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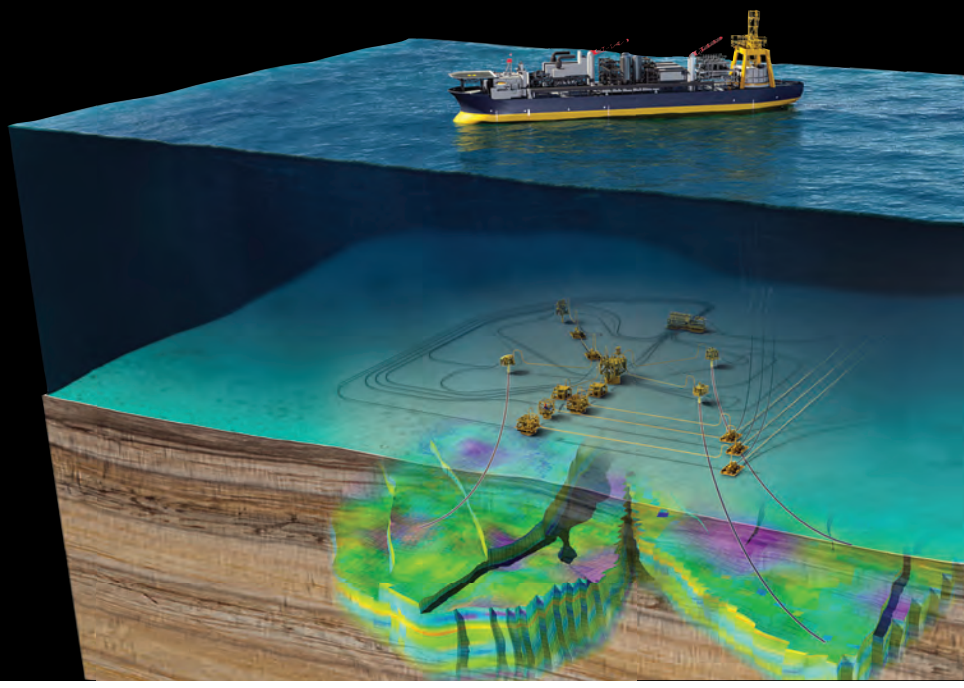

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Contents

Features

Recent progress on *Gulfstar*.
Photo from Williams Partners.

Gulf of Mexico

ON THE COVER

Eyes on the Gulfstar. Pictured is William's floating production spar-based system *Gulfstar*. Upended in February, it is set to serve Hess' Tubular Bells field by mid-2014. Built almost entirely in the US, its core module has the capacity to produce 60,000-90,000bo/d. Photo from Williams Partners. See page 50.

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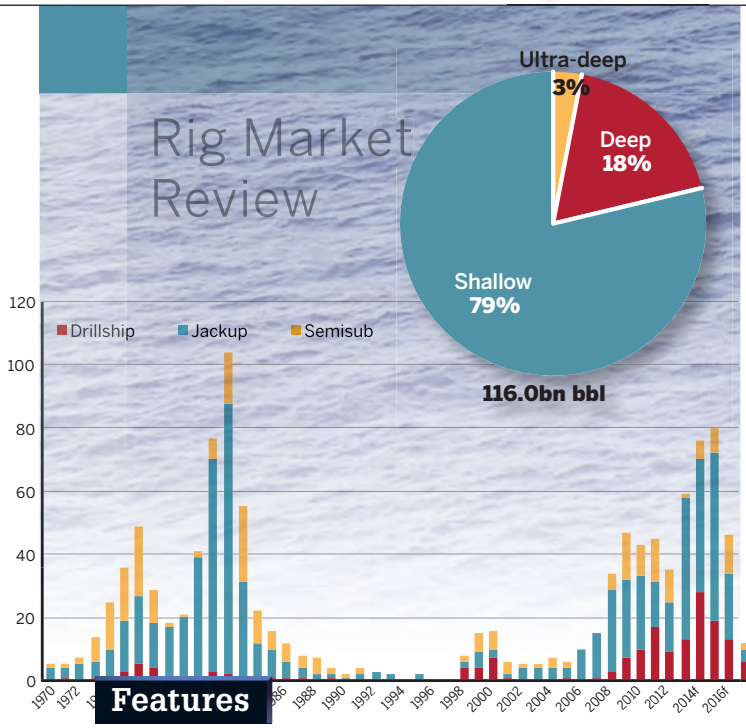

Features

Rig Market Review

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Volume 39, Number 4 April 2014

Departments & Columns

"What are the supply chain opportunities in Mexico?"

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1. What is your main job function?
(check one box only)

- ☐ 01 Executive & Senior Mgmt (CEO,CFO, COO,Chairman, President, Owner, VP, Director, Managing Dir., etc)
- ☐ 02 Engineering or Engineering Mgmt.
- ☐ 03 Operations Management
- ☐ 04 Geology, Geophysics, Exploration
- ☐ 05 Operations (All other operations personnel, Dept. Heads, Supv., Coord. and Mgrs.)
- ☐ 99 Other *(please specify)*_____

2. Which of the following best describes your company's primary business activity?
(check one box only)

- ☐ 21 Integrated Oil/Gas Company
- ☐ 22 Independent Oil & Gas Company
- ☐ 23 National/State Oil Company
- ☐ 24 Drilling, Drilling Contractor
- ☐ 25 EPC (Engineering, Procurement., Construction), Main Contractor
- ☐ 26 Subcontractor
- ☐ 27 Engineering Company
- ☐ 28 Consultant
- ☐ 29 Seismic Company
- ☐ 30 Pipeline/Installation Contractor
- ☐ 31 Ship/Fabrication Yard
- ☐ 32 Marine Support Services
- ☐ 33 Service, Supply, Equipment Manufacturing
- ☐ 34 Finance, Insurance
- ☐ 35 Government,Research, Education, Industry Association
- ☐ 99 Other (*please specify*)_____

3. Do you recommend or approve the purchase of equipment or services?
(check all that apply)

- ☐ 700 Specify
- ☐ 701 Recommend
- ☐ 702 Approve
- ☐ 703 Purchase

4. Which of the following best describes your personal area of activity?
(check all that apply)

- ☐ 101 Exploration survey
- ☐ 102 Drilling
- ☐ 103 Sub-sea production, construction (including pipelines)
- ☐ 104 Topsides, jacket design, fabrication, hook-up and commissioning
- ☐ 105 Inspection, repair, maintenance
- ☐ 106 Production, process control instrumentation, power generation, etc.
- ☐ 107 Support services, supply boats, transport, support ships, etc
- ☐ 108 Equipment supply
- ☐ 109 Safety prevention and protection
- ☐ 110 Production
- ☐ 111 Reservoir
- ☐ 99 Other (*please specify*) _____

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Online Exclusive

End of the line for 'easy oil'

Anthresia McWashington examines how national oil companies are battling the depletion of the so-called "easy oil" found in shallow water and onshore.

What's Trending

OE's IHS CERAWeek coverage

- **Rising costs become 'new reality'**
- **Colombia raises offshore profile**
- **TOTAL CEO talks rising costs**

Have your smartphone handy!

Look for special icons in this issue indicating interactive content. Flip to p. 88 and unlock the video in our Gulf of Mexico feature "Kings of the Gulf." On p. 96, gear up for OTC by watching how the tradeshow comes together. Be sure to scan these pages with the Actable app, which can be downloaded for free via the App Store or Google play on any smart device.

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Steve Sponseller is a product manager at Kepware Technologies with a strategic business development focus on the oil and gas market. **To register, go to www.oedigital.com**

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Voices

Down Mexico way. With reform underway, OE asked:

"What are the supply chain opportunities in Mexico?"

Rapidly aging fields and new opportunities associated with the potential for direct foreign investment—under consideration by Mexico's government—present significant opportunities for automation solution providers like Emerson. More technology will be needed to reduce the impact of declines in production at legacy fields, which Mexico has depended on for the majority of their oil production. Greater visibility to the dynamic flow of oil in the reservoir coupled with real-time process control will help improve the recovery rate. As the market opens to new producers, new technology and investment will come to Mexico. This will help bring oil and gas to market sooner and more efficiently.

Larry Irving, Vice President Oil & Gas Solutions, Emerson Process Management

Manufacturing in Mexico has a 40% foreign component. This indicates in part that Mexico has not been able to deepen its own supply chain. This percentage is likely to be just as high or go even higher in the energy sector as reform is implemented, particularly in higher technology supplies. Over the next years, Mexico will require solid flow of foreign goods and services as well as investment in its own supply chain building, to aid in opening the energy sector. American companies are ideally positioned to take advantage of this important business opportunity.

Tony Payan, Director, Mexico Center at Rice University's Baker Institute

Mexico is the third-largest trading partner for the US, and ranks 53rd in the World Bank's Ease of Doing Business Index, which focuses on supply chain and logistics concerns. This year we expect to see the value of systems, including NAFTA information flow, in enabling movement across the borders. There will be a need to develop efficient bases for servicing the growing offshore market. Movement into and from these bases will require new, appropriate road infrastructure linked to the US. Reliable ocean movement of bulk goods from the US to Mexican ports will become attractive as volume increases.

John Vogt, Vice President, Global Logistics, Halliburton

With ongoing energy reform in Mexico, there is a wide number of supply chain opportunities – especially with the development of new fields, and the redevelopment of mature fields in the southern Gulf of Mexico. The ultra-deepwater Perdido Foldbelt is home to several recent major light crude discoveries that Mexico would like to exploit with the help of international experience. Opportunities are also upcoming in the gas fields of the shallow waters of the Bay of Campeche. Pemex is also continuing to increase its number of offshore drilling rigs and while many of the planned new wells will be developmental, there is also interest in vertical and sidetrack drilling.

Aimee Marsh, Executive Director, Energy Industries Council (EIC) North & Central America

The supply chain's ever-evolving landscape is currently undergoing continuous changes and creating new intricacies. Mexico's knowledge on manufacturing and export of large volumes of sophisticated goods, its positive outlook in terms of growth, and its openness to external investment–particularly with the structural reforms lining up–makes an imperative to maximize both its manufacturing presence and its increase in value through engineering and predictability services. Through our 17 manufacturing plants and our Center for Advanced Engineering (GEIQ) with a workforce of 1,700 engineers already operating in Mexico, we can provide innovative solutions to the Mexican market in the fields of aviation, energy and oil and gas. When we do projects for PEMEX for instance, we leverage the expertise of our engineers to get a preliminary analysis to successfully provide the best technology and through our capabilities in Industrial Internet we are able to provide predictability services which enhance the value of our solutions. The strategy for a successful supply chain must include several factors: be predictive, ask the right questions, have a great understanding of the needs and a true partnership between customers and providers. New manufacturing volume is indeed a felt need in Mexico, but manufacturing with a high value offering is a must if our country intends to increase its economic potential.

Gabriel Cerdio, Executive Director of Global Accounts, GE Mexico

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

Nina Rach

Colloquy

Scanning the drilling fluids market

The drilling fluids market is driven by increasing worldwide drilling activities, focused on deepwater. Onshore, operators are increasing their use of horizontal drilling in developing shale gas, CBM, and other unconventional resources. Nanotechnology is an emerging tool in fluid development.

Several drilling fluid market reports have been issued recently. They all review factors expected to drive (or restrain) the global and regional drilling fluids markets.

TechNavio released its "Global Drilling Fluids Market 2014-2018" in February. The report forecasts that the global market will grow at 8%/year. One of the key factors contributing to market growth, they say, is increasing natural gas exploration. A major challenge to market growth is the capital-intensive nature of drilling projects.

The Freedonia Group in Cleveland, Ohio, issued a report on oilfield chemicals in November, which analyzes the US$9.5 billion US oilfield chemical industry. "US demand for oilfield chemicals is forecast to increase 2.1% annually through 2017 to $10.5 billion," the report says. "Enhanced oil recovery (EOR) products and drilling fluid products will grow the fastest. Gains in value terms will be strong for commodity and specialty chemicals as well as gases, while demand for polymers will decline."

Dublin, Ireland-based, Transparency Market Research issued the "Drilling Fluids for Oil and Gas Market – Global Industry Analysis, Size Share, Growth, Trends and Forecast to 2018" report last July. It valued the global drilling fluid market at $7.20 billion in 2011 and expects it to reach $12.31 billion by 2018, growing 8% annually from 2012 to 2018.

Increasing drilling activities, coupled with a shift towards developing deepwater reserves, is expected to drive the global market for drilling fluids. The future is in nanotechnology, the authors say, which will be used to develop future drilling fluids.

Market players

Founded in 1940, M-I Swaco became part of Schlumberger in August 2010. It now has more than 13,000 employees and offices in more than 75 countries.

Schlumberger's Patrick Schorn, President, Operations and Integration, told an investor conference in December 2013 that the latest Spears survey listed M-I Swaco as the market leader for drilling fluids. Schorn also said the company foresees "growth in 2014, driven by exploration and appraisal drilling activity." The company expects the demand for service-intensive deepwater drilling to rise.

M-I Swaco's 4Q 2010 revenue increased 4%, reaching $1.18 billion.

Houston's Newpark Drilling Fluids provides drilling fluids, project engineering, and system design. Newpark opened new world headquarters and a state-of-the-art laboratory facility in Katy, Texas, last June. According to Newpark's presentation last month, the company had $1.042 billion in 2013 revenue, 89% attributed to its Fluid Systems business and 11% to Mats and integrated services. Most (68%) of its business is in the US, followed by Asia-Pacific (14%), and Latin America (10%).

Weatherford International has a relatively new COO, a new CFO, and a new VP of operations. It has said that it may divest drilling fluids later this year. Weatherford has identified four key areas (generating about $11 billion in revenue) as core competencies: formation evaluation, well construction, completion, and production. OE

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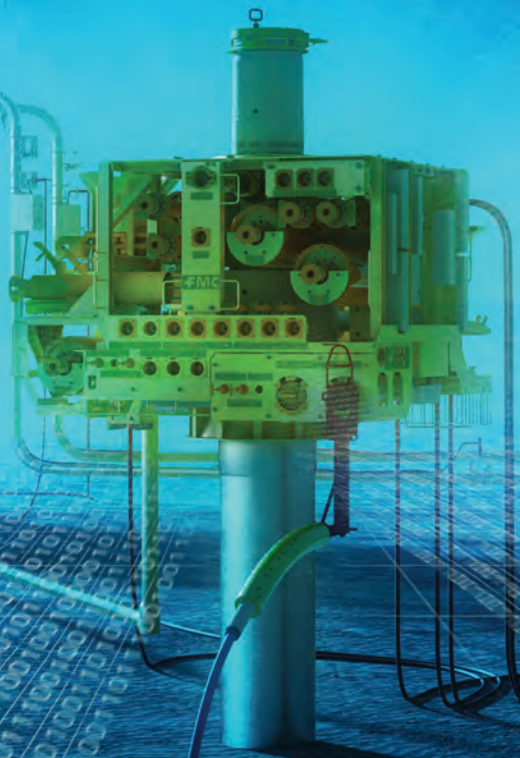

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ThoughtStream

David Price, CEO, International Well Control Forum (IWCF)

Post-Macondo, attitudes still need to change

Many positive changes have taken place in response to the International Oil and Gas Producers Association (OGP) recommendations for well control training, following the Macondo tragedy, but a culture shift in behavior and attitude is still needed.

The investigations found that, through the chain of events, processes where people could question, challenge or take action were not always followed.

New training standards to improve knowledge and competency are being introduced, but unless people involved in well operations feel empowered to act, they will never have the desired effect. This change in behavior needs to come from the top down and goes even further than empowerment.

We need to be demonstrating an expectation that those individuals will take the step to shut the well in if they deem it to be necessary–and they need to feel supported in their decision.

As an industry, we often put the cart before the horse with a culture of safety training, rather than teaching people how to do their jobs properly and safely, because the two go hand in hand. If we focus on the safety critical role of each individual in ensuring process safety as a whole, then perhaps we can achieve more.

We've still got some way to go for this to happen, but steps in the right direction are being made.

International Well Control Forum (IWCF) already had procedures for accrediting training through a global network of providers with candidates, assessed via independently invigilated, centrally generated examinations and a practical assessment program. However, overnight, Macondo placed a global spotlight on standards and hit home the need for more consistency in training.

We had already introduced audits for training providers, but post Macondo we took the step to increase the frequency and make them more robust.

We now have a system of four yearly audits, supplemented by spot checks when we've had a complaint or have a concern about a particular center. With 210 centers, we are carrying out one audit per week, using qualified auditors who we have trained internally to consider a number of factors including facilities, equipment, human resources, lesson observations, practical assessments, and management systems

If we focus on the safety critical role of each individual in ensuring process safety as a whole, then perhaps we can achieve more.

It is a significant undertaking for IWCF, as a not-for-profit organization, but we see the importance and in the future would like to be in a position to further increase the frequency.

Most centers have welcomed the audits. When needed, we will issue improvement notices and return to focus on areas of concern. We have in the most severe cases, removed accreditation from centers. It is only because we are fully independent that we can take that step. At the end of the day, the training being delivered should protect not just that person when they turn up to work but every one of their colleagues.

We witnessed a sharp spike in course take-up following Macondo and the scrutiny it brought has enabled us to make further changes that would never have been accepted before.

The syllabus was reviewed with new subjects introduced around assurance of well integrity throughout the lifecycle of the well, particularly around barrier management, casing and cementing and risk assessment, contingency management and implementation.

New levels to training programs are being introduced including a basic introduction course at level one that could even be taught in schools and universities and also a vocational competency qualification at level five for skilled engineers.

Ultimately, we want to move well training from a system where a candidate turns up on the day, sits a test and is handed a licence to a more continual style of learning.

What Macondo made the industry realize is that it's not just about having a piece of paper saying you can work. It's about the welfare of everyone on the installation; it's about big organizations being made bankrupt; it's about the environment and it's about whether governments will allow us to continue to drill.

***David Price** became CEO at IWCF in 2009 after a career of more than 30 years in the drilling industry.*

Price previously worked as a consultant, primarily teaching and advising on well control matters for organisations such as SedcoForex, Santa Fe, Shell and BG. He worked in Europe, Africa, the Middle East and Asia with a variety of organisations including operators, drilling contractors, training providers, universities and academic institutions.


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Global Briefs

A US rakes in $850 million for lease sale

The US Bureau of Ocean Energy Management (BOEM) received 380 bids for 326 blocks in the central Gulf of Mexico, totaling more than US $850 million. Gulf of Mexico Lease Sale 231 attracted operators to bid on almost 40 million acres. Arizona-based Freeport-McMoRan Oil & Gas was top bidder with 16 bids totaling $321.44 million. The company's highest bid went on Atwater Valley Block 198, which received the most bids of all blocks offered. Supermajor BP placed 24 bids totaling $41.6 million, following a recent agreement that was reached between the firm and the US Environment Protection Agency (EPA) to bid on deepwater leases after the 2010 *Deepwater Horizon* incident. Cobalt International Ltd. and Total E&P each placed 44 high bids totaling $26.6 million and $17.2 million, respectively.

B InterMoor completes decom job

InterMoor has completed decommissioning operations of the *Innovator* platform in Gomez field, Mississippi Canyon Block 711, Gulf of Mexico.

The scope of work, conducted in water depths of 910m, involved disconnecting 10 risers/umbilicals; disconnecting 12 mooring lines and then towing the *Innovator* to Ingleside, Texas.

InterMoor's involvement with the *Innovator* platform dates prior to 2006 when it was a mobile offshore drilling unit (MODU) known as the *Rowan Midland*.

C Johan Sverdrup concept chosen

Statoil and its partners on the giant Johan Sverdrup field have chosen a four-platform development concept, with power from shore. The field, containing 1.8-2.9billion boe, is one of the five largest discoveries on the Norwegian Continental Shelf. Located 1800-1900m below the seabed, it spans more than 200sq km and is expected to produce for more than 50 years.

Johan Sverdrup will be developed in phases. The first phase will comprise of a field center, export pipelines, power supply, and additional subsea installations, with a cost of NOK100-120 billion (US$16.5-19.5 billion).

The field center consists of four bridge-linked installations, a process, drilling, riser and living quarters platforms, will be on steel jackets in 120m water depth.

It is anticipated that 40-50 production and injection wells will be drilled to support Phase 1. First production is expected to start in late 2019.

D New Barents exploration area

For the first time in 20 years, Norway's government is looking to include a new area in the Barents Sea in its next exploration licensing round. Blocks in the Barents Sea southeast were included in consultation documents issued by Norway's Ministry for Petroleum on its 23rd licensing round.

The round proposal includes a total 61 blocks, with seven blocks in the Norwegian Sea, 34 blocks in the southeast Barents Sea, and 20 blocks in the rest of southern Barents Sea.

The Norwegian Petroleum Directorate has estimated recoverable resources for Barents Sea southeast between 55-565MMsq cu m oil equivalent. It says the potential for finding oil and gas is high. Gas is expected to account for 85% of the resources and oil for the remaining 15%.

To manage exploration in these new areas, the ministry said it would initially allocate a "limited number of key blocks," with the results from these areas informing decisions over what blocks to release in future licensing rounds.

E Prorefam's seventh round launched

Brazilian president Maria das Graças Silva Foster and Petrobras Director of Exploration and Production, José Formigli, launched the seventh and final round of the Fleet Renewal Plan for Offshore Support Vessels (Prorefam). The Brazilian national said it will issue calls for bids by 21 March.

Foster said that the company's priority is to increase its oil production, as outlined in the 2014-2018 Business and Management Plan. Proposals from the seventh round must be submitted by 27 June, and contracts must be executed by 30 October.

F Colombia raises offshore profile

Colombia's Vice Minister of Energy for the Ministry of Mines and Energy, Orlando Cabrales, appeared at IHS

CERAWeek in Houston in March to tout the country's new 2014 Round. Colombia's Agencia Nacional de Hidrocarburos (ANH) is offering 22 million hectares of acreage both on- and offshore.

Cabrales told press after his panel appearance at CERAWeek that the country is increasing investment into deepwater and ultra-deepwater. So far 20 offshore blocks have already been awarded in the Caribbean. The 2014 Round will offer 13 offshore blocks, 10 in the Caribbean and three in the Pacific.

G Eni enlarges field estimates

Eni has doubled its estimated size of the Nene Marine field offshore Congo after drilling the Nene Marine 3 exploration well, in the Marine XII block. Nene Marine 3 was drilled in 28m water depth and found a wet gas and light oil accumulation in the pre-salt clastic sequence, outlining a significant extension to the west of the reservoir and its hydraulic continuity, Eni said. During the production test in the oil interval, the well flowed more than 5000 b/d at 36° API gravity. Following the results of the well, Eni estimates that the Nene Marine field contains 1.2 billion bbl and 30 billion cu ft of natural gas in place, with upside. ENI says it is planning first production from the field in 2016.

H Ntem concessions

Murphy Oil started drilling the Bamboo-1 exploration well on the Ntem concessions, offshore Cameroon, early February, using the *Ocean Confidence* fifth-generation semisubmersible drilling rig. The well, about 56km off the coast, has an estimated target depth of 4200m true vertical depth subsea and will be drilled in 1600m water depth. Drilling is anticipated to take about 60-70 days. The Bamboo prospect is a basin floor fan target in the Upper Cretaceous play, with the primary objective estimated to have a mean un-risked, gross prospective resource of 422MMbbl and 170billion cu ft of gas.

I Ophir weighs FLNG option

UK-listed explorer Ophir Energy is considering floating LNG to develop its Equatorial Guinea gas fields and has signed a letter of intent with Petrofac to help it draw up a field development plan. Petrofac will provide services as operator of the proposed gas development up to the final investment decision, including preparing and issuing the field development plan.

Ophir has also held discussions with a number of floating LNG (FLNG) vessel providers for the project, in Block R, in the southeastern part of the Niger Delta complex, in 600m-1950m water depth. Total gross 2C gas resources discovered are estimated at about 2.6Tcf, with upside.

J McDermott conducts pipeline repair in UAE

McDermott International Inc. recently mobilized its dive support vessel (DSV) *Thebaud Sea* for an emergency pipeline repair offshore the United Arab Emirates. This is the third time in recent months that the DSV has been fast tracked to an emergency response.

K Russian giants form emergency response pact

Gazprom and LUKOIL signed a cooperation agreement on the prevention of and response to emergencies caused by oil and petroleum product spills offshore, including performing joint emergency exercises.

The companies agreed that in case of emergencies related to oil and/or petroleum product spills, they would provide mutual assistance in response to such emergencies, with the engagement of professional rescue services.

Gazprom and LUKOIL will

also conduct joint emergency drill in the locations of the *Prirazlomnaya* offshore ice-resistant platform and the Varandey oil export terminal before year's end.

L Noble Energy eyes Bohai exit

Noble Energy is in talks with potential bidders to offload its stake in an offshore field located in the Bohai Bay, China.

Australia's Roc Oil has been touted as the most likely buyer for Noble's Cheng Dao Xi (CDX) oil field, the Wall Street Journal reports. Roc Oil already owns shares in four offshore blocks in the Bohai Bay (Zhao Dong, Zhanghai, Chenghai and 09/05 fields).

M *Rubicon Vantage* risers repaired

Damaged risers on the Salamander Energy-operated *Rubicon Vantage* floating production, storage and offloading (FPSO) vessel have been repaired and production from the Bualuang field has restarted.

Bad weather had slowed work to replace riser sections, which were damaged when the FPSO came off station in a storm. Development drilling on the rest of the field was not impacted. Salamander is investing in the Bualuang oil field, in Block B8/38. In 2012, it installed a new production platform.

N KPOC wells underway off Sabah

ConocoPhillips has updated development plans for the Kebabangan project in the South China Sea, off the coast of Sabah, Malaysia. The consortium expects to complete phase one drilling of five wells by May. KPOC began drilling with the deepsea drillship *CHIKYU* in mid-2013, through a US$32 million contract with Petronnic Sdn. Bhd.

The Kebabangan gas field was discovered by Shell in 1994, and further delineated by an appraisal well drilled in 2002. The well penetrated gas columns in number of reservoir intervals. The field is estimated to contain about 2 Tcf of natural gas. The Kebabangan cluster asset comprises four non-associated gas fields.

O AWE to sidetrack Pateke well

Australia-based AWE Ltd will drill a sidetrack well in New Zealand after drilling issues encountered on the Pateke-4H were unable to be resolved.

The Pateke-4H development well sits in PMP 38158 in the Taranaki basin offshore New Zealand. AWE is the operator of the permit with a 57.5% stake, with New Zealand Oil & Gas and and Pan Pacific Petroleum holding 27.5% and 15% respectively. The well is targeting a mapped northern extension of the producing Pateke field. AWE said the well is being drilled in water depth of 124m, with a planned total depth of 5361. If successful, it will tied back to the Tui FPSO for production in 2015.

P Anadarko drills exploration well

Anadarko Petroleum Company started drilling the Caravel-1exploration well in the Canterbury basin offshore New Zealand mid-February.

Drilling is expected to take about 40 days, using the drillship *Noble Bob Douglas*. The expected total depth is 2800m subsea, in 1105m water depth. The joint venture partners on the license (PEP 38264) are: Anadarko New Zealand Company (Operator) 45%, Origin Energy, 45%, and Discover Exploration Canterbury, 10%.

Contract Briefs

Saipem to lay first South Stream pipe

Eni-subsidiary Saipem raked in contracts worth US$2.78 billion for the first of four offshore pipelines to be used for the South Stream pipeline. The system will run from Russia to Bulgaria across the Black Sea.

Saipem will generate the project documentation, build the first offshore line of the South Stream gas pipeline. The company will also erect process facilities in the shore crossing areas and construct the landfalls.

Pipes will be welded together on board a special pipelaying vessel and then laid in a proper position on the seabed at a depth of up to 2200m.

Cajun Express heads to Ivory Coast

CNR International (CNRI) secured a contract with Sedco Forex International for use of the semisubmersible Cajun Express rig for the next phase of development drilling at the Baobab field, located offshore the Côte d'Ivoire (Ivory Coast).

The fifth-generation deepwater drilling unit is expected to arrive on location later this year, or during early-2015, and will carry out a minimum six-well program at the Baobab field, with contractual options available to extend the campaign.

Seabed Geosolutions wins PETRONAS work

Fugro and CGG's joint venture business Seabed Geosolutions won a US$70 million contract for an ocean bottom cable contract for PETRONAS Carigali in Malaysia on the Temana and D18 fields.

The project will commence 1Q 2014, and is expected to take about six months to complete.

Three jackups for Fecon

Keppel FELS Limited (Keppel FELS) is to build three high-specification KFELS B Class jackup rigs worth about US$650 million for Fecon International Corp (Fecon). The three rigs are scheduled to be delivered progressively within 2H 2016.

Russian-backed Fecon is a new player in the offshore oil and gas industry, and is targeting the growing offshore drilling markets of Africa, Middle East, and Southeast Asia.

Petrobras picks Helix

Houston-based Helix Energy Solutions is to provide Petrobras with well intervention services for a minimum four years, using two new-build vessels.

The two new monohull vessels will be built at the Flensburger shipyard in Germany for Norway's Siem Offshore, at a total cost of about US$420 million.

Helix will charter the two vessels from Siem Offshore for an initial seven years, with options to extend this to a total 22 years. The first vessel is expected to be in-service for Petrobras mid-2016. The second vessel will follow later that same year.

Technip tapped for Åsgard

Statoil is to use Technip for intervention services on its Åsgard subsea compression project in the Norwegian Sea. The contract is a call-off of options under the Technip's Åsgard Subsea Compression Marine Operations contract with Statoil.

It will cover the use of construction vessel North Sea Giant for other inspection, maintenance, and repair projects, and construction work, whether for the Åsgard field or for other licenses in Statoil's portfolio on the Norwegian continental shelf.

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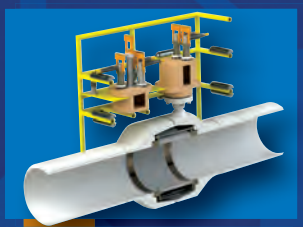

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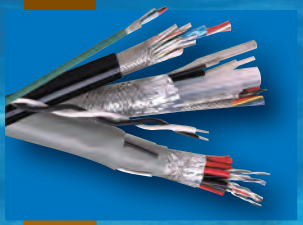

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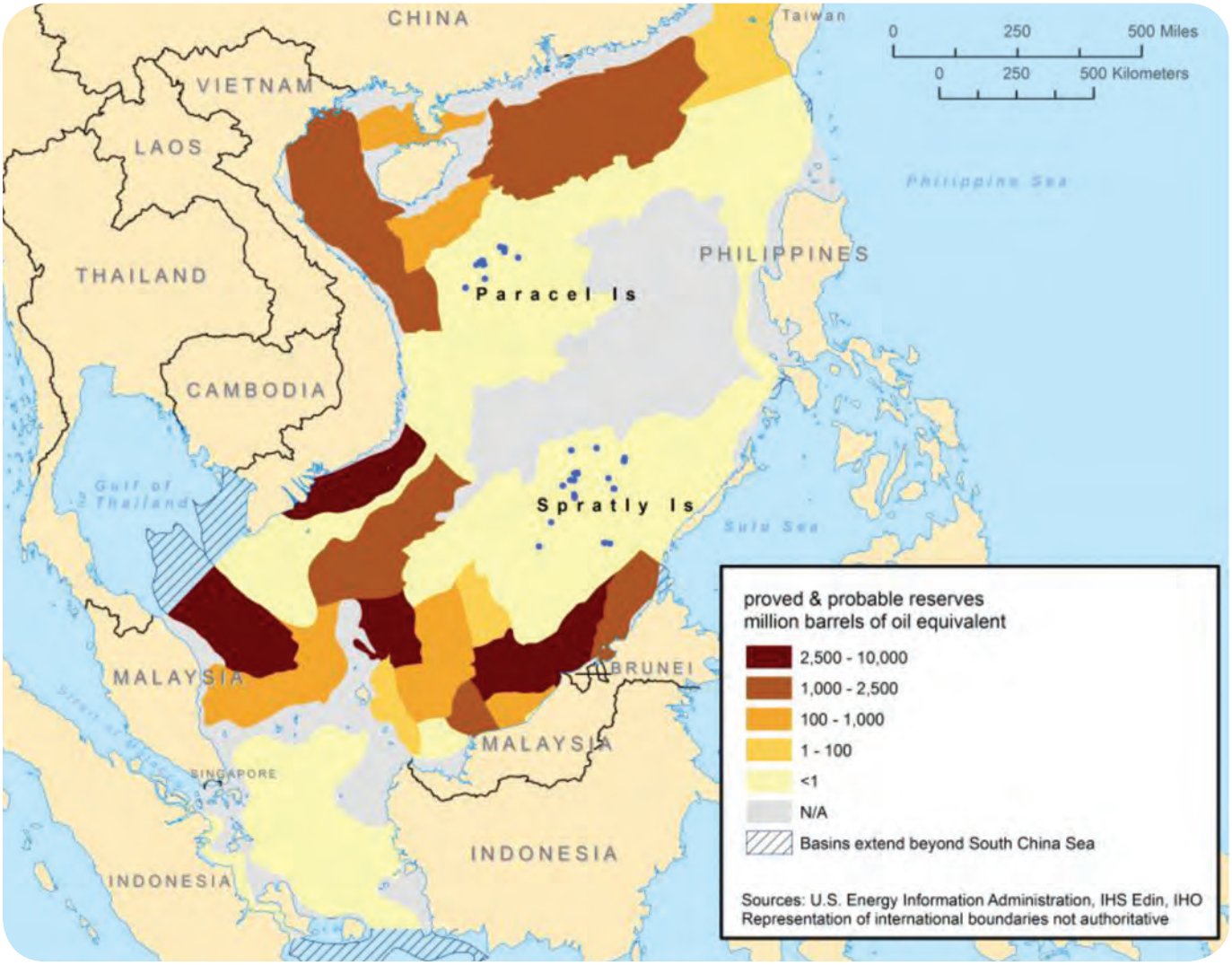

Fig. 1: South China Sea oil and natural gas proved and probable reserves. Image: EIA.

Sea of trade

"The South China Sea is not the new Persian Gulf. It should just be thought of as an important part of the supply picture of this region," Alexander Metelitsa, an economist at the US Energy Information Administration (EIA), told delegates at IP Week in London. Meg Chesshyre listened in.

"The South China Sea has a lot of problems, a lot of difficulties with production, at the same time there is not actually all that much there in terms of meeting the Asian demand," says EIA economist Alexander Metelitsa. The EIA estimates that there are about 11 billion bbl of oil and 190 Tcf of natural gas in proven and probable reserves. The oil is similar to the amount of oil in Mexico and the gas amounts to two-thirds of reserves in Europe, not including Russia (Fig. 2).

People also tend to think of the South China Sea in terms of territorial disputes, but this is not really a good way to look at the broad energy supplies in the region. "When you look at the map (Fig. 1), you see that the majority of proved and probable reserves are not in the contested regions of the Paracel Islands and the Spratly Islands, but, rather, close to the coasts of the coastal countries far away from the disputed areas.

"You might ask, but what about undiscovered resources? What about these massive gas and energy resources hidden in the disputed islands? Again, based on the best geological investigation from the US Geological Survey, we estimate there is not all that much potential for resources in these areas. We are talking reserves of maybe 100 Bcf of natural gas in the Spratly Islands, enough to power Hong Kong for a few days, and virtually no oil and gas reserves in the Paracel Islands. In terms of undiscovered resources, we are talking maybe a few billion barrels of oil, maybe, maybe not, and maybe 100 Tcf of natural

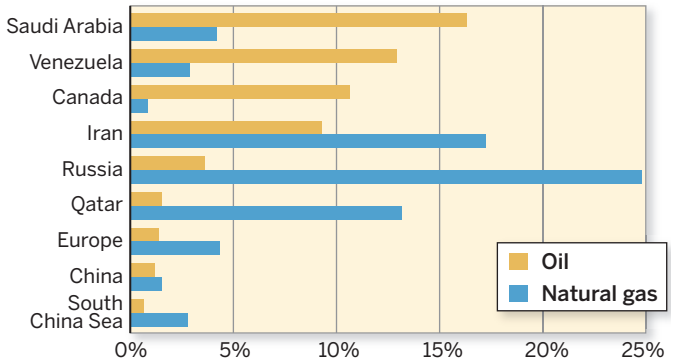

Fig. 2: Share of world proved oil and gas reserves for select regions (2012). Image: EIA.

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	2011	2012	2013	2014
Shallow (<500m)	104	75	66	4
Deep (500-1500m)	25	24	16	2
Ultradeep (>1500m)	19	37	30	–
Total	**148**	**136**	**112**	**6**
Start of 2014 date comparison	151	135	98	–
	-3	1	14	6

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 2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	16	738.25	1,060.00
Deep	16	2,615.00	2,515.00
Ultradeep	45	13,239.75	18,090.00
United States			
Shallow	22	109.40	342.00
Deep	24	1,608.11	2,104.57
Ultradeep	33	4,825.50	4,690.00
West Africa			
Shallow	170	4,604.02	22,577.83
Deep	51	5,956.50	7,240.00
Ultradeep	16	1,785.00	3,160.00
Total (last month)	**393** (405)	**35,481.53** (35,928.19)	**61,779.40** (62,432.70)

Greenfield reserves

2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow (last month)	1,340 (1,377)	54,309.42 (55,202.67)	842,988.86 (848,802.42)
Deep (last month)	177 (185)	13,837.48 (14,342.48)	108,639.77 (114,756.27)
Ultradeep (last month)	116 (121)	20,424.75 (20,696.75)	62,207.00 (88,847.00)
Total	**1,633**	**88,571.65**	**1,013,835.63**

Pipelines

(operational and 2014 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	42,127	(42,258)
Planned/ possible	24,573	(24,420)
	66,700	(66,678)
8-16in.		
Operational/ installed	78,734	(78,858)
Planned/ possible	48,876	(48,254)
	127,610	(127,112)
>16in.		
Operational/ installed	90,075	(90,244)
Planned/ possible	45,771	(47,202
	135,846	(137,446)

Production systems worldwide

(operational and 2014 onwards)

Floaters		(last month)
Operational	276	(276)
Under development	45	(42)
Planned/possible	332	(332)
	653	(650)
Fixed platforms		
Operational	9,569	(9,634)
Under development	99	(117)
Planned/possible	1,378	(1,390)
	11,046	(11,141)
Subsea wells		
Operational	4,503	(4,474)
Under development	408	(380)
Planned/possible	6,316	(6,256)
	11,227	(11,110)

Global offshore reserves (mmboe) onstream by water depth

	2012	2013	2014	2015	2016	2017	2018
Shallow (last month)	5,912.91 (5,923.14)	23,595.12 (24,157.76)	48,782.97 (46,925.48)	39,438.17 (42,481.43)	34,661.72 (34,117.77)	50,403.46 (50,672.58)	30,313.42 (31,326.78)
Deep (last month)	2,821.40 (2,821.40)	471.51 (471.51)	4,628.59 (4,729.17)	7,249.37 (7,218.27)	3,579.42 (4,816.80)	6,742.69 (8,311.26)	10,782.26 (9,490.50)
Ultradeep (last month)	737.15 (737.15)	2,937.44 (2,937.44)	2,826.43 (2,826.43)	2,173.17 (2,173.17)	5,255.06 (5,058.07)	14,436.64 (16,359.43)	6,701.05 (9,944.01)
Total	**9,471.46**	**27,004.07**	**56,237.99**	**48,860.71**	**43,496.20**	**71,582.79**	**47,796.73**

17 March 2014

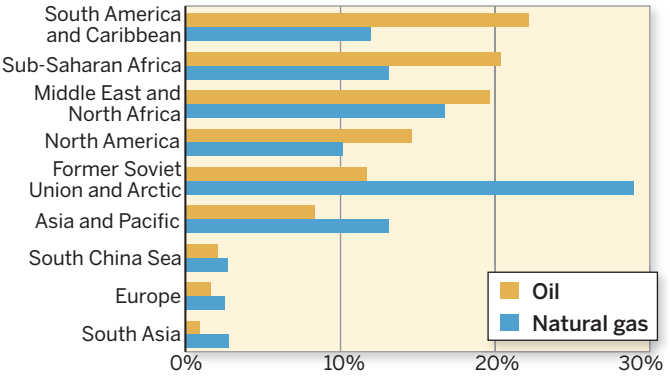

Fig. 3: Share of estimated world undiscovered conventional oil and gas resources (2012). Image: EIA.

gas, maybe not (Fig. 3)."

There might also be the potential for unconventional natural gas, for instance, natural gas hydrates in the Paracel Islands and in other parts of the South China Sea. China, and to a greater extent Japan, are investing a lot of time and energy in bringing these unconventional resources to market, but the technical problems are extremely large. The EIA does not see this area as being a significant source of natural gas hydrates production, but continues to expect the South China Sea to be a conventional oil, but mostly natural gas, producing region for the foreseeable future.

The established oil producers in the area–Indonesia, Malaysia, Brunei–are seeing a lot of declining fields, and are investing more to keep these fields going. The investment is not meant to expand production, but is meant as a rearguard action. The South China Sea supplies are being used to fill in the gaps in their own rising demand, and it will not be enough. They are going to have to complement those supplies with trade of other kinds.

