

Required reading for the Global Oil & Gas Industry since 1975

OGE

oedigital.com

EPIC
Marginal Fields **28**

SUBSEA
Flow Assurance **32**

DRILLING
New concepts **44**



FPSO Outlook & Technologies

page 20

Offshore Automation Review
page 48



Real change starts here

TechnipFMC is a new and dynamic force in energy.

We have the size, experience, and capabilities to transform the industry in pursuit of new possibilities and improved project economics. Our ability to innovate is testament to what's possible when you shake off the bounds of convention.

We're thought leaders, but we don't just think - we act. Working closely with partners and clients, we leverage technologies, expertise, and innovation to deliver fresh thinking, streamlined decisions, and smarter results.

From concept to project delivery and beyond, we're driving the change the oil and gas industry needs.

To not just imagine a better way, but to make it happen.

Discover more.

TechnipFMC.com



FEATURE FOCUS

FPSO OUTLOOK & TECHNOLOGIES

20 Testing the waters

In advance of OE's 2017 Global FPSO Forum, held in Houston this month, Audrey Leon chats with the forum's board members to learn what is in store for the FPSO sector and discover how digitalization may play a role.

24 Weathering the storm

Infield Systems' Catarina Podevyn surveys the FPSO market and discusses recent projects awards.

26 Making MODUs into FPU's

Mobile offshore drilling units could be a FPU conversion alternative. Karen Boman sets out the details.



Workers aboard Shell's Prelude FLNG facility. Photo courtesy of Shell.

Features

EPIC

28 Marginal options for small pools

The UK North Sea's marginal fields offer an attractive prize, if they can be economically unlocked. Steve Hamlen reports.

30 North Sea honey bee

Elaine Maslin surveys solutions to tap an estimated 3.4 billion of resources locked up in UK marginal pools.

SUBSEA

32 Nightmares on wax

Waxy crude on the Pil and Bue project and topside constraints has led VNG Norge to explore pipe-in-pipe heating systems. Elaine Maslin reports.

34 Let's get connected

Sometimes seen as the weak link in the system, subsea connectors have come a long way, says Hydro Group Systems' Bill Mildon.

PRODUCTION

36 Design once, build many

Rob Gill and Steve Henzell explain how WorleyParsons intends to make wellhead facilities production cheaper and faster with a design one, build many ethos.

38 Room for improvement

While UK North Sea production efficiency has made improvements since diving to a dire 60% in 2012, more can still be done, says Gordon Lawrence from Asset Performance Networks.

42 Mining for ideas

With its remote and harsh operations, mining has similar characteristics to oil and gas exploration. Could the industry learn from mining's efficiencies? Innes Auchterlonie and Andrew Woodward explain.

DRILLING

44 Designs on the future

Diamond Offshore is championing a new Floating Factory concept meant to meet future deepwater challenges, but drumming up support during the downturn may be tough. Karen Boman reports.

QUARTERLY AUTOMATION REVIEW

48 Internet of oil things

The Internet of Things is becoming ever more embedded in the oil psyche. Steve Hamlen reports.

50 Virtual metering

NEL's Damian Krakowiak examines the potential of virtual flow metering technology and how better testing could enable its adoption.

52 Improving maintenance

Karen Boman speaks with Prasantha Jayakody of Bsquare about the benefits of condition-based maintenance and the challenges of implementation in the oil and gas industry.

REGIONAL OVERVIEW: GULF OF MEXICO

54 Turn the page

After years of turbulence fueled by scandal and debt woes, Brazil and its oil company Petrobras detailed how they intend to get back on the right track. Melissa Sustaita reports.

56 Pioneering under pressure

Petrobras' insatiable deepwater production plays a significant role when it comes to driving global subsea systems demand. Elaine Maslin speaks with the firm's Subsea Systems Executive Manager Cristina Pinho.

58 Pre-salt prevails

Brazil is slowly emerging from one of its worst economic crises with the country's oil and gas sector no exception, says the EIC's Pietro Ferreira.



ON THE COVER

The journey awaits. In mid-July, Inpex announced the *Ichthys Venturer* FPSO has set sail from South Korea to its new home at the Browse field offshore Western Australia. Cover photo courtesy of Inpex.

