient and effective IM program will be more valuable to the operators and will increase the likelihood of passing the BSEE audits, as a small side benefit.

Age of deepwater structures

The earliest deepwater structures in the GoM are approaching the end of their design service life, which is typically 20 years as shown in Figure 3. Approximately 2% of the total assets in the GoM are beyond their original design life, and approximately 15% have been in operation for more than 15 years and are approaching their design service life. As the service life approaches, operators have to decide between decommissioning, life extension or divestment. Not only is this a complex decision, but it is one that many GoM engineering teams are facing for the first time in their career. New subsea tiebacks to existing platforms offer an economical option for the operators in comparison to the installation of new structures, especially in the current financial environment. However, subsea tieback of new developments to the existing flowline-riser systems that are nearing their service life requires a life extension assessment.

Confident decisions regarding life extension or decommissioning of aged structures can take a few or more years. A comprehensive IM program, incorporating some of the elements already discussed from the design phase through the operations phase, can provide a clear "health history" of the aged structure as a first step. The most commonly accepted steps of a life extension assessment include:

1. Detailed design review
2. Health history review
3. Inspection
4. Critical component identification
5. Reanalysis
6. Repair and/or replacement
7. Fitness for purpose evaluation for new service life

Life extension is a new activity for the GoM industry, and guidance on life extension assessment is developing such as ABS' draft life extension methodology for floating production installations. Starting early with engineering efforts and communication with regulators is recommended and gives the best possibility for life extension over forcing decommissioning or divestment.

Conclusion

The GoM faces many unique challenges including those related to long term IM of subsea systems. Program development and execution is a key to proactively manage these challenges. It enables operators to stay in compliance with regulations and provides visibility to

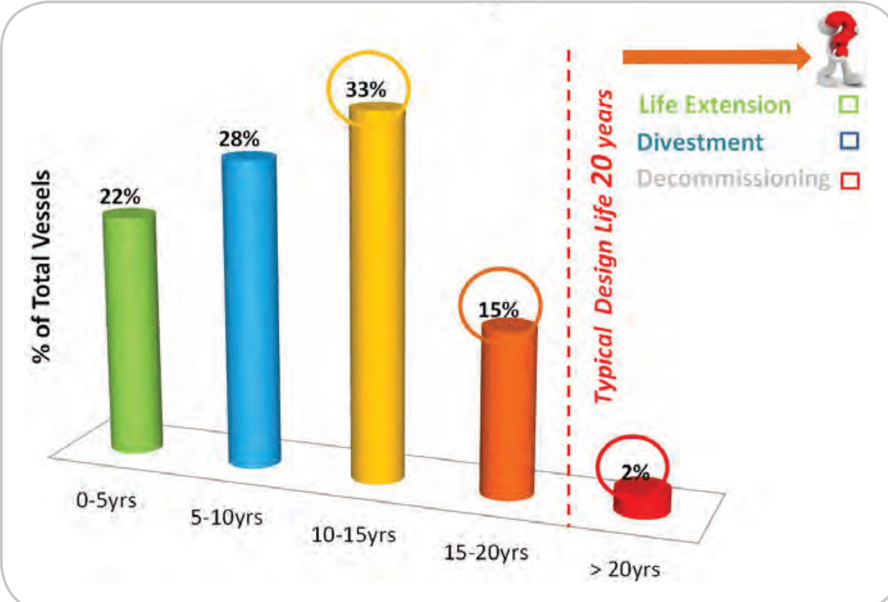
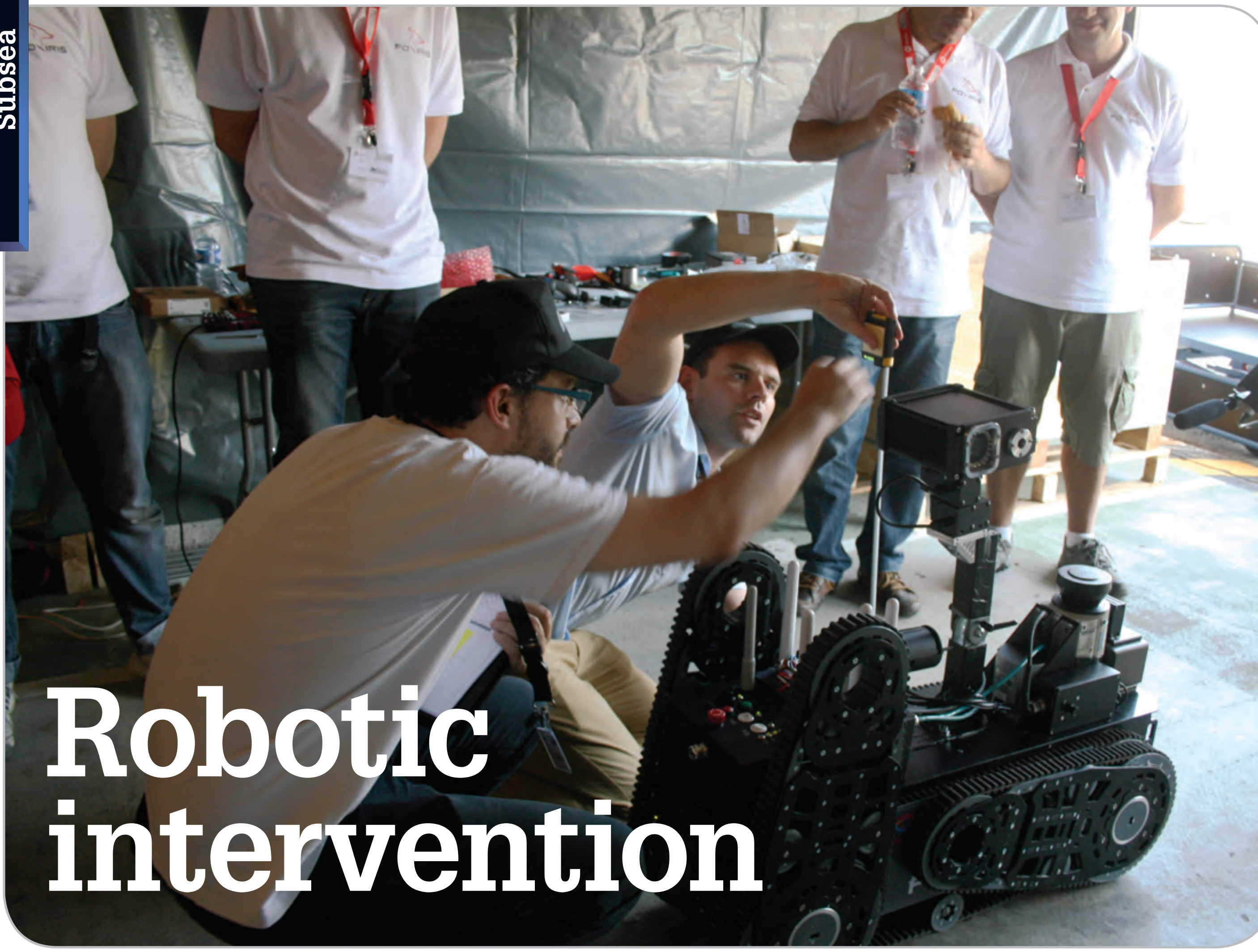


Figure 3: GoM vessels age

future opportunities with the asset. An IM program does not have to be expensive. Using the same efficient approach used to make this market a success can ensure that the GoM systems and the people operating within those units are safe. But, in order to do so, IM programs need to be written down and reviewed on a regular basis to address the unique issues faced by each asset. **OE**

__Vinayak Patil__ is an integrity specialist at Clarus Subsea Integrity in Houston. He holds bachelors and master's degree in chemical engineering and has accumulated seven years' experience in subsea integrity management, corrosion management and chemical process engineering. His project experience includes working with major operators in the Gulf of Mexico to provide integrity management support and solutions.

__John MacDonald__ is currently vice president at Clarus Subsea Integrity in Houston, a recent spin off of sister company 2H Offshore. He holds a BS in ocean engineering from Texas A&M University and is both a Chartered Engineer and a certified project management professional. He has accumulated 14 years' engineering experience in riser analysis, naval architecture, verification, acceptance testing and integrity management for 2H Offshore and Bath Iron works.



Robotic intervention

Homologation phase with the FOXIRIS robot. Photo from Total by VLK

Offshore workers could soon find themselves sharing their facilities with robots, particularly in remote, harsh or hazardous environments. Elaine Maslin looks at the Argos Challenge.

Robotics are becoming an increasing part of life on planet earth – from car manufacturing plants to our own living rooms. Their abilities are becoming ever richer and more agile.

They're going offshore, too. Total wants robotics to become part of the surface facilities – as intelligent inspection tools.

The French major is running a competition to help develop a robot that could operate autonomously in harsh, hazardous and offshore environments. It's a progression of what the company is already working on says Kris Kydd, head of prospective lab robotics at the R&D department of Total Exploration and Production, based in Pau, France.

The firm has a track record developing remotely operated vehicles (ROV) and autonomous underwater vehicle (AUV) technology (*OE*: *October 2014*). Robotics are also being used for flare stack and hull inspection, Kydd told the ITF Technology Showcase in Aberdeen in March. "It is only logical that surface robotics will come to oil and gas facilities, and not just in greenfield sites. "They could improve efficiency and operate at sites human operators cannot go to."

Such types of robotics have already been deployed on offshore oil and gas facilities. Kydd gives the example of Sensabot, a 350kg robot developed by the National Robotics Engineering Center in Pittsburgh, Pennsylvania, in cooperation with Shell Global Solutions, for the North Caspian Operating Co., consortium, for use on unmanned islands of the H_2S-rich Kashagan development, for faster, more efficiency 24-hour response and inspections.

Total's vision is a robot that can undertake inspection tasks and intervene in emergency situations.

The company, working in partnership with the French National Research Agency (ANR), has set up a competition to seek out the best robotics for the job – the ARGOS challenge, standing for Autonomous Robot for Gas and Oil Sites.

The French oil major hopes through the competition it can create a robot, weighing less than 100kg, which can move between floors, and on different types of flooring, from grating and corrugated iron to cement and wet slippery surfaces, under its own power. Total wants to improve the remote control functionality and, ultimately have an ATEX/IECEx compliant, technology readiness level 5, fully autonomous robot.

The robots are being tested through a series of competitions in Lacq, France, on a test rig, made from a gas dehydration unit currently used for training emergency response teams. "It will perform routine inspection, move around autonomously, read gauges and valve positions, and not only read and record but also know if valves are within their normal operating range and if not alert a human operator," Kydd says.

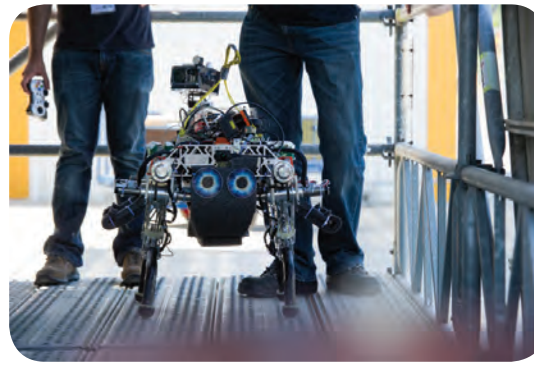
As well as more routine tasks, it would also be expected to operate at the site of an incident, such as a hydrocarbon leak, and in potentially hazardous and harsh environments, ranging from -50 to +50°C, hygrometry of up to 100% and sea spray, heavy rain and up to 100km/hr winds.

Kydd says that Total hopes the ARGOS challenge will trigger collaboration within the robotic community and in the oil and gas industry.

The challenge is being run in three phases, the first of which ran in June this year. The second and third phases will run in March and December 2016. "The intention is to make each harder than the last," Kydd says.

Five teams are taking part in the challenge: Air-K, Foxiris, Lio, Argonauts and Vikings.

They were selected from 31 entries received from 15 different countries. Four are based on track and wheel type locomotion systems, with a fifth a four-legged structure similar to Boston Dynamics' robots.



LIO robot. Photo from Total by Laurent Pascal.

They all have to meet set criteria, including weighing less than 100kg, being narrow enough to not get in the way of operators or obstruct 70cm-wide walkways and be capable of reading measurements at heights of up to 2m. Robots also must be capable of operating on site at least two hours without interruption and reach a minimum speed of 2km/hr.

In June, the robots were put through a series of tasks, including inspection missions, risk management and speed and endurance tasks. A path was laid out in a gymnasium for the speed trials and each passed the test. Vikings' was the fastest with Foxiris' showing promise by finishing the test with a remaining energy reserve of three hours.

Overall, the jury concluded: Vikings impressed the jury by performing an inspection mission autonomously in a record time of three minutes and 30 seconds; Argonauts demonstrated a good man-machine interaction system; Air-K showed strong autonomous mobility capabilities; Foxiris had exceptional endurance; and Lio achieved the best instrumentation reading and analysis.

The teams now have nine months to improve their performance before the next stage of the competition in March. OE

BP's Shah Deniz facility, which started up 2006. Photo from BP.

Overcoming obsolescence

There is a big risk circling mature production installations where hardware that was once state of the art now poses a problem for managers on late-life assets. That risk is obsolescence. John Bradbury reports.

"Obsolescence is becoming a growing challenge within the offshore oil and gas industry and subsea industry," warns David Saul, reliability and technology lead for BP global subsea hardware.

Saul suggests equipment obsolescence is inescapable; the challenge is managing it. "Obsolescence is inevitable," Saul says. "It cannot be avoided." However, he says, operators can minimize its impact and its potential for higher asset costs by planning and proactive action.

Speaking at the MCE Deepwater Development conference earlier this year, Saul suggests obsolescence involves many facets including equipment and supplies, skills, and software.

Hardware can become obsolete through technology progress, along with the equipment necessary to maintain it, such as test apparatus. But, it applies to software, too. Saul points out many systems now rely on unsupported applications, procured without any thought about obsolescence. "There are lots of systems out there – with Microsoft prefixes such as XP and Windows NT," he cites.

Equipment obsolescence can occur for a number of reasons: "The supplier may have taken a commercial decision not to supply the equipment any longer...or they could have gone out of business," Saul says, warning of reliance on a sole equipment source, since sub-suppliers may stop producing a necessary product. "You may be creating vulnerabilities you are not aware of," he says.

Hitherto, industry suppliers have offered to keep manufacturing parts, but Saul suggests that is now happening less. But, he sees this as a positive, arguing it provides supply chain clarity, when a supplier is no longer prepared to manufacture key components, particularly for electronics packages, telling customers: "'You have six months left to make a last time buy.' Actually, that sort of clarity, I find helpful," Saul says. "Today, there is a lot more proactive mitigation out there."

Knowledge

Obsolescence stems from access to knowledge within original designs, documents and drawings, and engineers themselves may have retired. Saul urges companies to consider historical document storage, to ensure they can still access data, which may exist only on an outdated device. Field operators change, leading to a loss of knowledge; test standards change, and procedures become outdated. All lead to obsolescence. "People retire and you lose that knowledge," Saul says. Obsolescence can also come from materials that are no longer legal. "With long-life fields, system obsolescence is a particular issue to us," he says.

Saul urges companies to consider product life cycles as a series of connected gears: "In the time it takes to get from concept to delivery for a large mechanical structure, some electronic subsystems components could have gone through five generations."

With newer products, reliability issues emerge over time, particularly with electronics, such as a mobile phone, which may only have an 18-month lifetime. Whereas with substantial offshore assets, a product's lifetime could be 25, 30, 40 or even 50 years, so the objective is maintaining production without interruptions from minor component failures: "You are going to have to plan how to do that."

BP's approach towards obsolescence has changed, Saul says. About 10 years ago there was an "uncontrolled" transition to off-the-shelf parts, to ensure spares didn't run out, to offset equipment obsolescence. This was particularly true of subsea packages: Similarly, Saul notes that when Motorola withdrew from manufacturing military-specification parts it caused consternation in the defence industry.

Furthermore, newer legislation, for example regulations on the Restriction of Hazardous Substances, and OSPAR – have compelled operators and contractors to meet more strict criteria for products.

Now, BP is more proactive, using JIPs to offset obsolescence risks. Suppliers are checked during vendor audits. BP places greater emphasis on conforming to industry standards, using fewer bespoke systems. "We are expecting subsea systems commissioned in the 1990s to go on until 2030+ now. That is going to be a challenge."

Saul also warns against spending less money up front for a short-term solution: "If you go down the bespoke, redesign route, you could end up adding two or three noughts to your costs." OE

Designs for the future

Jeannie Stell speaks with classification organizations ABS and DNV GL to discuss today's trends in new pipelay vessels.

Bigger is better, when the object of discussion is offshore pipelay vessels. Today's generation of pipelay vessels, and almost all of the associated on-deck equipment components, have been upsized because, for example, larger reels equate to more pipe that can be spooled into place with less reloading required. Larger and more robust engines and highly developed geo-positioning technologies mean the pipelay vessels can remain in place for long work periods – even in harsh environments. And new engine designs bring fine-tuned efficiencies to the forefront of operations to ensure fuel conservation for economics and reduced emissions.

"In the past five years, we have noted the growing demand for pipelaying vessels in deeper waters," says Mike Sano, manager of energy development for ABS. "As a result, large pipelaying assets were designed and delivered to satisfy this demand. One of those was Saipem's *Castorone*."

The *Castorone* is an ABS ice-class pipelay vessel built for Saipem. The Navalimpianti Tecnimpianti Group was contracted to design and assemble the vessel's pipe handling and storage system. Engineering assistance for the completion of the design was provided by ship design firm Navalprogetti.

Mike Sano

With a handling capacity of more than 500m/hr of pipe, the vessel's pipe-deck receivers, handling and storage systems minimize the transfer time between the pipe barge and pipelay vessel holds. A full contingent of 702 workers can be accommodated onboard the vessel, and it has a 4300sq m of cargo deck area.

The *Castorone* is fitted with a knuckle boom crane that has a safe working load at a 30m outreach at 600-ton, and at 46m, the outreach is 350-ton. Additionally, the vessel includes two gantry cranes, each with 52-ton capacity at 35m, three tensioners of 250-ton each and an abandonment and recovery winch.

For dynamic positioning (DP), *Castorone* has eight side thrusters, two bow thrusters, six azimuth thrusters, and a fully redundant class-3 control system comprising two HiPAPs (high precision acoustic positioning) for 3000m of water depth and two differential global positioning system reference systems.

"It was designed to have both S-lay and J-lay capabilities in deepwater, and can handle up to 48in diameter pipes," Sano adds. "That vessel has been working for a couple of years now. It had a tremendous backlog of work." On her first assignment, the new vessel performed marine activities for the development of the Chevron-operated Jack/St. Malo fields in the US Gulf of Mexico (GoM).

