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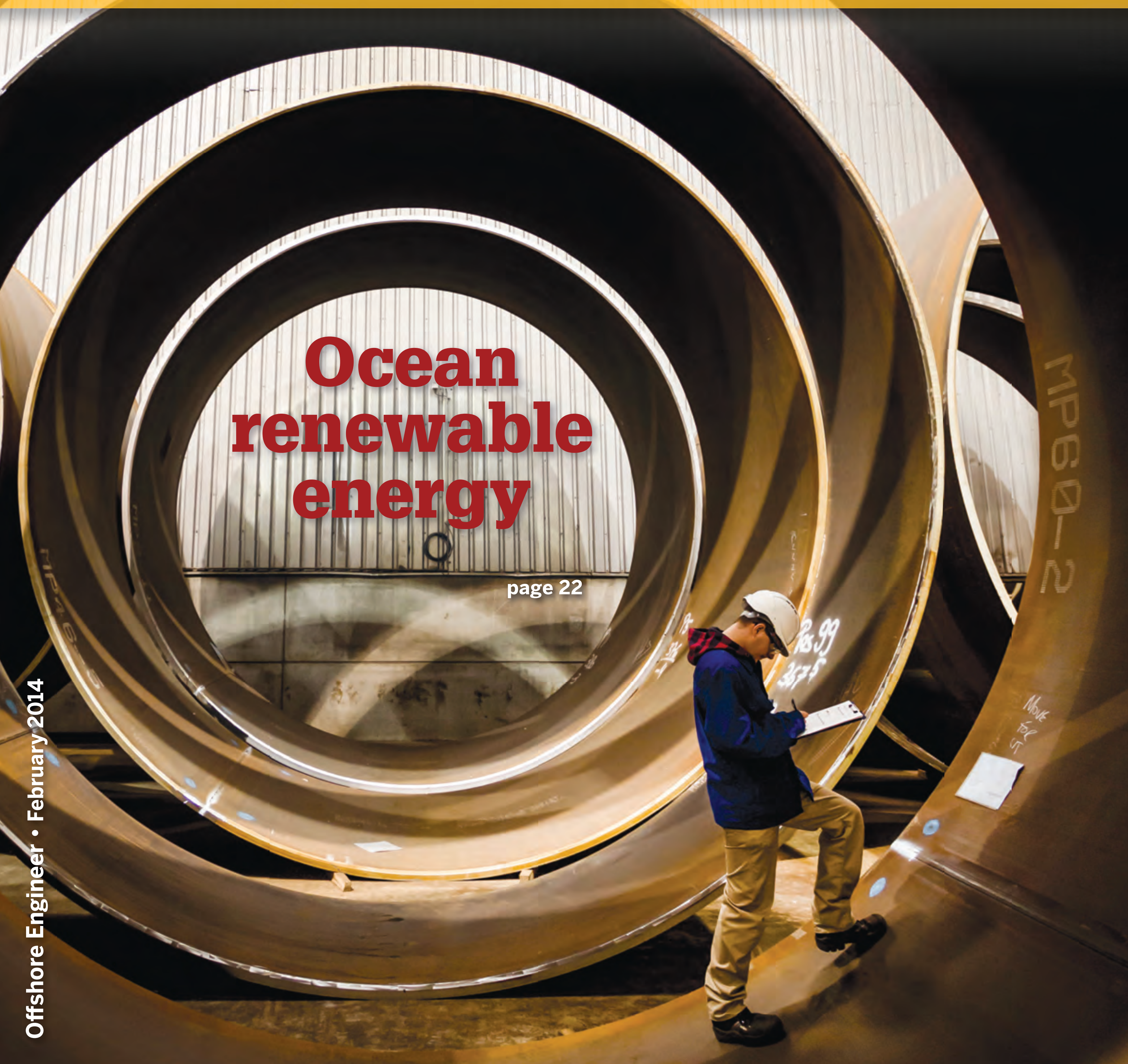

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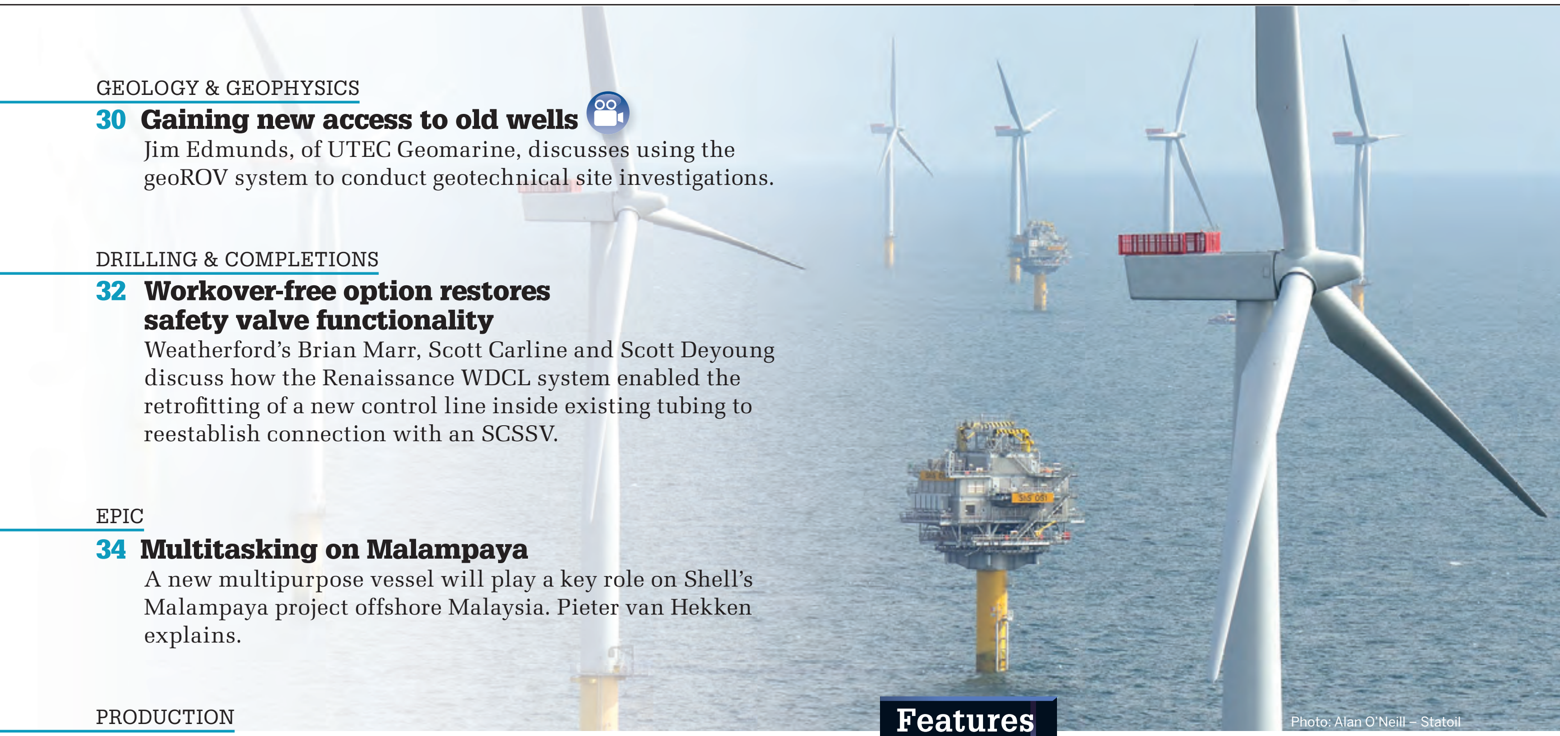

Photo: Alan O'Neill – Statoil

ON THE COVER

The DanTysk offshore wind farm, located west of the island of Sylt and directly on the German-Danish border, is a large-scale offshore wind farm built in the German North Sea. Vattenfall and Stadtwerke München are behind the project, which will have 80 wind turbines operating. On Dec. 13, 2013, the project team completed the installation of 80 foundations offshore. The 161m-long, new-build installation vessel Swire Blue Ocean's *Pacific Osprey* will now start installing the turbine towers, nacelles, and blades. An accommodation platform, being built in the Abu Dhabi MAR dockyard Kiel, will be installed in Q3 2014. Photo: Jorrit Lousberg, courtesy Vattenfall.

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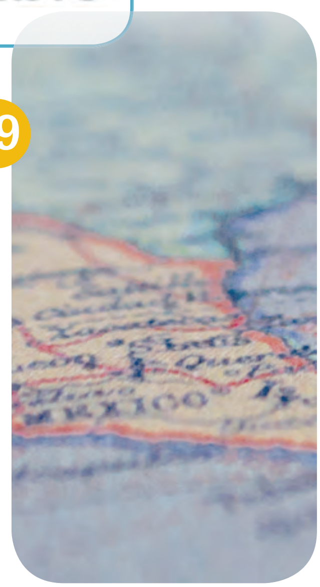

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Online Exclusive

Will marine energy catch up?

Marine renewable energy lags 15-20 years behind offshore wind, according to Augmentias Maritime. Elaine Maslin chats with the Aberdeen-based company to discover more.

What's Trending

Floating trouble

- Deepsea Aberdeen semi-sub sinks in Korean yard
- Fire aboard Petrobras' P-20 production platform
- Rubicon Vantage FPSO damages riser off Thailand

People

DNV GL appoints new CEO

Elisabeth Tørstad was recently named CEO of DNV GL - Oil & Gas, effective in January.

OE goes interactive!

OE takes another step into the future by providing interactive content in our print magazine. Have you ever read one of our articles and wanted to find out more, either through extended photo galleries, video, sound bites, or data? Beginning in this issue, look for a special icon indicating interactive content. Scan the page with the Actable app, which can be downloaded (free) from the App Store or Google Play on any smart device, and enjoy our expanded content options. Try it out for yourself by scanning pages 30 and 67.

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Voices

Waves of progress. With several mega projects underway, OE asked:

Can floating LNG be done economically on a smaller scale?

Yes, there will be a niche market for floating, small-scale LNG in the future. It will be especially relevant for small, dry gas reservoirs with little impurities, for associated gas, and for liquefaction of pipeline gas. In short, these are projects where a relatively simple topside is feasible, and for many such projects floating LNG will be the only economically viable option.

Lars Petter Bilkom, DNV GL LNG Segment Director

The market circumstances, the environmental circumstances, and the technical maturity mean that FLNG has now grown to become a very serious gas monetization option in a widening portfolio of opportunities. Shell's current FLNG technology allows for the development of smaller fields through tiebacks and the ability to move the facility to a new opportunity at the end of field life. The development of a small FLNG facility for an individual field is being studied by our industry but is expected to be more challenging based on a combination of technological and economic factors.

Marjan van Loon, VP LNG, Shell Upstream Development

The obvious answer is that we believe so, but it depends on the application. Wison Offshore & Marine sees smaller-scale, barge-based FLNG as a niche that addresses the unique market needs to export and monetize surplus gas produced from onshore shale sources, as well as offshore stranded gas assets. These cost-effective LNG generation solutions are analogous to the use of power barges deployed to meet the electricity needs of emerging countries. The barge-based FLNG facility is not going to compete with premier projects like Shell's Prelude development, but they do offer quick to market, relocatable resources to monetize second and even third-tier opportunities, or, in some cases, may serve as a temporary or "early production" unit until the larger and more costly permanent unit is developed - either floating or onshore. Additionally, by using our "Plug & Play" approach, we offer a much more cost-effective solution that may be brought in quickly or expanded in phases as near-shore developments grow.

L. Dwayne Breaux, President, Wison Offshore & Marine Ltd.

Small scale FLNG is not only feasible, down-scaling has already started. Smaller FLNG means faster lead times, greater shipyard flexibility, easier financing, and rapid return on investment. Thanks to shale gas, we're also seeing small-scale coastal FLNG being considered as an economical alternative to large onshore terminals. We've worked on a variety of FLNG R&D and planning projects, and think that for environmental and economic reasons there is a great potential for these systems in the future.

Hayato Suga, General Manager, Natural Resources and Energy Department, Class NK

Yes, but we need to continue to drive down the cost of FLNG vessels. One way to achieve this is by leveraging our experience from FPSO tanker conversions, and generating a new range of FLNG solutions from converted LNG tankers. SBM Offshore's "Twin Hull" FLNG concept is a good example of what can be achieved by innovative thinking in this area, being more economical than the equivalent newbuild FLNG.

Mike Wyllie, Group Technology Director, SBM Offshore

Yes, and as a matter of fact EXMAR is currently constructing what will be the world's first floating LNG liquefaction unit under a "Build-Own-Operate" contract for its client Pacific Rubiales Energy (PRE). This floating liquefaction unit will have a LNG production capacity of 0.5 MTPA and will come online offshore Colombia in Q2 2015. The LNG produced is meant to be sold by PRE to Gazprom Marketing & Trade under a five-year, FOB Sale & Purchase agreement.

This project proves that small-scale floating LNG is a quick-to-market and cost-effective alternative, combining available small-scale LNG liquefaction technology with marine construction and operations experience.

Miguel de Potter, Chief Financial Officer, EXMAR

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

Colloquy

OE adds interactive print experience

Augmented reality is a new communication tool that brings the print and digital worlds closer together. Scanning a page with a smart phone or smart device reveals additional "hidden" content.

Interactive print campaigns are slowly spreading into the oil & gas industry. We have incorporated 2D matrix barcodes (quick recognition, QR codes) in prior issues to link to websites.

Beginning with this issue, Offshore Engineer will offer extra animated editorial content.

OE's interactive content in the print magazines can be accessed using the (free) Actable app for smart phones and tablets. Designed by Quad/Graphics, the app can be uploaded to Android devices running the 4.0 operating system and higher. It is available from Google Play: 11MB, updated 21 Dec 2013. The Actable app is also available for Apple devices running iOS 6.0 or later. This includes iPhone (it's optimized for iPhone5), iPad, and iTouch. Visit the iTunes store, Utilities category, 30MB.

Special icons indicate the type of content (this issue contains video and easy PECOM conference registration on p. 67) and we will roll out additional icons in the coming months. We are building toward a totally interactive issue in October. Look for the icons and start scanning today!

UTEC Geomarine provides a video of its geoROV system during a geotechnical investigation, accessible on p. 30. Download your Actable app now to view.

Staff changes

We recently augmented our Houston editorial staff.

Sarah Parker Musarra joined us as a staff writer last year, following communications and writing positions at Waste Management, ENI Trading & Shipping Inc., AEI, and Houston Community Newspapers. She graduated from the University of Texas at Austin with a BA in English and has been promoted to Associate Editor.

Anthresia McWashington came to OE as an editorial intern last year, first cutting her teeth at the Offshore Technology Conference in Houston. She recently graduated from the University of Houston (UH) with a BA in Journalism. As a student, she served as a reporter and photographer at the UH newspaper, The Daily Cougar. She has now joined the OE staff as Web Editor. Welcome to both!

AtComedia
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AtComedia
1635 W. Alabama
Houston, Texas 77006-4101, USA
Tel: +1-713-529-1616 | Fax: +1-713-523-2339
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BPA WORLDWIDE BUSINESS

PUBLISHING & MARKETING
Chairman
Shaun Wymes
shaunw@atcomedia.com
President/Publisher
Brion Palmer
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neil@aladltd.co.uk

EDITORIAL
Editor
Nina Rach
nrach@atcomedia.com
Managing Editor
Audrey Leon
aleon@atcomedia.com
European Editor
Elaine Maslin
emaslin@atcomedia.com
Associate Editor
Sarah Parker Musarra
smusarra@atcomedia.com
Web Editor
Anthresia McWashington
amcwashington@atcomedia.com
Contributing Editors
Meg Chesshyre
Bruce Nichols
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ART AND PRODUCTION
Bonnie James
Marlin Bowman

CONFERENCES & EVENTS
Events Coordinator
Jennifer Granda
jgranda@atcomedia.com
Exhibition/Sponsorship Sales
John Lauletta
jlauletta@atcomedia.com

PRINT
Quad Graphics, West Allis, Wisconsin, USA

EDITORIAL ADVISORS
John Chianis, *Houston Offshore Engineering*
Susan Cunningham, *Noble Energy*
Marshall DeLuca, *Wison Floating Systems*
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ThoughtStream

Scott Tessier, Chair and CEO, C-NLOPB

Offshore Safety Demands Continuous Focus

As the regulator for the Newfoundland and Labrador offshore oil and gas industry, it should come as no surprise that everything we do at the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) is seen through the lens of the 1982 *Ocean Ranger* disaster, the 1985 Universal helicopter crash, and the crash of Cougar 491 in 2009. The *Piper Alpha* disaster and the *Deepwater Horizon* tragedy in the Gulf of Mexico were also formative events in the world of offshore safety.

The ensuing investigations and inquiries into these events led to sweeping changes in the industry. It is truly a global industry and we are constantly reminded of the risks and consequences associated with operating in a harsh environment. It is important that we share information, learn from each other, and maintain continuous focus on improving offshore safety.

Last fall, our Chief Safety Officer, Daniel Chicoyne, and I attended the International Regulators Forum (IRF) conference and annual general meeting in Australia. We each gave a presentation to an attentive audience at the conference about improvements to offshore helicopter safety and Canada's broader regulatory regime.

The IRF is comprised of offshore regulators from Canada, the U.S., UK, Norway, Australia, Netherlands, New Zealand, Denmark, Brazil and Mexico. It provides a forum to collectively promote safety in the upstream offshore oil and gas sector through collaboration and information sharing.

Following the IRF meeting, the CSO and I identified five offshore safety areas of current concern in the Newfoundland and Labrador offshore, beyond helicopter passenger safety.

It is truly a global industry and we are constantly reminded of the risks and consequences associated with operating in a harsh environment. It is important that we share information, learn from each other, and maintain continuous focus on improving offshore safety.

The first is training and competency. The demand for drilling installations is high and it appears that installations may be getting built faster than the time it takes to build competency among the workforce to operate a new rig. Operators are hiring new rig workers and providing training, but many experienced rig workers are retiring, so there is a risk of less mentoring to ensure new workers attain competency. A decline in the number of experienced offshore workers demands a higher level of training among those who remain.

The second area is a disturbing trend in the number of dropped objects and near misses, which, of course, means an increase in the potential for serious injury, or death. In many ways, this problem speaks to the need for companies to step up efforts to improve safety culture and develop more robust programs.

A third issue is the fact that our offshore facilities are aging, which creates a need for greater attention to preventative maintenance, inspection and testing, and corrective maintenance to ensure continued asset integrity. Aging facilities can pose increased risks if preventative maintenance is not conducted regularly and if corrective maintenance is not attended to in a prompt manner.

The fourth area is the need for improved information sharing on things like incidents and accidents, including near misses. Operators and workers need to learn from one another to prevent making similar mistakes that can lead to serious injuries, or death. Safety conferences and forums are useful in this regard, but more is needed. The industry needs to find ways to better share information openly and regularly in the interest of preventing incidents and injury.

The fifth issue is the need for global standards. If operators want to move people and installations from region to region, there should be standards for similar known and accepted qualifications and/or equivalency.

Offshore safety is always the top priority of the C-NLOPB. Moving forward, the C-NLOPB will increase our focus on these issues and continue to expect improvements from the industry. OE

***Scott Tessier**, Chair and CEO, Canada-Newfoundland and Labrador Offshore Petroleum Board.*

Mr. Tessier was born and raised in St. John's and holds a bachelor's degree in engineering from Memorial University of Newfoundland. Prior to his appointment in February 2013, he was a Senior Advisor for Legislative and Regulatory Affairs with Chevron Canada in Calgary, Alberta.

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BAKER HUGHES

Global Briefs

A Hibernia \addresses oil leak

Hibernia Management and Development Co. Ltd. (HMDC) has reported an ongoing leak of crude oil from the hose end valve (HEV) of the Northern Offshore Loading System (OLS).

On Dec. 18, 2013, approximately 10L of crude was spilled from the HEV during the connection attempt. On Dec. 27, a sheen was noted in the area of the Northern OLS. On Dec. 30, a remotely operated vehicle confirmed leakage from the HEV of the Northern OLS. Offloading to tankers was suspended and production rates at the Hibernia platform were cut back significantly. HMDC estimates the total volume contained in the affected portion of the loading system to be 16,000L.

B US enacts Transboundary Hydrocarbons Agreement

The US Department of the Interior (DOI) announced that the US-Mexico Transboundary Hydrocarbons Agreement has been enacted. The agreement establishes a framework for US oil and gas companies and PEMEX to jointly develop transboundary reservoirs and opens up resources in the Western Gap.

The Transboundary Agreement removes uncertainties regarding development of transboundary resources in the resource-rich Gulf of Mexico. As a result of the agreement, nearly 1.5 million acres of the US Outer Continental Shelf will now be made more accessible for exploration and production activities. Estimates by the DOI's Bureau of Ocean Energy Management (BOEM) indicate that this area contains as much as 172 MMbo and 304 Bcf of natural gas. The agreement also opens up resources in the Western Gap that were previously off limits to both countries.

C Stone Energy busy in the GOM

Stone Energy Corp. is drilling past 15,300ft at its deepwater Amethyst prospect, located on Mississippi Canyon Block 26, with a targeted depth of 20,000ft.