Rough seas

South China Sea exploration is particularly difficult because of the sea itself. It is a tough place to do business. There are submarine valleys, strong currents, a high pressure environment, and typhoons. The producers are, however, are getting better at dealing with some of these issues. Production was only down for a few weeks after the devastating typhoon Haiyan in the Philippines last November. Storms that have hit the Gulf of Thailand have only knocked out production for weeks at a time.

Cooperation, rather than competition, helped. The majority of production takes place in the Gulf of Thailand area, the Malaysia area, and, to a somewhat lesser degree, in the Pearl River Basin, in China. The countries that have actually looked past their territorial disputes, or settled them, have had the most production success. Brunei and Malaysia settled their territorial disputes in 2009, and entered production sharing agreements. Despite not having settled their dispute, Thailand and Malaysia have agreed to work together in a joint development area.

There are a variety of different ways that companies and countries approach drilling in the area. These range from service agreements in the Philippines–where foreign companies come in and take on the risk of drilling themselves– to investing in offshore assets globally, to build up technical expertise, which China has been doing.

"We call this the 'sea turtle' strategy," says Metelitsa, where China National Offshore Oil Corporation (CNOOC)

and other companies are going out and investing, not so much to keep market share in these other areas, but really to have the technical knowhow, the technical expertise, to come back and build up their own market share, particularly in the South China Sea region. So we are seeing the most technically advanced production being done by China, especially with deepwater natural gas drilling in the eastern part of the South China Sea."

Energy choke point

If the South China Sea isn't that important in terms of its production, Metelitsa says, its "true importance lies in its trade, particularly in the Strait of Malacca. The EIA calls the strait one of the world's energy choke points."

It is a critical energy trade route, the shortest route between Africa and the Middle East suppliers to Asia. It sees about 15MMbo/d passing through it, while the most important energy route, the Strait of Hormuz, sees about 17MMbo/d. The Strait of Malacca is very comparable, with extremely large amounts of oil feeding Hong Kong, Japan, and Korea and some other countries (Fig. 4).

"What we don't see on these trade routes are large slots of intra- south China Sea trading," Metelitsa says. It is really the external trade coming in through the Strait of Malacca, and to some degree through the Sunda and Lombok Straits as well. It is a similar picture for LNG trade, which is increasing (Fig. 5). "Here we see about half of the world's LNG trade coming through the Strait of Malacca and the South China Sea region as whole, totaling about 6 Tcf of natural gas a year, and that figure is rising, with most of it going on to Japan, the biggest consumer in the area, with other parts going to South Korea and China as well"

In terms of security of supply, some countries are beginning to react to this sitiation, particularly China, which is financing a pipeline to Myanmar. This may have some impact in the medium term, but these are still marginal sources of production and marginal gas and oil amounts. For the time being, the Strait of Malacca and the South China Sea will continue to be a critical trade route.

"The oil and gas on top of the sea is more important than that under the sea," Metelitsa concludes. "This is a trade route area first and foremost... We are going to see that increasing both in terms of oil and in terms of LNG." OE

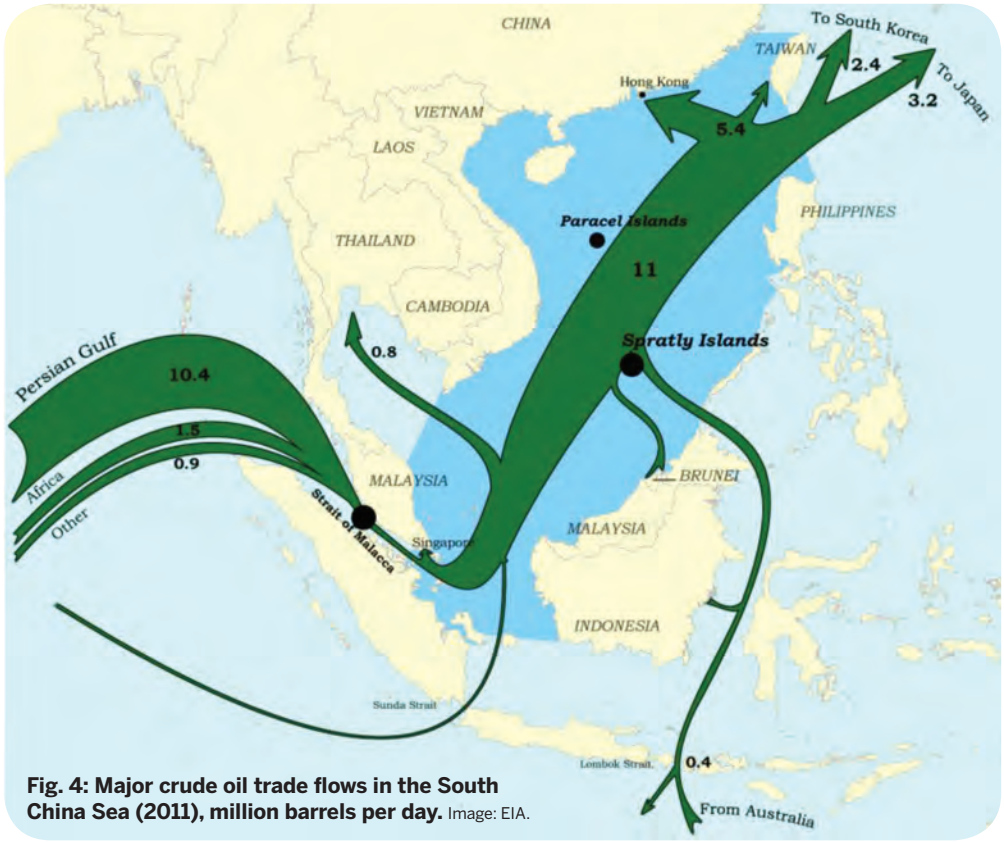

Fig. 4: Major crude oil trade flows in the South China Sea (2011), million barrels per day. Image: EIA.

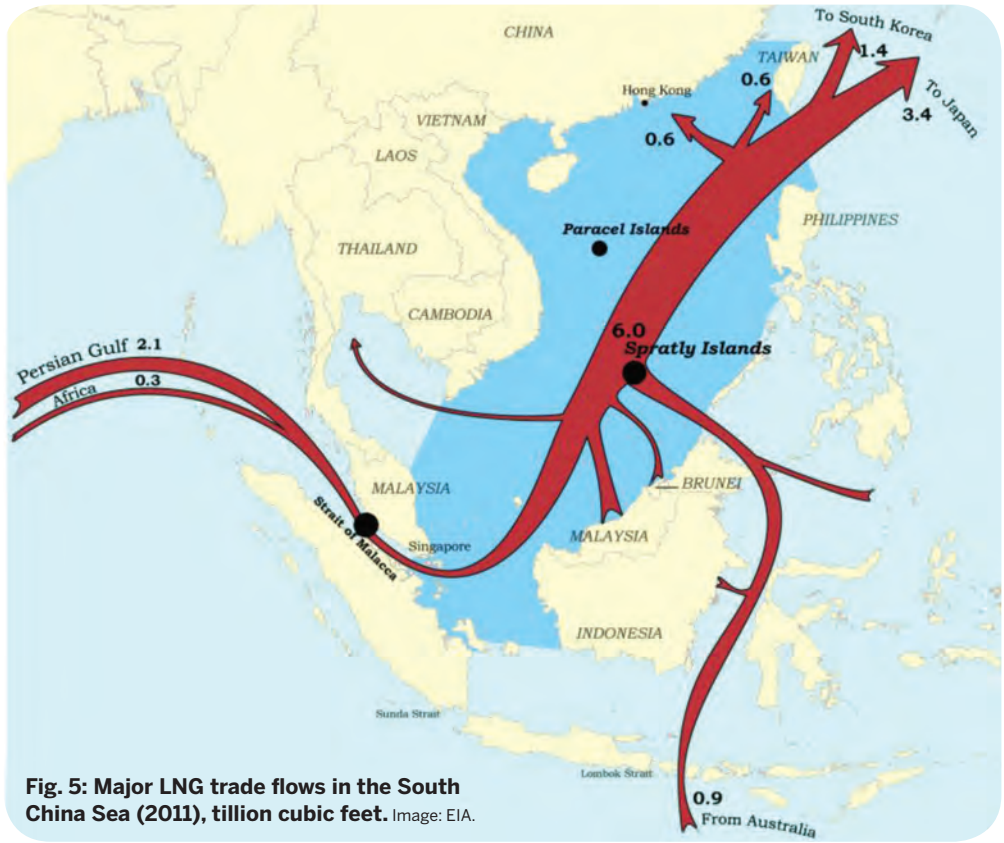

Fig. 5: Major LNG trade flows in the South China Sea (2011), tillion cubic feet. Image: EIA.

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A North Sea watershed

The Wood Review proposes a new regulator for the North Sea. Elaine Maslin looks at Sir Ian Wood's recommendations and why a regulator is necessary.

Nearly 50 years after the first major discoveries in the North Sea, the basin's UK industry is facing what representative body Oil & Gas UK has described as a watershed moment.

The industry is visibly buoyant. Aberdeen, the UK's operational center, is booming: North Sea investment hit its highest in three decades, at £14.4 billion (US$24 billion) in 2013, and recruitment is high.

However, recent events—the final Wood Review report and Oil & Gas UK's 2014 Activity Survey—have highlighted that all is not well.

2013 UK North Sea production was 1.43MMboe/d—the lowest it has been since 1977. Yet, in 1977, all the production came from just seven fields. Today, the same level of production comes from 346 fields, figures highlighted recently by James Edens, vice president and managing director of CNR International (UK).

The record-high spending is expected to halve by 2016-17, according to the Activity Survey. Operating costs have risen painfully more than expected, and will continue to do so, and exploration rates are woefully low.

The Wood Review was commissioned to assess the situation and propose solutions. It was commissioned by UK Energy Minister Edward Davey last year, after a sharp, three-year decline in production and exploration drilling on the UK Continental Shelf (UKCS).

The final report, Sir Ian Wood's "UKCS Maximising Recovery Review," includes recommendations to set up a new industry regulator. He says industry collaboration, regional hub developments, and increasing exploration will be keys to the basin's future success.

Sir Ian Wood

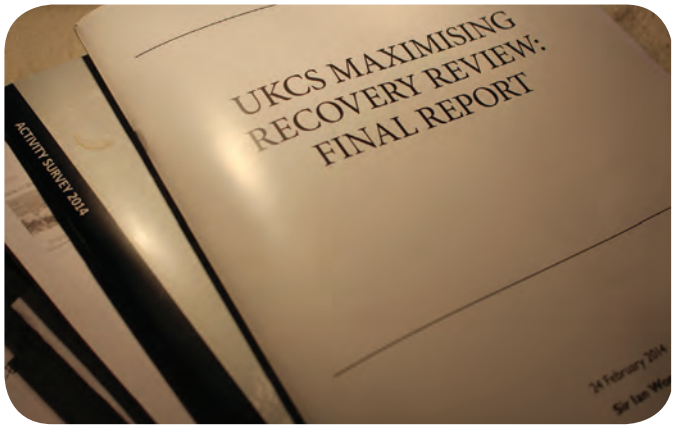
Launching the final recommendations from the review in Aberdeen in February, Sir Ian, founder and former chairman of engineering services group Wood Group, did not mince his words. He said the industry was "individualistic," and had seen too many "failures, disputes, and lost opportunities."

The backdrop – production falls, costs rise

Production in the UKCS has fallen 38% over the past three years. Exploration drilling fell to a record low in 2011, with just 14 exploration wells drilled, and it has yet to recover. In 2013, there were 15 wells drilled, discovering just 80MMboe. The fear is that, if exploration drilling does not increase, known and yet-to-find reserves will be lost, because infrastructure will no longer be in place.

Further, fields that are found now tend to be smaller, with more complex ownership, and the ability to agree on access to third party infrastructure notoriously difficult.

"The current rate of exploration drilling is totally inadequate to exploit the undiscovered potential of the UKCS within the lifespan of existing infrastructure," Sir Ian's final report warns. "To highlight the size of the challenge, based on exploration performance seen over the last 4-5 years, the review estimates that less than 3 billion boe will be discovered by 2030. Even increasing exploration drilling back to that seen prior to 2008 will only lead to an additional 1-1.5 billion boe being discovered by 2030. A step change in approach is needed."



Sir Ian Wood's "UKCS Maximising Recovery Review: Final Report"

The exploration challenge

Oil & Gas UK's Activity Survey, published days after

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	97	92	5	94%
Jackups	410	359	51	87%
Semisub	192	171	21	89%
Tenders	32	21	11	65%
Total	**731**	**643**	**88**	**87%**

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	23	22	1	95%
Jackups	92	80	12	86%
Semisub	30	27	3	90%
Tenders	N/A	N/A	N/A	N/A
Total	**145**	**129**	**16**	**88%**

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	15	13	2	86%
Jackups	115	98	17	85%
Semisub	36	31	5	86%
Tenders	24	15	9	62%
Total	**190**	**157**	**33**	**82%**

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	27	26	1	96%
Jackups	9	6	3	66%
Semisub	42	41	1	97%
Tenders	2	2	0	100%
Total	**80**	**75**	**5**	**93%**

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackups	46	44	2	95%
Semisub	46	45	1	97%
Tenders	N/A	N/A	N/A	N/A
Total	**93**	**90**	**3**	**96%**

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackups	103	88	15	85%
Semisub	3	3	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	**107**	**92**	**15**	**85%**

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	29	28	1	96%
Jackups	23	21	2	91%
Semisub	20	16	4	80%
Tenders	6	4	2	66%
Total	**78**	**69**	**9**	**88%**

Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackups	22	22	0	100%
Semisub	15	8	7	53%
Tenders	N/A	N/A	N/A	N/A
Total	**38**	**31**	**7**	**81%**

Source: InfieldRigs

19 March 2014

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

Malcolm Webb, chief executive, Oil & Gas UK

the Wood Review, echoed the review findings. It said exploration in the basin is facing its biggest challenge in 50 years, adding that capital spending is expected to decrease by 50% by 2016-17.

Oil & Gas UK chief executive Malcolm Webb said: "This year, 25 exploration wells are planned, which still stands far below the 44 drilled just six years ago, and, even if all the wells proceed, the rate of drilling is too low to recover even a fraction of the potential resources."

Overall, proven reserves on the UKCS fell from 7.1 billion boe in 2012, to 6.6 billion now, according to the survey. The problem is not limited to finding reserves. The survey found that while there is more than 10 billion boe currently in company plans, 4 billion boe of it has yet to secure investment.

Further, oil firms are struggling to keep a lid on costs, with operating costs reaching its highest annual costs, in real terms, in the life of the UKCS. In 2013, while production fell 8%, operating costs rose 15.5% to a record £8.9 billion ($14.8 billion)–or £17/boe ($28.4/boe) on average (compared to £13.5/$22.5/boe in 2012). The figure is expected to rise in 2014, to about £9.6 billion ($16 billion). The number of fields with operating costs greater than £30/boe ($50/boe) also doubled in the last year, according to the survey.

Work to date

The industry, with the government, has been trying to tackle the challenges. Oonagh Werngren, Oil & Gas UK's operations director, says initiatives are underway, through PILOT, the industry/government body, to increase exploration and recovery around existing assets, as well as helping to commercialize known but "parked" discoveries.

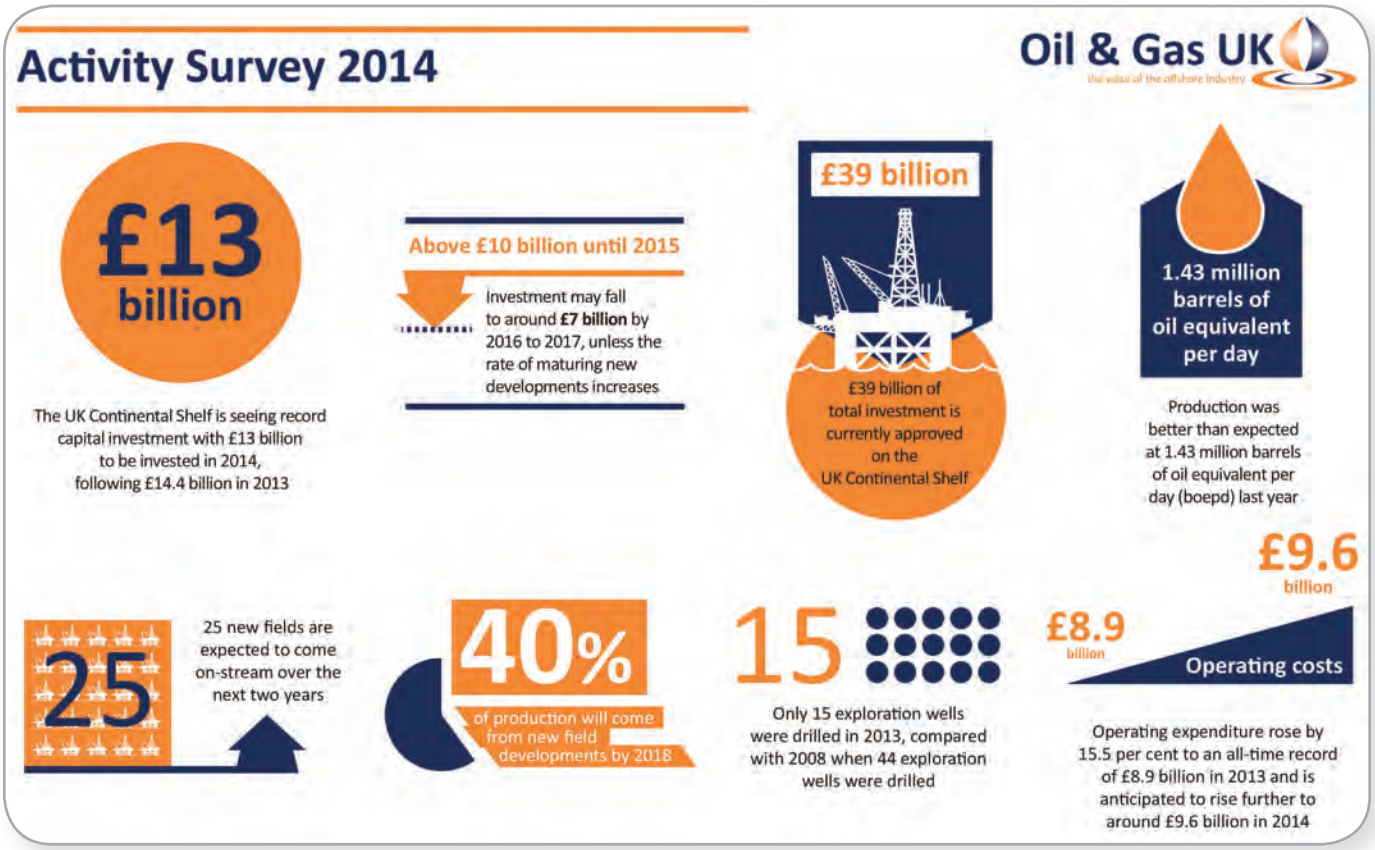
"There are 14 different projects the industry could get involved in and deliver significant returns from, but at $100 million a well, individual companies are unwilling to take the risk," she told the Oil & Gas UK breakfast briefing. "Volumes companies are mostly drilling for focus on 10-20MMboe. We need a new wave of investment in different and new plays to go elephant hunting (fields over 1 billion boe) again."

The Exploration Task Force (ETF) was recently created by PILOT to see how to boost exploration. The ETF has been looking at opening up new or neglected plays on the UKCS; improving use of seismic imaging, other new technologies, and data sharing; collaboration with other PILOT initiatives; and a comparative review, to see how the UK's regime compares with those in other countries around the North Sea.

But, it has been acknowledged that the Department of Energy and Climate Change, which oversees the licensing regime on the UKCS, has been under-resourced and therefore unable to cover as much ground as it might wish.

A new paradigm

Summarizing the report's main recommendations, Sir Ian said there should be a new shared strategy for maximizing recovery from the UKCS, with clear commitment from government, a new arms-length regulatory body, with additional powers to those under the existing regime, and a focus on greater collaboration in industry to enable regional, or cluster, hubs and field developments, and a reduction in delays and



The basin in 2014, according to Oil & Gas UK, based on its 2014 Activity Survey.

complexity. He emphasized that the new regulator's role would focus on stewardship, rather than regulation.

The review outlines six sector strategies, covering: exploration, asset stewardship, regional development, infrastructure, technology, and decommissioning.

Exploration

The largest section, and the biggest challenge, among these was how to increase exploration rates.

According to the review, more than 360 exploration wells have been drilled on the UKCS since 2000, leading to the discovery of 4.2 billion boe. However, post-2008, exploration activity has fallen sharply, reaching a low of 14 wells in 2011. Last year was not much better, with just 15 exploration wells reported.

According to the review, to boost exploration rates, access to geological information and the corresponding ability to evaluate new plays needs to be addressed. It suggests that "more high-quality seismic coverage of new plays could be a game changer."

This could be through better seismic, data sharing, and government support for underexplored or new plays. New plays identified by PILOT's ETF are listed as: West of Hebrides; Carboniferous, beneath the central North Sea, east Irish Sea, and southern North Sea; western Graben margin; fractured basement; sub-basalt and cretaceous sands; high CO2 gas; Triassic west of Shetland; English Channel and southwest approaches; Permian in the east Irish Sea.

The review recommends the new regulatory body should help facilitate industry and seismic companies to carry out speculative seismic data acquisition, particularly targeting new plays, which lack up-to-date seismic coverage, with financial support if necessary.

The review also proposes creating, within 18 months, a new online, up-to-date, digital resource containing information about the prospectively and geology of the UKCS.

It also says more should be done to enable timely sharing of well and seismic data, and that both the industry and government fail to make the best use of the British Geological Survey.

According to the review, industry also believes the current fiscal, or taxation, regime in the UK failed to provide sufficient incentive to explore, particularly in less prospective and more technically challenging areas, despite a recent string of tax allowances announced by the UK government's Treasury. Work is currently ongoing to add a high-pressure, high-temperature field allowance.

Broad support

The recommendations in Sir Ian's review have gained strong support from industry, via Oil & Gas UK. But, the body says, they will need support from the industry and government to be implemented and to return the basin to growth in investment, jobs, and production.

"This will not be achieved without much hard work and dedication to radical change and sustained improvement, which will be required of us all, in both the industry and government–and there is no time to lose," Malcolm Webb says. "We need to implement these changes without delay. The clock is ticking."

Speaking at a press briefing to launch the final "UKCS Maximising Recovery Review," Edward Davey said an implementation team to carry out the review's recommendations was already running. He hoped to appoint a chief executive for the new regulatory body by summer, with a shadow body to be formed by autumn this year. Legislation to form the new body would also be put to the UK Government's next session. OE

FURTHER READING

Read the full Wood Review report: www.woodreview.co.uk

Heading for **deepwater?**

Infield analyst Edward Richardson examines whether the newbuild rig market is heading for deeper waters.

History shows us that when oil prices are high operators seek to expedite the development of existing reserves and prove up additional resources. Demand for newbuild drilling assets therefore tracks price cycles very closely.

But what of the latest cycle? Since 2005, real oil prices have increased 124%. This has driven billions of dollars of investment into new offshore drilling assets. InfieldRigs data shows nearly 300 newbuild rigs (60% jackups, 21% drillships, and 19% semisubs) over the same period[1]. Current firm orders suggest that this growth will continue into 2015 but momentum may then begin to slow from 2016.

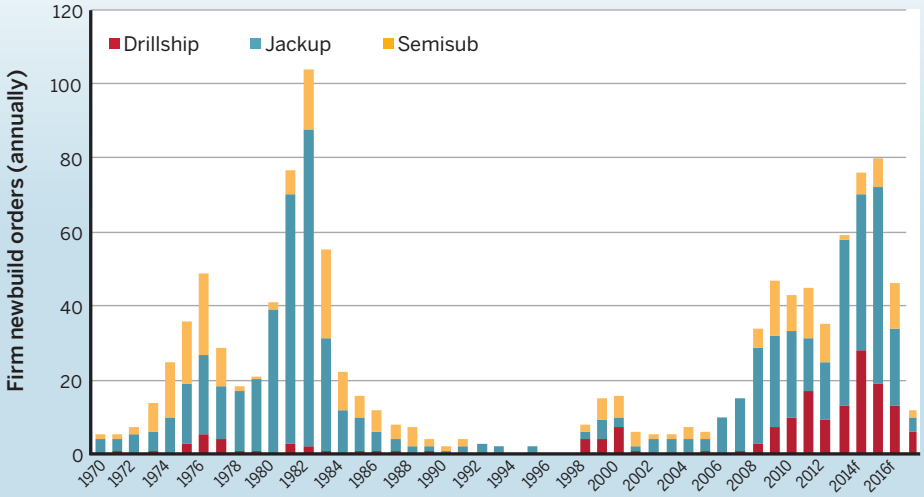
The exact pace of this slowdown remains difficult to determine, not least because firm contract visibility becomes very patchy beyond 2016. A jackup ordered in 4Q 2014, for example, could be operational in 1Q 2017 but would not yet appear in the data.

It also takes time for changing price signals to feed through into the newbuild market. If a rig manager was considering offering a contract today, it would need to raise the necessary capital, agree a final investment decision, and secure appropriate yard space. Delivery could then take anything between 18-36 months depending on the nature of the asset. Consequently, newbuild cycles tend to lag oil price signals by a year or two.

While the exact timing of the downturn is uncertain, it is clear that the newbuild market may well be approaching its zenith. There are three main reasons for this.

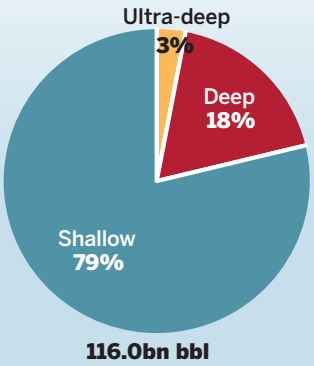
Firstly, demand and supply fundamentals suggest that oil prices may have passed their peak. Improving energy efficiency, particularly vehicle efficiency, the reduced use of crude for direct power generation, slowing emerging market economic growth, subsidy reform, and

Fig. 1: Offshore Rig Construction Cycles



Source: Infield Systems Limited

Fig. 2: Undeveloped Offshore
2000 vs 2013



growing oil substitution are all likely to precipitate a structural moderation in oil demand over the remainder of the decade. On the supply side, output is growing rapidly led by North America's unconventional revolution.

These two factors will boost global spare capacity over the long term. Indeed, BP estimates this could almost double to 6MMb/d by 2018[1]. That capacity should push down oil prices and help remove some of the geopolitical premium that has so occupied the market over recent years.

Secondly, a decade of high prices has already had a huge impact on global exploration and production activity. It has provided the impetus for the development of North America's unconventional resources (both tight oil and oil sands). Just as significantly, although perhaps not as newsworthy, volumes are also set to rise from conventional assets across key producers such as Saudi Arabia, Iraq, Angola and, perhaps in due course, Iran. Rig counts across the Middle East are at record levels (403) as of January 2014, while the count in Africa is now more than three times 2000 levels (139)[2]. It is only a matter of time before this huge investment in new

Located in the Gulf of Mexico in 4500ft of water, BP's *Mad Dog* platform can produce up to 80,000bod and 40 Mcf of natural gas per day. Photo from BP.

Oil Reserves (2P)

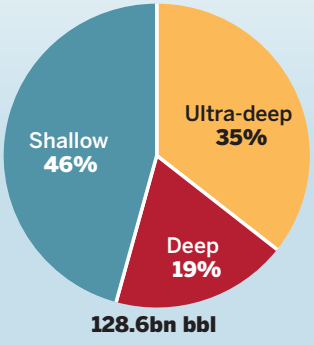
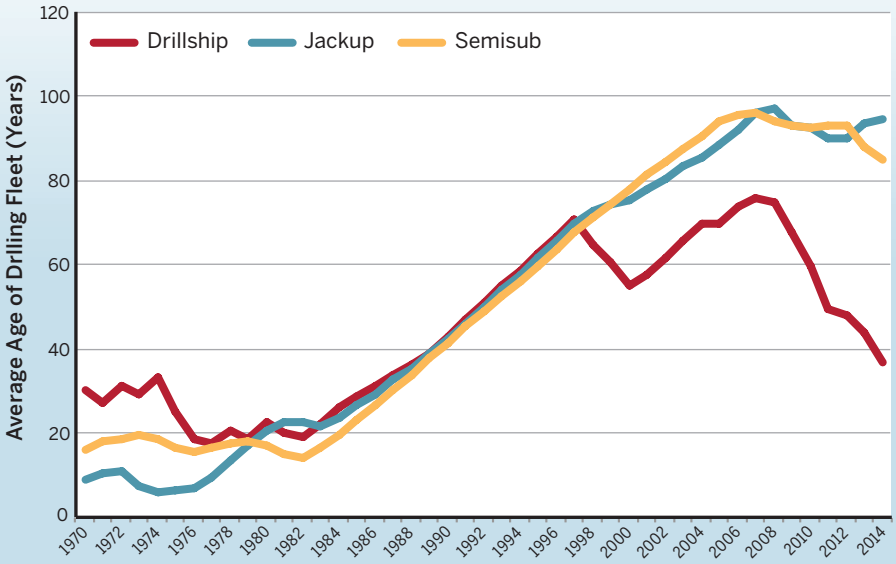


Fig. 3: Average Offshore Drilling Fleet Age by Asset Class



exploration and development drilling begins to bear fruit – and it should be a bumper crop.

In the offshore arena, rising prices have also driven a surge of exploration and production activity in deeper waters. In 2000, global undeveloped offshore oil reserves (2P) stood at 116 billion bbl, with just 21% of these resources in over 500m of water. By the end of 2013, undeveloped reserves had grown to 129 billion bbl, with 54% of that total now in deepwater and ultra-deep water (see fig. 2)[1].

In other words, a decade of high prices has already unlocked a vast array of new resources that will support the next generation of developments. The impetus for investing in new exploration may therefore be on the wane – particularly if the oil majors continue to prioritise 'value over volume' across their upstream portfolios. This transition is likely to be reflected in new rig orders.

The third key point is runaway inflation. Increasing competition for scarce resources and personnel has seen costs soar right across the oil and gas supply chain. The rig market has suffered its own share of cost escalation, particularly in relation to drilling packages. Indeed, these are now the primary cause of delays to new deliveries. With a more uncertain outlook in terms of rig demand and a rising cost base, rig managers may well begin to think twice before committing capital to new rig projects, particularly more speculative newbuilds.

Given this context, it is more than likely that newbuild orders will begin to decline from 2016. History says it will be a sharp decline. Rig deliveries fell from a 1982 peak of 104 to just 22 by 1984[2]. However, there are two main reasons which lead Infield Systems to believe that the anticipated downturn in newbuilds will not be so severe this time around.

Firstly, the average age of the global fleet has been falling since 2007 but still remains above 20 years[3]. This, in and of itself, is not a compelling argument because legacy assets can still be used on new exploration and development projects. However, demand is increasingly shifting towards higher-performing assets that meet stringent operational

Located off New Orleans in the Gulf of Mexico, BP's *Na Kika* sits in 6300ft of water. Photo from BP.

and safety requirements. Older units will find it increasingly difficult to meet these standards.

The natural churn of these old assets should provide continued opportunities for newbuilds over the long term. Jackups are likely to make up the lion's share of numbers simply because of the fleet's age profile. By contrast, drillship orders are likely to fall dramatically given that the fleet is now, on average, nine years old[4].

The outlook for semisubs is more complex. There is clearly scope for additional sixth and seventh generation newbuilds, not least because of a growing backlog of deepwater development drilling. In all, subsea tree completions[5] over the next five years (2014-2018) are expected to increase by a CAGR of 11.8%[6]. Moreover, new rules on asset capabilities in the US Gulf of Mexico[7] are likely to see increased demand for more modern semisubs in this key market.

While on the face of it these factors should provide strong impetus for new orders, the market has in fact been relatively subdued in recent years. This could be for two key reasons. Firstly, the increasing tendency of rig owners to upgrade existing assets ahead of commissioning newbuilds. Secondly, the recent proliferation of drillships may see these assets used on a greater range of development work despite their relative operational shortcomings[11]. These two factors may mean that semisub newbuild demand will remain relatively subdued despite a booming market for deepwater development drilling.

Leading indicators highlighted by InfieldRigs data therefore suggest that, after more than a decade of rising prices and a booming newbuild market, the wind may be about to change. Predicting the exact timing of that change is very difficult but Infield Systems expects that, from 2016, newbuild orders will slow.

There are, however, good reasons to believe that the downturn, when it comes, may not be as severe as that seen in the previous newbuild cycle. This is largely because the nature of the industry has profoundly changed. Activity has broken ground in deep waters and harsh environments. Moreover, stakeholders have new operational and safety requirements that legacy assets will increasingly struggle to meet. InfieldRigs data therefore shows that the newbuild market is heading into deepwater but it's unlikely to sink without a trace. **OE**

1 Source: Infield Systems Limited
2 BP, Global Energy Outlook to 2035 (February 2014)
3 Baker Hughes, International Rig Counts (January 2014)
4 Source: Infield Systems Limited
5 Source: Infield Systems Limited
6 Source: Infield Systems Limited
7 Source: Infield Systems Limited
8 This refers to subsea satellite well and template well completions
9 Source: Infield Systems Limited
10 Post Macondo rules limit the use of older 4th and 5th generation semisubs in the US Gulf of Mexico
11 Semisubmersibles are often preferred for development drilling because they can be moored rather than rely on more costly DP systems over the course of more lengthy development drilling campaigns.

Edward Richardson *is an analyst with Infield Systems' Business Strategy team. He graduated with a BA in History from St Catherine's College, Oxford, and completed a post-graduate diploma in law before joining the oil and gas team at research house, Business Monitor International (BMI). At BMI, Edward focused on oil industry analysis and forecasting with emphasis on North American energy markets. With Infield, Richardson has worked across a broad range of projects focused on the offshore market with particular emphasis on support service.*

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Drilling rig market set to change

Market drivers point to a slowdown in new project activity, Ian Simpson and James Graf of ABS report.

Changes in the drilling rig market are indicators of industry ups and downs. A look at today's numbers indicates that the most recent upswing is about to change direction.

There is fairly good agreement among the organizations that track drilling rig day rates and utilization numbers. Rigzone's RigLogix numbers provide a snapshot of the market, offering a good starting point from which to begin drilling rig sector analysis.

In February 2014, Rigzone reported drillship utilization at 86.7%, with 85 of 98 vessels working. Jackups were at 85% utilization, with 367 of 431 on contract. And the semisubmersible sector was even higher, with 89% of the units – 168 of 189 – on contract.

While day rates have fluctuated somewhat, they have remained relatively strong. Drillships capable of working in more than 4000ft water depth are averaging US$500,000/day, while high-spec semis are bringing in more than $400,000/day. Jackups vary broadly, of course, based on water depth and drilling capability, but over all, these units are averaging approximately $90,000/day.

At present, the Middle East has the most rigs working offshore, followed by the Asia-Pacific region and Europe. And while the distribution of working rigs is likely to remain more or less the same, the number of rigs working most likely will not.

The utilization numbers are high, but it is worth noting that they have all dropped slightly from January, when 91% of the drillships, 87% of the jackups, and 90% of the semis were on contract.

Because ABS classes jackups, semisubmersibles, and drillships, the organization follows activity in these sectors closely. Globally, 84% of jackups, 57% of semis, and 55% of drillships are ABS classed.

Jackups

The jackup market currently stands at around 530 units. There are 120 additional units contacted or under negotiation, not including options. About 470 units make up the operational fleet, but nearly 300 of these units are more than 30 years old. Some have passed middle age, with 45 years or more under their belts since originally being delivered.

Worldwide demand appears to be somewhere between 450 and 480 units. Not surprisingly, the preference is toward higher-spec units; so the demand for these units will continue to grow, with steady ordering at a somewhat lesser level than currently seen for the remainder of the decade.

Drilling contractors are well aware of the bifurcation of the market. Asset owners realize that to maintain a healthy balance between utilization and day rates, they will have to scrap or find alternative uses (other than drilling) for at least 200 of the aging units in the fleet as higher-spec newbuilds come in and displace older units.

Drillships

The drillship fleet has grown from less than 40 units in 2005 to more than 100 units at the beginning of 2014. The profile of the fleet is young, with approximately 75% of the vessels less than 15 years old. A further 76 or so units are on order, and steady ordering is expected for the remainder of the decade. A fleet of 200 units would appear to be sustainable with some removals from the older end of the fleet. Drillships will continue to be the asset of choice for extending industry frontiers – deeper targets in deeper water and further from logistic base support.

Semisubmersibles

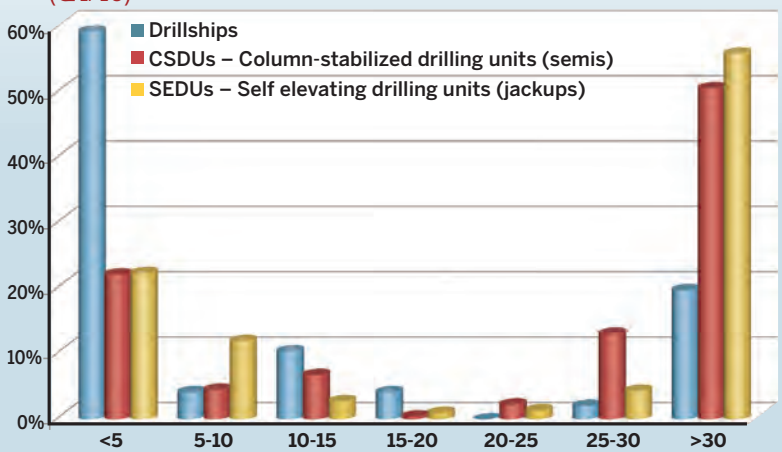
The semisubmersible fleet of around 240 units is one where 65% of the rigs are more than 20 years old. But unlike the drillship

ABS MODU outlook – Spring 2014

Mobile Drilling Units	2014	2015	2016	2017
Demand Growth	1.3%	1.1%	1.4%	2.3%
New Construction				
Orderbook Fleet %	19.2%	17.0%	16.4%	16.2%
Delivery Slippage1	12.7%	13.0%	10.7%	8.7%
Newbuilds Fleet %	7.0%	7.2%	6.4%	6.4%
New Orders Fleet %	5.2%	5.8%	6.2%	6.6%
Fleet Growth	4.0%	4.2%	3.0%	2.6%
Idle Rate	5.2%	5.0%	4.9%	4.9%
Removals Fleet %	0.4%	0.5%	0.8%	1.2%
1- Projected estimate				
Key:	High	Moderate		Low

MODU fleet age distribution by type of unit

(Q4/13)



and jackup sectors, the semi sector has not seen a sustained newbuilding program over the last 10 years. Today, there are only about 25 newbuilds under way, and the majority of those are being built specifically to work offshore Brazil and Norway.

There certainly still is a place for semisubmersibles, but the newbuilds will be constructed for focused mission type operations, where they can compete with drillships. Fleet replacement will happen, and the semi will reinvent itself to compete in a bifurcated floater market.

Forecast

Over all, the market appears to be taking a breather from the surge the past few years. There are 31 drillships and semisubmersibles slated to leave the yards by year-end, and nearly half are not contracted. Demand has begun to drop off, in part as a result of a number of international operating companies cutting back on their exploration programs.

Those watching the international market began to recognize toward the middle of 2013 that the market was beginning to soften. Rig supply is somewhat outpacing demand. And the large number of drilling rigs due to come out of the yard by the end of this year is compounding that problem. A slowdown in the market is shaping up, and with stagnant oil prices, it could last a few years.

ABS has framed its forecast based on macro industry demand drivers, and using a supply vs. demand approach to project future supply needs. Oil price and oil demand are closely correlated to offshore industry activity on a longer term trend basis, and consequently represent a primary base demand indicator used for longer-term activity projections.

Barring any major geopolitical event or natural disaster, oil prices should remain relatively flat for the next few years; in part dampened by weak oil demand growth, the growing shale oil contribution, and the growing demand for natural gas. Oil demand is projected to grow at only a modest 1-2% per year over the next four years. As a result of a series of factors – which includes dampened demand, stagnant oil prices, recent large inflow of new supply, large current orderbook, and a short term backlog in vendor equipment – new supply demand will likely be weaker for the next year or two.

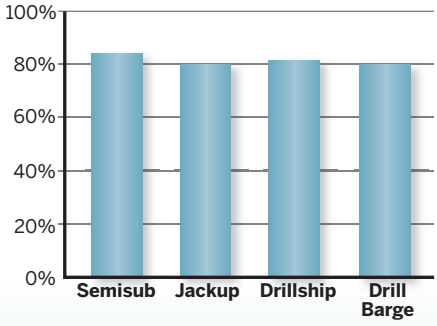
While the near-term market is less than rosy, the longer-term outlook is still strong. Regulatory and environmental requirements, technology-driven expansion to deeper water, and other short-term drivers will generate new orders to meet both new demand and to replace existing units.