ONSHORE. OFFSHORE. EVERY SHORE.™

IT ALL STARTS WITH API STANDARDS.™

No matter where you go around the world, the oil and gas industry relies on API Standards to meet the highest level of safety. Show the world your commitment to safety. Start with API standards by starting at API.org/Standards.



It's times like these you need people like us.®

877.562.5187 (Toll-free U.S. & Canada) | +1.202.682.8041 (Local & International) | sales@api.org | www.api.org

© 2017 – API, all rights reserved. API, the API logo, the "Onshore-Offshore-Every Shore" tagline, the "It All Starts with API" tagline, and the "It's times like these" tagline are trademarks or registered trademarks of API in the United States and/or other countries.

Departments & Columns

8 Undercurrents

Two high-profile floating production projects are on the move.

10 Global Briefs

News from the around the world, including discoveries, field starts, and contracts.

14 Field of View: The nutcracker

Marginal fields don't always turn out to be that marginal, especially when you have efficient topsides and an ability to find hidden pockets in your reservoir. Elaine Maslin reports.

16 In-Depth: The fruits of Mexico's labor

Mexico's energy reform efforts have been realized with recent successes from prior bid rounds. Now, Mexican national Pemex has added a steady schedule of farm-outs in shallow and deep water. Audrey Leon surveys the plays on the agenda.

60 Solutions

An overview of offshore products and services.

62 Activity

Company updates from around the industry.

64 Editorial Index

66 September Preview & Advertiser Index

ATComedia
Atlantic Communications Media

AtComedia
1635 W. Alabama
Houston, Texas 77006-4101, USA
Tel: +1-713-529-1616 | Fax: +1-713-523-2339
email: info@atcomedia.com

US POSTAL INFORMATION

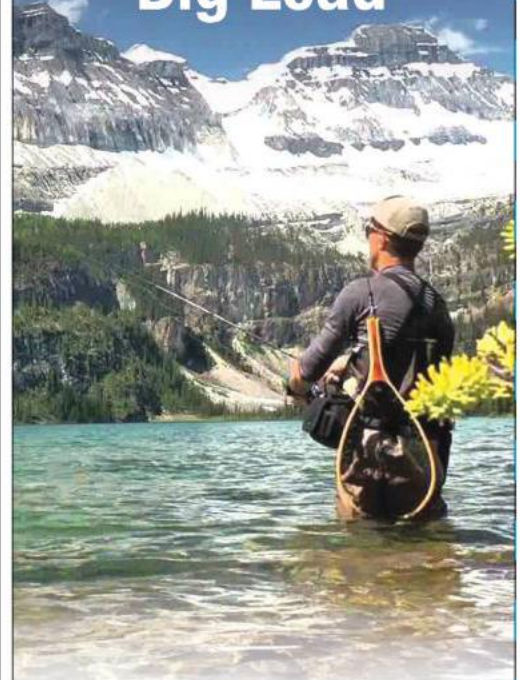
Offshore Engineer (USPS 017-058) (ISSN 0305-876X) is published monthly by AtComedia LLC, 1635 W. Alabama, Houston, TX 77006-4196. Periodicals postage paid at Houston, TX and additional offices.

Postmaster: send address changes to Offshore Engineer, AtComedia, PO Box 47162, Minneapolis, MN 55447-0162

OE (Offshore Engineer) is published monthly by AtComedia LLC, a company wholly owned by IEI, Houston. AtComedia also publishes Asian Oil & Gas, the Gulf Coast Oil Directory, the Houston/Texas Oil Directory and the web-based industry sources OilOnline.com and OEDigital.com.



Land Your Next Big Lead



Tradequip offers many options when it comes to advertising to the oil and gas industry. Don't miss the chance to cast your product in front of an active buyer. Call today to learn about our multi-level marketing approach.

Tradequip
International

**THE ENERGY EQUIPMENT
MARKETPLACE**

Since 1978

800-251-6776

www.tradequip.com





SIEMENS
Ingenuity for life

The power of partnership.

