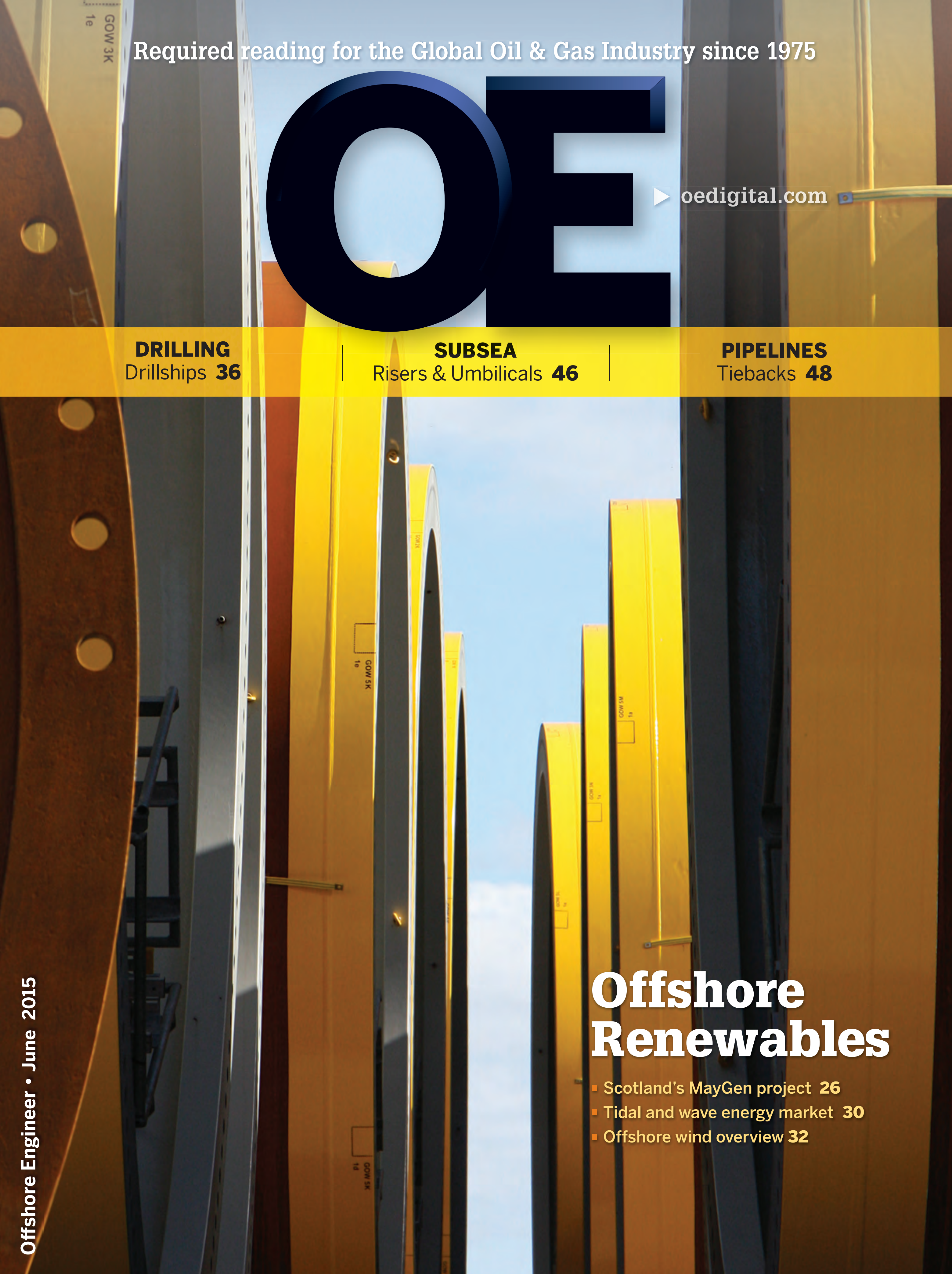

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Offshore Renewables

Offshore Engineer • June 2015

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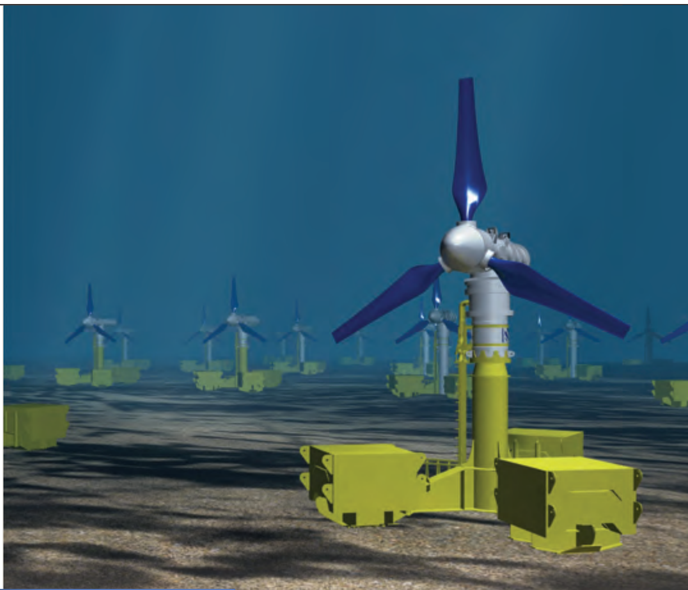

ON THE COVER

Offshore wind turbine foundations await their future deployment offshore at Bladt Industries' 35 hectare, coastal yard in Aalborg, Denmark. Bladt Industries' has been involved in the fabrication of more than 1300 foundations for the European offshore wind market. *Photo by Tenna Hørby from Bladt Industries/bladt.dk.*

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Online Exclusive

OTC Review

OE staff reports on all the highlights and lessons learned from this year's Offshore Technology Conference in Houston.

What's Trending

A new start

- Chevron, Exxon pre-qualify for Mexico's Round One
- South Stream project on again... for now
- Unmanned floating LNG – the next frontier

Activity

Huisman opens Brazil facility

Huisman opened its new production facility in Navegantes, Santa Catarina, in southern Brazil, this April. The facility will manufacture offshore equipment for the local market. "Being able to produce our equipment locally provides us and our clients with an important competitive advantage," said Joop Roodenburg, CEO of Huisman.

People

Cao named Saipem CEO

Saipem's board of directors chose Stefano Cao as the company's new CEO. Cao previously served as COO of Italian operator Eni.

Undercurrents

Third time's the charm

Forty years ago this month, after a frenzy of exploration and something of a race to be first, first oil was produced from the UK North Sea.

Opened by then-UK Energy Secretary Tony Benn, the Hamilton Brothers' Argyll field beat BP's Forties field to the post by just over three months. Hamilton Brothers had upstaged BP by deploying a floating production unit – a modified drilling rig – with shuttle tankers to export the oil.

As our regular readers will know, this year, too, is ***OE's*** 40th anniversary. What may be truly amazing to those bell-bottom-wearing early pioneers, both at ***OE*** and at Hamilton Brothers and BP, is that all three are still going (albeit with something of a stop-start history at Argyll), despite early expectations that the industry would be short-lived.

OE, like the North Sea's innovative supply chain, has continued to grow, expanding globally. Forties is still producing, well past its expected cessation of production date, and, despite decommissioning activity becoming a growing reality on the UK Continental Shelf (see our feature focus this month), Argyll is due to be revived for the third time in its life later this year.

Argyll's story should be a welcome one in today's climate. Despite being given up twice – the first time due to low oil prices – the industry has persisted and found news ways to produce the field.

Argyll was discovered in 1971, 310km southeast of Aberdeen, Scotland. On 1 June 1975, first oil from Argyll was pumped onto the 35,000-ton tanker *Theogennitor* from the *Transworld 58* semisubmersible drilling rig, which had been modified to function as a production platform, some 180mi off the Firth of Forth, AP reported at the time.

In 1992, Argyll's life was to be cut short. The field was decommissioned due to the low oil prices. Argyll had, during 1975- 1992, produced 74.8 MMbbl*. At cessation of production, the field was producing 5000 bo/d with a 70% water cut.

However, with reserves remaining in the ground, a new operator decided it was worth bringing back into production. Tuscan and Acorn renamed the field Ardmore and brought it back on stream in 2003, producing 5.2 MMbbl up to 2005. But, due to low profitability, it was again decommissioned.

In 2011, a new operator – thrice lucky for Argyll – UK independent EnQuest took over the Ardmore license and submitted plans to redevelop the field, renaming it Alma, via six production wells and two water injection wells, from two subsea templates, using the 57,000 boe/d and 625,000 crude storage capacity *Uisge Gorm* FPSO, now renamed the *EnQuest Producer*. Last month, EnQuest started pulling in risers on the *EnQuest Producer* and first production is expected mid-2015.

It's later than EnQuest's initial 2H 2013 plan, but, it's better late than never for the former Argyll field. According to EnQuest, field life on Alma will be about 10 years, with 20.7 MMbbl base case recovery.*

It proves both the willingness and ability of smaller players, both at Forties (now-operated by Apache) and at Argyll, under EnQuest, to eke the maximum remaining reserves from these fields. The concern is, however, that the attractiveness of such an enterprise is lessened due to lower oil prices. And as activity around decommissioning ramps up, less infrastructure will remain in place, into which smaller projects can be connected, helping to reduce costs.

Either way, as technology continues to evolve, new basins, margins and geologies open up. We're pretty sure there will still be an active North Sea for ***OE*** to report on in another 40 years' time. OE

**According to current operator EnQuest's environmental impact assessment for the current Alma project.*

OE

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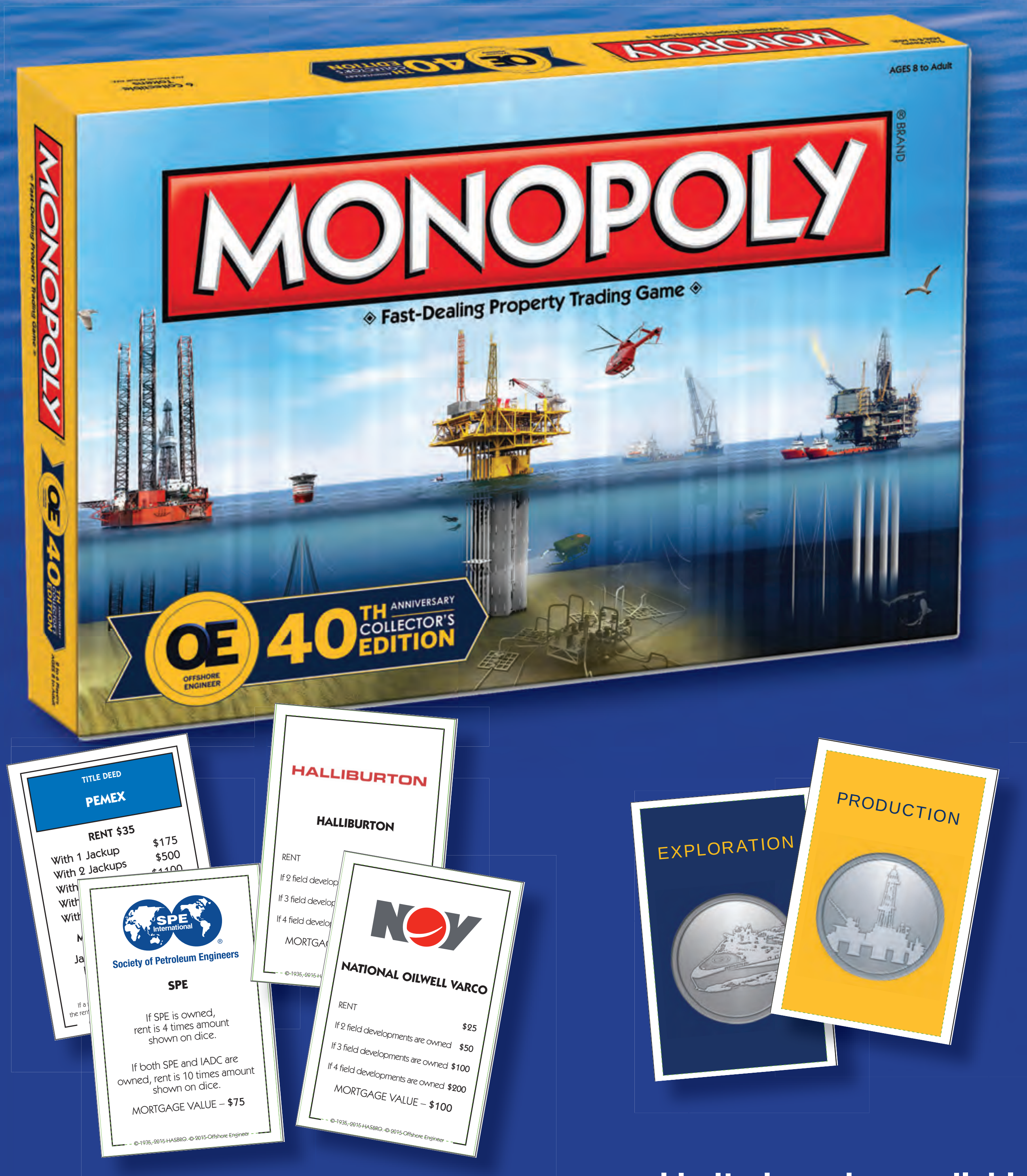

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Voices

Renewed Interest. With offshore wind and tidal projects viewed as costly endeavors, OE asked:

What will it take to make offshore renewables cost-effective?

Focus on cost reduction for offshore renewables usually falls on costly manufacturing of large components such as the towers, foundations and blades. However we should look seriously at innovation in assembly, installation and O&M, all of which present significant opportunities to reduce costs throughout the lifetime of the assets.

As the UK lead in the FP7-funded ECOWindS project, OrbisEnergy and Nautilus have been exploring cost reduction in offshore wind servicing. Our research indicates that innovation in vessel operations (both installation and operations and maintenance), turbine integrity monitoring, and effective logistics planning could take leaps to make offshore renewables a more cost effective source of energy for the long term.

Johnathan Reynolds, business development lead, OrbisEnergy, and director of energy industry consultants, Nautilus Associates

Cost reduction is a major focus for the whole offshore wind industry and significant cost gains have been made over the past few years, through improved technology and better working methods. A regulatory framework enabling a step development of large Round 3 offshore wind farms will be key to maintaining this downward trajectory. This would help to facilitate a sustainable supply chain and enable economies of scale, which in turn would mean more innovation and associated reductions in cost. Long-term visibility of the level of capacity growth the government will support, as well as flexible consenting windows, would ensure these large scale projects could be matured and phased over time.

Tarald Gjerde
general manager
Forewind

Offshore wind costs have already reduced due to increased use of larger size (6MW+) turbines. However, further cost reductions are required. New technologies such as floating wind turbine foundations can achieve this, as assembly can be performed onshore, vastly reducing installation costs. To date, floating wind turbines have had some success, with a number of prototypes currently operational. However, the best chance of achieving cost-efficient offshore wind project relies upon the standardization of infrastructure and cooperation between wind developers, whereby information and expertise can be shared.

Rachel Stonehouse
senior analyst
Douglas-Westwood

There needs to be increased collaboration and sharing of lessons learned between project owners and with and between contractors, but it rarely happens as it is seen as commercially sensitive. The current way of working allows cost competitiveness, but this is a bit of a red herring as it can lead to inefficiency/quality issues that cost more to fix in the long run.

Standardization of methods and equipment is an ambition, but has proven difficult to achieve. However, as a young and learning industry that still needs to develop solutions for the wind farms of tomorrow, which are bigger and further offshore, standardization should be part of our innovative thinking.

James Hunt
global low carbon lead
Xodus Group

Cost reduction is absolutely key to the success of offshore renewables. We've already seen significant reductions in the offshore wind sector, mainly driven by the trend towards larger turbines, but the sector has to continue to find innovative ways to drive down costs.

When it comes to wave and tidal, the challenge is quite different. These are much less mature technologies and we must be careful not to force cost reductions too quickly. Sustained and targeted innovation programs are vital for these sectors to reach commercial viability.

Lindsay Leask
senior policy manager, offshore renewables, at Scottish Renewables

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

ThoughtStream

Neil Kermode, CEO, European Marine Energy Centre

Globalizing marine energy

This past year has undoubtedly been one of the most challenging experienced by the marine energy industry in its short life, with some of our colleagues within the wave sector hardest hit.

However, as an emerging industry working in the most extreme of environments, setbacks are par for the course. Technology developers have known this from the outset, yet they've remained undaunted, approaching the task in hand with determination and energy.

Writing a new chapter in the global energy story was never going to be easy, but that goal we are all striving for — of meeting a significant proportion of the world's energy needs cleanly and from a perpetual resource — is now tantalizingly close with commercial array testing fast approaching.

In Orkney, Scotland, we've witnessed the shift from hypothetical potential to the actual reality of what the industry can achieve, with around 300 people employed locally in around 40 different companies. As a case study for marine renewables, the rest of the world is paying very close attention to what's happening in our peripheral community.

At the European Marine Energy Centre (EMEC), we are working closely with countries across the Americas, Asia, Australasia and Europe to support the establishment of a global network of test sites that, I believe, will lead to a community of interest with common approaches to the business of marine energy.

The establishment of common global standards, developed by worldwide experience, is critical to the development of a global marine renewables industry.

One only has to travel overseas and attempt to plug in a computer or other electronic device to realize the difficulties that will likely occur if we do not work at this together.

Each country established its own standards for plugs and sockets in isolation and the end result is pointless diversity of detail in the simple plugs throughout the world.

Marine energy devices are no different. In time, wave and tidal technologies will find their markets in dozens of countries and EMEC wants this to be as easy as possible both for the technology developers at EMEC and the ultimate customers here and overseas. We want a wave or tidal device that is certified at EMEC to be immediately marketable in any country, without expensive and time consuming re-validation.

"Each country has its own unique conditions, both physical and political, and exploring these challenges simultaneously will enable marine energy technologies to colonize these optimum niches more rapidly than if tackled in isolation."

Critical to this is the development of a standard approach to performance and resource assessment. If technologies invented in the UK and developed here at EMEC are to become established as global products, then it is vital that each international test center uses the same standards so investors can compare results from one center with results at another.

Each country has its own unique conditions, both physical and political, and exploring these challenges simultaneously will enable marine energy technologies to colonize these optimum niches more rapidly than if tackled in isolation.

Alongside technology development, we need to be able to assist policy makers. A tremendous technology is useless if there is nowhere to put it and, as our experience in Scotland has shown, policy has a central role to play in creating a marine energy market.

Each country with marine resources will have to think about policy measures for seabed leasing, environmental impact assessment, grid infrastructure, grants and tariffs. Scotland's experience and expertise in these areas is already being sought around the world and trade is being developed because of it.

Scotland has led the way in harvesting energy from the sea so far, but now Canada, Chile, China, Japan, Singapore, South Korea, Taiwan, the US, many European countries and others are all in the business of establishing their own national infrastructures — having sought EMEC's advice and consultancy services as they establish their own testing centers.

No one said that marine energy was going to be easy. However, this network of worldwide test centers will foster global market development, create common standards and enable the progress of wave and tidal energy into the global mix. OE

__Neil Kermode__ was appointed as managing director in November 2005. Before EMEC, Kermode worked as a project developer of a tidal scheme in Orkney following six years at an environment agency dealing with regulation and development issues, particularly relating to public participation in decisions on flooding, waste and water resources. He was a keen scuba diver and is a Fellow of the Institution of Civil Engineers and a Chartered Environmentalist.

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Global E&P Briefs

A Shell's Arctic plan approved

After receiving conditional approval from the US Bureau of Ocean Energy Management this May, Shell will now return to the Chukchi Sea to drill two wells. Shell's revised exploration plan proposes the drilling of up to six wells within the Burger Prospect, located in approximately 140ft of water about 70mi northwest of the village of Wainwright.

B Deep Panuke production halted

Encana Corp. shut in production from its Deep Panuke platform off Nova Scotia, due to excess of water in the gas reservoir. Production is expected to resume 4Q 2015 when gas demand ramps up. The Deep Panuke field is 155mi southeast of Halifax on the Scotian Shelf.

C Mexico authorizes seismic projects

Mexico's Comisión Nacional de Hidrocarburos (CNH) authorized three seismic projects.

Houston-based TGS will acquire the Gigante 181,500km regional 2D seismic survey in 2Q 2015. The survey will cover the Perdido fold belt and Campeche Bay.

Petroleum Geo-Services (PGS) began a multi-client 2D seismic program using the *Atlantic Explorer* and *Sanco Spirit*. Spectrum, with Schlumberger, will acquire and process more than 44,000km of regional 2D seismic data in the new frontier Campeche/Yucatan area. The long offset 2D survey covers complex structures located in deepwater, including both pre-salt and post-salt plays.

D Juniper development progresses

Diamond Offshore's *Ocean Victory* semisubmersible drilling rig has arrived in Trinidad and Tobago, destined for the Juniper field 50mi off the southeast coast of Trinidad.

Juniper is BP Trinidad and Tobago's (BPTT) first subsea field development, comprising five subsea wells tied into the Juniper plat form. First gas is expected in 2017.

E Exxon hits oil off Guyana

ExxonMobil confirmed a significant oil discovery on the Stabroek Block, 120mi offshore Guyana. The well, spud on 5 March 2015, encountered more than 295ft (90m) of high-quality oil-bearing sandstone reservoirs. It was drilled to 17,825ft (5433m) in 5719ft (1743m) of water.

F Drilling delays at Isobel

Premier Oil announced oil shows at the Isobel Deep well 14/20-1, in the North Falkland Basin, in a high pressure formation. The well will now be cased, delaying the drilling program. The interval will be cement plugged before drilling through the prognosed Isobel reservoir interval. Results will be likely made in early June.

G Light oil find in Sergpipe

Petrobras encountered the presence of light oil at well 3-BRSA-1296-SES in concession BM-SEAL-10, BlockSEAL-M-499 in the Sergpipe basin's ultra deepwaters offshore Brazil.

According to Petrobras, the higher market value light oil has good reservoir porosity and permeability.

The well is located 94km off the Aracaju coast, 10km from the discovery well and was drilled to a depth of 6060m, at a water depth of 2988m. Petrobras holds a 100% interest in the block.

H Big pay offshore Ireland

Europa Oil & Gas says an independent review of Frontier Exploration License (FEL) 3/13 estimates it contains nearly 1.5 billion boe prospective resources based on three prospects, Shaw, Beckett and Wilde. FEL 3/13 is in the Porcupine Basin, offshore West Ireland.

Europa says it is now working with operator Kosmos Energy on a potentially "play-opening" first well on FEL 3/13. Under the terms of the farm-out agreement, Kosmos will incur 100% of the costs of the first exploration well on FEL 3/13, subject to an investment cap of US$110 million. Costs in excess of the investment cap would be shared between Kosmos (85%) and Europa (15%).

I Alma/Galia, Kraken on track

EnQuest says its North Sea projects, Alma/Galia and Kraken, are both on track, the first due to start up mid-2015 and the second in 2017.

The firm is preparing to pull in risers on the *EnQuest Producer* floating production, storage and offloading (FPSO) vessel on the Alma/Galia development. Drilling on the Galia production well is to be completed and tied in during 2H 2015.