Drilling continues past 14,000ft at the deep gas Tom Cat prospect, West Cameron Block 176, with a targeted depth of approximately 16,000ft. Both the Amethyst and Tom Cat wells are expected to encounter their targeted objectives in early 2014. Stone will spud its Mica Deep prospect (MC 211) in Q1 2014.

D Mexican states approve energy bill

Mexico's Federal Congress certified that 24 of the country's 31 state legislatures approved energy reforms to allow private companies to explore for and produce oil and gas. This was the third step required to enact the constitutional reform, which amended Articles 25, 27, and 28 of the Mexican Constitution.

E New COSL jackup delivered

The COSLGift, an independent leg cantilever jackup rig, has been delivered, and was en route to Southeast Asia, China Oilfield Services Ltd. (COSL) announced. The jackup was expected to start working in January 2014, while its sister COSLHunter was towed to Gulf of Mexico in early December 2013 to begin a 5.5-yr contract with PEMEX.

F Petrotrin acknowledges oil spills in Trinidad

The state oil company of Trinidad & Tobago, Petrotrin, suggested sabotage and environmental terrorism as the cause of December oil spills. The Oilfield Workers Trade Union said Petrotrin should shoulder the blame for the disaster, citing poor management practices that resulted in lax security and monitoring, and the lack of oil spill response contingency contracts.

G Statoil makes NCS discovery

Statoil made a gas discovery at the Askja West prospect and an oil discovery at the Askja East prospect in the Norwegian sector of the North Sea. Exploration wells 30/11-9-S and 30/11-9-A were drilled using the *Ocean Vanguard* semisubmersible between the Oseberg and Frigg fields, in PL 272, about 13km southeast of the Statoil-operated Krafla/Krafla West discoveries.

Well 30/11-9 S tested the Askja West prospect and proved a 90m net gas column. Sidetrack 30/11-9-A on Askja East proved a 40m net oil column.

Statoil estimates total recoverable reserves in Askja West and Askja East are 19-44 million boe.

H Lundin spuds Sverdrup

Lundin Petroleum AB started drilling the latest appraisal well at the giant Johan Sverdrup discovery, in the Norwegian sector of the North Sea. Well 16/3-8S, on PL501, is at the crest of the Avaldsnes high. Planned total depth is about 2025m below mean sea level, and the well will be drilled using the semisubmersible *Bredford Dolphin*. Drilling is expected to take about 45 days.

I Shell grabs Petrobras' BC-10 stake

Petrobras' partners in the Parque das Conchas (BC-10) development have finalized a buyout worth approximately US$1.6 billion for the Brazilian national's 35% interest in the project.

Shell will pay $1 billion for an additional 23% interest and will now hold 73% operating stake. Partner ONGC Videsh announced in October that it will pay $529 million for an additional 12%, which ups the Indian national's total stake to 27%.

Petrobras was previously in discussions with China's Sinochem to sell its 35% share for a reported $1.56 billion, according to Reuters.

J Ensco rig reaches Malta

The Netherland's Fairmount Marine, part of the Louis Dreyfus Armateurs Group, safely delivered the *Ensco 5004* semisubmersible to Malta at the conclusion of a voyage that originated offshore Rio de Janeiro. *Ensco 5004* was built in 1982, is 94.7m (311ft) long and 70.4m (231ft) wide.

It was towed 5782nm and exceeded speeds of 7 knots.

K BG spuds Kenyan well

BG spudded the Sunbird-1 exploration well offshore Kenya, joint venture partner Pancontinental Oil and Gas announced. The well site is located in License Area L10A, in 721m of water. The *Deepsea Metro 1* drillship will take 50 to 60 days to drill 3000m below sea level, with an option to extend to 3700m. Sunbird-1 is the first exploration well in the Lamu basin offshore Kenya. The well will be plugged and abandoned, but could be re-entered at a later date, Pancontinental said.

L Tanzanian well disappoints Ophir

Ophir Energy said the Mlinzi Mbali-1 well off Tanzania has not found commercial hydrocarbons, but still offers "crucial information" about Block 7, off the East African coast. It was the first well to be drilled on that block.

The Mlinzi Mbali-1 wellsite is located in about 2600m of water and sits nearly 210km east of Dar es Salaam. Drilling was completed by the *Deepsea Metro*. It was the deepest stratigraphic test offshore Tanzania, said Ophir Chief Executive Officer Nick Cooper.

M Oman well suspended

Lime Petroleum PLC subsidiary Masirah Oil Ltd. has halted drilling exploration well Masirah North North #1 (MNN #1) for safety reasons. The well was drilled to 1000m before mud losses in two carbonate sections prevented the operator from reaching the planned target depth. Analysis completed Dec. 21, 2013, indicated non-commercial hydrocarbons.

The well was the first to be drilled in Block 50, offshore Oman. The Block 50 concession area is about 17,000sq. km (6563sq. mi) and is estimated to have to risked resources of approximately 390MMbo.

N First oil at Prirazlomnoye

Gazprom Neft Shelf announced the start of oil production from the Prirazlomnoye platform in the Russian Arctic. The start of production at Prirazlomnoye had long been delayed due to aging equipment and a change in the project's shareholder structure. Located on the Pechora Sea shelf, 60km offshore (Varandey settlement), the Prirazlomnoye field is in shallow water of 19m to 20m. Gazprom estimates 72MM tons of oil reserves and the potential to achieve annual production of 6.6MM tons.

O CNOOC in production

CNOOC Ltd.'s Qikou 18-1 adjustment project commenced production in the west part of Bohai in water averaging 10m. The project is expected to hit its peak production in 2014. CNOOC also began production at the Liuhua 19-5 gas field, located in the Pearl River Mouth Basin in the South China Sea with water averaging 185m. CNOOC operates both the Qikou 18-1 oil field and the Liuhua 19-5 gas field with 100% interest.

P Rig inks in Korean yard

A semisubmersible drilling rig under construction at a yard in Korea is resting on the seabed after water entered the pontoon hull and the unit sank. The rig, *Deepsea Aberdeen*, was being built for Odfjell Drilling at the Daewoo Shipbuilding and Marine Engineering (DSME) yard in South Korea. The unit was evacuated after the water ingress and the rig stabilized on the sea bed, with draft at around 21m, Odfjell said. The semisub was due for delivery in May.

Q Egypt offers exploration blocks

The Egyptian General Petroleum Corporation (EGPC) has launched a new bid round for exploration licenses in the Gulf of Suez. Fifteen blocks, five in the Gulf of Suez and 10 in the Western Desert sedimentary basins, will be available, with licenses to be agreed on a production sharing basis. Data purchasing and data room will be available in EGPC Geological & Geophysical Information Center, Nasr City.

R Salamander Energy enters Malaysia

The UK's Salamander Energy signed a production-sharing contract for Block PM322 in the Melaka Straits, the company's first license in Malaysia. The shallow-water block includes about 20,000sq. km on the Malay side of the Central Sumatra basin, off peninsular Malaysia. The PM322 PSC contains the Port Klang oil discovery made by Sun Oil in 1991, in the same drilling campaign that resulted in the discovery of the Salamander-operated Bualuang oil field in the Gulf of Thailand.

S ONGC invests in Krishna Godavari basin

State-run Oil and Natural Gas Corp (ONGC) will invest more than US$9 billion to bring an array of oil and gas discoveries in its Krishna Godavari basin block off the east coast into production by 2017-2018.

ONGC has made 11 oil and gas discoveries in Block KG-DWN-98/2, which is next to the Deendayal gas field. The block is divided into a Northern Discovery Area (NDA) and Southern Discovery Area (SDA). ONGC plans to invest $9 billion in producing discoveries in NDA. ONGC said that NDA holds an estimated 92.30 MM tons of oil reserves and 97.568 Bcf of gas reserves spread over seven fields.

Contract Briefs

Aker wins Johan Sverdrup FEED

Statoil awarded Aker Solutions a 10-year framework contract worth approximately US$105.8 million for the North Sea Johan Sverdrup field. The first call-off is the front-end engineering design (FEED) work of the field center, Statoil announced.

The contract also includes an engineering services, procurement and management assistance (EPMA) option for the first phase of development, and additional options for later phases.

Fugro surveys Gorgon Project

Fugro will provide survey services supporting Subsea 7 Australia Contracting Pty Ltd's heavy lift and tie-ins contract on Chevron's Gorgon project, 60km off Western Australia.

The contract involves providing a DP2 survey vessel and deepwater work-class remotely operated vehicles (ROVs). Through offshore supply ship Rem Etive, Fugro will install and calibrate long baseline arrays, along with spoolpiece metrology operations on a 24-hour basis. Fugro will also provide personnel and equipment.

Barents seismic cooperation

Seismic acquisition firms Electromagnetic Geoservices ASA (EMGS) and TGS have announced new contracts and an expanded cooperation agreement. The two firms said they will increase the number of blocks covered in the Barents Sea cooperation agreement from 11 to 17. In addition, TGS will increase its investment in all 17 blocks. Multi-client surveys in the area are already complete. The contribution from TGS is about US$3.4 million.

EMGS has signed a data licensing agreement, worth about US$1.2 million, for the provide 3D electromagnetic data from its multi-client Barents Sea data library.

Russia to explore offshore Syria

The Syrian Ministry of Petroleum and Mineral Resources signed the "Amrit" contract with Russia's Soyuzneftegaz for offshore oil drilling, development and production in Block no. 2 of Syria's territorial waters. The contracts covers oil exploration in the area between Tartous and Banyas, to a depth of 70km (43 mi.), an overall area of 2190sq km., with this stage costing more than US$15million. The second stage will involve drilling at least one test well, with estimated spend over $75million. Soyuzneftegaz will be responsible for funding all the stages of the contract, and will begin operations immediately after the contract's ratification and publication.

Bumi inks Kraken deal

Malaysia-based international offshore oilfield services provider, Bumi Armada Berhad signed a bareboat charter contract with EnQuest for a floating production, storage and offloading vessel (FPSO) to be deployed at the Kraken field in the UK North Sea. Bumi Armada UK Ltd. also signed a reimbursable contract for operations and maintenance (O&M) of the Kraken FPSO.

Both contracts run simultaneously for eight years, and are valued at US$1.4 billion, with options for 17 annual extensions.


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Analysis

Mexican energy reform:

Awaiting secondary legislation and the first bidding round

Now that reform has passed in Mexico, GlobalData's Adrian Lara weighs in on what to expect from the country's budding energy industry.

Mexico has approved its most liberal reform concerning its energy sector. It introduces new arrangements such as profit-sharing contracts, production-sharing contracts and licenses and a complete opening for private participation in the downstream and midstream sectors.

Congress legislators now have 120 days after the promulgation date to pass the secondary laws that will include the terms and details for the new forms of private participation.

Pemex was given 90 days after promulgation of the reform to request, under preferential treatment, its chosen existing and prospective areas for exploration and production.

For accounting and financial purposes, the changes in the constitutional text will allow for the private sector and the state company to report any contract and its related benefits. It is still to be seen whether the secondary legislation and rules for implementation will allow for booking of reserves.

The path towards a liberal reform

In August 2012, the executive branch of the Mexican government sent to Congress a proposal for reforming the country's energy sector. Concerning oil and gas, it argued that the bulk of the country's remaining hydrocarbon reserves are located in challenging areas from both geological and engineering perspectives. As a result, their recovery requires sophisticated and expensive technology. Pemex has ample expertise in shallow waters but does not have the expertise to enter more complex projects located in deep water or onshore shale plays. Moreover, the proposal established that, from a business point of view, it would be unwise to let Pemex assume the risk of such projects.

The ruling Institutional Revolutionary Party (PRI) put forward an original proposal that only considered a profit-sharing contract as the new addition to contracting options. However, the approved reform also includes the options of production-sharing contracts and licenses, which are generally considered much more attractive. These additions were pushed by the right-wing National Action Party (PAN).

Future contracting scenarios

Type of Resource	What has been Pemex Role?	Possible Contracts for Private Participants	Possible Bidding Round	Expected Date
Onshore conventional fields	Dominant position in exploration and production	- Service contracts - Profit-sharing contracts	Round Zero and subsequent rounds	2014
Shallow-water fields	Dominant position in exploration and production	- Service contracts - Profit-sharing contracts	Round Zero and subsequent rounds	2014
Unconventional onshore fields (i.e. Shale)	Exploration and production in some areas (i.e. Chicontepec)	- Production sharing contracts - licenses	First Round	2015
Deepwater fields	Exploration in some areas	- Production sharing contracts - Licenses	Second Round	2016

Source: GlobalData

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	60	1
Deep (500-1500m)	25	24	16	
Ultradeep (>1500m)	20	36	28	
Total	149	135	104	1
Start of 2014 date comparison	151 +2	135 –	98 +6	– +1

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	15	2,265.00	2,435.00
Ultradeep	44	12,873.75	18,030.00
United States			
Shallow	19	93.90	298.00
Deep	22	1,686.11	1,984.57
Ultradeep	33	4,819.50	4,690.00
West Africa			
Shallow	184	4,361.28	22,164.83
Deep	55	7,246.50	7,940.00
Ultradeep	21	2,580.00	3,760.00
Total (last month)	412 (363)	38,094.59 (32,653.76)	63,504.70 (53,863.96)

Greenfield reserves

2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow (last month)	1,384 (1,372)	55,606.69 (55,384.39)	849,356.76 (788,267.31)
Deep (last month)	186 (188)	15,020.48 (15,381.68)	114,991.27 (113,341.57)
Ultradeep (last month)	123 (124)	21,902.75 (21,946.95)	89,247.00 (90,147.00)
Total	1,693	91,529.92	1,053,595.03

Pipelines

(operational and 2014 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,396	(41,634)
Planned/ possible	25,433	(25,383)
	66,829	(67,017)
8-16in.		
Operational/ installed	78,039	(78,085)
Planned/ possible	49,390	(49,511)
	127,429	(127,596)
>16in.		
Operational/ installed	89,108	(89,263)
Planned/ possible	49,539	(49,726)
	138,647	(138,989)

Production systems worldwide

(operational and 2014 onwards)

Floaters		(last month)
Operational	274	(277)
Under development	44	(44)
Planned/possible	334	(335)
	652	(656)
Fixed platforms		
Operational	9,596	(9,600)
Under development	118	(118)
Planned/possible	1,471	(1,474)
	11,185	(11,192)
Subsea wells		
Operational	4,337	(4,389)
Under development	431	(427)
Planned/possible	6,353	(6,350)
	11,121	(11,166)

Global offshore reserves (mmboe) onstream by water depth

	2012	2013	2014	2015	2016	2017	2018
Shallow (last month)	5,941.77 (5,947.62)	26,335.74 (39,535.70)	48,006.10 (37,387.51)	41,942.71 (39,331.24)	33,117.77 (33,099.27)	51,364.35 (51,487.64)	31,588.93 (33,725.39)
Deep (last month)	2,821.40 (2,821.40)	1,784.63 (2,910.28)	3,967.22 (5,717.19)	7,166.95 (4,368.72)	5,010.60 (4,930.34)	8,577.10 (8,957.36)	10,606.95 (11,425.53)
Ultradeep (last month)	737.15 (737.15)	3,090.07 (3,240.07)	2,673.80 (2,871.43)	2,264.67 (2,067.04)	4,880.02 (5,666.75)	16,387.06 (15,950.97)	10,432.09 (11,284.32)
Total	9,500.31	31,210.45	54,647.12	51,374.33	43,008.39	76,328.51	52,627.97

14 January 2014

From the beginning, the left-wing Party of the Democratic Revolution (PRD) never agreed with the idea of changing the Constitution. When they decided to leave the institutional channels for negotiation and declared that they would protest in the streets, PRI gave in to PAN's demands for a more liberal reform.

The left-wing PRD has plans for organizing a referendum in 2015, seeking to invalidate the approved reform. They presented the case to the Supreme Court arguing that the right of citizens to decide on key national decisions should be guaranteed. It is now for the Supreme Court to approve or disaprove the possibility of organizing such a referendum.

Ambiguity in the new contracting schemes

According to the transitory articles that will modify the Mexican constitution, the contracting options for hydrocarbon exploration and production must include service contracts, profit or production-sharing contracts, and licenses. Nonetheless, the changed law does not specify which type of contract will be applicable to the different types of hydrocarbon exploration and production. Also, the inclusion of the words "among others" in the bill text may leave the door open for more tailored contracts which can give the State flexibility in terms of including the right fiscal incentives for private companies.

However, Pemex's financing and technological needs indicate the opportunities for private investment. Deepwater, shale and even shallow water areas can benefit from different combinations of technology transfer, capital expenditure in exploration and development, and managerial expertise.

For instance, Mexico's deepwater prospective area in the Gulf of Mexico is considered underexplored. In this case, the licenses could be an appropriate type of contract for attracting the necessary capital while also compensating for a high exploratory risk. Profit and production-sharing contracts will most likely be intended for areas where the State and Pemex consider that capital has already been successfully invested but that a partnership can still be beneficial.

It seems fair to assume that the first bidding round for private investors will presumably include production and profit-sharing contracts, to test the waters.

The licenses will remain a politically sensitive and costly issue since they are associated with concession schemes and might, therefore, be more difficult to implement in an initial round. Furthermore, in subsequent rounds, the Mexican State could benefit from the interaction, feedback and results of any previous round. Service contracts will remain the preferred scheme for oil and gas services companies and some may also incorporate a risk or performance-related adjustment. These contracts were originally designed for use in rounds offering offshore mature fields and some areas in the resource-rich onshore Chicontepec play.

However, since Chicontepec is also considered an unconventional play due to its geological characteristics and drilling requirements, it's possible that the new contracts will be used for its development (see Table).

The new challenges for Pemex

As indicated in the approved reform bill, a Round Zero is expected to be held by mid-2014. As is the case in these initial rounds, preferential treatment is given to the national oil company

(NOC) in proposing which existing and prospective projects they would like to keep out of future offerings. This is important for two reasons: one is the obvious one of what will be left for private bidding, but it is also the beginning of a far more serious role on the part of the existing regulatory agency, the National Commission of Hydrocarbons (CNH) and the Energy Ministry.

The approved reform states that Pemex's status will be changed from a Decentralized Public Organism to a Productive Public Company with the goal of greater autonomy and financial flexibility. However, modernizing Pemex would require more than just lowering its fiscal burden or giving the company the opportunity to associate with experienced oil and gas companies. Pemex is a company with severe operational and financial inefficiencies in its refining and petrochemical subsidiaries and many agree that their excess of labor is an issue that requires an urgent solution. In this context, one interesting turn of events during the reform negotiations was to strip the powerful Pemex workers' union of its advisory board seats. As is evidenced by examples such as Norway's Statoil, Brazil's Petrobras and others, a competitive NOC can be a powerful tool, expanding the state's reach beyond its own domestic resources. Getting this right will therefore be a crucial test for the approved reform.

The road ahead

Private participation in Mexico's energy sector is expected to bring the necessary injection of capital and technology that could unlock vast hydrocarbon resources. What now follows, starting in 2014, is the modification of the related secondary laws. They only require a simple majority in Congress to be approved and therefore PRI's political maneuver, as well as the policy directives of the Energy Ministry, will be influential in negotiating the content of this additional legislation.

A crucial test will be how international oil companies (IOCs) react when the new opportunities are offered, which will depend to a great extent on what they contain. In any case, there is still a long way to go before the approved reform materializes in actual new production or has a significant effect on the wider Mexican economy through lower energy prices.

To sum up, there is still a lot to be clarified in the secondary legislation, but for the moment, this reform seems to bring the opportunity for ending an inert situation that has lasted longer than necessary. After all, the current PRI administration seems to have a clear interest in expediting all of the pending procedures and testing the reach of the reform in attracting private capital as soon as possible. The most important point is that the passage of this bill removes the barrier of the constitution from a wide range of future reforms, allowing Mexico's energy sector to adapt to prevailing conditions in the future. OE

Adrian Lara is a senior upstream analyst, Americas, for GlobalData. He has several years of experience as an oil and gas industry analyst, having held different positions within the trading arm of Mexican state-owned company Pemex. Adrian has a MS in Mineral and Energy Economics from the Colorado School of Mines, with a specialization in oil and gas from the Institut Français du Pétrole. He has a BA in Economics and Political Science from the Instituto Tecnológico Autónomo de México (ITAM).