Engineering Ingenuity

Making your project a success takes more than just technology. It takes ingenuity — the ingenuity to understand your needs and tailor integrated solutions accordingly. From pipeline compressor and pump stations, to LNG plants and FPSOs, we've got you covered. We draw on an extensive equipment portfolio (including turbomachinery, motors, drives and gearboxes), a comprehensive software suite, as well as engineering expertise. And we'll partner with you every step of the way to ensure your project is a success, from pre-FEED through maintenance. That's the power of engineering ingenuity.

www.siemens.com/turboshow2017

Come see us
at TPS,
Sept. 12-14,
Houston,
Booth #1934





What's Trending



Making history

- Prelude FLNG sets sail for Australia
- Talos makes "historic" find off Mexico
- GE, Maersk Drilling step up digitization pact

White Papers

Check out the latest White Papers on OEDIGITAL



Offshore service sector: 5 trends to watch in 2017
 As operators across the supply chain adapt to challenging market conditions, we explore the themes set to dominate the offshore service sector this year and beyond.

IoT in Oil & Gas: Don't Get Left Behind
 In today's cost-conscious Oil & Gas industry, data is king. With fully digitalized, remote production sites generating huge volumes of data every second, how can you analyze and act upon this massive quantity of information to cost-effectively achieve your critical business objectives?



Solutions for the Oil & Gas Industry

SPIR STAR is recognized worldwide as a leading provider of high pressure fluid control products. We offer an extensive inventory, as well as a knowledgeable staff that can assist you with any technical issues that you may have.

Our commitment to providing quality products and outstanding customer service has established SPIR STAR as a key supplier to the industries we serve.

Featured Products

- Hose Assemblies up to 46,000psi Working Pressure
- Temperature ratings up to 300° F
- High Pressure Fittings & Adapters
- Quick Disconnects up to 30,000psi
- High Pressure Valves up to 60,000psi
- High Pressure Tubing up to 60,000psi
- Instrumentation Valves
- Tube Compression Fittings

SERVICE - SELECTION - SOLUTIONS SPECIALISTS IN HIGH PRESSURE:

HOSE | ADAPTERS | QUICK DISCONNECTS | VALVES



© 2017 SPIR STAR

Undercurrents

The journey begins



Photo from Shell.

As *OE* went to press two huge pieces of news floated by our desks. In June, Shell's giant *Prelude* FLNG facility (pictured above) set sail from Geoje shipyard in South Korea and began its 5800km trek to Western Australia, where first production is set for 2018.

The vessel, built by the Technip-Samsung consortium, will be stationed 475km north-northeast of Broome, and will have a capacity of at least 5.3 MTPA of liquids: 3.6 MTPA of LNG, 1.3 MTPA of condensate and 0.4 MTPA of liquefied petroleum gas. The *Prelude* FLNG facility is 488m-long and 74m-wide, making it the largest offshore floating facility ever built, Shell says.

Japan's Inpex also announced in July that its Ichthys LNG's FPSO facility, *Ichthys Venturer*, sailed away from its Okpo, South Korea, yard beginning its 5600km journey to the Browse Basin, 220km offshore Western Australia.

The vessel, which will be moored in 250m water depth, measures 336m-long ship-shaped FPSO has a storage capacity of 1.12 MMbbl of condensate. Inpex said that following its mooring, the FPSO will undergo hook-up and commissioning, along with the Ichthys Explorer central processing facility 3.5km away. The field is expected onstream by Q3 2017.

The *Ichthys Venturer* is featured on this month's cover.

Reaping Digitalization's benefits

In *OE*'s June issue, we set out to showcase the new world of digitalization technologies that are ready to infiltrate the industry and influence positive change. This month's issue looks at how various industry segments are applying them.

In our FPSO Outlook, *OE* asks floating production experts, from *OE*'s Annual Global FPSO Forum, how digitalization could help the FPSO segment, which is trying to bring about new cost savings to make the use of these massive systems more viable.

One of our respondents, on page 21, said digital technology could automate high-cost, dangerous, or error-prone tasks. Automation can significantly improve [companies'] bottom lines, and improve production efficiency. Another respondent said that digital technologies will allow access to more real-time data, enabling better decision-making.

In our Quarterly Automation Review, starting on page 48, writer Steve Hamlen dives deeper into the benefits of the Internet of Things (IoT). "In an IoT world, many companies will discover that being just a manufacturing company or an internet company will no longer be sufficient," says Dave Mackinnon, head of Technology Innovation at Total E&P UK. "They will need to become both – or become subsumed in an ecosystem in which they play a smaller role."