On the Kraken heavy oil field FPSO development, EnQuest will spend 2015 installing subsea hardware. Manifolds for the first drill center are already installed, as are the two templates for the second drill center. A drilling rig is due to leave the shipyard for the Kraken field during 2Q 2015, while work on the *Kraken* FPSO conversion continues in Singapore.

J Danish HPHT discovery

Maersk Oil has made a

hydrocarbon discovery on the high-pressure, high-temperature Xana-1X exploration in the Danish Sector of the North Sea.

The Xana-1X well was drilled in license 9/95 in 68m water depth. It reached a total drilling depth of 5071m in the Jurassic formation.

The well was spudded on 8 December by the jackup rig Noble Sam Turner and is currently being plugged and abandoned.

"At present the partners are in the process of assessing the technical and commercial implications of the discovery and looking at potential follow-up," said Martin Rune Pedersen, managing director of Maersk Oil's Danish business unit.

License 9/95 is operated by Maersk Oil, which holds 34% interest, with partners Dong E&P A/S (20%), Nordsøfonden (20%), Noreco Oil Denmark (16%) and Danoil Exploration (10%).

K Albania offers offshore blocks

Albania plans to offer seven offshore and onshore blocks for oil and gas exploration: offshore blocks Ionian 5 and Rodoni and onshore blocks four and five in southern and southeastern Albania, Dumre in central Albania and the onshore Panaja and C.

The bid awards will allow companies to explore for an initial period of up to five years, which could extend to seven, and they can develop and produce in the block for 25 years or more in accordance with Albanian oil laws. Part of the Ionian 5 block offered by Albania overlaps with the Ionian Sea area in which Greece seeks to search for oil.

L Kosmos hits pay at Tortue-1

Kosmos Energy hit additional hydrocarbon pay at its Tortue-1 exploration well offshore Mauritania.

Tortue-1 is located in Block C8, about 285km southwest of Nouakchott in 2700m water depth. Using the *Atwood Achiever* drillship, Tortue-1 is drilled to a total depth of 5100m.

Kosmos said Tortue-1 intersected approximately 10m (32ft) of net hydrocarbon pay in the lower Albian section, interpreted to be gas. This is in addition to the 107m (351ft) of net pay encountered in the Cenomanian, the primary objective.

The Tortue discovery, renamed Ahmeyim, is owned by Kosmos (90%) and Société Mauritanienne Des Hydrocarbures et de Patrimoine Minier (10%).

M Kizomba Phase 2 starts up

ExxonMobil started oil production at the Kizomba Satellites Phase 2 subsea development project off Angola.

Phase 2 of Kizomba is a subsea infrastructure development of the Kakocha, Bavuca and Mondo South fields, in Block 15 about 150km off Angola's coast, at 1350m water depth.

Peak production at the project is expected to reach 190 MMbbl or approximately 70,000 b/d of oil. ExxonMobil subsidiary and operator of Block 15, Esso Exploration Angola, expects total production of Block 15 to reach 350,000 b/d. Esso Angola first began production at Mondo South and will begin production at the other two satellite fields in the coming months.

N Area 1 LNG terminal progresses

Following a front-end engineering and design tender process, Anadarko contracted a consortium comprised of CB&I, Chiyoda, and Saipem to develop the onshore LNG terminal for Offshore Area 1. However, before final contracts can be signed, Anadarko has to make a final investment decision (FID) on the project, near Afungi in the northern Cabo Delgado Province. Andarko's CEO Al Walker called the award a "significant step" toward achieving FID.

O BP adds to West Nile Delta interest

BP increased its interest in the US$12 billion West Nile Delta (WND) project in Egypt after partner DEA farmed down its stake. WND is expected to produce 1.2 Bcf/d from two offshore concession blocks: North Alexandria and West Mediterranean Deepwater.

According to BP, there is the potential through future exploration to add an additional 5-7 Tcf, which could boost WND production. Production is slated to begin in 2017. The agreement will leave DEA holding a remaining 17.25%.

P Qatar seeks Al Shaheen partner

Qatar Petroleum is looking for a partner to undertake the future development of the Maersk Oil-operated Al Shaheen field, as the current agreement expires mid-2017.

Al Shaheen is located off the northeast coast of Qatar in the Persian Gulf, 180km north of Doha. Maersk Oil has been operator of the Al Shaheen field since 1992.

Q Lundin awarded Caspian license

Lundin Petroleum won a production license for the Morskaya field in the northern Caspian Sea.

The license, in the Lagansky Block, will be valid until 2035 and covers about 50sq km. The Morskaya discovery was made on the field in 2008.

R Vietnam's first deepwater well

Gazprom and PetroVietnam agreed to explore offshore Vietnam later this year. Vietgazprom, the joint operating company of both firms, will preside over exploration activities in blocks 112, 129-132. Block 129 will see Vietnam's first deepwater well, with sea depth exceeding 1600m, in 2H 2015.

Vietgazprom has contracted the *Deepsea Metro I* drillship to operate on Blocks 130 and 131 offshore starting mid-3Q 2015, for about 20 weeks, including options for two well testing periods.

S Rayrai-1 hits oil

KrisEnergy hit oil at Rayrai-1 in the Wassana field off Thailand in the southern Pattani basin. Rayrai-1 intersected about 50ft of net oil-bearing sandstones after reaching a total depth of 1945m, in 170ft water depth using the Key Gibraltar jackup rig. The well lies 2.25km north of the Niramai oil discovery, in the 4696sq km G10/48 license.

T Indonesian PSC shuffle

AziPac acquired 50% interest in the North Madura deepwater production sharing contract (PSC) located offshore Java Sea, from MitraEnergy (25%) and North Madura Energy (25%). In Eastern Indonesia; Ophir Energy has acquired four PSCs from Niko Resources.

Azipac's acquisition in North Madura, covering 1850sq km, is located offshore East Java in 45m water depth.

Operator AWE, holding 50% interest, acquired 1000km of 2D seismic over the block's southern area, and following analysis, expects the first explorative well in 2016.

Ophir will operate its PSC's, West Papua IV, Aru, Kofiau and Halmahera-Kofiau, which it has commissioned 2D and 3D seismic with a view to drilling on 2016-17.

Ophir is also in the process of acquiring two additional PSCs from Niko: North Makassar Strait and North Ganal.

U Oz blocks up for bid

Australia has total of 29 offshore blocks across eight basins up for bid in its annual Offshore Petroleum Exploration Acreage Release.

Twenty-three areas are available for work program bidding and six areas are available for cash bidding.

These blocks are located in the offshore areas of the Northern Territory, the Territory of Ashmore and Cartier Islands, Western Australia, South Australia, Victoria and Tasmania.

Ranging in various water depths and sizes, investment opportunities are open in the Bonaparte, Browse Carnarvon, Roebuck, Ceduna, Otway, Gippsland and Sorrell basins. ▪

Contract Briefs

Wood Group wins OSRCL work

Wood Group Kenny (WGK) won a five-year contract with Oil Spill Response (Capping) Ltd. (OSRCL) to provide the maintenance support for a key part of a containment toolkit.

The project will include maintenance management, recommendations for preservation, inspection and testing of all ancillary and lifting equipment, as well as the flexible flowlines, stored at sites in the UK, Singapore and Brazil.

Aibel awarded Maria work

Statoil awarded Aibel a US$114.3 million contract for engineering, procurement, construction and installation work related to water injection from the Heidrun platform to the Wintershall Norge-operated Maria field.

Aibel's scope of work entails increasing the water injection capacity of Heidrun and perform the tie-in of the water injection from the platform to the Maria field via a riser. Aibel will purchase and install new SRP filter packages, upgrade existing equipment, expand the riser balcony, move a lifeboat, and upgrade the platform's control system.

Technip wins Thunder Horse gig

BP awarded Technip a lump sum project for the design, engineering, fabrication, installation and pre-commissioning of the new production pipeline systems on the south side of the Thunder Horse production drilling quarters unit.

The project scope covers: project management and engineering; coating, fabrication, installation and permanent anchoring of two rigid production flowlines of 3.25km each with four pipeline end terminations; pre-commissioning and testing.

The offshore installation is expected to be performed in the 2H 2016 by Technip's flag ship vessel the *Deep Blue*.

EMAS AMC racks up contract wins

EMAS AMC has won multiple new awards worth approximately US$55 million.

The scope of work includes project support, inspection, maintenance and repair (IMR), subsea removal work of pipelines and structures, installation of buoys and lifting of structures and mattresses, as well as a pre-FEED study.

Work has already begun for several projects, with the others slated for offshore execution from 3Q 2015 onwards.

Kongsberg wins FPSO contract

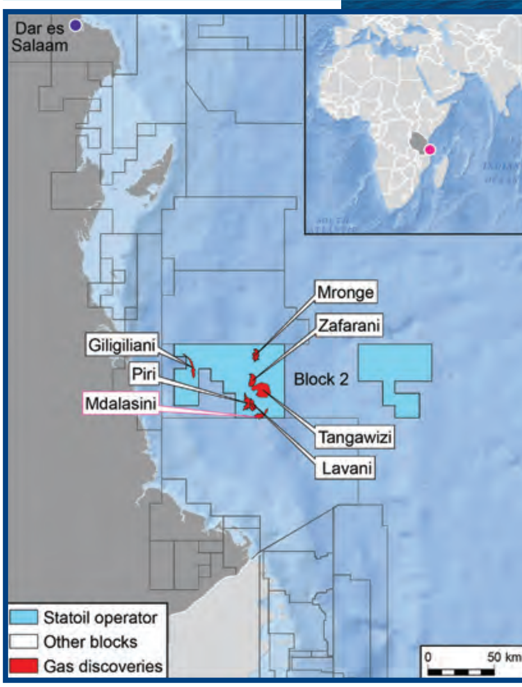
Kongsberg Maritime entered into a US$26.5 million contract to supply a complete electrical, instrument and telecom solution, including e-house, for the new Yinson Genesis floating production storage offloading unit (FPSO).

The FPSO contract was awarded by Eni Ghana E&P to a consortium consisting of Yinson Production (West Africa) Pte Ltd. and Yinson Production West Africa Ltd. The Kongsberg scope of work includes complete integration engineering, electrical systems, e-house and telecom and surveillance equipment. Kongsberg will also supply marine automation, process control, and a fire and gas detection system to the vessel. The FPSO is expected to be operational by 2017. ■

The spice of life

Statoil and ExxonMobil are seeking ways to develop the multi-trillion cubic feet of gas resources they have found in Block 2 offshore Tanzania. Elaine Maslin takes a look.

Transocean's *Discoverer Americas* drillship offshore Tanzania -
Photo by Paul Joynson-Hicks - AP – Statoil.



If you speak Swahili, zafarani, lavani, tangawizi, mronge, piri, giligiliani and mdalasini are spices – saffron, vanilla, ginger, horse radish, pepper, coriander and cinnamon.

To Statoil and ExxonMobil, they are also the names of eight major gas fields (Lavani has been classified as two, Lavani main and Lavani deep), totaling some 22 Tcf of natural gas resources, which they have discovered offshore Tanzania and are now planning to bring to the market.

Discovering the resources, 100km off southern coast of Tanzania, in 2200-2500m water depth, was a challenge in itself. Now the two firms are assessing how they are going to bring these resources to market. The current concept front runner is a subsea-to-shore project – using already proven and qualified technology as much as feasibly possible.

Statoil expects to take a final investment decision on the project in 2018, at the earliest. First production is likely to be start 2022-23, at the earliest.

Speaking at the Subsea Valley conference in Olso in April, Harald Eliassen, previously asset manager on the Peregrino field offshore Brazil for Statoil and now the firm's Tanzania offshore project director, says it is early days, but this will be an interesting project for the industry to watch with technology hurdles to overcome – not least when it comes to designing pipelines that can cross the seafloor valleys in 2200m deep water between Block 2 and the shoreline.

"The project is in the early stages," Eliassen told the event. "We have a lot of work ahead of us, both on technical solutions offshore, on the LNG plant and with the authorities. There is still a lot of time before we make a final investment decision. But still, it is an interesting project and something you should keep an eye on."

Discoveries

Statoil was awarded operatorship of Block 2, which covers about 5500sq km in 1500-3000m water depth, offshore Tanzania, in 2007. In 2010, ExxonMobil farmed in, taking 35% interest. The joint venture's exploration campaign started in 2012, with 13 wells now drilled, comprising nine exploration wells, one combined exploration and appraisal well and three appraisal wells.

Harald Eliassen

The Zafarani, Lavani, Tangawizi and Mronge reservoirs were discovered in 2013-2014. Piri and Giligiliani were discovered in 2014. Earlier this year, Statoil announced the Mdalasini discovery in Tertiary and Cretaceous sandstones 2296m water depth at the southernmost edge of the block.

The 14th well, and the last in the current drilling campaign, is an appraisal well on Tangawizi; it is ongoing. The *Ocean Rig Poseidon* drillship was used in the first exploration phase.

A crucial part of the drilling campaign was a drill stem test (DST) on Zafarani. The Zafarani-2 DST was one of the deepest tests ever done, in some 2400m water depth, Eliassen says. It tested two zones, flowed at a maximum 66 MMscf/d, constrained by equipment, confirming the production potential, reservoir connectivity and the extent of the Zafarani reservoir. The DST also gave a good indication of the production potential of the other discoveries, Eliassen says. Statoil now has some 15-16 subsurface professionals on the job to mature the understanding of the reservoirs already discovered, he says.

"Thanks to the long campaign using the *Discoverer Americas*, the JV has also had a learning curve drilling in Tanzania, which has reduced the number of days to drill a well in Tanzania," Eliassen adds.

Once the latest appraisal well, Tangawizi 2, completes (due this summer), Statoil will demobilize *Discoverer Americas* from Tanzania and, Eliassen says, enter the next exploration phase where it will evaluate further prospects and drilling in Tanzania.

Connected reservoirs and deep canyons

The gas in Block 2 is dry gas. Statoil believes this will produce through natural depletion, gas expansion and

some aquifer support, with a recovery rate ranging from 60-80%. "It all depends on how much water support we get," Eliassen says. "We need some to keep the pressure up, but we don't want too much water support because the water might break through and we might have to shut the wells."Since we will produce several discoveries into one common production system we have to manage to pressure depletion in the different reservoirs so we can reach a common pressure in the pipeline system," he continues. "With the depletion and gas expansion as the main drive there will be no injection wells."

It is thought that the Zafarani reservoir will need 5-7 wells, the Piri reservoir 3-5, Lavani deep 2-3, and Lavani main 3-5 wells. In total, that will add up to about 13-20 wells in the first phase of development. The results of the appraisal well on Tangawizi-2 will help decide if Tangawizi is feasible and economical to develop, and if so, this would probably be added to the production some 7-10 years after first gas. It would add another 5-8 wells and probably a second pipeline to the development, Eliassen says.

Then, there are the Mronge, Giligiliani and Mdalasini reservoirs. These have not been included in the first phase of development, partially due to the difficult seabed conditions. From the Tanzanian shoreline extending out to sea there are some very pronounced canyons and valleys, Eliassen says. (*OE: February 2015*) "Where our discoveries are, the valleys become even more pronounced. They are 200-300m deep with very steep edges and possibly unstable edges," he says. "Luckily, most of our discoveries are in the core areas between these pronounced canyons. That's why we're starting with in this area and we have found a feasible route for the pipeline to shore, too."

But, it will not be easy. "There are still some valley crossings [on the pipeline export route]… and there are still some issues related to that, but we believe that together with industry we will be able to find solutions to protect the pipelines so they can withstand any activities in these canyons. We can see there was some activity about 500 years ago and that is not long enough ago for us to rule it out that it will not happen while we are there."

Concept selection

In choosing its development concept for Block 2, Statoil looked at floating LNG, a floating production unit offshore, with the gas going into the shore for LNG production, and subsea to shore.

"The floating LNG was hot for a while," Eliassen says, "But, as we made more and more discoveries we realized that the amount of gas doesn't really fit the floating LNG system – it would be too small or you'd need too many units out there and it would become very expensive." The Tanzanian government was also very keen for onshore processing, to bring benefits to the local economy.

Statoil staff Geir Rune Hagatun and Nicholas Alan Maden on the *Discoverer Americas* offshore Tanzania. Photo from Statoil

Statoil then compared a floating unit offshore with a subsea-to-shore system. "Both were technically feasible," Eliassen says, "So we looked at concept differentiators to see if there was anything with a floating unit that would give us a higher recovery factor, better economy, less risk, etc., and we really didn't find anything that would pay for the extra cost of the floating production unit. So, due to the lower capex, opex and lack of differentiators, we ended up with a subsea-to-shore solution with the gas transported untreated to the LNG plant to shore."

A subsea system

Statoil looked at what it had done before on the Ormen Lange subsea-to-shore project offshore Norway. This created a concept with large manifolds, dual pipelines, dual services lines, dual umbilicals, "loads of redundancy." This was seen to be too expensive and would require mobilization of heavy lift vessels to Tanzania, where there were no heavy lift vessels before. The firm then looked at its leaner Snohvit subsea to shore development, and took that concept further – making it event leaner.

"The concept is a daisy chain layout, with no manifolds, no large modules to be lifted, simple inline Ts on the flowlines to connect each well, too," Eliassen says. "It allows us to spread the Xmas trees around on the seabed so we have an easier well path and lower drilling costs. All of this made the system a lot cheaper and we managed to cut something like 30% of the cost from the original system we had. Cutting cost on this project is very important. It's a huge investment project."

Statoil is now going into an equipment and technology selection phase. Eliassen is very clear that the company only wants already proven equipment and technologies as far as is feasibly possible. "We don't want to go into any technology development programs or technology qualification programs that we don't absolutely have to do," he says. "We need to get together with industry and our partners – ExxonMobil has a lot of ultra-deepwater experience – to find out if there's anything out there we can use copy and standardize. If there is, we will do it in Tanzania."

Onshore

Based on a request by Tanzanian authorities, the onshore processing terminal will be built under a partnership between the operators on Blocks 1, 2, 3 and 4, led by BG Group.

A memorandum of understanding between the government of Tanzania, the partners in Blocks 1, 3 and 4 and the partners in Block 2 was signed in April 2014. A contract for the LNG plant pre-FEED was awarded in August 2014. A joint integrated project team is working on the project in London working on the onshore project.

"We believe we've found a feasible and cost effective solution – subsea to shore into a common LNG plant," Eliassen says. "There are still some challenges, notably on the seabed in 2500m water depth and we need to work together with the industry and our partners to come up with cost effective solutions for this development."

Statoil's Tanzania office, in Dar es Salaam, has about 50 people, mostly local with about 15-20 people Norwegians. OE

In-Depth

Fernando C. Hernandez

Closing Mexico's deepwater gap

Following Mexico's historic energy reforms, Fernando C. Hernandez of Reaching Ultra, discusses what is still needed in order to make Mexico a major deepwater player.

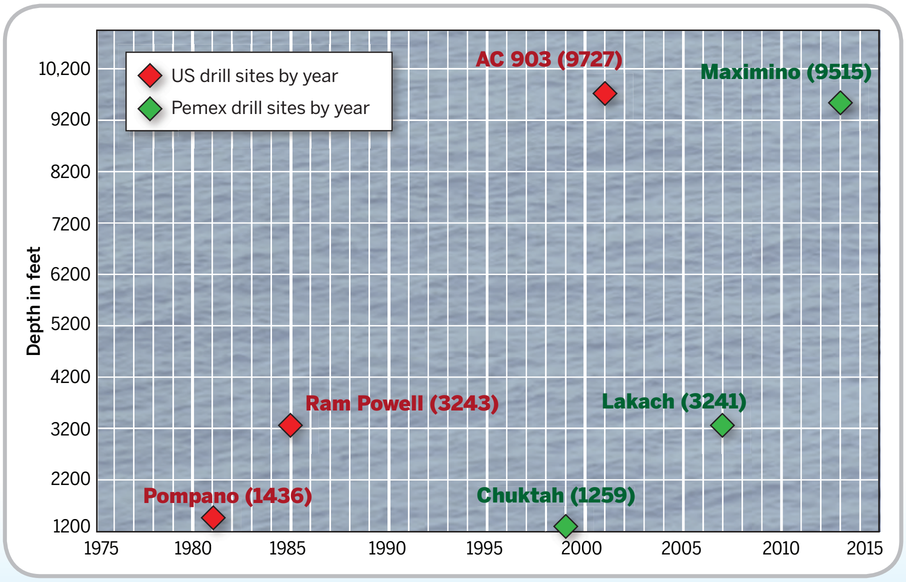


Fig. 1: A comparative analysis of the gap in deepwater drilling and exploration efforts between US and Mexico.

Mexico's national oil company (NOC), Pemex, is in a transitional phase, soon to function as a state productive enterprise following the pasage of Mexio's historic energy reform. The reform was driven by Mexico's ambitions to increase its waning production output, while positively impacting its economy. But for this to happen, Mexico will require the infusion of foreign capital, and foreign expertise—as noted by Mexican officials and industry experts at Mexico's first oil and gas summit held in 2014. Additionally, the reform generated great interest—in regards to wells located on- and offshore—by both US and Mexico's private and public sectors.

Historically, offshore, Pemex has largely focused on shallow water projects; and in particular the Campeche region, illustrated by the Cantarell the field. However, Pemex has made great investments, beginning in the late 90s, to venture into deeper waters. This is highlighted by exploratory drilling, which took place adjacent to the US's Perdido region: the 2013, 9515ft deep, Maximino find being a prime example. The Perdido region extends from US waters into Mexican waters. Furthermore, Pemex previously referred to this deepwater discovery as "the jewel in the crown." The US surpassed Maximino's depth at Trident-2 in Alaminos Canyon Block 903 in 2001 (See Figure 1).

Understanding the gap

A key difference in regards to the Perdido basin is that Mexico has no producing assets there. Moreover, the basin continues to be a focal point on the US side due to its productivity. This furthers the incentive for Mexico to develop its side. And, because of the US's close proximity to Mexico, and its familiarity with the deepwater realm, this will require Pemex to tap into the US's deepwater technologies, methods and experience, along with non-US companies.

This is especially true for Lakach—discovered in 2007— set to be Mexico's first deepwater seabed production scheme, at 3241ft of water, southeast of Veracruz City.

The US made a similar discovery to Lakach at a depth of 3243ft in 1985 via Ram-Powell, which highlights the extent of the deepwater

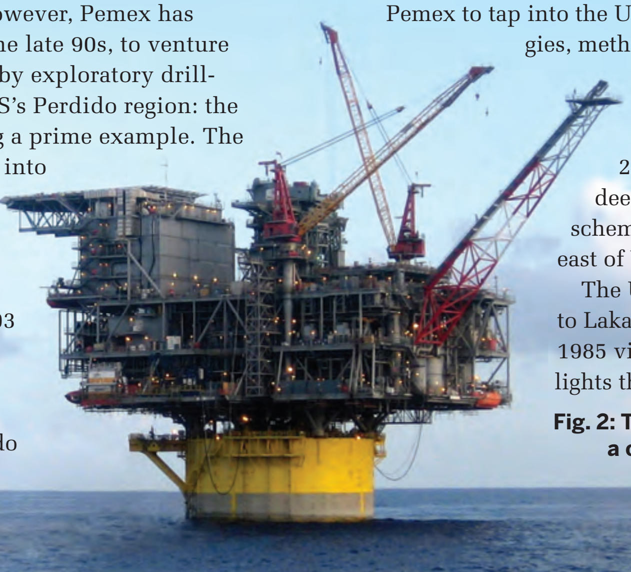


Fig. 2: The Perdido Hub as seen from a crew boat. Photos from Reaching Ultra.