Even as owners, operators, shipbuilders and designers geared up for an exciting new generation of pipelay vessels, with some record-breaking megastars already delivered, the vessel market

With a handling capacity of more than 500m/hr of pipe, the Saipem *Castorone* pipelay vessel's pipe-deck receivers, handling and storage systems minimize the transfer time between the pipe barge.
Photo from HGG Group.

began to recede as a result of the oil price crash.

"The level of offshore activity has dropped significantly," Sano says. "This has impacted the offshore support vessel fleet, such as pipelay vessels, because many of the oil companies' projects have been put on hold or significantly moved to the right."

Arnstein Eknes, special ships segment director for DNV GL, agrees.

"The oil prices will have the effect that many new or planned offshore fields with a high break-even level will be delayed or put on hold," he says. "The situation today is that the backlog for companies engaged with planned subsea activities is quite good for this year, then very much weakening next year. Many of the EPC companies utilizing pipelay vessels are reducing their manning to adapt to a reduced cost and activity level, hence making it more likely that the market for newbuild vessels will remain weak."

New designs

When the economics recover, or possibly even before then, some new pipelay vessel designs could be brought to the market. "I think we will probably see more pipelay vessels designed specifically to work in harsh environments," Sano says.

"For example, Shell has proposed a drilling program in the Arctic that will need pipelines to flow well production to midstream facilities," he says. "But, currently, there are no harsh environment pipelay vessels. I think that is something we will probably see in the future, because subsea pipelines make sense, to keep the lines away from ice formations and bad weather."

Another new development is the inclusion of liquefied natural gas (LNG) as vessel fuel. "This is a new focus for the industry," Sano says. "ABS has been involved with LNG as fuel for OSVs for more than five years now. In fact, earlier this year, Harvey Gulf International Marine introduced the first LNG-fueled supply vessel in the GoM."

Shell contracted the *Harvey Energy*, a 302ft offshore supply vessel to carry equipment, drilling hardware, fluids and other supplies to Shell's deepwater operations in the GoM. The *Harvey Energy* sets an example for future pipelay vessels, with its three dual-fuel Wärtsilä engines that can be powered by 99% LNG fuel and can be operated for nearly seven days before refueling.

"If used in pipelay vessels, LNG fuel could enhance fuel efficiencies, reduce costs and abide by new sulfur and nitrogen oxide emissions regulations necessitated in the North American Emission Control Area," Sano says. "LNG produces less emissions. It also is cleaner as it burns inside an engine, so it helps to lower maintenance costs. Diesel and other liquid fuels leave behind residual particulate matter in the engine that causes contamination of the lube oil and abrasives that wear down the cylinder liners over time."

But, the technical challenge will be to refuel LNG-powered pipelay vessels offshore. "There will need to be some type of LNG bunker barge that is capable of delivering LNG fuel offshore," Sano says.

"The lack of bunkering vessels can explain why 16 out of 17 offshore vessels presently fueled by LNG are operating in the North Sea where they now have good and close access to LNG bunker terminals onshore," Eknes says. "Without a proper market within a region for a bunker vessel, a pipelay operator will need to build alliances with the LNG distributor directly in order to safeguard own bunker supply. Technically, this is fully possible. The key question will be if the players find it commercially attractive to lead the race knowing that the full benefit will come when you have at least two bunker suppliers available. This is why we do a lot of scenario building together with operators and ship designers assessing the long term economics of different fuel alternatives."

Diesel-electric engines

Another efficient technology is diesel-electric engines. "These can be used to provide the right level of power to the vessel when it needs it, which results in more efficient operations," Sano says.

Earlier vessel designs had a direct-drive diesel engine powering the propulsion. With a diesel-electric design, all of the propulsion is electric. As a result, the engines can produce energy as efficiently

Pipelay market outlook

Audrey Leon spoke with Infield Systems' analysts James Hall and Wei Liu to get the bigger picture.

According to Infield Systems, the offshore pipeline installation market over the next 12 months will be challenging. Infield has revised down its three-year forecast for pipeline installation capex by approximately 25% as the market downturn tightened. Spending for the period is now anticipated to be about 10% lower than the 2012-14 period, sitting at some US$45 billion.

The operators hurt the most during the downturn have been the tier two- and three vessel players, Infield says, while larger vessel operators have opted to make reductions in workers and business segments. Subsea 7 announced in May it would cut its global workforce by 2500, and cut 11 of 39 vessels from its global fleet. Technip followed in June saying it would reduce its global workforce by 6000 and sell two of its vessels. In July, Saipem followed suit implementing $1.4 million cost-cutting program that will downsize operations in Brazil and Canada, scrap five vessels, and reduce 8800 employees through 2017.

Hall and Liu say that Africa will drive pipelay demand growth, however, risks remain if low oil prices end up pushing back large scale projects in Angola, Egypt, and Nigeria. Additionally, Infield expects moderate growth in Latin America due to a few gas export projects in Brazil and Mexico. Although, by the end of the decade, Australasia demand will be led by expansion of the Darwin LNG projects, the pair say. North America, according to Hall and Liu, will likely see pipelay demand shrink in the coming years as shallow water activity in the Gulf of Mexico has been negatively affected by the onshore shale boom.

Due to high sanction costs and significant capex reductions, Infield sees European pipelay activity through 2015-17 will be moderate, with an annual installation of 1200km. The pair say this is a 50% drop from forecasts a year ago.

However, it's not all bad news, Infield expects that some recovery will be felt in 2H 2017, although a 6-12 month lag will experienced by the pipelay fleet.

Hall and Liu say that during the coming two years (2015-16) global pipeline installation is anticipated to average 8035km per annum, 33% lower than forecast a year ago. Major delays or cancellations within the coming 12-18 months include the Russia-Bulgaria-Romania South Stream trunk line, the Algeria-Sardinia- Piombino pipeline project through Algeria to Italy. The Shah Deniz BW project in Azerbaijan and the Callantsoog (Balgzand) - Bacton (BBL) development in Netherlands. ■

The ***Castorone.*** Photo from Saipem.

as possible while also having access to additional power when needed. Also, the response time, in relation to the variation in power demands, is significantly shorter, which drives the quicker transfer of power to the ship.

DNV GL's Eknes agrees. "With the currently reduced oil price, the necessity to reduce cost is evident," he says. "A natural consequence of this will be to reduce the amount of fuel being used onboard. The opportunity to implement more flexible power systems onboard, such as a combination of different engines to ensure a flexible and capable power plant configuration, is one of the key trends happening these days."

Battery technology is also a buzz word these days, adding electrical storage and availability of power as key features. "To gain full benefit from batteries onboard, operating alone or in a hybrid mode with other engines, it is still important to maintain a reliable DP function and power during a critical pipelay operation," Eknes says. "Together with the guidelines for maritime battery systems (2014), DNV GL's new rules for propulsion and power generation published this year will act as a guide for how to safeguard operation while tapping into the benefits of reduced engine running hours, less emissions and a more flexible & reliable system onboard."

No silver bullet

"There is no silver bullet in this market, as far as we are aware, with regard to design or equipment for pipelay vessels," Eknes says. "The drivers toward deeper and harsher environments will continue in the long run, but the most pronounced driver supporting pipe-laying activity is probably the strong trend to develop more subsea, and also shallow water with tie backs to existing installations."

Offshore evolution necessitates the incorporation of new technology, Sano says. "Pipelay vessel capabilities will continue to expand as industry moves into new frontiers – becoming not only larger, but faster, safer, and more efficient." **OE**

Challenging times

Europe is facing a tough downturn, but it will not last forever. Rystad's Audun Martinsen takes a look.

The development of offshore oil and gas reserves in Europe is losing relevance in the battle with shale resources in North America and conventional oil in the Middle East.

The ongoing fight over market share has flooded the market with cheap oil and resulted in a lowering of the oil price to a level that makes the resources in mature offshore basins more challenging to develop.

Offshore producing countries in Europe are fighting escalating costs and operational inefficiencies to become more competitive in the new world order of oil.

In 2014, we saw more than US$100 billion being directed to the development and production in Northwest Europe for the first time ever. This equates to an average 9% annual growth from 2009-2014 and was caused by more activity and higher unit costs in both Norway and the UK.

Even with rising demand of oil and oil prices, we do not expect the spending to grow to these levels again for the rest this decade. Companies will conserve cash, focus on completion of existing projects and await the business outlook.

The Norwegian Continental Shelf

In Norway, exploration and production companies spent about $51 billion in 2014, a 6% growth from 2013. The Norwegian oil and gas sector is far from sheltered and is expected to decline in 2015 by about 9%.

Most of the decline is driven by capex cuts, estimated at about 11%. The drop is an effect of a normalization of extraordinary activities from the 33 greenfield developments committed to between 2010 and 2013, such as Gudrun, Goliat, Eldfisk II. In addition, it is also the effect of cost cuttings and efficiency programs by Statoil. Statoil aims to reduce their maintenance, modification and operations budget and increase the drilling efficiencies substantially.

Looking towards 2020, there are a lot of uncertainties in investment estimates, specifically regarding the sanctioning of new projects and exploration levels. For example, Statoil has pushed back the final investment decision (FID) on both Johan Castberg and Snorre 2040 – both expected to be multi-billion dollar projects with new platforms (floaters); FID's are now expected by 2H 2017, with startup around 2022-2023.

With this current timeline, these projects are important to meet the forecasted 2020 expenditures of about $55 billion. Other key projects are Johan Sverdrup phase 1 and 2 and potential developments of the Skarfjell, Alta/Gohta and Pil discoveries. In the current forecast, a relatively flat exploration capex at around $5-6 billion has been assumed from 2016 onwards after peaking at $7 billion in 2014.

Clair Ridge modules onboard Dockwise's *Mighty Servant* transport vessel earlier this year. Photo from BP.

UK Continental Shelf

The UK Continental Shelf (UKCS) was surpassed by the NCS to be the largest oil and gas market in 2006. In 2014, the UK almost closed the gap with $46 billion expenditure on upstream activities.

2015, on the other hand, will be much more dramatic for the UK than for Norway. The money spent will drop by more than 20%, and we will see the spend contract even more in 2016, before stabilizing at around $35 billion at the end of the decade.

The reason for this immense drop is an extreme case of what we observed in Norway – record high oil prices and inflation, which led to massive investments and rejuvenation programs in old discoveries and fields.

Some 58 greenfield investments started between 2010 and 2013, such as Clair Ridge, Quad 204 and Mariner. So when completion simultaneously occurs and investments stop, there are only a few new discoveries to be developed.

The current field development boom observed on the NCS includes a healthy mixture of old discoveries having matured into economical projects and discoveries made over the last decade. Comparing discovered volumes at the NCS with the UKCS, pinpoints one of the key issues for the UKCS – that exploration results have been persistently poor and on decline since activity peaked in 2007-08.

In 2008, 121 wildcat and appraisal wells were drilled at the UKCS and 444 MMboe of oil and gas were discovered. Since then the exploration activity has decreased and in 2014 only 38 exploration wells were drilled and only 98 MMboe of oil and gas were discovered.

Glancing ahead towards 2020, the portfolio of stand-alone candidates that could spur UK greenfield investments is limited to a handful. The Culzean field is the first runner up. Operated by Maersk Oil, it could see a final investment decision in August 2015 with startup in 2020-2021.

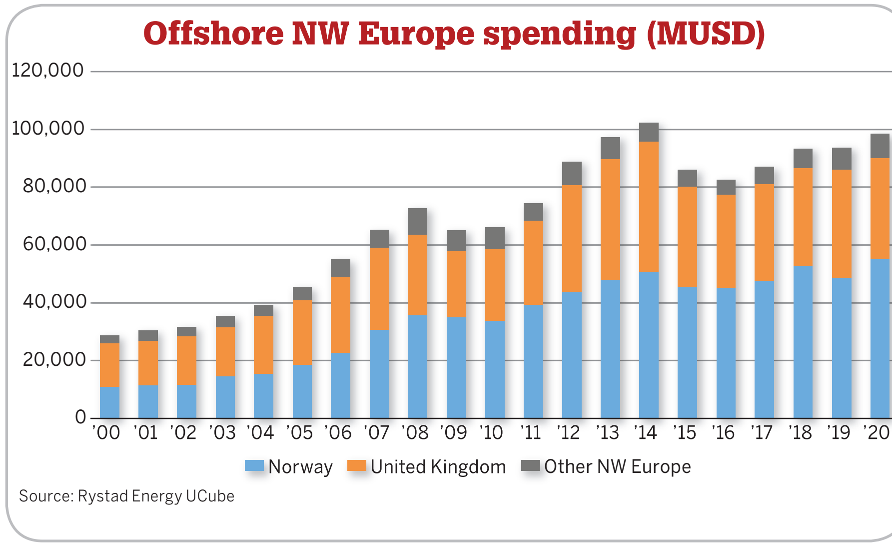
The field is to be developed with bridge linked platforms including a central processing facility, a wellhead platform, and combined utility-living quarters. The total investment for the project is expected to be in excess of $4.7 billion.

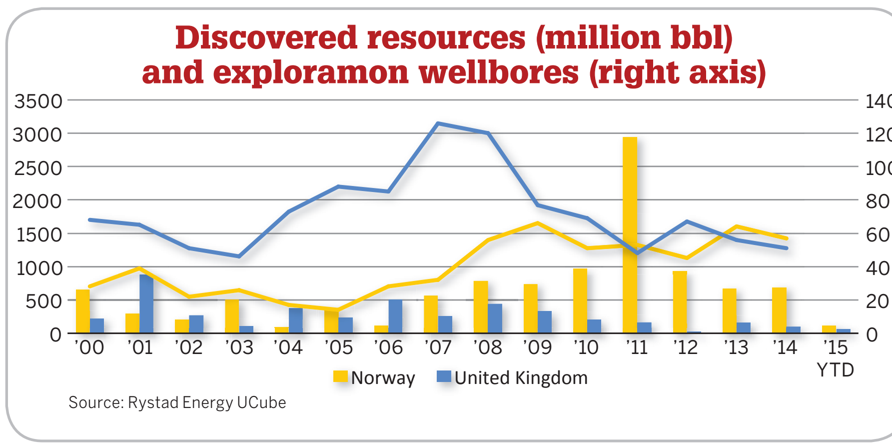
Chevron has not given up on its challenging Rosebank development west of Shetlands and Statoil is expected to decide on a concept for the Bressay heavy oil field in 2015. The British government has introduced different measures for tax reduction, supporting investments in maturing offshore prospects and exploration, to improve the dark outlook. There is still potential to maximize the recovery from the UKCS, and hopefully, through the fiscal changes and the current cost cutting schemes, there could be a significant upside.

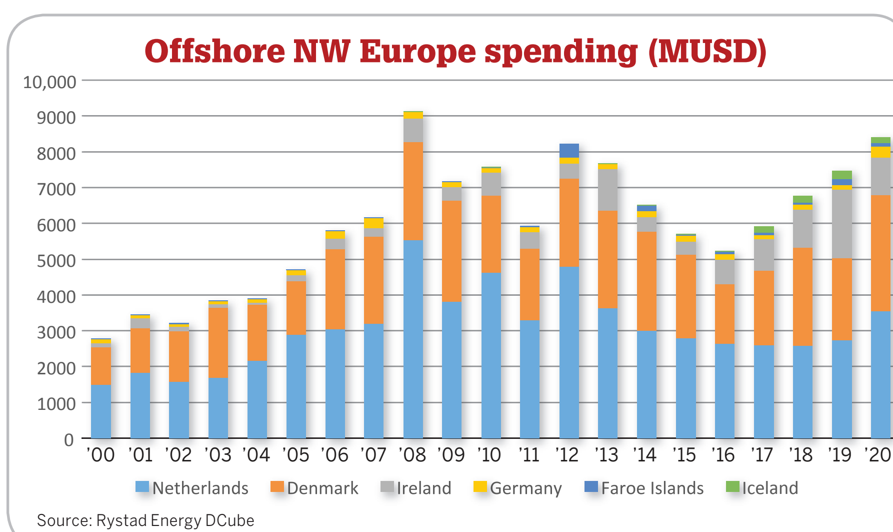
Other Northwest Europe

Outside Norway and the UK, the market has been declining since 2008. From $9 billion in 2008, 2014 clocked in at $6.5 billion. The Netherlands and Denmark have been the key drivers of this decline. In general, these markets are mainly driven by brownfield spend at existing producing fields. There is limited exploration and new developments, but some other basins show positive signs. In Ireland, there is good progression around the Barryroe development, and smaller undeveloped discoveries can become commercial with new developed infrastructure.

In Iceland there is still an unrealized potential at the awarded Dreki region and future license rounds in the North East. Although some growth is expected from 2016, the offshore European market will still be dominated by the markets in Norway and the UK, and both will see a new wave of importance at end of this decade. OE







__Audun M. Martinsen__ is the product manager and lead analyst of oilfield services at Rystad Energy. His fields of expertise include the global offshore and onshore oil service market, E&P cost analysis and supply and demand studies. He holds a MS in marine engineering from the Norwegian University of Science and Technology (NTNU) and University of Berkeley, California. He previously worked at Coriolis, Shell and BW Offshore where he has worked as a lead engineer, product developer, system consultant and analyst.

Current North Sea major projects

With help from Infield Systems, *OE* charts the current, ongoing major projects in the market place in Northwest Europe, covering the UK Continental Shelf, offshore Norway, Denmark and the Netherlands.