So, what does all this mean? The Industry 4.0 is upon us, and the oil and gas industry has an opportunity to adopt new technologies that could make the massive data glut work better for decision-making. Mackinnon describes a future where the supply chain will be digitized and will allow for the tracking and tracing the lifecycle of many things, including a subsea Xmas tree.

There is a whole open world of possibilities due to digital technologies, and you can read more about them in this issue's Quarterly Automation Review. **OE**

OE

PUBLISHING & MARKETING

Chairman/Publisher

Shaun Wymes
swymes@atcomedia.com

EDITORIAL

Editor/Associate Publisher

Audrey Leon
aleon@atcomedia.com

European Editor

Elaine Maslin
emaslin@atcomedia.com

Senior Editor

Karen Boman
kboman@atcomedia.com

Asia Pacific Editor

Audrey Raj
araj@atcomedia.com

Web Editor

Melissa Sustaita
msustaita@atcomedia.com

Contributor

Steve Hamlen

ART AND PRODUCTION

Bonnie James
Verzell James

CONFERENCES & EVENTS

Conference Director

Jennifer Granda
jgranda@atcomedia.com

PRINT

Quad Graphics, West Allis, Wisconsin, USA

SUBSCRIPTIONS

To subscribe or update details, email: subservices@atcomedia.com or visit oedigital.com. Rates \$99/year for non-qualified requests. \$10 for individual copy.

NOTICE: Print magazine delivery for free qualified subscriptions restricted to North America & Western Europe. All other regions will be receive digital format – email address is required

CIRCULATION

Inquiries about back issues or delivery problems should be directed to subservices@atcomedia.com