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	69	13
Deep (500-1500m)	23	19	25	8
Ultradeep (>1500m)	36	35	12	5
Total	133	126	106	26
Start of 2015	135	125	90	-
date comparison	-2	1	16	26

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	9	177.75	2,363.28
Deep	16	1,616.00	2,935.00
Ultradeep	47	14,098.75	15,973.00
United States			
Shallow	15	86.30	23400
Deep	16	849.27	1,225.48
Ultradeep	23	2,876.50	3,370.00
West Africa			
Shallow	113	3,684.45	15,969.22
Deep	38	4,622.50	6,740.00
Ultradeep	13	1,635.00	2,460.00
Total	281	29,468.77	48,906.70
(last month)	(302)	(30,755.27)	(51,594.70)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	945	39,549.36	577,804.96
(last month)	(1024)	43,505.45)	(592,331.88)
Deep	134	8,469.58	113,700.91
(last month)	(152)	(9,226.43)	(118,298.12)
Ultradeep	87	18,638.25	34,770.00
(last month)	(94)	(19,664.75)	(37,220.00)
Total	281	29,468.77	48,906.70

Pipelines

(operational and 2015 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,067	(41,047)
Planned/ possible	24,665	(24,683)
	65,732	(65,730)
8-16in.		
Operational/ installed	81,856	(81,517)
Planned/ possible	49,044	(48,901)
	130,900	(130,418)
>16in.		
Operational/ installed	92,480	(92,199)
Planned/ possible	40,678	(40,430)
	133,158	(132,629)

Production systems worldwide

(operational and 2015 onwards)

Floaters		(last month)
Operational	269	(266)
Under development	50	(50)
Planned/possible	320	(321)
	639	(637)
Fixed platforms		
Operational	9231	(9240)
Under development	98	(96)
Planned/possible	1347	(1343)
	10,676	(10,679)
Subsea wells		
Operational	4796	(4773)
Under development	443	(428)
Planned/possible	6453	(6517)
	11,692	(11,718)

Global offshore reserves (mmboe) onstream by water depth

	2013	2014	2015	2016	2017	2018	2019
Shallow	23,611.54	14,066.92	40,436.02	31,255.85	19,876.13	29,803.84	26,575.60
(last month)	(23,738.00)	(14,066.92)	(40,436.02)	(31,255.85)	(19,876.13)	(29,803.84)	(26,575.60)
Deep	480.55	4445.73	4375.97	3047.51	3225.33	6760.13	12,670.66
(last month)	(481.00)	(4445.73)	(4375.97)	(3047.51)	(3225.33)	(6760.13)	(12,670.66)
Ultradeep	2928.44	2342.81	2127.21	3037.99	5602.10	5481.85	8519.40
(last month)	(2928.00)	(2347.31)	(2116.71)	(3034.99)	(6194.26)	(6852.54)	(8028.50)
Total	27,020.53	21,028.80	46,640.47	35,130.16	26,012.43	39,568.26	47,360.40

18 May 2015

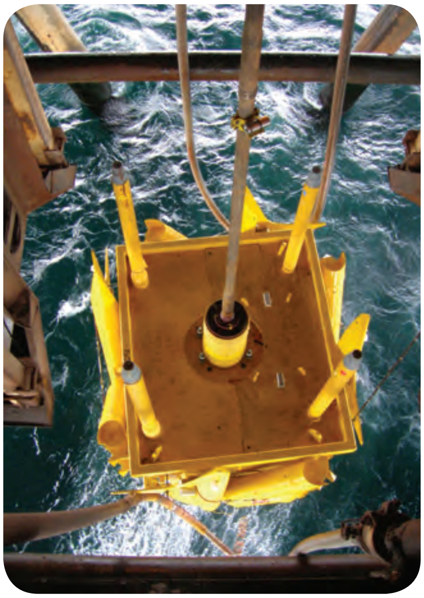


Fig. 3: Installation of a subsea christmas tree in deepwater. Photo from Connect Subsea.

gap. But, to truly understand why such gap exists, we must revisit the 1970s, when a fisherman named Rudesindo Cantarell Jiménez inadvertently discovered what would become Pemex's Cantarell field.

Pemex's offshore history

In 1979, the Cantarell complex—named after the aforementioned fisherman—would come online, and by 1981 it would go on to reach 1.16 MMbo/d. Furthermore, Cantarell produced at an almost constant rate of 1 MMbo/d for 14 years. Pemex's multi-billion dollar investment in Cantarell paid off, and so had the allure of continuing to produce in this shallow water region.

But in the late 1990's, the field's output began to decrease at an alarming rate, resulting in Pemex embarking on a nitrogen injection program to boost the field's production, according to the US Energy Information Administration (EIA).

This, too, would be a multi-billion dollar investment. Pemex began its injection program in 2000, achieving promising results, and catapulting the field onto the global stage when production peaked at 2.1 MMb/d in 2004. In turn, Cantarell contributed to 63% of Pemex's crude oil production for that year, the EIA said. However, in subsequent years, the field's production rates began to decrease. The result: Pemex exploring outside of its shallow water assets, and into deeper waters with greater interest. Mexico's deepwater ambitions ran parallel with Pemex's nitrogen injections, due to the fact that by 2013, Cantarell's contribution to Pemex's totalized production went from 63% to 17%, according to EIA data.

Reaching Perdido: The importance of 2013

From a historical vantage point, Pemex's deepwater ambitions can be traced back to Chuktah, which was drilled in 1999 at 1259ft water depth, following the planning of drilling and completions for their deepwater program in 1996-1997. After Chuktah, Pemex's deepwater exploration continued to gain momentum—when Pemex made their then-deepest find at Lakach at a depth of 3421ft in 2007.

And in 2013, Pemex increased their drilling depth by over 6000ft by way of Maximino located in 9515ft of water. The NOC had now made a quantum leap in to the ultra-deepwater category. It is this rapid and unprecedented advancement by Pemex that illustrates the importance of collaborative efforts between the two countries (US and Mexico), so as to ensure Mexico breaks in to the deepwater safely and with a fit-for-purpose philosophy.

In regards to the Perdido basin, the Perdido spar functions as a hub that connects multiple fields back to it. In 2007, the US's offshore regulatory agency—then known as the Mineral

Management Services (MMS)—expressed that, "The oil and gas fields beneath the platform lie in a geological formation holding resources estimated at 3-15 billion boe." In 2010, it was expected that production would peak at 100,000 boe/d, however, by 2013, Perdido exceeded original production estimates. The hub was outputting over 115,000 boe/d. It is important to note that other projects are coming online nearby Perdido that are equally delivering on expected returns.

Depth increase

Though much emphasis has been placed on the Perdido basin; Pemex's first subsea production scheme in deepwater will be Lakach, south of the Perdido Basin. The first few wells are expected to enter production later in 2015. Conversely, the Popeye field which is quasi-comparable to Lakach, came online in 1996, creating a 19-year deepwater production gap. Subsea production-wise, Pemex is on-track to make an additonal quantum leap.

For all intended purposes, Lakach can be viewed as a pilot project for Pemex from which future seabed production initiatives will be modeled, but future projects in deeper waters can expect to have lessons learned from Lakach incorporated. This too is applicable to engineering and technical adjustments such as, well head design and associated downhole jewelry; the overall composition of underwater christmas trees that are to be installed on top of wellheads to export a well's content; the way peripheral subsea equipment/assets are interlinked so as to complete a subsea production scheme; the methodology employed to operate a scheme in its entirety, in order to properly export, route, distribute, and control a well's content; the manner by which flow assurance is approached, so as to prevent hydrate blockages, which can render a scheme inoperable. Some of the additional engineering and technical adjustments include:

- The need for dynamically-positioned platforms, which would break away from the stationary jackup rigs commonly used in the Bay of Campeche.
- The need to shift away from relying on divers to using work class ROVs for all phases of projects: From commissioning to plug and abandonment efforts.

Conclusion

With the reform passed, and as Lakach nears production, Mexico's new energy policies will continue to garner global attention, as it positions itself to become the newest member of the deepwater golden triangle, and regain market share. Procuring technological and engineering talent will be fundamental in closing Mexico's deepwater gap, and will ensure Mexico can successfully and safely produce from deepwater depths. On the other hand, foreign companies that support Mexico's future oil and gas ambitions equally stand to benefit by having their products and services employed to further Mexico's ambitions. OE

Fernando C. Hernandez is the subsea technical advisor at Reaching Ultra. Hernandez speaks three languages and has extensive field experience in the ROV tooling, automated controls, subsea and well intervention sectors.

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	109	92	17	84%
Jackup	417	321	96	76%
Semisub	164	133	31	81%
Tenders	33	21	12	63%
Total	723	567	156	78%

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	37	34	3	91%
Jackup	79	55	24	69%
Semisub	21	18	3	85%
Tenders	N/A	N/A	N/A	N/A
Total	137	107	30	78%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	12	6	6	50%
Jackup	116	87	29	75%
Semisub	35	20	15	57%
Tenders	22	12	10	54%
Total	185	125	60	67%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	28	27	1	96%
Jackup	9	7	2	77%
Semisub	33	30	3	90%
Tenders	2	2	0	100%
Total	72	66	6	91%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	52	44	8	84%
Semisub	43	42	1	97%
Tenders	N/A	N/A	N/A	N/A
Total	96	86	10	89%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	112	94	18	83%
Semisub	3	3	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	115	97	18	84%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	25	21	4	84%
Jackup	25	18	7	72%
Semisub	14	10	4	71%
Tenders	9	7	2	77%
Total	73	56	17	76%

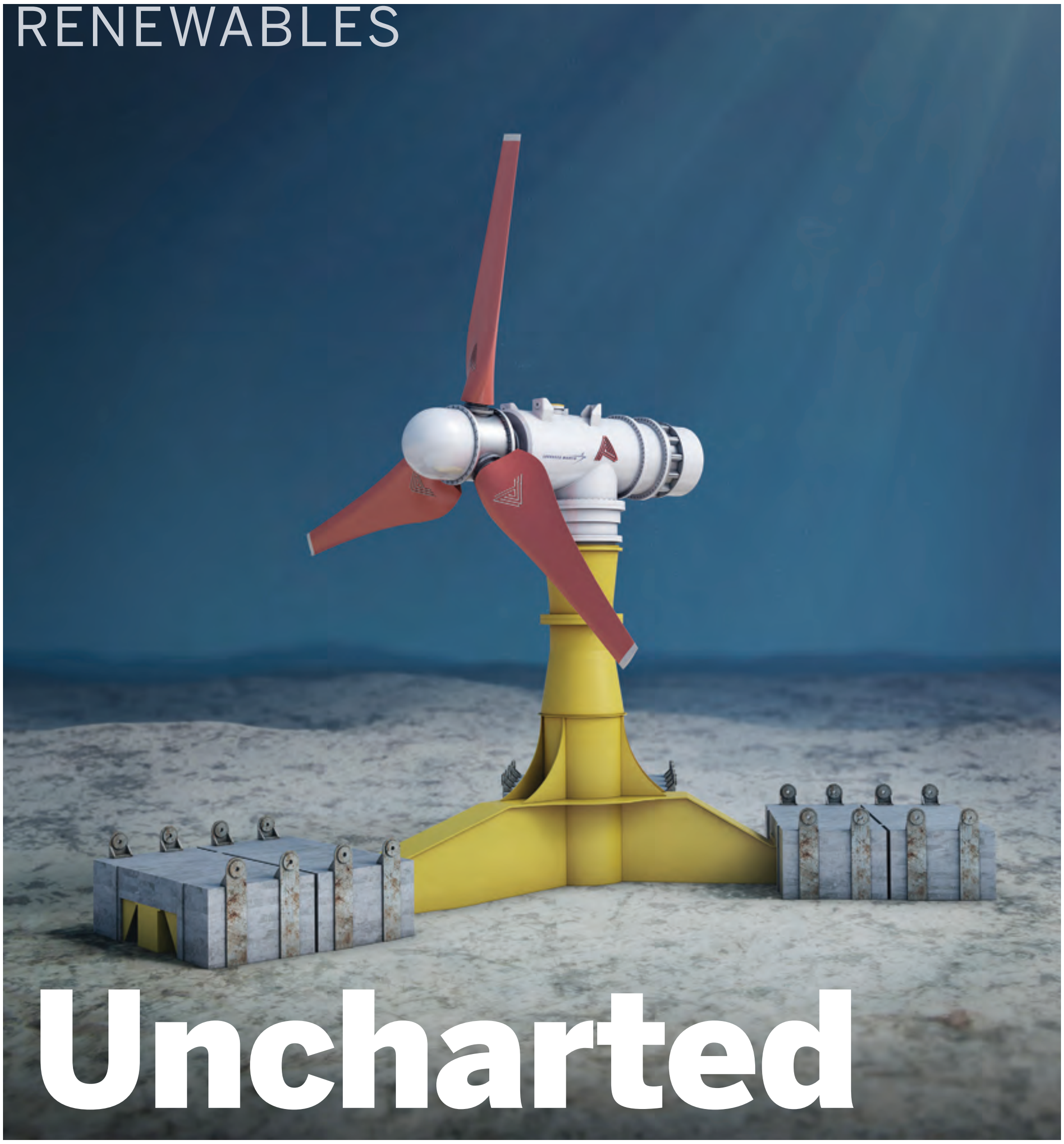
Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	5	3	2	60%
Jackup	24	16	8	66%
Semisub	15	10	5	66%
Tenders	N/A	N/A	N/A	N/A
Total	44	29	15	65%

Source: InfieldRigs

18 May 2015

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



Uncharted waters

A milestone is about to be reached in the tidal energy industry off the cold harsh coast of Scotland. Elaine Maslin talked to the project director behind the MeyGen tidal array development.

First, assemble a generator, gearbox, electronics and instrumentation with an 18m-diameter rotor to power it. Then attach it to a rocky, 30m+ deep seabed, scoured clean by a 5m/sec mass of turbulent energy rushing from the Atlantic to the North Sea and back. Then expect it to operate for 25 years.

It's a challenge, but for an engineer, it's also pretty interesting work. It's a job David Collier, project manager on the MeyGen project, the world's largest planned tidal development project, is relishing. When fully completed, MeyGen will see 269 tidal turbines, totaling 398MW, installed in the Inner Sound of the fast flowing Pentland Firth, between mainland Scotland and the Orkney islands.

Earlier this year, construction started on the onshore part of the first phase (1A) of the project. Offshore, Phase 1A will see four turbines, totaling 6MW capacity, installed on the rocky seabed and tied into the grid 2km away onshore. Phase 1 will see a further 61 turbines installed, with the final project working up to 269 turbines.

The MeyGen project, which is owned by Atlantis Resources, will deploy two different turbines in Phase 1A. Norway-based Andritz Hydro Hammerfest is supplying three of its HS1000 turbines and Atlantis Resources will supply one of its AR1500 devices, to be built by Lockheed Martin.

All four will sit in 31.5-36m deep water. First power to grid is expected to be delivered in 2016.

Humble beginnings, early learnings

Atlantis Resources began life as a turbine technology developer (see "Spotlight," page 62). In 2010, the firm was part of a consortium awarded the development rights for the Inner Sound of the Pentland Firth by the Crown Estate.

Atlantis Resources' AR1500, artists' illustration.
Images from Atlantis Resources.

In 2013, the MeyGen project secured its final regulatory consents, making it the largest, fully consented tidal project in Europe. Not long after, Atlantis Resources took 100% control of the project. Last year, the firm listed on the London Stock Exchange and then secured a £50 million funding package for Phase 1A.

Front-end engineering has been completed and the firm is still working through some finer details, including cable stability. For Phase 1A, the power export cables (one each per turbine) will travel from the onshore power conversion building under the rocky cliffs to the seabed via four, 550m-long, 404mm-diameter bore holes, with 315mm plastic liners, directionally drilled from shore. The bores are lined with 315mm-HDPE ducts, pushed through the bore hole from shore. The remaining 2km lengths of the 100mm-diameter, 4.4kV export cables, and future array cables, will be laid directly on the rocky seabed, which over the years has been scoured bare of all lose sediment due to the combination of fast currents and waves running through the Pentland Firth, and be fixed so that they remain stable for up to 25 years.

"We are trying to lay a stable cable in a very unstable environment," Collier says. "From our research, this has not been attempted before. From an engineering point of view, it's a probably one of the most challenging aspects of the project. I've worked in oil and gas for 15-20 years, and there were plenty of challenges, but most of the routes to the solutions had been trodden. That's been the tricky bit on this project. It's new territory."

Testing turbines

MeyGen Phase 1A will use three HS1000 turbines and one AR1500 turbine. The design for both devices is similar in terms of requirement – an 18m rotor diameter with 3-bladed propellers – but they also have significant differences. For one, Andtriz Hydro Hammerfest has decided to use steel propeller blades on its 200-tonne HS1000, whereas the 160-tonne AR1500 is sticking with lighter composite blades.

"The steel blades have some advantages and some disadvantages," Collier says. "They are very robust, but then you have to deal with fatigue and manufacturing them can be quite difficult. But, Andritz Hydro has a history of large hydro plants, so beating metal is not scary to them. It also makes it a bit heavier so you have higher inertia, which can be a benefit and a disadvantage. The AR1500 has stuck with composite, which is proven and quite successful. It is a bit less robust, but lighter and easier to handle."

The two turbines also have different generators. The AR1500, described by Atlantis as one of the largest capacity single-rotor turbines built, has a permanent magnet generator with a two-stage gear box and the HS1000 an induction generator with a three-stage gear box. Both turbines have a common foundation, which is a three-legged, gravity-based structure that the turbine sits on with a stab connection and is maintained with gravity and the same size propellers.

The propeller blade diameter would ideally be bigger, just as in wind turbines where greater size means greater capacity. But, while some of the site could accommodate up to 20m-diameter blades, MeyGen's research found that 18m was a good optimum, Collier says. To work at their rated power, 3m/sec flow is needed. Up to 3m/sec, the power output gradually increases. Once 3m/sec is exceeded, power availability has to be dumped."When we started, we had 1MW devices," Collier says. "We looked at the best optimization based on the flow profile and rated power and it turned out to be fairly flat between 1.4MW and 1.6MW, so we went for 1.5MW, which is achievable with an 18m-diameter rotor."

At 18m-diameter, the turbine's propeller tips will reach about 5.5m from the seabed and minimum 8m from the surface to ensure adequate clearance for any shipping (the tidal range

Turbinefarm – How the array could look on the seabed.

is 2-3m). The turbines will include an active pitching system and full nacelle yawing capability that will be developed by Lockheed Martin, to enable them to adjust to the current strength and direction.

Testing, testing, testing

Both turbines to be used in Phase 1A have already been tested offshore, at the European Marine Energy Centre, Orkney, for one- to two-year trials. This identified some improvements that were needed around electronics and reliability and redundancy. The real test will be the longer-term operation in the harsh environment of the Pentland Firth. A key lesson learned from the trials was, "you can never have too much instrumentation," Collier says. "We are still in a phase where we need to know more about performance. What happens to the generators and gear boxes after 5-10 years of operation?

"They [the devices] have been tested at EMEC, which is a less harsh environment. Our site has more turbulence, more waves and slightly higher flow that they will be subjected to. We need to learn more about how these different elements will work in combination. And we are designing for 25 years, so we have to manage what that means in terms of design of the turbines."

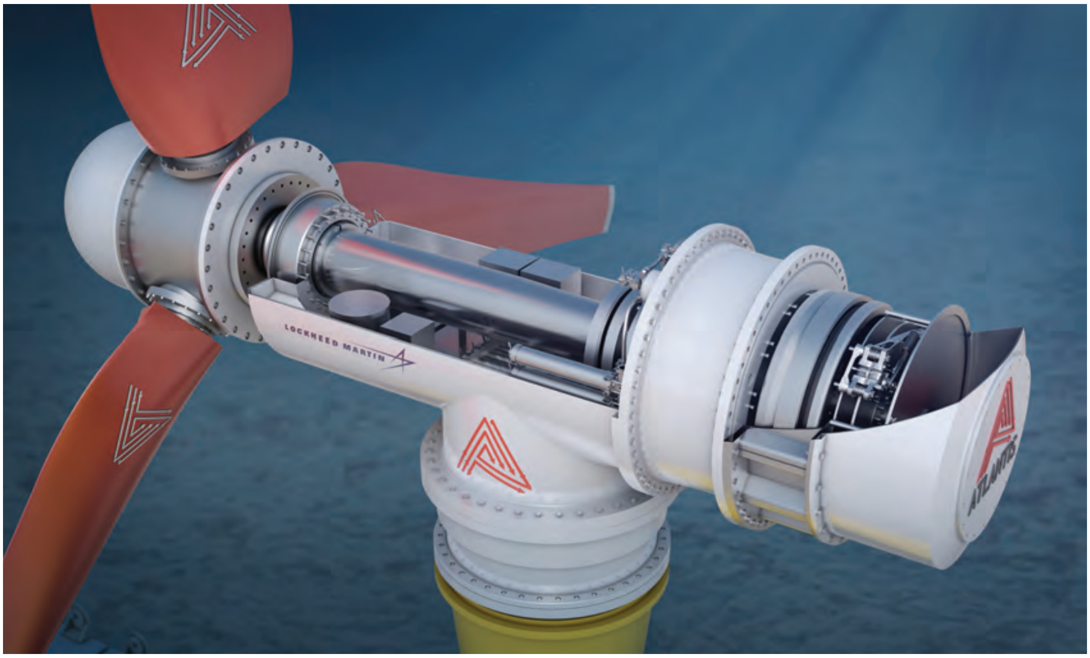
The firm will monitor the turbines and see the effects the external environment has on them so that the next time the same situation occurs, the loading can be adjusted. The sub-structure, nacelle, bearings, etc., will be monitored for fatigue. Another form of monitoring will be around marine wildlife, birds and seals for example, to monitor the interaction with the turbines and to ensure environmental consents are met.

"We don't want to over design, but we don't want to under estimate it either," Collier says. "Getting it right is very important. On wind turbines, to some extent, you can always get access to the moving parts, electronics, etc., by boat. We do not have that option. If anything goes wrong with these turbines, we can't do anything about it from shore. We have to pick it up out of the water and bring it back to shore. That, in itself, is a relatively expensive operation, losing potential revenue."

As the project scales up, the MeyGen team will also have to learn how the turbines interact with each other, just as wind turbines interact according to the wind patterns created by other turbines around them, to design an optimum layout. Work is already under way. Patrick Farrell, now a research fellow at the University of Oxford, was commissioned by MeyGen to engineer the best shaped array layout. MeyGen found that, although an idealized solution can be found, when specific site conditions, such as the seabed bathymetry, are applied, the dynamics change. It's a 3D problem, Collier says.