Project/ shelf	Operator	Topsides	Jacket	Notes	Reserves
UK Continental Shelf					
Cygnus Blocks 44/11A and 44/12A	GDF Suez E&P	Four platforms, three bridge-linked: accommodation platform, built at Burntisland Fabrication (BiFab), Scotland, wellhead (2 x 1640-tonne) and 4000-tonne process and utilities platforms and a compression module, being built at Heerema Fabrication Group (HFG), Hartlepool, compression platform with bridges and other structures, HFG, Hartlepool. Due March 2014-2015. Hartlepool delivered the ACM, PU and Bravo Cygnus decks July.	Four jackets and piles (total weight 8000-tonne) being produced by BiFab at its Methil, Burntisland and Arnish yards.	2014-2015 installation campaign by Seaway Heavy Lifting using the *Oleg Strashnov*. The APU topsides will be heaviest lift *Oleg Strashnov* has ever performed. The Ensco 80 drilling rig in use throughout.	Gross proven and probable reserves of 18 Bcm gas
Mariner 9/11a	Statoil	Production, drilling and quarters platform with 50 well slots, being built by Daewoo Shipbuilding and Marine Engineering (DSME) South Korea, with a floating storage unit alongside being built by Samsung Heavy Industries (SHI). Drilling supported by a jackup for the first 4-5 years. Heavy lift operations is being carried out by Saipem while Subsea 7 has the SURF contract. Odfjell Drilling are carrying out the drilling services. **See page 46.**	21,000-tonne jacket: largest to be built by Dragados Offshore, Cadiz, Spain. Due to be installed September 2015. On 28 July, Dragados loaded out the large jackets for Mariner.	Production due to start in 2017. Aker Solutions contracted for engineering during the hook up phase.	250 MMbbl recoverable
Bressay 3/28a	Statoil	Concept initially developed to mirror Mariner, but it is being revised in 2015, with final investment decision expected 2016. Statoil is still looking at a simplified development concept compared with earlier plans			100-300 MMbbl recoverable
Culzean 22/25	Maersk Oil	12 slot wellhead platform, central processing facility and utilities/living quarters. KBR contracted as topsides front-end engineering and design provider. Wellhead access deck at HFG Hartlepool. MODEC and Teekay Offshore competing for FSO contract. However, in May 2015, Maersk asked for revised bids for the infrastructure of the field.	Ramboll Oil and Gas awarded detailed design for two jackets for the central processing facility platform and a separate utilities and living quarter platform. 2100-tonne wellhead jacket to be built by HFG, sailaway March 2016.	Targeted start up for 2019	Reserve estimates remain under wraps. Although Maersk said it could provide about 5% of the UK's total gas consumption by 2020-2021
Fyne 21/28a	Antrim Energy	Production buoy concept under consideration working with Enegi Oil, license currently lapsed.			Proven plus probable reserves of 11.7 MMbbl
Montrose Arbroath Redevelopment 22/17	Talisman Sinopec Energy UK	9500-ton topsides, HFG, Zwinjdrecht, Netherlands. Due out March 2016.	5400-tonne jacket built by OGN, Newcastle. Sailed out 2014		Proven and probable reserves estimated at 38 MMboe plus 58 MMboe of possible resources
Lancaster	Hurricane	**See page 58** for a detailed feature on Lancaster.			
Darwin block 211/27a	Taqa Bratani	Up to 21 subsea wells tied-back to either a fixed platform host facility or FPSO. Feasibility studies are ongoing.		Southern end of the former North West Hutton field. First oil anticipated in 2020	29.6 MMboe
Perth 15/21C	Parkmead	**See page 42** for a feature on the Perth hub concept.			
Bentley Block 9/3b	Xcite Energy	MOU signed with Teekay for a bridge-linked Sevan design floating storage and offloading facility to be linked to a self-installing ACE MOPU platform, with a newbuild N-Class drilling rig alongside.			250 MMbbl proven and probable reserves
FPSOs					
Catcher 28/9a and 28/10c	Premier Oil	FPSO to be supplied by BW Offshore. Hull being built by IHI Corporation of Japan.		First oil due 2017	96 MMboe
Kraken Blocks 9/2b and 9/2c	EnQuest	Bumi Armada will supply and operate the FPSO (an ice-class tanker conversion to 600,000 bbl capacity) for the heavy oil project.		First oil due 2017	140 MMbbl gross oil reserves
Glen Lyon 204/20a	BP	The Quad 204/Schiehallion redevelopment. *Glen Lyon* FPSO being built by HHI in South Korea. Due to be installed in 2016. **See page 87**.		First oil due 2017	Estimated recoverable oil reserves of 450 MMboe
Western Isles 210/24a	Dana Petroleum	Sevan-type FPSO being built under contract with China's COSCO.		Behind schedule, due on stream 2H 2017	Recoverable reserves of approximately more than 45 MMbbl

Project/ shelf	Operator	Topsides	Jacket	Notes	Reserves
UK Continental Shelf (continued)					
Captain	Chevron	New bridge-linked platform to house EOR process equipment for the Captain heavy oil field.			360 MMboe
Cheviot Blocks 2/10a, 2/15a and 3/11b.	Alpha Petroleum	FPSO redevelopment of the Emerald field. Xodus Group awarded pre-FEED study this year with field development plan and environmental statement to be submitted 2H 2015.		First oil planned for 2020	Remaining recoverable reserves of at least 55 MMbo and 100 bcf
Greater Stella Area block 30/6a	Ithaca Energy	*FPF-1* floating production facility is being upgraded at Remontowa's yard in Poland.		Sailaway scheduled for 1Q, 2016, with first production 2Q 2016.	Proven and probable reserves of about 32 MMbbl
Rosebank 205/1	Chevron	292m-long, 99,750-tonne FPSO, initially due to be built by Hyundai Heavy Industries (HHI). Project on hold to reassess economics.			Infield estimates 240 MMbo and 400 Bcf
In commissioning					
Clair Ridge 206/08	BP	Drilling and production platform and quarters and utility platform, fabricated by HHI, installed this summer.	22,300-tonne and 9000-tonne jackets built by Aker Solutions, Norway, installed in 2013.	Supported by *Flotal Victory*. Due onstream mid-2017	Recoverable reserves of 640 MMbo
Alma/Galia 30/24 and 30/25	EnQuest	7 production wells tied back to the *EnQuest Producer* FPSO, previously Bluewater's *Uisge Gorm*, capable of processing 57,000 boe/d and storing 625,000 bbl crude oil.		Due onstream mid-2015	2P reserves of 34 MMboe
Solan 205/26a	Premier Oil	3500-tonne topsides built at Methil and Arnish yards, Scotland, installed 2014.	8000-tonne jacket, built at BiFab, Methil. Installed 2014.	Due onstream 2015	30 MMbbl proven and probable oil reserves
Norway					
Ivar Aasen PL 001B, 028B and 242	Det Norske	15,000-tonne platform, built by SMOE, a subsidiary of Sembcorp, in Singapore and Batam, Indonesia, due to be lifted into place in 1H 2016.	9000-tonne jacket built by Saipem at its Arbatax facility in Sardinia and installed June 2015.		Recoverable reserves of 210 MMboe
Aasta Hansteen	Statoil	Deck and living quarters for spar development, HHI, South Korea. Living quarters subcontracted to Hertel, Rotterdam.	Spar hull, consortium of HHI and Technip	Start up due 2016. First production spar on Norwegian Shelf.	Estimated 47 Bcf (recoverable)
Martin Linge (formerly Hilde)	Total	22,600-tonne topsides, SHI. Living quarters to be fabricated in Norway by Apply	Jacket and piles weighing 21,400-tonne, Kvaerner, installed 2014.	FSO part of the project. Due onstream 2016.	Recoverable reserves of 190 MMboe
Gina Krog	Statoil	Topsides to be built by DSME, South Korea. Living quarters to be built at Stord, module in Poland.	17,000-tonne launch jacket, HFG Vlissingem, Netherlands. Installed June	Due onstream 2017	Estimated 225 MMboe
Edvard Grieg	Lundin	21,000 tonne topsides, Kvaerner.	13,400-tonne jacket, Kvaerner Verdal, installed 2014	Due onstream 4Q 2015	Proven and probable reserves of 186 MMboe
FPSOs					
Vette (Bream)	Premier Oil	Sevan-type FPSO to be owned and operated by Teekay Petrojarl on lease.		First production due in 2019	Probable reserves of 54 MMboe
In commissioning					
Goliat	Eni	Sevan-type FPSO built by HHI in Ulsan, South Korea.		Due onstream 2015	Recoverable reserves of 178 MMboe
Denmark					
Hejre	DONG Energy	Topsides, Technip/DSME consortium, South Korea, pre-drilling wellhead deck, HFG, Netherlands	HFG jacket 8000-tonne delivered last year.	Had been due onstream in 2015, now scheduled for 2017 due to topsides delays.	Recoverable reserves estimated at about 170 MMboe
Netherlands					
P11-E	ONE	HFG is building an unmanned 500-tonne topside and 1000-tonne jacket powered by solar and wind energy. **See page DO-12** of the *Dutch Supplement*.		Sailaway due April 2016	
A18	Chevron	950-tonne topsides and 1200-tonne jacket. *See Dutch supplement.*			Infield estimates 170 Bcf

Adding EOR to Quad 204

BP has been making strides in LowSal enhanced oil recovery techniques and Bright Water. It now has its sights set on polymerized water for its Quad 204 development. Elaine Maslin found out more.

Onshore, enhanced oil recovery(EOR) using polymers is an established practice. Offshore it is a different ball game and, until now, not quite mastered by the industry. But, after a string of projects, mostly pilots, operators are getting to grips with offshore polymer EOR.

EOR technologies are attractive because they can help operators increase their reserves – without having to spin the exploration bit. According to France's Total, global conventional recovery rates are about 32% of oil in place; improving this performance by 5% could add some 300 billion of additional reserves.

Polymer EOR is like water flood, but it involves increasing the viscosity of the water using polymers to stabilize the flood front and help divert water from high-permeability zones (potentially already swept) to improve sweep efficiency and aid additional oil recovery. However, it is also expensive and typically most cost-effective on more viscous oilfields or, where oil in place is large, on moderately viscous fields.

To date, polymer use for EOR offshore has been limited to a handful of projects. Since 2003, CNOOC has been using polymer from platforms on its heavy oil fields in Bohai Bay, offshore China, first as a pilot and then extending it across 27 wells on three oilfields by 2010*. Total was first to take polymers on a floating production, storage and offloading (FPSO) vessel deep offshore with its polymer EOR pilot on the Camelia field offshore Angola in 2010-11, with a skid-mounted injection pilot on the deck of the *Dalia* FPSO. More recently, Chevron, in the UK North Sea, has been trialling polymer EOR on the Captain heavy oil field, a project which has led to plans for a new bridge-linked platform on which it can store, mix and pump polymer.

Others have been considering offshore schemes, with Statoil working on pilots at Heidrun, Norway, and Peregrino, Brazil. BP now looks set to join the polymer party.

Further to its multi-billion pound redevelopment of the Schiehallion and Loyal fields, known as the Quad 204 project, West of Shetland, BP has been considering introducing polymer EOR. The Quad 204 project involves a newbuild FPSO, the 270m-long *Glen Lyon*, which will become the North Sea's largest unit once operational, onto which BP is planning to pre-invest in key polymer injection facilities. If the subsequent polymer project goes ahead, it will be the first deepwater subsea polymer EOR project.

Quad 204

Quad 204 is 175km West of Shetland. Schiehallion was discovered in 1993, and Loyal a year later, with production starting in 1998 from the *Schiehallion* FPSO, which the *Glen Lyon* replaces. Schiehallion and Loyal together had more than a billion barrels in place and recovery to date had been about 15%.

Recognizing the greater potential of the area – BP has produced ~400 MMbo to date and thinks there's a similar amount to be had – and both the falling efficiency and limitations of the original *Schiehallion* FPSO, the operator, with partners Shell and OMV, decided to redevelop the field through the Quad 204 project, investing in the new, higher capacity *Glen Lyon* FPSO, subsea infrastructure renewal, a seven-year drilling program, with at least 20 new wells

BP's *Glen Lyon* FPSO taking shape in South Korea.
Photo from BP.

planned, as well as pre-investment in key polymer EOR facilities. As a result, it hopes it can maximize recovery to above 30%.

Key to the project has been improving liquids handling capability. The *Glen Lyon*, due onstream in 2016, will have 320,000 b/d liquids capacity. It will be needed. Some 380,000 b/d of water injection capacity will be installed to sweep the field and maintain pressure, with the vessel having a capacity to produce 130,000 bo/d.

For Quad 204, which had been under a water flood scheme since 1998 (with 50%+ water cut in places), a large part of the benefit of polymer is that, through reducing the mobility of the water, less water will be produced, freeing up valuable plant capacity for more infill wells or tieback opportunities.

"When you inject regular water in to the field, the water fingers through the reservoir and leaves oil that has not been swept, which can get left behind," says Scott Thomson, area subsurface manager, BP. "If you use polymer, instead of creating fingers, the polymerized water moves in a more piston-like and efficient manner. That is the traditional industry application of polymer flood.

"Quad 204 is a bit different," Thomson says. "Our new wells will benefit from the traditional mechanism of piston-like sweep, but because we have already produced several millions of barrels from the field and we have been injecting water for some time, there are huge chunks of the field where the water has already broken through at the producers.

"We are less interested in delaying water breakthrough in these areas and more interested in capturing some of the oil that has been left behind via the mechanism of viscous cross flow," he says. Viscous cross flow happens when pressure gradients created by the polymer-flood force water into parts of the reservoir that were previously bypassed by fingering.

Using polymer will also have another, significant, beneficial effect. Despite being set to be the biggest FPSO in the North Sea, the *Glen Lyon* will still have limitations, i.e. there's only so much water you can produce. This would mean that production has to be choked back. "We want to reduce the fractional flow of water into our facility and polymer helps us do this," Thomson says. "The polymer effectively slows down the water in the reservoir and means the water cut is reduced at the surface. With less water coming to the surface, we can open up more wells and accelerate production."

An intense subsea campaign is ongoing West of Shetland, ahead of the FPSO's arrival.
Photo by chrisallanphotohraphy.com.

Powder or emulsion?

Once a decision has been made to use polymer, the next step is looking at how it is deployed, including in what form it is supplied, and overcoming the challenges around deploying it.

There are two ways polymer can be supplied, in powder form and, more recently, as an emulsion. In most onshore deployments, polymer is supplied in a powder form, which requires a mixing process before it is injected downhole. The risk with having the polymer supplied as powder, especially offshore, is inefficient powder wetting, creating inconsistencies in the mix, which can adversely impact well injectivity.

As an emulsion, the polymer molecular chain is delivered coiled up within a water droplet, within an oil main phase. Water is then added to the emulsion, which allows the water droplets to join, enabling the polymer chains to unfurl and link, causing the water to viscosify. This is called "inverting" the emulsion. "We believe the emulsion will be easier for us to handle and to prepare for injection in the relatively harsh environment, deepwater, West of Shetland," Thomson says.

The next challenge is deployment. Many large offshore fields that could be suitable for polymer EOR may be viewed as having limited application because they have been developed using subsea wells. Offshore, because the polymer is injected from topsides, it has to go through various restrictions, such as the choke, as it flows into the wells. Onshore, injection could be downstream of the choke, which can be prohibitively expensive for subsea wells.

"Every restriction poses an opportunity to damage the polymer," Thomson says. "The polymer unfurls in the dilution process to the specified viscosity. If the polymer chain is then stretched and sheared as it passes through a restriction, it loses some of that viscosity. You could overdose the polymerized water, but all the wells are choked at different rates, so the polymer will shear differently in each well. We are looking at ways to get the target viscosity to the reservoir without shearing the polymer. We have ideas how we can overcome these problems and improve commercial performance."

Wider benefit

BP is also working with vendors to test polymers for this application. Getting it right could be a game changer for the vendors, as well as BP, Thomson says. A successful EOR project in the Schiehallion and Loyal fields will create a large demand for polymer, the production of which may require new manufacturing facilities. This in turn would make polymer for EOR more widely available to the broader industry.

Although the Quad EOR project is still only in concept development with several technical and commercial hurdles to overcome, BP and its partners are working hard to make polymer deployment in the North Sea a reality. **OE**

******SPE paper SPE-144932-MS, presented at the SPE Enhanced Oil Recovery Conference, Kuala Lumpur, 2011.*

OE would like to credit SPE Aberdeen and DEVEX, which held events at which Thomson and Collins spoke about the project, respectively.

Busy work

Introducing a new FPSO into a brownfield while overhauling the subsea infrastructure led to a complex multi-year SIMOPS campaign for Technip. Elaine Maslin reports.

SIMOPS, or simultaneous operations, has been the name of the game on the subsea decommissioning and installation campaign on BP's Quad 204 project.

Technip is the main contractor and had the task of removing and then installing new subsea infrastructure in a complex, multi-year, multi-vessel campaign.

With five drill centers, and gas lift and water injection planned, a lot of subsea infrastructure is needed on Quad 204. In addition to its own vessels, this year Technip has also had to contend with the semisubmersible drilling rig *Deepsea Aberdee*n starting operations in field as well as the *Island Constructor* offshore construction and light well intervention vessel. At any one point, there has been up to 10 boats working in the field.

"In terms of vessels, this is one of the busiest projects we have worked on. We typically had three in the field last year. This year it has been five, six, and even seven at one point in early March," says Richard Wiley, project director for Quad 204, at Technip.

Some 18 risers were recovered and 14 moorings. For the installation campaign, Technip supplied 23 new risers, as well as the associated DMAC connectors and buoyancy modules, 78 jumpers and 15 corrosion resistant alloy (CRA), metallurgically bonded clad pipe pipelines. Most of the manifold, controls, jumpers, connectors were provided under free issue from BP suppliers.

In field, Technip's scope is to reconfigure and install the jumpers, install fly to place connections for new structures and five static umbilicals, as well as installing 15 new CRA pipelines, the new *Glen Lyon* FPSO, 23 risers, 99 flexible pipes and 20 moorings. What's more, it made its largest ever bend stiffeners for the project, through Aberdeen based Balmoral Group.

Richard Wylie

To handle the DMAC riser connection system tooling, BP also commissioned two new tooling stores, given free issue to Technip, such is the scale of the project.

In total, the project will have involved about 2500 vessel days over 4-5 years, Wiley says, with some 800 people within Technip having charged time to the project. "The challenge for us was the scale of the project," he says. "The size and scale of the project had ramifications on how to organize the project team. The weather and limited construction season West of Shetland also had to be taken into consideration and because of the weather, the design is for a 100-year wave height of 31m, which makes everything that bit bigger. It is also a brownfield project, which means it's very crowded, so you have to be very careful where you put stuff."

To handle the multiple work streams, Technip split the project into three, with about 100 people in the project team. The first work stream was dedicated to flexibles, the second split into two construction teams, one for seabed and one for in the water column, and the third for HSE, QHSE and contracts.

Key to the SIMOPS has been using GIS to track all the boats and remotely operated vehicles (ROVs) in the field. With it, the operators can all see where all the other vessels and even the ROVs being used are.

The campaign started in 2013-14, with field disconnection and the old *Schiehallion* FPSO removed. The FPSO mooring system was recovered and wet stored and flexible jumpers and fly to place connections disconnected and recovered.

In 2014, the installation of the new field infrastructure started, with a new mooring system installed, new structures, two static umbilicals and flexible jumpers laid down, eight CRA-clad rigid pipelines installed. The wet store riser hold back installed.

In 2015, the program continues with another seven CRA-clad pipelines manufactures and installed, 21 risers, three static umbilicals, and deployment and tie-in of control jumpers and flying leads, with the drill centers the key focus ahead of drilling starting this year and the arrival of the *Glen Lyon* FPSO. Decommissioned control jumpers will also disconnected and recovered. In 2016, the last remaining structures will be installed. **OE**

A GIS image shows the complexity of the SIMOPS at Quad 204, with the photo showing the same view from the surface.