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Jackups	412	359	53	87%
Semisubs	192	171	21	89%
Drillships	94	88	6	94%
Tenders	31	21	10	68%
Total	**729**	**639**	**90**	**88%**

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Jackups	90	74	16	82%
Semisubs	29	26	3	90%
Drillships	21	20	1	95%
Tenders	N/A	N/A	N/A	N/A
Total	**140**	**120**	**20**	**86%**

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Jackups	117	105	12	90%
Semisubs	36	30	6	83%
Drillships	17	13	4	76%
Tenders	24	16	8	67%
Total	**194**	**164**	**30**	**85%**

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Jackups	8	7	1	88%
Semisubs	42	42	0	100%
Drillships	29	29	0	100%
Tenders	2	1	1	50%
Total	**81**	**79**	**2**	**98%**

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Jackups	45	42	4	91%
Semisubs	46	42	4	91%
Drillships	2	2	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	**94**	**86**	**8**	**91%**

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Jackups	103	88	15	85%
Semisubs	3	3	0	100%
Drillships	1	1	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	**107**	**92**	**15**	**86%**

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Jackups	24	22	2	92%
Semisubs	20	16	4	80%
Drillships	23	22	1	96%
Tenders	5	4	1	80%
Total	**72**	**64**	**8**	**89%**

Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Jackups	24	21	3	88%
Semisubs	16	9	7	56%
Drillships	1	1	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	**41**	**31**	**10**	**76%**

Source: InfieldRigs

7 January 2014

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

Cable-laying CAPABILITIES

Offshore wind is predicted to continue growing, and, with it, expertise in cable laying. Elaine Maslin reports on the challenges and solutions facing offshore wind farm developers.

"Power cable installation is the problem child of the offshore industry," according to the stark introduction to a recent report on cable installation in the renewables industry.

Author, Enventi, based in Aberdeen, says that despite accounting for 2-3% of the budgeted upfront capital spending, array cable installation is said to be responsible for 70-80% of all insurance claims, due to damaged cables.

In fact, 5% would be a more accurate estimation of final capital spending on cable installation, once all costs are taken into account, the report says.

Electrical transmission systems in offshore wind usually comprise a 3-core cable from turbines, which generate electricity at 33kV AC, to offshore substations, where the voltage is stepped up to around 150kV (or 220kV for larger farms), for transmission to shore.

The 630MW, 175-turbine, London Array phase 1 development has two 33/150kV offshore substations, and four 170kV-rated export cables (two for each substation) to shore.

Cable laying is performed in a number of ways: ploughing, where the cable is guided into a trench created using a plough; free lay, where the cable is laid and then buried using ROVs; and trenching, using either high-pressure water jets or mechanic cutting tools, to bury the cable.

"Many of the problems experienced to date are outside installation contractor's control and relate to poor upfront design, that shows a basic lack of know-how in the offshore environment," says Enventi director Scott Macknocher.

He identifies the main problems as: poorly-designed interfaces between cables and related infrastructure (mostly turbine foundations); contracting philosophies used by utilities based on civil contracting principles, which are not suited to the specific needs of operating offshore; immaturity of contractors, who lack relevant experience; arbitrary burial specifications, with no link to what is realistic and achievable; lack of understanding of cable installation operations and technologies by clients.

Another common complaint is the lack of knowledge sharing, with operators not willing to discuss their problems, despite government-backed projects, like the Offshore Renewable Energy Catapult, trying to encourage knowledge exchange.

Some of the issues have been put in the public domain. In January 2012, Vattenfall's 300MW, 100-turbine Thanet offshore wind farm had to run at half capacity because one of its two export cables developed two faults: one where it had been bent at an acute angle, and a second near the substation, which led to costly repairs.

Damage to cables can occur during installation, with different burial methods putting varying levels of stress on the cables. There is also potential for post-lay damage, such as anchor damage from vessels, trawler board harm from fishing boats, and general abrasion, if cables are not buried appropriately.

Appropriate burial can be complicated by environmental constraints, such as restrictions on burial tools that cause sediment plumes, affecting shellfish, and on timing the installation correctly to avoid restrictions in fish spawning grounds.

Opportunities

Despite these issues, offshore power

Above- Export cable laying operations on the London Array Offshore Wind Farm. Image courtesy of London Array Limited.

Right- Vattenfall's Thanet Offshore wind farm, off the Kent coast, England. Image courtesy of Vattenfall.

The two London Array wind farm substations, pre-wired, en-route for offshore installation. Photo courtesy of London Array Limited.

cable installation is predicted to grow, creating opportunities for those with solutions.

Chris Marchant, head of cables and offshore development at quality assurance and solutions firm Intertek, says there has been a maturing of the industry and a degree of consolidation of knowledge. Membership body Subsea Cables UK has been working towards a set of guidelines for submarine cable laying, and a European code of practice is being developed.

Intertek, which has experience in cable laying for offshore wind farms, as well as interconnectors and island connections, worked on the London Array project.

Intertek's Don Liversidge oversaw the export cable laying operations on the project. He says its success was helped by Intertek's involvement throughout the project, from tendering through to commissioning, plugging a gap in operational experience on the project.

A high priority was placed on planning, Liversidge says. "The majority of the risk in cable installation lies at the shoreline, or where it connects to a structure. Getting that interface right is essential. We spent over a year planning our operations, working together several times a week and the result was we did exactly what we said and we were within the timeframe planned. Planning up front saved so much time operationally. With anything subsea, it's all about metocean conditions, knowing what season you can working. Knowing the soil condition is vital, subsea and on land."

This knowledge resulted in a specific innovation—using a long-reach mechanical excavator on the mud flats, where the cable rose to, before transferring to dry land. This meant the operation was not dependent on a plough, or ROVs, which would be water-line dependent.

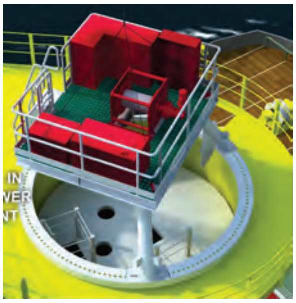
A significant time and man-power saving was made by pre-wiring the cables on the offshore substation, built by Fabricom, while it was still onshore, saving an estimated 40,000 offshore man-hours, and offshore complications. There is still room for improvement, especially in pulling cables up into J-tubes, however, Liversidge says.

Cable pull-in

Technip Offshore Wind, a division of Technip, is addressing that challenge. Turbines comprise monopiles, onto which transition pieces are landed. Inside the transition pieces are up to three J-tubes, into which the power cables are pulled-in, using lifting equipment, and secured on a hang off ready for termination.

"To date, most cable installation has been and still is completed blind," says Mike Kearney, of Technip. This is due to poor subsea visibility in strong currents, and shallow water depths restricting use of ROVs and divers.

Other issues include the calculated pull-in load being up to 3.6-tonne, which is 50% of the allowable cable tension. There are also no strong points to suspend rigging equipment above the J-tube, no strong points on the external landing platform, no provision for bolting a winch foundation, and the cable



Left — Technip's pull-in module, being lifted onto a transition piece on the Lincs Wind Farm, offshore Lincolnshire. Right — A visualization of Technip's pull-in module. Images courtesy of Technip.

deck floor not being designed to take loads associated with cable pull-in equipment.

"Traditionally these issues have been overcome by utilizing a simple steel Tripod A-frame, installed on the turbine flange, which is the only area strong enough to take the forces associated with the cable installation," Kearney says. However, set up takes up to three hours, is weather sensitive and the installation process poses risks to crew safety, with potential for significant harm if the cable, under high tension, breaks, and operational risk.

Technip's solution is a 5.9-tonne pull-in module (PIM), consisting of a tripod structure (to install in one lift using self-aligning guide pins onto the turbine flange on the transition piece, with a small integrated winch) and dedicated power supply, able to run for more than 18 hours. A secondary independent power supply could power lighting. It also has two large storage units, with about 100kg of equipment often required on a pull, and multiple hang-off points around the hand rails, to enable equipment to be loaded before transfer to the transition piece.

The PIM eradicates any effects of vessel motion on winch wires during pull-in, currently performed from a vessel, and allows the winch operator to be located at the work site.

In addition, Technip suggests certified attachment points be added all over the structure to give personnel clip-on points is working close to an exposed edge, as well as hand rails and equipment guards on the upper work platform.

The system has been deployed on the Lincolnshire Offshore Wind Farm, off England, with an average 2.5hr cable pull-in time, compared to 6.5hr on the Thanet Offshore Wind Farm, Kearney says.

Inter-array cable laying

IHC Merwede aims to resolve some of the challenges of offshore wind cable installation, specifically burying inter-array cables, with its Hi-Traq subsea trenching vehicle, developed by its business unit, IHC Engineering Business.

Chris Jones, product manager, subsea vehicles, says: "We started with a clean sheet and looked at all the environmental impacts, cost, schedule and technical issues around burying inter-array cables. The shallow water (20-50m typically) makes it a completely different environment from deeper water oil and gas operations. Wind farms are in shallow water to limit foundation costs, which means a stronger seabed and wave interaction, which in turn influences current and activity at the seabed, such as shifting sand ripples and mega ripples. This influences the type of vehicle needed."

In these environments, free-swimming ROVs, or using cutting or jetting technology to trench, may not be suitable.

The smallest Hi-Traq unit, equipped with pressure jetting equipment, has been designed to weigh 15-tonne in the water (25-tonne in the air, compared to 40-50-tonne for existing tracked trenchers). This is estimated to be the minimum weight required to keep it on the seabed in 4-6 knot currents. It will be rated to 1000m water depth to perform cross-market operations.

The aim is for it to be easy to mobilize, and to have a minimum footprint, to enable its use on smaller vessels. A larger version, incorporating a mechanical cutter, could have a submerged effective weight of 30-tonne, with potential for an 80-tonne version to be built, which could operate in the oil and gas market.

The system, developed with regional development fund funding, is based on a four-track undercarriage design with bogie arrangements. Each track has independent suspension, maximizing seabed traction capability, which means it can turn in a 10m circle instead of a 50m circle on previous vehicles. It also has the capacity to 'crab,' for working on slopes or uneven surfaces.

The shallow water environment means it can cope with burying the laid slack required for the pull-in operation. While a jetting ROV could do this, it cannot do it all the time, depending on the current. Hi-Traq can also reverse up to foundations, then track away.

A demonstration vehicle was completed earlier this year, with testing and validation scheduled for Q1 2014. OE

IHC Merwede's Hi-Traq inter-array cable laying concept. Image courtesy of IHC Merwede.

Making WAVES

With the sustained global push for cleaner electricity production, wave energy offers significant potential for the global energy mix. It is an abundant resource that can be captured through a variety of devices, including the oscillating water column. Katie Jernigan delves into wave energy's global potential and how the oscillating water column assists in production.

Dresser-Rand's HydroAir turbine design that can be incorporated into an OWC structure.

A vast renewable, almost untapped energy resource can be found in the world's oceans. According to the Lloyd's Register Global Marine Trends 2030 report, if just 0.1% of the renewable energy available in the ocean were converted into electricity, it would supply more than five times the current global demand.

The primary types of ocean energy include wind, wave, tidal and ocean current. Wave appears to be the most promising as a recoverable resource because it contains higher energy potential than other ocean energies. K. Gunn and C. Stock Williams, in "Quantifying the Potential Global Market for Wave Power," estimate the world's theoretical wave power resource to be 2.11TW (or 2.1 million MW). This is almost 10 times the global installed capacity of wind, which was about 282,587 MW in 2012, according to the Global Wind Energy Council (GWEC).

Wave energy varies in different parts of the world, but is particularly abundant off of the European Atlantic coast (especially off Scotland), northern Canada, southern Africa, Australia, and the northeastern and southeastern coasts of the US. According to the Electric Power Research Institute (EPRI), the total wave energy resource along the US outer continental shelf is 2,640 TWh/yr. Of that figure, 1,170 TWh/yr is recoverable, which represents almost 1/3 of the 4,000 TWh/yr of electricity used in the US each year. By comparison, there was approximately 446 TWh of electric power produced from wind worldwide in 2011, according to the GWEC.

Dr. Sean Barrett, Technical, Wave Resource and Project Analyst of Oceanlinx Ltd., considers wave energy to be a more reliable renewable resource because waves can be predicted several days in advance, allowing for higher energy production without complete dependence of wind.

"Even when the wind is not blowing, there are still waves rolling into the beach," said Barrett.

Converting this massive potential resource into actual electrons will poses a daunting task, however. Gunn estimates that wave energy converters (WECs), a group of diverse devices that can capture energy from waves, can convert approximately 4.6% of potential energy into electricity.

WECs devices include point absorbers, attenuators and oscillating water columns (OWC), each of which is equipped with a power take-off (PTO) unit that consists of a turbine and generator. Along with the PTO unit, many devices have additional moving parts. Since the OWC does not have any other moving

Dresser-Rand's Hydroair turbine integrated with an Oceanlinx unit. Images courtesy of Dresser-Rand.

parts underwater, it has a competitive advantage when compared to other WECs.

"The additional moving parts will reduce the efficiency of the devices, and also significantly increase the operation and management costs," said George Laird, business development manager for Dresser-Rand. "In addition, it might affect their reliability."

An OWC is a partially submerged WEC that can be installed in various water depths: on the shoreline, near shore or offshore. Using subsea cables, energy is transferred from the OWC to the power grid.

Traditional turbines have been powered by gas or steam that flows in only one direction, whereas the air flow produced by an OWC is bidirectional (the rising and falling of the incident wave). This requires a specially designed turbine. The turbine on an OWC is above the surface line, making it easier to maintain.

"The HydroAir product makes the most of the impulse turbine design, which has a broad operating range," Laird says. "It also uses the variable radius turbine (VRT) principle to increase efficiency and has minimal moving parts to ensure high reliability and reduced maintenance."

HydroAir is Dresser-Rand's patented turbine design that can be incorporated into the OWC structure. It contains two sets of static guide vanes that are on either side of the rotor, at a larger diameter than of the rotor. These vanes are connected by a shaped duct, used to direct the airflow. Entering the duct at a slow velocity, the air moves in a swirl as it passes through the inlet vanes. As the air passes through the narrowing duct, it accelerates and turns the rotor. The air then decelerates as it travels back through the expanding duct before passing over the outlet guide vanes. The OWC will then repeat the process during the next wave cycle.

Dresser-Rand says the goal is to "increase OWC's power capture." The company works with OWC developers to match the damping ratio (pressure to flow ratio) that is required to optimize the power capture for the specific device.

Australia-based Oceanlinx is one of the companies developing OWCs for wave energy. For the past 16 years, the company has developed three types of OWCs: the greenWAVE, blueWAVE and ogWAVE.

- The greenWAVE is a 1MW, a 3000 tonne, bottom-sitting device that is installed at a water depth of 10-15m. The device is able to sit under its own weight on the seabed, enabling it to be installed without anchors or mooring. Oceanlinx says this model can be incorporated into a breakwater system or seawall in the near-shore.
- The blueWAVE is a floating unit, designed to be installed and anchored at water depth of 40-70m offshore. In March 2010, Oceanlinx launched the Mk3PC project off Port Kembla, Australia, incorporating the blueWAVE device. The project was completed three months later.
- The ogWAVE is also a floating offshore unit that can also connect to offshore oil and gas platforms. Oceanlinx says it will be used to supply small island communities who rely on these platforms and diesel fuel for energy needs.

Each of Oceanlinx's devices is equipped with airWAVE turbines. Barrett says the design allows the turbine to spin at a high efficiency in one direction, even though airflow oscillates in two directions.

Overall OWC's power capability depends on the width of the device, suggesting that wider devices can potentially generate more power. Currently, individual OWC units are capable of producing several megawatts.

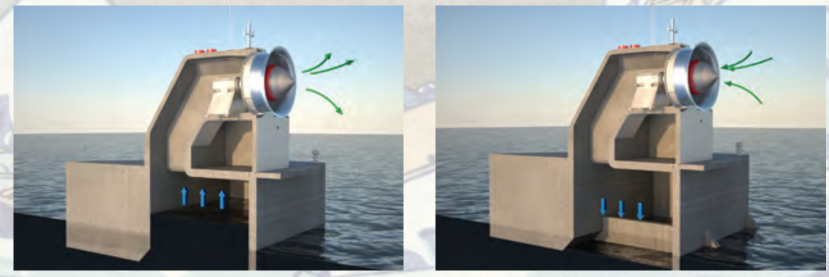
In October 2013, Oceanlinx announced that a 1MW greenWAVE device, located off southern Australia in Port MacDonnell, will be connected to the electrical grid in February.

The device was part of a two-year test project, federally funded through the Emerging Renewables Program (ERP) for approximately AU$4 million. It is projected to supply electricity to 1000 homes in the Port MacDonnell area. Oceanlinx says that once the greenWAVE proves to be a viable, cost-effective source of renewable energy, the company will begin installing arrays of devices around the world in 2015.

As the world looks to utilize more environmentally friendly methods of producing energy, wave energy is a sound option with its high production capability and minimal impact to the environment.

"We believe there will be an increase of wave energy devices in the future, although it is difficult to quantify the magnitude of the increase," Laird says. "Next to wind energy, marine energy is believed to have the largest market potential in the renewable energy industry.

As wave energy converters, like the Port MacDonnell greenWAVE, are being commissioned, the enormous potential of wave energy likely means that surfers won't be the only ones looking to "catch a wave." OE



As waves pass, the water column moves up and down. Air is compressed and is driven through the turbine under pressure, generating electricity (pictured left). As waves recede, air is sucked back into the OWC, continuing the electricity generation (pictured right).

Images courtesy of Oceanlinx Ltd.

Oceanlinx's blueWAVE comprises six OWCs designed for deepwater applications.

Oceanlinx's greenWAVE holds a single OWC designed for shallow water applications.

Photo: Alan O'Neill – Statoil

DUDGEON sees daylight

By Katie Jernigan

The Dudgeon Offshore Wind Farm development, off North Norfolk, England, is moving forward. In January, partners Statoil and Statkraft announced they awarded Siemens plc two contracts valued at US$848 million, covering the supply and service of 67 wind turbine generators (WTG).

The scope of the supply contract covers the engineering, procurement, assembly and offshore commissioning of the wind turbine generators (WTGs). Each turbine will have a 6MW capacity, and contain a tower section, nacelle, and three separate rotor blades. Statoil says the first group of turbines is expected to be complete for load out and installation in January 2017. Engineering started in January and will play a role in the design work for the foundations and electrical infrastructure.

The service contract will cover the operations and maintenance needed for the WTGs through the first two years after the installation is complete. It also covers the three years Siemens will provide technicians for Dudgeon and complete other agreed services.

The Dudgeon Offshore Wind Farm is located in water depths ranging from 18-25m. After Warwick Energy reviewed the Dudgeon wind farm site and plans, the partners submitted proposed variations of the project to the UK Department of Energy and Climate Change (DECC), which were approved in September 2013.

The review discovered the presence of mobile sand waves and layers of chalk in the seabed, which could impact the stability of the turbines. The Dudgeon Offshore Wind Ltd. (DOWL) partners submitted an application to the DECC and the Marine Management Organisation (MMO) to extend the project's red line boundary to increase the wind farm area in an attempt to prevent turbines from operating in areas that contain mobile sands. The document also discusses the need for new foundation concepts to stabilize the turbines, proposing either suction buckets or larger monopiles. The concept will be chosen at a later date.

Suction buckets are seen as a cost-effective alternative to steel monopiles or pylons by utilizing the sediment-rich sea floor as a foundation. Once suction is applied to the steel bucket, pressure swiftly sinks the structure in the quicksand it generates when the water from the bucket is dispersed into the seabed. Gravity takes over, and secures the bucket and the turbine. According to the variations document, the suction buckets will only penetrate the first few meters of the seabed, avoiding the chalk layer.

Monopiles are long steel tubes that can be driven deep into the seabed by a hydraulic piling hammer. DOWL submitted an application to the DECC and MMO to change the Marine License to enable use of larger, 8.5m-diameter monopiles over the 6.5m-diameter version. The larger design can increase surface friction and foundational stability in the chalk areas, while also permitting the on-site construction of 5-6MW turbines.The proposed variations document says that the wind farm has the potential to produce 560MW, but that a review of the project design caused the partners to reduce the total generating capacity to a maximum of 400MW. This downgrade was an attempt to curb the risk of the wake effects — or downwind effects — that occur when turbines operate too closely together. Furthermore, the total number of turbines was also reduced by 100 to a total of 78.

Once in operation, the Dudgeon wind farm is projected to reduce carbon emissions by 19 million tonnes over its 25 years lifetime. It is expected to supply electricity to about 400,000 homes in the UK market, which accounts for about 0.5% of the UK's annual electricity demand.

DOWL holds the licenses and the consents that enable the wind farm's construction. DOWL is operated by Statoil (70%) and Statkraft (30%). The final investment is scheduled for Q3 2014.

The Dudgeon Wind Farm is the Statoil-Statkraft partnership's second offshore wind farm. The partnership owns and operates the Sheringham Shoal located off the Norfolk coast. OE

Gaining traction

UTEC's Jim Edmunds explains how the company's geoROV tool can assist with geotechnical surveys.

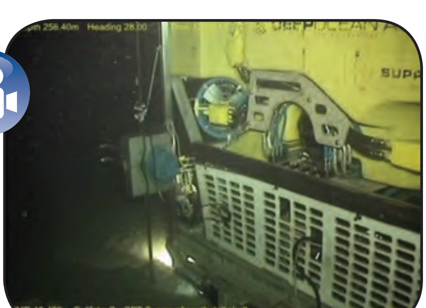
UTEC Geomarine's geoREACT suction anchor tooling skid

Geotechnical surveys are a prerequisite for establishing engineering soil parameters to enable robust and efficient seabed interaction design solutions – foundation design, on-bottom stability, excavation assessment, geohazard evaluation, etc. There are a number of methods in common use for acquiring the soils data including *in situ* test methods, such as cone penetration testing (CPT) and T-bar testing, as well as recovery of physical soil samples for subsequent logging and laboratory testing. Historically geotechnical surveys have been conducted using standalone seabed samplers and *in situ* test machines deployed on lift wires or using a geotechnical drilling system.