The research fellow, however, has written an algorithm for turbine array optimization. "It is quite amazing. It takes into account local flows and flow boundaries, etc.," Collier says. "The most interesting outcome for us is that the final optimized arrangement of turbines is not intuitive, so it really makes us think." The project also has to balance reliability, cost and risk. "And they are not complementary," Collier says. "Part of the project is to demonstrate we can make money doing this. But, we also have to do it at a low risk, so nothing breaks from day

Atlantis Resources' AR1500, artists' illustration.



one, to also prove it is reliable."

Phase 1A will prove the concept and reliability. Future steps for the project will be about reducing costs. "We are always going to be looking for cost reduction," Collier says. "Part of that will be doing everything cheaper next time and finding ways to get the cost of the turbine down."

As good as it could be

So far, the project is going as well as it could do, Collier says. "The nice thing about what we have done, having been there from the start, is that we have the project design about right," he says. "No one has said we cannot do this or they want to change that. From a personal point of view, that's pleasing.

"We had a plan, and we said we were prepared to listen to other ways of doing it, which we did, and we changed a few things, and it has gone about as well as it could do. The process is to learn as much as we can along the way and feed that into the next array."

For a nascent industry with nascent technology, MeyGen is showing the way. OE

Realizing potential

Tidal and wave energy projects are getting grid-wet this year, yet there's still more to learn. Emma Gordon reports from All Energy.

An OpenHydro device. Image from OpenHydro.

Carnegie Wave Energy's Perth Wave Power project.
Image from Carnegie Wave Energy

The wave and tidal energy industry should be optimistic about the future of marine renewables, given the range of technologies being developed and deployed.

Yet, after a tough 3-4 years, more needs to be done in areas such as collaboration, investment and industrialization to make wave- and tidal-based energy more competitive and cost-effective in comparison to other resources, specifically offshore wind.

That was the message during a panel session, chaired by Rob Stevenson, president of Ocean Energy Europe, during the All Energy Exhibition and Conference in Scotland in early May.

Wave and tidal presentations during the show covered the global market, research and development as well as project updates.

Tidal

Garrett Connell, project development manager at Ireland-headquartered OpenHydro, says 2015 is a milestone year for the company, with delivery on both sides of the Atlantic of two of the world's first grid-connected tidal arrays.

In the Bay of Fundy, Nova Scotia, OpenHydro is working with Emera to deploy two of its 2MW, 16m, seabed-installed open-center turbines. Offshore Brittany, France, at EDF's Paimpol-Bréhat site, another two 16m turbines will be installed and connected later this year.

Elsewhere, the second phase of the Canadian array will ultimately use the existing infrastructure at the Fundy Ocean Research Centre for Energy (FORCE) facility.

"In 2017, we're aiming to increase capacity by adding a further six turbines, bringing it to 16MW," Connel says. "From then, we'll build out on a phased basis from 50MW to 300MW in the 2020s."

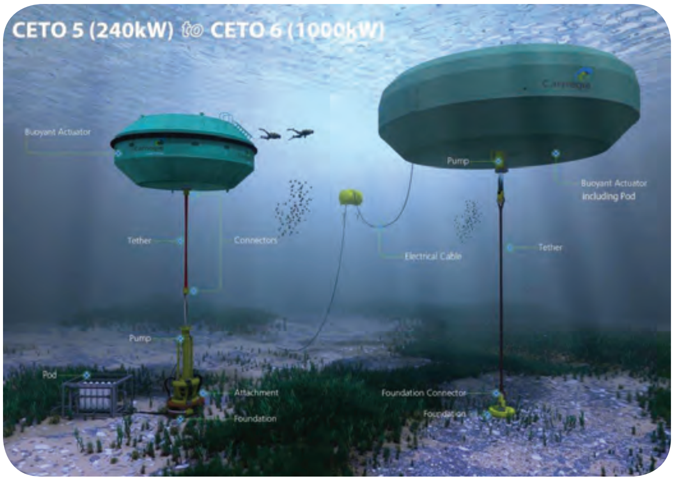
Wave

Learnings from Carnegie Wave Energy's Perth Wave Energy (PWE) project, using its CETO 5 unit, will help develop the next

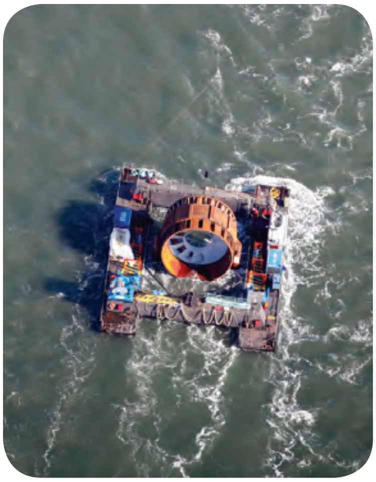
Ocean thermal-energy conversion gathers steam

Against a backdrop of growing global activity, ocean thermal-energy conversion (OTEC) is increasingly attracting investment, with work underway to develop technical specifications.

Martin Brown, convenor of the International Electrotechnical Commission team charged with developing these outlines of technical specifications for land-based, shelf and floating OTEC systems, says the specifications will serve to reassure potential investors, aid the due diligence process and give



Carnegie Wave Energy's CETO 5 and CETO 6 units.
Image from Carnegie Wave Energy



A deployed OpenHydro device. Image from FORCE.

generation of wave technology, with projects due to be commissioned in Australia and the UK during the next three years, says Tim Sawyer, CEO at CWE UK, the UK subsidiary of Australia's Carnegie Wave Energy.

Sawyer says 2015 will see further development of the CETO 6 project, which will be built near the three-unit PWE CETO 5 array off Garden Island, Western Australia. The CETO 5 PWE project is currently the world's only operating, grid-connected wave-energy project, he says.

Submerged CETO buoys convert wave energy into zero-emission electricity and desalinated water.

Since grid connection in February, the Perth Wave Energy project has experienced sea states of up to 4.8m and accumulated more than 8000 hours of operation. The first unit is due to be removed, inspected and serviced in May.

Neil Kermode
Image from EMEC.

Each next-generation CETO 6 unit will have a 1MW power capacity, around four times that of its predecessor, and, unlike CETO 5, the technology will be capable of offshore power generation.

"Essentially [CETO 6 buoys] can operate deeper, further offshore and in more exposed sites," Sawyer says. "It opens out different markets to us. We'll be deploying three of these units in Australia...They'll be commissioned in 2017, constructed next year. We'll take those learnings and bring them to UK Wave Hub project [off Cornwall, England] with construction [scheduled for] 2017 and commissioning thereafter."

Lessons learned

Neil Kermode, managing director of the Orkney-based European Marine Energy Centre, which provides accredited open-sea testing facilities, emphasized the importance of collaboration, both globally and cross-industry.

He also acknowledged the importance of, and contribution from, a vibrant supply chain. "We believe [making it work] is an international endeavor," he says. "It's fundamentally important we find a way to work together to harvest energy in a proper, sustainable way, and as efficiently as possible."

He says specific lessons have to be learned for a concept to work and be commercially viable. "It has to be able to be installed, able to supply, be reliable, be able to be maintained and you have to be able to operate it before you can say it has a life in the market because it's cost effective. If you don't learn those lessons, you won't get to the bottom line… all of these lessons are being learned by a variety of people [along the supply chain] and not purely us."

Hi Flo 4 vessel update

Mojo Maritime's *Hi Flo 4* (*HF4*) vessel has the capacity to both accelerate the installation of tidal systems and reduce costs for the offshore wind and oil and gas industries, according to company chairman Martin Wright.

He says the HF4, designed to carry out installation maintenance and decommissioning operations, can dynamically position itself in up to 10 knots of tidal stream, compared to five knots for standard dynamic positioning vessels. This increases the operational window, reducing installation time and cost.

"The quicker you get a wind or tidal turbine working, you massively improve the economics, [because] you've got revenue coming in," he says.

Mojo Maritime analyses shows the vessel can potentially install tidal turbines for less than £1million per MW, which is less than the cost of many offshore wind projects.

"In terms of getting one of these built, we need a contract to build it," he says. "This is a piece of supply chain equipment that can massively improve the chances of accelerating the building of [tidal] projects. We need to think about these tools…. It's not just about the turbines themselves, we need the complete system," Wright says. Mojo Maritime was bought by UK-based James Fisher and Sons earlier this year. OE

developers guidance on how to proceed with this technology.

The various types of OTEC systems, which are particularly useful for island nations and are well suited to tropical climates, use the temperature difference between warm surface water and cooler deeper water to generate electricity.

"In essence you're making use of the oceans themselves as solar collectors," Brown says. "It is a huge resource, a major source of base-load 365-day renewable power."

In particular, he says technological advances around floating production systems in the oil and gas industry during the past 15 years, such as in mooring systems and risers, along with the sector's strong capability, will prove useful for the development of floating OTEC systems.

Current international activity includes an operational system in the Okinawa Prefecture in Japan, plus Akuo Energy and DCNS' joint NEMO project, which was awarded €72 million in funding from the EU's NER 300 program for the development of an offshore pilot OTEC plant in Martinique.

"These technical specifications will help to ensure more projects get approval. Quite a lot of investment is happening with OTEC around the world...time is very much moving forward for developments." ▪

Picking up wind

About US$336 billion (€300 billion) could be spent in offshore wind capex over the next 10 years, with cumulative capacity surpassing 57GW. Douglas Westwood's Rachel Stonehouse explains.

Cumulative offshore wind capacity is forecast to reach 57GW by 2024, driven by the continued development of established markets such as the UK, Germany and China and bolstered by emerging markets such as the US and France.

Over 5.3GW of capacity is expected to be installed in 2015, with additions anticipated to remain on an upward trend, peaking at 7.5GW in 2020. Capital expenditure will total $269 billion (€240 billion) between 2015 and 2024.

However, these figures only include projects which have surpassed the conceptual phase of development, resulting in a large potential for upside post-2020 totaling $67 billion (€60 billion). This upside potential assumes that a proportion of conceptual and speculative projects will progress through the stages of development.

Capital costs have reduced recently, predominantly due to the larger sizes of turbines installed, resulting in less infrastructure (such as support structures) being required. This presents new challenges for installation contractors but should result in lower operational expenditures once wind farms go on-line.

The UK will install over 11GW over the next ten years, with most of this expected to occur by 2022, as Round 3 developments take place. Germany will also install over 11GW, with a longer term outlook predicting activity levels will recover in 2018 following a slowdown in capacity installed 2016-17. China is expected to install over 8GW of capacity – this is lower than previously targeted, but still represents a strong growth market.

Emerging markets include countries such as the US and France, who are expected to have their first operational wind farms in 2015 and 2017 respectively. The US is expected to install 1.8GW of offshore capacity over the next decade, and France 3.2GW. Other emerging markets include countries with historically low levels of offshore wind activity, such as Sweden, Denmark and Belgium.

Market forecast: components

Over 10,200 additional turbines will be installed by 2024, with the majority in China, Germany and the UK. The 6MW turbine is the most common size, with <4MW turbine installations reducing dramatically by 2025. Whilst Siemens will maintain the majority market share, the growth of markets such as China

and France presents opportunities for smaller, local turbine manufacturers such as Sinovel and Areva.

Monopiles remain the most common type of support structure, however jackets and tripods are increasing in popularity. The emerging trend of utilizing several foundation types within a single wind farm is observed over the forecast period. Furthermore, new technologies such as floating semisubmersible foundations are emerging, with several successful prototypes currently operational.

Over 23,000km of cabling (array and export) is forecast to be installed over the next 10 years. The UK, Germany and China are the largest markets due to the larger number of turbines and a higher than average cable length. HVDC cables are becoming increasingly common, as distances from the shore increase. Over 130 substations will be installed and commissioned over the next decade. Previously, wind farms have been small or close to shore, resulting in low demand for substations. AC substations will continue to grow in line with offshore wind development activity, whilst DC substations are increasing in popularity, particularly offshore Germany.

Operational expenditure (opex) has been increasing in recent years as wind farms are installed farther from shore. Opex will grow from $3.9 billion (€3.5 billion) in 2015 to $16.3 billion (€14.5 billion) by 2024, a CAGR of 15%.

Conclusions

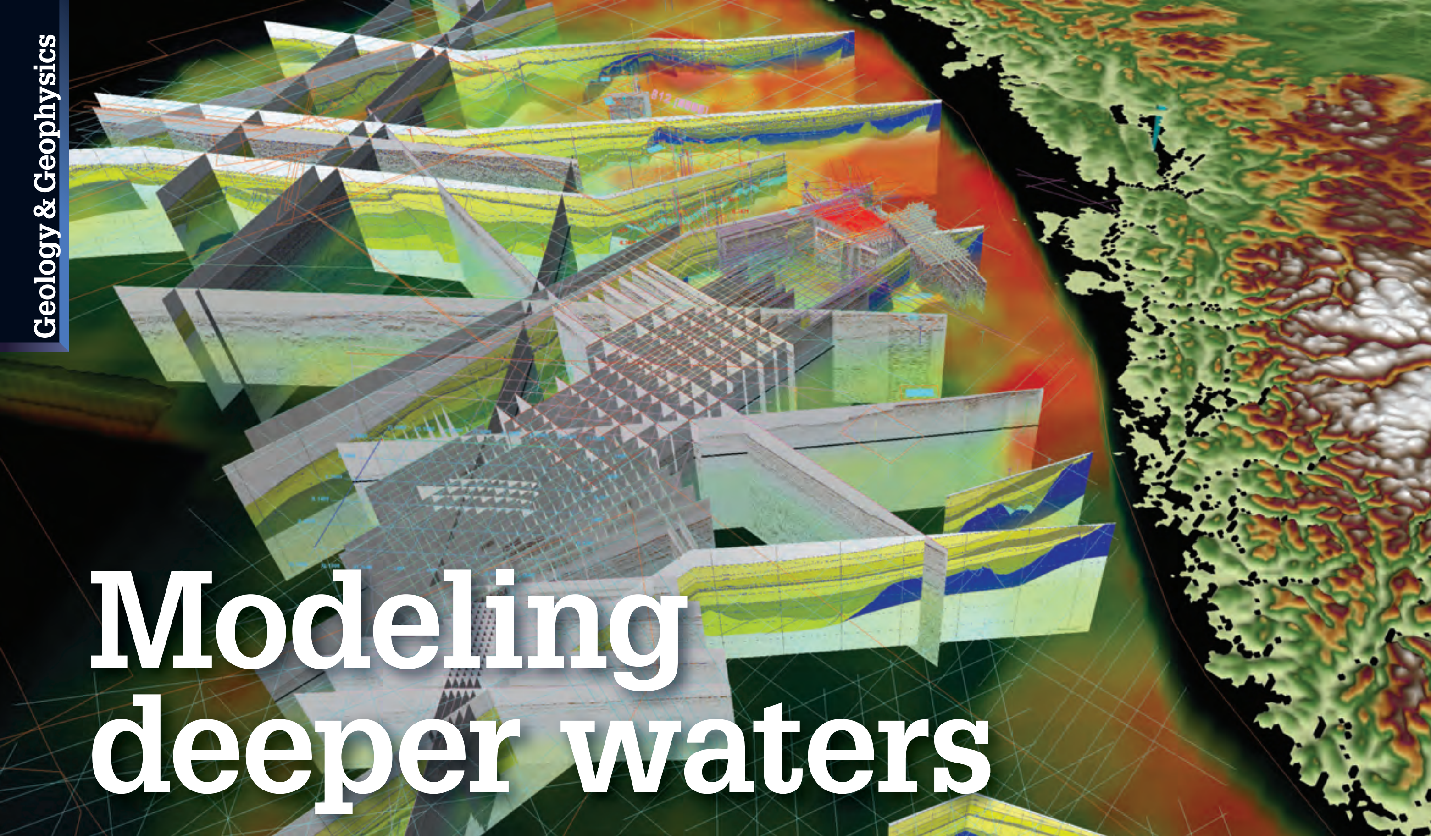
High levels of activity are expected over the next 10 years in the offshore wind market and a record year is anticipated in 2020, facilitated by larger turbines, improved technology and small cost reductions. The UK, Germany and China continue to lead the way, with a host of new countries expected to enter the offshore wind market by 2025.

The EU renewable targets are a key driver of activity, with other countries following suit and introducing their own targets. However, despite this positive outlook, offshore wind costs must reduce further in order to ensure the viability and a consistent pipeline of projects post 2020. **OE**

Rachel Stonehouse *is a senior analyst based in Douglas Westwood's UK office. Since joining the firm, she has led a range of research and advisory projects and conducted analysis spanning the oil, gas and renewables sectors with a focus on the offshore and deepwater markets. Stonehouse graduated from the University of Kent with a first-class degree in economics with econometrics.*

FURTHER **READING**

Renewables investment reaches record highs.
http://www.oedigital.com/component/k2/item/8658-renewables-reach-record-highs



Modeling deeper waters

Evaluate uncertainty from play to prospect scale, calculate chance of success and risked volumes, and move prospects through to the exploration drilling program.
Images from Schlumberger.

Audrey Leon spoke with Schlumberger's Alexander Neber, technical marketing manager, Software Integrated Solutions (SIS), to discuss how software can solve reservoir engineering and other deepwater exploration challenges.

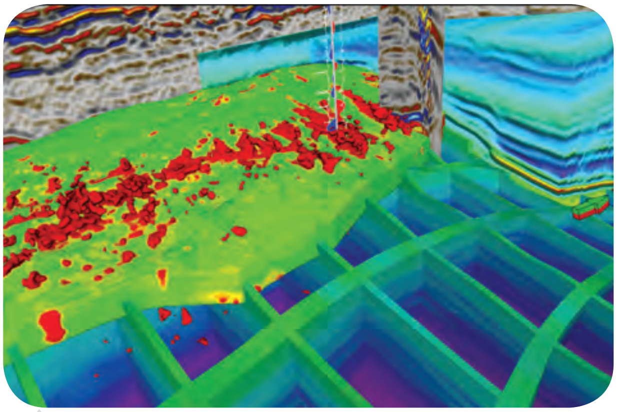
OE: What are the specific deepwater challenges that have to be addressed by a modern software platform?

Neber: In deepwater, the objective of modern geoscience and engineering solutions is to enable users to maximize prospect knowledge and reduce technical and economic variables. With rising rig costs and ever deeper and more complex drilling targets, operators are driven to achieve short decision and evaluation time. At the same time, they strive to minimize the number of exploration and appraisal wells and to reduce the associated risk and cost, as well as to maximize the value of their acquired data. Economic success of any deepwater exploration campaign is associated with the identification of the right plays and productive prospects, before extensive drilling, to verify and appraise the target closures.

OE: Could you illuminate these deepwater challenges in more detail, for example, for Geophysics workflows?

Neber: Generally speaking, deeper waters are accompanied by deeper prospects, often hidden below complex and seismically opaque geological structures.

Exploration teams must illuminate complex structures in as much detail as possible, often below overlying geology such as carbonate rocks or laminated sands below salt, and basalt formations.

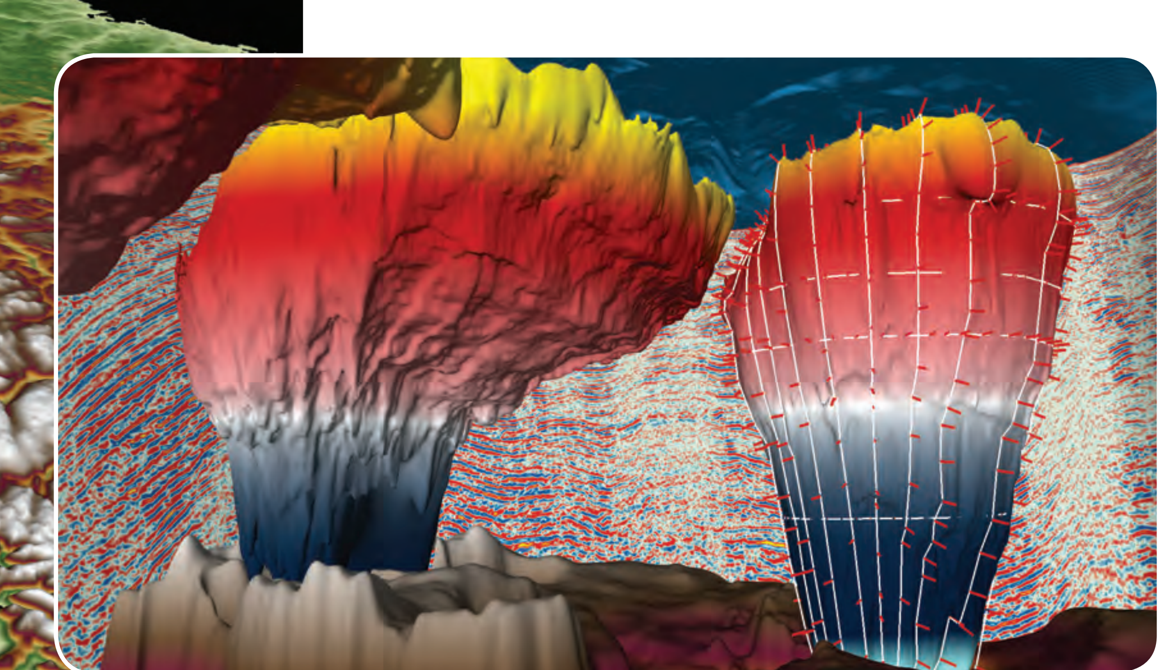


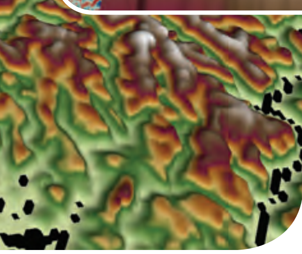
Predict lithology and pore fluid content with a complete range of advanced, intuitive, and interactive tools for seismic data conditioning, rock physics, AVO or AVA analysis, prestack and poststack deterministic and stochastic inversion.

Deepwater exploration uses techniques based on acoustic and elastic inversion, rock physics analysis, and property modeling. In addition, pre-drill pore-pressure analysis is key to evaluate pore pressures that might be encountered during drilling.

OE: How does Petrel make deepwater exploration less risky and more cost efficient?

Neber: The Petrel E&P software platform delivers collaborative workflows that unite the subsurface disciplines of geophysics, geology, geological modeling, reservoir engineering and drilling. Its framework makes workflows repeatable to ensure comprehensive uncertainty assessment from seismic to simulation. By enabling disciplines to work together, all team members and their work processes contribute to developing a single volumetric earth model – static and dynamic – scalable for both deepwater exploration and development projects.





Visualize the interplay between regional tectonics, salt morphology, and the overburden to identify potential oil and gas traps. Combine powerful 3D rendering and advanced edge-detection attributes with multi-Z salt interpretation for delineation and characterization diapirs, domes, and other salt structures.

Streamlining efforts are further supported by the Studio E&P knowledge environment that enables multi-user collaboration, as well as effective capturing and sharing of knowledge between remote users.

OE: What specific, software-related measurements are required to address reservoir engineering challenges in deepwater?

Neber: The primary goal of deepwater reservoir studies is to answer essential questions concerning structure, reservoir extent, compartmentalization, formation quality, and producibility. Petrophysical and geological measurements can be made while drilling to get an early understanding of the reservoir and to plan further detailed data acquisition and sampling programs.