Construction, Industry Outlook

New construction activity will remain high but will not reach the peaks witnessed over the past few years. The MODU orderbook is projected to decline for the next year or two as deliveries outpace new orders, leveling off at about the same level seen by the industry in mid-2011. High-specification jackups will make up the lion's share of exploration unit activity.

The correction in the market is likely to take a year or more, but the industry will emerge on the other side of the decline with a much more capable drilling fleet to meet the more demanding operating environments that operators are targeting. The upgraded fleet will be much better placed to meet their exploration needs. OE

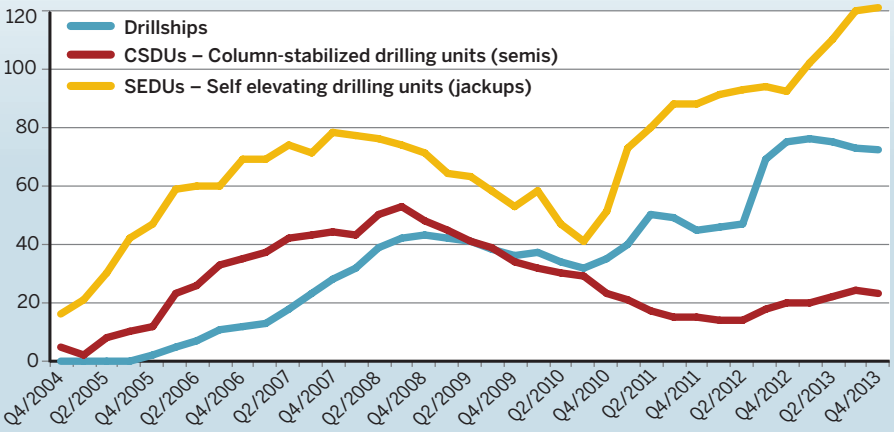
Current competitive offshore rig utilization by rig type March 2014



Drillships	80.6%	(79/98)
Jackups	79.8%	(343/430)
Semisubmersibles	84.1%	(159/189)

Source: RigLogix, www.Rigzone.com

MODU order book levels

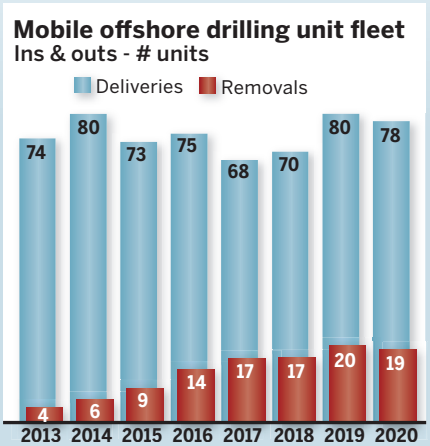


The rise in newbuilds in recent years is evident in this chart. The drillship fleet has grown from less than 40 units in 2005 to more than 100 units at the beginning of 2014.

Ian Simpson *is the Director of Offshore Technology and Business Development for ABS Americas. He is responsible for coordinating survey, engineering and R&D efforts to meet offshore industry clients needs. Ian has over 40 years of offshore experience covering marine and drilling operations, technical and regulatory support and new construction projects and existing unit maintenance and repair.*

James (Jim) Graf *is the Corporate Vice President of Business Planning and Analysis, where he has the responsibility for global ABS business planning and performance, and industry outlooks. Jim holds a BE in Naval Architecture from the State University of New York Maritime College. He is a member of the Society of Naval Architects & Marine Engineers (SNAME), Society of Marine Port Engineers (SMPE) and the Shipping Analysis Institute (SAI) in Stockholm.*

Deliveries/removals from the MODU fleet to 2020



Deepwater drilling markets – already coming to an end?

Deepwater drilling is no longer just about exploration. Lars Eirik Nicolaisen looks at market sentiment and potential reality.

Reporting season 1Q 2014 saw deepwater drillers' reporting numbers in-line with expectations, but still stock prices have plummeted.

The reason for this has not been poor operational performance or lack of ability to deliver revenue growth thus far. Based on the ever more bearish outlooks communicated by drilling company management teams, and their inability to fix new contracts for the next 12 months, drilling stocks have been punished hard by markets which now factor in the apparently softening market conditions and lowering revenue growth expectations.

What happened to the deepwater playground? Is the deepwater resource extraction already coming to an end after reaching 9% of overall oil supply in 2013 (125m+ water depth)? To understand the future of the deepwater drilling markets, we first turn to the customers, the oil companies, to understand their behavior during the past year.

Oil companies cut spending growth and allocate capital to shale

Given deepwater exploration and exploitation's technical challenges, there is only a handful of companies with the setup and competence base to carry out these operations. Only 18 companies globally are currently operating ultra-deepwater (7500m+) production. See figure 2.

Many of these companies have dividend policies and other capital discipline instruments to relate to, making their free cash flow a key performance indicator. As such, to maintain margins (which eventually drive free cash flow), in the event of an oil price drop, companies typically reduce their investments. That was the case during the 2008-2009 oil price shock, where we saw oil companies cut back their investment programs.

Although not as drastic as in 2008-2009, and not triggered by an oil price collapse, we are seeing similar behavior today; capex growth is reduced and immediate cash projects are prioritized. In a world where immediate cash has high priority, unconventional shale projects in North America have proven as attractive investment candidates.

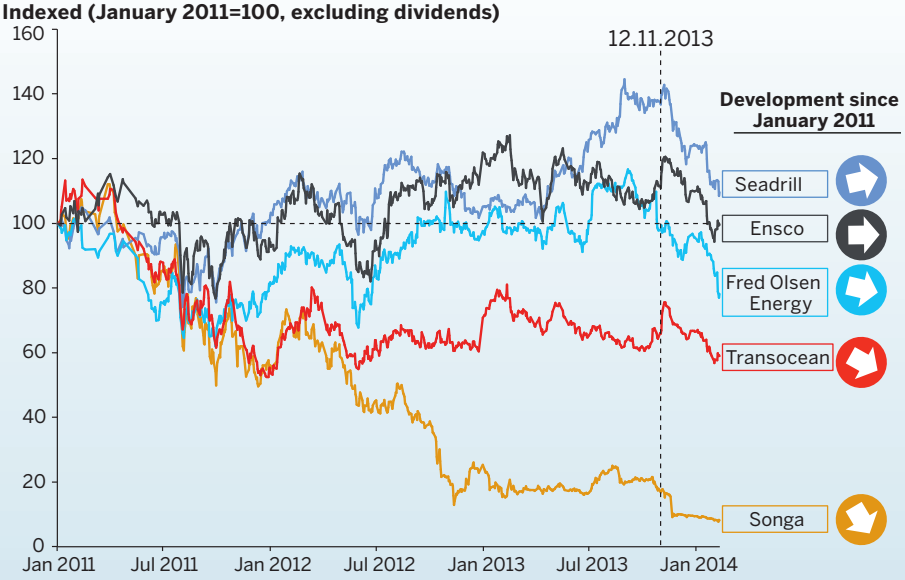
Marathon Oil and Talisman's current efforts to exit the North Sea, partly to focus and pursue more opportunities in the North American unconventional space, provides anecdotal evidence that the economic features of these plays speak to oil companies in the current economic environment.

Examples of companies disfavoring the deepwater space as an investment arena include BP's postponement of US Gulf of Mexico Mad Dog phase II and Chevron's postponement of its UK Rosebank project. Moreover, in the current environment, exploration efforts are typically one of the budget items at risk, given the long time to positive cash contributions.

The forecasted, lowered, exploration expenditure in Norway for 2014, (forecast by Statistics Norway to come down 12%) serves as anecdotal evidence of this. In such an environment, the scene is set for lowered market sentiments for deepwater drilling services in the short term.

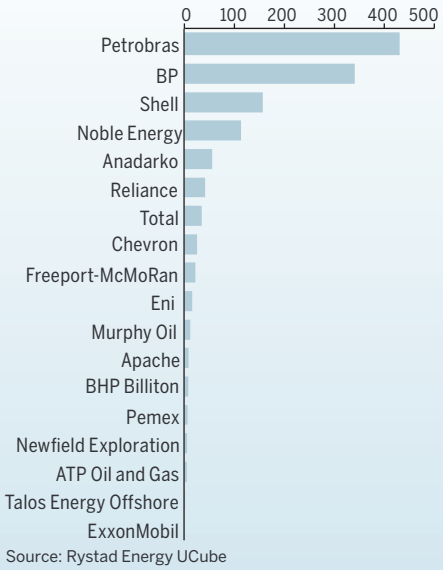
But are deepwater drilling markets already coming to an end? Our analysis suggests not. We highlight three drivers that point to continued growth in deepwater drilling markets.

Fig. 1: Share price performance selected oil service companies



Source: Rystad Energy research and analysis; Euroinvestor

Fig. 2: Ultra deepwater production



Source: Rystad Energy UCube

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1 – A robust deepwater inventory

During the past decade, about 40% of the global floating drilling fleet has been allocated to exploration efforts (Figure 4), an activity that has yielded results. The total material resource base in deep water currently amounts to about 230billion boe, of which almost 70% is not yet developed into production (Figure 5).

Among these barrels are high-quality discoveries, with breakeven prices competitive with alternative upstream investment opportunities. We are confident that these will play a key role in supplying the ever growing global demand for oil and gas. As such, the future of the deepwater rig market does not hinge on growth in future exploration levels, as we expect a turn to development drilling—a driver with far more predictable and robust features.

2 – Capacity needed for infill drilling

Once past the initial investment of an offshore development, infill drilling opportunities could offer significant economics and even satisfy oil companies' immediate cash flow generation requirements.

The rationale is simple; once the capex for installing export infrastructure (floating production units, subsea equipment, etc.) is spent, the economic benefit of keeping this infrastructure alive is added to the value analysis of an incremental well in that field.

This is especially the case for fields that were sanctioned, and developed (with respect to number of wells), based on oil prices lower than at present. Our analyses suggest that drilling targets containing as little as 1MMboe could provide healthy economics, based on current oil prices, and we believe this is a vastly underestimated activity by other analysts. Evidence of this includes the Troll oil field in the Norwegian sector of the North Sea, where Statoil and partners are stepping up drilling efforts, utilizing four semisubmersibles in parallel, for the foreseeable future.

Driver 3 – Capacity needed for other work

Drilling is the first and obvious activity that comes to mind when analyzing rig demand. However, rigs are full lifecycle workhorses, adding services during the entire lifetime of an oil and gas field. Fields call for activities such as well workovers and plugging and permanent abandonment of decommissioned production wells.

This part of the demand, often not recorded as drilling days, will constitute an increasingly important and inevitable part of the floater demand in tomorrows' markets. Comparing contracted floater capacity with recorded drilling days, in seven key offshore nations, enables us to visualize this trend (see Figure 5). As seen through the parameter drilling days per contract year, the fleet has ever less time available to do what we expect to be the main job–drilling. The maturation of deepwater basins will make sure this trend continues, and we will see, as we have seen for jackups, more of the capacity being allocated to non-drilling related activities.

Not an end, just a growth pause

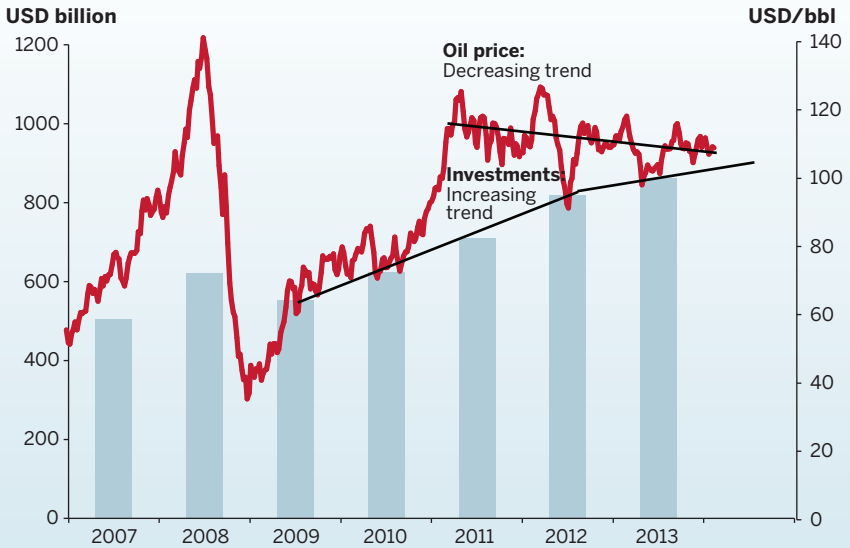
Coupling lowered upstream investment willingness with a rapidly increasing rig fleet has created the market sentiment in which we are in the midst of – a cooling down for the deepwater drilling markets.

However, with no abundant sources of easy oil available, deepwater production will play a key role in tomorrow's energy supply, and the project backlog is already proven. Our analysis does not find any basis for the deepwater drilling market growth coming to an end, but certainly sees the rationale for oil companies to lower short term investment growth.

Long-term, likely triggered by increased oil prices, we will see the demand once again outpacing supply, resulting in the need for added capacity. This scenario will play out before reaching the next decade, and as such – we cannot wait for too long before contracting more rigs. OE

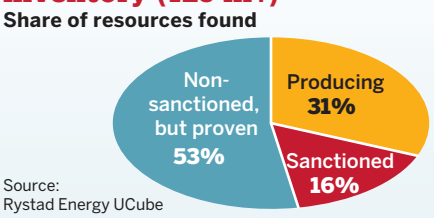
Lars Eirik Nicolaisen joined Rystad Energy in 2008. His experience includes rig supply and demand, well technologies and exploration performance analysis. Lars has managed Rystad Energy's RigCube development and he has been a core member of the team behind the NCS Business Development Atlas.

Fig. 3: Global E&P Investments* vs. Brent blend



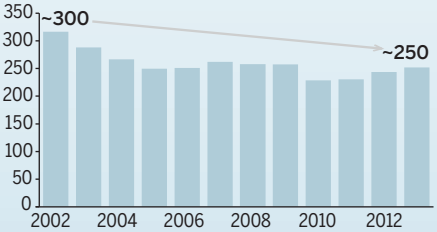
*Includes capital expenditure and exploration expenditure onshore and offshore
Source: Rystad Energy research and analysis, Rystad Energy DCube, EIA

Fig. 4: Current deepwater inventory (125 m+)



Source: Rystad Energy UCube

Fig. 5: Drilling days per contracted rig year



Source: Rystad Energy RigCube

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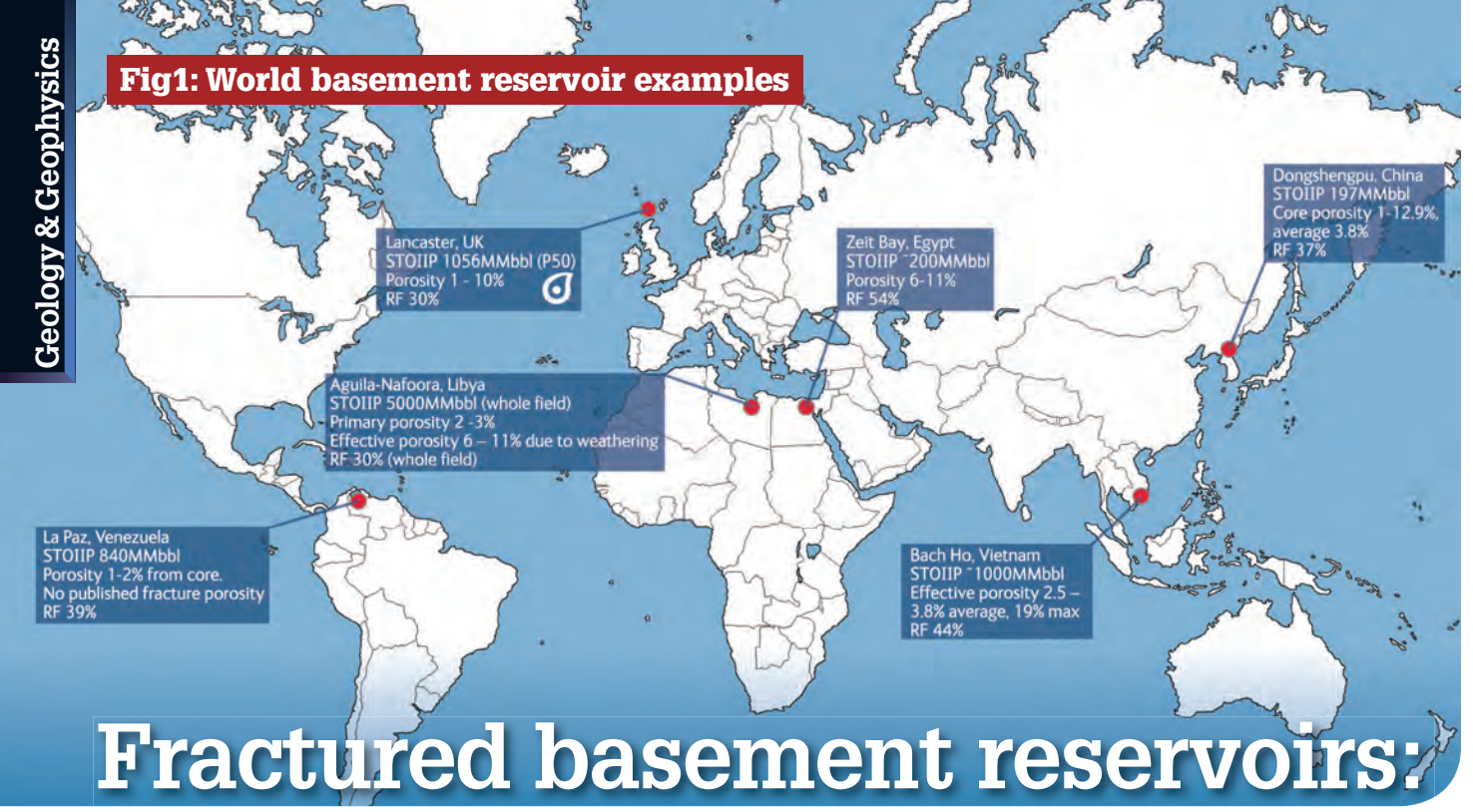

Fractured basement reservoirs: a new play for the UK

Are the UK's fractured basement reservoirs ripe for exploitation? Hurricane Energy's Robert Trice explains why he believes they are.

The potential of fractured basement reservoirs is often overlooked by explorers, yet there are numerous examples of basement fields having been discovered and produced over the decades from around the world (See Fig.1).

Furthermore, the volumes of hydrocarbons found within fractured basement can be significant and production rates can be high. In some countries, for example Vietnam and Yemen, the contribution from fractured basement reservoirs has had a transformational effect on the country's reserve creaming curve.

Basement potential in the UK

To date, basement on the UK Continental Shelf (UKCS) has largely been underexplored, despite the fact that numerous indications of hydrocarbons have been reported from basement in wells dating back to the 1970s. As production from the UKCS continues to decline, and with the exploration potential of the more traditional plays becoming increasingly mature, the potential from the overlooked and underrated basement play therefore warrants further exploration.

Over the past eight years Hurricane Energy

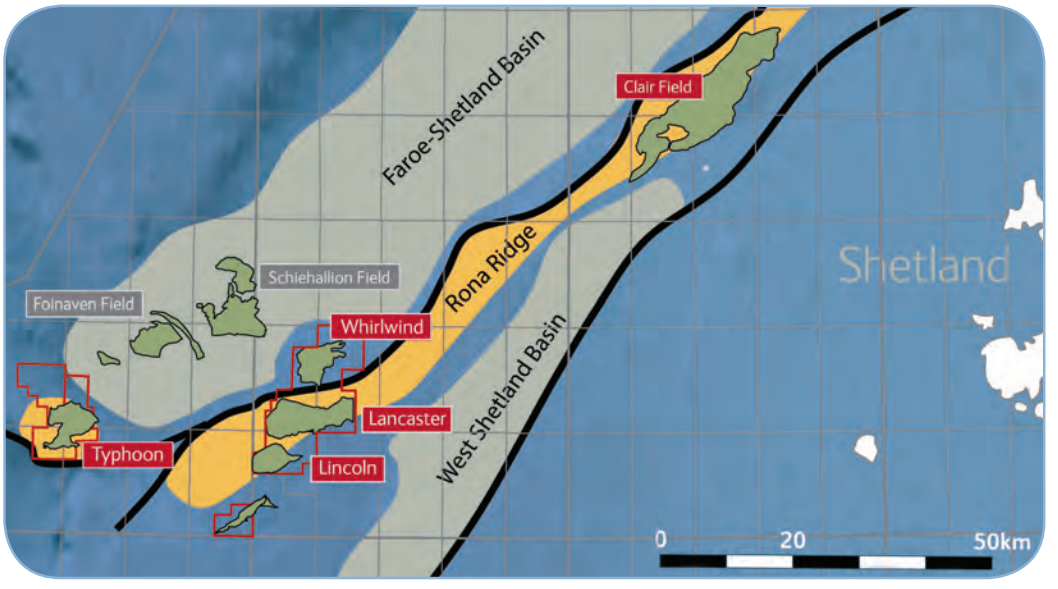

Fig2: Prospectivity associated with Pilot's proven fractured basement play along the Rona Ridge, West of Shetland, including the Clair field and Hurricane Energy's Lancaster and Whirlwind discoveries.
All images from Hurricane Energy plc.

has set out deliberately to explore this potential untapped resource, initially focusing on the West of Shetland area, where the extremely old (2.33 – 3.2 Ba) and fractured Lewisian basement forms extensive ridges and localized highs, which are the focal point for charge from the prolific Kimmeridge Clay source rock in the area.

However, other areas of the UKCS also offer basement potential, as now being promoted through the PILOT (an industry/government group) *New Plays Initiative*, as described in Sir Ian Wood's February 2014 UKCS report *Maximising Recovery Review* (See page 25).

To date there is still no formal assessment from the government, geological survey, or oil industry on the resource potential of the UKCS Fractured basement play, however, Hurricane has made significant progress in evaluating the basement play West of Shetland. A summary of that progress is provided below.

Progress in opening the UK's basement play

Data acquired by Hurricane Energy through the drilling and drill stem testing of over a kilometre 1km of basement encountered in three wells has provided an insight into the reservoir properties of the Rona Ridge fractured basement Play. (See Fig. 2).

Analysis of these data has allowed for the detection of productive fractures and characterization of fractured basement reservoir properties.

Fractured reservoirs require a different workflow to clastic reservoirs and basement is no exception. The workflow Hurricane has applied to exploring for hydrocarbon in basement West of Shetland is tried and tested, and has successfully generated 450MM boe of 2C resources. The approach used includes:

- Prospect generation through the integration of fieldwork, seismic and well data
- Successful well placement, targeting faults as defined on 3D seismic, with well prognosis of top basement and fault locations accurate to within meters
- Thorough review of offset well data and global analogues to establish optimum bottomhole assemblies, resulting in rate of penetrations (ROPs) in the basement of 5-7m/hr and the acquisition of quality logging while drilling (LWD) data sets
- Generation of confident static reservoir properties (e.g. fracture frequency, fracture orientation, and fracture porosity) from a combination of wireline and LWD data
- Establishing an understanding of effective fracture porosity, by comparing bulk porosity estimated through nuclear magnetic resonance and density neutron techniques, with discrete fracture porosity estimated from acoustic and electrical image logs.
- Identifying dynamic reservoir properties from gross flow zones, to flow rates estimated from single fractures, evaluated through image log and production

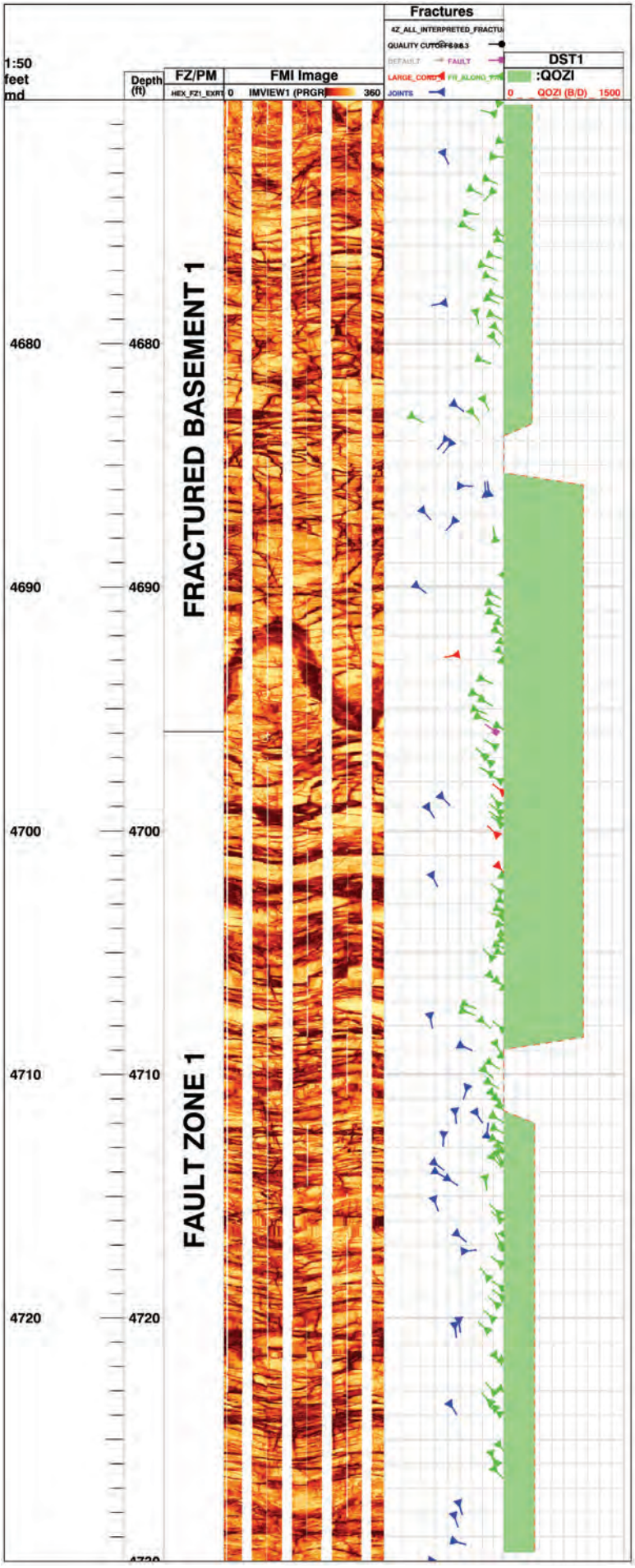

Fig3: Interval of borehole exhibiting preferential oil flow associated with a seismically mapped fault.

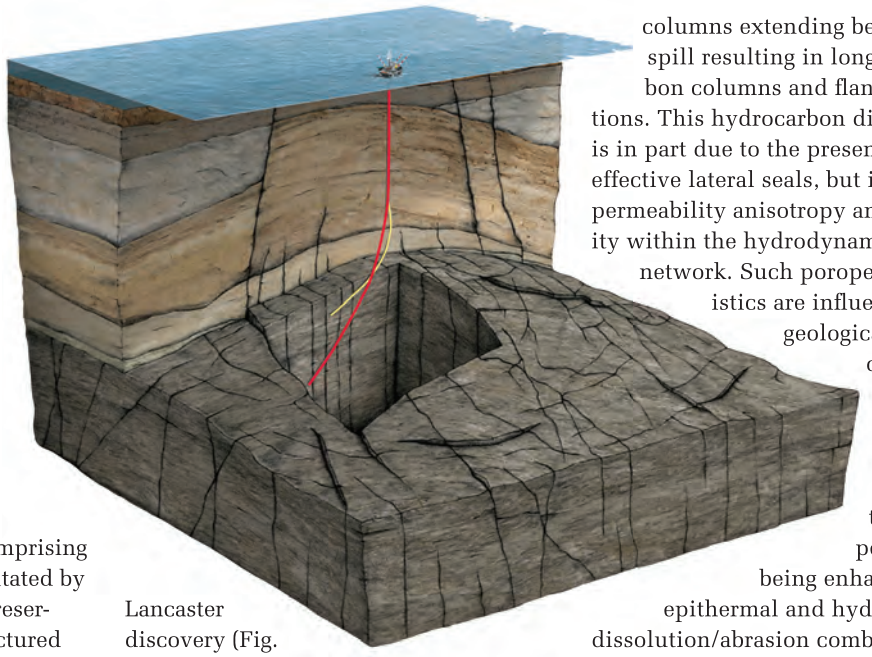

Fig4: Geological realization of the Lancaster discovery portraying well paths in relation to the seismically mapped fault network.

logging tool (PLT) integration. Fluid typing established through bottomhole samples procured under variable choke size and flow rates.

- Establishing reservoir behavior away from the borehole environment through transient pressure analysis modelling combined with Petrel, sector and discrete fracture network (DFN) models.

The analytical components comprising Hurricane's workflow are necessitated by the fact that fractured basement reservoirs are classified as Type 1 Fractured Reservoirs, in that the poroperm system is provided entirely by a natural fracture network. This means, gaining and developing an early understanding of the distribution and characteristics of the fracture network is essential. Specifically an understanding of the hydrodynamic fracture network is key for optimum well placement.

Consequently, wells are targeted to intersect faults which are identified from 3D seismic, the faults being considered important targets as their associated fault zones are considered to have enhanced reservoir properties. An example of this concept is seen in Fig. 3, which shows an interval of borehole that has been identified as a fault zone from 3D seismic an interpretation, corroborated by image log analysis and demonstrably preferentially productive as seen through PLT logging.

Hurricane has drilled two wells on the Lancaster discovery (Fig. 4), the data from which supports a 2C resource estimate of 207MM boe recoverable.Hurricane's next Lancaster appraisal well, scheduled for 2Q 2014, is designed to test the flow potential of the reservoir through the drilling and testing of a 1km-long horizontal basement section.

The well is targeted at evaluating the P90 oil volume that resides within structural closure (Fig. 5) by penetrating nine seismically mapped fault zones and undertaking a series of open hole tests, designed to evaluate flow rate, as well as reservoir response to shut in and build up. The 25-day testing program is planned to demonstrate a commercial flow rate, which, if achieved, will result in the well being suspended for use as a future producer.

The trapping of hydrocarbons within basement can include a significant stratigraphic element, with hydrocarbon columns extending below structural spill resulting in long hydrocarbon columns and flank accumulations. This hydrocarbon distribution is in part due to the presence of highly effective lateral seals, but is also due to permeability anisotropy and heterogeneity within the hydrodynamic fracture network. Such poroperm characteristics are influenced by long geological histories of subaerial exposure and tectonic activity, with fracture network permeability being enhanced through epithermal and hydrothermal dissolution/abrasion combined with tectonic reactivation of pre-existing joints and faults.

The Lancaster resource range so far identified is in part based on the potential of stratigraphically trapped oil identified through pressure surveys (modular dynamic tester) and gas returns measured as part of mud-logging acquisition. However further appraisal wells, including flank and deep penetrations, will be required to refine the stratigraphic upside and also the presence and characteristics of an aquifer.

If Hurricane's appraisal efforts confirm the anticipated oil-in-place and reservoir deliverability, the Lancaster field is expected to be produced via a phased development, utilizing an existing suspended well and the planned 2014 horizontal well in the first stage of development. Early oil from such a development is anticipated for 2018. OE

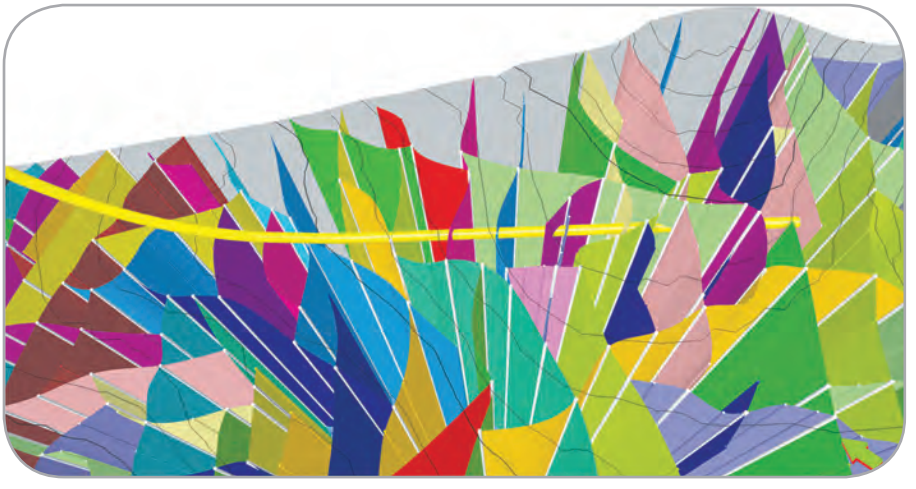

Fig. 5: Well path showing horizontal reservoir section and seismically mapped faults.

Robert Trice *is CEO and founder of Hurricane Energy. He has a PhD in Geology from Birkbeck College, University of London, and gained the bulk of his geoscience experience with Enterprise Oil and Shell. He has worked in field development, exploration, well-site operations and geological consultancy. Robert has held the position of Visiting Professor at Trondheim University (Norway) and has published and presented on subjects related to fractured reservoirs and exploration for stratigraphic traps.*

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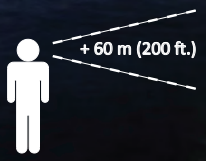

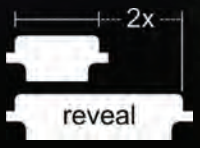

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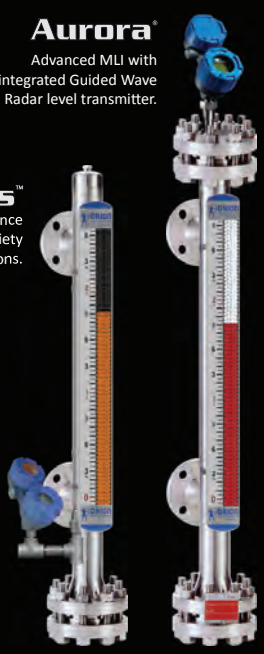

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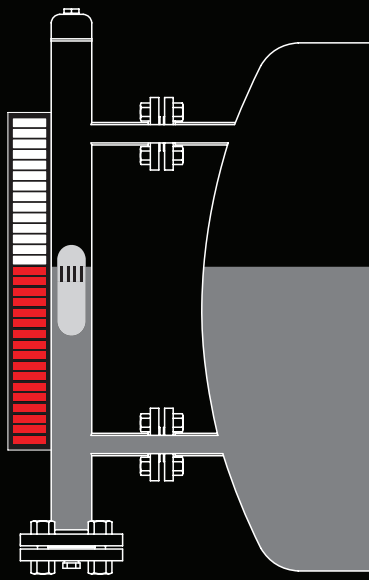

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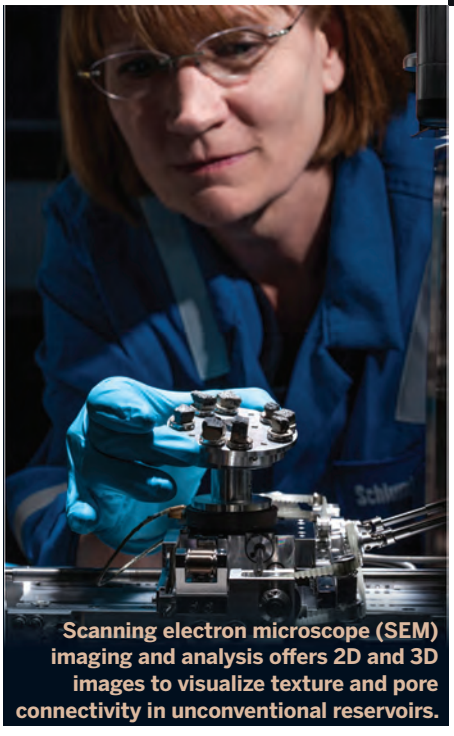
Schlumberger's CoreFlow services combine both physical and digital analysis to reduce lab time from months down to days, and even hours. Audrey Leon spoke with Schlumberger's Mark A. Andersen to find out more.

Rock analysis enters new era



Scanning electron microscope (SEM) imaging and analysis offers 2D and 3D images to visualize texture and pore connectivity in unconventional reservoirs.

Schlumberger introduced CoreFlow digital rock and fluid analytics services at its core analysis laboratory in northwest Houston in December 2013. The lab builds digital rock models for carbonates, sandstone and shale, and examines pores and grains at the micro- and nanometer levels, providing digital views of flow characteristics.

The lab is not meant to replace physical analysis, but to complement it, says Mark A. Andersen, Schlumberger Domain Head for Core Physics and Manager of the Digital Core Analysis group at the Schlumberger Reservoir Laboratory in Houston.

"By having both physical and digital analysis in the same building we have all the material to make the comparison and help the client get more complete answers," Andersen says.

The process

The whole-core method uses samples that are captured from the reservoir that are typically 4in in diameter and up to 3ft long. Schlumberger uses a helical whole-core dual-energy CT scanner to scan cross section slices of the rock sample until the whole core is captured. The images from these samples are then used to construct a slice-by-slice 3D movie.

"This is valuable, the ability to look at recovery of the rock without taking it out of the liner," Andersen says. "You can do CT imaging in the liner, leaving the rock untouched. Scanning gives us a sense of core recovery – what's the quality? If the rock is friable, it may not stand up well to mechanical shaking involved in transport. CT scanning allows us to determine if the core analysis can continue as planned. "

"The initial CT scan allows identification of different rock types," Andersen says.

"If you do one energy scan, you correlate to the bulk density of the sample. Addition of a second energy level provides information about the effective atomic number; from that we can back out chemical information that indicates mineralogy," he says.

Another component of the rock analysis is the heterogeneous rock analysis (HRA), which allows the system to type similar rock characteristics, and label them by color. This helps to obtain more information from limited sample quantity. "If I think the black-labeled sample type is important, HRA coding guides us in sample selection and also for physical analysis," Andersen says.

The next step is the microCT scan, another X-ray method. Here the typical sample size can be 8mm in diameter. The X-rays shine through the samples to get a backscatter image. Then the lab technicians

Schlumberger uses samples of various sizes for physical and digital core analysis.
Images: Schlumberger

will rotate the sample a 10th of a degree and take another image, eventually ending up with 3,600 backscatter images, which helps create a 360-degree view.

"What we do next is a mathematical inversion, computing tomography based on the backscatter images, and end up with a 3D image of the rock," Andersen says. The process gives a 3D volume with a resolution of 1-2 microns on a side. Andersen says this is important with conventional rocks such as sandstones and carbonates. Unconventional materials will need a higher resolution in the nanometer range.

SEM analysis

In order to get to that higher resolution, SEM (scanning electron microscopy) imaging must be conducted. SEM provides a higher level of magnification including 2D and 3D images. First, the sample surface is flattened using argon-ion mill and later imaged. The 2D images show features of the flat surface, but the 3D images can identify pore connectivity.

For 3D imaging, the ion beams are an integral part of the SEM machine, Andersen says. "You select a portion of the surface, take the image; mill it and take another image, and as you mill into the sample, you're getting a 3D volume," he says. This provides a representation that is 100 microns across, about the diameter of a human hair, Andersen says. This is needed to see the pore spaces in mudstones.

This type of image analysis can measure porosity and both organic and mineral content. The surface of the sample could be as large as 25mm by 15mm. "This is small but in SEM, this is a huge amount of real estate," Andersen says.

The higher resolution provides detailed information about the pores, which is important because their location and the shape help determine what is a good pay zone for the client, Andersen says.

DHD Simulator

What's different about Schlumberger's approach, Andersen says, is the DHD (direct hydrodynamic) simulator. This takes the volume representation of the rock and simulates flow, allowing engineers to see how fluid flows through the pores. "The simulator uses a model of the fluid, captures the physical and chemical features such as surface tension and viscosity," he says. "What's truly unique about our simulator is it utilizes realistic pore geometries and fluid characteristics."

"The DHD simulator allows us to do what no one else can do," Andersen says. "We can model behavior of the fluid and answer specifics to the client's reservoir and reservoir conditions." This can be done multiple times on the same digital rock model, representing behaviors at any distance near or far from the wellbore, he says.