In 2010, UTEC Geomarine introduced a new ROV-deployed geotechnical survey tool, the geoROV CPT and Sampler. The geoROV system is a plug-and-play addition to a work-class ROV spread comprising a linear drive unit with control and real-time data acquisition. The system can be flown to the required location and works in water depths to 3000m, where it can be precisely positioned and *in situ* test data or soil samples acquired. Multiple *in situ* tests can be completed on a single dive; in excess of 50 tests have been completed in a single 12hr shift.The geoROV linear drive unit is capable of delivering around 15kN of thrust force, but in order to use this force without jacking the conveyance vehicle off the seabed, sufficient reaction force must be available. Some vehicles (such as trenching machines) are sufficiently heavy to provide the full reaction, but a free-flying ROV can typically only deliver up to 0.4kN reaction force using a combination of negative buoyancy and vectored down-thrust. An ROV-delivered 0.4kN is sufficient to penetrate up to 3m in loose sands or low to intermediate strength clays, but for deeper penetration in stronger soils, more reaction force is necessary.

In 2013, the geoREACT tool skid was introduced to increase the capabilities of the free-flying ROV deployment. The tool skid utilizes two suction cans to provide additional reaction force in suitable seabeds (i.e., most seabeds, except gravel or strong clay). The geoROV drive unit is mounted above the pair of suction cans and the chassis is attached to the underside of the ROV using a standard, four-point tool-skid connection.

The system is useful where conventional deployment may be technically challenging, hazardous, expensive, or impossible to undertake, and it is also gaining a reputation for efficient operation compared with conventional methods. Additionally, it is often convenient for a contractor to have the ability to recover high quality geotechnical data during their offshore campaign without



Scan this page with the Actable app to see video. See pages 7 and 10 for more details.

actable

dedicating the entire spread to the sole purpose of acquiring geotechnical data. The geoROV system can be installed and removed from an ROV in less than an hour, allowing for flexible mission planning in response to events and evolving requirements.

Since inception, the geoROV systems have been used in a wide and interesting range of projects including:

- Investigating thickness of sand cover above soft clay along a planned pipeline route (for design of the pipeline against down-heave buckling).
- Obtaining geotechnical parameters for foundation design in an area of gravel dump adjacent to existing subsea infrastructure – the test location could be positioned in between individual gravel pieces to ensure reliable data; several locations were adjacent to or beneath a live platform and all were adjacent to subsea structures in an area of gravel dump.
- Cable and pipeline route investigations mounted in a standalone frame.
- Mounted on a variety of jet trenching machines to benchmark trencher performance, to quantify unexpected trenching behaviour, or to enable real-time route and trenching programme development
- ROV-deployed acquisition of data for design of foundations for subsea manifolds offshore Vietnam.
- ROV-deployed seabed investigation for a planned large gravity base platform on Australia's northwest shelf; about 200 CPTs were conducted on tight grid spacing to verify the absence of localized pockets of soft material.
- As part of a multi-task campaign gathering data for the decommissioning of a large platform in the Central North Sea, geoROV CPT was used to conduct a series of 50 tests on the drill cuttings mound beneath a live platform. Due to operational constraints, the work had to be completed in a single 12hr window.
- As part of a multi-task ROV campaign in the Gulf of Mexico, geoROV was used to investigate newly appeared seabed anomalies and obtain engineering data (pipe-soil friction factors) for pipeline design.
- The first use of geoREACT was for a major development project West of Shetland in 2013; geoROV CPT and Sampler were used together with geoREACT to acquire around 200 CPTs, cyclic T-Bars, and push samples; an intensive program of advanced laboratory testing followed, enabling optimized design using cutting edge techniques of flowlines and subsea structures.

Further advances and innovations in the geoROV tool suite are planned in 2014, including a heavier duty linear drive unit, electric drive version, and ultra-deep water (6000m) capability. OE

__Jim Edmunds__ has spent 20 years in the offshore geotechnical industry, four with UTEC Geomarine as technology director. Edmonds has also been heavily involved in developing new technological solutions for seabed investigations starting with miniature CPT equipment in the 1990's, progressing to a deep water heave compensated drilling spread, and more recently ROV-deployed geotechnical drilling, sampling, and in situ testing systems. In 2010, Jim joined UTEC Geomarine to head up the development of new and innovative subsea technology and to build the integrated consulting and contracting business. He holds a B.Eng (Hons) Civil Engineering from Manchester University.

Intermediate spool inserted below the Christmas tree; spool provides a profile for landing the control line hanger and hydraulic penetration to allow control on WCS Safety Valve.
Photo courtesy of Weatherford.

Workover-free option restores safety valve functionality

Weatherford's Brian Marr, Scott Carline and Scott Deyoung discuss how the Renaissance WDCL system enabled the retrofitting of a new control line inside existing tubing to reestablish connection with a surface-controlled subsurface safety valve (SCSSV). The installation, which was performed without a workover rig, improved production at a significant cost savings. By T Moon

The well, an offshore oil producer in the Middle East, was required by law to include a SCSSV. Like all downhole safety valves, SCSSVs act as a failsafe to prevent the uncontrolled release of reservoir fluids in the event that surface wellhead integrity is lost. These valves are popular well control options in the industry due to their ease of operation, which consists of hydraulic control from the surface. Hydraulic pressure is applied down a control line connecting the valve to surface. During normal well operation, the continuous application of this hydraulic pressure keeps the valve open. When hydraulic pressure is removed during a wellhead integrity event, the valve is forced shut, thus acting as a failsafe to isolate the wellbore.

However, SCSSVs are prone to malfunction, which is commonly caused by piston failures, leaks within the valve body or some type of control line failure such as crushing, leaking or blocking by an obstruction. Such a control line failure occurred in the offshore Middle East well, which forced the valve closed and shut in production.

The conventional remediation method calls for bringing in a workover rig to pull the tubing, replace the blocked control line and then redeploy downhole. While this option is relatively cost-effective and easy to implement in an onshore well, the logistics, cost and complexity of performing a workover offshore make this a time-consuming and expensive operation. Even a relatively simple workover of an offshore well in the Middle East might cost upwards of US$6 million, according to estimates from the operator.

Weatherford collaborated with the operator to develop an alternative process—an intervention that would restore functionality to the SCSSV by retrofitting a new control line and inserting a new valve within the existing well architecture. The operator required the intervention to be performed without killing the well, pulling the tubing or incurring the time delays and costs that commonly come with a major workover.

A Renaissance in well revival

Upon review of the well parameters and intervention requirements, the operator decided to deploy Weatherford's Renaissance WDCL system, a wireline-retreivable subsurface safety valve that allows both the control line and the safety valve to be replaced in a straightforward retrofit procedure.

The system has a modified packing mandrel and wet connection, and a valve-and-lock assembly that can be installed in an existing tubing-mounted safety valve or safety-valve landing nipple. A capillary line is then run from the surface inside the tubing and connected to the valve to provide control.

The retrofit process for this offshore well was performed from a jackup rig, and began by modifying the wellhead to provide the correct profile for the capillary hanger and gain access for the new capillary control line. A wireline crew set plugs in the well to keep the well isolated, after which the tree was pulled and a spool piece containing a hanger profile was installed. The tree was then reinstalled and after the wellhead was pressure tested, the wireline crew went back in and pulled the plugs.

Another trip downhole was conducted to lock open the existing tubing-retrievable safety valve, after which a new subsurface safety valve was deployed and landed inside the previous valve. Once the new valve was set, the capillary control line was run down the center of the tubing to a pod on the valve.

A weighted and centralized stinger placed at the end of the capillary string was used to join the capillary to a mating connection on the valve. This was a wet-connect assembly, which was hydraulically locked in place by applying pressure to the capillary string. The wet connect contains unique design features, including the ability to be mated and unmated should the capillary need to be removed, and dual-back check valves that prevent backflow through the capillary line as an additional safety feature.

The top end of the capillary was then landed into the new spool piece below the tree through a specially designed, 4-in. control-line hanger. A Type-H profile was provided above the hanger to allow for the installation of a backpressure valve, which would be required to secure the well during future wellhead maintenance.

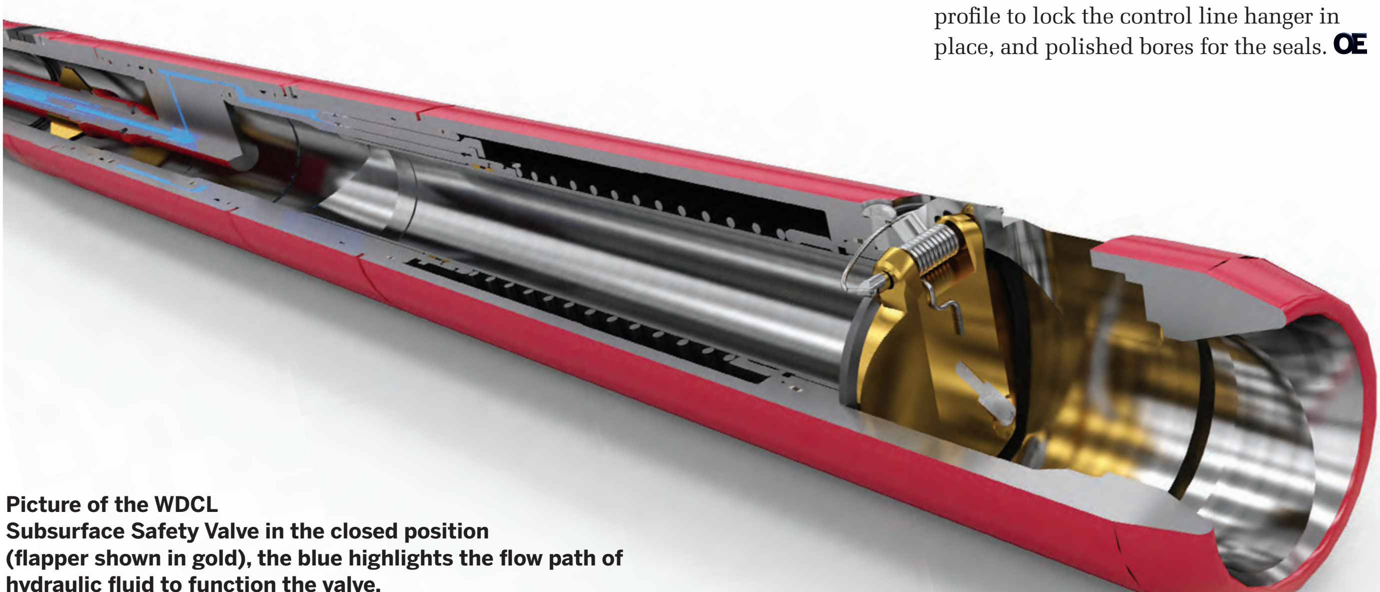
The entire installation took only two days of rig time, allowing the well to be brought back into production much sooner than a conventional workover. This helped to significantly lower the risk of formation damage or lost production that may result from extended well downtime. The installation was also conducted at a fraction of the price of a full workover, coming in at less than 10% of the estimated US$6 million workover cost.

The installation in the first well successfully proved the viability of this technology, and it has been running without issue since May 2013. The operator was pleased with the ease of installation of the system, the significantly lower rig time and the fewer number of trips required. The new SCSSV system also eliminated the need for a storm choke, which was prone to repeated tripping and caused production interruptions.

The operator was able to restore the well to full production once the SCSSV was fully operational, and now plans to install this solution on a number of additional wells suffering from the same control line blockage issues. These issues are not unique to this operator, or to the Middle East; Weatherford is actively working with other operators to install similar SCSSV systems in offshore wells throughout the world.

The Renaissance WDCL was installed without incident, allowing the operator to bring the well back to full production quickly, while adhering to offshore safety regulations in the region.

A new spool piece was placed below the lower master valve on the wellhead. The spool piece was custom-built with a profile to lock the control line hanger in place, and polished bores for the seals. OE



Picture of the WDCL Subsurface Safety Valve in the closed position (flapper shown in gold), the blue highlights the flow path of hydraulic fluid to function the valve.

Image courtesy of Weatherford.

A new multipurpose vessel will play a key role on Shell's Malampaya project offshore Malaysia. Pieter van Hekken explains.

Boskalis Offshore's new multipurpose vessel, the *Ndeavor*.
Photo courtesy of Boskalis Offshore.

Multitasking on Malampaya

In the Q1 this year [2014], Boskalis Offshore will start one of the most challenging projects in its history.

Boskalis Offshore, a subsidiary of Netherlands-based Royal Boskalis Westminster N.V., is responsible for the seabed work—excavation and rock placement—as well as for the Transport & Installation (T&I) of a new offshore platform at the Malampaya gas field, off the island of Palawan, under a contract with Shell Philippines Exploration.

Malampaya's production, at about 380MM scf/d natural gas and 15,000 bbl/d condensate, currently supplies fuel to three natural gas-fired power generation plants in the Batangas area. At the moment, it is the country's only major source of natural gas supply. Shell estimates Malampaya powers about 30% of the Philippines' electricity requirements.

The Malampaya Deep Water Gas-to-Power Project is a joint venture involving the Philippine National Oil Company (10% WI), Chevron (45% WI), and Shell Philippines Exploration (45% WI and operator). Operations began in 2001.

The Malampaya reservoir, in the deepwater Palawan basin, is produced via a 10-slot subsea manifold in 820m water depth tied back to a platform 30km away in 43m water depth. A Phase 2 of the project saw two more subsea production wells drilled on the field, using the ENSCO 8504. Phase 3, the current project, is part of the optimization of the field.

To maintain the gas pressure in the field, an offshore depletion compression platform (DCP), currently under construction in Keppel Subic Shipyard Inc.'s fabrication yard in Subic Bay, on the west coast of the island of Luzon in Zambales, Philippines, will be installed alongside the existing production platform.

The DCP's two gas turbine-driven compressors will maintain the gas at reservoir pressure. Condensate is removed on the platform and the dry gas transported via a 504km-long (313mi) 24in. export pipeline to Batangas port for further processing.

The project is one of the first in which the expertise of Boskalis and SMIT, acquired by Royal Boskalis in 2010, have been brought together in an integrated package.

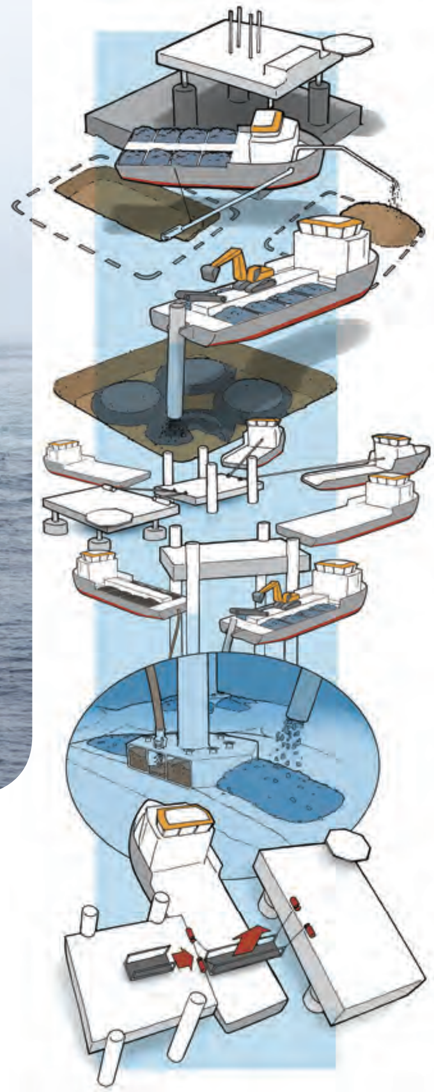
Boskalis was awarded the contract in April 2013. Boskalis Offshore opened a project office in Manila, next to Shell, as part of the preparation work. One of two new, multipurpose vessels, the *Ndeavor*, delivered in November, was also designed with the project in mind.

The Malampaya depletion compression platform.
Image courtesy of Boskalis Offshore.

The first phase of seabed preparation begins in Q1, this year, and the T&I phase in Q4. Timing and proper planning for this project are crucial. The power plants in Batangas port area are responsible for the electricity supply to some 40% of the people of Philippines. It is vital that the gas flow isn't interrupted.

When the DCP platform is hooked up to existing platform, Shell will have to take the existing facilities offline, so the whole procedure has to be planned years in advance.

Preparation work has involved sourcing rock to create rock pads for the platform



The phases of the project.
Image courtesy of Boskalis Offshore.

legs, with some 50,000-70,000-tonne procured from local quarries. A further 10,000 tonnes of iron ore is needed for ballasting, with Boskalis' Rock Department is providing assistance to test if the rock meets the specifications.

The project also involves the use of two new multi-functional cable-laying/offshore services vessels, the *Ndeavor*, and the *Ndurance*. Both vessels are 99m-long, 30m-wide, have a 4.7m draught, and weigh 7500 DWT. They have 62 cabins, for 104 people, Both vessels were built by Samsung C&T Corporation and Shanghai Zhenhua Heavy Industries Co., Ltd. and classified by Lloyd's Register.

Ndeavor, which underwent sea trials in November, also has a 100-tonne, active heave compensated crane, with a 15m reach, and a helideck. It will be used for the excavation and rock-placement work. It will also be the command vessel during installation of the platform, placing ballast in the footings, and during the positioning of a bridge between the two platforms.

Ndeavor's sister vessel, *Ndurance*, is the designated cable layer, and is being fitted with a 5000-tonne turntable.

These vessels had to be as versatile as possible to fulfill the requirements of the client. *Ndeavor* had to have DP2 capability and we felt the best solution was to fit the vessel with both excavation and rock installation equipment.

The first phase of the work offshore will be preparing the seabed for the installation of the DCP, which will involve excavating down to various depths.

Ndeavor can handle the entire scope in the first phase. The vessel will remove the top layer of carbonate sand, and, after excavation, use engineered rock to back fill to an elevation of -42.73m Lowest Astronomical Tide (LAT). The removed sand will be taken to a designated location alongside the platform.

A trial seabed preparation pad will then be constructed and validated south of the proposed DCP location before construction of four seabed preparation pads on the backfilled surface, to a target LAT -41.73m.

Surveys of each phase of the work, including pre-excavation, post-excavation, pre-backfill, post-backfill, pre-pad installation, post-pad installation surveys and progress surveys during the execution of each phase.

The next phase of work will see Boskalis Offshore take the DCP to the location, position it and install it using 3-4 100/200-tonne anchor handling tugs. Temporary equipment will be installed on the DCP. Installation will involve coordinating involved subcontractors, to perform the grouting operation, and constant surveying the platform's position to ensure installation

To stabilize the platform, dense iron ore gravel ballast is put into all four footings as soon as the installation has been completed. Rock, for scour protection, and sourced from local quarries, will then be placed around the four footings.

Ndeavor will take command during the positioning of the new platform, and transportation of the iron ore ballast.

Then, a permanent bridge, linking the gas production platform to the new compressor platform, will be installed between the two platforms. A second bridge will be installed giving temporary access from the bay to the platform.

To install the permanent bridge, a Barge Master motion-compensated platform lifting system will be fitted on the aft of *Ndeavor*. It will then sail out to location. Once on site, the bridge will be held still by the Barge Master so it can be lifted off safely by two temporarily installed lifting arrangements.

This bridge, which is around 220-250 tonnes, can be lifted safely from the moving vessel by the Barge Master system, which provides a very stable platform.

The use of the Barge Master is a world first, using largely proven technology but in an innovative way.

The integrated approach has many benefits for the client. We can handle all of the work in-house: rock installation, earth moving, tow out, installation of the new platform, ballasting of the legs, install the iron ore to give stability and the bridge between the new and existing platforms.