Deepwater reservoirs are often thinly layered and highly laminated and the assessment of each is critical for decisions on completions.

The analysis of fault distributions based on downhole measurements and 3D seismic fault identification techniques is important.

The Petrel platform unites the subsurface disciplines of geophysics, geology, geological modeling, reservoir engineering and drilling to evaluate structure, reservoir extent, compartmentalization, formation quality and producibility. Earth-model uncertainties are analyzed in the Petrel platform and can be connected to the ECLIPSE industry-reference reservoir simulator and the INTERSECT high-resolution reservoir simulator to perform flow simulations. Optimization and experimental design techniques allow rapid analysis of multiple realizations to evaluate numerous development alternatives to come up with a robust field development plan.

OE: In general, how does software, like Petrel, change the way deepwater exploration is conducted in the oil and gas industry?

Neber: Until now, the majority of industry effort has been spent on defining the trap and reservoir. Also, in the past, the charge and seal analyses have been difficult to use and integrate into a streamlined geoscience workflow, although a significant percentage of exploration failure is related to a lack of understanding of these processes. Today, software platforms like Petrel can address and simulate charge and seal. Petrel incorporates science and workflows from the PetroMod petroleum systems modeling software, and fault seal evaluation software, making them easier to perform on an integrated system. The GeoX exploration risk and resource assessment software has been integrated into Petrel workflows for an easy-to-use and scalable decision-support technology for risk, resource and economic evaluation of exploration projects and portfolios.

OE: As new technologies continue to be developed, how do we see exploration needs changing in the future?

Neber: In the future, the need for technology advances will be greater to meet the challenges of finding the smaller fields, more subtle traps and traps in hard-to explore areas and reducing costs.

A typical question is often simply "How do we start?" followed by "How can an objective and auditable assessment be made, what are the controlling factors, what data is needed and which factors are really important?" As always, the geology is the starting point and resource assessments are only meaningful if they take the petroleum system risk factors that control the development of the resource into account. It is also essential that all of the underlying data can be audited and the entire assessment workflow is reproducible and open for critical reviews.

OE: It must be difficult to train operator staff on all these new technologies for deepwater exploration and keep a high knowledge standard with fast changing software capabilities.

Neber: Yes. Modern training has to go well beyond traditional software classroom training and support help files. For example, technology adoption packages (TAP) combine consulting, targeted training, deepwater workflow optimization and best-practice methodologies designed for specific workflows.

We also have a cloud-hosted workflow centric guidance module — Petrel Guru — embedded in our Petrel platform. It allows a fully interactive automation of common deepwater workflows, making common tasks faster, more approachable and comprehensible. **OE**

__Dr. Alexander Neber__ serves as technical marketing manager, Software Integrated Solutions (SIS). He came to Schlumberger in 2007. He worked as a petroleum systems modeling and discipline lead for exploration technology in the Middle East and Asia. After two years as geoscience business manager in Australia, he joined the Schlumberger Software Integrated Solutions HQ team in 2014. He received a diploma in geology from Frankfurt University, Germany, and a PhD in sedimentology from the University of Cologne.

Fincantieri's Proxima drillship design.
Images from Fincantieri Offshore.

Seeing double in the deep

Elaine Maslin takes a look at Fincantieri's latest ultra-deepwater drillship design – Proxima, sporting twin cylindrical drill towers and two moonpools.

Since the first drillships were built in the 1950s, with the *CUSS I*, capable of drilling in 400ft of water, drillship design has come a long way – and so has what we consider deepwater.

Today, technology development continues apace as much of the offshore industry's future profits are set to be gleaned from deep waters and from high-pressure, high-temperature reservoirs.

Italy's Fincantieri Offshore, part of the Trieste-based Fincantieri group, recently unveiled what it hopes will be a drillship to meet the future deepwater drilling market needs. Working with its Norwegian subsidiary Castor Drilling Solutions, the firm created Proxima, an innovative drillship provided with two drilling towers.

Fincantieri was founded in 1959, bringing several existing shipyards, including one in operation in Naples since 1780, under one organization.

The new design consolidates some of the previous concept, Overdrill, – introduced in 2013 – where the drilling systems were integrated into the lean body vessel with greater capabilities and performances. The new design goes beyond Overdrill, substituting the conventional lattice-design derrick structure for enclosed cylindrical drilling towers, based on wind turbine support structures. The design allows for an extended, open drill floor, by reducing the potential for dropped objects and simultaneous and safer drilling operations.

The towers, with hydraulically powered low-speed winches, controlled by digital hydraulic valves, are provided with a passive and active motion compensation system also integrated into the structure of the vessel. Other innovations have also been included in the design, including the spaces and equipment to carry on board in future two, 20,000 psi blowout preventers (BOP) and the option to make the vessel LNG-fueled.

"We had three main drivers in our idea: the performance, to drill wherever possible; safety; and added value for our clients," said Gianni Scherl, Fincantieri,

Deepwater briefing

Towards 2025, deepwater exploration and production will save the offshore industry, Norwegian energy analysts Rystad said in a recent presentation.

According to Douglas Westwood's World Deepwater Market Forecast, 2014-2018, deepwater spending is due to rise by 130%, compared to the previous five year period, totaling US$260 billion.

while describing the new 208m-long, 40m-wide, design at the Offshore Mediterranean Conference (OMC) in Ravenna earlier this year.

Scherl said that the vessel will deliver a cost saving of about 10% of the overall well costs per well, shared between the drilling contractor and the operator.

Fincantieri set out with a number of goals for Proxima: an ability to drill in up to 12,000ft water depth and to 50,000ft of total drilling depth, transit at more than 14 knots, accommodate up to 250 people, carry two 20,000 psi BOPs and have a variable deck load up to 32,000-tonne. Scherl said the vessel will be safer, due to the cylindrically-shaped, enclosed, drill towers, situated over two well centers, spread 26m apart. Compared to few hundred bolts in the new tower concept, developed by Norway-based Fincantieri subsidiary Caster Drilling Solutions, a standard, lattice design tower has some more than 5000 bolts, Scherl said.

Fincantieri's Proxima drillship design.

The top drive, rated at 1500-tonne and suspended from six pre-cut wires, which connect directly to a hydraulic winch, has been configured so that it doesn't have to be connected to a traveling block or pulley system, cutting the need for cut and slip operations, Scherl said. An auxiliary top drive is also included, rated at 1150-tonne. The winch, installed at the bottom of the tower, is driven by hydraulic motors and can be used for tripping as well as active heave compensation. However, the cylinders underneath the winch also provide passive and active heave compensation.

"We worked closely with Castor Drilling Solutions to integrate an innovative rig into the ship to have the total benefits – for the equipment but in particular for the efficient operations of the ship," Scherl said.

The 2000-tonne capacity setback (where stands of drill pipe or tubing are set back and racked) is embedded in the ship's hull on the opposite side of the vessel to the towers. The variable load is then compensated using a pair of water ballast tanks dedicated to heeling service.

The towers may also be telescopic, which means they can be lowered for safer maintenance using the onboard cranes and also should they need to be lowered to go under a bridge. For this operation they will employ a rack and pinion system.

The drill floor itself is open and extended, running continuously from aft, where stands for the drill pipe are stored, to the accommodation deckhouse, allowing easy access for dedicated onboard service cranes.

To accommodate the 26m distance between the two drill centers, Fincantieri opted to incorporate two circular-shaped smaller sized moonpools into the design, helping to increase deck space as well as reduce hydrodynamic resistance. In tow tank testing, the company compared the three configurations, no moonpool, one traditional big moonpool and with two smaller moonpools. Scherl said this confirmed that the resistance with two smaller moonpools was less than that with one bigger, traditional configuration moonpool. The firm also found that this reduction in residual resistance is linked to the oscillations of the water inside the moon pools, developed through sloshing or piston mode water oscillations.

"Where for the rectangular moonpool (L/B > 2) the natural sloshing mode starts at around Fn = 0.1 and increases with speed, while for the squared or circular moonpool (L/B = 1) only the natural piston mode is present and well developed around Fn = 0.1 and decreases to zero at around Fn = 0.14," Fincantieri said. The water oscillations inside the rounded or squared moonpools is of the piston mode, by far lower in absolute value respect to the sloshing mode typical of rectangular shapes lowering the residual resistance in transit and allowing to reach the 14 knots of transit speed with the power delivered by the three aft thrusters.

The vessel also has an automated, fully redundant riser handling system, Scherl said, so risers are always held in clamps and never hanging, during transferal from the riser hold to the catwalk and vice versa, removing the risk of damage to the risers. This solution also helps to reduce the amount of space needed inside the riser hold when they are outfitted with standard overhead cranes.

With its extended drill floor design, with two elevators, fore and aft, which connect the service corridor under the main deck with the drill floor deck, Fincantieri also said that use of forklifts could be extended, because it would enable continuous circulation of the forklift in all operative areas, reducing the use the onboard cranes. Proxima will also have an extended helipad so that, if required, two helicopters could be landed. OE

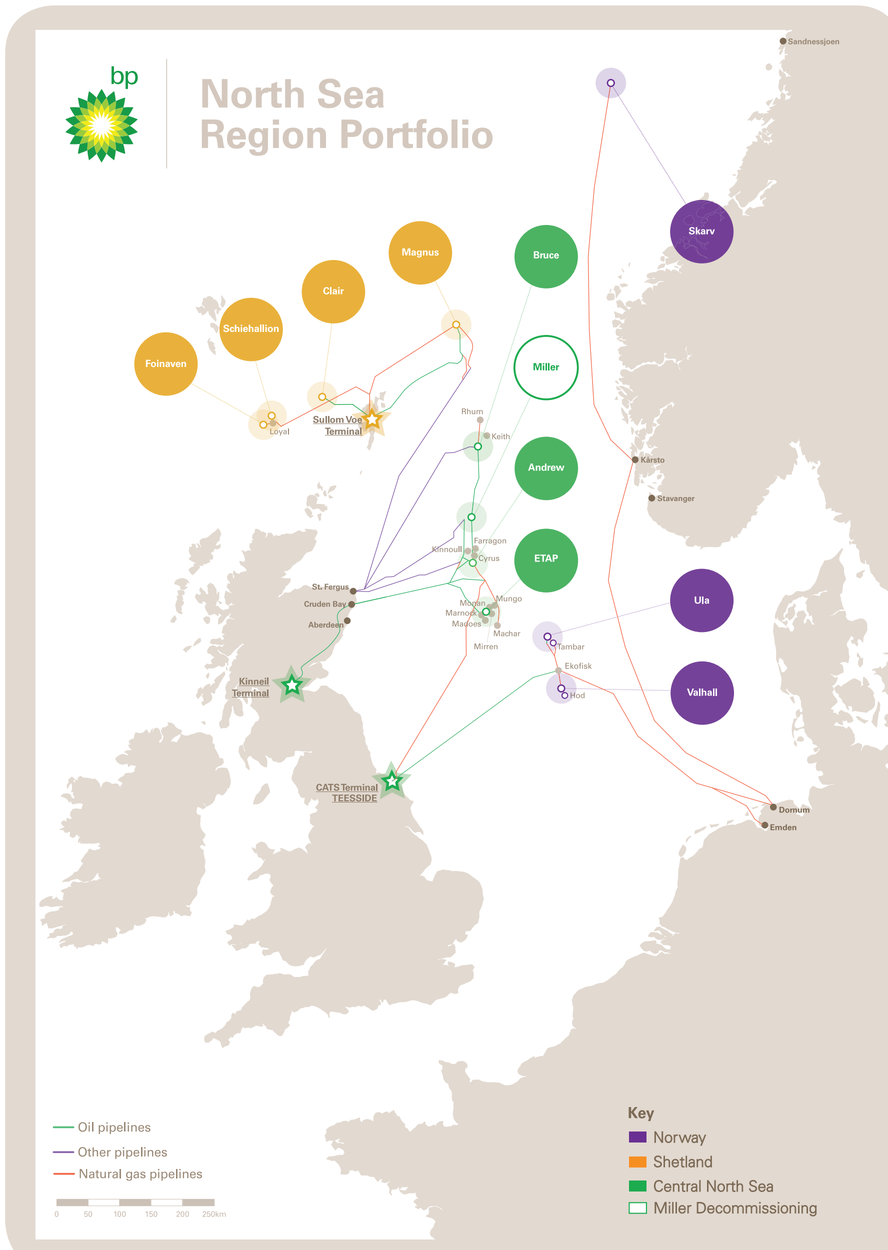
In its Deepwater and Ultra-deepwater Market Report to 2018, Infield puts the capital spending growth rate in deepwater at about 8% in 2014-2018.

The first drillship design was the *CUSS I*, designed through the CUSS consortium (Continental Oil Co., Union Oil Co., Shell Oil Co. and Superior Oil Co.). It was managed by Robert F. Bauer, who went on to become the first president of Global Marine Exploration Co. This company would build the *CUSS II* drillship, capable of drilling in 600ft water depths.

The CUSS line of drillships would later be renamed Glomar, short for Global Marine. The company would be party to several mergers including one with Sante Fe in 2001, adopting the name Global Sante Fe. In 2007, the company merged with Transocean, maintaining the Transocean name. ▪

Creating a severe-weather riser system

Jeannie Stell provides an update on BP's partnership with Wood Group Kenny to design and manufacture an FPSO riser suitable for the "dark and stormy" weather at BP's Quad 204 redevelopment.



BP and Wood Group Kenny have worked together for the past 15 years, since 2010, to design a robust riser system capable of serving a harsh environment floating production storage and offloading (FPSO) facility with a 25-year life cycle. The robust riser technology will be married to a production platform, the new, purpose-built, turret-moored *Glen Lyon* FPSO, slated to tackle BP's massive subsea asset — the Quad 204.

Located west of the Shetland Islands in Blocks 204 and 205 of the UK Continental Shelf at water depths of 300m to 550m, the new Quad 204 is an ambitious project to redevelopment the Schiehallion and Loyal fields. Considered to be one of the largest and deepest developments in the North Sea, the Schiehallion is one of the largest UK North Sea fields discovered to date.

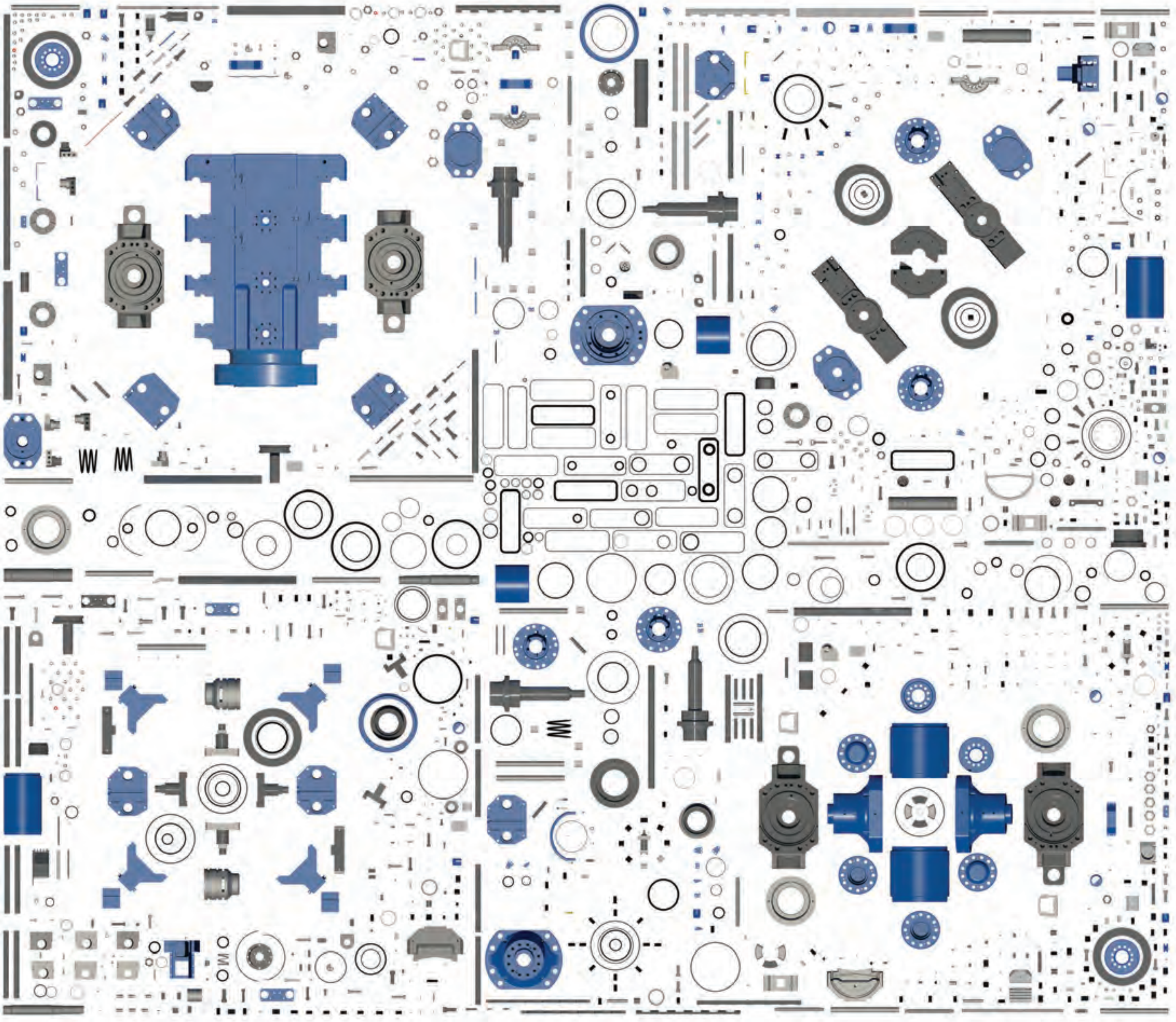
The plan is to construct a new FPSO unit to replace the existing *Schiehallion* FPSO and the project will include an extension of the existing subsea system with 15 new and replacement flow lines, 21 new and replacement risers and 14 new wells added to the 52 existing wells.

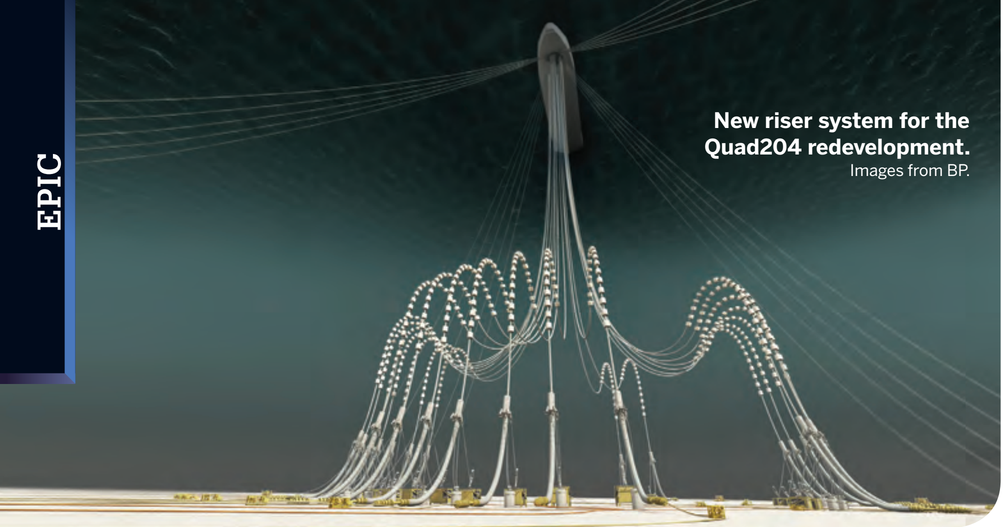
Although the field has been in operation since 1998, recent appraisals show that the field holds more reserves than originally anticipated. This redevelopment will give BP the ability to increase production. The FPSO and its subsea structures will be installed in modules and the total facility is expected to begin producing in 2017 to reach an eventual capacity of 130,000 b/d of oil. The project will extend the life of the two fields to continue production beyond 2035.

The project was approved in July 2011 and is estimated to cost about US$5 billion. Partners in the project include BP (36.3%), Hess (12.90%), Murphy Petroleum (4.84%), OMV (4.84%), Shell (36.3%) and Statoil (4.84%).

Stormy weather

The project is an unusual amalgamation where new equipment will be integrated into an existing brownfield environment. One of the most critical challenges to the project will be the engineering, manufacturing and installation of the FPSO risers, which must be long-lived and able to withstand an extremely severe environment. In fact, the location has been known to experience harsher weather than most other UK marine environments. The topside weather can include 40 mph winds, 18m high waves, and complex, severe





New riser system for the Quad204 redevelopment.
Images from BP.

currents that can lead to directionally skewed fatigue loading of the platform.

Additionally, the risers and mooring system must be able to withstand brutal winter storms and be sturdy enough to require minimal intervention during normal operations because construction access is only possible from May to September.

BP identified a group of specific, value-added project features it deems necessary for the long-lived redevelopment, including:

- Additional layers of tensile armor to extend riser corrosion fatigue life
- Double outer sheaths to forestall the consequences of installation damage
- Autonomous annulus monitoring
- Enhanced turret and end-fitting venting capacity
- Turret motion-response monitoring
- Riser I-tube inspection facilities
- Pipe specimen retention

Additionally, the Quad 204 will incorporate some new designs that were formulated as a result of past experience. For example, in the past the Schiehallion used a two-part bend stiffener design. However, the latching mechanism in the design that connects the two parts of the bend stiffener to the bend-stiffener connector experienced several failures over time. The failures resulted in full or partial slippage of the inner bend stiffener of various risers. As a result, some dynamic risers had to be decommissioned and replaced. During the replacement activities, engineers also discovered that the outer sheath contained a 1.1m-long groove, which was believed to be caused by the metal of the inner bend stiffener abrading against the sheath as it slipped along the riser body.

To avoid such future damage, the new Q204 anchoring mechanism design will anchor both parts together without a latching mechanism. This design will be similar to the one used at BP's Thunder Horse facility. Also, the new design ensures that the outer bend stiffeners have suitable corrosion and abrasion protection to avoid any potential damage.

Another design change will be the use of a new vent-gas monitoring system. The previous system was based on a flow meter, which was unable to detect annulus-venting behavior with enough sensitivity to reduce risk. Therefore, the Q204 will employ an online vent-gas monitoring system to provide continuous readings of the production and gas risers' conditions. The system will be backed up by a vacuum-testing program during the first two years of operation.

Also, to reduce the probability that embedded debris can occur in the I-tube, the Q204 risers will include a second protective outer sheath than will be thicker than the external sheath. Furthermore, a layer of Kevlar tape will be wrapped between the two outer sheaths to bolster the impact resistance of the outer protective layers. The design includes access hatches below the riser hang-off location so cameras can be inserted as needed into each I-tube to inspect the risers.

As if the harsh weather and strong current weren't enough, the designers had to plan for damage from marine life as well. In this location, buoyancy modules are vulnerable to hard marine growth such as cold-water coral. If left unchecked, the heavy buildup of coral causes integrity concerns due to the significant loss of buoyancy. To avoid this hazard, the designers of Q204 incorporated specifications for a fit-for-purpose anti-fouling layer to be applied to the buoyancy modules that is expected to retard hard-coral growth attachments. As a result, the Q204 will have the only red buoyancy modules in the North Sea.