Images from Technip.

Focusing on efficiency

High oil prices in a mature basin led to a tight market and cost escalation. With low oil prices, the industry is working hard to rein in spending. Elaine Maslin spoke to Oil & Gas UK CEO Deirdre Michie on some of the initiatives underway.

Taking over the reins of the UK North Sea's leading industry body at a time when depressed oil prices are exacerbating the already price-pressured sector may seem an unwelcome task to many.

Oil & Gas UK CEO Deirdre Michie appears up for the challenge. Up until 1 May, when she took over from long-standing CEO Malcolm Webb, Michie was working for supermajor Shell, where the graduate in Scots Law had a 30-year career in senior UK and global upstream and downstream management positions.

When she took over, WTI crude was US$55/bbl, half that from just under a year before, after falling from a four-year steady high at around $100. But, even at that high, the North Sea was under pressure – with cost escalation and skills shortages.

Before the price collapse, government and industry had already recognized the situation was unsustainable, not if the UK's resources were to be "maximized." Some key recommendations from Sir Ian Wood's *Maximising Recovery* report have already been put in place, including setting up a new regulator (the Oil and Gas Authority) and government support for new seismic.

But, undoubtedly, more needs to be done. "Our focus is on cost efficiency," Michie says. "The regulator has been set up, Treasury and the fiscal piece is happening and they are committed to working with us.

"It's all about optimizing the engineering, rather than what a commercial barrel is. The industry is very good at engineering, but it is about applying an innovative approach to standardization and thinking about that."

Dierdre Michie

Photo from Oil & Gas UK.

"Our piece is cost and efficiency, recognizing we have become incredibly inefficient and that costs got out of control," she says. "Production efficiency had dropped from 80% to 60%, and lifting costs were $30/bbl. That's not sustainable. Companies where looking at this at $110/bbl, before the [low] oil price, recognizing the cost base was not sustainable and something needed to be done."

But, she says: "It takes time. You can take out costs relatively overnight, and we have seen that. Where we are seeing more and more sustainable changes coming through is on efficiency."

In this area, Oil & Gas UK is building a "box of stories," or good examples, to share with the industry. For example, Nexen studied the Tour de France winning Sky Team's marginal improvements ethos. The Sky cycling team made gains because they focused on every way possible they could make marginal improvements. By following this ethos, Nexen reduced wrench time in one shift from 8, down to 5.5 hours. "That's a huge improvement and the fact they got the workforce involved in the process really helped," Michie says.

French oil major Total is working with its technicians and operators to use visualization technology when they are putting a job in place to look at what they need to do. It helps them create a more efficient process – cutting 10-12% of the time it previously took them to do a particular job, Michie adds. In another example, Centrica Energy held a hackathon – an event bringing together contractors to see what the operator and they could do to generate ideas on how they can work together. Some 70 people attended and generated hundreds of ideas. Centrica is now helping EnQuest run a hackathon with its suppliers. Centrica also has a "save $100 million in 100 days" campaign internally.

One of the questions the industry has to ask itself is how it became so inefficient and unsustainable. It's a combination of things, Michie says. "We had a hot market with the high oil price driving certain behaviors. It is also a mature basin and things are more complicated and more challenging than a greenfield site," she says. "The combination of these factors drives behaviors and we have woken up to the fact that this is not a sustainable way to go about. Even with a high oil price, it would still be inefficient.

"Whatever happens, we need a more sustainable efficient model," she continues. "It's all about optimizing the engineering, rather than what a commercial barrel is. The industry is very good at engineering, but it is about applying an innovative approach to standardization and thinking about that."

Oil & Gas UK has a tranche of projects ongoing. It is planning a campaign promoting industry collaboration. "Where aerospace and automotive industries made their breakthrough was when they came together to cooperate," Michie says. Oil & Gas UK is also running project to benchmark contractor rates and it is looking at how spares utilization can be used through cooperation. This year, Oil & Gas UK released guidelines to both reduce and optimize the number of shutdowns and turnarounds.

A group driven by Oil & Gas UK has also been set up to focus on business process, standardization and behaviors and cultures. "It is about moving forward with early adopters and if we can demonstrate a couple of companies can so this you will get everyone coming with you," Michie says.

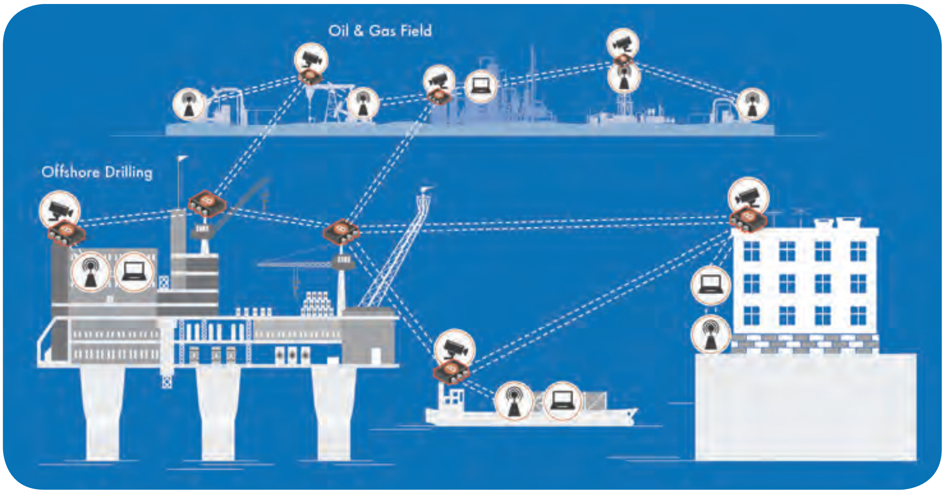
Business processes will focus on the inventory management piece, i.e. spares utilization. "Inventory is sitting around and no one has any idea it's there. Improving management of this means having the right spares at the right time and reducing wrench time," Michie says.

Standardization and simplification will focus on a number of areas, such as valves standardization, having standard subsea modules to put in place and replicate, and in wells plugging and abandonment having a standardized approach to improve the efficiency of P&A operations. Oil & Gas UK already recently released new guidelines around well abandonment, including cost estimation guidelines to help improve estimate accuracy.

For cultural behaviors, there is an alignment needed, Michie says. "Moving from competition to cooperation is a challenge – it is a competitive industry. We have a supply chain code of conduct, which needs updating with an 'efficiency head' on, rather than a process head. It's also about shared KPIs (key performance indicators)," she says. Sharing efficiency measures will also be a key theme at the next Pilot Share Fair.

But, it's also all about how people ask questions and what questions are asked. If operators ask the supply chain the right questions, giving them scope to deliver solutions, rather than just asking them to take out costs, it would be a good start. OE

Wireless to the rescue offshore



A kenetic mesh network in action on and offshore oil and gas rig. Image from Rajant Corp.

Communication is key, even offshore. Gregory Hale examines how wireless can improve operational efficiencies.

A gas producer offshore needed to modernize an aging 30-year-old wellhead platform off Southeast Asia to optimize output of its wells.

An oil rig in the Gulf of Mexico needed to coordinate traffic coming into and going out of the vicinity of the platform. These are two separate scenarios, but the producers knew the most economic and efficient answer was wireless.

In an environment where a barrel of oil dropped from its heady days of over US$100 to hovering in the $40-50 range, producers have to find all the efficiencies it can get. Wireless is one way to pull in as much data as possible to glean more visibility into what is going on and help squeeze out inefficiencies.

"It is all about operational efficiencies right now," says Kirk Byles, vice president of Rajant Corp. "You put the rigs together and they cost billions of dollars and they have to get the oil and how do you make things more efficient.

"Part of the efficiency is the communications piece," he says. "It can just be as simple as reading a monitoring station or meter that says we need to put more pressure on the down pipes to get more oil out they might not have seen before.

"That itself would save (producers) a few thousand barrels a day," he says. "It is very quick to see the operational efficiency. It pays for itself in under a year and sometimes within a month."

As offshore operations demand smarter and cost-effective application solutions, the traditional practices relating to physical equipment are changing. Along those lines, wireless is handling condition surveillance, machine-to-machine communication, smart sensors and data transfer techniques.

According to a paper written by Malka N. Halgamuge and Priyan Mendis from the University of Melbourne, Australia and Jayantha P. Liyanage, from the Center for Industrial Asset Management at the University of Stavanger, Norway, such an intelligent environment will end up based on three principal components:

1. Smart sensors that continuously or periodically monitor the condition of a given item automatically, and transfer signals to receiving units on the health of the item.

2. Data processing and analysis solutions that compile complex data within designated units, process and analyze them for feature/pattern recognition.

3. Advanced data transfer and communication channels that connect a given set of data sources to a given set of user groups/decision makers located remotely. Sensor networks embedded within the physical equipment configuration of a facility allowing real-time 24/7 signal transfer between an identified set of units will have major contributions on the technical and safety integrity assurance processes.

Slip in efficiency

Average production efficiency dropped in the past decade, while the performance gap between industry leaders and other companies widened, from 22% in 2000 to 40% in 2012, according to a McKinsey & Co. report.

Benchmarking data also illustrates the broad opportunity for improvement. Best-in-class players do not incur higher costs to improve production efficiency, and high performance does not link to a specific asset type or the maturity of assets. Instead, companies with high production efficiency are often similar in their quality of operations, approach to eliminating equipment defects, equipment choices, and planning and execution of shutdowns, the report said.

Regardless of location, most oil and gas producers face issues that complicate efforts to achieve sustained production-efficiency improvements.

Let's face it, in large and complex offshore facilities, it is impossible to install a fully featured physically wired network to oversee what is going on 24/7. A wireless sensor network can help bring about real-time monitoring and automatic control of vital applications.

The oil industry wants private networks where producers can get data off and on the oil rigs.

Wireless in action

In the case of the Southeast Asia platforms, the platform is a hub with 16 active wellheads as well as production headers from four nearby platforms, with power generation equipment to support the five platforms. If there is an issue on any of the platforms, production losses could last for days. As they say, time is money.

As a result, the producer implemented a mixture of wired and wireless devices during the retrofit to optimize monitoring and control of the platform while keeping power limited.

Wireless instruments now monitor wellhead status on all 16 wells of the hub, as well as gas receiving for all five platforms, production headers, and the fuel skid. The plan minimized power and space requirements and gave the user reliability needed to optimize production.

Routing traffic

In the case of the rig in the Gulf of Mexico, it had a series of boats or helicopters coming in for docking or landing. The rig needed to monitor and have communications with them and the company didn't want to reconfigure the network whenever one vehicle left or joined the area.

One way to create a better communications forum, they felt, was to create a wireless network around the rig.

"We created a 'bubble' around one of the largest oil rigs in the Gulf of Mexico," Byles says. "They had flotillas of maintenance boats and all kinds of boats coming in and out, helicopters landing. They couldn't communicate with them very well as they were getting closer to the rig or leaving the rig."

The rig operator deployed about five portable wireless nodes on the oil rig, one on the top and one on each corner of the rig. These nodes were not fixed points, users could move them without any changes in network configurations.

"We created the 'bubble' around the rig and they put the nodes on all the vehicles that had to communicate with the rig. When they came within a mile or two they could communicate with the rig just like they had run a wire to the boat, and on the boat they could have WiFi or wired access to the rig," Byles says. "And they could communicate to other vehicles with a node as well. All of a sudden you have a web of connections around the rig at a very high speed and not have to worry about a connection going down as long as they were within the range."

They can ensure no lost communication because the wireless nodes use multiple frequencies so they can direct the data packet — whether it was voice, video or data in any direction.

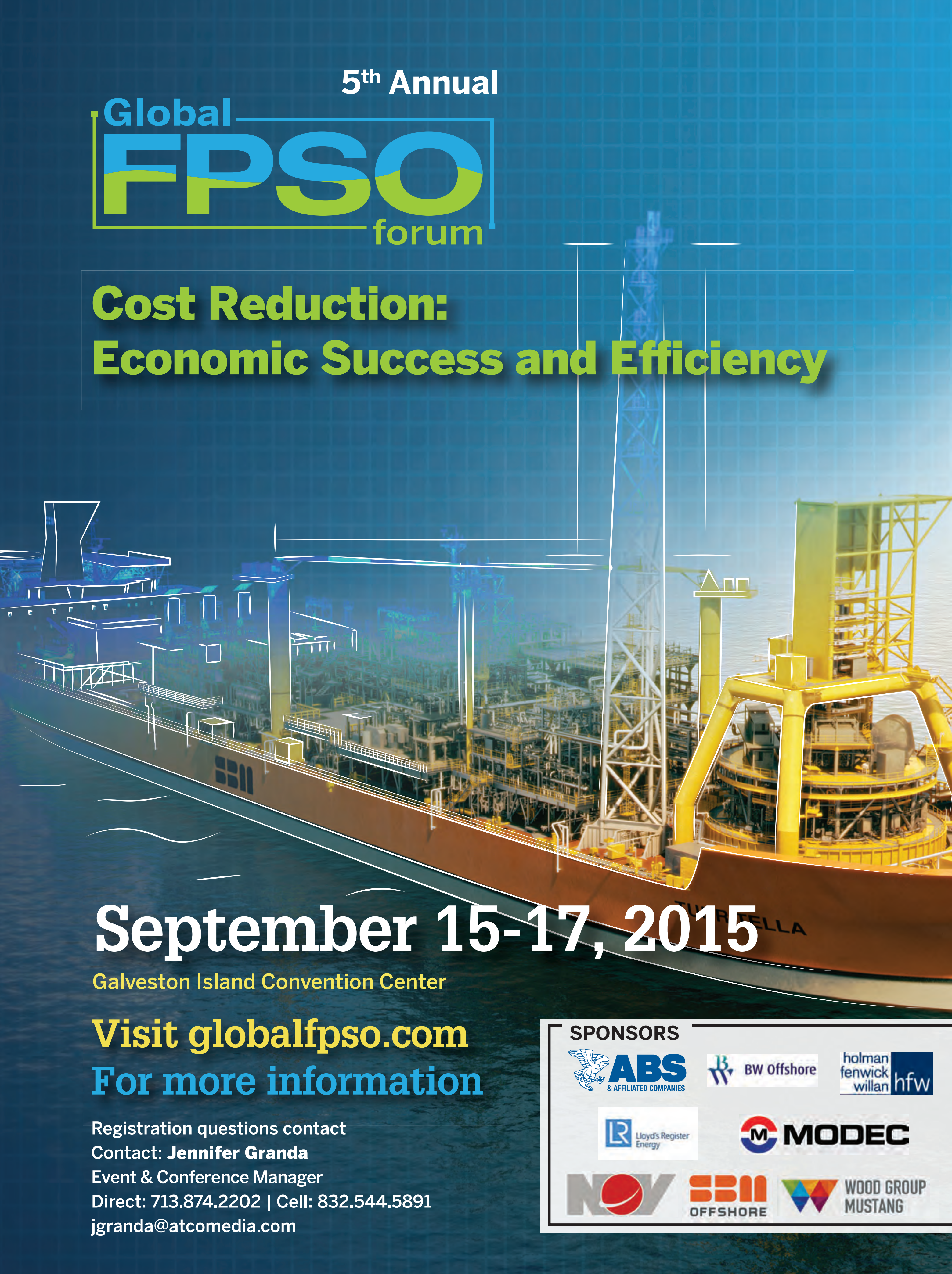
The node is a multi-radio box with a motherboard and software. "In that box, you have different radios running on different frequencies. There could be a 900 MHz radio, 2.4 GHz radio, or a 5.8 GHz radio or even a 4.9 GHz radio. What that provides is the ability to mitigate interference and to take on different propagations," Byles says. "You have all these different frequencies to work with, as you move all these boats around there may be interference on the 900 so you might be able to pass data using the 2.4 or the 5.8."

"(The rig) was able to provide a mobile network and there was no real configuration, no need to maintain any routing cable, and no controller to worry about. Each node was a piece of the infrastructure. The more you put into the mesh, it became stronger and stronger. The data overhead continued to remain low, sub one millisecond between mesh nodes and there was no limit to how many mesh nodes you could use," Byles says.

The oil industry is going through some tough times, and it needs real-time answers to complex problems.