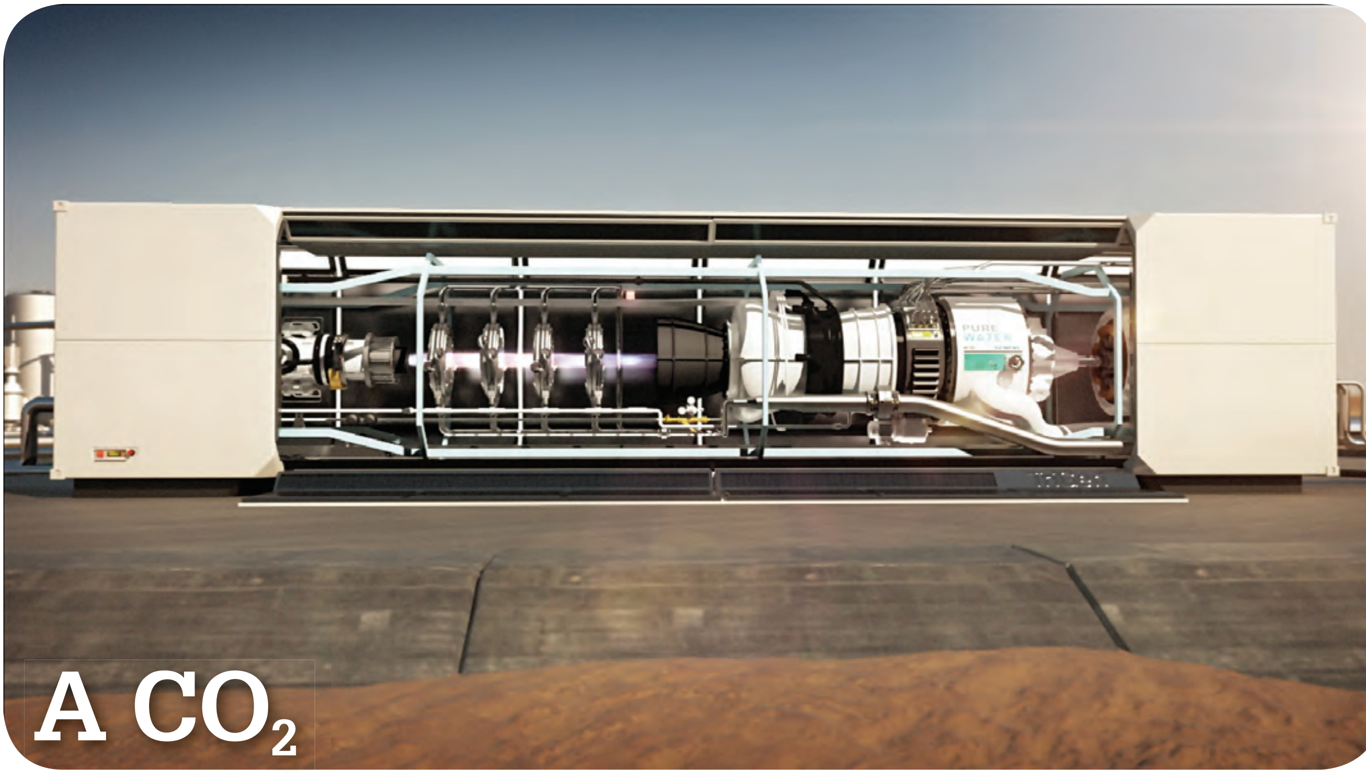
Our client does not have to deal with interface issues. Usually the seabed work would be completed, then we would hand over to the client, and then the client hands over to a second contractor for the rock installation. Also, because one multipurpose vessel is doing many tasks, the client has to approve only this vessel.

Shell accepted Boskalis' own safety program No Injuries, No Accidents (NINA), on the project.

The Malampaya project is the second assignment in a row that Boskalis Offshore is executing in the Far East for Shell.

On the Bukom project in Singapore, Boskalis Offshore completed trenching, pre-lay and post-lay rock placement. In addition, all diving activities related to the pipelaying for an import pipeline and installing an SBM buoy were carried out by divers from Boskalis Offshore Subsea Services. **OE**

Pieter van Hekken *is regional manager for Boskalis Offshore Subsea Contracting in the Far East and Australia. He holds a BSc in Civil Engineering from the University of Applied Sciences in Utrecht, the Netherlands, and an MSc in Civil Engineering, Management and Geo-Technology from the Southbank University in London. Before assuming his current position in 2007, he worked in various project management roles for Boskalis worldwide for more than seven years.*



A CO_2 EOR solution

The TriGen gas generator system, side view. Photo courtesy of Maersk Oil.

EOR is fast becoming a priority in the Middle East, not least the UAE. Elaine Maslin takes a look and describes how Maersk Oil's TriGen technology is hoping to provide a solution.

Changes are coming to the United Arab Emirates (UAE), which are likely to hail changes in the companies making up the operating community, and how they operate.

According to the Energy Information Agency (EIA), the UAE holds the seventh-largest proved reserves of natural gas in the world, at just over 215 trillion cubic feet (Tcf).

Despite these numbers, the UAE became a net importer of natural gas in 2008, due to heavy use of natural gas for reinjection, for enhanced oil recovery (EOR), and growing domestic demand for electricity, largely from gas-fired facilities.

With the likelihood of any further major oil discoveries low, according to the EIA, EOR will play an increasing role in the region, if production is to be maintained or increased.

The issues are not lost on Abu Dhabi National Oil Company (ADNOC), which

Bob Alford, senior business development manager, Maersk Oil. Photo courtesy of Maersk Oil.

has plans to increased daily production capacity to 3.5MM bbl/d, from 2.8MM bbl/d.

ADNOC is also looking to reduce CO_2 emissions. The firm recently signed a joint venture (51:49) agreement with Masdar to set up the Middle East's first company focused on exploring and developing commercial-scale projects for carbon capture, use and storage.

The JV plans to extract CO_2 at Emirates Steel, the UAE's largest steelmaking facility, compress it, and then transport it to ADNOC-operated oilfields for EOR, and storage. The project will sequester up to 800,000-ton of CO_2 annually, says ADNOC.

The agreement has already seen an AED450 million engineering, procurement and construction contract awarded to Dodsal Group to build a carbon dioxide (CO_2) compression facility in Abu Dhabi, and a 50km pipeline, with project completion due in 2016.

In addition, ADNOC is currently selecting new partners for its legacy onshore concession, due to expire this month [January], and an offshore concession, scheduled to expire in 2018.

It is understood new concessions being offered offshore Abu Dhabi by ADNOC will contain requirement for EOR initiatives in order to take recovery rates to more than 60%, says Moss Daemi, executive VP Middle East and Africa at DNV GL.

Oil firms have previously offered their expertise for CO_2 EOR in the region, including BP, but with limited uptake, due to not being deemed commercially attractive enough, in a region "floating on oil", and technically challenging.

It has been tried, however. In 2009, ADNOC's onshore operating company, started injecting CO_2 at the onshore North-East Bab field, Rumaitha. In 2009, Saudi Arabia's Aramco announced plans to trial CO_2 injection on mature fields including Ghawar.

With concessions becoming available, operators are again offering their EOR expertise, including Maersk.

Bob Alford, senior business development manager, Maersk Oil Middle East, says Maersk has developed skills in tight, chalk, low permeability carbonate reservoirs, common offshore Denmark, and in the Middle East.

Maersk has been operating the Al Shaheen field offshore Qatar since 1992. It had been deemed uneconomic to produce, but it is now the biggest field in Qatar, producing 300,000 bbl/d.

"The rock properties are very similar here in Abu Dhabi, so we are excited about the opening of the market," says Alford.

Maersk now has new technology up its sleeve, which it wsays will help increase EOR on this type of field, and residual oil zones, without using imported natural gas, as well as producing power, for the local grid, and water, without the need for desalination—another issue facing the Middle East.

Maersk has developed, with the help of ex-NASA scientists at California-based Clean Energy Systems, Inc., TriGen, an oxycombustion process, derived from the space industry.

Similar technology was used for the main engine of the space shuttle, which has a power output similar to that needed to power all of California or the entire UK national grid, says Alford.

An air separation unit is used to separate nitrogen and oxygen from air, through a cryogenic distillation process. The oxygen then goes into a high pressure (20-80 bar), high temperature, OxyFuel gas combustor, with turbo expanders, and re-heaters, based on rocket-engine combustion principles, to generate electricity.

"We are mixing the oxygen, gas and water together and burning it across a very short distance," says Alford. "As we mix it together we are combusting it at more than 2000°C. Water is used to partly cool the gas before it hits the turbine blades and stop them melting, as their materials are not ready for this level heat yet. As we can get turbines able to operate with the higher temperatures we would be able to further increase the efficiency."

A key element of the Oxycombustor is "platelet" technology, which is used for the fabrication of the combustor, to control the reaction during the Oxy-Combustion process, to ensure the oxygen and fuel mix to form a homogenous flame front, avoiding hot spots or producing un-combusted product.

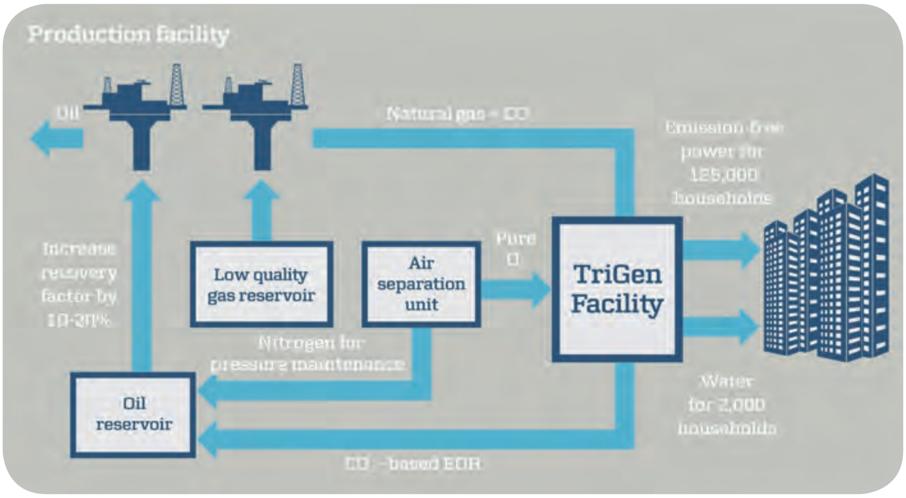
The technology, which involves, thru and partial-depth patterns chemically machined in thin sheets of metal, producing "platelets," was developed by Maersk's partner Clean Energy Systems.

The platelets are "stacked", and joined by solid state diffusion bonding to form a structure containing internal passages, with precise flow control manifolding and metering features, and filters.

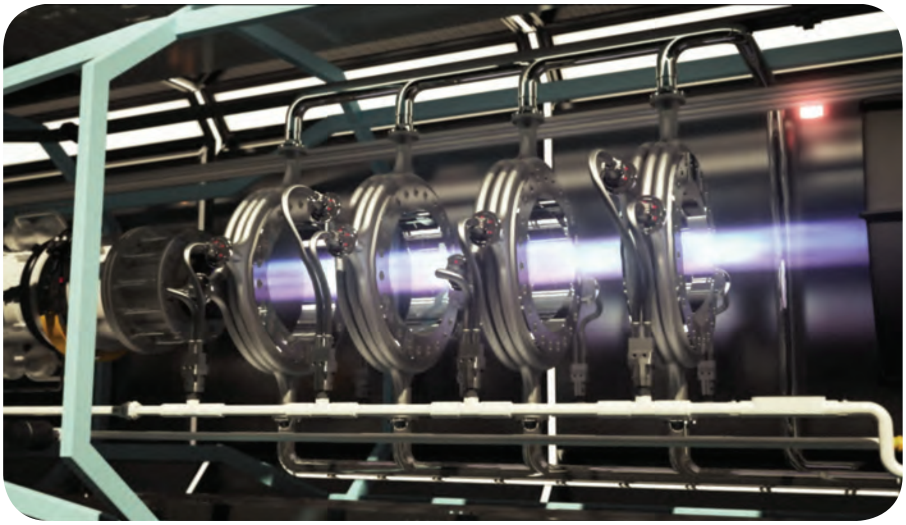
TriGen's turbines are based on existing technology machines, such as the Westinghouse W-251 (Siemen's SGT-900) are able to work with CO_2 or steam as a drive gas, because they can produce drive gas at any combination of pressure and temperature.

TriGen can also take in contaminated fuel gas streams, especially with CO_2. "It can be used for non-associated gas that you do not otherwise know what to do with," says Alford. After combustion, a simple process is then used to separate the water and CO_2 from the gas/steam turbine.

The CO_2 is used for oil recovery, with any associated gas produced separated and recycled back into the process. Clean Energy Systems, says the steam could also be used for assisted gravity drainage or cyclic/constant steam floods.



How TriGen could fit into a power, water and CO_2 for EOR system.
Chart courtesy of Maersk Oil.



A TriGen unit during combustion. Illustsration courtesy of Maersk Oil.

An artist's illustration of the system installed onshore. Illustsration courtesy of Maersk Oil.

CO_2 EOR

CO_2 EOR would be well suited to MENA reservoirs, says Alford, with 47% of the worldwide CO_2 EOR potential in the region, according to a 2010 paper by Michael Codec.

Alford says CO_2 water alternating gas injection has the potential to be 50% more efficient than methane gas injection or convention water flood, increasing rates from 30- to 50%.

"It is important to note that these are barrels not recoverable by any other means," says Alford. "This is fully incremental oil. Water flood, methane gas injection, will not get you this oil.

"The CO_2 dissolves into the oil and creates miscibility, and gives energy to the oil, which means you can get a better sweep of the reservoir," says Alford. "Depending on how much CO_2 you use, recovery could theoretically be up to 100%.

"One thing we are looking at is, do you really need 99.9% pure CO_2? You can also get miscibility with nitrogen if reservoirs are deep enough. For the reservoir's here we expect 95% purity CO_2 to be adequate."

However, it's not a one size fits all solution. EOR using CO_2 is more suited to light oil, than heavier oils, where steam would be a better option.

A unit onshore would cost about US$400 million, including the air separation plant, says Alford.

"We are working on different size units that require from 25-45MM cf/d of gas and produce up to 200MW of power. Water production can be tuned, so is about 0.5MM imperial gallons/d per unit.

"Reservoir size is dependent on how long the injection would continue for. We would need a reservoir of about 400MM bbl originally in place to operate for 20 years with our biggest unit. CO_2 production is almost the same amount as the inlet fuel gas."

On one plant, 40-50 MM cf/d fuel gas would be combusted with double the amount of oxygen, at nearly 2000°C. This produces about 160-180 MW power, and 40-50MM cf reservoir-ready CO_2, and about 500.000 gallons/day of pure water.

Alford says one gas generator would be the size of two shipping containers, however, the air separation unit, which has not yet been optimized for offshore use, currently covers a larger area.

"Offshore, you may require a separate platform for the air separation plant, for process safety."

Pilot projects

A laboratory-scale plant was created in 1995, followed by a 40MW demonstrator plant in 2005. The first commercial scale unit, at 150MW, was built in 2012, in Bakersfield, California, by partner Clean Energy Systems.

Siemens is a partner on the project, to provide the turbine. The US department of Energy provided US$30 million funding for the first plant.

Maersk has proposed an onshore site for a Trigen plant at Mirfa, which could supply CO_2 via pipelines to offshore fields in shallow water, or to onshore fields. Oxygen created in an existing nitrogen production process onshore, and currently vented, could be a source of supply.

Deployment of one unit could be within three years, with further units in three year execution intervals. Masdar has proposed CO_2 pipelines running between onshore fields, at coastal points, where pipelines could be landed.

"We are engaging with ADNOC and Masdar," says Alford. "We are currently in discussions to get a unit in the field, and it would take a three year execution period to build a full project with a turbine lead time of one year."

The Bu Hasa field is a potential future candidate subject to ADNOC requirements. It could accommodate 20 units, says Alford. It still has over 20Billion bbl recoverable.

"Kuwait, Saudi Arabia, Oman, they are needing all these products, CO_2, water, and power," says Alford. "We also have a lot of interest from Malaysia and Indonesia, where they have naturally occurring CO_2 in the gas. Because we are burning with oxygen, it is the best oxidizer out there. You do not need to do any pre-separation of CO_2, and can utilize low value gases." OE

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Riserless drilling makes a comeback

A dual drillstring
Image courtesy of Reelwell

When one thinks of "retro," a number of things may come to mind – old clothes, vintage furniture, maybe even a classic car – but in the world of subsea well operations, there are three words that best fit: Riserless drilling systems

By Stephen Whitfield

Riserless drilling systems are based on schemes that have been around for the better part of 50 years. They've always been on the back-burners of companies looking to increase the efficiency of drilling operations and reduce the heavy costs that come with them. But the technology was not there to make those schemes a reality.

In the last decade, however, as technology has caught up to theory, riserless drilling has become an attractive alternative to standard methods.

Out with the old...

For decades, risers have been a standard in drilling operations, but as companies wade further offshore, traditional drilling methods will pose greater financial and technical difficulties.

Risers are more cumbersome to use in deeper waters; the money and labor needed to build a riser capable of handling the stresses drilling beyond 5000-6000ft, as well as the platform required to hold it, are extensive. Large risers also increase the risk something could go wrong with equipment. A malfunctioning riser in a deepwater well could significantly impact the environment.

Watkins patented the first riserless system in 1969, in part to balance subsea well pressures and make it easier for the drill pipe to re-enter the drilling hole. At the time most offshore rigs drilled relatively shallow waters, and although companies continued exploring deeper water, any problems could be solved by increasing the size of the marine riser and the subsea wellhead.

Today, it's a different story. The US National Oceanic and Atmospheric Administration (NOAA) says about 63% of the 1.6 million b/d of oil produced in the Gulf of Mexico come from depths lower than 1000m (3280ft).

Riserless systems are not foolproof. Several studies have pointed out flaws, including difficulities in cleaning a top hole, potential tubular failures, and increased torque and drag. There's the potential for oil or natural gas to seep through the tophole and into seawater, causing environmental problems and potentially endangering the rigs or drill ships. Gas bubbles building underneath a rig could trigger an explosion, or in the case of a drillship, cause the density to drop enough to make the ship sink.

In a 2011 study examining drill casings in riserless topholes, Robello Samuel of Halliburton and John Gradishar of Shell pointed out buckling failures with some riserless systems, in which poor hold conditions led the casing to compress above the mud line. In that same study, they proposed a "new modeling approach" to help deal with the torque and drag issues.

But regardless of the potential pitfalls,

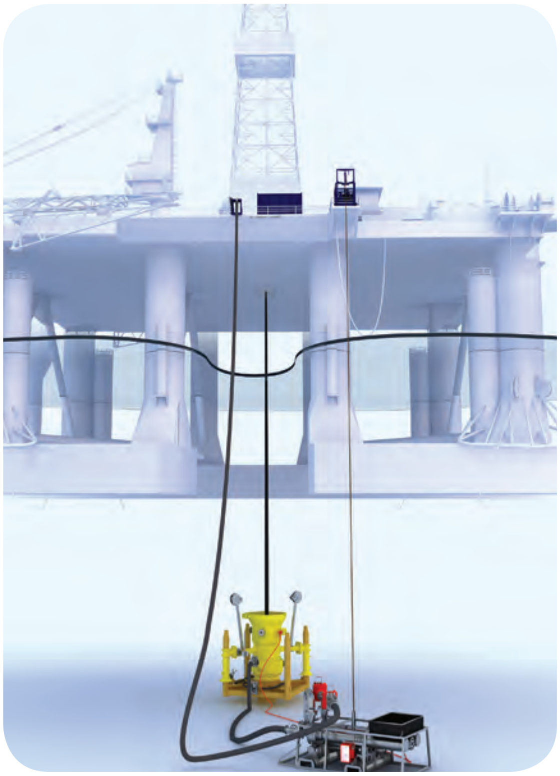


Illustration of AGR's riserless mud recovery system.

the technology is there, and companies are out there with systems that are becoming the new standard in the industry.

The RDM-Riserless

One system getting the most attention right now is the RDM-Riserless from Norway-based Reelwell. Developed in 2004, this system hinges on a dual drill string, a 6.625-in. pipe that comes with a 3.5-in. inner pipe – in other words, a mini-drill in a mini-riser. Drilling fluid flows down through the annular channels of the well and comes back up through the inner pipe. Rock cuttings are transported to the surface through the inner pipe along with drilling fluid, which leaves them out of the well annulus and helps keep the hole clean.

As the return flow of drilling fluid comes through a closed-loop high-pressure system, the Reelwell system helps mitigate some of the possible pitfalls of conventional drilling. With its ability to switch between managed pressure and underbalanced drilling without any pressurized equipment on the surface, it can help make deepwater drills safer. And it's lighter: a 21-in. riser puts out around 1000kg (2200lbs) of liquid per meter, but the Reelwell drill cuts that volume down to 50kg (110lbs) per meter.

"It's a major weight difference," Reelwell CEO Jostein Aleksandsersen said. "The main capacity of these drilling weights is to handle the fluid volume. It reduces the need for a higher capacity [because] you don't need to fill the riser."

The end result of all this is a system that can support the increased pressures of a deepwater and public recognition. Reelwell received a Spotlight on New Technology Award from the Offshore Technology Conference in 2013, one of 15 developments to be so honored.

Reelwell has marketed its riserless system as a means for companies to get more use out of their older rigs. Instead of building new rigs to operate heavier risers, they can retrofit its drill and save on construction costs.

In that sense, Aleksandersen calls it a "rig of opportunity."

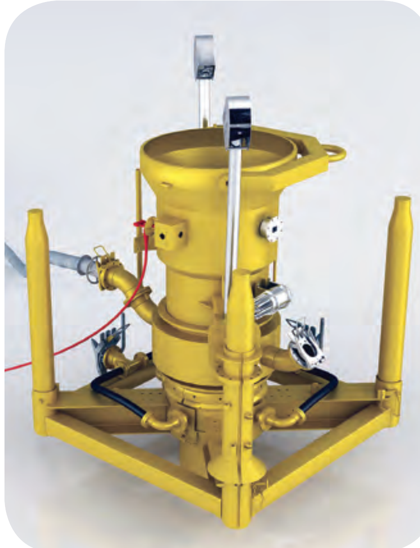
"That's the major reason of going into the market," Aleksandersen said. "It's an opportunity. If you look at the situation of deepwater drilling today, there are not enough sixth-generation rigs out there. By introducing [riserless drilling systems], you can go into the marketplace with lower-capacity rigs. You don't need newer rigs."