Integrity management

The Q204 integrity management system will be a risk-based system that relies on the probability of damage or failure as documented by known flexible pipe failure modes described in the public domain, as opposed to company experience, because BP has never experienced a flexible pipe failure. The integrity management protocol that pertains to flexible risers, bend stiffeners, buoyancy modules, hold-down and hold-back arrangements and cathode protection systems will include:

- I-tube camera inspections of bend stiffeners and borescope inspection of risers inside the I-tubes
- Real-time monitoring of the chain-table geometry for early detection of bend stiffener damage
- Annual-vacuum testing to confirm the integrity of gas and production riser outer sheaths and the gas-venting system
- Topside continuous temperature and pressure monitoring
- Monitoring of produced sand and bore-fluid pressure, temperature and flow rates
- Pressure sheath coupon sampling and analyses
- Monitoring of the turret position and motion and waves
- Fatigue life reassessments to continuously compare operational parameters to design parameters.

Together, BP and Wood Group Kenny designed a robust and fit-for service riser system, capable of operating in one of the most severe environmental conditions in the world. The design is based on lessons learned from a history of operating experience in the offshore West Shetland a region. The final riser system will be a combination of state-of-the-art bespoke hardware and integrity-management tools for the harsh weather floating production system. **OE**

Based on a paper presented at the 2015 Offshore Technology Conference in Houston, Texas.

FURTHER READING

Project directors from BP and Wood Group Kenny detailed BP's Quad 204 subsea redevelopment for OE in July 2013.

www.oedigital.com/component/k2/item/3480-quad-204-takes-shape-subsea

Fit for HPHT

Exova Group's Stuart Bond shows how the company is working to develop testing technologies to ensure SURF components are fit for HPHT and H_2S service.

The behavior of materials in the presence of hydrogen sulphide (H_2S) for sour service has been studied for nearly 50 years using standard tests, which can adequately predict resistance to degradation via testing in laboratory-standard conditions.

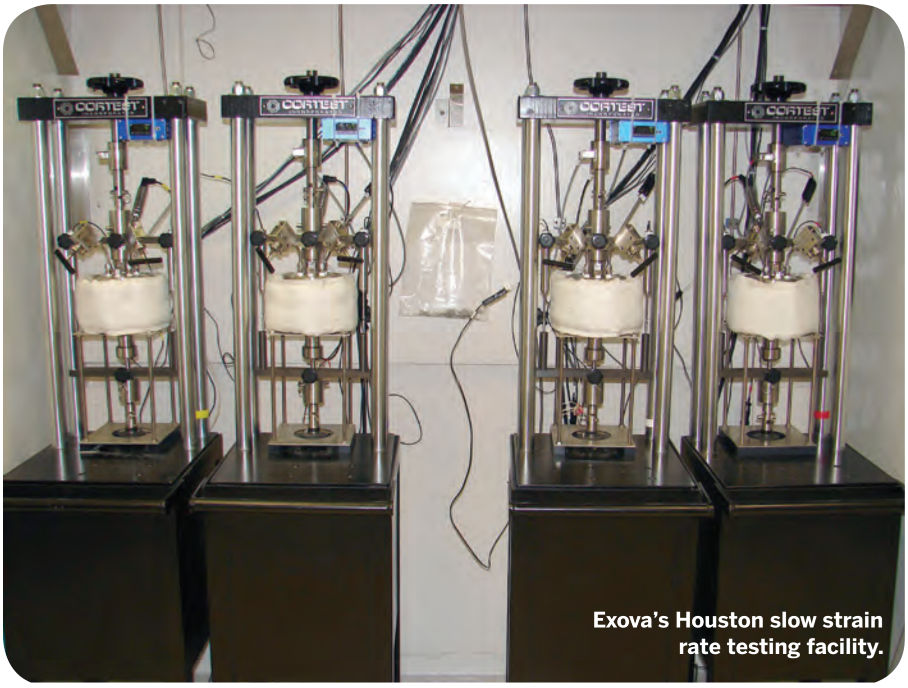
Today, technology exists to perform tests in simulated service conditions. Such tests can ensure safe materials selection while avoiding excessive conservatism in testing that could potentially eliminate good candidate materials.

During the past two decades, deepwater and ultra-deepwater developments have driven the need to assess the corrosion-fatigue performance of steel catenary risers (SCRs) in mild sour conditions as well as the impact of the external seawater environment with cathodic protection. More recently, the corrosion-fatigue behavior in sweet produced fluids and the effects of lateral buckling have been addressed.

However, in these cases, the vast majority of endurance testing has been performed under ambient pressure and has been limited to maximum test temperatures of around 80°C. Some endurance testing of wires for flexibles, plus fatigue crack propagation and frequency scanning, has been undertaken at elevated temperature and pressure by Exova.

Now industry professionals need to consider how clad systems can be tested using elevated temperature and pressure. In addition, high-pressure, high-temperature (HPHT) developments could further drive corrosion-fatigue testing – even for components such as downhole tubulars and wellhead equipment.

Exova's Dudley, UK, autoclave facility.
Images from Exova



Exova's Houston slow strain rate testing facility.

Proactive fitness for purpose (FFP)

During the initial design phase, materials selection for subsea umbilicals, risers and flowlines (SURF) components can be predicated upon knowledge of suitability from field conditions or, in borderline cases, a desire to test materials to optimize selection. Testing is required to qualify materials and weldments for proactive fitness for purpose (FFP) for new developments, which extend the material's application to higher pressures and temperatures. Sometimes tests are undertaken early, using non-project specific material to avoid later difficulties.

Aspects to consider include:

- Mechanical properties and tolerable flaw sizes for installation
- Material resistance to degradation (e.g. corrosion), environmentally assisted cracking and corrosion fatigue
- Operational conditions and changes
- Predicted upset or intermittent conditions

These factors then influence the material selection, which is based on:

- Environmental conditions, mechanical properties and compatibility with other materials

- Installation methods and imparting of high plastic strain
- Commissioning and subsequent lay-up prior to operation
- End-of-life condition and potential recovery/abandonment

For existing assets, FFP must be considered to have confidence in continued integrity if a change in service or life-extension is required.

Materials sampling

In most test methods, it is necessary to sample materials to produce test specimens. For tubulars, line pipe and girth welds, the range of test methods available to assess resistance to degradation in sour service is quite wide (listed in ISO15156/NACE MR0175). Therefore, both specifiers and users of the standards must understand the ramifications of the test technique. Test techniques include reproducibility, ease of testing and material sampling, retaining the as-received surface condition and microstructure, sampling from within the wall of the product, relaxation of residual stress, relevance to service, and more. These factors influence the degree of confidence in the results and the extrapolation to consideration of FFP for the intended service duty.

Factors to consider include:

- Influence of specimen geometry and extraction upon relevance of the test method to service.

Uniaxial tensile specimens must be selected from within the body of the material (to allow the machining of threads) and are fully machined. Therefore, these cannot be used to sample the surface microstructure and condition. However, this is a reproducible geometry that provides confidence that there will be little variation between specimens influencing test performance.

- Weldments need special consideration.

The extraction of material from weldments results in a relaxation of the residual stresses, which can contribute to environmentally-assisted cracking. Due to the thermal cycle (development of the heat affected zone, HAZ), dilution of the weld metal in the root and presence of heat tint oxide, the microstructure in weldments differs from the parent material. Thus the usual recommendation is root-intact 4-point bend testing.

It is also necessary to ensure that all appropriate damage modes are assessed in materials selection, including testing when required. In the latter case, ensure the test method is suitable, e.g. stress-oriented hydrogen-induced cracking (SOHIC) for which Exova has developed a test method (as there is no standard technique, although full ring testing can induce this damage in susceptible material). Exova plans to conduct a joint-industry project for a round-robin assessment for potential adoption of the test method as a standard.

Techniques that do not require an extraction of specimens can offer potential advantages, such as:

- No relaxation of residual stresses
- Retention of the as-received material condition
- Depending on the technique adopted, testing of entire girth weld

Testing of clad components requires the isolation or removal of the carbon steel. In long-term testing for corrosion-fatigue endurance studies in particular, isolation can be difficult to guarantee via coatings, especially at elevated temperature, but the substrate must be retained.

A single edge notch tension in a test chamber.

Standards

It is imperative that the industry has appropriate standards to ensure commonality of materials, processes and testing protocols. However, it is essential that users and specifiers understand the


A full ring test with axial loading.

limitations of techniques (e.g., impact of sampling or ability to reproduce the service conditions), particularly for elevated temperature and pressure. This can be quite difficult and needs discussion between the client, engineering contractor and testing organization to ensure agreement in advance.

Additionally, as the offshore sector places increasing demands on materials to handle more aggressive conditions, test techniques need to be reviewed, modified or developed to allow laboratory testing to provide confidence in materials performance and qualification.

Exova supports international standards development and maintenance via leadership and representation on committees such as NACE MR0175/ISO15156, NACE TM0177 and TM0284; support of the European Federation of Corrosion Working Party 13 and the two sour service guidance documents (EFC16 & EF17).

Testing

Originally, test methods for sour service such as NACE TM0177 (SSC) and NACE TM0284 (HIC) were developed to provide QA/QC methods using laboratory test environments, which were formed to aggressively identify materials susceptible to damage. Now, the industry seeks to reduce the excessive conservatism this approach imposes and the assessment of corrosion resistant alloys has increased. Therefore, more application-specific testing has been undertaken to simulate operating conditions.

Corrosion resistant alloys require testing at elevated temperature and pressure using autoclaves and 4-point bend (4pb) specimens in constant deflection (particularly for weldments). When ranking tests are required to compare materials, slow strain rate testing (SSRT) (or ripple strain rate testing (RSRT) is used.

Similar considerations apply to the fracture toughness testing of materials, such as carbon steels in which the damage mode is related to the presence of absorbed hydrogen interacting with the plastic zone of the crack tip. If the material is charged under cathodic polarization, the hydrogen concentration in the material is considerably less than that induced from sour service.

If the material is charged and then tested in air – after it has been, for example, stored in liquid nitrogen to reduce losses from hydrogen diffusion – the rate of loading, temperature of testing, and the loss of hydrogen from diffusion must be considered. Such techniques can be suitable to assess the impact of an embedded flaw in hydrogen-charged material. However, these techniques do not consider the behavior of a surface-breaking flaw in the production environment, where hydrogen is generated near the crack tip due to the corrosion of the freshly exposed metal resulting from the crack extension (to derive critical stress-intensity factor). Loading modes in fracture-mechanics testing must also consider the replication of in-service conditions; single-edge notch tension (SENT) geometry is suitable for installation assessment but single-edge notched bend (SENB) geometry might be better suited to assess fracture response in operation.

New test methods from Exova

Exova has developed a proprietary technique for full ring tests with axial loading that can impart the desired stress for evaluation, even as high as 90% actual yield stress (AYS) of the parent material for conservative assessment. The technique can be used with loadings suitable for design or operating conditions.

The axial loading technique is currently being assessed for modification to deliver a new proprietary approach to corrosion-fatigue endurance testing, allowing testing of carbon steels in sour conditions above ambient pressure, and corrosion resistant allows (including clad products) at elevated temperature and pressure. Unlike the traditional segment (strip) testing for corrosion-fatigue testing in production environments, which might not sample the most susceptible region in the joint, this method will test the entire weldment (including start-stop location) under very realistic loading.

Exova believes that this new concept will allow industry to undertake the testing necessary to support research in HPHT materials performance without compromise in test environments (up to about 200°C) or in sampling of material (SURF and wellhead components including clad items). Feedback from the sector worldwide has been positive in terms of its potential to help them meet challenges now and in the future. OE

***Stuart Bond** is group corrosion business development manager, of Exova, global testing, calibration and advisory services provider, Exova. Bond has more than 27 years of experience in consultancy and industrial applied research, with a particular focus on the oil and gas sector. Prior to joining Exova, he managed TWI's Materials Performance and Ferrous Alloys Section. Before joining TWI, he was a corrosion engineer at British Non-Ferrous Metals Technology Centre. Bond is a professional member of the Institute of Corrosion and recently took over the post of vice chairman of NACE STG32, a two-year post prior to two years as chairman.*

Pushing limits on the line

John Bradbury reports on new equipment designs for risers and umblicals from DeepFlex and Technip, which the two top-tier players say can stretch the performance envelope.

Houston-based DeepFlex has been working for some time on a new design of hybrid reinforced pipe under the auspices of RPSEA (Research Partnership to Secure Energy for America) to develop an ultra-deepwater composite pipeline.

This has been worked to a design brief for a pipeline with a 7in internal diameter, capable of operation in 10,000ft of sea water (3000m); suitable for sour service, and capable of withstanding up to 120°C.

Engineers have worked to produce what it claims is a unique structure with a fully unbonded layer construction. It features an outer jacket with a flooded outer annulus, and although composite material is exposed to sea water, it is not subjected to permeated gases, which can escape from the pipeline core, and it has low failure risk under bending and rapid pipe bore depressurization, as permeated gas is not absorbed by a composite.

An inner annulus provides a flow path to surface for permeated gas, and monitoring it allows early detection of fluid leakage, before any major containment loss.

Presenting at the MCE Deepwater Development conference in London in March, Eric Wilson, sales manager at DeepFlex claims the line pipe design is unique, comprising an outer jacket, anti-buckling tapes, tensile reinforcement, anti-wear tapes, a hoop layer, a membrane, a second hoop layer, a liner, a tape wrap layer, and a carcass.

The pipe features a composite tensile armor, which does not corrode in sea water, and an intermediate anti-collapse sheath with a membrane seal to prevent sea water ingress. Hybrid pressure armor has zero risk of corrosion: "We have a lot less risk of corrosion because it is a non-metallic material," Wilson explained.

In air, the weight of the new pipeline is 170kg/m and in seawater it is 68.2kg/m.

During its development the new design has had to undergo a series of qualification tests. This has covered material qualification for the composite pressure and tensile armor reinforcement, gap spanning, wear and permeation tests, and then DeepFlex has moved on to prototype testing involving static, bending, dynamic and thermal cycling tests of the completed pipe, to meet the API 17B prototype qualification test standard. All of this is due to be completed by 2H 2015.

Phase 3a involves preparation of the pipe based on field specific data, incorporating findings from phase 2 as well as a dynamic fatigue tests, involving a service life simulation, and thermal cyclic testing to verify the integrity of pipe liner seals.

"It is easier produce, light, easier to get around," Wilson said. Suitable for sour service, the new pipe has a 50% U value compared with a conventional flex riser, and so one continuous catenary riser is possible, Wilson said. "We are pushing riser technology beyond today's limitations, to enable deepwater solution," he said.

During phase 2b, a prototype pipeline was constructed at DeepFlex's Manitowoc, Wisconsin, facility. By the end of this year DeepFlex aims to complete all testing.

Afterwards the company will move into development phase 3a, pipe manufacturing, involving material procurement, manufacturing, procurement of end-fittings and verification of ancillary equipment qualification and procurement of bend-stiffeners. A sample has already been assembled and underwent factory acceptance tests.

Phase 3b is field deployment, which involves selection of an installation contractor and mobilization to the selected field. By 2Q 2016 DeepFlex aims to move to full manufacturing and field installation in 4Q 2016.

DeepFlex composite deepwater pipeline design characteristics

Parameter	Value
Inner diameter	177.8mm (7in)
Design temp	120° C
Design pressure	68.9m Mpa (10,000 psig)
Outer diameter	3590mm. (14.1in)
Empty weight in air	172kg/m
Empty weight in sea water	68/.2 kg/m
Storage bend radius	2.7m
Operating bend radius	4.0m
Burst/design ratio	2.0
Collapse design ratio	1.9
Failure tension	20,498 KN

Source: DeepFlex MCE Deepwater Development, London, March 2015, London.

Deepwater umbilicals

Meanwhile Technip has been working to cut down the cost of design and deployment of deepwater umbilicals and earlier this year presented the fruits from its research.

DeepFlex composite pipe design test results

Tensile and burst pressure tests produced the following results:

Predicted tensile failure	2246 kps
Actual tensile failure	2197 kps
Predicted burst pressure	21,312 psi
Actual tested burst pressure	22,496 psi

Umbilical spools on Technip Umbilicals' quayside in Newcastle. Photos from Technip.

Defining the characteristics of a subsea umbilical, Ian Probyn, research and development business manager for Technip, outlined the units as the critical connection to control subsea oil and gas equipment. Typically they comprise a protective outer sheath, polymer filler elements, fiber optic and electrical cables and fluid conduits within thermoplastic hoses, or steel tubes.

Deepwater umbilicals have to perform against a number of key factors including the basic design, component mix, capacity requirements and manufacturing assets.

And during their installation, Probyn explained how umbilicals have to contend with hold-back tensioners, manage the effects of inertia or DAF (dynamic amplification factor), as well as installation unit track length, and type, in addition to crush loads, heavier inner bundles, and offshore hold times. And they have to deal with in-service conditions of usage, fatigue, buoyancy, and the type of vessel to which they are attached.

In deepwater, the "install-ability" of an umbilical depends on the nature of the friction equipment – usually caterpillar tracks or grabbers on deployment vessels – and the top tension imposed on the umbilical, as well as its size, length, and its crush capacity. Installation is described by Probyn as the most critical phase in the service life of an umbilical.

In deeper water, there is greater top tension, greater weight, more components, necessitating larger installation equipment, which in turn imposes greater crush forces, and greater friction factors.

All of this has pushed up umbilical construction and installations costs, Probyn explained.

To combat this rising cost trend, Technip has developed a 3D finite element analysis modeling tool, FEMUS 3D, to analyze crush forces and top tension, to achieve umbilical designs which fulfill operational requirements but which also mitigate the higher cost trend.

Using FEMUS allows engineers to model installation methods. Umbilical crush capacity can be tailored for a specific installation scenario, allowing increased confidence in an umbilical design, while reducing conservatism and providing better behavioral insight and reducing cost.

"We can run the model for a range of crush forces....We can determine exactly what the limit is. We can learn exactly how the elements are inter-reacting with one another," Probyn said at MCE Deepwater Development.

Outlining a typical approached to deep water umbilical installation, Probyn said this has involved use of a sufficient Factor of Safety (FoS), while physical tests have been used to confirm actual performance limits. This has resulted in larger, more expensive lay spreads and unnecessarily high crush loads, he argued.

Technip's new tool can interrogate an installation process, and advice on the best setup, including pad size, type and spacing on an installation tractor unit.

Alternatives to the tool considered and rejected by Technip include physical testing, which although answering questions about crush force analysis, does not provide much insight, while being expensive and time consuming. "The information you get is either a go or a no go; it does not give you where the design limit is," Probyn told conference attendees. "An FEA model gives you much more insight than a physical model."

Empirical or mathematical modelling is deemed to be fast but provides less accuracy, and requires many assumptions to be made, while being built from test data only.

And 2D FEA analysis, while quick and inexpensive, Probyn said that with this approach 3D effects can be missed.

Turning to deepwater installation issues, Probyn said the typical industry approach has been to give an accepted friction coefficient and apply a FoS, backed up by physical tests to confirm the friction factor. But this relies on a high FoS, leaving more unknowns and more risk.

Using this FEA analysis tool, Technip has devised a new, patent-pending high friction tape for umbilicals, which when crushed, doubles the friction or grip on an umbilical held in an installation tractor.

Probyn said once crush forces are removed from the tape, there is no effect on the umbilical fatigue life. With increased umbilical friction during deep water installation, there is less crush force imposed overall, reducing risk, and the cost on the unit.

Further work has been done to improve umbilical performance by using high strength aluminum, rather than copper in cables, to reduce weight, in high-density, low-strength components. This, Probyn suggests, can lead to less weight, higher strength, better fatigue performance, and greater water depth capability.

Another innovation is the introduction of high strength strain members to increase stiffness and to reduce umbilical strain while exposed to top tension force.

Also Technip has sought to "evolve" umbilical design down the water column; High tensile strands are used to stiffen the top section; an 'evolving joint' is used in a mid-section and a polymer filler is used in lower sections where strain is lower. OE

Going with the (model) flow

Modeling flow assurance regimes is no easy task, not least for long distance tiebacks, where the need for accurate modeling is crucial. Alexander Belkin outlines a model he has worked on.

During the past several decades, offshore oil and gas production has moved from shallow to deep and ultra-deep water. Also, marginal fields located at substantial distances from host platforms have introduced the need for long subsea flowlines, which are often laid over hilly terrains.

The economics of these types of developments quite frequently do not allow the installation of sophisticated completions and the implementation of subsea processing, so unprocessed reservoir fluids, often imbedded with particulate matter, are transported via the long-distance flowlines. Inevitably, flow assurance problems such as hydrates, paraffin plugging and solids deposition arise. Solids deposition, in particular, is related to insufficient flow velocity.

These problems become more challenging in high-pressure, high-temperature (HPHT) environments where pressure, volume and temperature (PVT) changes are more pronounced and occur very quickly. Flow assurance issues can be very costly to repair, or if unrepaired, can lead to erosion and corrosion and can endanger asset integrity. Furthermore, deposition of solid matter reduces the line throughput, sometimes leading to complete blockages and making profitable production of hydrocarbons practically impossible.

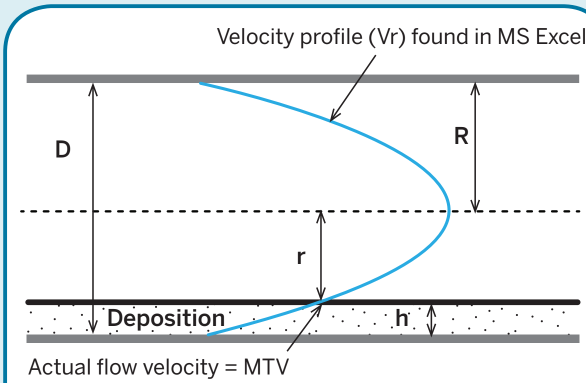
Many researchers have attempted to understand the physics of unprocessed fluid flow, characterized as multiphase flow. Primarily, the scientific efforts were focused on understanding the phase interaction between and its impact on flow dynamics. The greatest difficulty is that the nature of the flow is transient due to constantly changing flow patterns, so it is hard to predict flow behavior.

As part of the development of a comprehensive subsea tieback management strategy, the Well Engineering Research Group at Robert Gordon University in Aberdeen, Scotland, has endeavored

Minimum transport velocity for rolling in the pipeline

The graph created in MS Excel demonstrates the MTV for rolling changes in the pipeline. It is possible to locate the places where it changes significantly and to calculate how much velocity is required to transport particles at specific sections along the pipeline route. The pipeline angle and flow regime are factors that influence the MTV.

To perform the analysis, engineers modeled the fluid flow in a production system and identified places of flow-pattern transition. A commercial software, called PROSPER, was used to obtain data input parameters for the production system, such as pipework length, dimensions, angles and find fluid properties, pressure and temperature profiles using appropriate correlations. The software contains several examples of subsea wells and one of them (subsea black oil well, 11,400ft subsea true vertical depth, 10mi-long subsea flowline) was taken for this project.



h = D – (r+R) – bed height – important in evaluation of the blockage severity and damage to production

PVT data and nodal pressures (well head pressure (WHP), pressure at the manifold) were assumed and the software calculated the bottomhole pressure from the WHP under the specified operating conditions (5000 STB/d). Hence, the pressure traverse curves were generated for the tubing and flowline and correlation comparison was performed. The Beggs and Brill (1973) correlation showed the best closeness of fit and was chosen for the flow pattern identification.