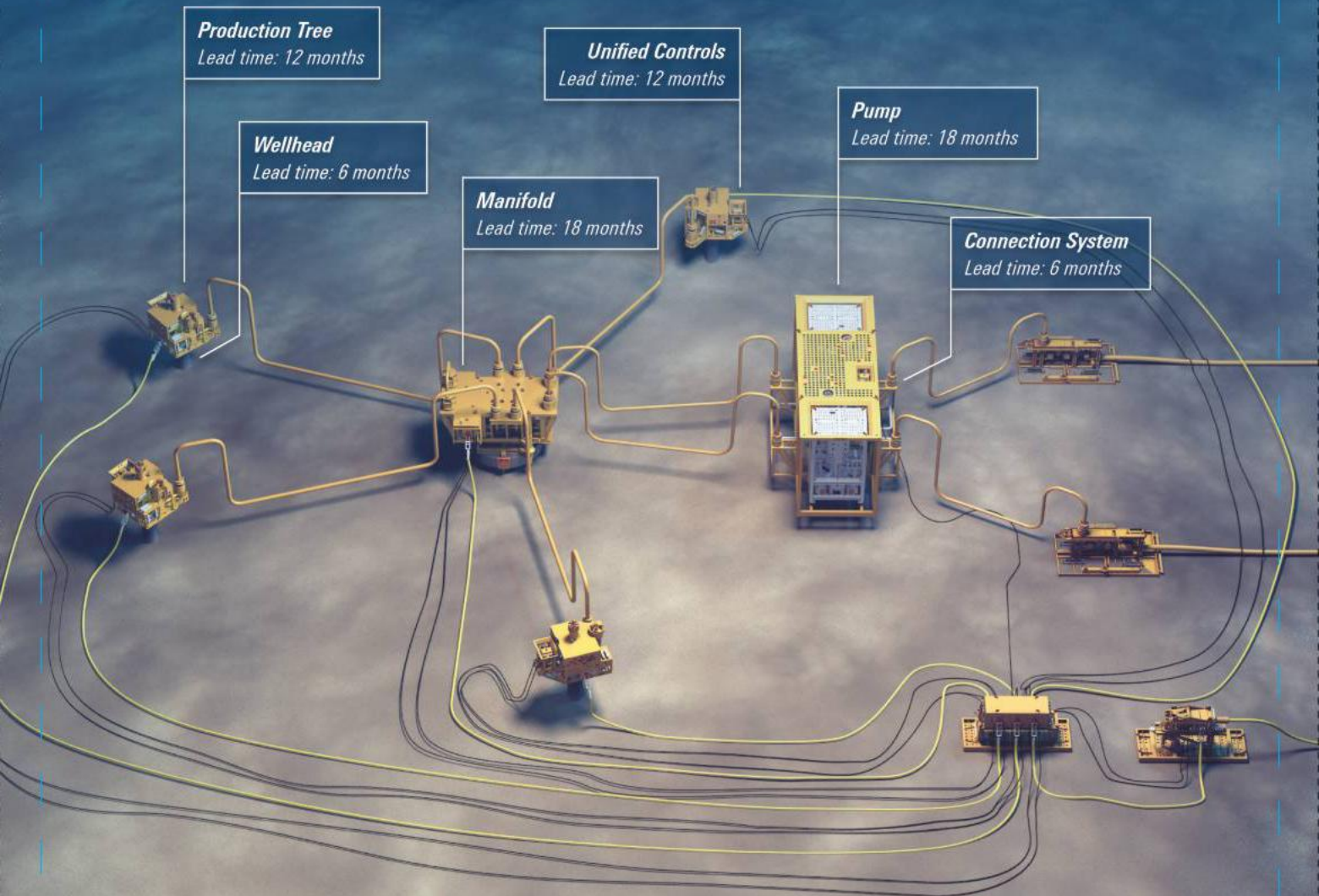
REPRINTS

Print and electronic reprints are available for an upcoming conference or for use as a marketing tool. Reprinted on quality stock with advertisements removed, our minimum order is a quantity of 100. For more information, call Jill Kaletha at Foster Printing: +1-219-878-6068 or email: JillK@fosterprinting.com

DIGITAL

www.oedigital.com
Facebook: fb.me/ReadOEmag
Twitter: twitter.com/OEdigital
Linked in: www.linkedin.com/groups/4412993

Capital-Efficient Subsea Solutions



Redefine economic viability with a new approach to subsea production.

The OneSubsea portfolio of standardized designs supports streamlined processes, documentation, and manufacturing to deliver integrated production systems that enable achieving first oil as soon as 24 months after contract award.

Customized to your field architecture, these capital-efficient solutions help you maximize recovery from new fields to transform deepwater economics across the life of the asset.

Find out more at
onesubsea.slb.com/standardization



Global E&P Briefs

A Flemish Pass comes up dry

Statoil and partner Husky Energy failed to discover hydrocarbons in the Flemish Pass Basin, offshore Newfoundland. The two-well exploration drilling program with the Seadrill *West Aquarius*, some 500km east of St. John's, Newfoundland and Labrador, was within tieback vicinity to Statoil's 2013 Bay du Nord discovery.

"These results are disappointing, as we had hoped to add additional optionality to the near-field area at Bay du Nord," says Trond Jacobsen, vice president, Exploration, Statoil Canada. "We will now take the time needed to evaluate the results before firming up any plans for additional drilling near-field to Bay du Nord."

B Shell hits at Whale

Royal Dutch Shell found hydrocarbons in the initial Whale exploration well in the deepwater Gulf of Mexico. The well was drilled with the *Noble Globetrotter I* in Alaminos Canyon Block 772, approximately 322km (200mi) offshore southeast Texas. Shell and co-owner Chevron will need to conduct further evaluation to determine the size and potential amount of barrels of oil recoverable. Shell owns 60% interest in the well; Chevron holds 40%.

C Exxon eyes Suriname

ExxonMobil signed a production sharing contract offshore Suriname for deepwater Block 59, which spans 4430sq mi (2.8 million acres), and is about 350km (190mi), in 2000-3600m water depth, off Suriname's capital city, Paramaribo.

The block shares a maritime border with Guyana, where ExxonMobil operates three offshore blocks, including the giant Liza field. Following contract signing, the Exxon-led joint venture is preparing to begin exploration activities, including acquisition and analysis of seismic data.

D Statoil ups Carcara stake

Statoil has added more stake offshore Brazil, following a US\$379 million deal with

E Talos, Eni score 1 billion+ boe finds

Talos Energy and partners Sierra Oil and Gas, and Premier Oil have made an estimated 1.4-2 billion bbl, "world-class" light oil discovery at the Zama-1 exploration well, offshore Mexico. The find has been described as one of the 20 largest shallow water finds in the past 20 years and the first private sector oil discovery in the country. Zama-1 was drilled in 166m water depth, about 37mi (60km) off Tabasco, in the Block 7 in the Sureste Basin, using the *EnSCO 8503* semisubmersible.