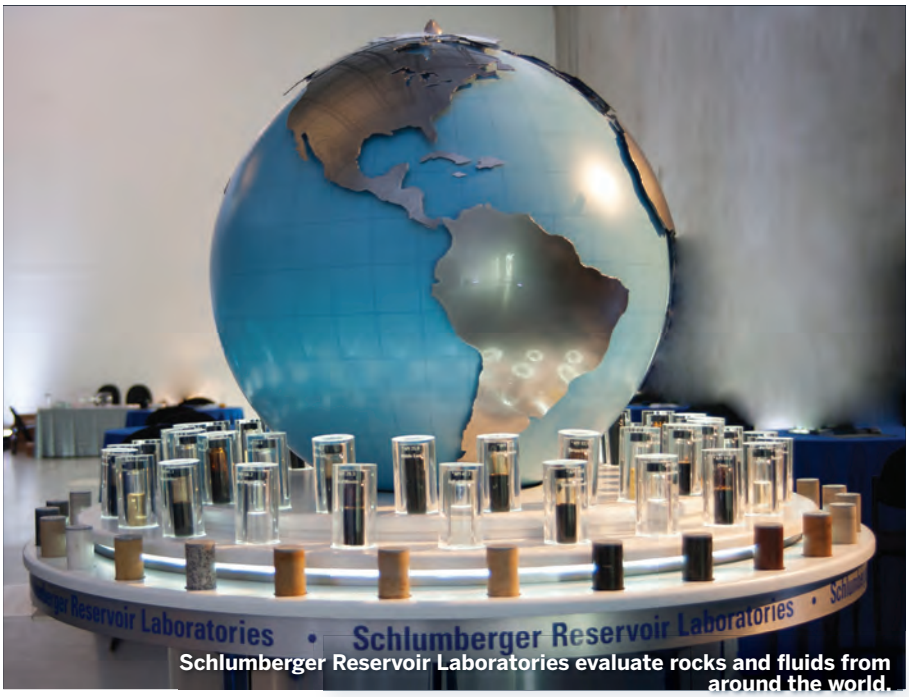
The physical principles in the DHD simulator go all the way back to the 19th century, Andersen says. However, relevant work began almost 20 years ago with a research scientist in Moscow. That scientist started working for Schlumberger and began development on the simulator approximately five years ago.

Schlumberger teamed up with Shell to validate the simulator's fluid properties and interactions. Shell used a synchrotron-based x-ray computed micro-tomography (results presented in two papers at the International Symposium of the Society of Core Analysts in September 2013). The analysis showed where flow of treated fluid entered a pore. Using the same starting point, the simulator was able to predict where the fluid flowed.

"The two images were very similar," Andersen said. "You'd think it was the same picture."

The Future

Physical analysis won't ever go away, Andersen says. "The combination of digital and physical core analysis is more powerful than either alone. Physical analysis is a proof point that people have been obtaining for decades. It will be a long time, if ever, before petrophysicists are willing to bypass the laboratory work. What is likely to happen," he says, "is that the balance of emphasis between the two is likely to shift with time toward additional digital analysis."OE



Schlumberger Reservoir Laboratories evaluate rocks and fluids from around the world.

Image from Tessella- ©iStock.com/DrAfter123

An explosion of data and ever more complex work flows requires new ways of working in order to realize the digital oilfield goal. Ray Millward addresses the issue.

Advanced analytics in the digital oil field: A team game

As sensor deployments proliferate, and digital oilfield technologies continue to mature, operators are increasingly looking at how to make best use of their data asset, from the raw seismic data through to generated data from reservoir simulations.

The goal for the digital oilfield is to create a more powerful fusion of historic data, present knowledge, and predictive modelling, allowing future operating decisions to be as near to optimal as makes economic sense. In an industry with so many expert disciplines, the biggest difficulty is to ensure that specialist engineers are equipped with the right analytics tools and able to access the right data, at the right time. Only then can they quickly gain the right insight through which to make better decisions.

In the past, subject matter experts (SMEs), such as geophysicists, reservoir engineers, and well test engineers, had been able to learn enough software engineering to analyze the data directly available to them and, unaided, make improvements to their analytical tools and platforms. Typically, SME's can write functional programs that work with files on their local drive, for example processing rate and pressure history data to find trends in order to formulate a model, or processing surfaces to find features and model time dependent behavior.

These localized innovations could then be shared with other specialist colleagues, or passed onto IT departments for commercialization and large scale release. Today, however, there is an explosion in data quantities from sources such as fiber equipped wells, continuous seismic monitoring, and increasingly large simulation grids, and there's a corresponding increase in the complexity of upstream architecture and workflows.

This makes it harder for SMEs to maintain the necessary expertise in both their specialist area, as well as in professional software engineering, which itself continues to evolve apace. Even those SME's with sharp software engineering expertise struggle to make writing new code a priority amongst the other pressing demands on their time.

To alleviate this, there has been an emerging rise in the number of small teams and departments responsible for technical computing. Technical computing specialists have a more robust mathematical background, and are able to introduce new computational techniques to solve subsurface problems.

It is now feasible to ask new kinds of questions of huge data sets, and to use high performance computing to get answers in minutes instead of days. The difficulty, however, is in matching up the right kinds of algorithms to solve subsurface problems in the most efficient way.

Problems can arise when there is insufficient overlap between the domain knowledge of the SME and of the technical computing specialists. This runs the risk of delivering a project with a set of tools that ask the wrong questions and delivers insight which does not meet the original brief.

An overlap in domain knowledge is necessary to ensure that when the SMEs and technical computing specialists collaborate, they are able to understand each other sufficiently to create a suitably broad problem space that fully defines and interprets the problem at hand, so that it is possible to explore a broad variety of relevant solution strategies. In this way, the SME is able to learn about how new

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computing techniques can be applied to existing problems, and, in turn, the technical computing specialist becomes more aware of the SME's domain.

As an example of how technical computing specialists with domain expertise start to think about existing problems, consider the use of forward modelling as an alternative approach to seismic inversion. This would involve starting with a basic gridded model of planar geological features, and using this basic model to generate synthetic seismic data, which can then be compared with the original seismic survey data.

By employing a carefully designed iterative process, which uses genetic algorithms, pattern matching techniques, and optimization, the process would continue until the gridded model evolves to generate synthetic seismic data to appropriately match the observed data. Once techniques such as this are perfected and automated, geophysicists and reservoir engineers can spend less time fighting to create a simulation grid. More time becomes available for identifying good starting points for the optimization as well as incorporating complex features of the reservoir.

Other emerging techniques that technical computing specialists can offer involve the use of large scale complex platforms for processing 4D seismic data in a massively parallel fashion, either on a high performance cluster or using map reduction platforms. The result fragments can then be combined back into a dynamic and evolving reservoir model.

When real-time data from intelligent fields is integrated with current well data, specialist engineers will be able to use analytics tools to spot trends and improve history matching for the field. This supports a more informed and timely choice of the appropriate extraction method.

In the long term oil companies can then begin to capture the decision making processes that expert reservoir engineers have built up over decades of experience, and as pattern matching techniques improve, to then make this data accessible when similar geological features are explored in future.

While it is possible to begin to articulate what the future of the digital oilfield might look like, these kinds of problems will be extremely challenging to solve, and will require software engineering and data analysis talent that can clearly understand how these complex systems work best together.

Operators will be increasingly reliant on broad vendor ecosystems to ensure that their SME's can be matched with the right kinds of technical computing specialists to provide a bridge between them and the managed software development cycle. Finding the right partner that understands the domain can significantly shorten the software release cycle.

This allows the wider business units to benefit from the many innovations becoming available, but within a known workflow that they are comfortable with and trust. We must remember that human needs are just as important as those of the data.

Ray Millward *joined Tessella Ltd two years ago, working within the upstream oil and gas industry. Before Tessella, Millward earned his PhD at the University of Bath, studying a new adaptive multiscale finite element method, with applications to high contrast interface problems.*

Cyber risks

The adoption of internet-based, or "open," industrial control systems (ICS), has left the global energy sector vulnerable to cyber attacks and hacking, according to a new Marsh Risk Management research paper.

The paper, entitled "Advanced cyber attacks on global energy facilities," says the adoption of internet-based ICS and supervisory control data acquisition (SCADA) systems has grown as companies seek greater business insight, remote access, and interoperability between systems.

"For the last quarter of a century, the global energy sector has relied on the protection offered by standalone and closed ICS as the primary barrier to the cyber security threat. Today, however, with energy facilities worldwide generally aging, upgrades and expansion projects are ushering in a wave of new ICS and SCADA systems, built on openness and interoperability.

"Unlike past industrial control systems, which were closed and predominantly exclusive to respective operating companies, these new systems have integrated control systems with other information technology networks, providing malicious persons with the opportunity to gain access to a facility's IT software, without needing to be onsite," the paper says.

"Once inside the system, an infiltrator could, in theory, open an emergency shutdown valve, or adjust alarm system settings at a gas or petrochemical plant."

According to the US Department of Homeland Security, 53% of the 200 incidents responded to by its Industrial Control Systems Cyber Emergency Response Team, between October 2012 and May 2013, were directed toward the energy sector.

To date, cyber attacks on the energy sector have mostly been untargeted and data-driven. But this is starting to change, Marsh says, with hackers now seeking to control ICSs in order to inflict damage to property and operations.

"The energy sector's resiliency to date is certainly not due to a lack of effort on the part of the hackers," the report says. "In August 2012, Saudi Aramco, was the victim of a malicious attack intended to halt the company's crude oil and gas supplies. Although the virus—given the nickname "Shamoon" by investigators—failed in its primary objective, it nevertheless destroyed the hard drives of more than 30,000 desktop computers and 2000 servers, forcing IT systems to be disconnected from the internet for two weeks.

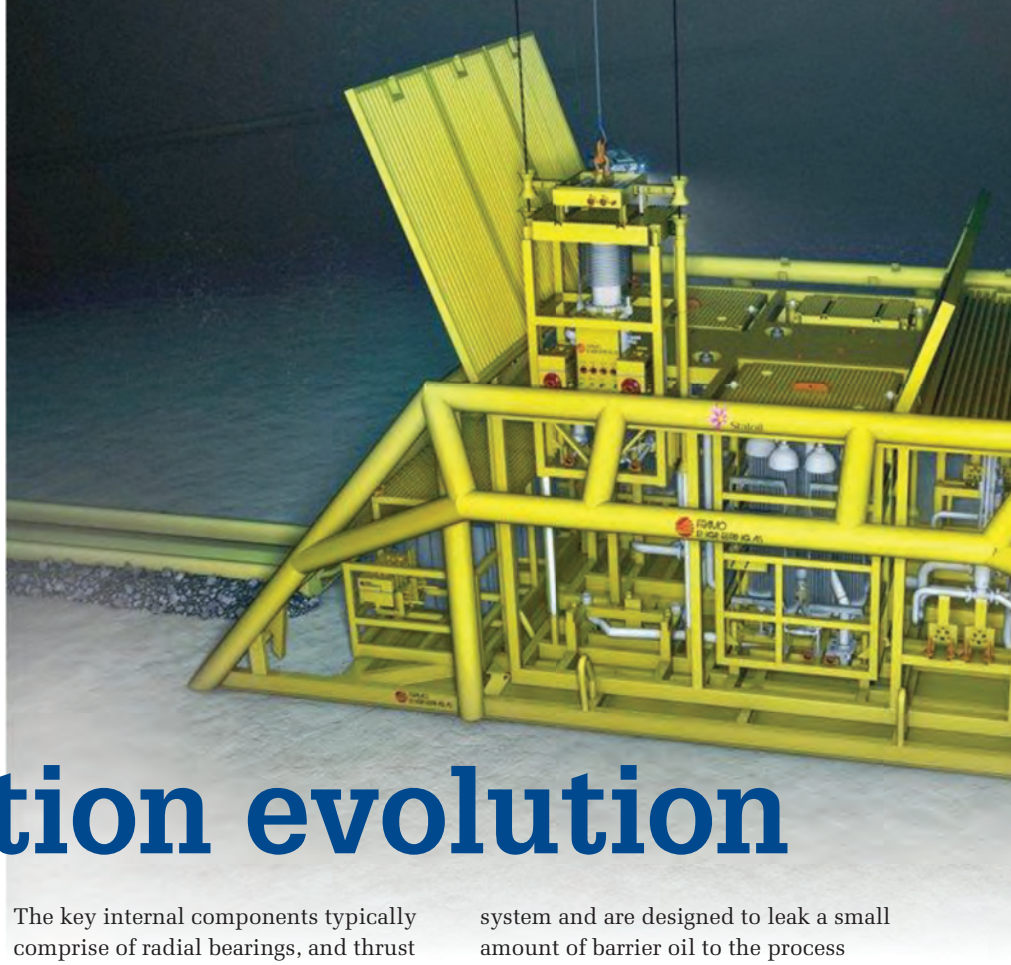
"Computer viruses such as Shamoon and the US-developed Stuxnet virus, the latter of which successfully disrupted uranium enrichment at the Iranian Natanz nuclear facility in 2010, have drawn the energy sector's attention to the potential disruption that could be caused by a malicious piece of software."

A 2013 report by Zpryme Research & Consulting found 63% of energy companies polled were "very concerned" about the prospects of cyber or network attacks.

Governments are taking note and acting. In the US, the Obama administration's new Cybersecurity Framework has sought to define a common set of security standards for a list of 16 defined critical infrastructure sectors, including standards and approaches for ICS.

In Europe, the EU is close to finalizing its own cybersecurity directive to reduce the cyber threat posed to critical infrastructure, communications, and public services.

"The next and much more difficult challenge will be to identify common vulnerabilities before assessing the potential impacts of cyber risk to the energy sector – particularly from an economic perspective...It is imperative that energy companies consider the risk of cyber attack as an inevitable one, and focus on preparing scenarios to identify, respond, and contain any attacks accordingly." **—OE**



A new environmental lubricant supports key subsea boosting and compression technology. Castrol Offshore's Chris Morrissey reports.

Lubrication evolution

In recent years, the offshore industry has seen key processes move from surface facilities to subsea, along an increased usage of increased oil recovery techniques. This has led equipment manufacturers to develop high performance subsea boosting pumps and gas compressors, driven by increasingly powerful, efficient and compact electric motors. These motors, together with the shaft bearings and seals, need to be lubricated and cooled efficiently by a lubricant with specialist properties suited for operation in the subsea environment.

The lubricant is normally supplied to the subsea unit via an umbilical from the host surface facility and is vital to the reliability of the equipment. The performance characteristics of the lubricant must cope with industry trends such as increasing process stream temperatures, higher pressures and higher shaft rotational speeds.

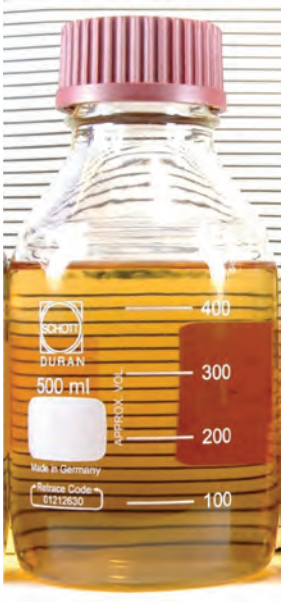
In combination with these demands, tightening environmental legislation governing the use and discharge of chemicals into the oceans requires that the industry adopts more environmentally-responsible lubricant technologies. Lubricating fluids are important in helping to ensure reliability and reducing operational risk.

Functional requirements of the lubricant

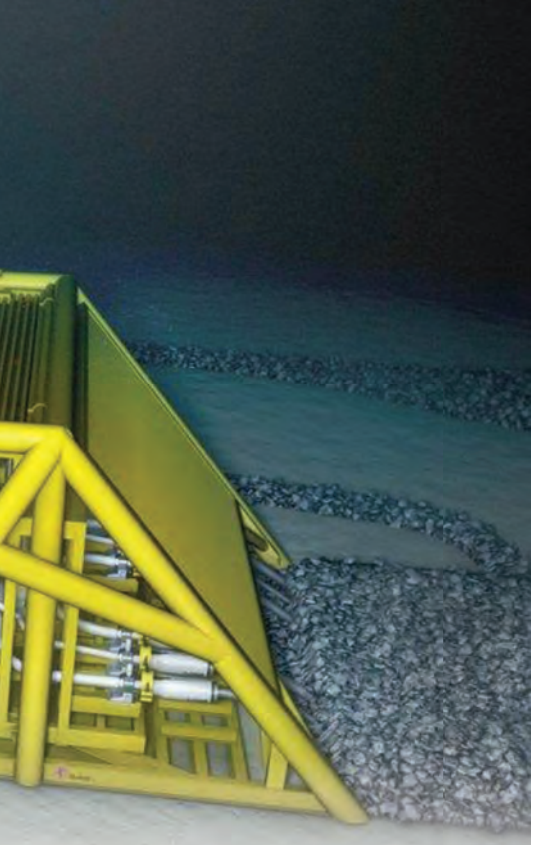
The subsea equipment plays a vital role in extracting oil and gas reserves, and ultra-high reliability is a necessity. The key internal components typically comprise of radial bearings, and thrust bearings and mechanical seals. A fluid is needed to lubricate, cool and clean away wear particles. In addition, the lubricant is needed to remove heat from the powerful electric motor; a good electrical insulator is necessary, too. Advances in machine technology mean that lubricating oils are being thermally stressed beyond limits previously seen and, with shaft speeds up to 6000rpm and high process temperatures, there are a number of key performance challenges that must be overcome, together with meeting tight environmental legislation.

The process must start by gaining a detailed understanding of the conditions inside the various rotating elements within a specific pump and compressor. Critical parameters that should be reviewed include long-term thermal stability, lubricant viscosity, lubricity, load carrying properties and water contamination management. The lubricant will interact with many different components in the system so material compatibility is vital. The mechanical seals act as the barrier element for the internal lubrication system and are designed to leak a small amount of barrier oil to the process stream. The frictional losses in mechanical seals are related to rotational speed and pressure and result in local temperature rises. As shaft sizes and speeds increase, the heat generation at the sealing interface is significant, and may lead to high peak temperatures. The fluid is required to reduce friction, remove heat and retain its integrity. Formation of deposits will upset the seal gap causing increased leakage and potential failure.

Together with ever-increasing performance demands, the environmental legislation relating to chemicals discharged by the offshore industry continues to become tighter and more widespread. The legislation was first developed for operations in the North Sea, but now extends to other regions including the Gulf of Mexico, Canada, West Africa and Australia. However, the Oslo and Paris (OSPAR) Convention requirements remain the most stringent. The OSPAR



Castrol oil blend, 220C, at 4 weeks, with anti-corrosion additives. Its color clarity indicates that it is stable after exposure to high temperatures.
Photo from Castrol Offshore.



legislation covers the North East Atlantic and states that all fluids that have the potential to be discharged to sea by operational discharge or by leaks that cannot be prevented should be assessed and registered. OSPAR currently requires that every individual component in a product is tested for marine toxicity, biodegradability and bioaccumulation. To meet evolving environmental legislation, it is essential that environmentally-responsible components are used in the development of a lubricating fluid.

Lubricating fluid development process

Conventional, low viscosity lubricating oil formed the baseline for the product development program, with the first step being the selection of a suitable base fluid. The oil needs to be of a low viscosity to reduce shear in rotating elements, provide low levels of leakage across the mechanical seals, effectively remove heat from the electric motor and be environmentally compliant. Performance enhancing additive components are then chosen that will deliver the key functional requirements, and levels are optimized to deliver maximum performance. For example, if the additive level is too high, it might have a detrimental effect on the electrical insulation properties or form deposits on mechanical seal faces. By developing an oil with increased thermal stability, the fluid is more likely to meet the current and future needs of more powerful pumps and compressors. In addition, the lubricant may need to cope with upset conditions such as seawater contamination and high breakdown voltage requirements. The lubricant must also successfully pass all original equipment manufacturer (OEM) functional testing.

Typical mineral oil, 150C, at 4 weeks. The darkening indicates degrading after thermal aging.
Photo from Castrol Offshore.

The importance of validation testing

Thermal stability is a key product attribute, and once the initial thermal stability tests are complete the formulation must then undergo physical and chemical testing at higher temperatures and for longer durations. This involves testing at up to 220°C, with samples monitored during the test period to ensure the fluids remained stable with no visible deposits. The aged samples are then subjected to more in-depth testing, including infrared (IR) analysis which uses a fingerprint technique to identify any changes in the chemistry compared to an unexposed sample. If the IR traces remain virtually identical, this indicates that the fluid has remained stable throughout the test.

It also is essential that the formulation performs well against testing for insulation properties (breakdown voltage). This is determined by running an IEC156 test, in which two electrodes are immersed in the oil, and the voltage is increase until an electrical short occurs. This value must be high enough to prevent shorting under high voltage operation within the motor.

The final lubricant will be exposed to internal pump and compressor parts such as elastomer and thermoplastic seals and motor internal parts and there are methods in place to analyze the compatibility of materials. The seals need to be tested for compatibility with the oil by immersion testing according to NORSOK M710 procedure. They are aged at higher temperatures to accelerate the testing. For the motor internals that contains epoxy resins and cable insulations, additional electrical measurements are carried out on sub-assemblies throughout the test period.

Conclusion

Functional testing to ensure performance assurance is increasingly critical, and Castrol Offshore has designed a method to demonstrate the superior performance of a lubricant. The approach involves testing the fluid beyond the expected conditions to provide enhanced reliability assurance. The screening tests that are carried out take place on bespoke test rigs to ensure that the performance of the lubricant is monitored in an environment that is as close to operational as possible.

Due to the comprehensive testing program, Castrol Offshore has recently been involved in the development of a lubricating/barrier oil that meets the machine performance and environmental needs of the current and the next generation of subsea boosting pumps and wet gas compressors. The lubricant is fully compliant with the tightest OSPAR environmental legislation and outperforms conventional mineral oil solutions on thermal stability, whiledelivering good electrical insulation and drying capability. The final lubricant solution will increase the operating envelope of subsea pumps and compressors. OE

Chris Morrissey joined Castrol Offshore in 2004 as product advisor for the subsea business. He moved on to manage the technical service team, and then to specialize in product qualification, where he worked closely with many subsea equipment vendors. He is currently team leader for offshore product development within Castrol's central technology function.

Before joining Castrol, Chris has held several design and development positions within Parker Hannifin UK, and John Crane Ltd. These positions allowed him to gain a wide experience in the design and application of hydraulic equipment and high performance mechanical sealing. This work spanned many different business sectors such as chemical processing, paper making, automotive manufacture and oil & gas.

Chris has a B Eng. Degree in Mechanical Engineering from the University of Hertfordshire.

Gulfstar system nears completion

Williams' Gulfstar floating production spar (FPS) system is nearly complete, and set to serve Hess' Tubular Bells field in mid-2014. Stephen Whitfield provides an overview of the spar's development.

It has been touted as the future, a job creator, a source of vital infrastructural development mixed in with some old-fashioned American pride. The technology behind it is not new, but its very existence may prove crucial to companies looking for a more efficient direction in mid-sized field development.

Gulfstar is a floating production spar-based system, one of several to come around in the last few decades. Scheduled to launch this year, it should spearhead major production for Williams Partners, its creator and owner, and Hess and Chevron, co-partners in Tubular Bells, a field off the New Orleans coastline for which Gulfstar will serve as the central processing facility. The models have been drawn, the parts built, and pieces are almost in place.

And now, nearly three years after its initial commission, the time is near for this thing to show exactly what it can do.

Origins

Upon first glance, the partnership between Williams, Hess, and Chevron looks like an old fashioned marriage of convenience.

Hess first discovered the Tubular Bells field in 2003, finding reserves in waters ranging from 4300-4600ft on Mississippi Canyon Block 725. Most of the field is now located on MC 726. BP, the company behind the original discovery and subsequent appraisals, sold its stake in the field to Hess and Chevron in 2010. Hess is the controlling partner in Tubular Bells, holding a 57.14% interest. Chevron holds the remaining 42.86% stake.

Williams was brought into the project in October 2011, five months after Tubular Bells had received a letter of award from Hess. In a news release issued at the time, the company said it would handle "production handling, export pipeline, oil and gas gathering and gas processing services" for the project; in other words, it would design the engine that made the whole thing work.

Costing an estimated US$2.3 billion, Tubular Bells was designed in the ever-popular "hub and spoke" delivery model. Under this layout, Gulfstar is the hub, the center to which all resources will eventually go. It will be connected to two subsea drill centers, which in turn will be connected to three subsea production wells and two water injection wells.

Gulfstar's platform was installed at a depth of 4300ft. Its core module has the capacity to produce anywhere from 60,000 to 90,000 bo/d, but Hull expects to yield 120 billion bbl from Tubular Bells, with peak production estimates coming at 40,000 to 45,000 boe/d.

Crews upended the Gulfstar floating spar in February. Photos: Williams Partners.

What is Gulfstar?

While new, Gulfstar's design is firmly rooted in traditional concepts. As the company had no specific offshore location in mind when it conceptualized the system, it had to make it as flexible as possible to adapt to the different logistics of a given site. That all changed after Williams signed on for the Tubular Bells field, thus giving it parameters from which it could build and operate.

Gulfstar is a system with a classic spar hull connected to a three-level topside, with each deck – a main deck, a production deck, and a cellar. The hull was fabricated in an overlapping sequence to speed construction of the module. This design was supposed to speed up the time from the discovery of reserves to first production to about 30 months.

The topside does not feature a rig, only wells based on wet-tree technology: the centerwell, 30-in. diameter, is accessed via a valve tree attached to

a well head on the seabed, instead of a riser. It is a more complex design than a conventional dry tree system – since well access is not at the surface, it is harder to access during intervention – but it allows for a lower-cost hull and does not restrict vessel flexibility to the spar.

Gulfstar's topside has a maximum operating payload of 8600 short tons, three two-phase production separators, and a one-phase test separator, each of which can handle 30,000 bbl of liquid per day (blp/d). Its three T60 power generators each run on a dual fuel configuration and features a waste heat recovery system. It is built to last 25 years and house up to 50 people at any given time. It has a single-piece lift that can handle up to 6600 short tons.

The hull can reach a depth of 8500ft. Its outside diameter is 85ft, and it measures 60ft from the top deck to the waterline. It has two pull tubes that can accommodate export risers as long as 14-in. in diameter, its flowlines consist of eight pull tubes that can accommodate 15K risers up to 8.625-in., and its umbilical/injection lines consist of eight pull-tubes.

Contained within the hull is 10,440 bbl of dry oil, which will help with unexpected well shut-ins. Should that happen, the dry oil can be pumped to the flow lines, taking the place of live crude reserves. Gulfstar has 1160 bbl of methanol and other chemicals like asphaltine and paraffin inhibitors on board as well to help with flow assurance.

A speedy delivery

One of the central tenets of Williams' vision for Gulfstar was to significantly reduce the time from the discovery of reserves to the first production. The goal is to finish the project in 30 months, which would be sometime this year; initial production has long been slated for mid-2014. So far, things appear to be on schedule. After mooring the floating spar to the ocean floor in February, crews in March lifted and installed Gulfstar's three-level topside platform.

Williams was able to accomplish this goal by serving as a one-stop shop for everything. Williams funded Gulfstar and the export pipelines itself, essentially cutting out the middleman and creating a consistent set of interfaces within the system, as opposed to the multiple interfaces one would get in dealing with multiple companies.

Another key to reducing the construction time was choosing to build in the US. It is no secret that Gulfstar is the first spar-based FPS whose major components were built in America – the topsides were constructed by Gulf Island Marine Fabrication in Houma, Louisiana, while the hull was constructed at Gulf Island Fabricators in Aransas Pass, Texas. In all, about 90% of the materials for Gulfstar came from the US.

Gulfstar's floating spar was towed 135-mi. southeast of New Orleans before being moored in about 4000ft of water in February 2014.

Gulfstar's American origins undoubtedly provided a boon of good publicity for Williams, as well as a boon to the economy – the project led to an estimated 1000 new jobs in 20 states during the course of its development – but it was also a practical measure. Since both towns are on the Gulf of Mexico, shipping the components to Tubular Bells was a much quicker process to execute than if they had been built overseas.

Gulfstar was also the first spar built on a graving dock, allowing for a simplified load out process. Its deck was lifted as one singular piece during the installation process, which limited the time needed to hook up offshore. The hull blocks were built vertically, thus allowing for better access to the equipment as it's being installed and reducing the problems that can come with horizontal construction. According to Williams' video on the system, the vertical blocks were rotated to a horizontal position once completed, after which they were lifted and set into the graving dock for incorporation into the hull.

"Gulfstar provides a complete 'floating production system to market clearing point' solution for producers in the Gulf for their oil, gas and liquids production, designed specifically to maximize their net present value and minimize risk," said Mark Cizek, Williams' Gulfstar Project Director. "The 'design one, build many' construction concept allows for standardized design options and enhanced safety and reliability of each unit. The repeatable concept also increases speed to market."

What's next?

In addition to anchor commitments from Tubular Bells owners, Gulfstar executed agreements in January with Gunflint field owners. The Gunflint tieback is designed and engineered with modifications expected to occur after completion of the base Gulfstar project. With hook-up and commissioning activities currently underway, Gulfstar is on schedule to start serving Tubular Bells in 3Q 2014 and Gunflint in 2016.

"Landing this Gunflint tieback before first oil is received from the anchor tenants demonstrates the promise of the Gulfstar model for producers, both economically and technically," said Rory Miller, senior vice president of Williams' Atlantic-Gulf operating area. "As a midstream company, Williams is focused on infrastructure solutions of this nature that connect the best supplies with highest-value markets. Gulfstar is one of approximately $4.5 billion in large-scale projects we expect to bring into service in 2014 and 2015."

Gulfstar could potentially be a model for future developments of mid-sized fields, as companies look to cut down on the time and cost needed to construct offshore systems. Williams hopes to connect it other systems that it owns and operates in the Gulf of Mexico, and it could become a primary facility for other deepwater fields. And perhaps, down the line, there will be other projects like it developed in the Gulf's waters. OE

Maersk Drilling's *Maersk Viking* drillship.
Photo from Maersk Drilling.

Testing subsea BOPs to the limit

Third party, hardware-in-the-loop (HIL) testing has been taken beneath the waves on a subsesa MUX BOP. Elaine Maslin reports.

Automation is playing an increasing role in offshore operations. With automation comes software and a need for it to be tested, ideally with its hardware.

When the hardware in question is being installed on a floating production unit, drilling rig or drillship, as a long and complex build program moves towards commissioning, how and when the testing is carried out becomes crucial.

Testing a system as early as possible will enable suppliers and those receiving the systems, to better manage their risks.

Machine and system vendors do test their own software, but third-party hardware-in-the-loop (HIL) testing is helping to increase software reliability and safety, and smooth out the commissioning schedule.

HIL-testing has been adopted by the oil and gas industry for some time, but has only recently been used to test MUX blow out preventers (BOPs), used for deepwater drilling.

The project was undertaken by Norway's Marine Cybernetics (MC) for Maersk Drilling, Samsung Heavy Industries and the MUX BOP's manufacturer GE Oil & Gas, ahead of its integration into Maersk Drilling's latest drillship, *Maersk Viking*.

The ship is the first of four being built by Samsung, in South Korea. All four have MUX BOPs, which will undergo the same HIL testing by MC.

Maersk Drilling had already been using HIL-testing on dynamic positioning and power management systems. The company saw its benefits and wanted to use the same test concept also for drill floor equipment in 2008. Since then the number of products being tested has grown and now includes subsea systems like BOPs, says Einar Leirvik, operations project manager, at MC.

HIL-testing is a black-box method for testing and verification of control system software. Instead of being connected to the actual equipment, the control system is connected to an HIL simulator, which models of the equipment due to be controlled.

This enables systematic and comprehensive control system functionality and failure handling testing, without risk to personnel, equipment or the environment. This includes testing safety-critical software barriers that otherwise cannot be tested before they are needed.

For SHI, this is crucial. Dillip

Moharana, senior manager-instrumentation, SHI, Geoje Shipyard, says: "HIL testing means we can thoroughly test the software. Normally, we have to believe the vendor, who is supplying the software, and do not have a mechanism ourselves to 100% check the software before it is commissioned. Introducing third-party HIL testing means the software developed by the vendor can be thoroughly checked and we can make sure it is robust."

This then reduces the risk that the software could fail during an operation, which could potentially cost millions of dollars in lost revenue due to downtime for fault-finding and corrective work. For a subsea BOP, removing any potential for failure, especially in deep water, is even more important, Moharana says, safety also being critical factor.

For deep water—typically above 1200-1500m—it is not acceptable to control the subsea valves by direct hydraulic lines between the topside control manifold and the BOP stack. Due to the compressibility of the hydraulic fluid, the time delay becomes too large. To meet deepwater requirements, the BOP stack is typically controlled through a serial copper line, and more recently via fiber optic communication cables.

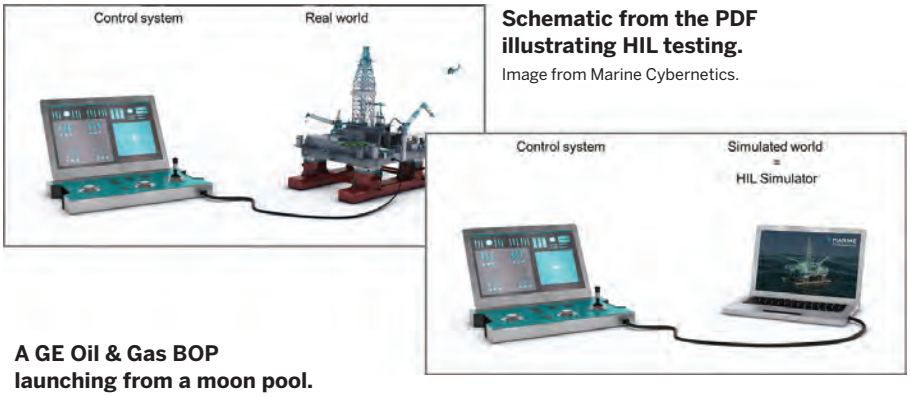
Redundant programmable logic controller/microcontrollers subsea, handle this communication. Subsea controllers are also programmed to initiate and execute emergency disconnect sequences, if certain criteria are fulfilled or if commanded by the operator on the ship.

The control system interacts with the BOP and auxiliary systems through a set of input and output (I/O) signals. Inputs are provided by sensors that measure the various physical properties, as well as inputs from operator stations. Based on the inputs and internal states in the control system, the control system calculates control signal outputs to the actuators.

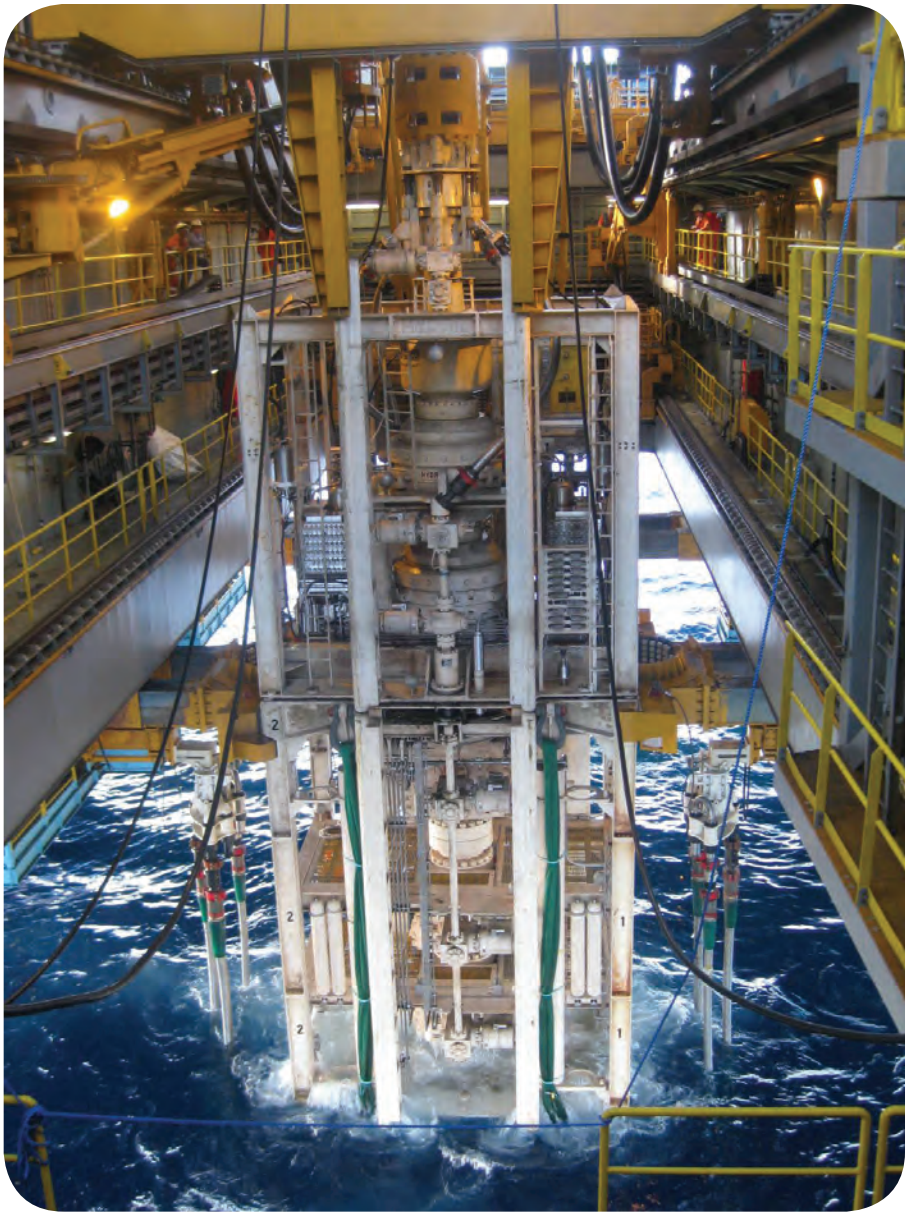
HIL-testing is performed by isolating the control system and its operator stations from its surroundings, and replacing all actual I/O with simulated I/O using an HIL simulator in real time. The HIL simulator imitates the BOP, responds to the commands from the control system, and provides realistic and consistent measurements. The control system cannot sense any difference between the real world and the virtual world in the HIL simulator.

"The earlier you can test as complete a system as possible the better," says Raj Sen, subsea section manager, electrical controls team, Houston. "What HIL allows is the control system to be tested with the hardware that it is to be interfaced with in the ship at a later date. It gives an additional level of confidence and allows an additional level of risk management up-front in the process.

"At the end of the complete cycle, the quality of the product remains the same, it is just a matter of timing, when you are managing the risks out. We are allowing the customer to focus on the ship building and the assembly, instead of dealing



Schematic from the PDF illustrating HIL testing.
Image from Marine Cybernetics.



A GE Oil & Gas BOP launching from a moon pool.
Photo from Marine Cybernetics.

Einar Leirvik , operations project manager, at Marine Cybernetics.

with supplier products at the final stages of a build, in the final cycle."

A non-disclosure agreement was agreed upfront, and MC presented a list of necessary documentation to be able to develop the simulators, write the test program and prepare the interfaces to be used between the BOP control system and the simulators.

"We have to do a thorough analysis of the system to understand how it works and how it is built up," Leirvik says. "When we get this overview we start on the process of preparing the test program and the simulators based on the vendor documentation. In this particular project we also arranged a workshop with Maersk Drilling to look into which areas should be more focused and which should have less priority, he says.

"HIL-testing is the best way to test how the control system is handling failures. We are stressing the system by introducing various failures from the simulators and then verifying that the control system response to those failures is acceptable. Today, there is no other test methodology covering this in such a comprehensive and detailed manner than the HIL testing."

MC used its own technology platform CyberSea to create the HIL simulators. The simulators were programmed and configured according to the piping and instrumentation diagrams, electrical schematics, IO-lists (listing instrumentation input and outputs), and general arrangement drawings, received from GE Oil & Gas, using Matlab and Simulink. The simulators can run on standard laptops.

The majority of the tests are "failure tests," where the control system's ability to handle failures in various operational modes is tested. Failures range from sensor and command signal failures to mechanical failures, or loss of power or communication.

The functionality of the system was also tested by writing "function tests" to verify that the system operates in accordance with its functional description, operator manuals and so on. Once written, the test program was agreed by all the parties.

A separate team at MC prepared the hardware and communication drivers, or interfaces, to be able to communicate between the BOP control system and the simulators. On this system, both hard-wired signals and serial communication were used. All interface equipment was prepared at MC's facilities in Norway before being shipped and tested at GE Oil & Gas' facilities in Houston. It was then ready to start HIL-testing on the actual control system hardware, following GE Oil & Gas' own internal testing.

The control system and the simulators were connected to each other and put through HIL-commissioning before the HIL test could start. Acceptance criteria was being able to operate all functions from the BOP control system and verify correct behavior and feedback from the simulators. Commissioning lasted five days.

The first phase of testing lasted 10 days. If results were unclear, or a party wanted verification of the observed result, re-tests were performed. When testing was complete, the parties met before a test result report was issued by MC.

"By conducting HIL-testing of the BOP control system all parties have contributed to increased offshore safety," Leirvik says. "Co-operation between the stakeholders is essential and both GE Oil & Gas, Maersk Drilling and Samsung have been very supportive."

By March 2014, MC has in total signed contracts for 10 BOP's to be HIL-tested. Several BOP-HIL projects are ongoing now while four projects are already completed. OE

L-R Einar Leirvik – Marine Cybernetics, In Sung Lee – Maersk Drilling, Dillip Moharana – Samsung Heavy Industries, Geir Hamre – Marine Cybernetics, Michal Bury - Maersk Drilling. Photo from Marine Cybernetics.

Marine Cybernetics' (MC) founders saw an opportunity to introduce HIL testing to the maritime and offshore industry. Professors Thor I. Fossen, Asgeir J Sørensen, Olav Egeland and Tor Arne Johansen, from the Norwegian University of Science and Technology in Trondheim, Norway, founded the company in 2002.