In the end, it always ends up being about communication. There are solutions to those problems; whether it is a remote gas field in Southeast Asia or routing traffic into and round a rig in the Gulf of Mexico, wireless automation can provide answers. **OE**

***Gregory Hale** is the editor and founder of Industrial Safety and Security Source (ISSSource.com) and is the contributing Automation editor at Offshore Engineer.*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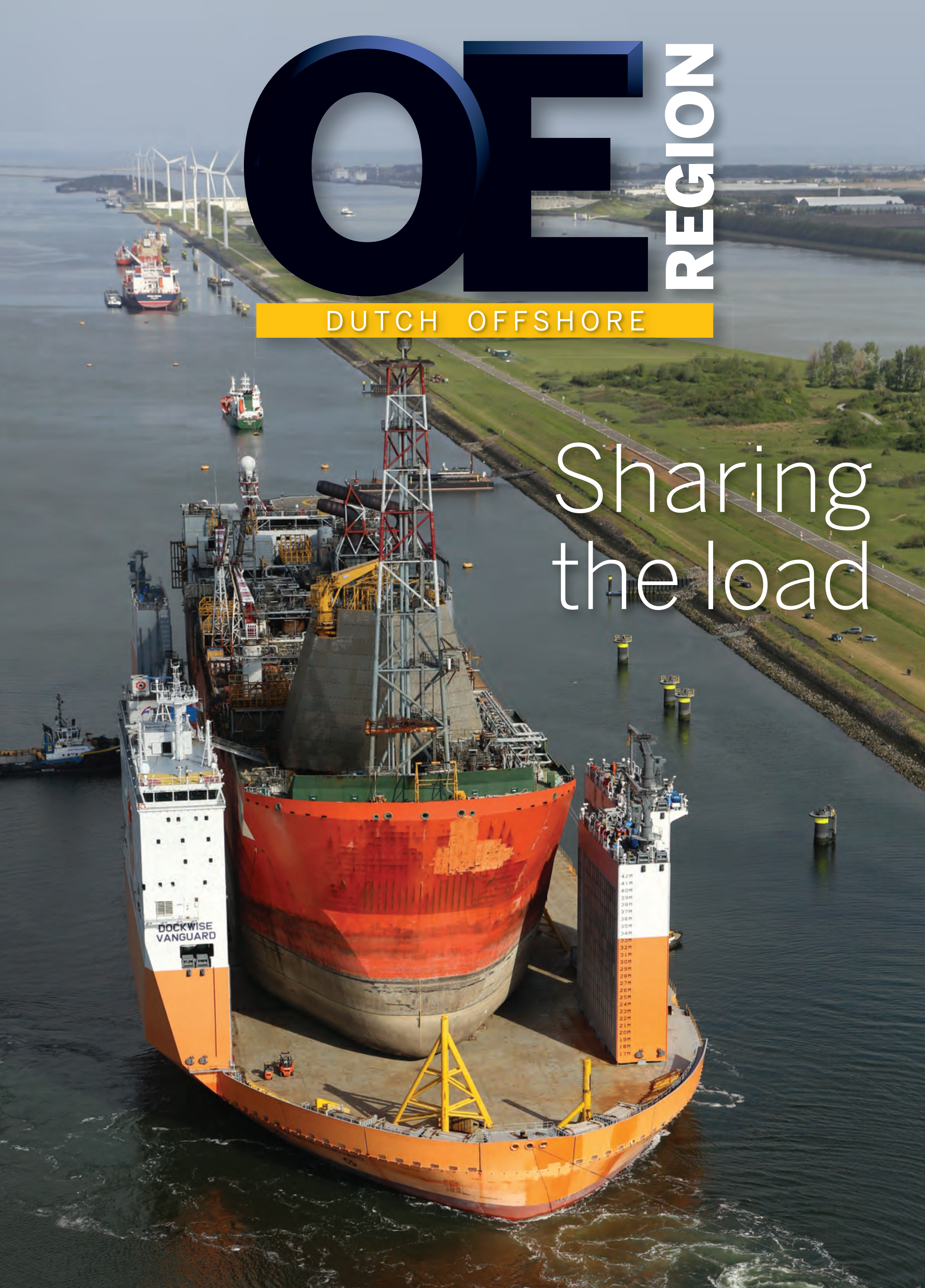
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- ☐ 02 Engineering or Engineering Mgmt.
- ☐ 03 Operations Management
- ☐ 04 Geology, Geophysics, Exploration
- ☐ 05 Operations (All other operations personnel, Dept. Heads, Supv., Coord. and Mgrs.)
- ☐ 99 Other *(please specify)*________________

2. Which of the following best describes your company's primary business activity?
(check one box only)
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- ☐ 22 Independent Oil & Gas Company
- ☐ 23 National/State Oil Company
- ☐ 24 Drilling, Drilling Contractor
- ☐ 25 EPC (Engineering, Procurement., Construction), Main Contractor
- ☐ 26 Subcontractor
- ☐ 27 Engineering Company
- ☐ 28 Consultant
- ☐ 29 Seismic Company
- ☐ 30 Pipeline/Installation Contractor
- ☐ 31 Ship/Fabrication Yard
- ☐ 32 Marine Support Services
- ☐ 33 Service, Supply, Equipment Manufacturing
- ☐ 34 Finance, Insurance
- ☐ 35 Government,Research, Education, Industry Association
- ☐ 99 Other (*please specify*)________________

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(check all that apply)
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- ☐ 701 Recommend
- ☐ 702 Approve
- ☐ 703 Purchase

4. Which of the following best describes your personal area of activity?
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- ☐ 102 Drilling
- ☐ 103 Sub-sea production, construction (including pipelines)
- ☐ 104 Topsides, jacket design, fabrication, hook-up and commissioning
- ☐ 105 Inspection, repair, maintenance
- ☐ 106 Production, process control instrumentation, power generation, etc.
- ☐ 107 Support services, supply boats, transport, support ships, etc
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True to style

Sander Vergroesen, managing director, the Association of Dutch Suppliers in the Oil & Gas Industry (IRO)

The 2014-15 oil price collapse has unquestionably severely dented confidence in the global offshore oil and gas industry, with job losses above 150,000 and tendering largely on hold.

But, true to style, the Dutch are not panicking. While many are having to make adjustments to their businesses, as operators cut or delay spending amid US$60/bbl prices, backlogs are still being worked through and there are still opportunities.

When markets change, the characteristically innovative and adaptable Dutch are able to respond accordingly, says Sander Vergroesen, managing director, the Association of Dutch Suppliers in the Oil & Gas Industry (IRO), be it offering new cost saving solutions or looking to new markets, such as renewables, decommissioning or emerging economies across the globe. They also have a trump card – the willingness to work together.

"Our business is one of boom and bust," Vergroesen says. "This is the third drop since 1996, so we have seen this cycle before and most of the companies, they have seen this coming, more or less. Yes, it was sudden, but there had to come a time for the industry to slow down a bit."

Many companies are still busy, fulfilling existing orders, but the next year and a half will be a challenge, because order in-take is at a minimum level, Vergroesen says. "The operators are waiting to see what is happening with the oil price, so all the decisions are being postponed." But, there are opportunities, he says. "If you come up with solutions, which can reduce costs, that's what everyone is looking for. There are opportunities in other parts of the industry, too. Companies that can use their knowledge and equipment for decommissioning oil and gas fields, for example, could find that they will be using it on decommissioning sooner than they thought, because decisions to shut down fields could be taken earlier than originally expected."

Vergroesen says the Dutch also see opportunities in countries where, despite the oil price, there is still a growing demand for energy and the local governments wish to draw on their own reserves instead of importing oil and gas. "That's an opportunity in the future and they often need help doing this," Vergroesen says. "They need the knowledge and that's what we have."

IRO recently ran a trade mission to Mexico, a country that has decided to focus on unlocking its own reserves, the result of which has been major market reform enabling the entry of internationals in the country after a long state monopoly. "We see more of these areas coming up," Vergroesen says. "Of course it takes a while, but there are opportunities. Abu Dhabi has allocated $25 billion for offshore developments, this is another example."

As a once major maritime nation, with considerable engineering skills developed over the years at home and overseas, the Dutch seem to have maritime engineering in their blood. But, they also have another skill, which has meant they've been able to leverage each individual company's strengths – the willingness to collaborate.

An example of how the industry collaborates to create new solutions is the *Kroonborg*, a walk-to-work vessel designed by Wagenborg working with Dutch operator NAM and supermajor Shell and built at Dutch yard Royal Niestern Sander Shipyard. It uses walk to work technology from Dutch firms Ampelmann and Barge Master (see page DO-23).

"That is the kind of solution operators are looking for," Vergroesen says. "Instead of flying crew to a facility with a helicopter, which is sometimes grounded by the weather, or boats, which only work in a certain wave height, they can use this and stay on board, going from one installation to another with ease. You can also use a crane on this vessel with these waves because of the Barge Master system. This kind of solution, where operators, suppliers, work together is a Dutch solution," Vergroesen says. ■

Wagenborg's *Kroonborg* multi-purpose vessel. *Photo from Wagenborg.*

Step by step, the 60,000-tonne *Armada Intrepid* is loaded onto the *Dockwise Vanguard*.

The *Vanguard* of ocean transport

Heavy transport firm Dockwise performed a market first with the transport of a ship-shaped FPSO, the *Armada Intrepid*. Elaine Maslin explains.

When the *Dockwise Vanguard* was conceived, Dockwise, part of the Boskalis Group, had a vision for a new market – transporting the world's largest cargos, including floating production, storage and offloading (FPSO) vessels.

It hasn't taken the vessel – the largest of its kind – long to prove its worth, as well as the feasibility of such a feat.

The vessel recently delivered its first ship-shaped FPSO cargo, Bumi Armada's *Armada Intrepid*, which also happens to be one of the three largest cargos ever transported. It's worth noting, before delivering the ship-shaped *Armada Intrepid*, the *Dockwise Vanguard* had only just completed the transport of the cylindrical, Sevan-design, *Goliat* FPSO from Hyundai Heavy Industry's yard in South Korea to Hammerfest, Norway, for Eni Norge - then *Vanguard's* largest cargo.

What's more, the 110,000-tonne capacity *Dockwise Vanguard*'s next major job will be yet again bigger in size and weight – Total's 85,000-tonne, 250m-long, 60m-wide *Moho Nord* floating production unit (FPU), which will be transported from Hyundai Heavy Industry's yard in Bulsan, South Korea, to West Africa early 2016.

All three projects are feathers in Dockwise's cap. However, transporting the FPSO is the biggest and serves to prove the ship-shaped FPSO transport concept. Being able to transport FPSOs using a heavy transport vessel offers FPSO operators and owners a faster and safer alternative to the current industry norm – slower wet tows using tugs.

"This is opening a new market," says Taco Terpstra, senior project manager for the *Armada Intrepid* project, Dockwise. "We just completed transporting the heaviest cargo (the 107m-diameter, 64,000-tonne *Goliat*), and now the *Armada Intrepid*, our first ship-shaped cargo. Next, we will be getting ready for *Moho Nord*. To have these three contracts in a row shows why we brought the *Dockwise Vanguard* to the market."

Safe loading

The *Armada Intrepid*, previously known as the *Schiehallion* FPSO while it was working for BP, west of the Shetland Islands, was safely and successfully loaded on to the *Dockwise Vanguard* in Rotterdam's Caland Canal on 8 May, just eight days after the heavy transport vessel's arrival in port.

The job, loading and transporting the *Armada Intrepid*, posed the Dockwise project team some interesting and unique challenges, due to the dimensions of the cargo. Terpstra says: "The configuration of the loading marks this out from other projects. At first sight, it looks like a normal transport, but what's quite novel is that it was the first ship-shaped FPSO we transported on the *Dockwise Vanguard*. Weighing 60,000-tonne (42,000-tonne plus ballast), it is among the top three heaviest cargos ever transported. That, in combination with its ship-shape, with a 245m-long, 45m-beam hull, makes the this project quite interesting."

Unlike normal loads, which are positioned on the *Dockwise Vanguard*'s 275m x 70m deck by ballasting the vessel beneath the water line and floating the load across its beam, the *Armada Intrepid*, which is too long to float across the beam, had to be floated over the deck via the *Dockwise Vanguard*'s stern, carefully slotting between the two aft casings, or stability boxes, with just 2.5-3m leeway either side.

This loading configuration meant more handling (tugger and tow lines) was required compared to normal jobs, due to the careful maneuvering required. Getting the water depth and tidal window right was key, making loading location and timing crucial.

Preparation was also key. The *Dockwise Vanguard* first had to be cleaned, following its transport of the *Goliat* FPSO. Then, the vessel had to be fitted with cribbing material – a 600mm-high wooden layer fixed with angle bars bolted to the deck, on which the *Armada Intrepid* or any other load would rest. In addition, the guide posts, against which the FPSO is positioned, had to be installed. All of this was done before 8 May.

To make sure the FPSO remained secure during the transit, about 54 sea fastenings were fitted once the vessel was loaded.

During the voyage, the FPSO, sea fastenings and cribbing were regularly inspected and, for this transport, Dockwise tried something new – permanent, real-time pressure monitoring on the cribbing.

All in all, it's a big job. For Leerdam, the biggest achievement is proving the FPSO transport concept.

Photos from Dockwise.

"For me, this is an innovation, a first," he says. "We are able to show to the market this is a better, faster, more efficient solution to transport ship-shaped FPSOs from one side of the world to another, be it for refitting or new builds. The alternative is a wet tow – at half the speed. We expect the *Dockwise Vanguard* to cruise up to 12 knots. Wet tow speed is about 6-8 knots. You can also be more flexible, going around bad weather. You are safer and more in control."

In fact, insurance premiums for wet tows are 10 times more expensive than the dry tow alternative, showing that insurance companies recognize that dry transport is a safer solution, says Hans Leerdam, category manager, strategic vessels, Boskalis Offshore.

The *Dockwise Vanguard*, with the *Armada Intrepid* on board, arrived in Batam, Indonesia, 8 July, having sailed via the Cape of Good Hope, without the need for tugs and in less time than a wet tow would have taken.

Now Dockwise is preparing the *Dockwise Vanguard* to transport the *Moho Nord*, in 1Q 2016, with possibly another job in-between.

To accommodate the *Moho Nord*, a vessel wider than the *Intrepid*, Dockwise had been considering removing one of the aft casings, for the loading, and then reinstalling them. The firm is now planning a permanent solution, which will mean moving the vessel's aft casings further apart, on permanent out riggings, to make the slot big enough for the *Moho Nord*, and other similar wide-beam units, to float in across the stern, like the *Intrepid*, Leerdam says. ■

Taking Bravenes steps

Van Oord has been taking its engineering expertise in the dredging sector and applying it to the oil and gas business – with much success. Elaine Maslin reports on a first in deepwater and a new market.

Van Oord's new rock installation vessel, the *Bravenes*.
Photos from Van Oord.

Family-owned, Van Oord has a luxury – it can do things differently. And the firm, traditionally a dredging contractor, is doing just that, creating new possibilities and new markets as it does so.

Last year, the company set a world depth record for rock installation, on the Aasta Hansteen development and associated Polarled pipeline, using its flexible fallpipe vessel *Stornes*, which will continue work on the project this year and into next.

Through working with an American operator offshore Australia, Van Oord has also developed a new way to ease pipelines down steep inclines, a technique since adopted and used offshore Norway for Statoil.

In both cases, there was no market before Van Oord came up with a solution. In deep water, pipelines were built thicker to withstand long freespans, as rock installation wasn't thought an option. For laying pipelines crossing steep and deep submarine ridges alternative routes were found or long free spans again had to be incorporated.

Van Oord is also investing. It has a new rock installation vessel, the *Bravenes*, being built at Sinopacific Shipbuilding Group Shanghai's yard in Ningbo, China. It will be able to install rocks in three modes, and, with a shallow draft, be able to operate in both shallow and deepwater up to 600m.

"Developing new technologies will develop new markets," says Cor Jan Stam, offshore engineering manager for Van Oord. "When you have a new technique or technology, that is cost effective, it will generate a new market."

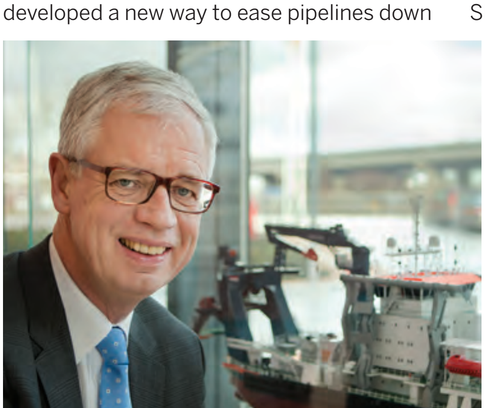
The industry certainly needs it. In the current low oil price and slashed spending climate, costs are under the microscope. "A lot of projects have been delayed or canceled and everyone has been used to certain levels of cost, which has been increasing over the years," says Joep Athmer, managing director, Van Oord's offshore division. "Now everyone in the supply has to get used to different costs, be cheaper and more efficient without cutting corners in safety. Productivity has to increase on the contractor and operator side."

But, there are still opportunities, he says. "The opportunities are reducing the paper work. One of the reasons for the enormous increase in costs has been more and more specifications. Every operator has their own standards, making it difficult for us to comply. There is also going to be work around facility replacement – such as old pipelines and installations – as well as LNG. Those are, for us, some of the opportunities in the future."

Deepwater record setting

Last year, Van Oord set a record for the deepest water rock installation campaign, on the Aasta Hansteen project and associated Polarled pipeline. Over a four-week campaign, using the *Stornes* flexible fallpipe vessel, with some modifications, the firm performed pre-lay rock installation in up to 1277m water depth, mostly to enable a stable support for the pipeline, which would otherwise be on unstable seabed. This summer it has been performing post-lay installation. In total, some 300,000-tonne of rock will have been installed, mostly on the deepwater section of the pipeline and some infield pipelines.

Over winter 2014-15, the *Stornes* was further modified, at Dutch firm Damen Shipyards, so that it can install rocks in deeper water for longer, in greater quantities and in a broader weather window. This meant splitting the fallpipe in two and hanging the two sections off two different hang off points on the vessel, spreading the increased weight, effectively doubling capacity from 900-1000m water depth to 2000m. "This has created a market where



Joep Athmer, managing director, Van Oord's Offshore division, Koos van Oord.

Cor Jan Stam, Offshore Engineering manager for Van Oord.

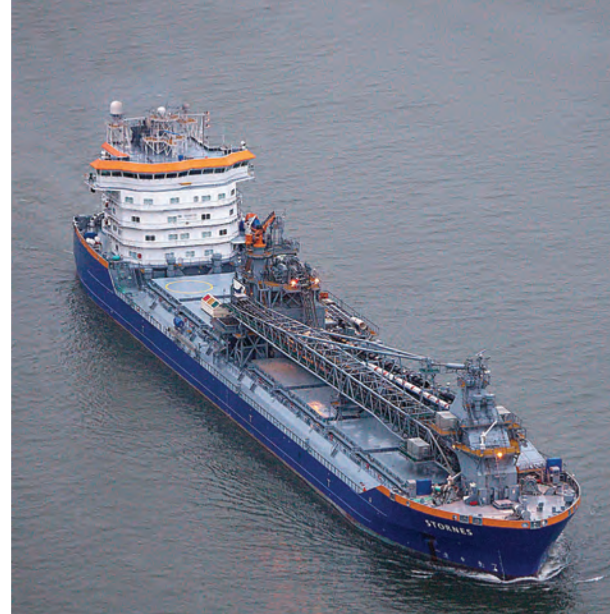
there was not one before," Cor Jan Stam says. "They were just not able to install rock at this depth. Now there is the ability and we think it will create its own market."

Deep excavation

Working with a client, Van Oord has created what it sees as another new market for the oil and gas industry, through its deep excavation system (DES). Created initially to solve a problem to laying a pipeline down a ridge, dropping, for example, from 600m to 700m water depth, over only 50m, offshore Australia, Van Oord created a system to dredge the edge of the escarpment so that the pipeline could better follow the curve, without bringing subsoil to surface. Van Oord designed the system using a hydraulic grab, controlled by the fallpipe vessel's ROV, from the end of the fallpipe. The 3m x 2m grab scoops up subsoil and places it to one side, using the propulsion inside the ROV and without moving the vessel. "This technique is more controlled than water jetting and can deal with harder soils," Cor Jan Stam says. Its accuracy, due to the ROV positioning, means that it can also be used near coral reefs. Van Oord has since invested in making the system more efficient and it is also being used on Polarled, where the seafloor has deep scours from passing icebergs.

Fleet addition

Van Oord also saw an opportunity when it ordered its new vessel, the *Bravenes*. It wanted to replace its oldest flexible fallpipe vessel *Tertnes*, but also wanted to add a shallow draft vessel to its fleet, which was also capable of deeper water work and handling larger rock for maximum flexibility, says Koos van Oord, area manager Subsea Rock Installation at Van Oord. *Bravenes*, due to be completed yearend 2016, is a modern Ice class 1A, X-Bow style design vessel with DP3. It can work in close proximity to platforms thanks to an over the side tremie pipe system as well as through its moonpool. It will also be able to handle larger size rocks and will be Van Oord's most high-tech rock installation system, incorporating a semi-automated system, linking the DP3, with ROV subsea positioning and rock distribution systems. Its accuracy will help reduce the amount of rock needing to be installed, Van Oord says.