Also in the Bay of Campeche, Eni has increased its estimate of resources in place at the Amoca field offshore Mexico to 1 billion boe, and has opted to accelerate its development plan.



Queiroz Galvão Exploração e Produção (QGEP) to acquire QGEP's 10% interest in the BM-S-8 license in the Santos basin. The additional 10% equity will increase Statoil's operated interest in the license from 66% to 76%.

BM-S-8 includes a substantial part of the Carcará discovery comprising high-quality oil of around 30° API and with associated gas in a thick reservoir with excellent



properties. Statoil estimates the recoverable volumes within the BM-S-8 license to be in the range of 700 MMboe to 1.3 billion boe.

F Dussafu FID agreed

BW Offshore and Panoro Energy have agreed on a final investment decision for the Dussafu project offshore Gabon, with first oil set for 2018. The proposed plan

consists of two initial horizontal wells at Tortue in the Gamba and Dentale reservoirs. An appraisal sidetrack well will also be drilled in the northwest of the Tortue field. The two production wells will be tied back to a leased floating production, storage and offloading vessel via subsea trees and flowlines.

G ONGC enters Namibia

India's ONGC Videsh will acquire a 30% stake in a license offshore Namibia from Tullow Oil, marking its entry into the country. Namibia Petroleum Exploration License 0037 covers Blocks 2112A, 2012B and 2113B. Tullow currently holds 65%



interest (operator), alongside Pancontinental Namibia, with 30% interest, and Paragon Oil and Gas, with 5% interest.

H Shell exits Corrib

Shell will exit upstream operations in Ireland, selling its Corrib gas field stake to a Canadian pension fund for up to US\$1.23 billion. Under the agreement, Shell affiliate Shell Overseas Holdings will sell its shares in Shell E&P Ireland, which holds 45% interest in the Corrib gas venture, to CPP Investment Board Europe SARL. The sale is part of Shell's strategy to reshape itself through a three-year, US\$30 billion divestment program. Corrib started production in late

2015. Shell's share of Corrib represented 27,000 boe/d in 2016.

I Aker BP targets PDO trio

Aker BP is preparing to submit plans for development and operation (PDO) for three of its operated projects:

Valhall West Flank, Snadd and Storklakken.

Aker BP will develop its Valhall Flank West project out of the Tor formation at the western flank of the Valhall field in the southern area of the Norwegian North Sea. The concept is a normally unmanned installation

with 12 well slots, tied back to the Valhall Field Center. Snadd is planned as a tie-in to the Skarv FPSO in a phased development. Phase 1 is planned with three subsea wells tied in to the Skarv A template, with first gas scheduled for 2020.

Storklakken will be a standalone development with a single multilateral production well tied back to the Vilje field, utilizing existing pipeline from Vilje to the *Alvheim* FPSO. First oil is set for 2020.

K Total to drill off Bulgaria

Total will drill one well offshore Bulgaria, beginning next month (September) with the *Noble Globetrotter II* drillship. In Bulgaria, Total has an interest in the Khan Asparuh license in the Black Sea, about 120km from the coast in -2000m water depth. The French supermajor made a deepwater oil discovery in October 2016 in the license.

L Shah Deniz II inches closer

BP has installed the topsides for the Shah Deniz Stage 2 quarters and utilities platform in the Caspian Sea, in early July, as the project inches closer to first gas in 2018.

BP says that the platform's

J Gina Krog online

Statoil started production on the US\$3.8 billion Gina Krog development in the North Sea on 30 June. The Gina Krog platform is tied into Sleipner A and uses both processing capacity on the platform and existing pipelines for sending the gas to the market in Europe. Oil from the field is transported by a floating storage and offloading unit. The recoverable reserves for Gina Krog are 16.8 MMscm of oil, 11.8 Bcm of gas and 3.2 million tonne of NGL. Gina Krog is 30km northwest of Sleipner and 230km offshore Stavanger, Norway. Statoil operates Gina Krog

with 58.7% interest. Its partners are Total E&P Norge (15%), KUFPEC Norway (15%), PGNiG Upstream Norway (8%) and Aker BP (3.3%).



Global E&P Briefs

first residents – the platform manager and the initial hook-up and commissioning (HUC) team – were transferred to the platform to begin HUC operations.