The system was tested onshore using the Nabors Rig 97 at various depths between 600m (1968.5ft) and 4250m (13,943.57ft) with a 6.625-in. dual drill string on an 8.75-in. portion of Shell Canada's Groundbirch field, in eastern British Columbia. The test compared the RDM-riserless system to a conventional riser-based drilling system. Reelwell says that test showed its system has "a competitive rate of penetration" to a riser. The RDM-Riserless was not used offshore until last year when BG Brazil chose Reelwell to develop a deepwater drilling system to be used at 2300m.

AMG'S RMR

Another system that's been widely accepted for much of the past decade is the riserless mud recovery (RMR) system from Norweigan company AGR.

RMR has been available for shallow-water rigs since 2003, but in recent years this technology has been tested in deep waters. It is a system centered on a subsea pump module that lets operators retrieve cuttings and used drilling fluid through a mud return line, allowing for better volume control when drilling a tophole. It can be used for closed-loop riserless drilling, and also with dual gradient systems.



Right- RMR system has been used on over 500 wells.

AGR participated in a 2008 study off the South China Sea along with BP America, Shell, PETRONAS, and the Norweigan Research DEMO 2000 program to test RMR in a deepwater setting. In the study, engineers ran a drill from a floating rig through 4657ft of water, eventually reaching a depth of 7404ft. They found that systems operated without a problem. The 7404ft depth was 169ft short of the original goal, but the discrepancy was not great enough to cause much concern.

The RMR system is now used in drilling operations the world over. As of last year, RMR and CTS, its sister system, have been used on more than 500 wells. AGR claims that several drilling operations have used RMR to help drill top holds in tough downhole conditions, and it says that its system has allowed operaters to use smaller casings for their risers, which in turn allows them to build lighter, longer risers that can be used for deepwater drilling. The example they point to most often is one where an operator went from a 2-in. casing to a 13.6.25-in. casing, allowing them to drill down to 7710ft. OE

Electromagnetic solutions

Weatherford's Alasdair Macneil Fergusson and Wiley Parker discuss how surface electromagnetic transmissions can help control downhole mineral scale deposition.

Controlling mineral scale deposition in oil and gas wells is a long-standing industry challenge. Weatherford's ClearWELL, based on transmission of an electromagnetic field, is effective in preventing the deposition of scale deposits in a broad range of oilfield production systems.

Scale, foreign materials, and paraffin deposits can all cause maintenances problems in wells. These deposits form on the inside of tubing walls and valve surfaces can restrict flow, reduce control, and change heat transfer characteristics, all of which can lead to compromised production and safety, and contribute to corrosion.

On average, oil and gas fields produce 7 bbls of water for each bbl of oil. This water often contains dissolved minerals that can deposit in the wellbore and its processing system. Calcium carbonate and barium sulfate deposits are typical of these mineral scales, which are often encountered inside tubulars, within surface facilities, and around the wellbore, where pressure drops are greatest.

Much of the effort to mitigate the scale problem has been focused on methods of chemical scale inhibition or by mechanical removal. Chemical methods have been developed that are generally effective but high costs and environmental impacts drive the need for an alternative.

Electromagnetic technology

Weatherford's ClearWELL technology is a non-chemical control strategy that uses a physical water-treating device to induce pulsed, high-frequency signals into the piping system. This energy causes micro-crystals of scale to form suspended in the produced fluid rather than on the surfaces of downhole and topside equipment.

Developed for industrial water treatment, the technology is based on an understanding that precipitation itself is not the problem; the problem is scale adhering to equipment. If scale can be induced to precipitate and remain in suspension, then the problems

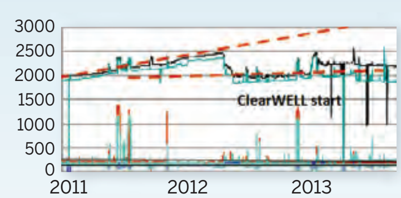


Fig. 1—Bottomhole pressure in well offshore Africa, showing effect of fluid treatment.

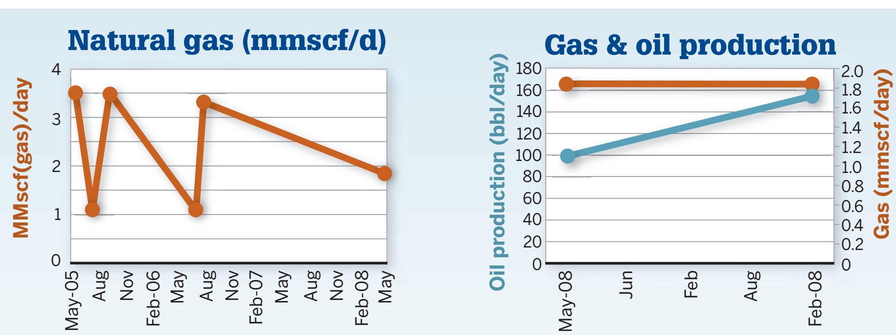


Fig 2-3 Carbonate scale reduced production despite acid, workovers, and perforating. Electromagnetic fluid treatment increased production without workovers or chemical intervention (SPE 133526).

associated with mineral scaling are reduced.

Scale chemistry

The materials that form mineral scales have a finite solubility in a fluid, and a system is saturated when this balance is achieved. If more materials can be dissolved, the system is unsaturated. When the solubility limit is reached, a chemical balance is created between the dissolved and solid forms of the substance. At the point material precipitates out of solution, the system is supersaturated. Many oilfield water systems become supersaturated as physical conditions change or dissimilar waters are mixed.

The thermodynamics of solubility determine that in an unsaturated system, overall energy is lowered when a solid dissolves. In a saturated solution, there is no energy advantage to being in a solid or dissolved state. In a supersaturated system, overall energy is lowered when the dissolved material precipitates.

When a material precipitates, not only is a new phase formed, a surface between the oil and new phases must be formed. It takes energy to create a surface, and this energy is not accounted for in the bulk description of solubility.

The energy liberated when forming a precipitate is proportional to the amount of the material undergoing transition. The energy demand to make the new phase is proportional to the size of new surface created: a deposit's surface area.

In a supersaturated metastable state, the system is waiting for enough energy to begin the phase change. When a particle begins to grow, an insufficient amount of energy is released by the phase change to create the surface. The particle's large surface area-to-volume ratio means that the energy released from its formation may not be sufficient to form the surface surrounding the particle. If the system cannot acquire this energy from fluctuations in the surroundings, the energy remains trapped. While thermodynamics says the system must form a precipitate eventually, the system can't begin the process.

If the new phase develops on an existing surface, then fewer boundary surfaces must be created. Less energy is required to make a solid crystal at an existing surface than in solution, so scale forms at surfaces. Unfortunately, when the new phase forms on an existing surface, it adheres strongly to that surface. At the wellsite, this existing surface is provided by pipe, valves, and other internal materials. And deposition on these surfaces causes problems.

The ClearWELL signal creates a time-varying electromagnetic field within the pipe, which acts as both an antenna and a transmission line. As charged particles respond, they absorb energy and move. This movement induces nucleation, but it does not occur at the surface level.

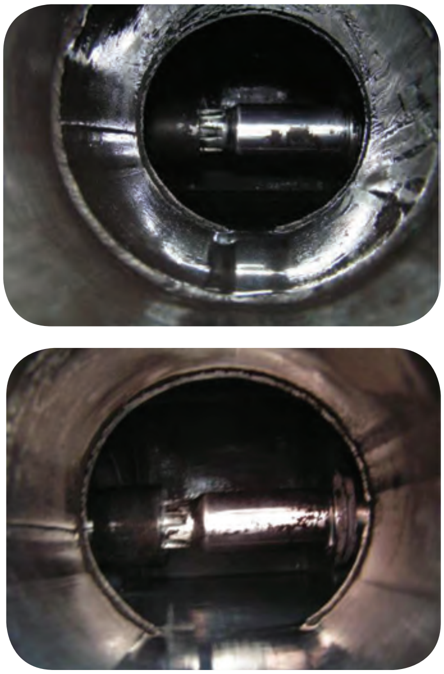


Fig. 4 – Mineral deposits had reduced pump effectiveness and lifetime in a reinjection system. No deposits occurred after installation of the ClearWELL system: (A) shows the pump condition at startup; and (B) shows it after three weeks (SPE 133526).

Forming a new phase always requires energy from the environment to start the process. If the only energy source is from the native environment, energy is limited. The systems normally develop according to the principle of least action, i.e., whatever requires the least amount of energy from the environment occurs most rapidly. Thus, deposits form under natural evolution of the system.

The ClearWELL system works by channeling energy from an external source into the materials that will form the new phase, providing sufficient energy for the new phase to form in suspension rather than on an existing surface. This channeling of energy to alter the natural evolution of a metastable system is illustrated with a carbonated beverage and an ultrasonic cleaning bath. When energized, the bath generates high-intensity sonic waves that impinge on a partially emptied soda bottle. The field induces nucleation of gas bubbles and the fluid spews from the bottle.

The surface-installed electromagnetic technology does not alter the thermodynamic state of the system or its evolution, as with chemical treatments. Instead, it controls where and how that thermodynamic evolution occurs by transmitting an electromagnetic field that interacts with the ions present in the aqueous solution to generate nucleation sites. ClearWELL works as a threshold nucleation device.

The technology uses a magnetic loop antenna to induce a radio frequency signal in the metallic piping and aqueous conductive path provided by the water system. The conductive medium acts both as an antenna and as a transmission line for the current.

There are several advantages to introducing an interaction that moves throughout the system. By delocalizing, the system can be installed and applied without detailed knowledge of the location where conditions exist for the formation of mineral deposits. Because the current moves throughout the system, the device can be surface-mounted, without intrusion into the wellbore.

Application examples

Offshore scale control is a complicated endeavor. There are logistical issues associated with timely chemical delivery as well as environmental concerns associated with any chemical residues which may be released into the environment. Environmental concerns have been especially problematic in North Sea applications. ClearWELL has been tested by an international operator off Denmark in the North Sea, on a platform well with a dry tree producing from a chalk reservoir. Treated seawater was used for reservoir pressure support. Historical operation of the well resulted in severe calcium carbonate deposition throughout wellbore and surface equipment. Chemical control is impractical and the deposit problem has been historically managed by reducing the choke setting to minimize pressure drop. This severely impacts the rate at which oil can be produced. Even with the reduced choke setting, acid treatments were required on a nine-month schedule to maintain production. Historical data showed that at full choke well scale up occurred in approximately two weeks.

ClearWELL-R was installed in March 2013. Production strategy was to maintain original choke setting for two weeks.

Result: no change in production. At the end of the two-week period the choke setting was changed to that where the maximum $CaCO_3$ deposition had been observed. The well continued to operate at high efficiency and production levels indicate no scale deposits after 10 months of steady operation.

ClearWELL was applied to control carbonate scale in wells offshore Africa. In this instance well operation was plagued by scale build-up, which restricted and eventually blocked oil production. The operator wanted a method to control scale as determined by bottomhole pressure without acid treatment or installation of capillary tubing for continuous injection of scale inhibiting chemicals.

Fig. 1 shows a graph of bottomhole pressure as determined during a trial period and prior to the trial. BHP steadily increased prior to the ClearWELL program and has remained near-constant since its introduction.

The technology can also be applied onshore. In the Ketchum Mountain area of West Texas, water from several sources is sent to a pumping system for reinjection. Mineral content of the waters produces significant $BaSO_4$ that reduces pump effectiveness and lifetime (Figs. 2-3). The water injection system uses polyethylene piping for the distribution headers to electric submersible pumps (ESP). The mineral content of the waters in the distribution system is very concentrated and thus the water conductivity is high.

This circumstance allows the aqueous medium to serve as both the antenna and transmission line for the electromagnetic signal. The impedance of the transmission line is much higher per linear foot than those seen in metal piping schemes. This limits the propagation of the signal. To partially account for this, two ClearWELL units were installed—one on the water input and one on the output distribution header.

The units were placed on the system after one day of operation. In a 34-day observation period, the installation saw no net deposit formation, and deposits that had formed in the unit prior to installation were cleaned up by the system (Fig. 4).

A major solution

Scale is arguably one of the most difficult and expensive problems facing production operations. Much of the mitigation effort has been centered on chemically inhibiting its formation or by mechanically removing it. But the steps are often unsatisfactory.

A new approach to the problem is focused on preventing the deposition of scale rather than treating it when it appears. The success of this system in global applications suggests a major step forward in production operations.

Mineral deposits had reduced pump effectiveness and lifetime in a reinjection system. No deposits occurred after installation of the ClearWELL system: (A) shows the pump condition at startup; and (B) shows it after three weeks.

__Alasdair Macneil Fergusson__ is the Director of engineered chemistry for Weatherford Oil Tool Middle East Ltd., based in United Arab Emirates. He has a degree in Chemistry from University of Aberdeen.

__Wiley Parker__ is a Technical Specialist in Weatherford's Business Development division, based in Houston. He earned a PhD in Chemical Physics from Washington State University.

The integrated flow solutions IRCD skid on Chevron's Tombua Landana drilling and production platform off Angola.

Charles Wemyss discusses positive displacement meters and how they can benefit flow measurement in chemical injection applications.

Chemical injection – maintaining flow assurance

Keeping up with the global demand for fuel creates intense pressure on producers to ensure oil production continues 24 hours a day, 7 days a week. According to the latest figures from the International Energy Agency's Oil Market Report, demand for oil in 2014 is expected to increase by more than one million b/d to 92 million b/d. Global demand was 74.8.1 million b/d in 2Q 2013 rising to 77.3 million b/d in the third quarter.

Flow assurance is therefore critical. Systems are designed to best ensure interruption to the production and processing flow is prevented at all times. There are a number of typical chemical injection applications that achieve this. These include, but are not limited to, demulsifiers, wax inhibitors, pour point depressants, corrosion inhibitors and hydrate formation inhibitors.

VFF Meter

Chemical injection systems are controlled using multi-discipline modular skids which consist of rotary and mechanical equipment, piping, instrumentation and electronic controls.

Most chemical injection applications face changes in process conditions over the lifetime of the oil field on which they are located. Using flow distribution panels as part of the skid means that substantial cost, space, weight and maintenance savings can be made. Using a robust meter such as a positive displacement flowmeter that can be customized to suit different conditions form an important element of these panels.

Managing ancillaries is essential to meet demand and maximize return on capital investment. Accurately controlling the amounts of chemicals, such as corrosion inhibitors, that are added to crude oil is essential to minimize production costs. If too much is used, they need to be removed when the oil is refined – and this can cost almost 10% of the price of a barrel of oil. If too little is used then the production lines may scale up, corrode through – or worse.

The chemicals are also expensive. Up to 30% of the running costs of a platform can be associated with the chemicals used to pre-treat crude oil before it is pumped ashore. Many of these chemicals are aggressive or corrosive. The effect of pumping them along tens of kilometers of carbon steel and stainless steel pipes at fluctuating pressures means that particles can erode from inside the pipe. Filters designed to capture these and other particles can become blocked. This can result in jamming the sensitive devices.

Contamination of the fluids can reduce the measurement accuracy of positive displacement flowmeters and lead to the incorrect amount of chemical being used – leading to additional cost to refine the oil.

Therefore, there is increasing emphasis on robust and reliable equipment such as positive displacement (PD) flowmeters. PD flowmeters work using the positive displacement of a volume of fluid. There is a chamber; inside of it, obstructing the flow, is a rotor.

The shape of the rotor and chamber vary greatly with each meter type but they all provide an output for each rotation. Most meter designs lend themselves to being totalizers. Most can have the flow rate calculated from this primary data.

An accurate PD meter will have minimal leakage across the rotor seal. This is generally minimized with the use of more viscous liquids and accuracies of ±0.1per cent are sometimes quoted.

Most meters are simple to maintain as they have only one or two moving parts and are coupled with simple readouts that are easily understood in the field

There is no requirement for straight pipe lengths, which may be needed for turbine or other devices. They can be connected directly to elbows or valves and in most cases in a variety of orientations.

As part of a continual process of extraction and refining, accurate and

Litre Meter VVF meters on a Geveke Pompen chemical injection skid.

A PVD coated meter wafer for Geveke.

consistent measurement is required to ensure that the consumption of chemicals is monitored accurately to maintain efficiency and control costs. All PD meters require clean fluid so a filtration level of 100µm is usual.

Engineering a flowmeter to meet the NAS1638 standard will enable it to operate reliably when measuring fluids with high particle contamination associated with corrosive chemicals. The NAS1638 standard was originally developed in the US for aerospace components but is now widely used in oil and gas applications. It defines the level of contamination in terms of the maximum allowed particle count for particular particle size ranges.

A VFF meter works by dividing the flow into discrete pockets. This prevents the flow by passing the meter's rotor and producing errors. Fluid flows through the meter causing a rotor to move within the measuring chamber. A sensor picks up the movement and gives a reading representing an increment of volume flow.

The disc-shaped rotor has an annular groove on its underside, which can hold and transport flow from the chamber inlet to the outlet.

Some fluid is also transported in a cavity formed between the outside of the rotor and the chamber wall. A center peg under the rotor is constrained to run in a circular groove in the body. A plate is engaged with a slot in the rotor to modify the rotation into an oscillation as the flow passes.

This oscillation allows the fluid to be divided up into positively displaced pockets. The movement of these pockets is detected by a powerful magnet fitted directly above the peg which engages and disengages with a reed switch sensor located in the top of the meter.

A volt-free contact closure output signal is given out for each oscillation, which represents a volume increment.

Because the majority of chemical injection applications tend to use more concentrated fluids, less is needed. Therefore, less is moved and smaller amounts are measured. A more concentrated chemical has a lower flow rate.

The VFF flowmeter is suitable for measuring liquids with flow rates from 0.0004 l/m (0.5l/d) to over 270l/min, at pressure ratings up to 4,000 bar (60,000 psi). It is of intrinsically safe design and manufactured to operate reliably at temperatures ranging from -40 to 100°C.

Research has lead to the development of highly customized versions of standard rotary piston meters. For example, the low-flow capability of Litre Meter VFF meters has been improved by providing the pressure balance chamber and titanium rotor with a physical vapor deposition coating designed to lower the friction properties of the meter to provide extended flow ability.

The additional hardness provided by the PVD coating also improves wear resistance.

Litre Meter's VFF LF05 is capable of measuring down to 0.03l/hour at viscosities of 2cSt and just 0.02l/hour when the viscosity is 10 cSt.

It has a flow range of zero to 30l/hour, a viscosity range of 0.8 to 2000cSt or greater, an accuracy of ±0.5% of reading and repeatability of ±0.25%.

At Offshore Europe 2013 in Aberdeen, Scotland, Litre Meter introduced the VFF LF03.

It takes the capability of the range down to lower flows than ever before – for example, on a fluid with a viscosity of 5 cP the LF03 will measure down to 0.015 l/hour rather than 0.024l/hour for the LF05 and 0.065l/hour for the LF15.

Standard meters are available with a 316 stainless steel body. Customized versions are available in titanium, duplex and super duplex steel bodies.

As a low-flow specialist working with suppliers to major companies such as BP, Chevron, Anadarko, Shell UK and Tyco, Litre Meter has supplied meters for chemical injection in the oil and gas industry for projects around the world for more than 20 years.

This experience in chemical injection applications onshore and offshore has confirmed the instrument's capability to reliably measure fluids to help maintain flow assurance under extreme conditions of both temperature and pressure. OE

***Charles Wemyss** is the chief executive officer of flowmeter specialist Litre Meter, joining the company as chief engineer after graduating with a degree in mechanical engineering from the University of Sheffield in 1982. Overseeing the introduction of the company's Viscous Fluids Flowmeter in 1986, he was then appointed engineering director in 1990. He purchased the company in 2001, selling it to the TASI Group in 2011.*

Equus delayed but not dead

US explorer Hess remains 'confident' that its billion dollar Australian gas project will proceed.

By Bruce Nichols

The Equus project, Hess Corp.'s planned contribution to Australia's push for world leadership in liquefied natural gas (LNG) exports, has been delayed pending a third-party contract to process its production, but Hess expects a deal soon, giving new life to the US$6 billion project off northwest Australia.

The final investment decision (FID) had been expected by mid-2013, after Hess rejected building its own liquefaction plant in favor of finding a partner, but it has taken longer than planned to close a processing deal. Still, Hess recently reiterated its desire to move forward with Equus and expects an export deal early this year.

"Hess is committed to maximizing the value of the natural gas discoveries that we have made offshore Western Australia. We are presently in commercial discussions with counterparties and are confident these discussions will result in the processing of Equus gas in third-party owned LNG facilities," a spokesman reconfirmed to OE by email in late December.

Development plans filed with Australian regulators in February 2012 called for first production in 2018 to a Hess-operated floating production system (FPS). From there, gas would flow via subsea tie-back to third-party offshore facilities. The receiving facility would then relay the gas ashore for conversion to LNG for overseas shipment or for domestic Australian use.