Van Oord's flexible fallpipe vessel *Stornes*.

Flexibility

Key to the firm's success has been adapting its marine engineering expertise from the dredging industry and applying its skills in innovative ways to the oil and gas industry, Athmer says. "We are a marine contractor bringing all our knowledge to the offshore market," he says. "Focusing on the problem and inventing new technologies, more versatile and more economic solutions." ▪

A18 Topside for Petrogas Transportation at HSM Yard, Schiedam, NL. Images from HSM Offshore.

Delivering on-time

Meg Chesshyre speaks with HSM Offshore business development manager Jaco Fleumer about the firm's current work program and future prospects.

First off the blocks in mid-July is the Flyndre Cawdor over Clyde modules M12 (1200-tonne) and M14 (400-tonne) being built for Aker Offshore Partners – on behalf of Clyde operator Talisman Sinopec Energy UK – for the UK/Norway cross-border Flyndre Cawdor project operated by Maersk. HSM had a procurement and construction contract here with Aker Solutions providing engineering assistance. Installation is expected to be by Heerema Marine Contractors.

Fabrication of the Dutch sector A18 satellite platform for Petrogas was on target for delivery from mid-August onwards. The EPCI contract comprised a 950-tonne topsides facility and a 1250-tonne jacket with engineering support provided by Iv-Oil & Gas. Installation is being carried out by Seaway Heavy Lifting using its 5000-tonne capacity heavy lift vessel *Oleg Strashnov*. Drilling will start once the platform is in place with first gas looked for around the turn of the year.

The A18 satellite platform is almost a carbon copy of the B13 platform, which HSM supplied to Chevron in 2011. Petrogas bought Chevron's Dutch sector operation last year. The A18 platform will be installed in the shallow gas fields (6-800m as opposed to a norm of around 2000m) in the northern part of the Dutch Continental Shelf. Special technology is needed here, because of the relatively low pressure, including sophisticated sand screen techniques. HSM Offshore supplied the risers for the tie-in of the pipeline coming from the A18 platform to the existing process system of the A12 platform. It is likely that more fields will be developed in the shallow gas fields area in due course.

Offshore high voltage substation for Horns Rev C for Energinet.dk currently under construction at HSM Yard, Schiedam, NL.

The 330-tonne E17a-A compression module for ENGIE (previously known as GDF SUEZ) was due for delivery by end-August – a procurement and construction contract with Iv-Oil & Gas on engineering support. The gas compression module will be installed on the existing E17a-A platform in block E17 of the Dutch continental shelf, about 100km northwest of Den Helder. The four-legged E17a-A platform was built by HSM Offshore in 2009, and has gas treatment and export facilities. The module will be installed by Tideway, using the self-propelled heavy lift jackup Neptune.

HSM started work this summer on an EPC contract for an 1800-tonne offshore high voltage sub-station for Denmark's Energinet.dk Horns Rev C wind farm, with KCI providing engineering services. HSM delivered the first Horns Rev A sub-station back in 2002, and a second one, Horns Rev B, in 2008. There has been a steady growth in the capacity of the sub-stations from 160MW for Horns Rev A, to 250MW for B, then 400MW for C.

Fleumer was confident that there is more offshore work in the pipeline, and was awaiting the result of current tendering. He said that HSM was always very keen to carry out EPIC contracts, because of the added value resulting from taking the interface risk. This was the ideal contract format for new entrants into the North Sea with limited contract staff.

Fleumer concedes that "the oil and gas market remains challenging, at least for the next year or so," with projects taking a long time to mature, because there was very little financing available. With rig rates coming down, hopefully more exploration would follow, leading to further new developments eventually, he says.

The renewable market, on the other hand, had stabilized, with a steady flow of work expected from the UK, Denmark, Germany and Belgium. HSM has a good track record in this market, including the delivery of a 325MW, 2200-tonne deck to the Belgian sector Thornton Bank project in 2012. Fleumer sees a lot of commonality in the two markets, needing the same fabrication and load-out facilities. ■

Fast fabrication

Cygnus PU sail away.
Photos from Heerema Fabrication Group.

Meg Chesshyre talks to Heerema Fabrication Group CEO Koos-Jan van Brouwershaven about the firm's latest projects.

The Alba B3 compression platform.

Heerema Fabrication Group (HFG) is benefitting from the timely award in early July this year by Oranje-Nassau Energie (ONE) of an engineering procurement and commissioning contract to build an unmanned satellite platform for the P11-E gas field on the Dutch continental shelf, 55km northwest of Rotterdam harbor.

"We are proud of this great and innovative assignment for Oranje-Nassau Energie," says HFG CEO Koos-Jan van Brouwershaven. It is a nice fit for HFG's Zwijndrecht yard to follow on from the Alba B3 compression topside for Marathon Oil (pictured) and the integrated production Montrose bridge-linked platform topsides for Talisman Sinopec Energy UK, both of which are in the end phase, and have moved out of the fabrication halls. Alba is due for sail away late October, and Montrose in March 2016.

The new P11-E platform is on a tight schedule. First steel will be cut by early September, and it will be ready for sail away in April 2016. ONE is also eyeing three or four more platforms in this area, with HFG in end stage discussions for one of them. "ONE is always thinking out of the box," Van Brouwershaven says.

The design is unusual in that the main risers go through the main jacket legs. The P11-E jacket design, and the jacket itself, can also be re-used in deeper water by adding more structural work. The 13m-high, 500-tonne topside will measure 31x25m. The 1000-tonne jacket will be 49m-high.

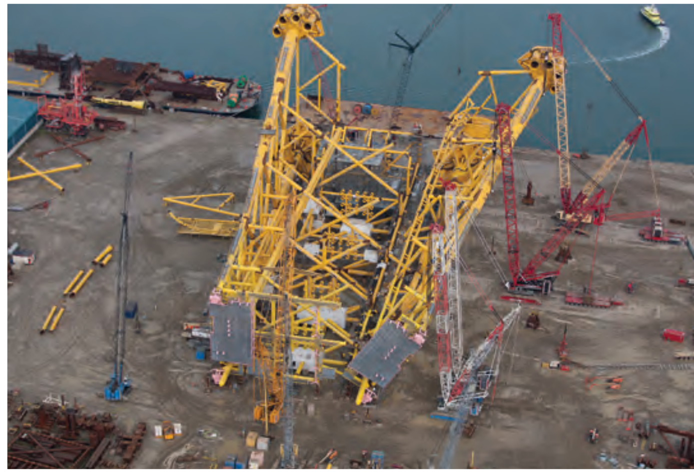
Some nodes for the project may be built at HFG Polska's facility at Opole, which is currently building some conductor guides for the Maersk North Sea Culzean project. It is also working on a structural frame for HFG's new innovation center, which will sit adjacent to the fabrication yard in Zwijndrecht, and will be operational by October.

In June, HFG's Vlissingen yard saw the departure of the launch jacket for Statoil's Gina Krog field (pictured right), which, at 17,000-tonne, is the largest jacket ever built by the yard. HFG invested in three skid beams for Vlissingen to accommodate both Gina Krog and the 8000-tonne DONG Hejre jacket, delivered last year. Van Brouwershaven says the roll-up of the sides of the Gina Krog jacket – planned 45 weeks in advance – was a special moment. Engineering for the project was carried out in-house.

In November, the 2000-tonne jacket and piles for Marathon Oil's Alba B3 compression platform are due to leave Vlissingen, along with the 4500-tonne topsides currently under construction at Zwijndrecht, with installation by the *Thialf* off Equatorial Guinea planned for January 2016. Vlissingen is also working on the 7100-tonne Culzean well head jacket for Maersk, due for sail away next March. The 700-tonne wellhead access deck for Culzean is being built at Hartlepool in the UK. Hartlepool delivered the ACM, PU and Bravo Cygnus decks to GDF SUEZ in July this year (pictured left).

Van Brouwershaven admits that competition is fierce at the moment. "We see there are lesser projects coming to the market at this stage," he says. But, he is confident that HFG's reputation and flexibility in term of sites will stand it in good stead. HFG is using its in-house facilities to the maximum – when there is more work around, there is more outsourcing.

He agrees that there is a lot happening in the wind energy market, where HFG has been active in the past, building converter stations for both ABB and Siemens. He adds a note of caution, however, saying that wind energy clients tend to ask for 100% liability. "We as a fabrication group struggle to accept those kind of liabilities, because if it goes wrong it could easily put us out of business. This doesn't fit our needs and demands, and we are quite reluctant to go that way." ■



The Gina Krog jacket roll up

More than an FPSO firm

The *Cidade de Ilhabela* FPSO sailaway. First production from the FPSO was in November 2014. Photos from SBM Offshore.

Global FPSO orders have fallen off a cliff in 2015. But, SBM Offshore is weathering the storm and there's more to the company than FPSOs, says its Schiedam managing director.

"Today's challenges for service providers such as SBM Offshore must be viewed in the context of the oil price drop," says Saskia Kunst, managing director of SBM Offshore's Dutch base in Schiedam.

"In order to work successfully with clients we believe we need to look for further integration of the value chain and revisit the way we define costs for the industry. Optimizing life cycle costs to us means a need to enter into a dialogue up front with our clients regarding capex and opex trade-offs for future floating production systems and hence find an optimum balance between initial costs of design and construction and operating costs down the line," Kunst explains.

"This trade-off is also required as today FPSOs are designed to operate for up to 25 years compared to a previous average of 10-15 years for lease and operate contracts. The cost savings over the longer period can be significant," Kunst underlines.

Dutch-born Saskia Kunst has played many roles within the company since joining in 2008. Before her role as managing director she clocked up five years as group strategy director. With the industry in flux Kunst explains that forecasts are constantly changing. "In October last year, SBM had an expectation that 13 FPSOs were going to be awarded by the industry in 2015. However, when we compiled our full-year results, the expectation was that the market would see only six awards during 2015, and that was the best case. There is even a scenario where we're not going to see any awards during 2015," Kunst says.

This conservative industry stance is reflected in SBM's 1Q 2015 directional

Saskia Kunst, Managing Director of SBM Offshore's Dutch base in Schiedam.

revenue, which came in lower at US$601 million versus $782 million in the year-ago period. This was driven by a decrease in turnkey activity primarily as a result of the delivery of two FPSOs, *Cidade de Ilhabela* and *N'Goma* last November and a lack of order intake in 2014. Directional Turnkey segment revenue came in at $326 million, down 40%, while Lease and Operate segment revenue increased 16% year-on-year to $274 million. The growth in lease and operate revenue is attributable to the start-up of the two aforementioned FPSOs for offshore Brazil and Angola, respectively. Directional backlog as of 31 March 2015 stood at $21.4 billion ensuring revenue with lease and operate contracts up to the year 2036.

Product strategy going forward

"The past three years SBM's strategy was focused on its core product, FPSOs, often quoted by analysts as 'FPSO, FPSO, FPSO'. This was because the company has shown consistent, solid results in the delivery of FPSOs and it allowed top management concentrate on rebuilding a solid financial foundation for the company, which had been somewhat eroded by a number of past, non-core projects losing money. With that step achieved, the last year has seen SBM emphasizing the remainder of our product portfolio, enlarging the envelope of floating production solutions by revisiting key products and technologies," Kunst says.

One key product that SBM is bringing to the table is their mid-scale floating liquefied natural gas concept (1.5-2 MTPA), which is a solution for stranded gas fields, both for new build as well as conversion solutions. The technology and the unique twin-hull concept have been developed in SBM's Schiedam center.

"With the increasing global demand for gas, we expect there will be a strong market for FLNG," Kunst says. "This new market is a good complement to SBM's leading position in the oil FPSO business and our extensive experience in designing, building and operating FPSOs can be leveraged for our LNG FPSO concept. We are engaging some clients – the interest is there. Many of the technologies and capabilities that SBM has in-house are applicable to the LNG FPSO concept, for example, the same turret mooring systems used for FPSOs can be used for LNG FPSOs.".

SBM Offshore's FLNG concept

Despite a lack of order intake in recent times, the company is working on completing some of their most ground-breaking projects, including three of the industry's largest turrets – one of which is for a pioneering Shell project – the Prelude FLNG. Work is advanced on another Shell project – what will be the world's deepest floating production unit. SBM is responsible for the EPCI of the *Turritella* FPSO, to be moored in 2900m water, and will operate the vessel for Shell's Stones development in the Gulf of Mexico.

In parallel SBM is using the industry lull to beef up its organizational structure and to optimize the cost base – the strategy required releasing 1500 positions worldwide (approximately half of which is contractors) while ensuring that the company's technological know-how remains intact.

"SBM continues to invest heavily in research and development and we are progressing key technologies that leverage the company's know-how and over 260 years of operating experience in floating solutions that will add more value to clients' projects when the industry upturn occurs," Kunst says. ■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The Leman AC platform engineering drawing rendering. Images from Iv-Oil & Gas.

Going for greenfield

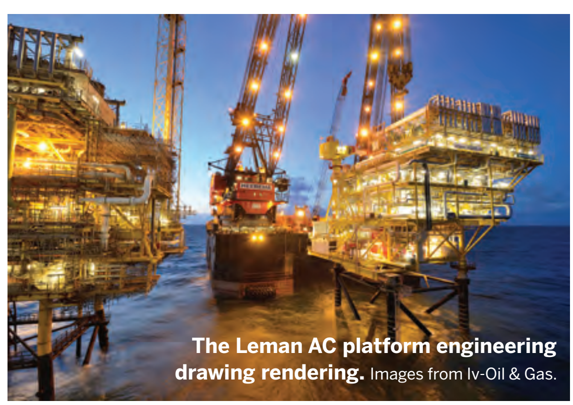
A greenfield platform was a more effective option over brownfield modifications on Shell's Leman Alpha complex in the North Sea. Elaine Maslin explains how Dutch expertise made it a reality.

At nearly 50 years old, anyone could forgive the Leman Alpha complex for needing a little bit of late life TLC.

The facility, comprising four bridge-linked platforms, is 50km off the coast of Norfolk, England, in the UK sector of the North Sea. The complex required new compressors to improve reliability as well as safeguard the continuity of gas export to the Leman and Corvette Pipeline Users Group fields until 2028. The question was, should a brownfield project be initiated by directly replacing the compressors, or should an entirely new platform be designed?

Operator Shell UK consulted the Dutch Engineering Company Iv-Oil & Gas and Fabrication Yard HSM Offshore to study the possibilities. This resulted in the advice to build a new platform, the Leman AC platform, complete with 40MW of new compression capacity, through two compressors (with in total three compression stages) with a capacity that runs from approximately 3 to 80 bar. The new compressors replace the compressors on the existing Leman AK platform. Additionally, the new platform also includes auxiliary equipment and a 1200 kW diesel generator.

"Greenfield work for a brownfield project was not only the more profitable option, but was also safer and more efficient, because all the systems can be tested onshore instead of offshore. This allowed production to continue on Leman Alpha," says Marcel Stevens, Project Manager at Iv-Oil & Gas. "Greenfield work is also less time consuming than carrying out brownfield modifications on a platform, which can be hindered by limited accommodation. This could result in the need for an accommodation vessel as well as helicopter transport for workers, etc. The less you interfere in the normal production of the platform the better. In a normal brownfield modification, the interference is quite high."



The Leman AC platform engineering drawing rendering. Images from Iv-Oil & Gas.

The conceptual design of the Leman AC platform is based on a conventional integrated steel frame structure. The topside structure of the Leman AC platform provides the framing for a compression facility containing a cellar deck, a compressor deck, a mezzanine deck, a cooler deck, a crane and laydown areas. In addition, it provides support for the bridge-link to the Leman AK platform. The bridge is 37m-long, made of a tubular steel construction with a rectangular cross section. This bridge-link supports piping and offers a location for the installation of the nitrogen storage vessels, power supply, personnel access/escape routes and trolley access for lightweight goods/equipment.

Shell UK awarded Iv-Oil & Gas the contract for the FEED phase of the project in February 2012. In August of that year, Iv-Oil & Gas received a contract for detailed engineering, procurement services and construction management (EPCM) of the project. This included the detailed engineering of modifications on the existing Leman complex in order to integrate the new platform with the existing installation. HSM Offshore was awarded the fabrication contract including mechanical completion, pre-commissioning, load out and sea fastening, which started in January 2013. Sail away of the 1030-tonne jacket and 3570-tonne topside both took place in August 2014. Heerema Marine Contractors provided transport and installation using its own crane vessel *Hermod*.

One of the challenges imposed on Iv-Oil & Gas was the design of the facility around the two compressor trains: one low pressure compression train from GE Oil & Gas and one high pressure compression train from Solar Turbines, which had already been purchased by Shell UK.

As part of its role as manufacturer, Iv-Oil & Gas supervised all construction and pre-commissioning services at the HSM Offshore yard during the fabrication phase. The Leman AC platform will be monitored and fully controlled from the Leman AD1 platform, the controlling platform for the entire Leman complex. This required new fiber optic cabling to be routed through the Leman complex. First gas is expected this month, September 2015. ■

Doubling Dutch wind capacity

The Gemini wind park in the Dutch sector of the North Sea has broken financing and renewables project size records. Elaine Maslin takes a look.

An artists' illustration of the Gemini wind park offshore Netherlands.
Photos from Gemini.

In 2014, global investment in renewable energy reached record levels, helped in no small measure by the record-breaking US$3.8 billion financing of the Gemini wind park offshore the Netherlands.

The 600MW project is the largest ever renewable energy project, excluding hydro power, according to a report by Frankfurt School FS-UNEP Collaborating Centre and Bloomberg New Energy Finance, and it will double the Netherlands' offshore wind capacity.

Construction on the 150 x 4MW, 7m-diameter turbines, plus two transformer stations, in 28-36m water depth, 85km off the coast of Groningen, started late in 2014, with Dutch contractors playing a significant role. Once complete, the park will produce roughly 2.6TWh of renewable electricity.

Gemini's CEO Matthias Haag says Dutch contractors are playing an important role in the project, led by main engineering, procurement and construction contractor Van Oord, with Siemens providing operations and maintenance for 15 years.

"It is essential to have this supply chain," he says. "It wouldn't be impossible without it, but it is certainly a benefit to have these local contractors. Minimal local content is not a given in the Netherlands, but you do see the benefits of it. And, while there have been offshore wind farms before, Gemini is putting it on a different scale. I was involved in the first offshore wind farm in the Netherlands 10 years ago, but there have not been too many built since then. But, the contractors have been working in other countries and bringing back that experience. This project will strengthen that experience further."