BP operates Shah Deniz on behalf of the Shah Deniz joint venture with 28.8% interest. Its partners include: TPAO (19%), Petronas (15.5%), AzSD (10%), Lukoil (10%), NICO (10%) and SGC Upstream (6.7%).

M Total, CNPC to develop South Pars

Iran signed a new contract to develop its South Pars gas field with France's Total and China National Petroleum Corp.

Total is expected to invest up to US\$5 billion to produce

gas for the Iranian market from 2021, under the 20-year deal, which is also the first Iranian Petroleum Contract (IPC) signed in Iran.

The first development phase will consist of 30 wells and two wellhead platforms connected to existing onshore treatment facilities by two subsea pipelines.

At a later stage, once required by reservoir conditions, a second phase will be launched involving the construction of offshore compression facilities, a first on the South Pars field and potentially the largest in the Gulf region.

Total says the project will have a production capacity of 2 Bcf/d or 400,000 boe/d, including condensate.

N Total, QP take Al-Shaheen reins

France's Total and Qatar Petroleum (QP) have taken over operatorship from Maersk Oil of the giant Al-Shaheen oil field offshore Qatar for a term of 25 years.

Al-Shaheen is 80km north of Ras Laffan in the Persian Gulf, and produces 300,000 b/d. The field began production in 1994. The first phase of Al-Shaheen's development plan consists of drilling 56 new wells, which is set to begin this summer with the mobilization of the first two rigs. A third rig will be added at the beginning 2018.

This first phase will be followed by two others over the next five years to further develop the field, Total says.

O ConocoPhillips submits Barossa plan

ConocoPhillips has submitted its development proposal for the gas and condensate Barossa field in the Timor Sea, to Australian authorities. The Barossa Area Development is expected to be a floating production, storage and offloading vessel based project in the Bonaparte Basin, in 130-350m water depth, about 300km north of Darwin. The expected LNG and condensate production rates are about 3.7 MTPA and 1.5 MMbo a year, respectively. The life of the project is expected to be about 20 years from first gas, which is targeted for 2023. A final investment decision is targeted for 2019.

Contracts

Wood Group wins White Rose gig

Wood Group will complete detailed engineering for Husky Energy's White Rose topsides for the concrete gravity-based wellhead platform, which will tieback to the *SeaRose* floating production vessel offshore eastern Canada. The project includes procurement services and engineering design work. First oil is scheduled for 2022.

SOFEC to supply Coral South

A TechnipFMC and JCG joint venture has awarded SOFEC a supply contract for the turret mooring system meant for Eni's Coral South Floating LNG facility.

Under the contract, SOFEC will conduct engineering, procurement and construction work related to the internal turret mooring system and its ancillary components, and

assist in turret integration and offshore commissioning activities in Mozambique.

Ocean Installer wins Statoil work

Statoil has awarded Ocean Installer a contract for subsea installations and tie-in operations on Johan Sverdrup, Utgard, and Bauge.

The award is part of Statoil's Marine Wave 2 program and means that Ocean Installer will continue playing a key role in the Johan Sverdrup subsea works, initiated under the Marine Wave 1 umbrella. The complete work scope encompasses umbilical installation at Johan Sverdrup, Bauge and Utgard, as well as spools, cover, tie-in and manifold installation at Utgard.

Offshore operations will take place in 2019 and Ocean Installer will utilize a combination of the construction support

vessels *Normand Vision* and *Normand Reach*. Project management and engineering will be based at Ocean Installer's headquarters in Stavanger and start with immediate effect.

OneSubsea wins EPCIC Otter deal

TAQA has awarded OneSubsea an EPCIC contract for a subsea multiphase boosting system for the Otter field in the UK North Sea. OneSubsea and its subsea integration alliance partner, Subsea 7, will supply and install a subsea multiphase boosting system including topside and subsea controls, as well as associated life-of-field services. The project will result in a 30km subsea tieback to the TAQA-operated North Cormorant platform. This will be the longest subsea multiphase boosting tieback in the UK North Sea.

Fugro to provide IRM services for Petrobras

Fugro has won a two-year contract from Petrobras to provide comprehensive inspection,

repair and maintenance (IRM) and pipeline inspection services in Brazil.

The new award follows Fugro's successful completion of an initial 12-month contract for the oil major, after taking delivery of the newbuild vessel *Fugro Aquarius*.