After the software has specified which flow patterns prevail in the production system, the project moved to the second phase – creation of the analytical model in MS Excel with the main objective of finding places of solid phase deposition. The solid phase loading and dimensions were assumed, specifying the flow as diluted with spherical particles. The fluid flow parameters were transferred onto the Excel spreadsheet for calculations, which started with plotting fluid flow velocity field profiles for different flow regimes. In order to do this, the pipeline diameter was divided in five segments on each side from the pipe center and the fluid velocity was found at each of them.

With the velocity profiles thus generated it became clear how quickly the fluid moves in the production system. The next step was to find the minimum transport velocity at which particles would roll and be transported in suspended mode. Obviously, if somewhere in the pipeline the lowest barrier for transport (MTV for rolling) is not met by the actual fluid velocity it means that particles will deposit on the pipeline wall. Therefore, the comparison between the two velocities was done and showed that the condition for solids transport was not satisfied only in the vertical section of the wellbore.

The higher barrier (MTV for suspension) was also found and compared with the actual flow velocities. The comparison showed that although the condition for transport was satisfied in most of the pipeline, particles were rolling alongside of the wall. Only in the horizontal section of the pipeline and close to the manifold to create a model for sand transport in long-distance subsea tiebacks. The ideal model would have the potential to solve problems of pipe and equipment sizing, locate places of sand deposition and improve sand management strategies. The previous particle transport models did not reflect the critical factor of flow pattern transition and therefore can be unreliable under varying operational conditions.

Several experiments were conducted during a study to establish the minimum transport velocity (MTV) for rolling and suspension for different flow patterns. The result of that study (Bello et al (2011)), were empirically derived equations for the MTV and flow velocity profiles under different flow regimes. As a continuation of that study, the subsequent project was to create an analytical model in MS Excel (using the concept of MTV) to locate places of deposition in pipelines and to formulate a method to assess the severity of blockages. OE

Originally from Komi Republic, Russia, ***Alexander Belkin*** *earned his first degree in Drilling Well Engineering in 2013 from Ukhta State Technical University. He recently graduated from RGU with an MSc in Oil and Gas Engineering.*

Belkin presented this paper at the Energy Institute's Msc Energy Paper competition, in which he was one of six finalists.

the solid phase was transported in suspension. It is important to note that the safest method of the solid phase transport is in suspension, as when particles roll there is the possibility of deposition as pressure drops further down the pipeline.

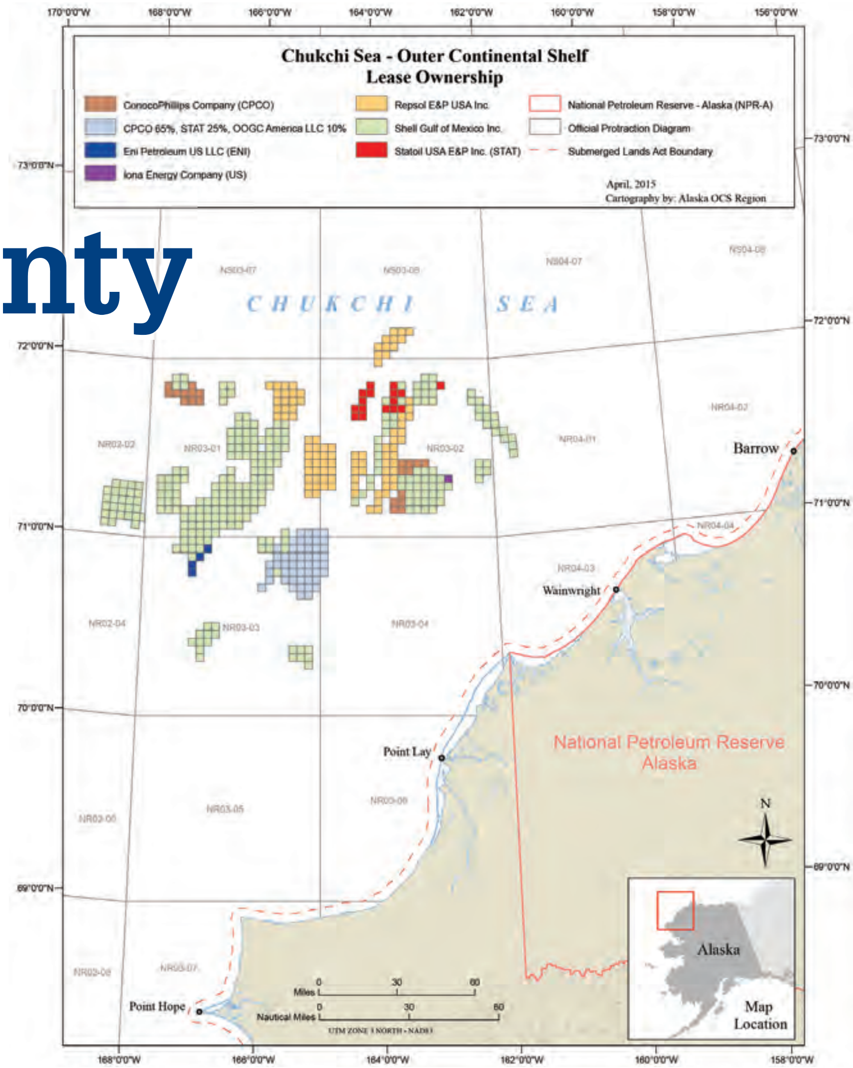
In places of deposition, the severity of blockage is determined by the height of the deposited bed, which can show the degree of production impairment. In this project it was attempted to analytically derive it from the given equations. Evidently, the top of the deposited bed is at the point where transport occurs, in other words, where the actual flow velocity is equal to MTV for rolling. Thus, the two equations were equalized and the distance from the pipe center where transport occurs was expressed. It then became possible to find the height of the bed by subtracting this distance from the rest of the pipe diameter space. The method proved to be reliable and demonstrated only small error margin (<0.5 %).

The project has laid the ground work for further development and industrial application. Apart from enabling location of places of deposition in the pipeline, it has given the insight into the key relationships between flow parameters and the solid deposition behavior as well as severity of blockage. The next step for this model will be its application in a field case study and comparisons of results with a real-time data. There is the opportunity to further complicate the model by adding parameters close to a real case scenario (non-spherical particles, paraffin, hydrates and wax occurrence, dense flow, varying operating conditions).

On demonstrating the reliability of this model and acknowledging its practical importance it would be possible to incorporate it into an industrial software. Thus, it would be a useful tool in the production engineer's hands for predicting solid deposition behavior in the production system under varying operating conditions. Subsequently, it might act as a part of an integrated subsea tieback flow assurance management strategy. ▪

Sea of uncertainty

With a mean estimate of 23.6 billion bbl of undiscovered, technically recoverable conventional oil in the Beaufort and Chukchi seas, the Arctic could be one of the last big finds. Heather Saucier examines what is at stake on the US side.



Source: US Bureau of Ocean Energy Management

While the melting of Arctic ice poses serious consequences to the planet, it also opens up vast amounts of ocean for exploration in an area believed to contain some of the world's last remaining large oil fields.

The US Department of the Interior (DOI) announced new lease sales off Alaska's coast, including areas in the Beaufort and Chukchi seas. However, it also made other areas in those locations off-limits from exploration, and followed with stricter exploratory drilling regulations. As the federal government strives to find a balance between tapping additional energy resources and protecting Alaskan frontiers, its efforts have cast the concept of economical Arctic exploration – during a time of mercurial oil prices, no less – into a sea of uncertainty.

Guessing game

The US Bureau of Ocean Energy Management (BOEM) estimates that in terms of undiscovered, technically recoverable conventional resources, the Beaufort Sea contains anywhere from 0.4-23.2 billion bbl of oil and 0.6 to 72.2 Tcf of gas (95 to 5% probabilities). Its neighbor, the Chukchi Sea, is estimated to contain anywhere from 2.3-40.1 billion bbl of oil and 10.3 to 209.5 Tcf of gas (95 to 5% probabilities).

If those ranges seem broad, it is due to the lack of understanding about existing Arctic resources, says Bob Swenson, retired deputy commissioner of the Department of Natural Resources in Alaska and former state geologist for the Alaska Division of Geological & Geophysical Surveys.

"We know we have a tremendously active petroleum system. But our understanding of what resources are actually there is fairly limited because there's been little exploration done in these areas," says Swenson, of Alaska's Outer Continental Shelf (OCS) and the Arctic National Wildlife Refuge, which has been subject to tight federal regulations for decades.

"This has always been frustrating to people who want to understand what resources we have," he adds. "We have a fair understanding of what our reservoir rocks might look like, but they are all based on models, and we have little data to base the models on."

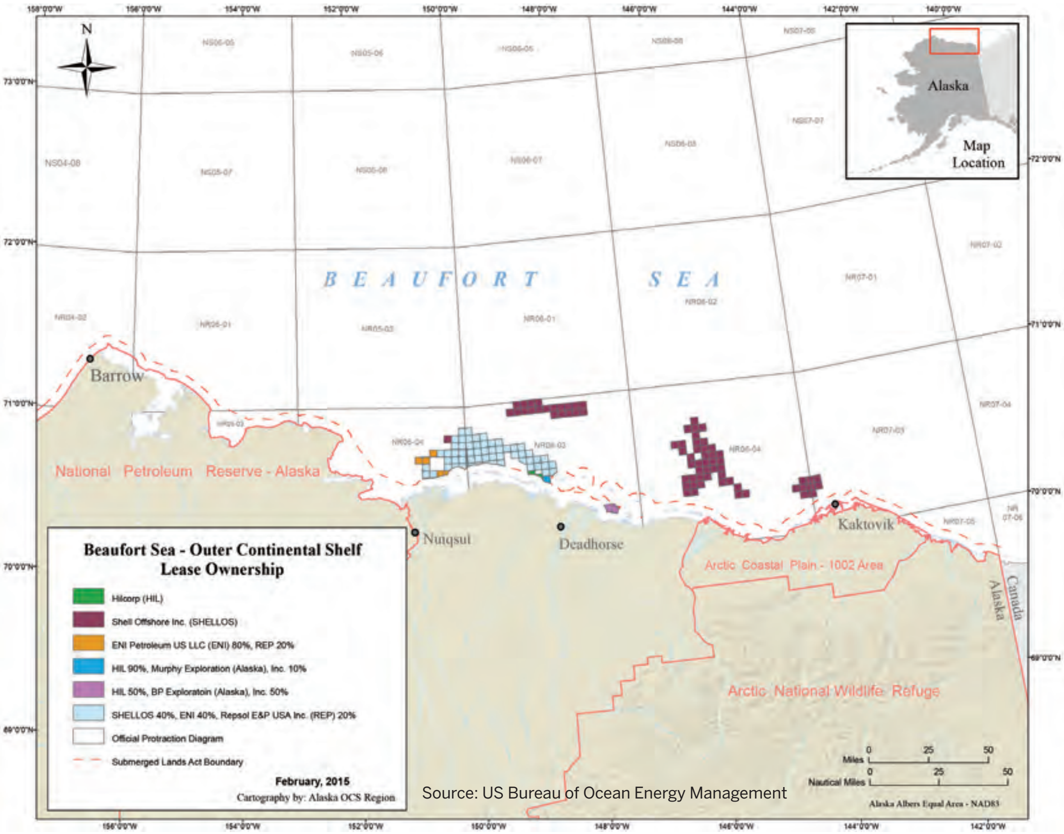
Until more information can be obtained, the roughly 12 operators, which hold 607 active leases in the Beaufort and Chukchi seas, are there for the respective estimated means of 8.2 billion bbl and 15.4 billion bbl of undiscovered, technically recoverable oil.

Finding a balance

In an effort to expand offshore areas for Arctic exploration, the federal government unveiled in January an offshore lease program for 2017-2022 that includes additional blocks in the Beaufort and Chukchi seas. The acreage has not yet been determined.

Also in January, President Obama designated 9.8 million acres in the Arctic OCS as off-limits to future leasing and exploration. The acreage includes subsistence whaling areas near the Inupiat villages of Barrow and Kaktovik in the Beaufort Sea, a 25mi coastal buffer from Point Hope to just east of Barrow in the Chukchi Sea, and – perhaps most valuable to the oil and gas industry – the Hanna Shoal in the Chukchi Sea.

"Even as we consider new places that may be appropriate to responsibly develop oil and gas, we can take meaningful steps to protect areas that matter most for our environment, our native communities, and our cultural identity," wrote Mike Boots, leader of the White House Council on Environmental Quality, and Dan Utech, deputy assistant to the president for Energy and Climate Change, in a



Source: US Bureau of Ocean Energy Management

27 January issue of the White House blog.

The DOI is most concerned with protecting areas that are home to endangered whales, in addition to walruses and bearded seals that feed on the biologically-rich Hanna Shoal, as well as the more than 40 species of fish that support Alaska's fishermen. Also of importance are the bowhead whales, which are essential to the subsistence and customs of native Alaskans.

"There is a perceived dichotomy between resource development and maintaining strict environmental protection. Most Alaskans understand the need to maintain both and appreciate both sides of the debate," Swenson says. "However, with strict stewardship, both should be maintained."

As a resource state, Alaska has essentially funded all government activities from resource development, with the oil and gas industry as its biggest taxpayer. And, industry eyes remain focused on the Arctic and its remaining potential for abundant oil and gas resources.

Unlike areas such as the Powder River Basin or the Bakken Formation where a discovery of 5-10 MMbbl of oil in place would be considered "significant," Swenson says those same numbers would equate to an economic "dry hole" in the Arctic, where it is much more costly to explore and produce in areas lacking infrastructure.

"You need a large field to make oil and gas economically viable to develop," he says. "Given the petroleum system we are dealing with in the Arctic, it is one of the last places where we have the chance to find very large fields."

What's the damage?

Although more than roughly 300,000 acres in the Beaufort Sea are now off-limits to exploration, none overlap with existing leaseholds, and the oil and gas industry has not shown much of an interest in those areas to date, says David Houseknecht, a senior research geologist and project chief for the Energy Resources program in Alaska with the US Geological Survey.

"Speculating about the geology here, there is some potential for prospective areas in the Beaufort Sea to overlap with those areas that have been recently blocked off, but that is dependent on when and if development ever occurs," Houseknecht says.

The Chukchi Sea is another story. Currently, 10 lease blocks owned by Shell and Repsol in the Hanna Shoal have been removed from exploration activity. While the government will have to reimburse the operators for lease fees, it might face additional backlash for projected loss of revenue, as the Chukchi Sea seems to hold higher promise for operators, as demonstrated by roughly three times the amount of active leases there compared to the Beaufort Sea.

While current areas of interest in the Chukchi Sea are south and west of the Hanna Shoal, the newly blocked off area, which covers roughly 1.5 million acres, is "clearly along the prospective fairway," Houseknecht says.

Although teeming with wildlife, the geology of the Hanna Shoal could also mean the area is rich in hydrocarbons.

Many of the 460 active leases in the Chukchi Sea are located above and along the margins of a rift basin called the Hanna Trough where a high concentration of source rocks, specifically the Shublik and the Kingak, occurs, Houseknecht says.

"Like most frontier areas, early wells are drilled on structural highs, and the best source rocks are located in structural lows. In this case, that's the Hanna Trough," he explains. "The hope is that when doing exploration, the low areas


Arctic OCS taken from Svalbard. Photo by David Houseknecht from the USGS

– the troughs – contain lots of rich source rocks and the high areas contain a lot of good reservoir rocks."

Yet, with just five exploratory wells drilled (by Shell and Chevron) to date, there is no complete picture of the succession of formations, Houseknecht says.

One well, the Klondike, which was drilled by Shell roughly 25 years ago, penetrated the Shublik Formation, which contains good source rocks on the Arctic OCS as well as on the North Slope. The well also penetrated good source rocks in the Ivishak Formation, which, ironically serves as the main reservoir rock at Prudhoe Bay, Houseknecht says.

As more wells are drilled, it may be revealed that the off-limits Hanna Shoal could hold more promise than ever imagined.

"From an exploration perspective, the greatest concern is the Hanna Shoal leases," says Paul Decker, acting director of the Alaska Department of Natural Resources' Division of Oil & Gas. Removing the Hanna Shoal "certainly can't help exploration," he adds. "It certainly has provoked strong feelings."

Demands on drilling

Just as both industry and the state of Alaska were digesting the news of new exploration limits, February brought an additional blow when the DOI proposed for the first time strict federal regulations for exploratory drilling in the Arctic OCS that could increase the cost of exploration by as much as hundreds of millions of dollars.

"The Arctic has substantial oil and gas potential, and the US has a longstanding interest in the orderly development of these resources, which includes establishing high standards for the protection of this critical ecosystem, the surrounding communities, and the subsistence needs and cultural traditions of Alaska natives," said Sally Jewell, secretary of the Interior, in a DOI press release.

Her words were echoed by BOEM Director Abigail Ross Hopper: "… We have an obligation to provide the American people with confidence that these shared resources can be developed responsibly."

Perhaps most restrictive is a proposed requirement for operators to have a separate relief rig available to enable a relief well to be drilled in a timely manner should there be a loss of well control. The DOI's estimated annual cost of a relief rig is US$55 million, which could halt some exploration ventures in their tracks.

Most vocal in the press about the requirement has been the American Petroleum Institute (API). "Other equipment and methods, such as a capping stack, can be used to achieve the same season relief with equal or higher levels of safety and environmental protection," said Erik Milito, API upstream director, in numerous publications following the announcement. "For this reason, it is unnecessarily burdensome to effectively require two rigs to drill a single well."

Milito's statement was addressed by US Bureau of Safety and Environmental Enforcement Director Brian Salerno: "We understand that the same-season relief rig is somewhat controversial. From our perspective, that sets a level of protection for the Arctic that is necessary."

Other proposed requirements include an integrated operations plan that details all phases of an exploration program for purposes of advance planning and risk assessment; region-specific oil spill response plans; and prompt access to source control and containment equipment, which essentially means all containment systems would need to be stored in the Arctic rather than contracted out.

Arctic OCS taken from Svalbard.
Photo by David Houseknecht from the USGS

Furthermore, in the event of a worst-case scenario oil spill, operators would be required to have in place the mechanical oil recovery equipment needed to address such a situation, in addition to dispersants and in-situ burning techniques.

Because such little drilling takes place in the Arctic, operators may find it difficult – if not impossible – to share resources to reduce extra expenditures required by more stringent drilling regulations.

Moving forward

The operator with perhaps most at stake is Shell, which hit the pause button on plans to drill two wells in the Chukchi and Beaufort seas in 2012 following several offshore drilling incidents.

Required by the DOI to fortify its Arctic oil spill prevention and response program, the operator responded by purchasing two custom ice class vessels; securing an oil spill response fleet that could be on site within one hour of an incident; constructing a capping stack similar to the one used to correct the 2010 Macondo blowout in the Gulf of Mexico; and building a custom containment dome and storage barge, among other measures.

In fact, the new drilling regulations proposed by the federal government are largely based on the requirements put on Shell.

Shell Spokesman Curtis Smith responded to the proposed regulations saying, "Our paramount concern in all our operations is safety and environmental protection. We support regulations that further these imperatives in the Arctic, provided they are clear, consistent and well-reasoned. We have and will continue to take unprecedented steps to ensure we can operate safely and responsibly in the Arctic."

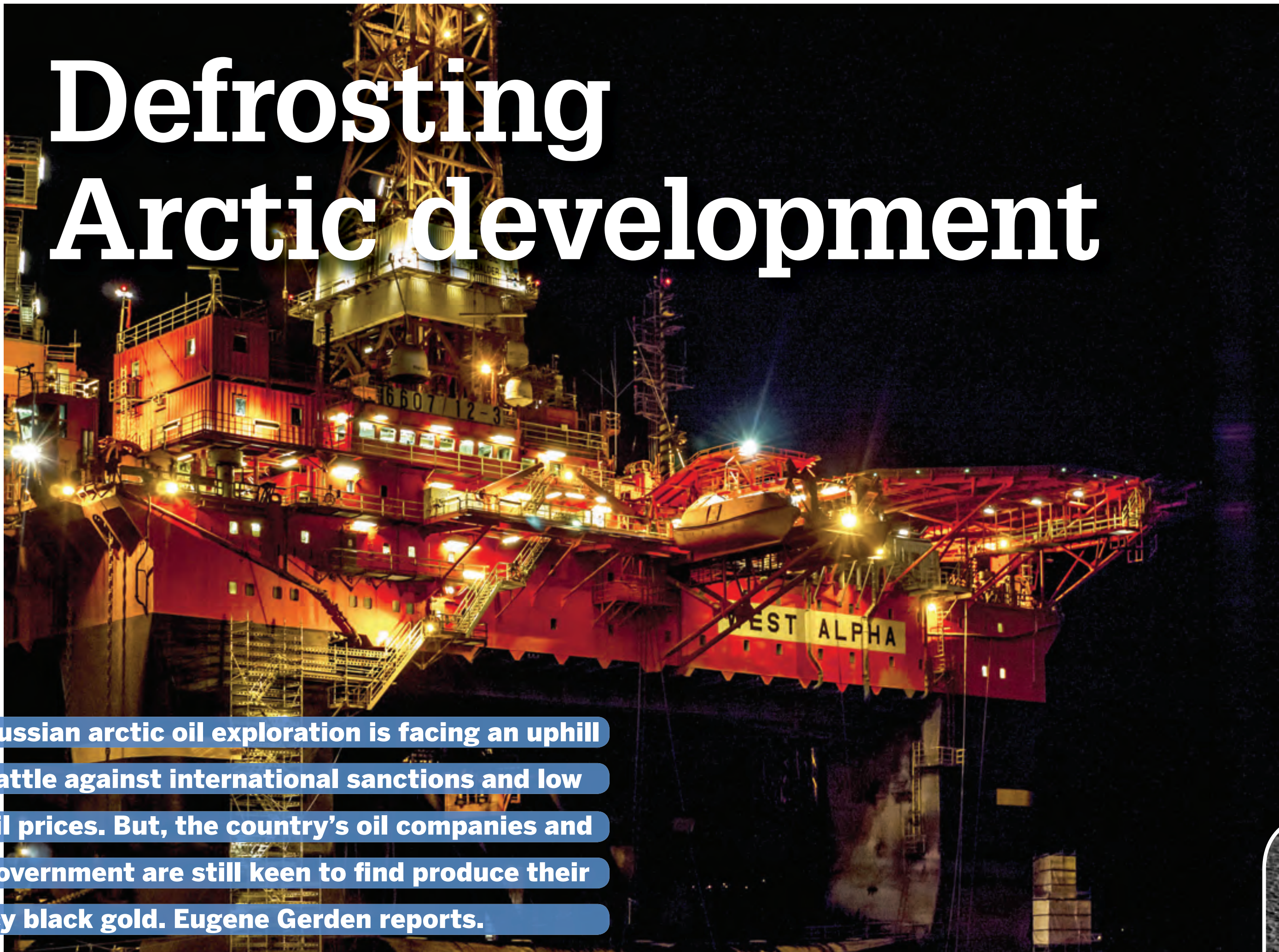
The deadline for public comments on the federal government's proposed regulations was April 27 (as ***OE*** went to press). In early May, Shell won conditional approval from BOEM, enabling the company to move forward with its 2015 Chukchi Sea exploration plan.