For Haag, who has worked for Shell and wave energy firm Aquamarine Power, the Dutch bring marine construction skills, particularly when it comes to tidal flats, which are submerged for part of the day and dry for others, as well as general construction of facilities in water.

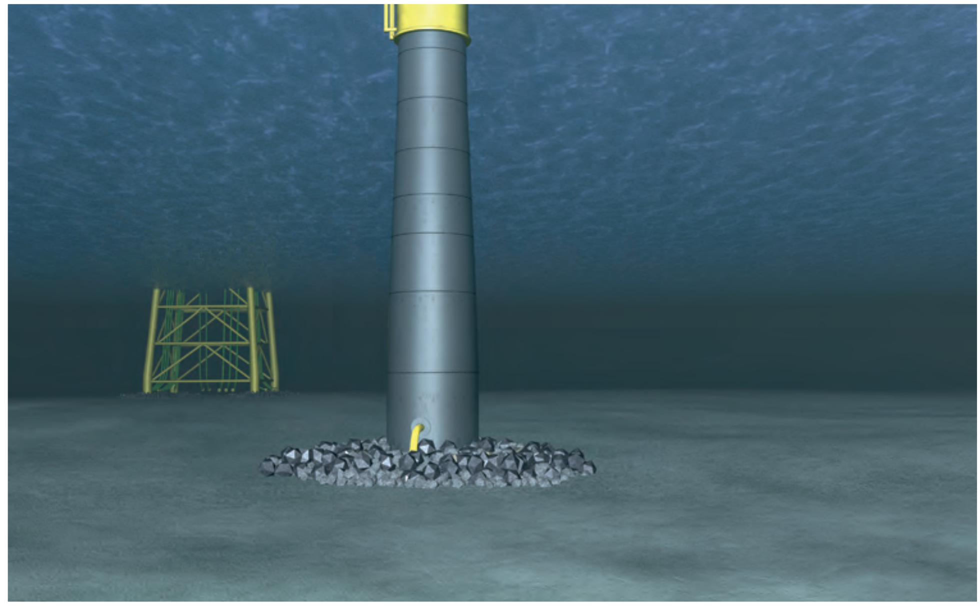
A Dutch attitude towards solving engineering problems – allowing contractors to work together to solve issues – also brings benefits. As an example, Haag says Gemini gave contractors BAM and Gebr. van Leeuwen a contract to install two, 500mm-diameter HDPE electrical cable tubes underneath existing cables laid under the sea in the Wadden Sea, for the Gemini export cables. Their solution was to use directional drilling between two jackups, which meant both the entry and exit points, 800m apart, were under water, out of sight. "Drilling from one jack up barge to another jackup barge is not something that has been done very often in the world," says Haag. "The joint venture came up with the solution and while there were some issues at first, the methodology was changed and it was successful completed in the first quarter."

For Van Oord, it is a significant project. As well as holding a 10% stake in Gemini, Van

Oord is the main engineering, procurement and construction (EPC) contractor, under a EUR 1.3 billion contract which helped tip Van Oord's turnover over EUR 2 billion for the first time. The project helped underpin investment in both acquisitions – including Ballast Nedam Offshore earlier this year – and two new vessels; the *Aeolus* offshore installation vessel, delivered in 2014, and the cable layer *Nexus*, launched at Dutch group Damen Shipyards' facility in Galati, Romania, last year and now working on Gemini.

Other Dutch contractors involved include SIF, which is supplying the monopiles, Smulders Projects, which is producing the transition pieces, and VBMS, a joint venture between VolkerWessels and Boskalis, which is assisting Van Oord with the export cable installation.

Oceanteam Shipping subsidiary RentOcean is supplying Van Oord with a 3000-tonne demountable onshore turntable system and accompanying equipment for long term cable storage, and the FICG (Fabricom, Iemants and CG) consortium is manufacturing the onshore and offshore transformer stations.



Subsea: wind turbines are mounted on piles, with a jacket-mounted transformer.

By late July, the project was on track, with most of the manufacturing completed or nearly complete, including transition pieces and turbines. The export cables were already nearly all installed and monopile installation started 1 July, once environmental restrictions were lifted. From 1-23 July, some 25 piles had been installed, and it is hoped all 150 will be installed by year's end.

Gemini is 60% owned by Canadian renewable company Northland Power, 10% by Van Oord holding, 20% by Siemens and 10% by renewable energy and waste processing company HVC. ▪

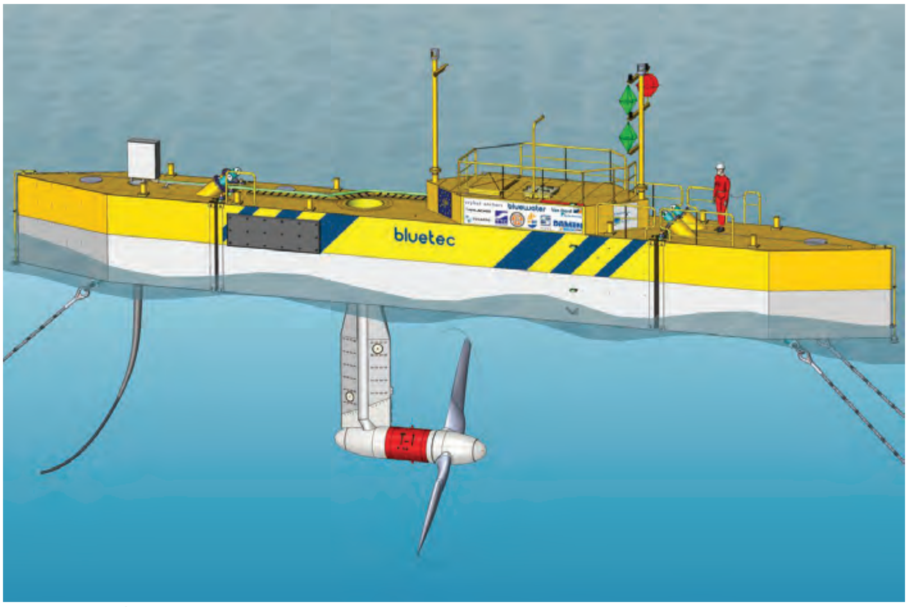
Partnering for success

Bringing together floating production technology expertise and Dutch know-how from electrical cables to shipbuilding has helped Bluewater turn a new tidal energy concept into reality. Elaine Maslin reports.

For most in the offshore industry the name Bluewater is associated with floating production units. However, Bluewater, based outside Amsterdam, has been developing another string to its ship-shaped bow and, in fact, it is less unlike floating production than you might think.

The firm, supported by a consortium of fellow Dutch companies, has designed the BlueTEC tidal energy unit, a moored, modular-design floating platform, which supports underwater turbines. The first unit, the Texel platform, was installed in the Wadden Sea offshore the Netherlands earlier this year, producing electricity into the Dutch grid from day one.

BlueTEC installed offshore Texel. Image from Damen.



The BlueTEC concept. Image from Bluewater.

It is fitted with a 100kW turbine, which will be upgraded to a T2 (200-300kW) turbine later this year, increasing to two T2s (or 500kW capacity) and in total producing electricity for a 1.5-year trial period.

The project has made rapid progress. It went from a blank sheet of paper in 2006, when Bluewater decided to investigate new potential business streams, to the formation of a project team in 2009, to the start of construction late 2014, and then grid-connection into the water this May.

"If you look back to November 2014, fabrication had not yet started," says Allard van Hoeken, Head of New Energy at Bluewater. "We only had a drawing. We went from a drawing to a new grid-connected platform in six months, which is unheard of in the tidal energy industry."

Key to the project's success has been a willingness to collaborate between a cluster of Dutch firms, each bringing their own expertise – and share of the project funding – to the table: Damen, Acta Marine (Van Oord), Tocardo, TKF, Vryhof, NIOZ Royal Netherlands Institute for Sea Research, and the Dutch Tidal Test Centre. Germany's Schottel Hydro and UK-based Nylacast are also involved.

While bringing all these companies together for one project posed communications and interface challenges, existing solutions were easier to find by keeping companies within their specialist scope, van Hoeken says. "It's not all new technology. What's new is the overall platform concept and putting these bits together with companies that understand the technology and the sea.

"A turbine manufacturer cannot yet predict the forces involved very well – there are so many unknowns and everyone knows at sea you get unexpected conditions," he says. "However everyone has a scope they are comfortable with. That way, there may be elements that might be difficult, like the mooring system or the dynamic power cable in a tidal race and their connections to the platform, but these can be addressed."

With BlueTEC, the company's aim was to design a platform and mooring system that could be operated for years in a sustainable way. Equipment needed to be accessible from the surface, and hook-up and hook-off needed to be easy. It also needs to be transported easily to remote locations where Bluewater sees the initial market for such systems, which led to a modular containerized design. It was also designed for using different turbines – some of them allowing change out ability in situ – for flexibility. And it had to be simple and low cost.

The result is a relatively simple and very cost-effective solutions, van Hoeken says. BlueTEC is comprised of container-like modules, like pontoons, for ease of world-wide transport, connection and scalability. The turbines are not the largest units, like some are aiming for; Bluewater believes the smaller units will be more attractive to start with as they are easier to hook-up and off as well as handle generally on- and offshore. Water can pass through the turbines in either direction, so they do not have to swivel with the tide and all the electronics are stored in a dry accessible space within the unit, which can be easily disconnected and taken to a quayside for heavier repairs.

Dutch ship builder Damen got involved by talking with Bluewater at Houston's Offshore Technology Conference two years ago, says Jeroen van Woerkum, sales manager Benelux, Damen Shipyards.

"This is an interesting market for Damen," van Woerkum. "When something

Allard van Hoeken. Photo from Bluewater.

floats, it is interesting for Damen. And this could grow into very large projects.

"The first step is to learn," he says. "Damen built the platform as well as research and development to make sure the shape of the platform is sufficient to carry the weight and also the thrust of the water as the tide changes."

Bluewater started electricity generation gently from Texel after installation in May, gradually building up the operational hours to today's 24 hours a day, seven days per week operation. As much as possible in the system is being monitored, including loads on the mooring lines. Planning is already underway to switch out the current 100kW 5m-diameter turbine to the 200kW 9.6m-diameter turbine.

Next year will see a second turbine installed on the unit, using a T-bar, building it up to 500kW.

Bluewater would then like to move to a capacity of 2-3MW, adding larger turbines to the T-bar and additional buoyancy, and to do so it will need to move to another deeper site. Bluewater's ultimate ambition is to design and build tidal farms of 50-500MW.

Ultimately, Bluewater is looking to be operating floating production units, not much unlike FPSOs, instead extracting clean power from the ocean. ■

Rising to TCP demands

A 6in TCP flowline. Photos from Airborne Oil & Gas.

A deepwater downline and reeler package for riserless light well intervention and pipeline pre-commissioning.

Airborne Oil & Gas is taking a staircase approach to introducing new thermoplastic composite pipe (TCP) technology to the oil and gas industry, with TCP risers in its sights. Elaine Maslin reports.

For a long time, composites were seen as an exotic material that many in the risk-averse offshore oil and gas industry have toyed with, but few have ventured to deploy.

Not anymore. Dutch composite pipe specialist Airborne Oil & Gas has been paving the way for use of thermoplastic composite pipes (TCP) in the industry, introducing well intervention lines and downlines. Now the company is introducing the first qualified TCP flowline, which is due to be installed offshore Malaysia by Petronas.

It may have taken about 15 years' research – initially into composite coiled tubing at the behest of Shell – and three years' qualification with Petronas, but it's a significant milestone for the firm and TCP, potentially helping to pave the way for TCP risers.

Development

Airborne Oil & Gas, formed out of Airborne Composites, first started exploring TCP for coiled tubing in 1999. A concept was developed by 2003, technology readiness achieved in 2005 and production technology to manufacture the pipe was developed by 2007. The fully bonded concept used a thermoplastic liner, surrounded by a carbon fiber or fiber glass in a TP matrix then coated in TP.

However, by then, the application of composite coiled tubing was seen to be limited – for cost reasons, due to the high-temperature resistant polymers needed, and operational reasons – and from 2008, Airborne focused fully on where TCP was seen to have the greatest potential, in the subsea umbilicals, risers and flowlines (SURF) market as well as the subsea well intervention market.

TCP well intervention lines, using polyethylene or polyamides and fiber glass were introduced in 2010, followed by downlines in 2012, including a 5000psi internal pressure downline for pre-commissioning on the Guara & Lula field, which achieved a depth record of 2140m offshore Brazil.

TCP flowlines – pipes that are installed on the seabed for 20-30 years – were the next step. The benefits are attractive. Being non-metallic and spoolable makes TCP flowlines easier to install, both from a handling point of view but also, because they're flexible, they have greater installation tolerances than steel, says Martin van Onna, Airborne Oil & Gas' chief commercial officer.

Martin van Onna

Airborne manufactures up to 7in-internal diameter (ID) TCP flowlines, replacing 8in nominal steel pipe and conventional flexible pipe, in up to 3000m lengths per spool, allowing for reel lay installation.

"According to the latest estimate, we are looking at 1300km per year of flowlines, which could be achieved in TCP; that's what the industry needs," Van Onna says. "But, reaching a point at which the first operator was willing to try TCP flowlines took time and acceptance.

"In pre-commissioning and well intervention, the pipe stays on the reel and it is used for shorter period of time, so it is easier for the industry to adopt," he says. "Flowlines are installed on the seabed with 20-30 years design life, carrying hydrocarbons, and therefore attract the highest level of qualification and technical record."

Deployment

The contract with Petronas will see 550m of 6in-ID TCP flowline installed in 30m water depth between two platforms in the South China Sea offshore Malaysia. As well as being the first TCP flowline, the contract is significant because it is a warm climate where issues with microbiology induced corrosion, which can be particularly damaging for metallic pipes, Van Onna says – a further benefit of using TCP.

Early next year, Airborne will deliver a downline for well intervention offshore Nigeria for Shell – another first; these lines will deploy chemical stimulation fluids, including acids, for subsea wells.

Risers

A future use for TCP is risers. Airborne has been looking at TCP risers since 2008, when it was part of a joint industry project which proved the concept. Since then it has been working with individual operators.

TCP risers are still a few years away, Van Onna says. "The composite riser will come one day, but I think it will not be before 2020 before it will be deployed in deepwater," he says. "The industry is so conservative. The offshore environment is risk averse, with good reason, which demands careful steps in building track record and confidence. Therefore, Airborne adopted the 'staircase approach,' using logical building blocks in downlines and flowlines to build track record, understanding and acceptance in the industry. "One day the industry will see the world's first TCP riser, and we bet it will be Airborne's," he says. ■

Multi-tasking

Collaboration on- and offshore the Netherlands has resulted in a new concept in platform operations and maintenance. Elaine Maslin reports.

Wagenborg's *Kroonborg*. *Photo from Wagenborg..*

Across the North Sea, platform maintenance is a costly and logistically complex exercise, involving supply ships, helicopters, crew changes, all often overlapping one another across multiple disparately owned assets.

In the southern North Sea, where many assets are now unmanned, operators Shell UK and Nederlandse Aardolie Maatschappij (NAM), working together as ONE Gas, operating some nine manned and 47 unmanned installations, decided to take a different approach by sharing logistics and transport.

With the help of Dutch contractors and engineers, they have created a new concept in offshore facility operation and maintenance in order to realize their new approach – it's called the *Kroonborg*, a walk-to-work offshore maintenance vessel.

The vessel, which started work offshore in April this year, is a completely new type of vessel, designed in corporation with Dutch shipyard Royal Niestern Sander, with the help of Groningen-based Conoship International and Dutch logistics firm Royal Wagenborg, which will operate the vessel on a 10-year contract.

It is a workspace, floating hotel and a means of transport to and from offshore platforms, rolled into one, a little like a Swiss army knife. Working on two weeks on, two weeks off rotation, the vessel, which enables crews to "walk to work," via a motion compensated gangway, will be used for everything from basic maintenance to isolation and live well restarts on unmanned installations.

"That approach of operating and maintaining the offshore installations is pretty new and not very common worldwide and that requires this new vessel," says Johan Adriaanse, director operations, Wagenborg Offshore. Gert Vanderheyden, client representative, NAM: "It is not just a replacement vessel of one or the other vessel, it is a brand new game."

According to Wagenborg, *Kroonborg*'s use will reduce helicopter flights by up to 600 flights a year and, being the first GTL-fuelled offshore vessel, it also has green credentials.

The dynamically positioned, DP2 vessel, is 79m-long, 16m-wide with a 5.4m draft, with a service speed of 12.5 knots and 10,000hp. It has transportation, accommodation, workshop and storage for 60 people, including 40 maintenance and service personnel, who will work in two shifts, walking to work on facilities using an Ampelmann offshore access system.

At its heart is a package of start-up and intervention equipment that will enable wells to be restarted quickly and efficiently. Carrying the chemicals required for startups meant new below deck chemical tanks had to be designed for the vessel.

The unit also has a motion compensated Barge Master T40 crane, to transfer equipment and supplies onto platforms, in wave height up to 3m, thanks to Dutch firm Barge Master's motion-compensation technology.

"Ensuring that the hook is stable in all directions really is new," says Theo Klimp, Fleet Director of Royal Wagenborg. The crane will be able to lift up to 5-tonne at 20m outreach and up to 30m high. *Kroonborg* comes with a fast rescue craft and a daughter craft, one which can stay on one location, so the *Kroonborg* can go to other location to deploy workers. It also has a FROG escape training unit for emergencies.

Perhaps the most impressive aspect of the new vessel is the time it took to design and build it. The cooperation agreement between NAM, Shell and Wagonborg was signed late 2013. To get the vessel built ready for launch early 2015, Royal Niestern started building the hull before the engineering was complete, so that engineering and construction were running in parallel. A key enabler in this type of approach was collaboration and use of a digital 3D model, which all the firms involved were are able to work on and in.

Now the vessel is out and operating, it is proving its worth. Tony Kett, marine operations manager, Shell UK: "I don't think we realize just how significant this is. You will see, I believe, we will be starting a trend here in completely changing the way we are operating and maintaining our platforms." ▪

Solutions

Impact Subsea unveils new altimeter

Impact Subsea has announced the release of the ISA500 – a 500kHz underwater altimeter, which also provides heading, pitch and roll.

The ISA500 is designed for AUV/ROV or standalone operation. Making use of a composite transducer and advanced digital acoustic engine, the ISA500 has a 120m (394ft) range capability, and can provide sub-millimeter measurement accuracy.

In addition to altitude, the ISA500 also provides heading, pitch and roll readings – used for basic AUV/ROV navigation or to monitor underwater equipment deployment.