Einar Leirvik, operations project manager, at Marine Cybernetics says: "The founders had been involved in control system development and they saw that the testing did not keep up pace with the software development and the use of software. Software was moving into all aspects of marine operations and the testing was not keeping up. So they looked at how other industries were testing their critical software."

MC introduced HIL testing for upstream systems and developed its CyberSea technology, which incorporates software development and modeling of physical systems such as hydrodynamics, electro-mechanical systems, hydraulics, and sensors and can be used to test systems from any control system manufacturer.

The first product was Dynamic Positioning (DP) HIL. Since then, MC has developed HIL testing for use on a wide variety of equipment, including Power Management Systems, Drilling and Pipe Handing Equipment and Emergency Shutdown systems.

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Making connections

Belden's Tim Wallaert explains how the proper networking solutions can reduce time to first oil and increase uptime.

In an industry where a single day, hour or minute of downtime in production puts millions of revenue dollars at risk, operating at anything less than capacity is not an option. It is critical for oil and gas companies – especially the offshore vessels keeping the world's petroleum supply flowing – to ensure they have a highly reliable, safe communications infrastructure in place.

There are many concerns and challenges around the need for absolute uptime while working in one of the harshest environments imaginable. These seemingly unproblematic elements can present risks or threats to the system. Essentially, there are no unimportant parts of a vessel's control or automation system.

Selecting high-quality cable that meets the environmental requirements will ensure high reliability and safety. In particular, low-smoke, zero-halogen jackets for marine-certified cable are a safety "game changer" for offshore operations.

Some key areas of communications infrastructure that are often overlooked include:

- The overall design of the vessel's communications network.
- The quality and safety of the components used to build out the communications infrastructure, particularly the physical media.
- The management of network traffic to protect the performance of automation systems from advanced malware threats or unintentional incidents.

As new offshore vessels are built or existing facilities are overhauled, incorporating these features from the onset provides several benefits. First, companies can shorten the time it takes to commission a new ship or complete a retrofit and ultimately reduce the time to first oil. It also enables a smoother transition of equipment from subcontractors to the ship or rig builder, and helps avoid common integration issues.

Fewer surprises will arise later on if the right questions are asked from the start. For example: "How is the network segmented?" "How can the right physical media reduce downtime and ensure safety?" and "What is the best way to secure systems and safeguard network performance?"

Design with industrial ethernet infrastructure in mind

First and foremost, an offshore vessel's communications network should follow today's best practices in network design.

Older SCADA (supervisory control and data acquisition) and ICS (industrial control system) systems were not designed with security needs in mind. Due to harsh environmental conditions, floating facilities have shorter lifecycles when compared to other industrial systems; therefore, new vessels or retrofit projects can more easily shift to the improved technologies available.

The main trend is the increasing adoption of Ethernet networking technologies for communications. Not only is industrial ethernet easy to implement, it offers instant access to data and scalable solutions. The ARC Advisory Group estimates ethernet networks are growing at more than 12% compound annual growth rate.

For engineers, IT professionals, or third-party ship and rig builders unsure of the best way to design an ethernet network, the most important principle is segmentation.

Offshore vessels and platforms generally involve a large number of systems and devices. Between programmable logic controllers, automated equipment and subsea systems, the network is usually large and dense. If the network is also flat, then performance and uptime will be reduced. A segmented network, on the other hand, is more manageable and makes isolating network issues easier.

To create an ideal network infrastructure, divide your network into zones.

- Subnets – Dividing up devices into physical groupings based on function or location makes it easier to maintain and secure them. Subnets prevent broadcast messages, reducing the chances of network traffic storms that can impact production.

Floating production, storage and offloading (FPSO) vessels can be commissioned and retrofitted faster when a network design with proper segmentation is implemented.

- Virtual Local Area Networks – VLANs create logical groups of ethernet devices that cannot be physically connected. Once tagged by a switch, other switches can read this tag and decide whether a message should be forwarded. VLANs provide traffic management, allowing devices to only see the data they need.
- Transparent firewalls – Some processes cannot be maintained across a subnetted system. When a system cannot be segmented, transparent firewalls are an option.

Having a properly-designed communications network with regard to segmentation will greatly reduce problems during the installation and improve reliability once in operation.

Ruggedize the system to withstand elements

The extreme conditions faced by offshore facilities require the use of quality, ruggedized equipment that will withstand the harshest environments. Extreme temperatures, corrosive hydrocarbons, direct sunlight and UV exposure are just a few of the challenges for the network.

Reliable signal transmission solutions that enable your offshore network to operate continuously while also connecting back to the control system on the beach are not optional. Products designed for and tested in this extreme setting will keep a network up and running.

Since most offshore projects involve a team of partners, subcontractors or shipbuilders, it's important to specify products so everything on the network works seamlessly together. This includes industrially-hardened ethernet switches, routers and security devices, ruggedized control and information cables, and sealed, oil resistant, non-toxic cable and connectors.

Choose the right cable

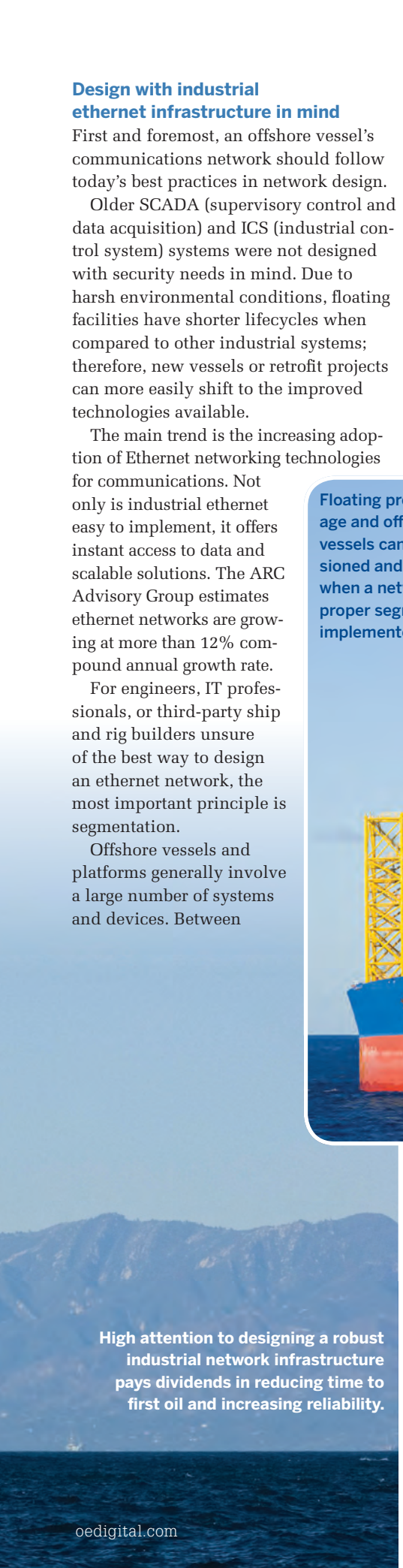
Studies show the majority of network failures originate from cables or connectors. Intermittent connector and cable issues are notoriously difficult to diagnose and correct. Avoid expensive downtime by selecting and specifying the proper cable qualities, like:

- Hydrocarbon resistant.
- Oil resistant.
- Able to withstand very high and very low temperatures.
- Crush and impact resistant.
- Wet and dry rated.
- Abrasion resistant.

Determining the right cable at the design stage for the conditions your vessel will encounter, and then specifying it for procurement, will pay dividends in terms of faster project completion and higher reliability. Improvements to prevent downtime and unreliable communications also increase overall safety onboard the vessel – protecting both employees and the equipment on board.

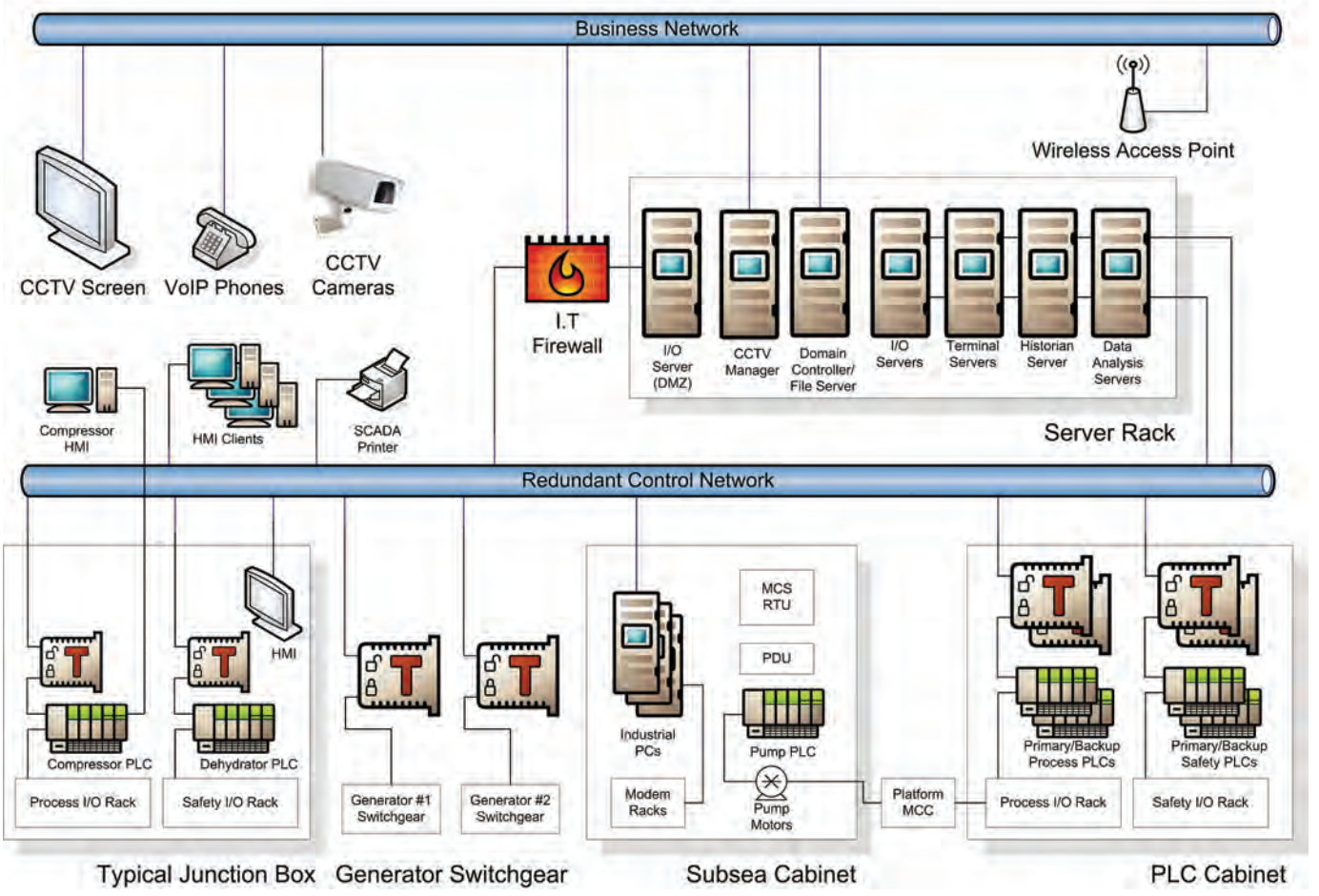
Adhere to global requirements

All offshore signal transmission systems require certification by relevant regulatory bodies, both domestically and internationally.



High attention to designing a robust industrial network infrastructure pays dividends in reducing time to first oil and increasing reliability.

ENI Longhorn simplified network diagram



Transparent industrial firewalls (devices shown with "T") are an important part of Defense in Depth. In this simplified network diagram, they are shown protecting the process control network, as well as switchgear and various packaged process units. Only the necessary operating protocols are allowed through the firewalls.

Historically, this has been a cumbersome process, requiring substantial engineering, procurement and installation resources. Thus, using products onboard the facility that have already been proven in offshore applications and meet the necessary certifications can greatly reduce the time to market and first oil.

The key global standards and certifications that companies, as well as third-party builders and integrators, should look for when considering products and solutions, include:

- The United States Occupational Safety & Health Administration's Class 1, Div 2 hazardous location conditions.
- The American Bureau of Shipping, or ABS certification, for marine and offshore operations within the coastal US.
- Europe's DNV GL Maritime rules, standards and regulations for every type of ship, vessel or offshore installation.

Industrial cyber security defense

Cyber security-related events have become an increasing problem for the oil and gas industry over the past decade. The importance of the industry to the economy is one of the biggest reasons, and in the last few years, the number and sophistication of cyber-attacks targeting energy facilities has grown greatly.

In addition, the complicated nature of offshore networks means that unintended attacks from internal errors or viruses add another layer of challenges in protecting the mission-critical system.

Take advantage of the cyber security best practices

There are a number of security solutions available that are not only cost effective, but are also easy to implement without disrupting production.

With oil and gas production, maintaining the integrity and availability of the system is paramount. A network's outside defenses are extremely effective, but what's concerning is the number of internal accidents caused by user error or malware introduced from contractor USB keys or laptops.

With the majority of incidents originating from secondary points of entry to the network, problems can spread rapidly through the network. A perimeter-style defense with a firewall at the edge of the network, while necessary, isn't enough.

To protect a system from within, a multi-layered defense, such as Defense in Depth (DiD), is needed. DiD is built on three core concepts: multiple layers of defense, differentiated layers of defense and threat-specific layers of defense.

A network protected using a DiD strategy responds to threats, such as traffic storms or viruses, by limiting the impact to the zone where the problem started. Alarm messages from the firewalls will pinpoint the zone, and even the source of the problem, making the situation faster and easier to correct.

Use transparent industrial firewalls to protect core processes

Transparent firewalls[1] are security devices with special features for industrial use. At first glance, they appear like a traditional

Using high-quality ruggedized components, including the cable and connectors, greatly reduces network failures on offshore platforms, such as this fixed, gas and oil processing structure.

Ethernet switch, but they actually inspect network messages in great detail.

The transparent feature allows them to be dropped into existing systems without requiring readdressing of the station devices. This means that organizations can retrofit security zones into live environments without a shutdown. They also allow the installation of security controls within a single sub-network.

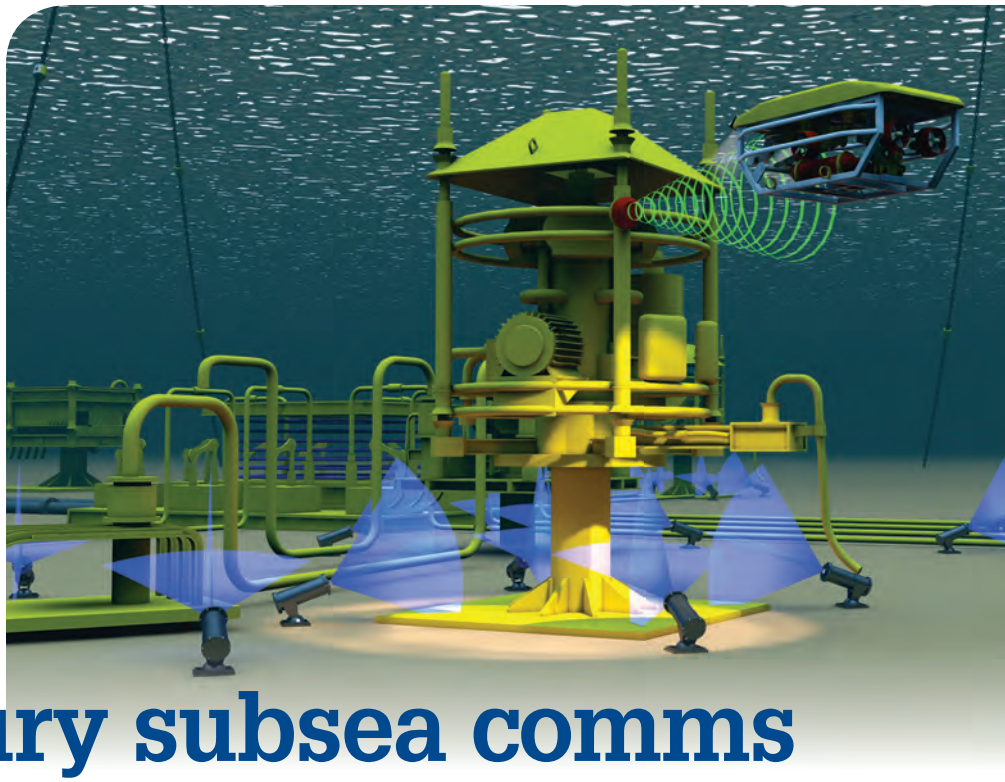
The firewall feature provides detailed "stateful"[2] inspection of all network protocols so inappropriate traffic can be blocked. For example, rate limits can be set to prevent "traffic storms," while deep packet inspection rules can be set to prevent inappropriate commands from being sent to IEDs or controllers.

Overall, there is a huge opportunity for offshore facilities to benefit from and stay ahead of the competition by laying out the proper network infrastructure. Decreased downtime and reduced security risks help keep the time and money spent on troubleshooting and fixing issues low. Ultimately, using the latest networking and communications technologies can reduce operations costs and engineering time and improve the return on investment. OE

1 Transparent (layer 2) firewalls are devices that connect the same network on its inside and outside ports. They are not a routed hop and thus can be safely installed in live networks. Layer 3 traffic, such as IP traffic, cannot pass through the security appliance unless it is explicitly permitted.

2 A stateful firewall keeps track of the state of network connections and allows only packets with a known connection to pass through it.

***Tim Wallaert**, Director – Vertical Markets, Energy, leads Belden's expansion into the power utility and oil and gas markets. He has spent more than 20 years in industrial automation, helping improve production operation across a range of industries. Tim's current focus is on energy communication and automation as one of the key enablers of the digital oilfield. He holds a BSEE from Michigan State University and an MBA from Case Western Reserve University.*



Subsea wireless communication is moving into a new era. The Subsea Wireless Group (SWIG) hopes to help the industry better understand–and use–this technology, thereby introducing new standards. Elaine Maslin reports.

21st century subsea comms

In 1854, Scottish-born James Bowman Lindsay patented "a mode of transmitting messages by means of electricity through and across a body or bodies of water," sending a transmission 2mi. across the River Tay, between Woodhaven and Dundee, Scotland, in the same year.

Lindsay was ahead of his time. It wasn't until 1897 that Guglielmo Marconi took out a patent on wireless telegraphy, through air, with his "black box."

Nearly 120 years later, wireless communication is still seen as something of a dark art, able to transmit multi-gigabytes of data through air.

For the subsea industry, it is an even darker art. The challenge is to harness wireless technologies—using sound (acoustic waves) and electromagnetic spectrum (EM) waves (radio and free-space optics)—to enable through-water communication, control, and even power transfer, between a suite of permanent and mobile subsea hardware and topsides, vessels, or onshore control and monitoring centers.

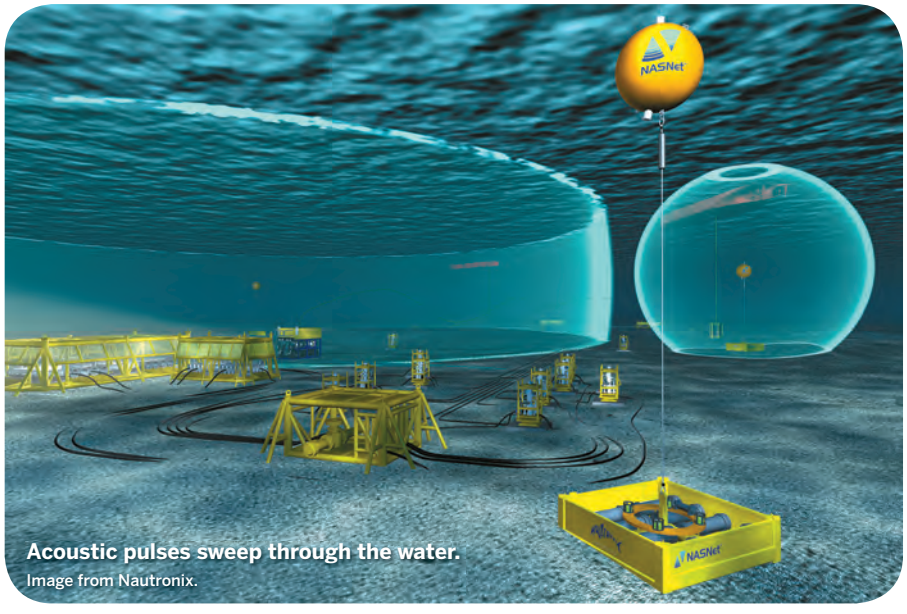
While acoustic technologies have been used subsea for some time, and radio frequency (RF) is starting to become established, there continue to be developments in both. New technologies are also emerging, such as free-space optics (FSO), offering further capabilities into the field.

However, according to the Subsea Wireless Group (SWIG), an industry body comprising technology firms, service providers and operators, few applications are addressed by just one of these technologies, due to the unique capabilities and limitations of each.

At the moment, there is also limited interoperability between different technologies and manufacturers' devices. SWIG hopes to improve the situation. The group was formed with two main aims: to enable interoperability by developing standards, and to help those wanting to use such technologies understand the benefits and limitations of each.

There is no easy answer to the question operators want answered; "how fast and how far can it communicate," says Ian Crowther, a director at Edinburgh-based WFS Technologies. "It is dependent on many things, not least if a particular system can work in a particular operating environment.

"Optical systems can carry very high bandwidth and, provided the water is clear, transmit over relatively long distances," Crowther says. "Radio is less sensitive to the environment, communicating through high levels of turbidity, inside complex structure and through solid barriers including the seabed, concrete and even metal. But it supports



Acoustic pulses sweep through the water.
Image from Nautronix.

Subsea wireless video transmission.
Image from WFS Technologies

lower bandwidths than optical systems."

Acoustic signals, or sound waves, travel more slowly through water than electromagnetic (RF and optic) waves (although sounds travels faster through water than air), but, because the wave lengths are longer, and frequency shorter, they travel further and are more robust, but have a lower bandwidth, so carry less data.

Wireless signaling works by encoding, or modulating, a sound or EM wave by altering its shape in a way related to the data required to be communicated.

Over time, methods have been developed to create more complex signals, or wave-shapes, by modulating the amplitude, frequency or phase of the signal either in analogue or digital data format. But, the transmission methods for acoustic and EM signals differ.

Standards

SWIG is developing a set of standards to support interoperability between acoustic, radio and optical systems subsea.

Work began on this body of standards in 2012, focusing initially on radio. The draft subsea radio standard was peer reviewed last year, then presented to the American Petroleum Institute (API) Subcommittee on Subsea Production Equipment (SC17) in January. No decision has been taken yet as to which subcommittee it will come under. This will be discussed at an API meeting in June.

"Radio was chosen first because it was the easiest standard to develop given the number of radio standards available for industrial applications," Crowther says.

"The idea is it would also create a template for the others, with future standards referencing the first. Work has begun on acoustics and free-space optics standards. Work will begin on subsea inductive power transfer in mid-2014.

These standards will be brought together to form a single hybrid technology standard, to provide a platform on which all the technologies can work together on certain levels."

The initial work on the acoustics standard has focused on investigating how to define an open standard in a relatively mature market with several de facto standards developed by competitors, most of whom are members of SWIG.

Differentiating subsea wireless technologies

There are currently three types of subsea wireless communication technologies: acoustic, radio, and free-space optics (FSO).

Each can be used on their own, and together, for subsea wireless communication. Performance factors to be taken into consideration for deployment are: bandwidth, range, efficiency, cost, and reliability.

Each have their own benefits. Acoustic through-water communication, for example, offers a long-range solution, but is limited in the data it can transmit, while optical communications can transmit HD video over a 1-500m range, but its signal is susceptible to turbidity, bio-fouling and light interference.

Here we give and introduction to each, with help from SWIG and its members.

Acoustics

Acoustic subsea communication is the most established through-water wireless communication technology in the offshore oil and gas sector.

It has been used in the industry for more than 40 years, but it has only recently been honed to a level at which operators are confident to use it for primary control on critical applications, such as primary control of subsea well isolation devices.

Acoustic signaling uses pressure (sound) waves in water. Their lower frequency means less data can be transmitted than a radio or optical signal; but it can be transmitted significantly further because water attenuates pressure waves far less than optical or radio wave forms.

One of the best known uses for underwater acoustic signaling is positioning, for vessels or subsea assets, such as remotely operated vehicles (ROVs) or autonomous underwater vehicles (AUVs), via long, short, and ultra-short baseline positioning techniques.

Acoustic's use has spread to other applications, such as Tsunami detection. This conveys data from pressure monitors on the seabed to floating buoys, which then transmit the signal, and data, via satellite, to onshore receivers. Acoustic communication is also used widely as a back-up to wired communication for divers, and to send control signals or general data from sensors, loggers, or other monitoring equipment subsea.

"Over the last 30 years, hydro-acoustic signaling has evolved significantly," says Ben Grant, technology product manager,

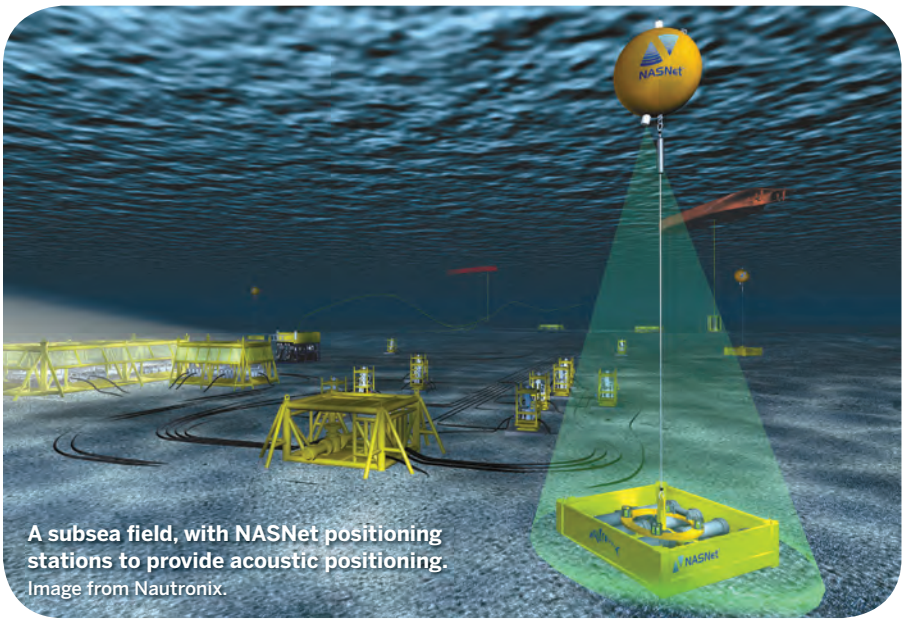
Subsea wireless technologies quick reference

Meter	Acoustic	RF	Optical
Bandwidth	Text message	Streaming video	HD video
Maximum range	100-10,000m	1-100m	1-500m
Environmental limitations	Turbidity Gas bubbles Bio fouling	Motor interference Steel structures	Light interference Bio fouling Turbidity
Efficiency	High efficiency for range performance Low efficiency bits/joule	High efficiency bits/joule Low efficiency range performance	High efficiency bits/joule Low efficiency range performance
Unit price	$10,000-25,000	$5,000-20,000	$10,000-100,000

Subsea wireless communications comparison

Parameter	Acoustic	RF	Optical
Frequency	~kHz	kHz – MHz	1014 – 1015 Hz
Wave speed (m/s)	1.5E3	3E8	3E8
Propagation loss	>0.1 dB/m/Hz	~28 dB/km/100MHz	Depends on turbidity
Typical antenna size	0.1 m	0.5m	0.1m
Typical comm data-rate*	~10Kb/s	~Mb/s	~100Mb/s
Typical range*,**	~5,000m***	~10m	100's of m
Efficiency	~102		~105
Major limitations	Bandwidth	Power	Water turbidity

Source: SWIG.



A subsea field, with NASNet positioning stations to provide acoustic positioning.
Image from Nautronix.

Nautronix, based in Aberdeen. "Early implementations of acoustic communications and positioning systems were seen as being unreliable and susceptible to interference.

"Going back 30 years or so, acoustic systems typically made use of single frequency, monotonic pulses. This form of signaling was relatively straightforward to generate with the available hardware of the time, but it was susceptible to interference. Since then, the underlying signaling has developed dramatically and signal integrity has increased substantially, leading to an overall increase in the robustness of acoustic systems."

More recently, spread spectrum signaling (sometimes referred to as digital signaling, due to a change from traditional analogue systems) has been developed, producing a more robust signal, with greater range capabilities.

Spread spectrum signaling works by sending symbols (spreading codes) to represent single information bits. Typically spreading codes are phase-modulated onto a carrier wave, and continuously transmitted. This method greatly improves the signal-to-noise ratio, and also improves the timing accuracy for positioning systems.

This type of acoustic communication was developed in the mid-late 1990s, for underwater defense applications, and was first introduced into the oil industry in the early 2000s by Nautronix, who have developed direct sequence spread spectrum acoustic signaling technology for underwater.

It is now being used in positioning and control applications, including wireless control of subsea blowout preventers (BOPs) or isolation devices. Here, it has predominantly been a secondary system, backing-up a primary wired system. But, some are starting to use it as a primary system (see case study).

New acoustic systems are also merging positioning and control capabilities within a shared subsea equipment. An example of this is Nautronix's NASNet system, which provides field-wide life-of-field positioning and communications.

In 2008, Murphy Oil deployed an acoustic control system for a surface BOP application in 1200m water depth, on the Azurite FPSO offshore Congo. This application made use of a subsea isolation device in conjunction with the surface BOP. The acoustic system provided primary control of the isolation device. It was used for a continuous two years.

The modulation scheme was an acoustic digital spread spectrum (Nautronix's ADS²). It operated at a central frequency of 10kHz and sent a heartbeat signal every five minutes, to ensure it was still in operation, with data and control as required. Power supply was via a lithium battery. Two transducers were used topside and subsea, for redundancy.

The deployment removed the requirement for a control umbilical, removing a failure point, and reducing effort required to deploy the subsea isolation device.

Radio

Radio frequency (RF) subsea wireless communication is relatively new to the oil and gas industry.

Radio waves lie on the electromagnetic spectrum below 300GHz. Terrestrially, they are used by mobile phones, AM/FM radio, television, cordless phones, Wi-Fi and Bluetooth.

Extremely low frequency (ELF) systems were used for submarine communications during the Cold War. Operating at 76-82Hz, they sent a few characters per minute across the globe, acting as signal to another submarine to surface for higher-bandwith communications using terrestrial radio.

To create a radio signal, electrical energy is changed into electromagnetic energy. The transmitter provides electrical current at an appropriate frequency. The signal is then modulated, to carry data, and launched via an antenna.

A receiver antenna detects the signal, which is then demodulated at the remote receiver.

Radio signals are attenuated when propagating through conductive media. Seawater is particularly conductive. Attenuation increases with frequency in the radio spectrum, therefore subsea radio systems use low frequency radio.

At very short distances (<cm) radio can support data rates up to 1Gbps (i.e. HD video), using a higher frequency, enabling great data to be modulated into the radio waves.

RF signals are immune to acoustic noise interference, and any negative effects of turbidly and bio-fouling. Subsea RF also doesn't suffer interference subsea from other radio, i.e. radio stations, or permanent magnets.

Using low power processors and techniques developed for the mobile phone market, the latest generation of subsea radio are energy efficient and designed to operate for many years off battery.

Subsea radio can be subject to interference from nearby sources of EMI (Electromagnetic Interference).

Common sources of EMI include electric thrusters and high voltage transformers.

The resilience of the latest subsea radios to local EMI continues to improve provided good practice is followed it is possible for subsea radios to be deployed on most subsea structures and vehicles. Disturbances can also be created from ferrous or other magnetically active materials, or electrically induced magnetic fields, such has motors or transformers, moving equipment.

To overcome such limitations, digital signal processing can be used. Data is converted to code-words or symbols, which are applied to the carrier wave using a digital to analog converter. Recent developments have seen RF bandwidths increase,

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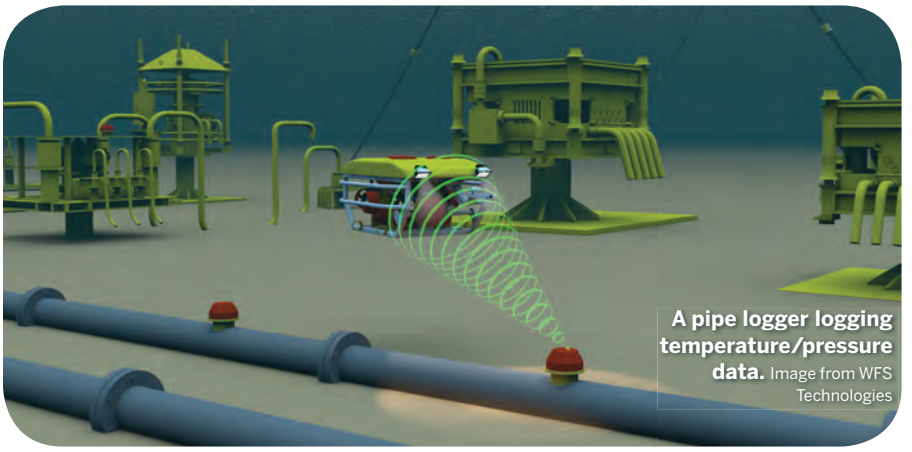


A pipe logger logging temperature/pressure data. Image from WFS Technologies

WFS Technologies recently delivered wireless communication systems to Baker Hughes for a pipeline pre-commissioning project.

The firm's Seatooth S100 system was used for wireless data logging during pipeline pre-commissioning on a project in the South China Sea, in 1000m water depth. The data transfer rate was 2.4kbps over 5m range through seawater (the system can operate at up to 4.8kbps up to 5m through water).

The transmitter included a Seatooth S100 connected to a hydro-test skid. The receiver comprised a Seatooth S100 mounted on the remotely operated vehicle (ROV), but key was its lower power use, relying only on batteries.

Both units were bidirectional and no configuration was required; the system was ready to plug in and deliver serial communications wirelessly between the test skid and ROV. Hydrotest data was downloaded at high speed, despite the high levels of salinity and turbidity.

due to advanced digital signal processing and signal compression techniques.

RF can transmit with greater band widths, more quickly than acoustics, is able to cross the water to air boundary, as well as through solid objects, such as pipe walls or ice. However, due to signal attenuation (degradation) through water, its range is limited.

RF has been used in the oil and gas industry since the 2000s. In 2006, WFS launched it's the Seatooth S1510 Medium range communications system, which is able to transmit signals of up to 16kbps over 20m in seawater, and the Seatooth S5510, able to transfer 1-10Mbps up to 1m through water.

Successful trials using an HD camera clamped to an asset with a 3-6m range to give multiple viewing angles during subsea construction operations have been run by WFS with Technip, Canyon, Fugro, and Subsea 7.

In the North Sea, a new generation of pipeline/flowline flow assurance solutions radio-enabled subsea instruments is being deployed.

This could be used to monitor pressure and or hydrate build-up, for example, building on existing internal pipeline inspection using pipeline inspection gauges. This would utilize wireless communications through the pipe wall, using modems on the PIG and ROV to receive the data, across the higher bandwidth.

Freespace optics

Free-space optical (FSO) communication offers the greatest potential for high data-rate communication, including HD video in real time subsea, but it also poses challenges and there have been few commercial applications to date.

FSO can have a higher data rate than any other approach because its beam is more collimated (light whose rays are parallel, and therefore will spread minimally as it propagates) and its short waves (higher frequencies) can carry more data.

It uses modest antenna size of about 10cm, with modest power consumption. It suffers less from interference from electromagnetic fields, acoustics, and, in deep-water, background sunlight.

But, subsea FSO is challenged by high extinction and the immense variability in the optical properties of ocean waters.

FSO uses visible light, in the blue-green region of the visible light spectrum, between blue and green on the electromagnetic spectrum, to communicate underwater wirelessly. This is because seawater is light absorptive, except around a 400-500nm (nanometer) wavelength window—the blue-green region of the visible light spectrum.

Blue-green light is therefore able to be transmitted as a continuous wave or pulsed wave, using semi-conductor light emitting diodes (LED) and laser light sources, and detected using highly sensitive, PIN, APD (avalanche photodiode), or single photon detectors.

With today's technology, FSO range is limited to less than 1km at high data-rates (sub- Mb/s), due to beam scattering and beam absorption in water.

Ocean water also has widely varying optical properties, depending on location, time of day, organic and inorganic content, as well as temporal variations, such as turbulence and surface motion.

Irradiance levels, even in clear water at 0.5 - 1 km distances, are comparable to those predicted for interplanetary laser communications.

FSO can also suffer from inter-symbol interference (ISI), a form of distortion of a signal, in which one symbol interferes with subsequent symbols, which has a similar effect as noise, and the transmit signal can be dispersed, due to power scattered in water.

To circumvent some of the limitations of free-space optics, optical link concepts have been proposed, using underwater repeaters (transceivers/relays) to transfer data to and from life of field AUVs, or along a network of links, spaced 0.5km apart, to send a signal.

Significant research and testing has been carried out in this field, however, to date, there are few commercial systems available.

Woods Hole Oceanographic Institute engineers recently developed and patented a free-space, underwater optical communications system using light to transmit data through water.

The system, BlueComm, provides 1 Mb/s bandwidth at ranges up to 200m. The system could be combined with underwater acoustic communication technology to provide more modest bandwidths over longer ranges.

BlueComm has been demonstrated in a 2010 project, in which it was used to control an ROV that was installing equipment on the seabed at the Juan de Fuca Ridge in the Pacific Ocean.

Woods Hole has been working with UK-based subsea communications firm Sonardyne International, to get the technology ready for the marketplace. OE

Cooling subsea power

Siemens says its subsea power grid aims to be the first at water depths down to 3000m at long step-outs. Elaine Maslin went to find out more.

Siemens' subsea power grid visualization.
Image from Siemens.

At a research center in Trondheim, on the northern coast of Norway, Siemens is close to completing a new system to help power the subsea factories of the future.

Siemens' says its subsea power grid will negate the need for multiple power cables from power suppliers to power consumers on the seafloor, reducing or eliminating the need for equipment topside.

It will also enable longer step-outs, in harsher environments, and increase oil recovery by enabling more subsea boosting and gas compression facilities.

Key to Siemens' system is containing nearly all of it in balanced pressure environments, including heat-producing components.

By using oil to fill the modules, instead of gases, they will be at the same, or absolute, pressure to the surrounding seawater, reducing the pressure resistance requirements on the vessels they are encased in, and therefore the system's scale and weight.

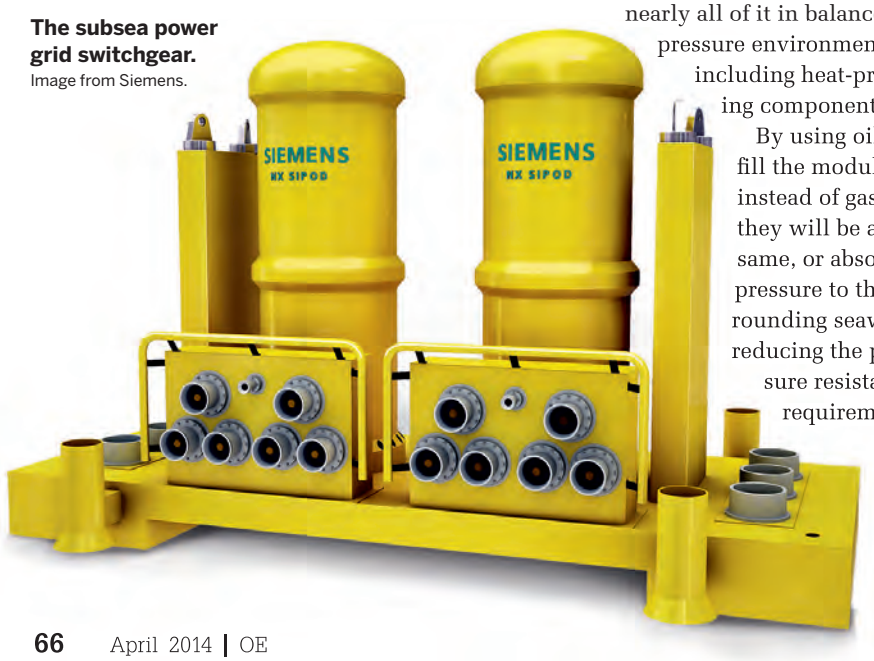
The individual modules will be connected by Siemen's 36kN subsea connector, with power supplied via one HV cable, containing the 36-145kV power, control, and signals cables, with monitoring, and firmware upgrades able to be performed remotely, potentially from onshore, up to 200km away.

Pressure-compensated equipment subsea is well established in the industry. But Siemens is aiming to put nearly the entire system, including electrical equipment and power electronics, in this environment. This means those components that produce heat need to be naturally cooled by convection to the surrounding seawater.

"This is a major technology challenge," says Jan Erik Lystad, head of Siemens' Subsea Technology Centre, Trondheim. "I think this will be the state of the art in 10-20 years' time."