Equus is located in permit area WA-390-P about 145km north of Northwest Cape. Nearby cities include Exmouth, about 112 miles (180km) to the south, and Karratha, about 186 miles (300km) to the east. Located between Chevron's giant Gorgon project and Exxon Mobil's Scarborough field, Equus

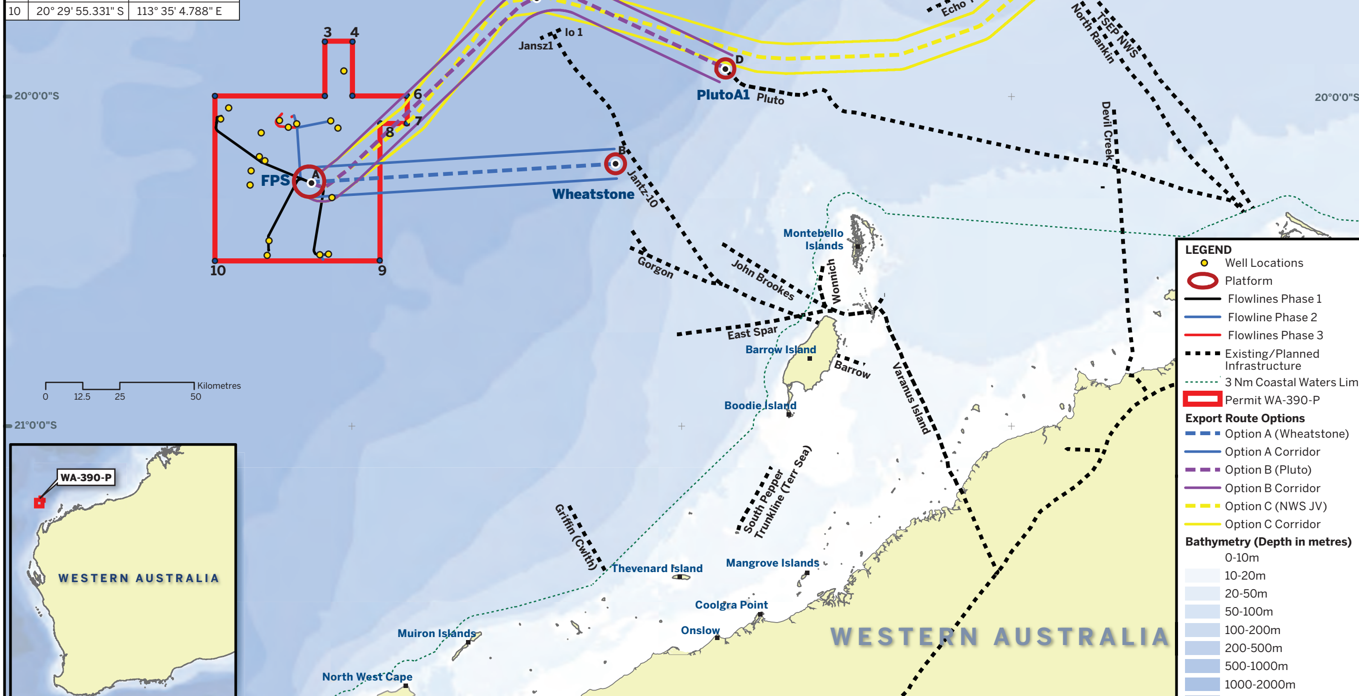
Project Location and Export Pipelines

Permit area WA-390-P co-ordinates
Geographic co-ordinate system GDA 1994

Id	Latitude (DMS)	Longitude (DMS)
1	19° 59' 55.317" S	113° 35' 4.761" E
2	19° 59' 55.310" S	113° 55' 4.742" E
3	19° 49' 55.299" S	113° 55' 4.742" E
4	19° 49' 55.299" S	114° 0' 4.752" E
5	19° 59' 55.310" S	114° 0' 4.752" E
6	19° 59' 55.303" S	114° 10' 4.742" E
7	20° 4' 55.299" S	114° 10' 4.742" E
8	20° 4' 55.306" S	114° 5' 4.761" E
9	20° 29' 55.317" S	114° 5' 4.788" E
10	20° 29' 55.331" S	113° 35' 4.788" E

Pipeline route co-ordinates
Geographic co-ordinate system GDA 1994

Id	Latitude (DMS)	Longitude (DMS)
A	20° 15' 43.993" S	113° 52' 41.044" E
B	20° 12' 15.276" S	114° 47' 56.695" E
C	19° 42' 4.82 " S	114° 33' 40.945" E
D	19° 54' 52.865" S	115° 7' 55.129" E
E	19° 35' 17.765" S	116° 8' 9.514" E

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Field characteristics

Field	Type	Reservoir pressure (psia)	Condensate to gas ratio (bbl/MMscf)	CO_2 (mol %)	H_2S (ppm)
Mentorc	Cretaceous	1288	40	<2	0
Bravo	Cretaceous	996	40	<2	0
Nimblefoot	Cretaceous	860	40	<2	0
Chester	Cretaceous / Triassic	1253	10	5-6	8
Glencoe	Jurassic	903	20	<2	2
Glenloth	Triassic	903	10	5-6	8
Brisels	Triassic	916	10	<2	1
Rimfire	Cretaceous / Triassic	977	10	<2	8

would be one of Australia's deepest-water projects.

Three candidate receiving facilities for Equus' gas were listed in Hess' government filings: Chevron-operated Wheatstone; Woodside's Pluto, or Woodside-operated North Rankin, which is part of the Northwest Shelf Venture, Australia's oldest LNG export project (startup in 1989).

Wheatstone (under construction with startup targeted for 2016-2017) is approximately 60 miles (100km) to the east of Equus; Pluto (in operations since April 2012) is about 90 miles (150km) northeast and North Rankin is about 150 miles (250km) northeast.

Chevron has had nothing to say publicly about any talks with Hess.

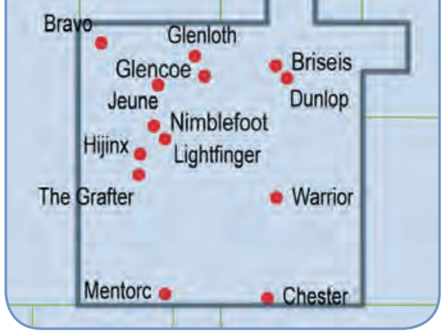
But Woodside managing director Peter Coleman in a December investor teleconference confirmed his company has had discussions with third-party producers about shipping their gas to Northwest Shelf and to Pluto (which started operation in April 2012). He offered no specifics on a possible link-up with Hess but said there are a growing number of options for gas producers.

"The good news is there's extra competition in the marketplace now with respect to getting their resources processed," Coleman said.

Equus, indeed, is part of a much bigger picture.

Australia-wide, from the far east to the far west, seven new LNG projects are underway, according to the October 2013 gas market report from the Australia Bureau of Resources and Energy Economics (BREE). With three projects already operating (Northwest Shelf, Darwin and Pluto), the new projects will boost Australian export capacity to 80 million tonnes by 2018 from 24.3 million

Field locations



tonnes in 2013. When the new plants are completed and operating at capacity, Australia should approach world leader Qatar's level of exports, providing around 20% of global LNG supplies, according to BREE's report.

"Beyond these projects, there are a number of other LNG projects at the feasibility and proposal stages, which if brought into operation would increase Australia's LNG capacity to more than 100 million tonnes a year and make Australia one of the world's largest LNG exporters by the end of the decade," the report predicts. Among those pending projects is Equus.

But there are reasons for caution in forecasting, the report says, and these factors which may have contributed to delaying the Equus FID.

Among the factors are rising development costs, the shale gas revolution and growing competition from US, Canadian and other international LNG exports. New floating LNG operations (Shell's Prelude is scheduled for startup in 2017) have "the potential to be transformative and unlock previously uneconomic remote offshore gas resources," BREE's report says.

The Carnarvon Basin around WP-390-P is a hotbed of gas-production activity, with numerous facilities besides Wheatstone, North Rankin and Pluto in development or on the drawing board, all within pipelining distance from Equus.

Hess listed several other nearby facilities in its government filings, including Chevron's huge Gorgon development (under construction with startup planned for 2015-16) 46 miles (75km) southeast of Equus. Also listed was Reindeer about 140 miles (220km) to the east and Angel 137 miles (220km) to the northeast.

In addition, Hess' papers on file mentioned three planned or existing major pipelines, Jansz 30 miles (50km) to the east, Echo Yodel 160km to the east and Cossack Wannaea 125 miles (200km) northeast.

The nearest production facility to Equus at the time of the February 2012 filing was the John Brookes unmanned platform, about 60 miles (100km) to the east. John Brookes' gas is sent to a Varanus Island processing facility via a 35 mile (55km) pipeline. Varanus Island, about 100 miles (155km) southeast of Equus, is site of a number of other production facilities.

Land-based facilities on Barrow Island are 85 miles (135km) to the southeast, Hess' filings says.

In any case, Hess, 100% owner of Equus, is unlikely to suspend or drop the project given that in 2007 it committed to spend $500 million on exploration and development in order to win the rights to WA-390-P. The commitment was a record for Australian permit lease auctions.

A 22-well exploration and appraisal operation from 2008 through 2011 used the Transocean semisubmersible rig *Jack Bates* and confirmed discovery of eight commercially viable fields. Reserve estimates run from 1-3Tcf of gas, and Equus is expected to have an operational life of 25 years.

The eight fields comprising Equus have been dubbed Mentorc, Bravo and Nimblefoot in Cretaceous strata; Chester and Rimfire in the Cretaceous/Triassic; Glenloth and Briseais in Triassic and Glencoe in the Jurassic. Reserve pressures range from 860psi in Nimblefoot to 1,288 in Mentorc.

The fields are 5200ft (1.6km) to 13,000ft (4km) beneath the seabed in 3200ft (1000m) to 4000ft (1200m) of water.

The three Cretaceous fields have the highest condensate to gas ratio, 40bbls per million standard cubic feet of gas, which could add value.

Hess began planning in 2011 and work is is well advanced. FEED work on the subsea layout of umbilicals, flowlines, tie-ins and export pipelines has been done by Wood Group Kenny. Worley Parsons' INTECSEA unit did FEED work on the topsides, semisubmersible hull, moorings and risers.

Hess' development plan calls for a three-phase, 17-well drilling campaign, with six producing wells to be drilled by 2017, five more by 2026 and six more by 2030. Also listed in the filing are three 12-inch flowlines totaling 27 miles (43.5km) in length, with branches linking producing wells.

A profile of the project on Project Connect, an affiliate of the Chamber of Commerce and Industry of Western Australia which lists jobs available to contractors, calls for the semisubmersible FPS to be permanently moored in 3475ft (1060m) of water. The facility would be 345ft (105m) long and 195ft (60m) wide. The hull would weigh about 25,000 tonnes and the topsides 15,000 tonnes.

Hess' original Equus timeline

Project Phase	Target Date
Final Investment Decision	Mid 2013
Implementation phase	Mid 2013 to late 2017
- Development Drilling – Phase 1	2015 - 2016
- Offshore Installation	2016 - 2017
- Commissioning	Late 2017
First Commercial Gas/ First LNG	Early 2018
Decommissioning	2043

Partial processing would be done on the platform – separation, gas dehydration and compression and Mono Ethylene Glycol (MEG) regeneration.

The export pipeline from Equus to third-party facilities would be a 20in. diameter line ranging from 75 miles (120km) to 180 miles (285km) in length, depending on which third party agrees to receive gas from the Hess project.

Depending on the tie-in location, the export pipeline could present challenges of its own, running through waters as deep as 4600ft (1400m) and climbing the continental shelf escarpment off northwest Australia at a 40-degree grade. At the escarpment, water depth goes from 3450ft (1050m) to 820 feet (250m) within 5 miles (8km), the Project Connect listing says.

Hess already has sought expressions of interest in several work packages on Western Australia's Industry Capability Network. Among the packages: engineering, procurement and construction of the hull and mooring; EPC of the topsides; FPS transportation to site and installation; and topsides installation.

In its filing with Australian regulators, Hess has explained its reasoning for not building its own independent LNG-processing facility.

"By tying into existing offshore infrastructure supplying an existing onshore LNG facility, the project will avoid the requirement for any onshore or near shore components," the company filing says.

"Hess considers this concept optimizes the economic and environmental outcomes for Australia in efficiently developing the natural gas discoveries in the Equus fields." OE

Making its mark

Above, the offshore and onshore pipelines are tied-in at the Omati landfall. Saipem's *Semac 1*, left, is shown during deepwater installation.

All images courtesy Esso Highlands Ltd.

Papua New Guinea is home to the Esso Highlands Ltd.- operated PNG LNG project, the first of its kind in the country's history. Sarah Parker Musarra provides an update and examines the milestone project's offshore pipeline.

Occupying a small corner of Southeast Asia, World Bank data shows that Papua New Guinea (PNG) is home to seven million people, which is 1.1 million less than the population of New York City (2012).

"The mineral revenue is the main driver of the economy right now," said Jonathan Lacouture, GlobalData's upstream lead analyst for Asia-Pacific. "The gas in the country is so depressed; the infrastructure is relatively lacking. There was no room to develop the gas production stream.

"When the national oil companies discovered the Hides, the Juha, the Angora, and a couple of other slightly small fields, they realized they had enough for an LNG facility," Lacouture said.

The field discoveries soon piqued the interest of supermajor ExxonMobil.

"It is a country that is uniquely located to high-demand markets in Asia Pacific," said Decie Autin, project executive, PNG LNG. Autin is responsible for all aspects of PNG LNG's planning, development and execution.

With sufficient proven gas reserves, ExxonMobil through its subsidiary, Esso Highlands Ltd., decided to establish an LNG plant in Papua New Guinea: PNG LNG.

Located on the Gulf of Papua in the capital city of Port Moresby, PNG LNG is a US$19 billion, two-train LNG production and processing plant. With in-house liquefaction and storage facilities, it is capable of producing 6.9MM tpy (mtpa), which Lacouture describes as "a pretty substantial level of production for [PNG]."

Esso estimates that PNG LNG will deliver more than 9Tcf of gas over the 30-yr life of the plant, and Autin said that the country of PNG will benefit in other areas as well.

"The PNG LNG project has the potential to lay a foundation for a sustainable economic future in [PNG] as the largest private-sector investment in the country," she said. "The project will boost GDP and export earnings...and provide a catalyst to further gas-based industry development."

Spanning three provinces within PNG, partner Oil Search Ltd. said that gas will

2013

- Construction of offshore pipeline completed following final tie-in, December.
- LNG plant commissioning phase began.

2012

- The barge *Castoro 10* connected two sections of the offshore pipe in July.
- A first-gas target date of 2014 was released and project capacity increased 5% to 6.9MM tpy (mtpa).
- The plant's tallest structure, the main cryogenic heat exchanger, was placed. The area where natural gas will be liquefied and sub-cooled, Esso referred to it as "the heart of the LNG plant."
- Nabors Rig 702 kicked-off drilling operations at the Hides natural gas field.

2011

- Saipem began construction on the offshore pipeline.
- First foundation for the LNG plant was poured in April, containing 20cu. m of concrete and nearly 2000kg of steel reinforcement.
- LNG equipment installation began.
- In March, a sales and purchase agreement was finalized with Taiwan's CPC Corp., supplying 1.2mtpa of LNG over a 20-yr period.

2009

- JV participants issued project approval.
- Days apart in December, Sinopec and TEPCO, respectively, finalized LNG sales and purchase agreements. Sinopec, a subsidiary of China Petroleum and Chemical Corp., purchased 2mtpa to be supplied to the company's Shandong province LNG terminal for 20 years.

be sourced from the Hides, Angore and Juha fields, with associated gas originating from Kutubu, Agogo, Moran, and Gobe Main. Esso said that more than 700km of pipelines transport the gas to the processing facility, which includes an offshore pipeline that runs alongside the coast of PNG.

Beginning at the Gulf Province's Omati River landfall, the offshore pipeline runs nearly 24km to the LNG plant site. Built with concrete-coated carbon steel, Esso said that more than 34,000 joints were necessary for the 407km-long, 36in.-ID pipeline.

Esso contracted Italy's Saipem to build the pipeline's offshore portion using two installation vessels: the 148.5m-long, semisubmersible pipelay barge, *Semac 1*, and the 140m-long trench/pipelay barge, *Castoro 10*.

The offshore pipelay began Oct. 31, 2011, with shore pull, hefting pipe onto the coast to connect it with the section onland.

Deepwater installation, which reached depths of 110m, began at the Caution Bay landfall and concluded at the Kumul marine terminal, was performed by *Semac 1*. Sections in the Caution Bay landfall up to the LNG shipping channel were trenched and backfilled for stability and protection. All other sections were placed directly on the seafloor to allow for natural burial over time. Trenching was used in the shallow-water section of the pipeline; however, Autin said that trenching was kept to a minimum to reduce the environmental impact.

Shallow-water work was completed by *Castoro 10*. The pipeline was laid in two sections over eight months.

On July 26, 2012, *Castoro 10* completed the offshore pipelay by connecting the deepwater and shallow-water sections through an above-water tie-in. Six cranes lifted each end simultaneously. The pipeline ends were cut off, joined and welded before the pipeline was lowered into the water.

Esso announced that all pipelay was completed Feb. 14, 2013, following the final tie-in to the 292m-long onshore pipeline at the Omati landfall.

First gas delivery is scheduled for Q2 2014, and Lacouture said that PNG is anticipating industry interest.

"PNG did not exist in the LNG market. This will be their first foray into the market. Depending on how this goes, PNG could become a moderately-sized LNG exporter," Lacouture said. **OE**

Japan's TEPCO also signed on for a 20-yr contract to purchase 1.8mtpa.
Osaka Gas purchased a total of 1.5mtpa of LNG for a 20-yr period.

- In December, engineering, procurement and construction contracts were approved for six companies and joint ventures for different aspects of the project.

Saipem was selected as the contractor for the offshore pipeline. The terms of the contract called for the pipeline's engineering, transportation and installation, as well as shore approach excavation and backfilling.

2008

- In May, JV participants executed a gas agreement with the PNG State. ExxonMobil announced that the JV decided to enter the Front End Engineering and Design phase.
- In March, operator ExxonMobil, through Esso Highlands Ltd., (41.6% working interest) executed an agreement with its JV participants, Oil Search Ltd.: 34.1%, Santos: 17.7%, AGL: 3.6%, Nippon Oil: 1.8%, Landowner Interests (MRDC): 1.2%.

[In 2014, the interests are: operator ExxonMobil: 33.2%, Oil Search Ltd.: 29%, NPCP: 16.6%, Santos: 13.5%, Nippon Oil: 4.7%, MRDC: 2.8%, Petromin: .2%.]

Stimulating vessel investment

In the early 1980s, the North Sea saw a spurge in stimulation vessels by the big three oilfield services contractors. Three entered the market over two years. Until October, two-thirds of that same fleet remained in place. Elaine Maslin looks at a new vessel on the market.

Baker Hughes' *Blue Orca* in the southern North Sea. Photo courtesy of Baker Hughes.

Nearly thirty years after it brought the first purpose-built stimulation vessel into the North Sea, Baker Hughes has returned to the market.

In October last year, the *Blue Orca* arrived in Denmark, after a successful journey across the Atlantic from shipbuilder and vessel operator Edison Chouest Offshore's yard in Louisiana.

By mid-November, the vessel had carried out its first acid job for Maersk Olie og Gas, offshore Denmark.

The vessel, ordered on the back of a non-exclusive contract with Maersk Olie og Gas, and built to meet a number of Maersk's requirements, was the eighth in Baker Hughes' now nine-strong stimulation fleet, with further vessels due.

It is one of the highest-capacity stimulation vessels globally, designed to treat a large number of stages in wells, which can be up to 12-18 in the North Sea, and multiple treatments in one mobilization.

It has 2.5million lbs (1134-tonne) proppant storage capacity, in top tanks, and lower sand silos, which are divided into four compartments, for multiple

The North Sea stimulation vessel fleet

The stimulation market in the North Sea began in earnest in the 1960s, with temporarily-placed, skid-mounted, limited scale, equipment on platforms.

According to 1984 SPE paper 12993-MS, stimulation operations from a vessel were first carried out in 1980, in the southern North Sea from a small Arabian Gulf vessel.

This led to the conversion of two large (at the time) North Sea supply vessels into dedicated stimulation vessels, operating in the northern and southern sectors.

Their capability was quickly found wanting, specifically around pumping, batch-mixing and proppant-carrying capacity. Maximum pumping power on both vessels was 4000-5000 horsepower (hp) and quality control and job monitoring were also limited.

sand types. It has eight main acid storage tanks, able to hold up to 180,000 US gals concentrate, or up to 414,300 gals at 15% dilution, and 24 liquid additive storage tanks, able to hold flammable fluids, and with remote monitoring and high level alarms.

Proppant delivery is via gravity feeds to two blenders, each with two 12-in.-diameter and one 8-in.-diameter horizontal sand screw. The 12-in. screws are able to deliver between 250-10,800 lbs/min sand, and the 8-in. between 76-2000 lbs/min.