A different kind of hurdle

A handful of scientists, including those at the University of California in Los Angeles, predict that by mid-century, ice in the Arctic will be so scarce or thin that vessels will easily be able to sail across the North Pole.

If ice is no longer a barrier to exploration, heftier drilling regulations and off-limit areas may very well take its place. **OE**

Defrosting Arctic development



Russian arctic oil exploration is facing an uphill battle against international sanctions and low oil prices. But, the country's oil companies and government are still keen to find produce their icy black gold. Eugene Gerden reports.

Since sanctions were first imposed on Russia in 2014, the prospects for Arctic exploration have been dampened. Add a sub-US$60/bbl oil price, and the high cost of operating in the harsh Arctic environment looks an even tougher proposition.

Yet, despite the challenges, Rosneft and ExxonMobil, hope to resume the development of Russian Arctic by the middle of 2016, according to recent statements by analysts in Rosneft's department of offshore exploration works.

Russia is also considering opening Russian offshore exploration to foreign operators, both for seismic acquisition and exploration drilling activities, which could mean Russian firms lose the exclusive grip they have held in this area to date.

Barents, Kara Seas beckon

Speaking during a press conference at Rosneft's Moscow offices, Timothy Streltsov, head of Rosneft's offshore exploration department, the company, together with ExxonMobil and other foreign partners, hopes to resume drilling exploratory wells on the Kara Sea shelf during the next 12-20 months, with preparatory work starting this year.

Exploration drilling in the Kara Sea was suspended in September 2014 due to sanctions imposed on Russia over its involvement in the ongoing Ukraine crisis (*OE: November 2014*). In late July, the US and the EU imposed sanctions on Russian oil firms and limiting trade relating to the energy sector in Russia. In September 2014, sanctions tightened on the energy sector, with the export to Russia of equipment for Arctic, deepwater and shale oil. In addition, sanctions have limited an access of leading Russian oil and gas producers to long-term funds in the US. Nevertheless, the partners plan to start preparatory work for drilling in the Barents and Kara Seas, Streltsov said.

"This year we will focus on the studying and analysis of materials, obtained during surveying season on the shelf in 2014," Streltsov said. "At the same time next year we plan to start drilling on the sites of the Barents and Kara Seas."

The drilling may focus on the recently

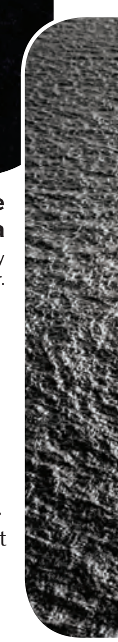
The West Alpha semisubmersible drilling rig, used to make the Pobeda discovery in the Kara Sea. Photo by Johnny Johnsen/Flickr.

discovered shallow water Pobeda (Russian for victory) field in the East Prinovozemelskiy license. Pobeda, estimated to contain about 130 million tonnes of oil and 499.2 Bcm of gas, was discovered on the Kara Sea shelf just as sanctions were imposed last September.

Light oil, comparable to Siberian light oil, was discovered in Cenomanian Age and Apy-Alb Age chalk, according to Rosneft, through the Universitskaya-1 well, drilled using Seadrill subsidiary North Atlantic Drilling's semisubmersible drilling rig *West Alpha*. The water depth was about 81m, about 230km off the Russian coast. The well, which was cut short of its planned total duration, cost around $1 billion.

According to sources close to Rosneft, the partners plan to initially focus on oil production, as gas production may significantly complicate transportation of oil from the shelf.

The partners would also only look to



develop a field with no less than 100 million tonnes, due to the large initial investments in infrastructure required for first oil in the area. Temperatures plunge to -46°C and the area is ice-bound roughly 270-300 days a year, Rosneft said.

Sanctions will not, however, prevent Rosneft and its foreign partners moving forward with their Arctic projects, according to recent statements of Alexander Novak, Russia's Minister of Energy.

"Sanctions resulted in some problems and difficulties in attracting of foreign partners for Rosneft," Novak said in a statement. "Nevertheless, the Russian government and companies, involved in the project, plan to continue its implementation."

According to Novak, the partners will procure all the equipment they need for the project from other sources. This may take place as part of a program of import substitution in the Russian oil and gas industry, which was recently approved by the government and involves imports of such equipment and technologies from other regions including Asia-Pacific.

The Prirazlomnaya platform in the Pechora Sea.
Photo from Gazprom.

In the case of imports of Western equipment and technologies, one possible option to resume supplies (in compliance with existing sanctions) may involve the use of foreign subsidiaries of EU and US oil service companies. Indeed, an official spokesman of the US Department of the Treasury, recently told Russia First TV that sanctions against Russia do not apply to foreign subsidiaries of the US companies.

This would enable companies such as Schlumberger and Baker Hughes to resume supplies of equipment and technology to Russian Arctic projects. In a sign of moves in this direction, Schlumberger recently agreed to acquire a minority stake in Eurasia Drilling Co., Russia's largest onshore drilling firm, for about $1.7 billion. However, the deal has not yet been approved by the Russian State Commission on Foreign Investments, headed by Russia's Prime-Minister Dmitry Medvedev.

Without the aid of international oilfield services companies, Rosneft has been struggling to meet its license obligations. In a letter to the Russian Mineral Agency (Rosnedra), Rosneft requested permission to postpone exploration activities in 12 Arctic licenses, due to foreign partners pulling out and consequent problems with getting the necessary project investments, reported Russia's Vedomosti news organization. For Chinese firms, the current situation has created an opportunity. An interest in developing oil and gas on the Russian Arctic shelf has already been expressed by some leading Chinese oil and gas producers, including CNPC, CNOOC and Sinopec, which have already started talks with Rosneft, regarding the participation in such activities.

Specific agreements have not yet signed, however. According to an official spokesman of Sergey Donskoey, Russia's Minister of Natural Resources, Chinese investors will probably bid for a 33.3% stake in Rosneft's Kara Sea project, which is similar to stakes offered to a consortium of foreign investors of Statoil, Eni and ExxonMobil.

According Vedomosti, Novak is keen to bring in new regulations to allow foreign firms to develop projects in Russia. Part of the reason has been due to lobbying by Lukoil against the monopoly position held by Gazprom and Rosneft.

Costly endeavors

Meanwhile, according to ExxonMobil's latest annual report, the volume of the company's losses associated with the suspension of Arctic projects is estimated at $1 billion.

ExxonMobil was attracted by the big numbers attached to the Kara Sea. According to the Russian Ministry of Energy, the volume of resources in just the Kara Sea region significantly exceeds those of the Gulf of Mexico, the Brazilian shelf, the Arctic shelf of Alaska and Canada, and is comparable with the entire resource base of Saudi Arabia.

This is coupled with flexible Russian legislation in the field of offshore operations, which is seen as being significantly lighter than those in neighboring EU countries. According to Denis Manturov, Russia's Minister of Industry and Trade, due to global warming, the conditions for the development of the Russian Arctic shelf have significantly improved.

However, Russian companies have struggled with the country's bureaucracy, which is reflected by frequent cases of delays during the provision of working permits, as well as issues with corruption. OE

PRIRAZLOMNOYE

Russia's Gazprom is planning a four-well exploration campaign close to the country's only offshore Arctic producing oil field.

Since coming on stream 18 months ago, nearly 3 MMbo have been extracted and shipped from Russia's only producing offshore Arctic oil field, via one well.

Production from the Prirazlomnoye field, which sits in the Pechora Sea, 60km offshore Russia's coast, is via the Prirazlomnaya platform. Crude is then shipped using the *Kirill Lavrov* and *Mikhail Ulyanov Arc6* class double-hulled icebreaking oil tankers with the support of two multifunctional icebreakers.

Pilot production began at the oil field in December 2013, from one well. Gazprom is now planning to start operating an injection well and a disposal well on the field. It is also planning four additional exploration wells.

According to Gazprom Neft, recoverable reserves exceed 70 million tonnes of ARCO oil, a dense (roughly 24° API) oil with about 2.3% sulfur content, as well as low paraffin content. ▪

FURTHER **READING**

Frosty relations.
www.oedigital.com/component/k2/item/7385-frosty-relations

Automation, reliability means efficiency offshore

Gregory Hale walked the aisles at this year's Offshore Technology Conference to find out what moves the industry is making toward automation.

Automation and reliability: those two words went hand-in-hand during May's Offshore Technology Conference (OTC) in Houston. In this down market, with capital projects drying up, reliability and efficiency – hallmarks of automation – are becoming focal points for producers.

"I am seeing interest, across the board, in automation," said Mario Azar, president of Siemens Oil and Gas and Marine global business unit at OTC. "The focus is really shifting. The industry has to think differently. Everyone has to ask 'can technology help us? How do we become more efficient?' You have to do things smarter. It takes time, we are not there yet. The more you automate, you are making costs lower and it is trusting technology more. Trusting technology is important with something so precious. There is a lot at stake."

Mario Azar

Indeed, a massive amount is at stake with oil prices kissing US$60/bbl. That means any kind of projects that will squeeze more costs out of production are paramount.

"Reliability is more important than anything else," said Robert DiStefano, vice president and general manager for reliability consulting at Emerson Process Management. "As much as 5% of production capacity worldwide suffers from reliability issues and 43% of that 5% includes unplanned downtime because of equipment problems."

Companies that have solid reliability programs reap benefits, including:

- Reduced downtime and increased profitability
- Spending less money for maintenance
- Increased safety — incidents go down when reliability goes up

"People are starting to use reliability as a business strategy," DiStefano said. "If a CEO is not asking direct reports about downtime and what money they are spending on maintenance, then they are derelict of duty. You have to change the practices."

As a part of that change process, users need to find a way to ward off the flood of data so they can capitalize on the right information at the right time and make immediate decisions, which can be the difference in profit levels.

"We are starting to see companies surviving in a downturn and flourish because they are investing now to grow in the future," said Jerry Hines, North American oil and gas manager in the energy segment at National Instruments.

Part of the growth strategy is maintaining equipment better, doing more with less people, and making sure equipment stays up and running, he said.

"Users are seeing the advantage of going digital," Hines said. "Ten years ago it was a different story. Now they are seeing the advantages and they say 'let's work in a collaborative partnership and implement the technology.'"

With capital projects drying up, Luis Gamboa, global business development manager for oil and gas at Rockwell Automation, said producers are not actually thinking long term, but rather need quick answers to get through this quarter.

"If you leave them on their own, they will cut costs," Gamboa said. "They will go to the service companies and they will say 'I need a 20% cut in service costs.' Oil companies are focusing on immediate results. Now that the first level of cuts has taken place, they are looking at protecting assets. They are spending for efficiencies. They are looking at asset integrity. You can't afford unplanned downtime."

Chet Mroz, former president and chief executive at Yokogawa Corp. of America, and now executive advisor for strategy and innovation, said that, in a down market, it is possible to look at other areas, such as midstream, for growth options.

However, having a plan of attack for a generation getting ready to hand in their papers, Mroz truly feels automation will help the cause.

"With baby boomers leaving and fewer younger engineers coming in, it sure helps to have more automation to replace empty seats, but it also helps to standardize and make sure everyone is trained and understands the standard operating procedures," he said. **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.*

Countdown to SPE Offshore Europe

Inspiring the next generation sets the theme for this year's SPE Offshore Europe 2015. *OE* takes a look at what's in store at this year's event.

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In under three months' time, the world's offshore oil and gas industry is set to descend on Aberdeen, Scotland, for one of the largest oil events in the calendar – SPE Offshore Europe 2015.

The biennial event, which has grown year-on-year since the first show back in 1973, is set for another bumper crop of keynote sessions, technical sessions, topical lunches and breakfast briefings, as well as the growing Deepwater Zone and extensive exhibition halls.

Michael Engell-Jensen

Despite the current difficulties in the market, the industry is far from over and that focus should still fall firmly on innovation, technology development, and – not least – attracting talent, is the view of those setting the agenda.

In fact, "how to inspire the next generation" is SPE Offshore Europe 2015's over-arching theme.

Neglecting to encourage talent into the industry at this time would be damaging, says Alistair Geddes, president of strategy, resource development and support, Expro Group, who is co-chairing the Development Talent committee at this year's SPE Offshore Europe.

"E&Y's recent UK study '*Fuelling the next generation*' highlighted the need for 12,000 new entrants into the industry over the next five years alone. We don't want to repeat mistakes of the past, so it's important we take a balanced and long term approach to talent management," he says.

Charles Woodburn

Global, geopolitical topics, technology, deepwater, health, safety and security are all also high on the agenda, which will feature both a keynote and technical program.

The keynote program, chaired by Michael Engell-Jensen, executive director of the International Association of Oil & Gas Producers (IOGP), will feature 11 sessions focusing on topics such as the basic challenge of meeting energy demand while balancing concerns over climate change, security of supply and consumer affordability.

Other topics include: health; the safety and security of people and assets; well intervention; financing investments; oil spill response; and inspiring the next generation to join the industry. Speakers will range from senior representatives from international operating companies and contractors, to trade association representatives, government regulators and academia.

The technical program, chaired by Expro Group CEO Charles Woodburn will feature more than 75 papers, demonstrating the industry's engineering, manufacturing and technology excellence.

Speakers drawn from all over the world will discuss topics such as asset and well integrity, maximizing economic recovery, smarter field development, pipelines and risers, subsea processing, talent development, unconventional gas development, process safety, and decommissioning.

Planning is also well under way on the dedicated Deepwater Zone, the breakfast and lunch agenda, and on an ambitious "Inspire" program aimed at the younger generation.

Engell-Jensen says: "For many decades to come, oil and gas will remain indispensable to the world for securing heat, light, mobility and prosperity. As a responsible industry, we must address society's concerns about our operations and the hydrocarbons on which the world relies.

"The keynote program will focus on the basic challenge of meeting energy demand while balancing concerns over climate change, security of supply and consumer affordability. This challenge incorporates related issues: the well-being of our people and neighbouring communities, environmental risks and the safety and security of upstream assets. These imperatives are fundamental in framing the oil and gas industry for the foreseeable future." OE

SPE Offshore Europe 2015 will take place from Tuesday 8 to Friday 11 September at the Aberdeen Exhibition and Conference Centre.

In 2013, SPE Offshore Europe attracted over 1500 international exhibitors and 63,000 attendees from more than 100 countries.

Full details of the conference sessions and speakers lined up for SPE Offshore Europe 2015 are now available on the event's website – www.offshore-europe. co.uk

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Spotlight

Current currency

The success of MeyGen will help lay the ground work for the future of the tidal power industry. The CEO of the company behind it believes he has the recipe for success. Elaine Maslin reports.

Holding Tim Cornelius' attention is no easy task. This year is poised to be his firm's, Atlantis Resources, busiest following a successful IPO on the stock market and securing £50 million funding for its milestone MeyGen project last year.

Atlantis has just started construction work on the MeyGen project, the world's first commercial-scale multi-turbine tidal energy project, and in late April it bought out turbine developer Marine Current Turbines from global firm Siemens, which in turn has taken a 9.99% stake in Atlantis.

Cornelius, who has already had careers as a commercial diver, ROV pilot and roles in management, alongside developing an interest in power and emissions trading and gaining an MBA, soaks up the challenge.

The Australian-born Cornelius started out studying marine biology aquaculture. After completing his degree he went to dive college in order to work on tuna and salmon farms in southern Australia.

But, his attention was gripped by others who were training in underwater welding and construction, leading him to later attain his commercial diving certificate. He worked in the submarine rescue escape team in Australia before moving to the North Sea to work in the oil and gas industry, retraining in submersible engineering and then as an ROV pilot. From there, Cornelius rose through the ranks, working around the world for Subsea 7, particularly in deep water areas off Brazil, and Trinidad and Tobago.

The taste for training, and now also management, as well as a growing interest in power and emissions trading, led him to his next step – an MBA at Bond University in Australia. At Bond, he was approached by Atlantis, then a small tidal technology concept developer.

Tim Cornelius

"I have a strange background. An underwater engineer that understands how markets and emissions trading works," he says. "They asked me to help build a concept for tidal power, initially very much on an interim basis while I was completing my MBA. Once I got involved I realized the potential, but saw that the company needed restructuring."

The challenges facing tidal energy development caught Cornelius' interest – understanding subsea engineering challenges, understanding the market on a macro-economic basis and how renewables fit in, as well as the influence of politics on renewables.

Atlantis was originally formed by serial entrepreneur and deepsea fisherman Michael Perry in Australia about 15 years ago. While he had success with other start-ups, his passion was harnessing energy form the ocean. Perry set up Atlantis to develop and design a turbine called the Aquanator.

"It has evolved considerably since then," Cornelius says. These days the company has become a project developer, which also does technology development, because it can, and, some in some cases, because it has to. The business has a global strategic alliance with Lockheed Martin, giving its technology, the AR1500, blue-chip engineering support and development.

But, the company isn't solely tied to using the AR1500, calling themselves technology agnostic. "We view ourselves as a leading developer of tidal power projects, a seabed real estate developer, with a fantastic partner in Lockheed Martin," Cornelius says.

All work up to this point has led Atlantis to the MeyGen project in Scotland's Pentland Firth. "I think a significant part of the future of the tidal power industry, not just in the UK but globally, hangs on phase 1a of the MeyGen project," Cornelius says, calling it the company's flagship.The project's first phase will install four 1.5MW turbines offshore and construct the onshore infrastructure to support the project. When fully operational the 398MW array will generate electricity to power 175,000 homes by the early 2020s.

Despite his immersion in the offshore renewables industry, Cornelius still keeps a close eye on the oil industry, however, and for good reason. "Marine renewables is a beneficiary of the recent reduction in capex, which has reduced vessel costs by 40-50%, which makes our operations a lot more affordable. The biggest variable in our cost base is the cost of installation."

The company also has a larger pool of potential staff and supply chain companies to draw on as oil workers and contractors look to other industries in the downturn.

But, there are other dynamics. Due to the low oil price and high operating cost in the North Sea, more assets could be decommissioned sooner, which would result in strong competition for yard space, so it's not a simple picture. But, it is a picture that keep Cornelius' constant attention. **OE**

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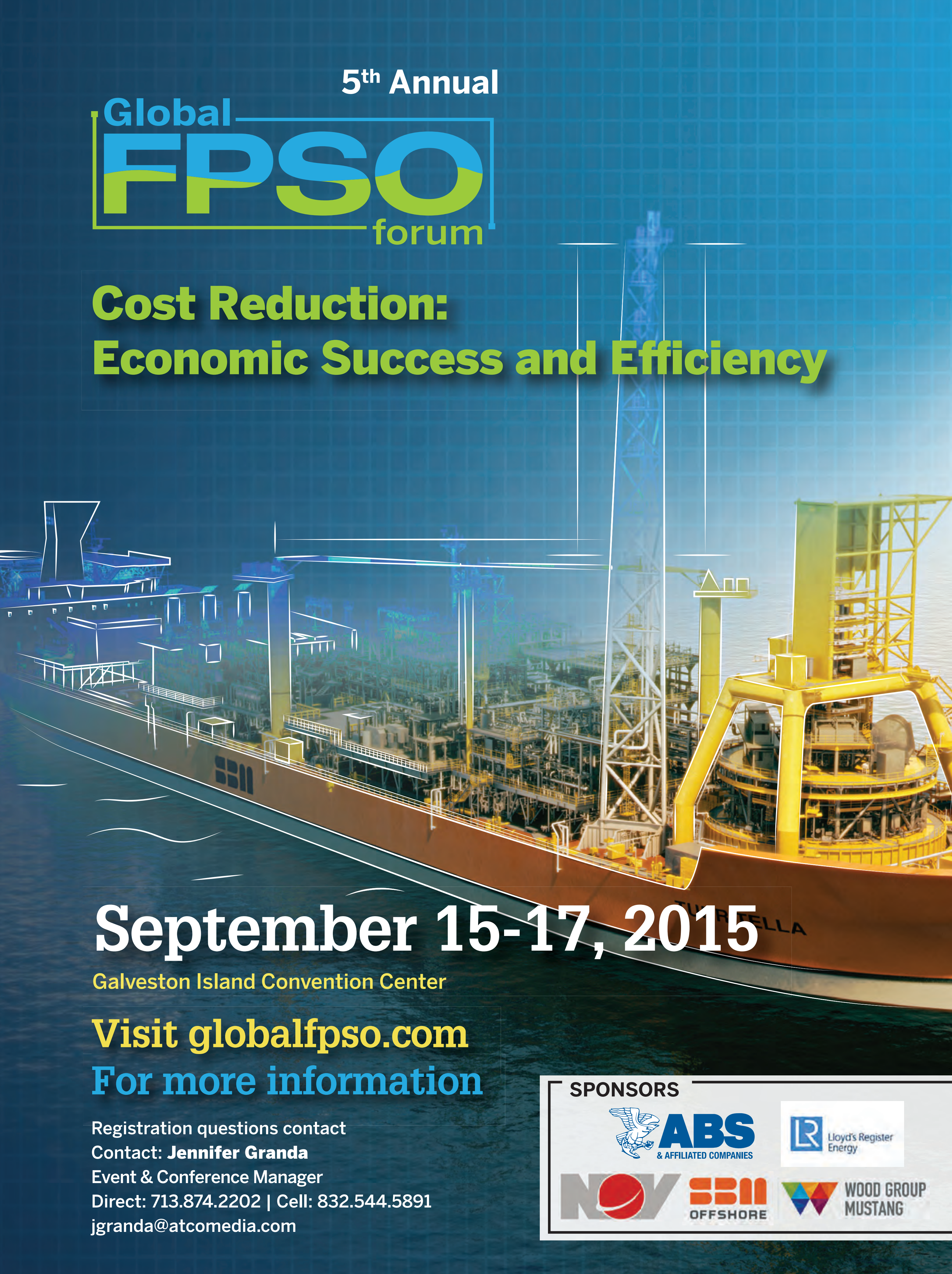
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Numerology

2 The wells Shell plans to drill in the Chukchi Sea this summer. See page 14.

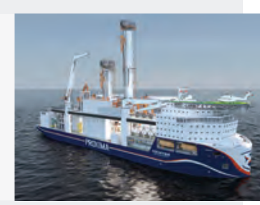
22Tcf The amount of natural gas resources discovered in Tanzania's in Block 2. See page 18 Photo from Statoil.

2013

The year the deepest discovery (Maximino) was drilled in the Mexican sector of the Gulf of Mexico. See page 23.

57GW The expected cumulative offshore wind capacity to be reached by 2024. See page 32.

US$260billion Total deepwater spending forecasted by Douglas Westwood from 2014-2018. See page 36.



300,000acres

The area now off limits to exploration in the Beaufort Sea offshore Alaska. See page 51.

Photo by David Houseknecht from the USGS

5% Of worldwide production capacity suffers from reliability issues. See page 56.

1973 The year Offshore Europe debuted. See page 58.

175,000 The number of homes to be powered by the MeyGen tidal energy project by 2020. See page 62.