The 155-tonne 6Mw system, which comprises a 25-tonne transformer, 30-tonne switchgear, and 100-tonne variable speed drive (VSD), or

The subsea power grid switchgear.
Image from Siemens.



frequency converter unit, has been in development and testing since 2009. A prototype is under construction, with the first transformer complete and in storage, following shallow water testing in 2012. The subsea switchgear is in assembly, and the VSDs completing final testing and qualification to 3000m water depth before assembly and testing in 2013-14.

Origins

The origin of the system was a project with Norway's EMGS AS. Siemens was asked to provide a power converter for a towed electromagnetic seabed logger, used for performing electromagnetic surveys offshore.

In the initial version, the power system was contained at atmospheric pressure in a cylindrical pressure vessel. The differential pressure created at depth caused leakage, so alternative means of containing the power systems were considered.

In 2004, oil was used, creating the start of Siemens' balanced pressure system. It was tested in water in 2005, and qualified to 3500m water depth, or 400 bar. Due to the balanced-pressure system, it has a Plexiglas top. Development on this, and the grid, involved close co-operation with the Norwegian University of Science and Technology in Trondheim. Some 16 towed units have since been delivered and a sixth-generation system is under development.

"The big difference with the power grid is that the system is on the seabed for 20-30 years," Lystad says. "We have used oil for years in transformer production. But we did not know how it would be when you put it on the seafloor—that had to be investigated and qualified by our qualification project."

The alternative is to have atmospheric pressure vessels, which require active cooling systems, in addition to thicker walls, making systems significantly larger, with greater numbers of components.

Siemens says it set out to use already proven technology, and qualify it for the subsea environment. The key was working out the cooling systems on an oil-filled balanced pressure system. "We have to control the equipment inside, including what heat it produces," Lystad says. "The distance between the equipment inside and the walls, and how you construct the housing is important, to create a good convection through the seawater."

Complexity

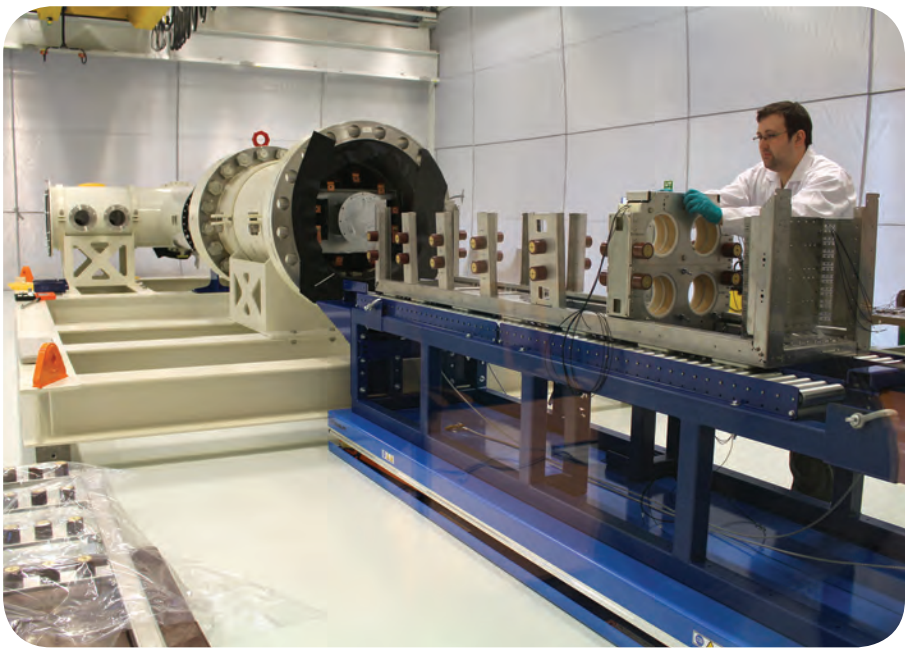
The most complex component to design was the VSD module, accounting for about two-thirds of the research and development cost.

"This a complex unit," Lystad says. "You have a lot of power modules inside, with many parts, and even if we have high efficiency, a lot of heat is generated and this must be removed and transported into the surrounding seawater."

Siemens' prototype VSD is built up by total 18 power cells (six cells per phase connected in series). All power cells operate in oil and under pressure. The power cells are cooled by the surrounding oil, which circulates inside the module by natural convection. The oil is cooled through the enclosure, which is relatively thin due to the system being at balanced pressure, by the surrounding seawater.

Since 2009, Siemens started using MIDEL 7131, a biodegradable liquid, which has good insulating properties and is often used as transformer oil where environmentally friendly solutions are required. "The main issue with the oil is when you fill the system, it has to be done very slowly so you are sure oil penetrates every hole and pocket,"

Jan Erik Lystad, next to a pressure vessel used for testing components at Siemens in Trondheim. Photo by Elaine Maslin.



The switchgear in assembly. Photo by Elaine Maslin.

Lystad says.

To control the pressure, during lowering, each module is fitted with a pressure compensator, which keeps the pressure inside the module the same as outside as it is lowered through the water column, compensating for both the compression and heat, which influences the oil's volume.

The only component not contained within oil is the medium voltage switch, within the switchgear. None have been developed in oil to date, Siemens says, so it is contained in an atmospheric canister, which is integrated onto a pressure-compensated base module.

While the prototype is a 6Mw unit, it is based on a modular system, which could be built into larger or smaller systems. The switchgear, for example, is itself built in modular form, so that it could be scaled up or down, by stacking additional sub-assemblies.

Redundancy

The system will have inbuilt redundancy. The VSD has a three phase power circuit, built up by six power cells in each phase. The power circuit has a cell by-pass system, where a fault in a power cell can be automatically by-passed to allow the VSD to continue operation without any intervention. Several cells can be bypassed and still maintaining full power of the VSD.

Condition-monitoring will involve monitoring and analyzing temperature and several other parameters to predict when something might need replacing, in order for preventative maintenance to be carried out during planned shutdown periods.

Bjørn Rasch, head of Subsea Power, Siemens Oil & Gas, with the transformer module. Photo by Elaine Maslin.

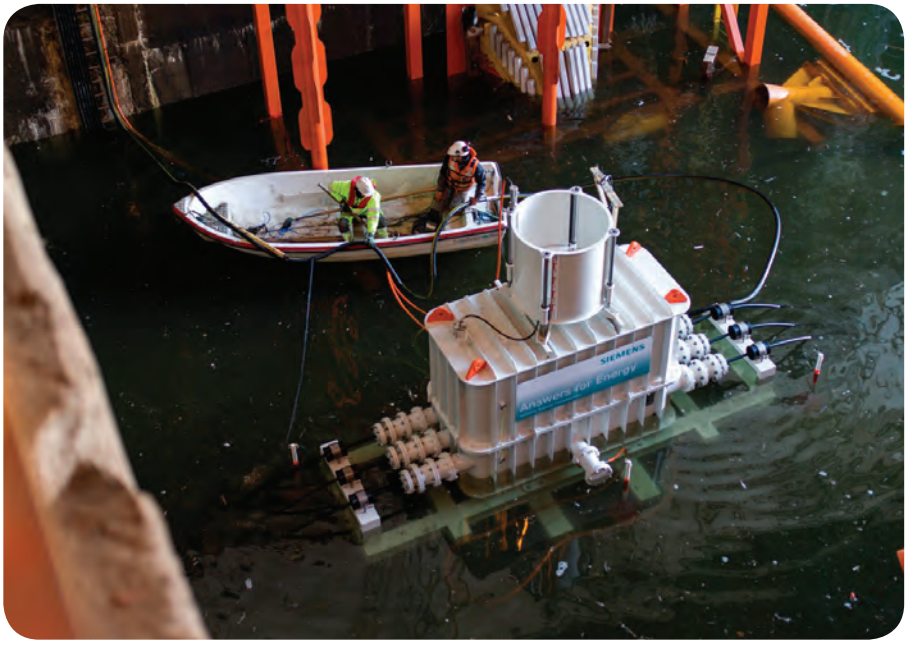
Siemens started testing components three years ago, in air, then in oil, at pressure, and included heat and stress tests. At its laboratories in Trondheim, Siemens has 23 pressure vessels, of varying sizes, which enables it to test components up to 530 Bar. Conditions in up to 3000m depth have been simulated in the laboratory and every sub-assembly has been pressure-tested.

Components are then tested in water, to perform heat runs. The entire system will be assembled and complete a short dry heat run before it is endurance tested underwater in a former submarine station, near Trondheim, in 2015. The complete system will not be pressure-tested as a single unit until its final installation.

"The next step is how we expand the system," Lystad says. Siemens has been working on a modular system, with standard size comprising six modules. Bigger and also smaller systems will need to be built, and the system qualified for other ocean-based power consumers or exporters, such as offshore wind turbines or tidal energy farms, but only when it becomes economical within these industries.

"When this started, I thought it would be impossible because of the issues around the liquid and cooling, and that this has to be on the seafloor for 20 years," Lystad says. The future could see power generation on the seafloor. However, Siemens' doesn't think this will arrive any time soon, with public antipathy towards nuclear, which had been an option, and fuel cell technology limited by requiring very pure natural gas and being limited in scale, says Bjørn Rasch, head of Subsea Power, Siemens Oil & Gas.

Siemens' subsea power grid project is support by equal partner Chevron, ExxonMobil, Statoil, and Petrobras, as part of a joint industry project. OE



The transformer undergoing shallow water testing. Photo from Siemens.

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Preventing integrity problems for flexibles

Experience can play a major role in the development of an effective flexible pipe integrity management system (FIMS) and plan.
Photos from Flexlife.

Unbonded flexible pipes have been deployed in the global oil and gas industry for more than 30 years, and historically they have proved their extreme reliability. However, like all long serving products, they can suffer integrity problems over time, and a lack of inspection or maintenance can be one of the biggest issues affecting their performance.

By Stuart Mitchell, Flexlife

One of the most common integrity issues relating to flexibles can be mechanical damage to the outer sheath, or a failing of the venting system leading to a pressure breach of the outer sheath.

Globally, about 35% of all flexibles experience an issue of this kind. This problem particularly affects flexible risers as opposed to flowlines. Given the number of pipes that suffer outer sheath damage, and the history of failures in pipes leading to loss of containment around the world related to this, integrity is clearly an issue that needs to be addressed.

During operation, a buildup of gases can occur within the annulus of the flexible that need to be vented.

Subsea pipelines are less susceptible to this issue because of the hydrostatic support of the seawater around them. A breach in a subsea flowline experiences fewer corrosion problems, due to reduced oxygenation of the seawater and support from the flowline's cathodic protection (CP) system.

By contrast, risers do not enjoy the same near-sea surface hydrostatic support. When over-pressurised, the outer sheath of the riser will tend to burst at the sea surface, or splash zone, where it is least supported and where there is a higher incidence of oxygenated seawater and sporadic – or no support – from the CP system. This can create significant general corrosion problems and lead to a product which is unfit for service.

The service life of the riser can also be reduced due to corrosion fatigue

issues associated with a seawater-flooded annulus.

Corrosion can significantly reduce the operating life of a pipe, which can then lead to failure and potentially a risk to life or the environment.

As an example, for a typical riser of about 350m in the UK North Sea, the financial impact has been estimated by Flexlife at approximately US$5 million, once vessel time and replacement costs have been included. Add to that a current lead time of at least a year, with all the implications associated with deferred production, and it becomes clear that effective repair and ongoing maintenance of risers is a much more cost-effective solution.

The North Sea has traditionally led the way in developing robust and proactive riser inspection and integrity plans on the back of stringent regulation. However, regulatory requirements around the world differ. An outer inspection by an ROV may miss outer sheath damage leading to internal issues in such a complex structure as a flexible pipe. It only takes a hole the size of a thumbnail in an outer sheath, letting seawater in, to potentially create localized corrosion and corrosion fatigue.

Understanding the risks associated with riser integrity is critical to the optimal effectiveness of the system. By deploying inspection and repair techniques as early as possible the operational life of the pipe can be extended.

Taking a step further back, the development of appropriate integrity systems and planning can actually help prevent problems occurring in the first place.

Approaching the problem

There are a number of approaches a company can take in ensuring its riser integrity is maintained and the pipe performs at the optimum. One approach is to involve a partner that understands flexible pipe, including its design and manufacture, at the earliest possible juncture, to provide a detailed understanding and analysis of the risks that may be encountered by the pipe in operations, and how those risks can be mitigated in its design.

A key element of this approach is the implementation of an appropriate and ongoing risk-based – rather than prescriptive, time based – integrity program. This should start from the very beginning of structure selection through the testing and installation stage and beyond, and will consider such factors as damage during installation, operational risk factors, and the design of operational systems, such as the annulus venting system. It will incorporate a regular inspection program to identify any immediate issues, or warning signs which will require action at a later stage, as early as possible.

Another approach is where a company installs a pipe and decides retrospectively that an integrity system and plan is required, or they are faced with an immediate issue and require a solution. Of course an integrity plan can be created at that stage but activity is very much reactive. Historically within the industry, the retrospective program has been the more commonly adopted approach.

As an example, the majority of Flexlife's inspection activity relates to older pipes in excess of five years old. Of these, approximately 40% have shown either outer sheath damage or venting system issues.

A third approach is the knock on effect from field life extension, where a client requires to understand the predicted ability of a pipe to cope with potentially new demands. In this situation, a review of the pipe as soon as possible is recommended to assess any damage to it and to calculate the degree of impact that will have on the remaining service life.

All three approaches require the deployment of modern and novel inspection technology.

A relatively straightforward, quick and cost effective method to determine whether or not a pipe has an integrity issue is an annulus test where nitrogen is introduced under positive pressure into the annulus, or a vacuum is created.

In both methods, which involve no reduction in production, the aim is to establish the size of the free volume in the annulus, which will provide information on the outer sheath integrity and therefore any seawater ingress.

It is a test which can be undertaken at any time in the pipe operating life, but the sooner it is carried out the better, preferably at the installation stage. Repeating this test based on a risk-based timeframe can help identify any annulus issues at the earliest possible stage.

Deploying Solutions

As testament to its experience and expertise in the sector, Flexlife, has carried out

Regular inspection, monitoring and repair can extend the operational lifespan of the flexible, optimising production and mitigating risk.

Flexlife is expert in providing life-of-field subsea engineering and technology globally.

approximately 200 riser annulus tests for most of the major operators globally, and the company has also established a strong share of the UKCS market in this field.

In one particular case study, the company carried out an annulus testing project for a client on a North Sea field where seawater flooding was found in some of the annuli of the risers. Flexlife encountered that some of the older risers had a completely blocked venting system, preventing an assessment of their condition.

The project involved the Health and Safety Executive (HSE) because a riser inspection was not possible, contrary to industry practice. Because the condition of the pipes was not known, there was also a risk having to shut down production, a consequential loss of revenue and a real concern that the installation may never resume production.

Flexlife deployed the ultrasonic scanning tool, Neptune, a ROV-mounted subsea inspection tool designed by Oceaneering that utilizes Flexlife's patented UT scanning technology in order to determine the state of a flexible riser's annulus with 100% accuracy.

Data gained from Neptune scanning provides invaluable information relating to the condition of the flexible riser annulus. The inspection tool also enables operators to make informed decisions regarding the remnant life of these production-critical assets.

Since Neptune does not require access through annulus vent ports, this method is currently the only means of accurately determining the integrity of flexible pipe annuli on risers with restricted or inaccessible vent ports.

The inspection tool was able to categorize precisely where seawater was prevalent within the riser's annuli, enabling an inspection of the armor wires during operation to measure for corrosion.

Fortunately in this project minimal corrosion issues were detected. The information was reported back to the HSE, which allowed the pipes to continue to operate. The risers were changed out at the operator's schedule, thereby minimizing down time, the number of replacement risers and delays in production, saving several million dollars.

While Neptune provides detailed pipe inspection, ongoing oxygenated corrosion can be mitigated through the use of Flexlife's modular Armadillo system, which can be constructed in bespoke lengths and diameters to encapsulate and seal known outer sheath damage.

The Armadillo will prevent the ingress of further oxygenated seawater into the annulus, and where the pipe structure has been proved to be suitable for continued operation through engineering, allow that pipe to continuing operating.

The Armadillo is clamped around the flexible at the location of the outer sheath damage and is filled with a sealing fluid, which seals off the damaged section of the riser. The repair gel cures to form a solid while the elastic nature of the gel and design of the Armadillo permits the riser to flex as normal whilst continuing to prevent seawater ingress.

For more restricted areas, the company has developed FlexGel, which is intended to be deployed around an annulus breach within an I-Tube or J-Tube, displacing the seawater. In doing so, the gel reduces further corrosion in the structural tensile armour wires of the flexible pipe, increasing its life.

There are a range of solutions available to solve riser integrity issues, from low-cost identification at the early stages to detailed inspection of the condition of the pipe through to the repair of outer sheath damage and an engineering assessment of the pipe's life expectancy.

However, establishing a program at the outset to appropriately design and regularly inspect a pipe, which would avoid these issues, represents a significantly lower cost and answers the risk question from the very beginning. OE

Stuart Mitchell *serves as global business development director for Flexlife, the life of field subsea engineering and technology firm, of which he is a founder. A degree-qualified chartered engineer, Mitchell has worked in the subsea R&D, technology and engineering space for 18 years and has specialized in unbonded flexible risers for the last 13 years.*

The inspiration for Flexlife came when Mitchell realized, through his own experiences that the available solutions to some of the most common subsea problems were not fully meeting the requirements of the market. Seeing a gap in the marketplace for an innovative consultancy offering its own patented solutions to these problems, Mitchell, with the help of his partners, established Flexlife in 2007.

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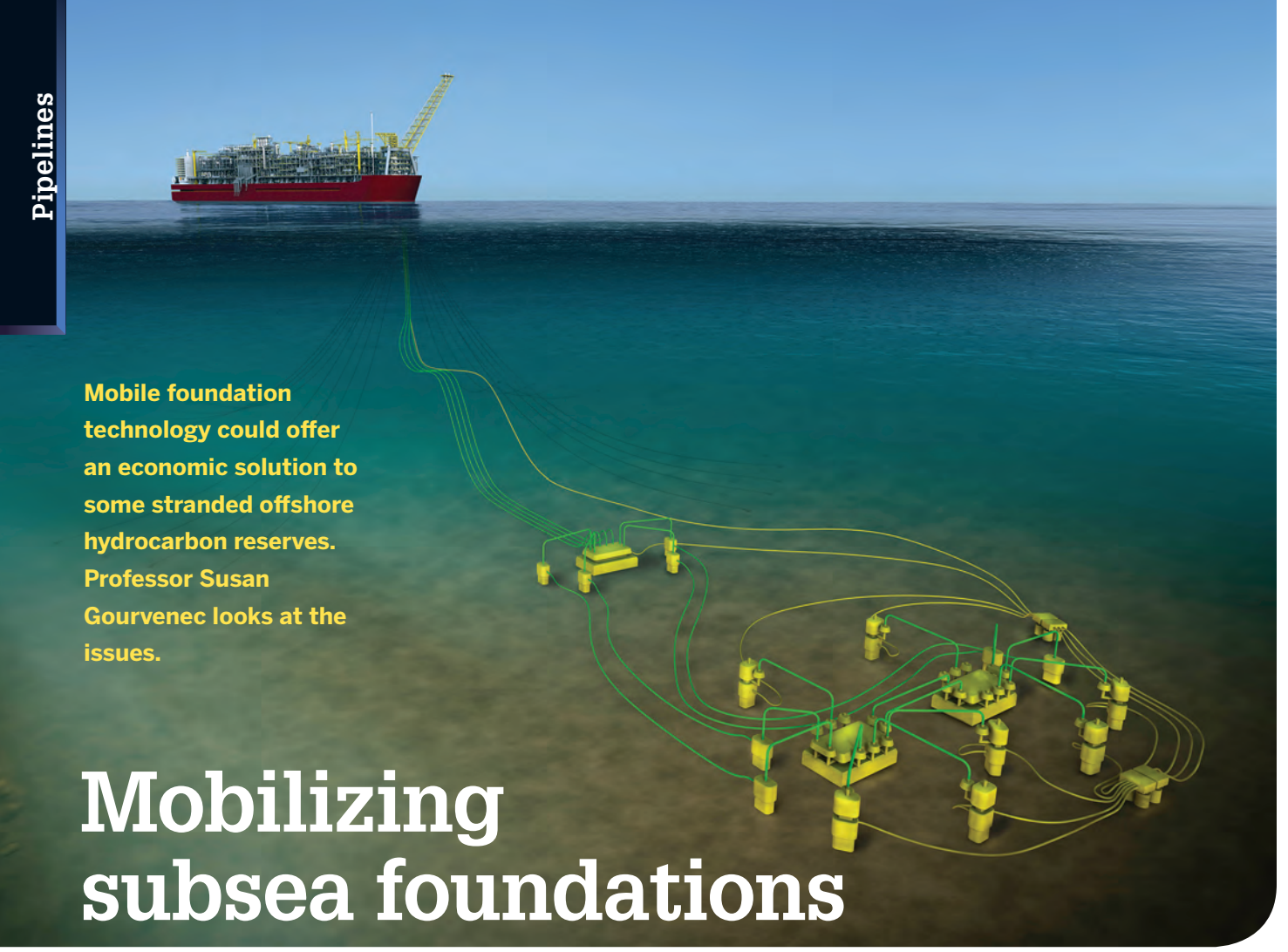


Mobile foundation technology could offer an economic solution to some stranded offshore hydrocarbon reserves. Professor Susan Gourvenec looks at the issues.

Mobilizing subsea foundations

Latest statistics show Australia's total petroleum output has an annual export sales value of more than A$25 billion (US$22.8 billion) and annual taxation payments by the industry of more than A$8 billion (US$7.3 billion).

One of the challenges the industry faces is unlocking the huge hydrocarbon reserves offshore Australia, and elsewhere, that are currently unreachable.

Australian research and development into mobile foundation technology is one piece of the jigsaw.

Existing foundations

Subsea developments involve a number of wells across a field connected by a network of pipelines, so-called infield flowlines. A variety of pipeline infrastructure supports the flowlines, such as pipeline end terminations (PLETs), pipeline end manifolds (PLEMs) and in-line tee structures (ILTs).

This seabed infrastructure is typically supported on shallow mat-type foundations, so-called mudmats, that are ideally small enough to be installed by the same vessel that lays the subsea pipelines, which transport oil or gas from wells to processing facilities.

Mudmats are typically 5-15m in edge length, but can be more than 40m in some cases. The purpose of the mudmats is to transfer the weight of the structure it supports over a sufficiently large area of the seabed so as to avoid unacceptable settlements and resist the lateral loads applied by the connected pipelines.

Offshore pipelines undergo cycles of thermal expansion and contraction over the lifetime of a field through cycles of start-up and shutdown. In service pipelines expand as hot oil or gas passes through them and contract when they cool due to a shutdown. The thermal expansion of the pipelines transmits lateral loads to the mudmats supporting the structures attached to the pipelines.

Increasingly, as developments move into deeper water, where seabed soils can be extremely soft, and as conditions such as operating temperature become more onerous, these foundations can be too large or heavy to be installed by the pipelaying vessel.

The requirement of a specialized heavy-lift installation vessel to be brought to site (to install these structures) adds considerable expense – pushing projects further up the cost curve.

The Prelude FLNG subsea architecture, supported by traditional mudmats.
Image from Shell.

Mobile foundations offer a solution

The term "mobile foundation" may seem an oxymoron—we typically expect foundations, and the structures they support, to remain stationary. It would be alarming if our homes or office buildings started to wander, but we accept that ocean-going vessels experience stability and mobility concurrently.

The concept of a mobile foundation is similar to a sleigh or ski on snow. It's a foundation that is engineered to slide or glide across the seabed to absorb some of the applied loads, rather than simply being engineered to be big enough to resist the loads and remain stationary.

A mobile subsea foundation might look much like a conventional mudmat foundation, at least at the seabed—comprising a rectangular plate resting on the seabed. Traditional mudmats are typically equipped with short skirts that penetrate

the seabed, whereas mobile foundations would be best designed to rest on the surface of the seabed to minimize the sliding resistance of the foundation. This encourages sliding rather than overturning.

A critical design feature of mobile foundations is that the predominant mode of displacement is translation, since overturning could lead to overstressing of connectors between the pipes and structure. A mobile foundation could be provided with sloping sides to assist in the desired translational motion should it settle into the seabed.

Where can mobile foundations be used?

Mobile foundations have particular potential in deep water or remote oil and gas fields that have been identified offshore Australia and elsewhere.

A pipeline heats up as hot oil or gas passes through it. This, in turn, causes thermal expansion along the length of the pipe and increased loading to the foundations supporting the connected pipeline infrastructure. To resist these loads can require a massive foundation.

Alternatively, a mechanical arrangement can be introduced to relieve the loads, with the pipeline termination being mounted on sliding rails. However, this solution involves a moving part that must remain operational during the life of the project, and the foundation footprint is still large because it must encompass the slider arrangement.

As an alternative, a compact mobile foundation can be designed to undergo controlled and limited sliding across the seabed to absorb some of the loads caused by this thermal expansion of the connected pipelines.

While some parallels exist between the mode of operation of a mobile foundation and a sleigh or ski, mobile foundations would not be intended for long distances of travel.

The movement would be limited to just a few meters at most, as a pipeline is turned on, heats up, and expands, and back again during shutdown, when the pipeline cools down and contracts.

The movement is periodic over the lifetime of the facility, each time the pipeline is started-up or shutdown, but would be sufficient to relieve loads both on the foundation and within the pipeline.

Mobile foundations will add to a portfolio of seabed infrastructure designed to allow movement. Other examples include the steel catenary risers that form trenches where they touch down on the seabed—which actually assist by easing this fatigue hotspot. Other examples are the installation of drag or plate anchors and lateral buckling of subsea pipelines.

Mobile foundations are a logical evolution of the now widely-accepted practice of allowing seabed pipelines to move in a controlled manner to accommodate operational loading.

Leading the way

Australia is well positioned to lead technology development of mobile foundations. Not only is it recognized worldwide as a centre of excellence for seabed engineering, but Australia has substantial stranded gas reserves, which coupled with Australia's geographic remoteness provides complementary drivers.

The industry is interested in a scientific basis for understanding the behavior of mobile foundations, but to date virtually no information is publically available.

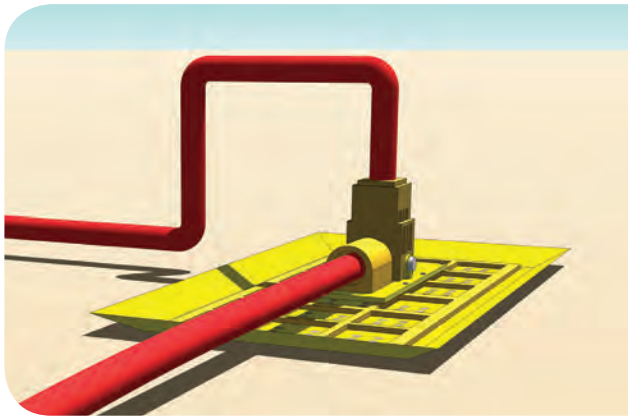
World-first experimental testing of mobile foundations at prototype scale is now being carried out at the Centre for Offshore Foundation Systems (COFS) at the University of Western Australia (UWA), supported by a three-year Australian Research Council grant, to create a design framework for industry for mobile foundations.

UWA is ideally placed to carry out the research, as host of the National Geotechnical Centrifuge Centre, which houses the busiest geotechnical centrifuge in the world. Geotechnical centrifuge modelling enables small scale models of geotechnical systems to be tested at accelerated gravity levels (up to 400x Earth's gravity), allowing field-scale soil stresses to be accurately replicated. Stress similitude is critical to capture the true response of geotechnical systems, while field scale tests of offshore geotechnical systems are prohibitive.

A first campaign of geotechnical centrifuge modelling of a prototype mobile foundation has been undertaken at UWA and observations of the foundation under realistic field conditions are promising.

The next stage is to develop a theoretically-based framework to describe the soil mechanics response of the seabed during the periodic cycles of foundation sliding, in order to predict the foundation response. Ultimately the method will be incorporated into a design tool for use by industry.

The Centre for Offshore Foundation Systems has a long-established relationship with industry and development of a design tool for mobile foundations will be carried out with input from operators, consultants, and contractors with an interest in the technology. The motivation for the project was driven by industry needs and the output of the research will be used by industry, so we will work with our industry colleagues to develop a usable and practical solution.



Schematic of a possible mobile subsea foundation.
Image from the Centre for Offshore Foundation Systems, University of Western Australia.

Conclusion

Costs associated with mobilizing a second installation vessel for subsea foundations are particularly significant for the bottom line of smaller developments and when vessels have to be brought in from far afield.

Mobile foundation technology offers an economic solution to a present challenge to offshore development, and will contribute to unlocking the huge hydrocarbon reserves located offshore Australia and elsewhere that are currently "stranded". OE

Susan Gourvenec *is a Professor at the Centre for Offshore Foundation Systems at the University of Western Australia. Gourvenec has more than 15 years of geotechnical engineering experience, with particular interest in offshore geotechnics. She is a consultant offshore geotechnical engineer to industry and member of the ISO and API Committees for Offshore Geotechnics.*

High hopes for growth

Mexico's road to passing recent energy reforms was forged by much needed collaboration in order to fix the country's productivity growth, which has been stagnating for nearly 30 years, Pemex CEO Emilio Lozoya told an IHS CERAWeek audience in early March. Audrey Leon listened in.

The passage of recent reforms in Mexico was a perfect storm, a rare event where the three main political parties (PAN, PRI, PRD) were able to put aside differences to do what is best for the country, forming the Pacto por México (Pact for Mexico).

"The three main parties agreed on 95% of issues including energy challenges," Pemex CEO Emilio Lozoya (pictured) said. "The political leadership of the president (Enrique Peña Nieto) and the three parties were key. After 75 years, it was quite a historic occasion."

The main focus of the energy reforms, Lozoya said, was to tackle a paradox. "Mexico has abundant reserves, but high energy cost," he said. "Mexico pays 70% higher electricity costs than US (its main trading partner.

"The main aim of the reform is to have new policy that allows Mexico to have competitive energy prices, and at the same time ramp up hydrocarbon production, especially oil, which has been in decline," Lozoya said.

Lozoya told Pulitzer Prize-winning American author, speaker, and economic researcher Daniel Yergin that the shale gas opportunity in the US, which has spurred tremendous job growth, had an impact on Mexico's government officials.

"Clearly what's happening in the US opened the eyes of our politicians," he said. "To the extent that Mexico can replicate (that success), in a regulatory environment that is conducive, is appealing. Cheap natural gas prices are re-industrializing some sectors of the economy. Mexico has a similar opportunity. We're committed to delivering on that."

Lozoya tweeted shortly before his CERAWeek speech that Mexico needs to invest in energy, at double the amount Pemex will invest this year. This year Pemex is due to spend US$27.7 billion, 85% of which will be spent on production and exploration. By 2018, Pemex hopes to increase total annual investment to $31.3 billion.

When asked about the lack of shale development, Lozoya said: "Mexico hasn't developed it because we have plenty of more practical and profitable opportunities. Mature fields are the immediate opportunity."

Mexico hopes to launch its Round Zero soon, which Lozoya said will be a great opportunity for private investors. Currently, Mexico's congress is waiting on Pemex to submit its list of fields that it wants to keep for exploration and production. The assets not on the list will be given up for sale. Pemex has until 21 March to submit its wish list.

Lozoya said Pemex is targeting 3MMb/d of oil production by 2018. It currently sits about 2.52MMb/d.

According to a January 2014 investor relations presentation, Pemex said it recognized the opportunity in deepwater Gulf of Mexico. Already, the company has acquired 124,790sq km of 3D seismic.

"When we look at the offshore opportunity, if you think about shallow water, Pemex has tremendous infrastructure there," Lozoya said. "Deepwater, in the northern area of Mexican territory, it is easy to use US infrastructure to get oil to market.

"The benefit of North American energy infrastructure is huge. Shale extends into Mexico, and US deepwater is similar to that of Mexico," he said, continuing that shared infrastructure could be key to development, but there would also be a learning curve.

Another aspect of the energy reforms will be a new Pemex. Lozoya said that after 75 years, Pemex will change its corporate governing structure to include a new board, with five independent members. Additionally, Lozoya said that the company will now be able to compensate workers with industry-competitive salaries. "This represents a way to develop and keep staff," he said.

Lozoya also discussed the opening of new subsidiaries, and the possibility of splitting the business into upstream and downstream sections. The company already opened a new procurement office in the US last year. OE

Pemex CEO Emilio Lozoya speaking at IHS CERAWeek 2014. Photo: Audrey Leon/OE.

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Mexico opens the door to foreign investment

After 75 years of monopoly, Mexico is initiating reforms that will allow foreign participation in domestic oil and gas exploration and production.

A 6th generation DP semisubmersible, Pemex's *Centenario GR* is capable of drilling in 3000m (10,000 ft) water depth. More than 85% of the rigs working offshore Mexico are classed by ABS. Photo courtesy of Grupo R

By Paul Delaire, ABS; Tom Nolan and Terry Hickey, ABS Group; and Stephen Gordon, Clarkson Research

After discussions and debates that have spanned decades, Mexico is in the process of implementing wide-ranging energy reforms that will end a national monopoly of oil and gas exploration and development that has blocked foreign participation for 75 years.

Mexican President Enrique Peña Nieto presented the constitutional reform to Congress on 12 August 2013. It was approved by the Senate on 11 December and by the Chamber of Representatives the following day. Mexico declared the reform constitutional on 18 December and published it in the official log of the Mexican Federation.

With these reforms, the playing field is about to change. For companies making their first forays into the country, this will pose challenges. For others with an established presence, the recent developments open the door to enormous opportunity.

As a company that has been active in Mexico for 58 years and has had a presence in the country since 1898, ABS falls into the latter category. It has been the preferred class society in the country for decades and has classed more than 85% of the rigs working in the Mexican offshore sector.

Domestic Production

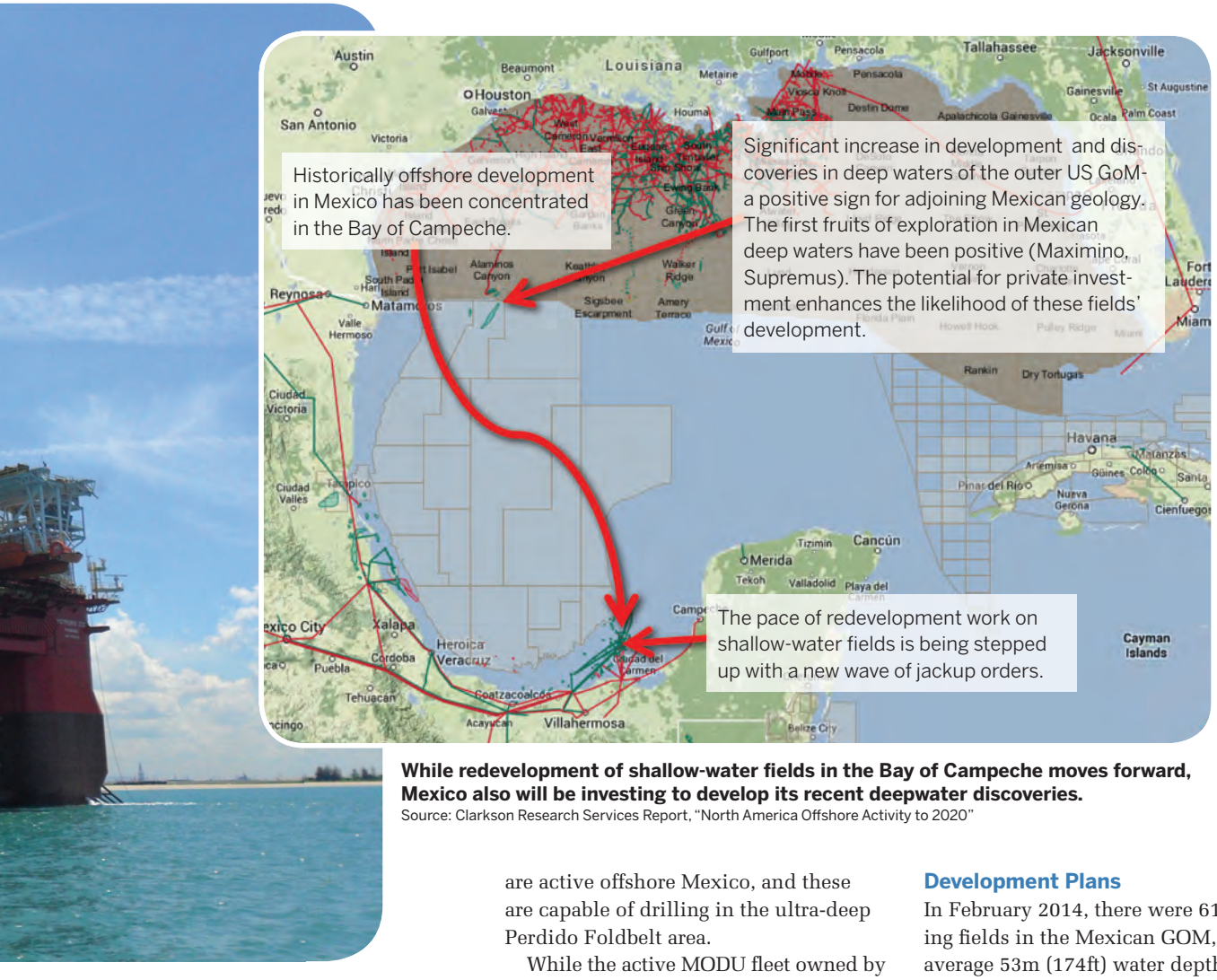
Mexico has nearly 10.5 billion bbl of proved oil reserves and approximately 17.3 Tcf of proved natural gas, but its legacy fields, the giant Cantarell and Ku-Maloob-Zaap in the Bay of Campeche, are in decline despite increased investment by state oil company Pemex. In fact, most, if not all, of Mexico's largest fields are now past their production peak in their present form and will require fresh investment to extend production.

Mexico's annual petroleum output has declined gradually in the last decade. Since reaching its peak of approximately 3.8 MMb/d in 2004 (about 74% of which came from offshore fields), production currently stands at about 2.9 MMb/d, with the offshore contribution now making up only 65%.

With the less complex fields already in development and many fields in decline, oil exploration and production is moving into new areas that present technical challenges. As Mexico opens its doors to foreign operators, the country will begin to lay the foundation for the technology transfer it needs to move into these frontiers.

Investment

The Pemex Business Plan, for the period 2010-2024, indicates a 20% increase in annual capital expenditure (capex) between 2010-2019, rising from $25 billion to more than $30 billion. Approximately 75% of that total will go toward exploration and production (E&P). The national oil company (NOC) is continuing a wildcat drilling program in the deepest sector of the Gulf of Mexico



While redevelopment of shallow-water fields in the Bay of Campeche moves forward, Mexico also will be investing to develop its recent deepwater discoveries.
Source: Clarkson Research Services Report, "North America Offshore Activity to 2020"

(GOM) close to the US/Mexico maritime divide, in the Perdido Foldbelt. Some of the E&P capex also will go toward redeveloping existing shallower fields to maximize recovery.

While much of the activity in Mexico has been onshore, the country has seen one very significant offshore discovery. Pemex's Maximino, the deepest discovery in the GOM in 2013, is the third of Pemex's quartet of recent wildcat discoveries in the Perdido Foldbelt area, preceded by the Trion discovery in August 2012, and the Supremus discovery in October 2012, and followed by the Exploratus find in January 2014. All of these potential developments are likely to require substantial foreign investment and technical experience to reach fruition.

Pemex's drive to arrest offshore production decline has contributed to rising drilling rig deployment in the Mexican GOM. As of February 2014, there were 43 jackups active in the area, up 26% from the beginning of 2013. Five additional mobile offshore drilling units (MODUs) are active offshore Mexico, and these are capable of drilling in the ultra-deep Perdido Foldbelt area.

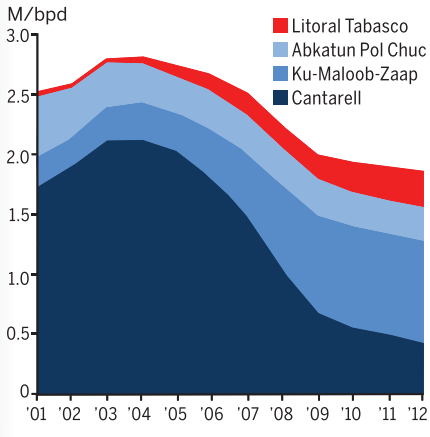
While the active MODU fleet owned by Mexican entities consists of 15 jackups and three semisubmersibles, the MODU orderbook for Mexican companies stands at 14 units (equivalent to 78% of the active fleet) all of which are jackups. Three are scheduled for delivery in 2014, and 11 are scheduled for delivery in 2015.