The onboard pitch and roll sensor can be used to automatically compensate for pitch, roll and altimeter misalignment to provide consistent true altitude readings.

Under 11cm (4.3in) long, 4.5cm (1.8in) wide and weighing just 0.5kg (1.10lb), the unit protected in a titanium housing, with an industry standard connector.

The ISA500 is applicable in areas where space and weight are critical considerations and is able to withstand harsh underwater environments.

www.impactsubsea.com

Viper Subsea upgrades V-Lock

Viper Subsea released the next generation V-LOCK hydraulic stab plate, which originally launched in 2011.

The new model is designed such that all the coupler float requirements are built into the flying half of the stab plate, with couplers rigidly mounted within the fixed half of the stab plate. This reduces susceptibility to the effects of cementation from calcareous growth and mitigates assembly risk for the small-bore tubing installation on the tree and umbilical termination assembly (UTA). Therefore, the need for long lengths of hydraulic tubing behind the fixed plate couplings is no longer required, reducing the size of the UTA structure and facilitating compliance with the Umbilical Termination Size Reduction (UMSIRE) joint industry project. The 'zero float' V-LOCK completed qualification early in 2015.

"The 'zero float' version will become our standard offering with its inherent benefits to both OEMs and the Operators," said Neil Douglas, managing director of Viper Subsea.

www.vipersubsea.com

SKF releases TKSA 51 tool and app

SKF has launched the TKSA 51 shaft alignment tool designed for use with tablets and smartphones, which facilitates the set up of motors, drives, fans, gearboxes, pulleys and couplings.

The TKSA 51, comprised of two laser measuring units, can be mounted on small machines with limited space using shaft brackets, or on large machines using extension chains, rods and magnetic holders.

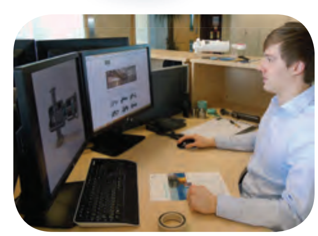
Connected wirelessly, the app uses real time data to provide a live 3D view of the measuring units. Measurements are made by touching a button or using the hands-free automatic measurement function by rotating the shaft to the next measurement position.

The measurement freedom is just one of the core features of the systems, allowing alignments in confined spaces as measurements can start at any angle and only require a total shaft rotation of 40°. After each alignment check or correction, a report is created that can be customized, emailed or uploaded to a cloud service for future reference.

www.skf.com

Trelleborg launches sealing solutions website

Trelleborg Sealing Solutions is launching a new online resource for engineers at SPE Offshore Europe as part of its "commitment" to the oil and gas industry.



The website – 'oilandgas-seals.com' provides a comprehensive overview of seal profiles proven in the oil and gas industry, enabling engineers to identify optimum sealing solutions for specific applications within the field.

It provides information on material compatibility covering issues such as sour gas and rapid gas decompression, spanning different applications, including drilling and exploration, completion and production systems.

The website is fully compatible across all platforms including tablets and smartphones – a response to the latest trends, with engineers increasingly turning to mobile devices to find technical support and solutions.

The new website complements the company's online Knowledge Center to bridge the gap between design engineers' needs and standard technology documentation, bringing useful information together as part of one digital portal.

www.tss.trelleborg.com

Activity

OneSubsea, Subea 7 form alliance

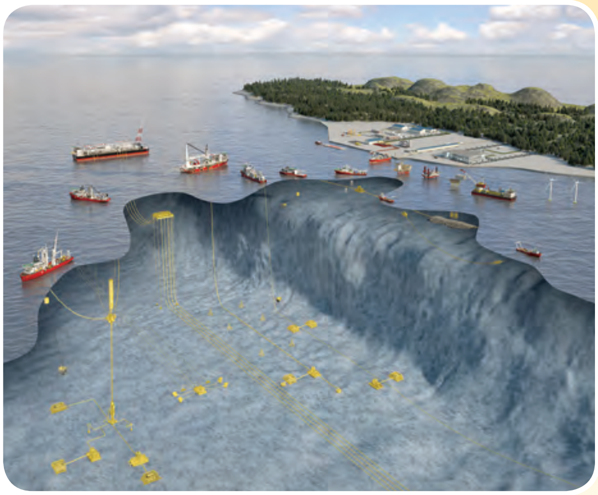


Image from Subsea 7.

OneSubsea, a Cameron and Schlumberger company, has signed an agreement establishing a worldwide non-incorporated alliance with Subsea 7 to jointly design, develop and deliver integrated subsea development solutions through the combination of subsurface expertise, subsea production systems (SPS), subsea processing systems, subsea umbilicals, risers and flowlines systems (SURF), and life-of-field services.

The alliance combines Subsea 7's experience and technology in seabed to surface engineering, construction and life-of-field services with OneSubsea's reservoir expertise and subsea production and processing systems technologies. The alliance will combine both companies' resources to collaborate on selected projects, engaging early to improve field development planning from the reservoir to the production facility. By combining the complementary capabilities and technologies, the alliance will work collaboratively with clients to design, develop and deliver integrated SPS and SURF solutions, which will enhance project delivery, improve the recovery, and optimize the cost and efficiency of deepwater subsea developments for the life of the field. ■

Enterprise sells GOM pipeline business

Enterprise Products Partners has sold its offshore Gulf of Mexico (GoM) pipelines and services business to Genesis Energy for approximately US$1.5 billion in cash.

The transaction is expected to close during 3Q 2015. Enterprise's offshore pipelines and services business segment include its ownership interest in nine crude oil pipeline systems with more than 1100mi of pipeline; nine natural gas pipeline systems totaling approximately 1200mi of pipeline; and its ownership interest in six offshore hub platforms.

"In recent years, earnings from our offshore business represented only 3% of Enterprise's gross operating margin, and our offshore assets do not effectively integrate with our downstream crude oil and natural gas pipeline systems," said Michael A. Creel, CEO for Enterprise's general partner.

Oceaneering makes waves

Oceaneering International has decided to drop its blowout preventer (BOP) control systems business. The decision, which Oceaneering said was due to deteriorating demand prospects, came after the company was impacted in 2Q 2015 by a $9 million inventory subsea write-down. Despite dropping its BOP business, Oceaneering's UK subsidiary, Oceaneering International Services, opted to acquire a minority stake in UK-based Viper Subsea technology.

"This is an ideal opportunity to accelerate the growth and the global reach of Viper Subsea's products and services," said Neil Douglas, Viper managing director. "Our technology and capability will also provide significant pull-through for Oceaneering.

"There will be no change in the day to day management team or management structure of Viper Subsea," Douglas said. "We have a successful and highly experienced team in place who will continue to drive the development of Viper Subsea forward."

Global SCS opens Dubai office

Aberdeen-based Global SCS, part of Scotland's Global Energy Group, has opened an office in Dubai to handle growing demand for its services in the Middle East and Africa.

Global SCS already has overseas offices in Houston in the US, Perth and Brisbane in Australia and Stavanger in Norway. Further offices in Canada and Singapore are also being considered.

"We are winning more work in the current market because our clients can save a lot of money through our techniques for risk mitigation," said managing director Tommy Hillock.

The quality assurance/quality control consultancy and quality engineering section of Global SCS has just landed a new contract with BG International. The company's annual turnover is being targeted to more than double to $50 million (£32 million) within the next five years.

TAM International reorganizes

Houston-headquartered oilfield services company TAM International, which specializes in inflatable and swellable packers, will restructure its regional businesses into two individual hemisphere-based groups in order to achieve higher performance rates and streamline its business objectives.

Under the new structure, the Western and Eastern Hemisphere operations will now function as two separate teams. Steven Scott, vice president of TAM's Eastern Hemisphere operations, overseeing Europe, Africa, Russia, FSU, and the Middle East, has added Asia Pacific to his group. Additionally, Ray Frisby is now vice president of TAM's Western Hemisphere operations, including the US, Canada, Mexico, and Latin America.

Honeywell: Committed to Improving Process Safety and Production Efficiency

Honeywell Process Solutions has 30+ years of experience in the global oil and gas industry, helping customers identify and integrate operational excellence into software solutions to meet critical demands.

Honeywell's advanced software portfolio offers sophisticated analytics with visualization, production and asset surveillance, open connectivity, operator training simulation, and measurement and control solutions to help petroleum firms integrate their operations, protecting both people and assets — while keeping CAPEX and OPEX down.

Using Honeywell's Digital Suites for Oil and Gas, upstream producers can improve production performance up to 5% with better productivity, higher uptime and more efficient remote operations. All around the globe, operations are safer and more profitable because of Honeywell's integrated solutions.

Improve Production Efficiency and Safety While Lowering Operating Expenses

The management of oil and gas operations has become increasingly complex due to growing market pressures, strict regulations, geographically dispersed sites, limited resources, and expanding volumes of data.

The current economic conditions with lower oil prices make it more important than ever to increase production efficiency and decrease ongoing operating expenses. Exploration and Production (E&P) companies are looking to get the most production from their best assets without sacrificing operation safety and data integrity.

The Industrial Internet of Things (IIOT) is creating an explosion of connectivity and information across the plant and business enterprise. E&P companies require solutions to support safe and efficient operations, and improve work processes. It is important to ride the digital transformation wave of enterprise connectivity, real-time analytics and collaboration, all powered by mobility and the cloud.

Achieve Smart Operations

For the offshore sector, the discovery and utilization of digital intelligence makes it possible to implement operational excellence as a business strategy. This approach can be leveraged to ensure safe production with higher uptime, reduce actual risks and prove regulations are met. The result is fewer unplanned shutdowns and more reliable processes, as well as improved economics by increasing oil and gas recovery and reducing production costs.

Digital Suites for Oil and Gas specifically addresses today's offshore challenges helping customers achieve smart operations. This comprehensive set of scalable applications, delivered worldwide and supported locally, enables operators to make critical decisions faster by capturing, managing and analyzing the right production information at the right time.

The solution combines field-proven technologies with new software and implementation methodologies delivered through Honeywell's new oil and gas center of excellence.

See Honeywell in Stand 2B50 at Offshore Europe

Discover more about the Digital Suites for Oil and Gas at **www.hwll.co/dsog**

Honeywell

Spotlight

Making an impact

Elaine Maslin speaks with new Oil & Gas Innovation Centre (OGIC) COO Ernie Lamza about his early career, his new role and the part technology has to play in the oil and gas industry.

Being left in charge of an oilfield start-up in Egypt's Western Desert at age 26 could be a daunting task. It was – but, it was also a brilliant learning opportunity, says Ernie Lamza, who is now COO at the less than one-year old Oil & Gas Innovation Centre (OGIC) based in Aberdeen.

Lamza, who had previously been working on a ConocoPhillips' North Slope project from their Oklahoma engineering center, went on to deploy new technologies in the North Sea with Hamilton Brothers, manage Penspen's worldwide engineering and project management business and, most recently, support Dutch floating production specialist SBM Offshore's research and development program.

Technology development is now his core focus and it's an area in which he sees a definite need, particularly in today's cash-strapped, low oil price environment. "Innovation should be at the forefront of everybody's mind because of the role it can play in maximizing economic recovery in the UKCS," says Lamza, who joined OGIC in February. "At OGIC, launched in November last year, we work to make the innovation process easier and provide funding for qualifying projects."

Lamza, from the Scottish Borders, studied chemical engineering at Heriot-Watt University. Upon graduation in 1982, despite the downturn at the time, he secured a job with ConocoPhillips supporting the firm's North Sea operations brownfield engineering projects, before being posted to Oklahoma, where he specialized in process engineering and worked on a new project in Egypt's Western Desert.

Working on the Houston-based design team, he was responsible for 2-3 packages of equipment and then flew out to Egypt for the project start-up. But, when the lead engineer had to return to the US, Lamza became responsible for the start-up of the project on-site.


Ernie Lamza

"I had arrived a week before the scheduled start-up, but delays meant the actual start was closer and closer to his departure date. Finally, we started up the day before he left and he worked on through the night handing back to me the next morning. We walked to the airstrip together, having a final handover and with last minute advice, said goodbye, and then I took over. There were a few exciting moments, but as a 26-year-old in the desert, it was brilliant – being given such responsibility, learning on the job, seeing a project through start-up safely to first production."

After returning to the UK, working on a range of modification projects he went into contracting, working for Matthew-Hall Engineering, later acquired by AMEC, before joining Hamilton Oil, later bought by BHP. The company was "lean and mean," he says, but also willing to innovate. Lamza was Hamilton's only process engineer in Aberdeen at the time, tasked with projects including topsides clean-up of hydraulically fractured gas wells.

"Hamilton was willing to take a bit of business risk to try new technologies. As well as the well clean-up system, there were other projects like on-line compressor water washing and injection rate control devices, which were pretty novel at that time," Lamza says. "To try these things offshore was very enlightened of Hamilton. My view is the operators nowadays are less willing to take that approach."

Which is where OGIC comes in, to link companies with challenges in innovation and development with Scottish Universities. "Within OGIC, we are trying to help companies manage the risks of taking technologies offshore," Lamza says. "The expertise within Scottish universities is well-placed to move technologies forward, advancing their technology readiness level to meet industry demand."

OGIC's objectives are aligned with Sir Ian Wood's *Maximising Economic Recovery* recommendations and the Technology Leadership Board's goals of stimulating well activity, encouraging small field development and improving asset integrity.

Aside from connecting companies to world-class Scottish researchers, OGIC has also placed two pieces of cutting-edge equipment in the universities using money from the Scottish Funding Council, a rock deformation apparatus and a computed tomography scanner, to allow industry and researchers to apply new techniques to target increased recovery of oil and gas from reservoirs. And, OGIC has priority should any of its projects need access. So far four OGIC projects have been approved with another 10-12 close to sanction and 24 more under consideration. In a short period of time, OGIC is already making an impact. **OE**


INTERNATIONAL AUCTION
TO SELL THE P-34 UNIT
PETROBRAS - XXXIV
P-34
Petrobras Netherlands B.V., represented by Petróleo Brasileiro S.A., will perform an international auction to sell the Petrobras P-34 Unit. The Call for Tenders (International Call for Tenders No. 001/2015) is already available on the Petrobras website (www.petrobras.com.br - Business Channel). The Unit will be sold by performing presential auction, scheduled to take place on 10/26/2015 at 10 a.m. (Brasília time), in Vitória, Espírito Santo State, at Vitória Building - EDIVIT.
The interested parties should contact the Bidding Committee, by 10/14/2015, on the phone number +55 27 3295-3655 (Brazil), or through fpsoib.petrobras@petrobras.com.br
The deadline for submitting the documentation required by the bidding documents and for the visitation of the Unit for sale is 10/14/2015.
All information about the Unit to be auctioned off, the material on board, rules and requirements for participation in the auction, documentations, the Call for Tenders, and Addenda may be obtained in the Bidding Notice on the Petrobras website.
Bidding Committee
International Call for Tenders No. 001/2015
Petróleo Brasileiro S.A.
THIS PHOTOGRAPH WAS TAKEN IN NOVEMBER, 2006, WHEN THE PLATFORM WAS STILL IN OPERATION.
BR PETROBRAS
challenge is our energy

NEW IN 2015

Extreme trenching

DeepOcean's UT-1 awaiting deployment. Spot the humans!

Creating a trench might seem like a straight forward task. But, then introduce varying geotechnical conditions and then put your trench on the seabed – and it becomes a little less straight forward.

However, in 2007, in northeast England, which has a heritage of subsea machinery, a new piece of equipment was launched to make the task simple. It's the Ultra Trencher 1, or UT-1 – a 63-tonne (in air), 2.1MW, 7.8m-high, 9.4m-wide beast able to work in up to 1500m water depth.

DeepOcean (at the time known as CTC Marine Projects) developed UT-1 to push the boundaries of jet trenching capacity, power and depth rating to exceed any free flying jet trencher in the market – and it's still the market leader, says Thomas Howard, business development manager – Intervention & Cable Installation.

Do you have an idea for an asset we should feature? Contact news@OEdigital.com

He says, despite its size, UT-1 is agile and configurable for applications including trenching up to 43in-diameter pipelines to small seismic array cables. UT-1's trenching system comprises a 3m twin-legged jet tool mounted on double scissor linkage and uses sophisticated drive motors to allow precise control of pressure and flow, giving a high degree of flexibility in varied environmental conditions. UT-1 can make multiple passes along the pipeline or cable to ensure the target trench depth is met. Jets mounted on the bottom of the jet legs can also be used to create soil collapse and backfill of the product.

Permanently mobilized onboard DeepOcean's multi-role subsea construction vessel *Volantis*; UT-1 is deployed using a heave compensated launch and recovery system, which includes a submersible latch beam, cursor and high-speed constant tension winch for deployment in heavy seas.

UT-1's first project was trenching a subsea export power cable for E.ON's Alpha Ventus offshore wind farm in the German North Sea in 2008. UT-1 has since trenched some 650km of subsea product including; pipelines, umbilicals, power cables and seismic cables in Europe, the Mediterranean, the Americas and the Far East.

Notable projects include:

- Installation and post lay jet trenching of a 20km control umbilical in 330m water depth as part of a larger construction package on Eni's North Bardawil field offshore Egypt.
- Installation and simultaneous jet trenching of 240km of seismic array cable on ConocoPhillips's Ekofisk Life of Field Seismic Project offshore Norway, which saw the introduction of UT-1's cable capture tool to allow for simultaneous lay and trench operations and upgraded swords allowing increased jetting performance
- Installation and post lay jet trenching of a 105km HVDC bundled power cable between Jindo and Jeju in South Korea, where the UT-1 achieved 3m depth of lowering in a single pass along areas of the route.
- Post lay jet trenching of 174km of the 30in. Liwan pipeline in 205m water depth for CNOOC in China.

One of its next projects will be inter array cable installation on the Bligh Bank Phase II Offshore Wind Farm offshore Belgium, which includes the installation and trenching of 50 inter array cables next year. OE

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Numerology

40

The number of years the Forties field has been in production. See page 20.

22,400 tonne

The weight of the steel jacket meant for the Statoil-operated Mariner A platform. *(Source: Statoil)*

73%

The increase in spending for floating production systems, according to Douglas Westwood. See page 26.

5

The number of teams taking part in the Argos robotics challenge. See page 74.

The estimated amount per annum of global pipeline installation from 2015-16. See page 80.

8035km

40 billion boe

The amount extracted from the UK Continental Shelf since the 1970s. *(Source: The Scottish Government)*

16

PROBLEM:
How do we manage to connect all our survey and inspection sensors when there are insufficient data connection ports on our ROV?

SOLUTION:
Fugro Subsea designed and built its own class leading, fibre optic communication system, built into its FCV ROV systems to ensure you never run out of data capacity.

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