The *Blue Orca* has five, 2750 hydraulic horsepower (HHP), Gorilla pumps, and two, 650 HHP, pumps. 5½-in. fluid ends provide a maximum working pressure (MWP) of 15,000psi (1035bar) at 17.7bbl/min.

Two, aft-mounted, 400ft Coflexip hoses, rated to 15,000psi MWP, with hydraulic quick disconnects, provide the connections to platform or rig-based wellheads.

The vessel is compliant for the UK, Dutch, Danish and Norwegian sectors, and could also work in the Mediterranean, offshore West Africa, and occasionally North Africa and in the Adriatic, says Tony Martin, director, offshore stimulation, Baker Hughes.

Baker Hughes, whose previous North Sea-based stimulation vessel, the *Vestfonn*, left the region in 2007, believes the investment and move back into the basin is worthwhile.

Martin says the company expects an increase in stimulation activity in the North Sea over a 4-5 year period, and that the higher level of activity will continue.

Enclosed tanks positioned above the main deck. Photo courtesy of Elaine Maslin.

John Clark, business development manager, pressure pumping, Baker Hughes, said: "We see the stimulation market in the North Sea increasing year after year, with 2015-2016 in particular being extremely busy."

The *Blue Orca's* design was based on the past 30 years' experience, and what Baker Hughes thinks the vessel will need to be able to deal with in the next 30 years, including reservoir pressures and temperatures.

Today's demands include being able to perform large-volume, low-rate matrix acid treatments, high-rate Paccaloni-style matrix acid treatments, acid fracturing and high concentration proppant fracturing. As a minimum, it needs to be able to pump at 60 bbl/min, with higher rates preferable for acid fracturing, and must mix all fluids on-the-fly with sea or fresh water, Martin says. There has also been a small but increasing demand for treatments in high-pressure, high-temperature formations, he says.

A key consideration was redundancy,

Baker Hughes, Schlumberger, and Halliburton, soon stepped in to fill the gap. Baker Hughes brought the 1983-built 82.3m-long *Vestfonn* on to the market in 1986.

In 1984, Schlumberger introduced to the market the 74m-long *Big Orange XVIII*, on a long term contract from owner Tracer Offshore ANS, and managed by Wilhelmsen Ship Management.

The following year, Halliburton contracted the 88m-long *Skandi Fjord*, owned by DOF Subsea and managed by DOF Management AS.

The three vessels were the largest of their type at the time, and remain so, Martin says, in paper SPE 168243. The requirements of the stimulation treatments far exceeded anything required in other parts of the world.

These requirements entailed mobilizing the world's largest capacity to store and blend raw hydrochloric acid, and the ability to store and blend unprecedented quantities of proppant.

The *Vestfonn*, which left the North Sea in 2007, and has been working offshore India since, has 10,000- and 15,000-psi (68.9- and 103.4-MPa) pumps, supported by 13,400-hydraulic pumping capacity.

It has 180,000-gallon raw acid storage capacity and more than 1.2 million pound-mass (lbm) (544,310.9 kg) for proppant.

The *Big Orange VIII*, remains in the North Sea. It has 4800- and 10,000-psi (at 58- and 70 barrels per minute (bpm) pumps, supported by 12,000-hydraulic pumping capacity. Schlumberger offers pumping pressures of up to 15,000-psi on request.

Big *Orange VIII* has 180,000-gallon raw acid storage capacity and 15,400cu ft total proppant storage capacity.

The *Skandi Fjord* is understood to have just been decommissioned. It also had

The *Skandi Fjord*.


The *Big Orange VIII*.


The *Island Patriot*.
Photo courtesy of Elaine Maslin.

The Blue Orca's touch screen control room. Photo courtesy Elaine Maslin.

Clark says. "If anything goes down, there will always be at least one back up," he says. "We should never have to stop a job because we were not able to switch pump." The blending and mixing process systems have full redundancy, he says, and stimulation and power plant systems run independently from the marine power systems.

The blending system allows for acid, water and additives to be blended, without going through an open tub, creating a closed, automated system, with a maximum delivery rate of 80 bbl/min, to minimize potential spills or releasing hazardous fumes. It will be able to work in automated batch mode, automated continuous batch mode, and continuous mix, all through a pre-programmed computer control system, which also continuously monitors the rates and adjusts them accordingly. Concentrations are monitored using a Coriolis-effect mass flow meter, with radioactive densimeters to measure the blended acid concentration.

The sand proportioning system is also computer-controlled and fully pre-programmable. Blender tubs are directly under the silos to simplify the sand delivery process. Pneumatic conveying delivers proppant from below deck storage to the above deck proppant silo, and it is possible to return proppant back to the below deck tanks.

The gel blending plant on the vessel uses dry-on-the-fly technology, which means oil-based slurried polymer concentrates are not needed. This system uses a full automated system, to control the addition of dry guar, or other gelling agents, into the fluid stream. High-energy mixers shear the polymers for hydration. The viscocity of the gel is monitored inside the vessel's onboard laboratory, with real-time pH, temperature and viscosity data recorded and displayed via the control system.

"Pumps have not changed much over the years, but instrumentation and controls are much more advanced now," Martin says. "We used to have a wall of the control room covered with a process flow diagram, switches and a panel of hundreds of valves that needed three people to operate. Today, controls look like something out of a science fiction movie. They are remotely operated by a small number of people in the control room via touches screens, and can even be operated from onshore."

The entire stimulation system is controlled from inside the control room. Within the vessel's monitoring system is a data acquisition system, which gathers data and transmits it to the data analysis software, which supports remote satellite monitoring, from onshore. A battery-powered wireless data acquisition skid can be positioned on a platform or rig to transmit data back to the vessel using wireless LAN communications.

The automated systems eliminate the need for staff to work in hazardous environments around the rotating or high-pressure equipment under normal operations.

The marine systems, have been built to be able to operate in the North Sea's harsh conditions, including a 10m swell, or 40knot wind. It has a drop-down, electrically powered azimuth thruster, able to rotate 360° for station keeping. The marine power systems are separated from the treatment and pumping systems.

The vessel has enclosed external walkways, and single-man cabins. The vessel works with two crews, for 24-hour operation. Support crews also arrive at the rig or platform before the vessel, so there is no need to transfer personnel from the vessel to the rig.

The vessel undertook its first job for a North Sea operator in December, to improve the injection profile of a water injector well, which supports reservoir pressure. The job consisted of three stages of a viscosified 15% HCL with two stages of Baker Hughes' diverter system, Enhanced Acid System. Pumping rates were 4-12 bbl/min. Pressures were 3000-4000 psi, using about 1200 HHP.

A step rate test (SRT) was performed before and after the treatment. The SRT after treatment showed much less surface pressure, compared to before the treatment.

The vessel was on location for about 24 hours and saw zero HSE incidents. OE

180,000-gallon raw acid capacity. Proppant storage capacity was more than 2 million lb. The *Skandi Fjord*'s maximum pumping pressure was 15,000-psi, supported by 10,400 hydraulic hp.

Apart from the short-lived introduction of the *Western Renaissance*, in 1993 (it left the North Sea in 1994, and was converted into a pipelay vessel after working in the Gulf of Mexico from 1994-1995), the departure of the *Vestfonn* to India in 2007, and the occasional use of modular stimulation packages on supply or support vessels, the stimulation vessel fleet in the North Sea saw little change until 2010.

Shortly after the *Vestfonn* left for India, a new company, StimWell Services, was launched out of Great Yarmouth, the *Vestfonn*'s former base. StimWell launched the 86m-long *Island Patriot*, a conversion, in 2010.

The *Island Patriot*, which is owned by Island Offshore and managed by Island Offshore Management, started a four-year contract with BP, primarily for use on the Valhall field, in 2010. Island Offshore is a 50:50 joint venture between Edison Chouest and Ulstein Group. ▪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Solutions

Sonardyne Sentinel provides rapidly-deployable underwater security

Maritime security company Sonardyne International Ltd. has successfully completed the installation of a Sentinel Intruder Detection System (IDS) onboard a drilling rig operating in an undisclosed offshore oil field in the Middle East. The system has been deployed to protect the platform against the threat of attack from underwater intruders. Sentinel is developed to meet the underwater security requirements of private, commercial, government and naval end users. The system detects, tracks and classifies divers and small underwater vehicles approaching a protected asset from any direction and alerts security personnel to the potential threat.

www.sonardyne.com

Puradyn launches bypass oil filtration system

The **Puradyn** TF-240 extends oil drains by filtering solid contaminants to below 1 micron, while trapping gaseous, and liquid contamination, and maintaining the oil's viscosity and chemical balance, thereby safely extending oil drain intervals. The Puradyn System provides microfiltration for engines with an oil capacity of up to 85 gal. (322L) and can be used in multiples on engines that hold amounts of lubricating oil in excess of 400 gal. (1500L).

www.puradyn.com

Tenaris designs new connection for GOM

The **Tenaris**Hydril Wedge 623 connection was developed to comply with recent changes in deepwater operating requirements in the Gulf of Mexico (GOM).

Suitable for deepwater and high-pressure applications, the new design features metal-to-metal pressure seals with tested compression ratings of 80-86% efficiency in an integral connection.

Both the internal and external pressure seals maintain gas-sealing capability under high axial loads and comply with API RP96 for deepwater applications.

Tenaris recently announced that Shell will use Wedge 623 connections in its Olympus tension leg platform in the Mars field, located in 914m of water in the GOM. The Wedge 623 tested under the ISO 13679 CAL I-E protocol along with operator requirements for survival loads.

www.tenaris.com

SRI International's underwater mass spectrometer couples with AUV

SRI International announces its in-situ membrane introduction mass spectrometry (MIMS) device successfully integrated into Bluefin Robotics' Bluefin-12 autonomous underwater vehicle (AUV).

Most underwater analytical equipment is tethered to a surface vessel. The unique capabilities of the SRI MIMS device integrated into the Bluefin-12 AUV platform addresses complex survey and data collection challenges associated with ocean monitoring and exploration. It can continuously measures volatile gases, light hydrocarbons, and organic compounds. The SRI MIMS also reduces operational risk, and increases data quality.

www.sri.com

Scottish firm creates £20m software platform

Scottish firm **C3global** launched its new 12th-generation software platform, Amulet Predictive Analytics. Since the Amulet was introduced in 1996, C3global has invested over £20 million in developing a future-gazing web-based application.

C3global chief executive David Smith said: "Amulet Predictive Analytics complements other software to extract data from operational processes, quickly analyze it and feed it back into the process to improve outcomes. By doing this, it gives people insight to solve real-world problems."

Amulet Predictive Analytics has been developed for use in C3global's core sectors - oil and gas, utilities, manufacturing, refrigeration, power distribution and sustainability.

www.c3global.com

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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
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Activity

GE Oil & Gas opens Brazilian logistics base

With an area of 590,000sq. ft and investments that exceed US$100 million, GE's base in Niteroi in the state of Rio de Janeiro was designed primarily to load and unload installer ships. These vessels carry heavy equipment, such as giant reels of flexible pipes, and target the mobilization and maintenance of oil wells.

"GE is proud to start the operations of this logistics base, a state-of-the-art structure that will enable a more efficient delivery of products and services for our client, Petrobras. This inauguration is an important step in strengthening GE's presence in the oil and gas sector and a significant contribution in terms of productivity gains for pre-salt fields exploration," said Marcelo Soares, global president and CEO of Wellstream, a GE Oil & Gas business.

The base has a 320-ton capacity crane, the largest "hammerhead" in the world. The crane, which gets its name from its long arm and T-shape, required an investment of US$7 million. It is 140ft tall, equivalent to a 14-story building.

Aside from its offshore capabilities, the base also features advanced land transportation infrastructure. The facility has, for example, two straddle trucks, which sit high above the ground and carry cargo beneath their structure, and other equipment for moving large pipes on the ground with capacities of 300 and 350 tons each. OE

Sandvik acquires Varel International Energy Services Inc.

Sandvik reached an agreement to acquire Varel International Energy Services Inc. (Varel) for approximately US$740 million. The closing of the acquisition is subject to standard regulatory approvals and certain environmental due diligence.

Varel is a global supplier of drilling solutions focusing on drill bits, downhole products for well construction and well completion.

Revenues in 2013 were approximately US$340 million. The acquisition is expected to be slightly accretive to earnings per share already in the first year. Varel will form a new product area within the business area Sandvik Venture.

Qatar buys into Total E&P Congo

Total announced that Qatar Petroleum International (QPI) is now a shareholder of Total E&P Congo, holding 15% of its capital. The news follows a framework agreement that was previously signed in May. The US$1.6 billion increase of Total E&P Congo's capital will consolidate its financial capacity at a time when it is progressing the development of the Moho Nord deep offshore project, the French player said.

Total E&P Congo, established in the country in 1968, operates 10 fields in the Republic of Congo, accounting for nearly 60% of national output. Total E&P Congo's equity production averaged 113,000 boe/d in 2012.

Shell boosts North American LNG profile

Royal Dutch Shell plc announced the acquisition of Repsol S.A.'s liquefied natural gas (LNG) portfolio outside North America for a headline cash consideration of US$4.1 billion. Shell will also assume $1.6 billion of balance sheet liabilities relating to existing leases for LNG ship charters, which increases its available shipping capacity.

The deal gives Shell an additional US$7.2 million tonnes per annum (mtpa) of directly managed LNG volumes. The company's portfolio will now include LNG supply in the Atlantic from Trinidad & Tobago, and in the Pacific from Peru.

Shell will acquire a net 4.2mtpa equity LNG plant capacity; Atlantic LNG trains 1-4, operated by Trinidad and Tobago's Atlantic LNG company; Peru LNG 4.5mtpa capacity; a fleet of LNG carriers; and 7.2mtpa LNG volume through take-off agreements. Shell will supply around 0.1mtpa of LNG to Repsol's Canaport LNG terminal in Canada over a period of 10 years.

N-Sea acquires Stork division

Asset integrity services firm Stork Technical Services has agreed to sell its subsea division to Netherlands-based N-Sea Group.

After the acquisition, the enterprise will employ more than 120 onshore staff, and, on average, 150 offshore staff, with 10 diving systems, nine ROVs, three offshore diving and ROV support vessels, and three daughter craft diving RHIBs, plus three support RHIBs, as well as extensive data management and subsea engineering capabilities.

N-Sea has two main offices, in Aberdeen and Zierikzee (NL). The Group will have a combined turnover of more than EUR75 million.

Stork said it would continue to develop and invest in technology associated with subsea integrity, cathodic protection, bolting, tensioning and tooling operations, which will not be affected by the sale of the subsea business.

Fugro opens new office in Mozambique

Fugro recently opened a new office in Maputo, establishing the only internationally-accredited laboratory in Mozambique.

The office in the port city of Maputo is located to enable quick and efficient response to client requirements for project support. In Pemba, the operational center and laboratory offers ISO 17025 accredited soil, chemical, electrical and materials testing and soil aggregate laboratory testing.

Spotlight

By Elaine Maslin

Influencing the decommissioning mindset

Brian Nixon's career has seen him transition from engineering and project management to international business development in Angola. For the past four years Nixon has lead industry body Decom North Sea.

Nixon announced his decision to step down as CEO of Decom North Sea, which he helped form, this past November, and he is now ready to consider new challenges.It is a long way from his days as an apprentice, but it has been an interesting four years, he says, with every day a school day because of the learning involved.

A recent recognition within the sector in the last 6-9 months has perhaps been a surprise to many. "The industry is led by first oil, first gas, the shortest possible shutdowns, fast modifications, and so on," Nixon says.

"The psyche of the management approval process reflects this. It is geared around a 'first and earliest' mindset. Right now, in decommissioning, the situation is the reverse of this.

"The recognition is that current decision processes are just not appropriate for decommissioning. Companies in Aberdeen, at the front edge of deepwater decommissioning, are at the point of going to their Houston headquarters to say 'we are having to go ahead with this spending and, by the way, your established investment decision processes are no longer fit for purpose.'"But, operators are coming to us and saying they don't think they are going to be able to do this internally. It needs to be on an industry platform, so they can go and say 'it's not just us, [there are] others'."

Decom North Sea has now launched a joint industry project to address the issue.

Nixon's career started with an apprenticeship at Babcock and Wilcox, followed by a BSc in Mechanical Engineering from Strathclyde University, 15 years at Motherwell Bridge, and stints at Atlantic Power and Gas, AOC International (which became part of PSN), and Wood Group.

At Wood Group he was seconded to the Angolan embassy, through what is now UK Trade & Industry, to help UK firms win work in the newly oil-rich country.

He was then headhunted by Scotland's business development organization Scottish Enterprise, with whom he undertook a study of the energy sector, which identified offshore oil and gas infrastructure decommissioning as an under-resourced sector, but with a potential to be a huge industry as the hundreds of facilities offshore the UK, Norway, and Netherlands start to require removal.

In 2009, following 12 months' consultation with the industry, a recommendation was approved, supported by industry, to form an independent, focused, forum on decommissioning, guided by the industry—Decom North Sea.

Four years later, the body has already had significant achievements. Last year it piloted and launched a standard decommissioning program template.

The new template – drawn up in cooperation with the UK's Department of Energy and Climate Change (DECC) – set out to streamline and standardize the format for decommissioning programs throughout the UK North Sea, whilst still satisfying regulatory requirements.

Decom North Sea is already working on a similar project, among others, to create a model for an environmental impact assessment (EIA).

Other ongoing work is looking at well plugging and abandonment (P&A). A recent workshop saw the launch of three new initiatives thought to have serious potential for improvement and innovation in this area, Nixon says.

Decom North Sea has also grown its national and international presence, holding and attending events across the UK, as well as Norway and the Netherlands. Both countries have member companies on the board.

At the start, decommissioning was seen as a very unattractive assignment for oil and gas professionals—someone else's job," Nixon says. "Now we are beginning to see a recognition that this is a really exciting 30-40-year career opportunity, with international dimensions, with a huge variety of skills and disciplines."

Overall, over the last four years, there has been a growing acknowledgement for the need for more innovative thinking and collaboration, Nixon says. OE

Brian Nixon, outgoing chief executive, Decom North Sea.

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NORTH AMERICA
John Lauletta (N-Z)
Ph: +1 713-874-2220
jlauletta@atcomedia.com

Amy Vallance (A-M)
Ph: +1 281-758-5733
avallance@atcomedia.com

UNITED KINGDOM
Mike Cramp, Alad Ltd
Phone: +44 0 7711022593 Fax: +44 01732 455837
mike@aladltd.co.uk

NORWAY/DENMARK/SWEDEN/FINLAND
Brenda Homewood, Alad Ltd
Ph: +44 01732 459683 Fax: +44 01732 455837
brenda@aladltd.co.uk

ITALY
Fabio Potesta, Media Point & Communications
Ph: +39 010 570-4948 Fax: +39 010 553-00885
info@mediapointsrl.it

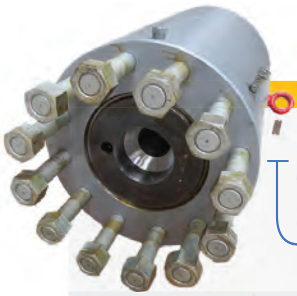
NETHERLANDS/AUSTRIA/GERMANY
Arthur Schavemaker, Kenter & Co. BV
Ph: +31 547-275 005 Fax: +31 547-271 831
arthur@kenter.nl

FRANCE/SPAIN
Paul Thornhill, Alad Ltd
Ph: +44 01732 459683
paul@aladltd.co.uk

CHINA, HONG KONG & TAIWAN
Henry Xiao
Ph: +86 21 3921 8471
henry.xiao@matchexpo.com

SINGAPORE, MALAYSIA, INDONESIA, THAILAND & KOREA
Anthony Chan
P +65 63457368
acesap@gmail.com

Numerology

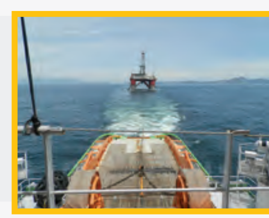


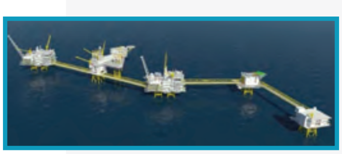
US$60,000 The approximate installation price of Weatherford's Renaissance WDCL system, coming in at less than 10% of the estimated cost for a workover. See page 32.

-41.73m The target Lowest Astronomical Tide (LAT) for a seabed preparation pad in a proposed depletion compression platform location. See page 34.

US$500million The amount Hess committed to spend on exploration and development in order to win the rights to Australia's WA-390-P in 2007. See page 50.

5782 The number of nautical miles the *Ensco 5004* semisubmersible was towed on its journey from offshore Rio de Janeiro to Malta See page 14.





NOK100-130billion Statoil's total investment in the first phase of development for the Johan Sverdrup field. See page 14.

50million liters of cold ocean water are drawn out hourly to cool the LNG on Shell's Prelude FLNG project.

1134tonnes The proppant storage capacity of Baker Hughes' *Blue Orca*. See page 56.

8.5million bo/d The US Energy Information Administration's estimated monthly US crude production in 2014, up from 7.5 million bo/d in 2013.

34,000 The number of joints in PNG LNG's offshore pipeline segment. See page 54.

Image courtesy Esso Highlands Ltd.