Development Plans

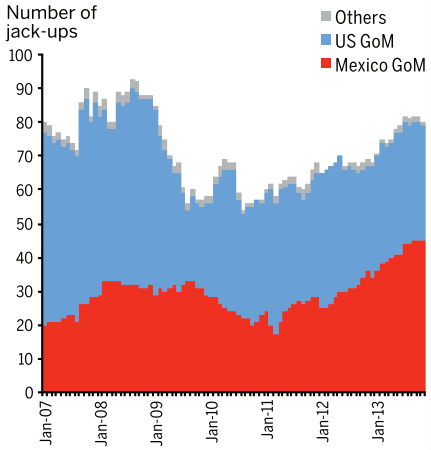
In February 2014, there were 61 producing fields in the Mexican GOM, with an average 53m (174ft) water depth. For Pemex to venture into deep water to develop its recent discoveries, it will be calling for support from international operators.

Mexican field development activity comprises a mixture of redevelopment on existing fields and new field

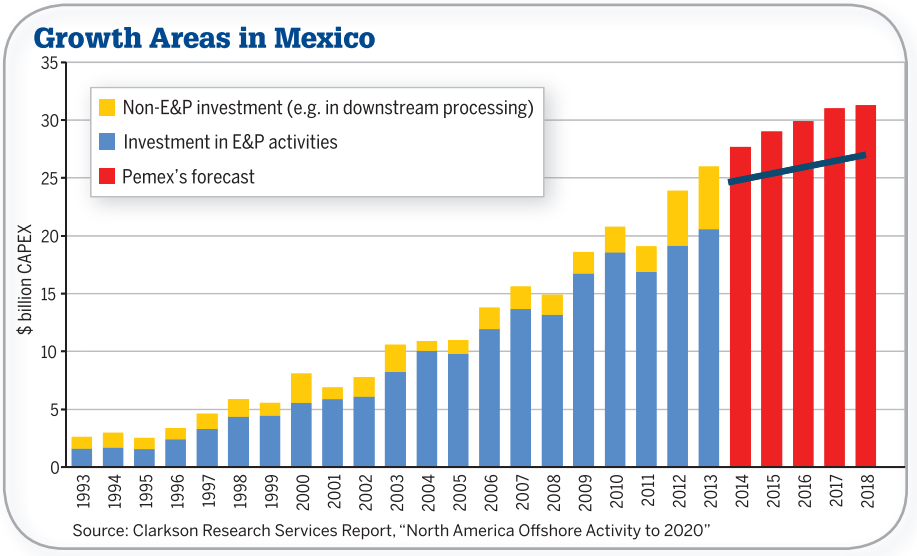
Key Mexican Field Production Trends



Jackup Drilling Rig Activity in North America



Source: Clarkson Research Services Report, "North America Offshore Activity to 2020"



developments designed to provide production volumes to compensate for the steady drop in production from the Canterell and Ku-Maloop-Zaap mega-complexes, where output is now in a process of managed decline. Despite the falloff in production from Mexico's existing large fields, however, the country presents major opportunities for vessel and structure operators, with major requirements expected for both redevelopment and new projects. The recent round of jackup ordering, for example, has included high-specification units destined for Mexico. And substantial support vessel needs also are expected to be generated by new project activity such as that on the Ayatsil and the Lakach developments in the southern sector of the Mexican GOM.

Pemex's Ayatsil heavy oil field, believed to be one of the most important in the Bay of Campeche in decades, is to be developed via four fixed platforms and a 300,000 b/d floating production, storage, and offloading vessel (FPSO).

The contract for transport and installation of the platforms was awarded to Dutch heavy lift specialist Heerema in July 2013, at an anticipated value of $114 million. Pemex is currently believed to be considering tenders for the FPSO, with a projected timeline for first oil from the field in 2015 or 2016.

The first deepwater project being undertaken by Pemex is the Lakach project, which is now proceeding, following some delays in authorization in light of conflicting reserves reports and worries over the weakness of North American gas prices. A 2015 startup is being targeted. A subsea development of a group of four fields in the Catemaco Foldbelt is being planned, with a tie-back to onshore gas processing facilities. Drilling on the first wells began at the end of 2013.

Yantai CIMC Raffles Offshore secured an order from Malaysia's Thaumas Marine, to build a Taisun 200B-design gas compression jackup unit, due to be delivered in 2015, and expected to work on the Ku-Maloob-Zaap heavy oil complex, to handle natural gas, for Pemex, on eight-year charter, with options.

These examples illustrate attempts Pemex is making to diversify its production portfolio beyond its aging fields. Doing so is requiring the adoption of complex subsea and mobile production mechanisms, which requires significant capital investment. At the same time, the NOC also is likely to generate requirements for the chartering of several other mobile structure types, including drilling units and support vessels. In some cases, this is generating sufficiently long-term needs that are likely to lead to newbuild ordering to meet the requirements.

Opportunity

The Mexican government is aware that energy reform in Colombia (2003-2012) has reduced the unemployment rate from 17% to 11% and increased oil revenue 80%, and that Brazil was able to double its oil revenue from 2000-2012. Mexico is optimistic that its own future will be brighter as a result of national energy reforms.

Like many countries, Mexico would like to move away from its dependence on energy imports and toward energy independence. The hope today is that by inviting other countries to help, Mexico can produce more of its considerable domestic reserves.

Toward that end, Mexico is evaluating energy investment across the board and is weighing the probable return on those investments for all types of energy production, taking into account that technology transfer will be vital to its success. **OE**

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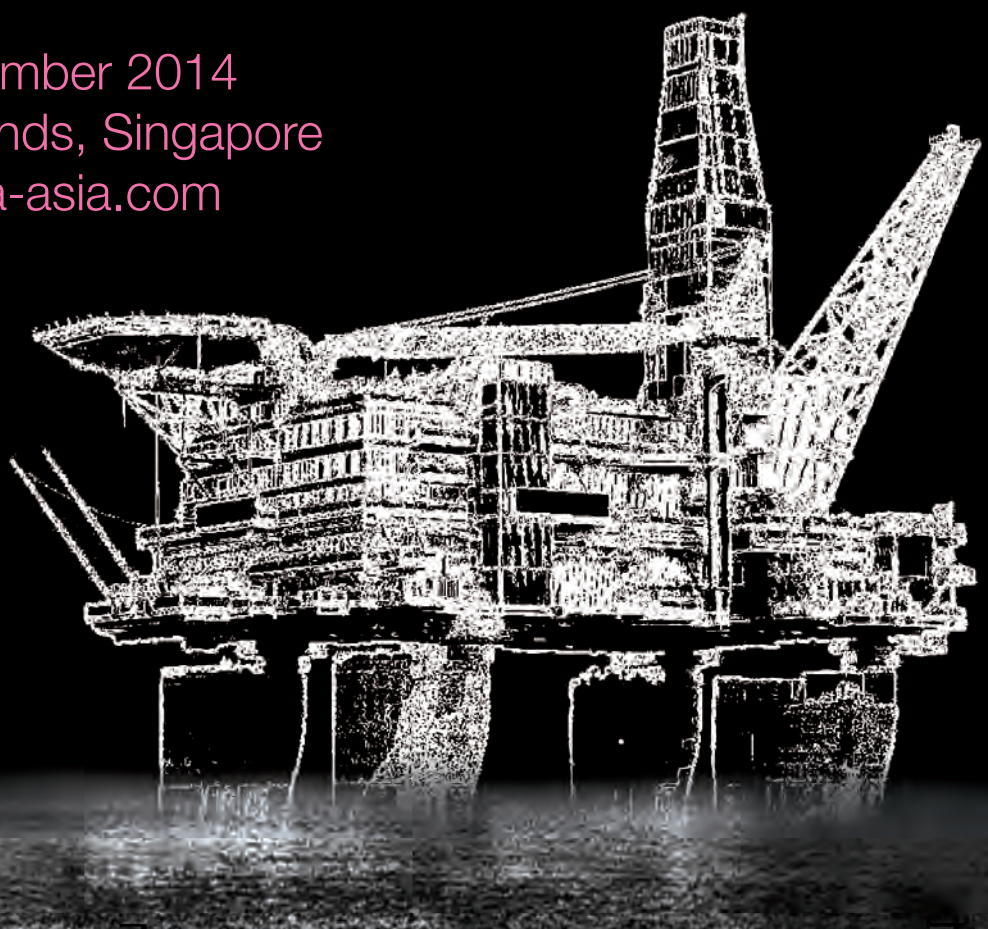

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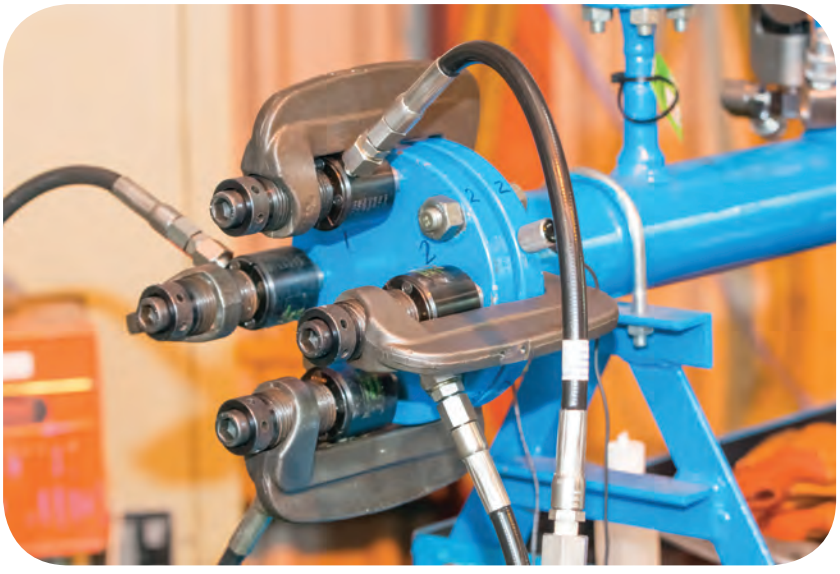
De-risking Gulf of Mexico operations and maintenance practices

By Martha Sandia, Stork

Maintenance, like safety, is everyone's business

Even a cursory examination of successful energy companies reveals a strong commitment to a maintenance and safety hierarchy that goes from employees in the field all the way to the executive offices. Strong safety and maintenance cultures go hand-in-hand because poorly maintained assets can be the root cause of accidents and collateral damage to personnel and assets.

Beginning at the field, platform deck or plant floor level, a company's skilled workers may perform complete end-to-end maintenance, or management may outsource operations and maintenance (O&M) activities to technical services providers. On the Gulf Coast, asset owners and operators routinely outsource advanced maintenance and repairs to technical service providers who specialize



Stork's hot bolt clamping system allows up to eight corroded bolts to be removed from flanged joints and replaced without the need for a costly shutdown. The bolt clamps replicate the clamping force induced by the existing bolts so that activity can be safely carried out in-service with no disruption to the standard line pressure. Photos from Stork.

in one or more aspects of the maintenance "ladder" that extends from construction, hookup and commissioning to operations, shutdowns and turnarounds. Today, even relocation and decommissioning activities are handled by highly specialized firms with the skills, equipment and processes in place to manage complex projects.

O&M outsourcing over the lifecycle of oil and gas assets was reviewed in a Gulf Coast research study. A key finding was the desirability of an unbroken chain of accountability—from the work scope and project goals outlined by the asset owner to the supervisors and crews of contractors doing the work. It was clear from the study that reducing the number of maintenance service providers to less than a handful makes managing accountability much easier. Working with fewer players ensures safer, more efficient and easier-to-manage operations. When significant risk reduction, reduced personnel on board and lower O&M costs are the end game, it makes sense to have one technical services supplier rather than many suppliers. The practice of dividing O&M among multiple suppliers can be more challenging and costly because each supplier has a limited work scope and lacks an understanding of the big picture. From a safety and efficiency standpoint, using fewer technical service providers gives better results.

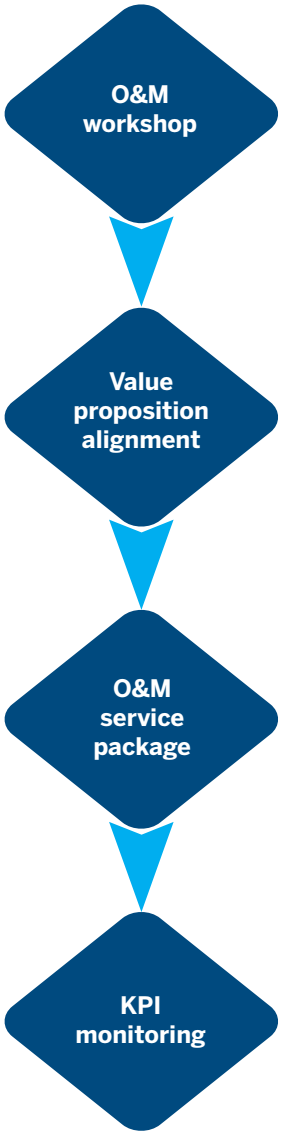
GOM operators can benefit from lessons learned from other offshore basins where operators have been employing the "fewer supplier/higher chain of accountability" philosophy for years. The best results come from partnering relationships where many O&M functions are given to a single provider who takes responsibility for improving safety, reducing downtime and lowering operating costs. Partnering relationships also facilitate flexible "bonus/malus" (reward/penalty) commercial models based on key performance indicators (KPIs). These performance gainshare models can be successfully applied in turnkey projects as long as there is excellent alignment between an asset owner/operator's staff and the technical service provider.

Some asset owners/operators are not accustomed to giving contractors access to the information necessary to design and implement an effective O&M program. Effective planning should start early, when technical advisors from the supplier are allowed to analyze and integrate all tasks into a coordinated plan that incorporates contingencies. To help overcome owner/operator reluctance, Stork is introducing an innovative O&M Supply Chain Lab process to allow asset owners/operators and Stork O&M project managers to jointly set project objectives and KPIs. The process includes a workshop led by a neutral facilitator whose agenda is to streamline O&M processes and focus on safety compliance, hazard awareness, and risk mitigation.

To be successful, the workshop must bring together four key stakeholder positions from each side—the asset manager, and O&M, HSE and procurement representatives. On the Stork side are the area manager, an O&M project manager, and HSE and commercial representatives. During the workshop, participants identify specific risk-reducing and cost-saving activities that the technical services specialist can provide—activities that most general contractors cannot offer. Both sides— the owner/operator and Stork stakeholders—formulate a specific value proposition that examines how operating expenses will be reduced while efficiency and safety are improved.

An example of such a value proposition comes from the cost savings that result from Stork's ability to combine field project managers and technicians with multiple skills. For instance, many Stork team members have not only task-related maintenance skills—such as hot bolt clamping and flange integrity management and

4 steps to de-risking O&M practices



Multi-skilled workers can apply hot work, such as metal-to-metal bonding for pipe and structural sections, in difficult-to-access locations by employing specialized rope access rigging.

Stork helps deliver long-term success by streamlining clients' processes that are key to ensuring efficient, sustainable operations and maximizing ROI.

repair—but also specialized rope access skills. They are recruited based on specific competencies such as structural repair knowledge and are trained to work on oil and gas assets by using rope access to gain entry to areas that are typically accessible only via traditional scaffolding. Not only is traditional scaffolding expensive, it is also time consuming to erect and dismantle, posing an increase in risk exposure. Stork's skilled workers with rope access experience can get to any place on stationary or floating facilities quickly and safely to perform inspections, repairs, rescues or fabric maintenance, as required.

Focusing on core competencies

If successful, the O&M Supply Chain Lab process should allow owners/operators to better manage a wide range of assets—such as offshore platforms, refineries and gas plants. These assets require specialized expertise for O&M activities. Recruiting and retaining skilled technicians to carry out these activities is increasingly difficult and expensive. And, more importantly, the fast-changing regulatory and compliance environment makes the chain of accountability an important factor in hiring personnel and selecting contractors.

In addition to these challenges, high turnover in the workforce, lack of experience, and limited resources for oversight and management are increasing risk and costs. It follows, then, that outsourcing to the right O&M provider should be based on finding a company that has O&M skills as a core competency. It is also

Stork's O&M lab allows Stork and its clients to set project objectives and KPIs. A neutral facilitator helps to streamline O&M processes and including safety, hazard awareness, and risk mitigation.

clear that choosing a technical services provider using three-bids-and-a-buy procurement practices may result in lower day rates but higher overall risks, costs and downtime. Since uptime, O&M costs and safety can be quantified, these factors should be weighted in importance over day rates.

Stork's management team is committed to helping asset managers choose between using their own teams to conduct O&M activities or to outsourcing to a firm like Stork. It is their belief that the O&M Supply Chain Lab process will result in a fit-for-purpose, managed performance package of services that increases asset value. When retained early in the O&M design and planning process, the Stork team can scope the project according to specific needs, devise appropriate solutions, and build a plan that is both measurable and traceable.

Stork is continuously enhancing and improving customer service by attracting and retaining the best people in the industry, driving innovation and problem-solving, and determining how to meet or exceed expectations by an assess-plan-act-check way of thinking and doing. Stork is dedicated to determining ways to continually improve on behalf of its customers, focusing always on quality, reliability and most importantly the safe delivery of services.

Stork provides full-service asset inspection and nondestructive testing, and mechanical and fabric maintenance that add value throughout the asset lifecycle. OE

Kings of the Gulf

Two of the major deepwater developments that have started production so far in the Gulf of Mexico belong to Shell and BP. Sarah Parker Musarra examines the technology and history behind two mammoth projects: Mars B and Na Kika.

In Greek and Polynesian mythology, Mars, Olympus, and Na Kika are synonymous with gods and kings: Mars, the Greek god of war; Olympus the great mountain ever-looming in Greek mythology; Na Kika, the Polynesian octopus-god. Mars B *Olympus* and Na Kika Phase 3 achieved first oil weeks apart in February 2014, and Shell and BP hope the developments reach the same elite status as their respective namesakes.

While Mars B and Na Kika share some surface similarities – both are in the Mississippi Canyon blocks, both are notable in size and in water depth – the main commonality between the two developments is their uniqueness.

The *Na Kika* semisubmersible platform in MC474 in the Gulf of Mexico.
Photo from BP.

Mars B

Discovered in 1989 and brought into production in 1996, Shell's Mars field is a massive resource in the Gulf of Mexico. The field has produced more than 770MMboe to date, exceeding Shell's own estimations at the time of discovery. The Mars field is located in 3100ft of water, and is home to the 24-well, 3250ft-tall *Mars A* tension-leg platform (TLP).

As the field aged, Shell surveyed Mars.

"We stepped back and looked back at the opportunities remaining at the Mars field purely as a deepwater giant," Shell Business Opportunity Manager Derek Newberry, who lead the team accountable for the Mars B *Olympus* project execution, explained. "It has a hydrocarbon column that spans from 10,000ft below sea level to 22,000ft below sea level.

"It is a significant resource base," he said.

Shell hit back-to-back discoveries with West Boreas and South Deimos in 2009 and 2010, respectively. At that point, Mars' future landscape started shifting.

"Once we made those discoveries, we assessed the range of potential hydrocarbon volumes that could be recovered from those fields," Newberry said. "Once we had the range and potential volumes, we worked out what kinds of development concepts we could place on West Boreas/South Deimos to recover that resource base."

Newberry said that recognizing the strength of the existing TLP and the close proximity of the West Boreas and South Deimos discoveries led Shell to make a landmark decision for the deepwater development, saying that it was "the first time in the deepwater Gulf of Mexico that the decision has been taken to add such significant infrastructure to an existing field."

Located in MC807, *Olympus*, the field's second TLP, discovered new life on Mars. Shell says *Olympus* extends the life of the field to at least 2050. Its first well produced first oil on 4 Feb 2014, Shell estimated production will reach 1 billion boe, with potential to deliver production rates at around 100boe/d. The company's largest floating deepwater Gulf of Mexico platform, it also has a self-contained drill rig.

Reservoirs are located at depths of 10,000 - 22,000ft, which is around 2-4mi below the seafloor.

Newberry said that the infrastructure of the Mars B venture can be broken into three major segments: *Olympus*, which is located about 1mi. southwest of the existing *Mars* TLP; West Boreas/South Deimos subsea development; and the development's export solutions.

The 6-well West Boreas/South Deimos is tied back to *Olympus* through a single seabed manifold located 3mi. west of the TLP. Two production flowlines along the seabed tie the manifold back to *Olympus* through production risers. Umbilicals power the wells, and provide the various fluids and chemicals the subsea wells may require throughout their lifetime.

Although Shell considered other options, the decision to employ a tieback fast became the best solution.

"We looked at the concepts and identified that there was tremendous energy (potential) by developing West Boreas/South Deimos as a subsea tieback to the

***Olympus*, forefront, and *Mars* TLPs in the Gulf of Mexico.** Photo from Shell.

Olympus TLP," he said, and explained that the short "competitive" cycle time from discovery into production was "through the tieback."

FMC Technologies supplied the subsea system and the controls. Spokesperson Citlalli Utrera said, for the project, FMC used "the first 15,000psi, 300ft vertical tree, ever," which was a "high-pressure/high-temperature (HPHT) milestone" for the company and the industry. The West Boreas/South Deimos trees were FMC's proprietary Enhanced Vertical Deepwater Tree, which was developed in partnership with Shell. Utrera said that it was "the first HPHT version of this successful deepwater tree."

The oil and gas export system runs north to the existing West Delta complex. Shell added an additional shallow water platform, West Delta 143C.

"The Mars B development truly is a global endeavor when you're looking at adding infrastructure of this magnitude," Newberry said. "We had activities that spanned the globe from Asia, to the US, to Europe. During the period of September 2010 to first oil in February 2014, over 20,000 people will have worked on Mars B within the US alone, covering 30-something states."

Shell is the operator of Mars B with a 71.5% stake. BP holds the remaining 28.5%

Na Kika Phase 3

As Mars B *Olympus* maximizes the potential of an existing field, Na Kika's novel design allows production from multiple independent fields through the host facility, Na Kika semisubmersible platform, which is located in a whopping 6300ft of water. The development's Octopus-like design is the inspiration behind its name, with the host semisubmersible platform acting as the body, and the flowlines to the eight fields serving as the tentacles.

According to the supermajor, the *Na Kika* platform has a design life of 20 years. It was BP's first semisubmersible platform, and was the only semisubmersible in the Gulf of Mexico at the time of installation. It also houses the largest oil storage facility in the Gulf of Mexico.

The original development, which started production on 26 November 2003, consisted of five fields. Like Mars B, Na Kika Phase 3 augmented existing infrastructure through the addition of new equipment to boost production and

Development facts at-a-glance

Na Kika host facility

- First oil: 26 November 2003
- Located in Mississippi Canyon Block 474, about 140mi. off New Orleans
- BP's first semisubmersible platform
- Located in 6300ft of water
- Lightship weight of 31,475 metric tons
- Services eight separate fields with the capacity to service more, the first of its kind
- Reportedly the largest oil storage facility in the GOM
- Annualized average oil, gas output (respectively): 130,000bopd, 550MMscf/d
- BP (operater) and Shell respectively hold equitable, 50% interests.

Mars field facts

- Discovered in 1989 over MC762, 763, 806, 807, 850, 851, with the discovery well drilled in MC763
- Reportedly the GOM's largest discovery in more than 25 years
- Began production in 1996
- Contains Pliocene and Miocene reservoirs
- Has produced more than 700MMbo
- Mars B development extends field life to at least 2050
- Contains the 40-mi. Mars Pipeline system that connects onshore in Fourchon, Louisiana
- Shell (operator) has a 71.5% working interest; BP holds the remaining 28.5%

Mars B Olympus TLP facts

- Located about 130mi. south of New Orleans and lies in approximately 3000ft of water
- It is Shell's largest TLP: The platform alone weighs 20,000tons.
- It displaces more than 120,000tons of water, heavier than 300 Boeing 747 jumbo jets
- From the hull base to the top of the derrick, *Olympus* measures 406ft tall
- Combined deck area of 342,000sq ft
- 24 well slots are tied back to the TLP
- Brought onstream in February with a projected production of 100,000boe
- Provides infrastructure for two Shell deepwater discoveries, West Boreas and South Deimos

Sources: BP, Shell

Building *Olympus*: a chronology of events

Take a closer look at the integration and delivery of first oil in Mars B through the Shell's *Olympus* tension-leg platform. See the video on any smart device by scanning this page with the Actable app, a free download in the App Store or Google play.

April 1989
Mars oil and gas field discovered over Mississippi Canyon Blocks 762, 763, 806, 807, 850, 851. Production began in 1996.

September 2010
Shell made its final investment decision and sanctioned Mars B.

September 2010
FMC Technologies won the subsea, topside systems contracts for West Boreas.

July 2011
The US government approved the West Boreas/South Deimos exploration plan and drill permit application

November 2012
Olympus hull leaves Samsung Heavy Industries' South Korean yard to embark on a 18,272mi trip to Ingleside, Texas.

January 2013
Olympus hull reached Ingleside after an 18,272mi.

June 2013
Tenaris announced it would provide *Olympus*' riser connections.

July 2013
Traversing 425mi in 10 days, four Crowley Maritime high-bollard-pull, ocean-class tugboats worked in tandem to deliver *Olympus* to the Mars B field

February 2014
Shell starts production from the Mars B development, extending the life of the Mars field to at least 2050. Combined future production from *Olympus* and the original Mars platform is expected to deliver an estimated 1 billion boe.

subsea infrastructure to tieback to the platform. Two additional wells were also drilled and completed. Na Kika Phase 3 achieved first oil 19 February 2014. Another well is expected to come online Q2 2014, BP said.

"The well locations were identified through studies involving the drilling, completion and subsurface teams, evaluating well trajectories to access the reservoir targets, considering subsurface geological structure and well design and execution risks," Brett Clanton, spokesperson for BP, said.

The giant, 31,475-ton Na Kika platform currently services eight fields through subsea wells and deepwater tiebacks – some of which are predominantly oil, and some of which are predominantly gas – and is capable of producing from additional fields.

The wells are in water depths ranging from 5800ft to 7750ft, making it the deepest subsea cluster in the world. Na Kika field has recoverable reserves of 300MMboe, with a peak production rate of around 110,000b/d oil and 500 million Tcf gas.

"The targeted reservoirs for this project were able to be accessed via wells drilled from locations in close proximity to the existing infrastructure, where subsea tie-in points for future access existed. The location and available facility capacity was key to concept selection for this project," Clanton said.

According to Shell International E&P Inc.'s W.H. Luyties and Shell E&P Americas' T.P. Freckleton's paper presented shortly after Na Kika's first oil at Offshore Technology Conference 2004 entitled, "Na Kika - Novel Development in Record Water Depths," "none of the fields on [their] own could be developed economically with the technology available [at the time of production]."

The unprecedented water depth affected most aspects of the development. Luyties and Freckleton listed "designing a robust subsea and surface production system that addressed all the complexities of multiple, small fields tied-back to a host," along with "drilling and completing the wells, including horizontal wells and multi-zone completions" in "record" water depths as some of Na Kika's greatest challenges.

Gas is exported through the Okeanos pipeline system, which in turn is a part of the Mardi Gras transportation system. The pipeline is roughly 75mi.-long. Oil is exported through a 74mi., 18in pipeline, which was the "deepest pipeline ever installed in the flooded condition," according to Shell E&P International – EP Project's Frans Kopp, Bruce D. Light, Thomas A. Preli, Vidish S. Rao and Kent H. Stingl paper "Design and Installation of the Na Kika Export Pipelines, Flowlines and Risers" presented at OTC 2004. The oil export pipeline is one of several "significant '[world]-firsts'" that were achieved in the design and installation of the export pipeline and subsea flowline systems.

FMC Technologies supplied the 12 enhanced vertical 10,000psi subsea trees, subsea distribution system, flowline connector equipment, and jumpers. FMC claimed its own first for the Gulf of Mexico: The Na Kika development is the largest platform to use the standard 4in.-by-2in. vertical tree completion system.

Na Kika is a joint partnership between BP, as operator, and Shell, which have equitable holdings. Shell transferred its operatorship to BP upon the start of production in 2003.

As companies jockey for position in one of the most promising exploration areas, Shell and BP's unique Gulf of Mexico partnership has resulted in two projects that, at least in name and size, reign the Gulf. **OE**

***Olympus* heads to the Mars field from Ingleside, Texas.**
Photo from Shell

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Seismic advances spur shallow water success

Andre Broussard
Senior Vice President, Geosciences
EPL Oil & Gas

The past five years have demonstrated that there is still plenty of life left on the Gulf of Mexico shelf, with bypassed oil-rich assets in plentiful supply. Exploration and production operators are now focused squarely on the shelf during this time period, and enjoyed a success rate that has advanced in lockstep with the latest algorithm advancements and vastly improved processing speeds.

Such advances include new inversion methods and bandwidth extensions to improve time to depth and gain a greater understanding of the depositional environment of the shallow sections of the reservoir. New high-frequency algorithms have allowed operators to see thinner sands than they were able to previously, and perform reconnaissance work within the interior pieces of their fields, using the existing logs as a starting point.

As processing speeds have increased exponentially over the past decade, the ability to run more complex algorithms has quickly changed the way infield development is occurring. Additionally, increased processing speed is driving the unit cost of seismic processing down significantly. This is allowing operators to reprocess seismic data on a scale and at a cost that was unthinkable a short time ago. Placing core assets in a regional context with state-of-the-art reprocessing is unlocking new drilling opportunities.

The datasets reprocessed with these new technologies have allowed some E&P companies, like EPL Oil & Gas, a shallow water operator in the Gulf of Mexico, to average an 80-90% commercial success rate, with this percentage of wells delivering the desired production goals to meet economic objectives.

This rate was unheard of two decades ago in the Gulf, with many operators achieving success only 65-75% of the time. The higher rates are indicative of the ability to take much of the mechanical guesswork out of the equation and drill wells in the right spot, by listening closely to what the reprocessed seismic says about reservoirs.

Now, shelf operators are poised to embark on their next phase of shelf exploration, by embracing new, highly sophisticated 3D seismic acquisition and reprocessing whose time has come. Using these advances, the industry will develop a clearer view and understanding of the size and location of previously unexplored hydrocarbon-bearing sands, much deeper into the formation. New reprocessing techniques—many of which have only been commercially available within the last five years—are particularly critical in improving the clarity and resolution of existing data sets that were acquired many years ago.

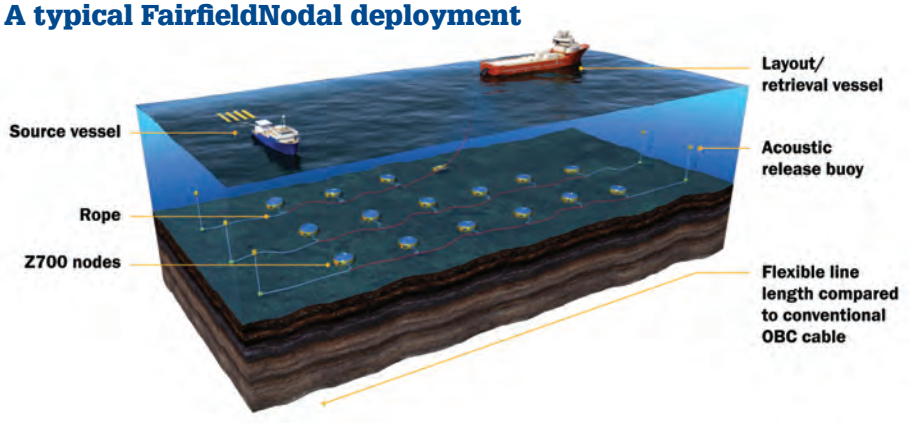
Technical expertise is just as important as the technology itself. For example, EPL employs experienced geologists and geophysicists who know how to correlate their knowledge of the subsurface rock morphology and marry that with the newly reprocessed data to drill down on a more precise location to land the well. This has reduced the risk profile significantly, and allowed EPL to consistently achieve double-digit rates of return over the past four years.

Further, the algorithm advancements operators are capitalizing on come from a collaborative approach between technical people in the field and the reprocessing software providers. This close and continuing work relationship is critical to tie the seismic to the geology, and ensure that the data set leads to a successful well.

Because this success is a constantly moving target, collaborations such as this will continue, with the aim of consistently improving data resolution with each new algorithm iteration.

Within the next two to five years, it is predicted that much of the GOM shelf will be reshot using new 3D technology, and new algorithms will bring an explosion of new ideas and further derisking. Shallow water operators are not content with waiting for these advancements, but intend to keep working with the seismic community to develop newer processing techniques to improve their understanding of the subsurface, both close to the surface and in deeper recesses of the reservoir. OE

A typical FairfieldNodal deployment



Andre Broussard *is Senior Vice President, Geosciences, at Houston-based EPL Oil & Gas. He has over 28 years of experience in domestic exploration and development as a geologist and geophysicist, focused on the Gulf of Mexico shelf. He began his career in 1984 at CNG Producing Co. Broussard earned a BS in Geology from the University of Southwestern Louisiana.*

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Newbuilds ready for center stage

By Alan Thorpe

There have been a number of newbuilding orders for series of drillships, especially for deepwater and ultra-deepwater operations, from various oil and gas contractors throughout the world over the past few years. Many are now coming to the latter stages of delivery. The main source for these ships is South Korea, where Hyundai Heavy Industries (HHI), Samsung Heavy Industries (SHI), and Daewoo Shipbuilding & Marine Engineering (DSME) are the main recipients.

One of the main orders outside South Korea involves Brazil's Jurong Aracruz, part of Singapore's Sembcorp Marine. The order comes from Sete Brasil, for the design and construction of a series of drillships based on Jurong Shipyard's *Jurong Espadon* drillship design. Since 2012, this shipyard has been awarded a total of seven sister ships for the same offshore oil and gas company. The first vessel will be delivered in 2015. However, the yard is a new one and many expect delays in this delivery program.

The *Jurong Espadon* drillship represents the next generation of high-specification drillships with advanced capabilities for operational efficiency and ultra-deepwater operations worldwide. The drillship will be equipped with state-of-the-art drilling facilities, a larger deck area with a 131ft (40m) wide main deck, efficient deck arrangement, and a large moonpool for enhanced drilling operations, as well as DP3 capabilities, superior motion features and azimuth thrusters for improved maneuverability. The design enables the vessel to operate in 10,000ft (3050m) water depth and drill to depths of 40,000ft (12,192m), with accommodation facilities for 180 personnel.

During late February this year, Sembcorp Marine's Singapore shipyard, Jurong Shipyard, signed two contracts for US$540 million each to build two drillships, with options for three additional units, from a subsidiary of Transocean. Scheduled for delivery during 2Q 2017 and 1Q 2018, the *Jurong Espadon III* design represents the next generation of high-specification drillships with advanced capabilities for operational efficiency and ultra-deepwater development drilling operations worldwide. The drillships will be equipped with state-of-the-art drilling facilities, a large moonpool to cater for a larger riser angle, and bilge boxes designed for superior motion characteristics. The ships also feature larger deck space with enclosed riser bay and round mud pits inside the hull for operational efficiency and safety. Equipped with DP3 capabilities, the drillships will be able to operate in water depths up to 12,000ft (3658m) and drill to depths of 40,000ft (12,192m), with accommodation facilities for a crew of 220 personnel.

Another Singapore shipyard offering drillship designs is Keppel FELS, a wholly-owned subsidiary of Keppel Offshore & Marine, which is proceeding witht the building of its new *CAN DO* drillship. When completed, in 2016, the drillship will be a state-of-the-art

The *Atwood Advantage* drillship alongside at DSME.
Photo from Atwood Oceanics.

The *Ulstein AXDS* is suitable for Arctic operations. Image from Ulstein Sea of Solutions.

deepwater exploration, development and completion drilling vessel. The newly developed design is capable of handling next generation 20,000 psi (1379 bar) blowout preventers (BOPs).

Jointly developed by Keppel Offshore & Marine Technology Center (KOMtech), the R&D arm of Keppel O&M, and its design partner – Holland's GustoMSC, Keppel's *CAN DO* drillship is designed to overcome the constraints of limited deck space found in most modern day drillships.

Apart from incorporating exploration drilling requirements, the design allows for the installation of third-party equipment invariably required for development and completion drilling through the incorporation of a large functional deck space. In addition, the drillship has a double BOP stack integrated into the design, and has a riser hold capacity meeting 12,000ft (3658m) water depth with the flexibility of storing either 75ft (21.3m) or 90ft (27.4m) long risers. The drillship has been model tested at the MARIN facility in the Netherlands and has also obtained class approval for the basic design. A full 3D model has been created for construction purposes.

Norway's Bassoe Offshore is currently offering the medium size drillship (BT-MDS) – a dynamic positioned vessel designed for efficient and safe drilling operations in Gulf of Mexico (GOM), offshore Brazil, West Africa, and Southeast Asia in water depths up to 8500ft (2600m) and drilling depths of 40,000ft (12,190m). The design has been further developed to allow for a maximum water depth of 10,000ft (3050m).

The BT-MDS is designed with a beam of 32.20m (105ft-8in.) to meet the maximum requirement of Panamax sized vessels. With a length of 184.55m (605ft-6in.), the vessel has a displacement of 53,700 tonnes and a payload of 20,000 tonnes.

The main objective for the design is a purposed designed, robust vessel includes a high degree integration of drilling equipment into the hull, with a simple, easy layout to inspect and maintain.

The arrangement of the vessel includes an accommodation for 184 people, with a galley and mess for serving half crew in one seating. Forward of the moonpool area is the riser storage located in a hatchless hold, supported by two knuckle-boom cranes and a catwalk machine. Aft of the moonpool is the drill pipe storage located on upper deck, supported by two knuckle-boom cranes.

A large, 41.60x 11.20m (136ft-6in. x 36ft-9in.), moonpool is located amidships. Above the moonpool is a drill floor and substructure arranged supporting a 210ft derrick.

Station keeping for the BT-MDS is achieved by a DP system in accordance with IMO requirements for DP2 vessel, including six thrusters, two large thrusters aft and four retractable thrusters amidships/forward. The power generation plant in two engine rooms includes six gen sets of 5500kWe each, total of 33MWe. Transit speed is achieved using the two aft thrusters with the remaining four thrusters retracted into the hull.

The vessel can be modified to meet IMO requirements for a DP3 vessel, dividing the power plant in three engine rooms.

The BT-UDS (ultra-deepwater drillship) developed by Bassoe for drilling of wells down to 40,000ft (12,190m) in water depths down to 12,000ft (3,650m) is also available.

Meanwhile, Bassoe has also developed a 75,000 tonnes displacement dynamic positioned ultra-deepwater drillship to be built at South Korea's STX's Jinhae yard, for Sigma Drilling, an affiliate to Skeie Technology AS. The first of these drillships will be delivered during 4Q 2015. Sundt Offshore AS has acted as broker for STX Korea for Sigma Drilling. Bassoe has also offered this design to China's Wangaoqiao Shipbulding, Shanghai.

Arctic exploration

One of the main new areas of operation in the industry is the harsh environment of the Arctic. Norway's Ulstein, through its Rotterdam office – Ulstein Sea of Solutions, has designed the Ulstein *AXDS* drillship, which is suitable for drilling operations in such areas as the Arctic. The *AXDS* design is suitable for drilling operations in the Arctic for 328-1640ft (100-500m) water depths and up to 4265ft (1300m) in open waters, such as the Barents Sea. The dynamic positioning system is operational in water above 1640ft (500m).

The operational profile comprises the ability to work on one well/season in a workable season of 120 days (the summer months in the Barents Sea). All drilling

The *Norshore Atlantic* drillship alongside at Batamec. Photo: Alan Thorpe

operations will have to be assisted by ice-breakers. Although designed as an Arctic drillship, the vessel can operate for nine months/year in very rough, but open, water conditions. The main dimensions are 760ft (231.8m) in length, 147ft (44.8m) breadth and 55.1ft (16.8m) depth.

The design features a disconnectable turret, a turret mooring depth of up to 1640ft (500m), a DP3 system, a composite shelter, and a HVAC using a heat recovery system. All equipment on-board this vessel is arranged under sheltered conditions, the safety and supply equipment, including a double helideck and two hovercrafts, with sheltered embarkation areas.

New deliveries

One of the latest deliveries in the drillship market occurred in February when Denmark's Maersk Drilling took delivery of its first ultra-deepwater drillship, *Maersk Viking*, from SHI. It has started a three-year charter with ExxonMobil in the US GOM. The *Maersk Viking* is the first in a series of four ultra-deepwater drillships to enter Maersk Drilling's fleet. The four drillships represent a total investment of US$2.6billion.

Featuring dual derrick and large subsea work and storage areas, the drillship design allows for efficient well construction and field development activities through offline activities. With their advanced positioning control system, the ships automatically maintain a fixed position in severe weather conditions with waves of up to 36.1ft (11m) and wind speeds of up to 85.3ft (26m)/sec.

Yearend 2013, Houston's Atwood Oceanics took delivery of the *Atwood Advantage* from DSME. The dynamic positioned *Atwood Advantage* has now commenced its drilling services contract with Noble Energy under a three-year contract in the US GOM. It can operate in water depths up to 12,000ft (3657m) and drilling depths up to 40,000ft (12,192m).

The second vessel in this series, the *Atwood Achiever* is due for delivery June 2014, with no charter yet disclosed. The third vessel, the *Atwood Admiral*, is due for delivery in 2015, and will enter a three-year contract with Dallas-based Kosmos Energy. The fourth vessel, the *Atwood Archer*, also due for delivery in 2015, and is so far unchartered.

During 2013, Houston's Diamond Offshore Drilling took delivery of the first two of four Gusto P10,000 drillships from HHI. The original contract, placed in 2011, was for three sister ships capable of working in water depths up to 12,000ft (3657m), although the first two vessels are outfitted for work in depths up to 10,000ft (3048m). The drilling depth is 40,000ft (12,192m). The *Ocean BlackHawk*, delivered during the 2Q 2013, and the *Ocean BlackHornet* arrived during December 2013, ahead of its planned delivery. Both vessels have started drilling operations for Houston-bsed independent Anadarko Petroleum in the US GOM this year.

The original order was for three drillships, with, during 2012, Diamond Offshore increasing the order to four ships. The third and fourth vessels, the *Ocean BlackRhino* and the *Ocean BlackLion*, are due for delivery later this year.

Design specifications include dynamic-positioning, dual activity capability, and a maximum hook-load capacity of 1250 tons. The unit will also feature two seven-ram BOP stacks, with the second available for use as a spare. The owner elected to equip its first three drillships with an additional seven-ram BOP to improve rig reliability. The cost to add a second BOP is approximately $34million, bringing the average total price for each of the drillships to approximately $640million.

During September 2013, the UK's Ensco took delivery of ENSCO DS-7, an advanced-capability, ultra-deepwater drillship from SHI, the vessel now involved in a three-year charter with France's Total off Angola. The *ENSCO DS-7* is the third Ensco rig contracted by Total and will be the fourth Ensco rig working in West Africa.

The *ENSCO DS-7* is the fifth of eight rigs in the company's ultra-deepwater DP3 drillship series, which are equipped with advanced technological features for drilling and completing deepwater wells including DPS-3 certified dynamic positioning, six-ram 15,000psi BOPs, enhanced offline capability, 2.5million pound hook load on main rotary, 6000-barrel active and 7400-barrel reserve dual-fluid systems, 165-tonne active heave subsea crane, significant storage and deck space, and accommodation for up to 200 persons. The *ENSCO DS-8* and the *ENSCO DS-9* will be delivered later this year.

This year will see the delivery of the ultra-deepwater drillships *Pacific Sharav* and *Pacific Mettem* for Pacific Drilling from SHI, part of a series of eight such ships. When delivered, the *Pacific*

Sharav will work for Chevron in the US GOM on a five-year contract.

The first ultra-deepwater drillship, the *Rowan Renaissance*, for Houston's Rowan Drilling, was delivered during early 2014, from HHI and immediately entered a three-year charter offshore West Africa for Spain's Repsol. It will be followed by the *Rowan Reliance*, and *Rowan Resolute*, both of which will enter three-year charters with Anadarko and Cobalt, respectively, and *Rowan Relentless*. One more is due for delivery during 2014, and the remaining two ships in 2015.

UK's Seadrill is currently in the process of taking delivery of a series of seven drillships from SHI, three being delivered in 2013, and the remaining four due in 2014. The drillships have a hook load capability of 1250 tons and a water depth capacity of up to 12,000ft (3658m) and drilling depths of up to 37,000ft (11,278m) targeting operations in areas such as the GOM, Brazil, and West and East Africa. Also, these units will be outfitted with seven-ram configuration of the BOP stack and with storing and handling capacity for a second BOP. The *West Tellus* and the *West Vela*, were delivered in 2013 and the *West Jupiter*, *West Neptune*, *West Saturn* and *West Corina* will be delivered later this year.

Seadrill recently signed a contract with LLOG Bluewater Holdings for employment of the *West Neptune*, offshore Gulf of Mexico. The contract duration is a minimum of three years plus an option for a one-year extension. The *West Neptune* will be the first dual BOP rig in the GOM for LLOG. LLOG will initially utilize the rig to complete of the Delta House wells. Having two BOP's will allow LLOG to complete the wells efficiently, saving up to 12 days/completion.

During July 2013, Seadrill entered into contracts to build four new ultra-deepwater drillships. Two drillships will be built at DSME and the other two at the SHI. Delivery of the four units is scheduled for 2H 2015. Seadrill has, in addition, received fixed priced options for delivery of two further units for delivery in 1H 2016.

Norway's Norshore Pacific BV, a wholly subsidiary of Norshore Holding AS, signed a contract during December 2013 with China's Yantai CIMC Raffles for the construction of the drillship *Norshore Pacific,* including options for a further three vessels. Delivery of *Norshore Pacific* is planned for Q4 2016.

This followed the successful delivery of the *Norshore Atlantic* from Indonesia's Batamec Shipyard, Batam. The 115.4m-long vessel was designed by Norway's Marin Tyeknikk (MT). The new order in China was led by the fact that the Norshore Pacific (and the optional sister ships) will be that much larger than the *Norshore Atlantic*.

Norshore developed the *MT 6022XL* multi-purpose drilling vessel for riserless operation utilising known and field proven technology. It can replace large drilling units in the initial stages of the drilling operations resulting in significant cost reduction.

The vessel is also equipped for performing light well intervention work, riser-less well completion, P&A and subsea construction work in both shallow and deep water. In addition the vessel is prepared for installation of riser tensioning system enabling the vessel to perform slender well drilling and well intervention with riser. OE

Technology with a twist

For those in the industry, there's only one place to be during the first week of May: the annual Offshore Technology Conference.

The tagline for OTC 2014 is "Come Together," succinctly encapsulating the offshore industry's flagship event, which boasts attendance levels of 90,000 industry professionals from more than 120 countries.

Among one of the largest 200 tradeshows annually in the US, OTC showcases exhibits from more than 2700 companies in 641,351sq ft of exhibitor space. Of OTC 2013 attendees, 55% were executives and managers.

Houston has been OTC's home since its inception in 1969. It kicks off for the 45th time this year 5 May at the Reliant Park, soon to be re-named NRG Park, closing out 8 May. New topics of discussion on the schedule include the impact of unconventionals offshore, process safety in offshore operations, and new applications and solutions for underwater monitoring networks and sensing.

See the time lapse video encompassing two weeks of move-in for OTC 2013 on any smart device by scanning this page with the Actable app, a free download in the App Store or Google play.

Invited organization Japan Oil, Gas and Metals National Corporation JOGMEC will present its results from the first marine methane hydrate production test in a technical session on Wednesday morning, chaired by the company's own Koji Yamamoto and the US Department of Energy's Ray Boswell. OTC calls the results an "industry breakthrough that makes producing hydrate from a seabed a near-term reality."

Before the conference sessions start, however, Sunday, 4 May brings attendees to Minute Maid Field to see the Houston Astros play the Seattle Mariners for OTC at the Ballpark. The OTC Distinguished Achievement Award recipients and others are recognized at the Annual OTC Dinner Monday night. Carl Arne Carlsen, senior vice president of DNV, will receive the OTC Distinguished Achievement Award for Individuals for his achievements in offshore safety and reliability in mobile offshore structures and risk management. BP's Clair Ridge Development in the UK will be recognized with the OTC Distinguished Achievement Award for Companies, Organizations, and Institutions for the deployment of the company's reduced salinity enhanced oil recovery technology.

The dinner is also a fundraiser for the Houston-based non-profit organization Medical Bridges, which redistributes surplus medical supplies to emerging countries.

Topical breakfasts and luncheons are scheduled Monday through Thursday, giving esteemed personnel from organizations such as BP America, the UK Minister of State for Business and Energy, Total, COPARMEX, Pemex E&P, Mexico's Federal Electricity Commission, Ministry of Energy and Mineral Resources, Indonesia, PT Pertamina, Oceaneering Space Systems, US Bureau of Ocean Energy Management, Shell, Citizens for Affordable Energy, Inc., WorleyParsons, University of Houston, Statoil, Chevron Environmental Management Company, GE, Noble Energy, Center for Offshore Safety, US Bureau of Safety and Environmental Enforcement.

In addition to these, there are also multiple R&D Showcases, a 45th Anniversary Celebration Concert on Wednesday, and a Teacher Workshop and High School Student STEM Event on Thursday. The latter two are part of OTC's traditional education day, which is held the Thursday of each show.

This year's technical program, which also runs throughout the duration of the week, are chaired by representatives of companies including: Schlumberger, Chevron ETC, Enbridge Offshore Pipelines, IHC Merwede, Petrobras, ABS, PETRONAS, Woodside, ExxonMobil, Fugro, and many others.

On Tuesday afternoon, Christopher Smith from the US Department of Energy will join Brian Salerno from the Bureau of Safety and Environmental Enforcement to form the panel a session entitled, "ACTIVE ARENA: Energy Security & Economic Prosperity: Oil Spill Prevention."

Twelve scientific and engineering organizations founded OTC 45 years ago, and this year, thirteen organizations sponsor OTC, including: the American Association of Petroleum Geologists; American Institute of Chemical Engineers; American Institute of Chemical Engineers; American Institute of Mining, Metallurgical and Petroleum Engineers; American Society of Civil Engineers, ASME International Petroleum Technology Institute; Institute of Electrical and Electronics Engineers, Oceanic and Engineering Society; Marine Technology Society; Society of Exploration Geophysicists; Society for Mining, Metallurgy, and Exploration Inc.; Society of Naval Architects and Marine Engineers; Society of Petroleum Engineers, The Minerals, Metals and Materials Society; and, regionally, Brazilian Petroleum, Gas and Biofuels Institute. Endorsing organizations are the International Association of Drilling Contractors; and the Petroleum Equipment Suppliers Association. OE

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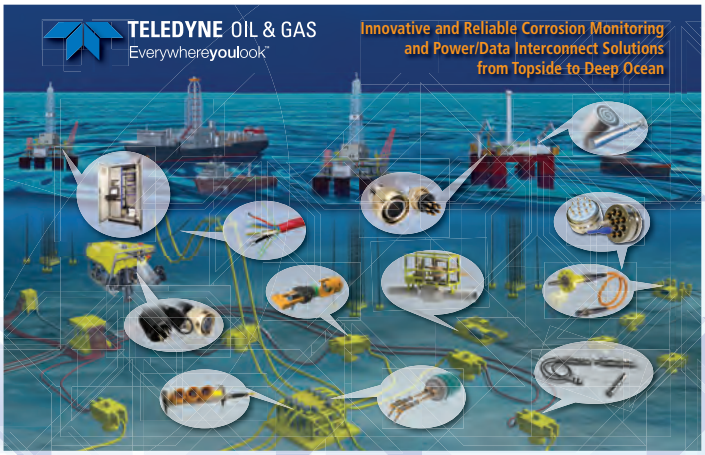

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From pockmarks to global forecasts

Industry analyst John Westwood will give a talk, *CAPEX Compression and the Impact on the Offshore Services Community,* at an OTC luncheon on 5 May, at Reliant Park. Elaine Maslin learned how the founder and chairman of energy analysts Douglas Westwood has come to have a unique perspective on the industry.

John Westwood

John Westwood has a unique view of the oil and gas industry; so unique, that in some cases, he has seen parts that few others have seen.

Westwood, chairman of energy analysts Douglas Westwood, spent part of the 1970s working for Vickers Oceanics in two-man submersibles in the North Sea, before the days of remotely operated vehicles (ROVs). He was inspecting the then-newly installed major oil and gas trunk pipelines and surveying seafloor sites for features such as pockmarks. The name masks the actual scale of these intriguing seafloor features, at up to 1km-long, 20m-deep and 10m-wide, created by focused seeping gas through sediment.

Spending up to six hours at a time at such sites, sometimes with the submersible's sonar, video, and camera technology turned off, due to passing shoals of fish, gave Westwood time to think.

"It occurred to me that if you had a cable from submersible to the support vessel, you could transmit the data to the vessel. You could then also move the power and control systems on to the vessel, so you would not need anyone in the submersible," Westwood says. "I discussed it with a few people and eventually found someone else who had the same idea."

That someone else was Roger Chapman, who rose to fame after being rescued, along with Roger Mallinson, from the *Pisces III* semisubmersible, after it sank more than 1500ft to the bottom of the Atlantic Ocean, 150 west of Ireland in 1973, after water ingress into a storage sphere.

In 1977, the pair founded Sub Sea Systems, which, after some resistance from the industry, become one of the first ROV operators, successfully operating adapted Consub II ROVs, units originally built for the British Geological Survey for seabed mapping.

The first job was for Marathon Petroleum, laying the Kinsale Head gas pipeline, offshore Ireland. "The real breakthrough came when we got a contract from Shell to inspect the FLAGS pipeline," Westwood says.

The success spread in the North Sea and then to Brazil and Brunei, and SSS designing its own ROVs. The ROVs were operating at half the cost of a two-man submersible, says Westwood, and were not constrained by the six-hour operating window the manned submersibles were. Working with Shell, SSS also designed a system which could track online pipelines, imaging both sides at once using cameras on booms, instead of having to two do passes, again halving costs.

The success led to the business being bought out. Westwood had already moved from the technical to the marketing side of the business and, in 1985, following a brief stint at BUE Subsea, was approached to form a business research business, focusing on oil and gas, with Smith Rea, called Smith Rea Energy Analysts. In 1990, he then decided to go it alone, founding Douglas Westwood.

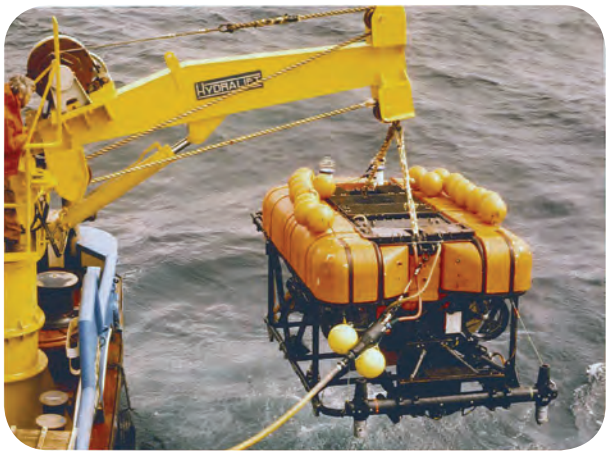
The company now has offices in Houston, Singapore, and the UK (London, Aberdeen and Kent), carrying out business research and consulting services, for the financial sector, to inform mergers and acquisitions, and industry. It has also spread into other energy sectors, and it also produces its own reports, to help promote its services.

One of Westwood's concerns for the industry is cost inflation. "Cost inflation is a big challenge right across upstream and downstream," he says. Fundamentally, more and more money is having to be spent on less production." It is the majors it is impacting more, as they are forced into harsher, deeper environments, while national oil companies own large onshore resources and are no longer as reliant as they have been on international companies.

There have been surprises, during his career, and not just finding Tenants lager cans (a Scottish brand) under pipelines, and seeing the giant pockmarks offshore Norway. One of the biggest surprises was industry reluctance to except new technology, Westwood says.

"If you take the example of the unmanned technology in oil and gas, it was a very long, hard, uphill struggle to get them used. I understand now why that is. No one manager of a big field will allow new technology near their field, they want proven technology."

A more positive surprise, he says, is the "incredible capacity" of the young people coming into the industry. OE



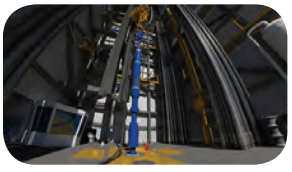
ROV Consub II. Photo from Douglas Westwood.

OTC Spotlight Awards highlights innovation

This year's Spotlight Awards showcases innovation in offshore drilling, offloading operations, intervention, performance maintenance and monitoring, and more. Congratulations to the recipients!

Views from the Spotlight on Technology award ceremony held during OTC 2013. Top photos: OTC Facebook/Image Catcher Photography.

Wireless Top Drive Cement Head



Baker Hughes won a Spotlight Award for its LaunchPRO wireless top drive cement head. This remote-activation system for deepwater applications launches balls, plugs or darts wirelessly during cementing of extremely heavy subsea long strings and long, heavy liners. LaunchPRO's remote wireless operation reduces HSE risk by reducing manual intervention and optimizing reliability. LaunchPRO's operation is powered by rig air through a single pneumatic hose that can be tethered to the cementing line meant to reduce the risk of damage during cementing operations. A wireless pressure transducer provides real-time data to the cementing operator to allow for adjustments during cementing operations. **Visit them in Booth 3731.**

Iso Pump

FMC Technologies won for its Iso Pump, an isolated pump that enables secondary intervention for BOPs in compliance with API Standard 53. In addition to being depth-insensitive, the Iso Pump is directly integrated with FMC's UHD III remotely operated vehicle, and meets the 45-second time limit for closing BOP shear rams. **Visit them in Booth 1941.**

Offshore Footless Loading Arm (OLAF)

Offshore Footless Loading Arm (OLAF) also proved to be another winning system for FMC Technologies. OLAF has been specifically developed for LNG transfer between FLNG and conventional LNG carriers. The OLAF design is able to accommodate the significant elevation difference between these two vessels. Additionally, the system retains operability in harsh environmental conditions due to its connectivity targeting system and Constant Position Monitoring System (SIL3). **Visit them in Booth 1941.**

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SeaLytics

GE Oil & Gas' SeaLytics solution received a Spotlight honor. This system enables drilling contractors to monitor performance and plan maintenance of BOPs using predictive analytics based on actual component performance data. SeaLytics can improve BOP system uptime, reduce unnecessary maintenance, and lead to improved cost forecasting. **Visit them in Booth 3163.**

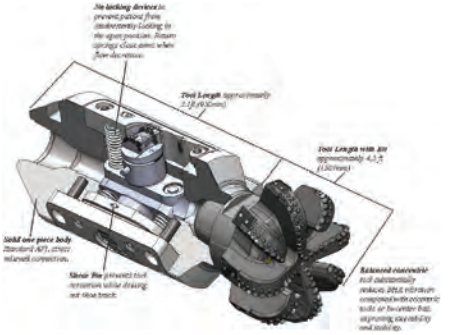
Zenith GFI™ Ground Fault Immune ESP Monitoring System

GE Oil & Gas picked up another award for its Zenith GFI Ground Fault Immune ESP Monitoring System. Because this system cannot be disturbed by ground faults, it enables operators to maintain well surveillance essential for production optimization and pump protection regardless of existing fault conditions. **Visit them in Booth 3163.**

FLAG Fluid Loss and Gain Detection Service

Geoservices, a Schlumberger Company, won for its FLAG fluid loss and gain detection service. This system provides an early warning system that is highly sensitive to fluctuations, but intelligent enough to prevent false alarms. The FLAG service provides accurate fluids monitoring and precise coriolis flow metering with any drilling fluid on any rig in regards to drilling, tripping, circulating and cementing. Visit them in **Booth 4441.**

TDReam Tool



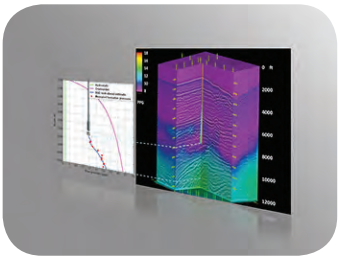
Halliburton Drill Bits and Services downhole TDReam tool received a Spotlight honor. It features optimized steerability, fluid flow, and reduced

tool length. This system is designed to significantly reduce rathole length and reach target depth in one run. **Visit them in Booth 2271.**

Very High Pressure Fluid Swivel

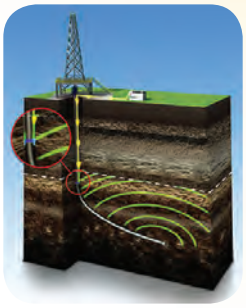
SBM Offshore was recognized for its Very High Pressure Fluid Swivel. This system increases the operating range of high pressure fluid swivels by cascading the pressure drop over multiple seals. The 12-in. prototype toroidal swivel has been fully qualified to 12,000psig and has completed long-term endurance test runs. SBM Offshore projects that the final product will be able to operate at over 14,500psig. This swivel is specifically aimed at gas or water injection from FPSOs into ultra-high pressure reservoirs. **Visit them in Booth 4131.**

Seismic Guided Drilling Technology



Schlumberger won a Spotlight Award for its Seismic Guided Drilling (SGD) technology. This system predicts formation pressures hundreds of meters ahead of the bit while drilling. The SGD service uses both surface seismic and logging-while-drilling (LWD) data to provide a 3D look-ahead velocity model with reduced uncertainty. Velocities ahead of the bit are re-calculated from seismic reflections by using LWD velocities behind the bit as a constraint. **Visit them in Booth 4441.**

CasingLink

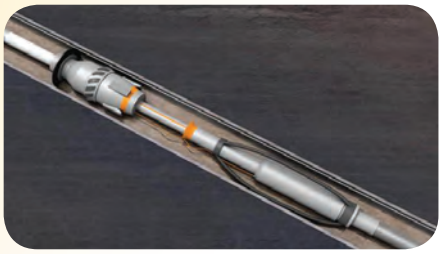


Weatherford CasingLink EM Antenna System picked up a spotlight award. This product was developed to address the signal attenuation encountered while drilling in deeper depths with an EM telemetry system. This method uses an insulated wire that is externally attached to a standard casing string in conjunction with a borehole receiver located downhole. The borehole receiver picks up the EM signal at the casing connection

OFFSHORE TECHNOLOGY CONFERENCE

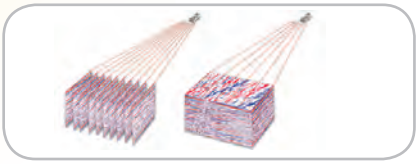
terminal and transmits it through the external signal wire to the surface transceiver. There is negligible signal attenuation within the transmission wire, which increases telemetry depth. **Visit them in Booth 3541.**

P&A Technology



West Production Technology AS, part of West Group, won a Spotlight award for SwarfPak, a system for P&A and slot recovery that exhibits a reduced environmental footprint and rig time. The swarf particles are left downhole to avoid the use of surface swarf handling equipment while greatly increasing the milling speed. **Visit them in Booth 5241.**

Marine Seismic Technology



WesternGeco, a Schlumberger company, won a Spotlight Award for its IsoMetrix marine isometric seismic technology. This system enables 3D measurements of seismic wavefolds using towed streamers capable of delivering high-fidelity point-receiver seismic data while overcoming spatial bandwidth compromises that have traditionally limited previous towed-streamer methods. A new streamer design which utilizes vertical and crossline gradient measurements of the seismic wavefield enables unaliased reconstruction of the pressure wavefield between the streamers. This results in data that is optimal for interpretation and reservoir modeling applications in exploration and reservoir development. **Visit them in Booth 4441.**

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Activity

Aquatic introduces health, safety training for offshore personnel

Aquatic Engineering & Construction Ltd. has worked with specialist health and safety training provider Survivex to create a bespoke course for its offshore teams.

Aquatic commissioned a customized course to improve body positioning and establish good practice for personnel assembling the AQPR-02 modular drive system. The course also covers the introduction of new work positioning harnesses that give technicians a higher degree of comfort and mobility while allowing them to use both hands for working.

Aquatic's modular reel drive systems can stand up to 7m high when assembled, and the company's offshore teams must use harnesses and ladders to complete the assembly. In addition to teaching best practice during normal operations, the course will also show personnel how to secure and rescue a colleague who has fallen in the harness or become unconscious.

The first training course was held in January 2014, and the content will be rolled out to all offshore personnel during the first quarter.

Atwood Oceanics moves office headquarters

Offshore drilling contractor Atwood Oceanics, Inc. announced the move of its corporate headquarters to the Energy Crossing II building at 15011 Katy Freeway to accommodate the company's recent record growth.

The company is in the midst of an ongoing US$4.5 billion fleet expansion and modernization program. Upon the program's completion in 2015, Atwood will have reduced the average life of its active rig fleet from approximately 30 years to 10 years.

Atwood Oceanics made the decision to relocate its corporate facilities, which includes 200 Houston-based employees, after 34 years in its former location at Park Ten Place.

Included in the new space is a ground floor training center for delivering competency-based drilling and technical skills curriculum. A prominent feature of the new facility, the learning center will emphasize workforce development for both shore-based and offshore teams, improving the safety, reliability, and efficiency of Atwood's drilling services.

The new 89,000sq ft-office space is located at the southwest intersection of Interstate 10 and Highway 6. Atwood is targeting a Silver LEED certification by the US Green Building Council.

GE opens Hungary O&G plant

GE formally opened its newly expanded oil and gas facility in Fót, Hungary. The GE Oil & Gas manufacturing plant has been substantially enlarged with the addition of a new 8000sq m manufacturing facility and a new office building of 3000sq m.

The new manufacturing base will provide central unit control panels (UCPs) for pipelines, LNG production facilities and other oil and gas applications. The increased capacity adds more than 100 jobs, including 40 engineering positions, an employment increase of more than 80%.

The Fót investment is the result of the cooperation between GE and Hungary's Government that contributes to the competitiveness of both the company and the country by strengthening Hungary's manufacturing base and expanding jobs.

Unit control panels for the oil and gas industry are designed for the specific customer needs. These are flexible control systems for multiple applications that incorporate a variety of sub systems such as safe operation of machinery, vibrations monitoring, control of unit speed and load, auxiliaries systems, and overall plant control. Panels are designed to enable local or remote operations.

Bringing production of these critical control panels to Fót, Hungary, supports GE's efforts to align its production to new customer needs and to extend its technology capability locally and globally. The Fót facility will also supply its advanced products and solutions to GE customers globally.

GE is the largest U.S. investor in Hungary with 12,500 employees. The company has 12 manufacturing plants, three technology centers and three regional headquarters in the country.

Wellsite Rental Services announces company formation

Wellsite Rental Services, LLC, (WRS) announced its formation as a new company, said Kirby Arceneaux, WRS chairman.

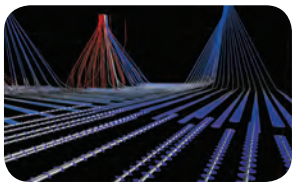
Headquartered in Broussard, Louisiana, WRS specializes in providing new and reliable rental products for drilling and production, said Kirby Arceneaux, WRS chairman. WRS products consist of specialty multipurpose trailers, cooling and heating trailers, automated slips, pneumatic mud buckets, variable bore rams and other rental equipment.

Company founders include Arceneaux; Fredrick Fondren, vice president; and Jessica Roger, secretary/treasurer.

Wellsite Rental Services will be announcing additional staffing, investment and product lines in the near future.

Solutions

Paradigm delivers software



Paradigm recently introduced Sysdrill on the Amazon Web Services (AWS) cloud. Sysdrill enhances well planning accuracy and reduces drilling risk and uncertainty. Its introduction to the AWS cloud will offer users improved provisioning, simplified management, and lower costs.

Paradigm will provide multiple levels of support for Sysdrill on the cloud, enabling customers to select their required level of management control. Additionally, Paradigm provides reference architectures and sizing guidelines to ensure customers can successfully deploy Sysdrill within their own AWS environments.

www.pdgm.com

3M introduces new sound level meters

3M announced two sound level meters designed to work in oil and gas environments. These new meters, known as Type 1 SE-401-IS and Type 2 SE-402-IS, are extensions to 3M's Sound Examiner SE-400 series.These instruments compute the average sound pressure level throughout run-time while measuring maximum, minimum and peak sound levels. These new models have obtained requisite ATEX approval, and can be used for oil and gas platforms. Additionally, these meters are certified intrinsically safe in accordance with UL and DEMKO standards.

www.3m.com

Schlumberger commercializes bed boundary detection service

Schlumberger announced commercialization of the PeriScope HD multilayer bed boundary detection service. The technology accurately detects multiple-formation layers, orientation of approaching beds and fluid boundary positions to enable

advanced well placement services in clastic and carbonate fields.

The PeriScope HD service uses a combination of inversion models and azimuthal measurements to delineate formation boundaries for advanced well placement and accurate definition of multiple productive layers. This real-time multilayer detection technology provides a better understanding of how formations are deposited, enabling geoscientists to position future wells for improved production.

www.slb.com

Varel introduces new drill bit line at IADC

Varel International Oil and Gas launched its IMax series drill bits on 4 April, at the opening day of the IADC/SPE Drilling Conference and Exhibition in Fort Worth, Texas.

The IMax and IMax+ are matrix bits designed to grind formations through the use of diamonds uniformly pelletized in its matrix. Varel said that its process cuts down on diamond aggregates, which results in a more consistent wear pattern and a better cutting process.

Suitable for offshore application, the IMax+ bit crossed the company's existing Vulcan PDC cutter for what Brian Ballard, Varel's global account manager EHO, called a "hybrid design." He said that one of the main features of the IMax+ is that is particularly effective in drilling through a softer formation into a harder one.

The company is targeting two specific areas: Africa and South America, where its design is ideal for Brazilian presalt regions.

"[The IMax+] allows you to drill quickly in the softer rock above the presalt layer," Ballard explained. "The presalt is hard and abrasive; it tears up the PDC cutter. Once the PDC blade wears away, the impregnated blade cuts through."

The line features Varel's SPOT proprietary bit design program, which operates in conjunction with the company's GeoScience rock analytics program. The bits are available in sizes from 6 ½-in. to 13 ½-in.

Director of Marketing and Intellectual Property Bill King said that the designs were under development for three years following the company's desire to shift its thinking towards both drill bit design and processes. "We set out to learn more about this segment of the market," he said. "We benchmarked it. We selected the best parts or technology we could."

—Sarah Parker Musarra

www. varelintl.com

Hydro Group showcases subsea connecter to US market

Hydro Group introduced its 36kV Dry Mate connector to the US market. This new connector is a significant improvement over its predecessor, with installation time reduced from 24 hr to less than 12 hr.

The 36kV connector was developed to withstand harsh environmental conditions, and was designed for flexibility and environmental endurance.

www.hydrogroupplc.com

Spotlight

By Elaine Maslin

Skills shortages and solutions

The industry looks to itself for the reasons for and solutions to skills shortages.

Endless eports have been generated regarding the skills challenge facing the industry in the North Sea and further afield.

In the UK, industry body Oil & Gas UK and skills and training body Opito have launched initiatives to address the shortage.

In Norwich, southern England, industry, through the East of England Energy Group (EEEGR) partnered with the University of East Anglia (UEA) to introduce energy engineering degrees, as well as forming close ties with the armed forces and apprenticeships providers.

Yet, during the Southern North Sea 2014 (SNS2014) conference and exhibition in Norwich, in March, a rather blunt assessment of the situation was given by the Chairmain of Schlumberger UK Ltd.

Gordon Ballard, who is also chairman of Opito International, said the industry only had itself to blame because it had failed to recruit enough people over two decades ago.

Ballard, who is also co-chairman of Oil & Gas UK's board, said: "It is up to us. We have to recruit and train people, and not hire someone from another company. It has always happened, but it is getting unsustainable."

He said the problem was not a lack of people wanting to get into the industry, highlighting oil and gas industry training body Opito's hugely oversubscribed apprenticeship scheme, which had more than 1000 applicants for just 100 places.

"There is also no shortage of graduates," Ballard says. "There is no shortage of people wanting to join the industry. We have to just go out and train them and accept it is going to take a while. It's all our own fault for not hiring in the 1990s. I refuse to blame anyone else, it is us. This needs to change and it is absolutely up to us."

Not all those in the industry would see it as their own fault, especially the smaller, supply chain businesses.

"It is an on-going issue that the large oil and gas companies and contractors hoover up the majority of good graduates, leaving few for the SMEs to choose from, yet it's the SMEs that provide the bulk of engineering support to the industry– those very same large oil and gas companies and contractors," Patrick Phelan, managing director of Norwich-based offshore engineering and services firm Aquaterra Energy, said at SNS2014. "So, these large companies need to recognize the issue and support SMEs through it, with collaborative approaches to graduate recruitment and retention."

Patrick Phelan

Phelan also says there is a need for more graduates and for companies to be creative in their approach to graduate recruitment.

"For example, employers shouldn't put engineers in non-technical roles; they should consider non-engineers for commercial roles and mathematicians for analytical roles; and they need to offer roles to non-EU students within four months of their graduation, before they have to leave the country," he says.

"There is a lot more that could and should be done to share with students the great opportunities that exist in engineering. Engineering isn't a school subject, so it's not widely understood in the school environment, and it's our role to ensure that teachers and careers advisers have the knowledge to advise students appropriately."

Aquaterra and other companies, alongside SNS2014 organizer EEEGR, helped UEA forge its first engineering program, starting with a master's degree in energy engineering with environmental management, in 2011, followed by undergraduate degrees (Bsc and Meng) in the same topic. To date, alumni have had 100% employability, says Paul Rijks, who worked for Shell for 25 years, before joining the EEEGR board and becoming a visiting professor at UEA. The university hopes to have 150 people on the program within five years, he says.

"We have had tremendous support from local industry," he says. "Companies cannot get the people they need here (in the East of England) to support their growth." Industry is helping to fill the void. OE

Paul Rijks, visiting professor at the University of East Anglia (UEA), center, with this year's UEA engineering program students at the SNS2014 conference, in Norwich, UK.

Carolyn Stewart

By Anthresia McWashington

Speaking out about industry gender gap

A recent report released by recruitment firm NES Global Talent depicts some of the issues that women face working in the industry, and some methods that could be utilized to resolve the slowly shrinking gender gap.

NES Global Talent's survey, "Attracting and retaining women in oil and gas engineering," a survey examining the gender gap, revealed that although 75% of women feel welcome working in the industry, 45% of them believe that they are not receiving the same recognition as their male colleagues.

NES Global Talent Business Development Manager for North America Carolyn Stewart explains that spreading the word about what is available can assist women in gaining more recognition.

"There needs to be more awareness brought out in the community about different opportunities available for women in oil and gas," she says. "Ultimately it is up to us, as females, to speak the loudest within our own network, and really bring the topic to the surface."

Of the women surveyed, 95% said that mentors are an important resource for career advancement; however, 42% are not currently involved in any mentorship programs.

"There's the perception that being in the oil and gas industry is very rough, that it's long hours and lots of travel—but there are other opportunities out there for women," Stewart says. "Within companies, more mentor programs could be put in place. A young woman can actually sit down at their induction into the company, and be assigned a strong, female individual who may have risen up in the company from a similar role, to help that young individual map out their career and get them involved in the community."

Educating school-aged girls was also mentioned as a way to attract younger generations to the industry. Stewart said that new schools were being chartered to get a head start on recruiting kids.

"In Houston, they've actually just started a charter for a technical engineering school," Stewart says. "It's going to be a part of the Houston Independent School District, but it's going to be one of the flagship charter schools. The school will look for sponsorships, and companies such as NES Global Talent can get involved in these schools and help these organizations bring young women up in the engineering world."

Overall, Stewart says it's critical for different divisions throughout the industry to come together in efforts to provide women with the resources they need to remain, or enter, in this sector.

"I don't think there's one answer for it," she says. "It's the companies' responsibility and it's the society's responsibility. It has to be a joint effort."

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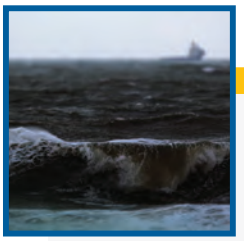
Numerology



1.43MMboe/d

The 2013 UK North Sea production rate, its lowest since 1977.
▶ See page 25.

5600km

The distance the *Ichthys* FPSO will be towed, from the DSME shipyard to the Browse basin off Western Australia, after construction. (Source: INPEX).

20,000 people

from more than 30 US states worked on Mars B. ▶ See page 86.

124%

The amount by which real oilfield prices have increased since 2005.
▶ See page 28.

US$500,000/day

is the average rate of a drillship capable of working in more than 4000ft of water.
▶ See page 32.

11 billion bbl

The amount of oil the EIA estimates to be in the South China Sea. ▶ See page 21.

8mm

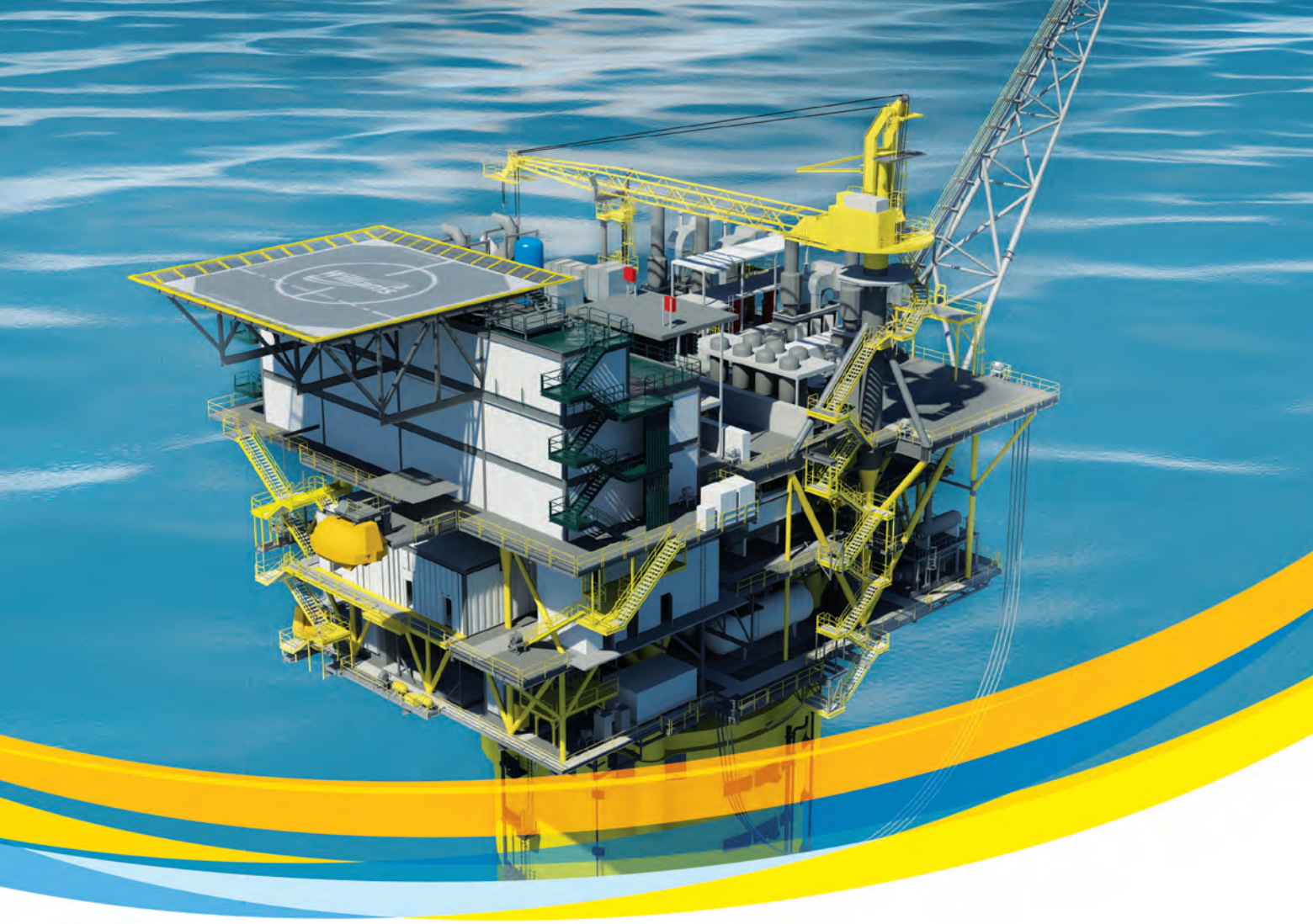
The typical sample size that Schlumberger's CoreFlow digital rock and fluid analytics services can utilize. ▶ See page 42.

45%

of women surveyed believe that they are not receiving the same recognition as their male colleagues. ▶ See page 109.

US$650 million

The contract value awarded by Fecon International to Keppel FELS for three KFELS B Class jackups. ▶ See page 19.



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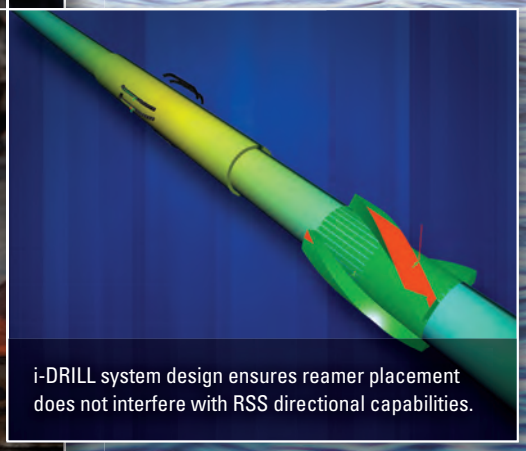

i-DRILL system design ensures reamer placement does not interfere with RSS directional capabilities.

Rhino RHE

DUAL-REAMER RATHOLE ELIMINATION SYSTEM

Dual-reamer system enlarges rathole, avoids a run, and saves 16 hours on a deepwater rig.

Rhino RHE rathole elimination system enlarged 178 ft of rathole while drilling a deepwater well in the Gulf of Mexico, saving 16 hours of rig time. The Rhino RHE system's dual-reamer process uses a hydraulically actuated reamer positioned above the MLWD tools to open the pilot hole and an on-demand reamer located near the bit to enlarge the rathole. The dual-reamer system eliminated a dedicated rathole cleanout run.

Read the case study at
slb.com/RhinoRHE

Schlumberger