Built specifically for the Brazilian market by Wilson Sons shipyard in São Paulo, with local content of more than 60%, *Fugro Aquarius* is an 83m, DP-2 ROV support vessel. With a deck area of 520sq m, the vessel is permanently equipped with two Fugro-built 150HP 3000m work class ROVs. Operations began in May 2017.

Wood Group inks Culzean job

Wood Group has won a new contract from Maersk Oil to deliver mechanical and management services for the hook-up and commissioning of the Culzean gas condensate field in the UK central North Sea. The three-year contract is effective immediately.



13th Annual **DEEPWATER INTERVENTION FORUM**

THANK YOU!



WE LOOK FORWARD TO ANOTHER SUCCESSFUL YEAR

AUGUST 7-9, 2018 Galveston Convention Center
Galveston, Texas

To our **Advisory Board**, for your commitment, leadership and dedication.
To our **Speakers**, for your contribution to the agenda and participation.
To our **Sponsors, Exhibitors and Delegates** for your continued support.

We couldn't have done it without you all!

Ray Stawaisz



Colin Nicol



Matt Weinstock



Mike Niewald



Anish Simon



Tom Meyer



Barney Paternostro



Colin Johnston



Ronnie Northcutt



Brian Skeels



David Carr



J.J. Duenas



Rob Hill



Daniel Vela



Ryan Schmidt



John Felarca



Matt Lewis



David Brown



Hakan Eser



Alex Lawler



Paul Barbre



Heath Jones



James Wells



Jason E. Dahlem



For registration, conference, exhibit and sponsor information visit:

deepwaterintervention.com

Hosted By:



Sponsored By:



Organized By:



Produced By:



The nutcracker

Marginal fields don't always turn out to be that marginal, especially when you have efficient topsides and an ability to find hidden pockets in your reservoir. Elaine Maslin reports.

Centrica's Chestnut field has been something of a fighter. Labeled stranded by Venture, the field, 200km northeast of Aberdeen, finally made it into production with the UK's first cylindrical floating production, storage and offloading (FPSO) vessel in 2008.

Initially thought to have just three years and 7 MMbbl production life, the field has produced 20 MMbbl. Now, facing the possibility of being shut-in this year, the field is set to produce yet more. A new well, under a US\$45 million (£35 million) investment project, is set to push field life out to 2020, increase production rates from 4000 b/d to 14,000 b/d, and quadruple Chestnut's initial field life estimate.

It's a cracker

"Venture branded [Chestnut] a stranded asset. It's the smallest standalone development in the UK North Sea, and almost definitely in the (wider) North Sea," says Nigel MacLean, Central North Sea manager, Centrica. "We never realized Chestnut would be as large as it is."

"Chestnut is unlike any of our other fields. It's an injectite reservoir, not primary deposition. It was found by accident, as they usually are, when a deeper Forties reservoir was being targeted," says Gemma Campbell, Centrica's development and production manager for the Central and northern North Sea. "Injectite sands come from a sand body deeper down in the sequence, for example a turbidite sandstone. The shale compresses, forcing the sand up through the overburden. Re-depositing the sand in a shallower part of the sequence," Campbell explains.

It is difficult to assess the size of such reservoirs, due to their uncertain nature

and that they're hard to image with seismic. It's also difficult to drill, in terms of finding reservoir, but not difficult to produce from, as "it's pretty much the best reservoir quality you can get, with 34% porosity. It's not really rock. It's sand. If you take a core, it falls apart," she says.

Discovery

Chestnut was discovered in 1986, and drilled in 1987-88, before being brought



online with a pre-drilled water injector, then two production wells, via the Sevan-design *Hummingbird Spirit* FPSO in 2008. The field was developed on the assumption that it contained 7 MMbbl recoverable. There had been a concern about the connectivity of the reservoir, but this was proved unfounded, and with very good water sweep, via an injection well, maintaining initial pressure.

The Sevan floater fitted Chestnut because it was a new technology – a cylindrical FPSO vessel – which meant then-operator Venture was able to get preferential rates (which have since been updated to reflect market conditions), MacLean says. The idea for *Hummingbird Spirit* was for it to go around and work on small pools with this small production unit, much like its namesake bird.

MacLean was working for Bluewater at the time and says that many were bemused by the new cylindrical concept. MacLean, however, liked it and managed to get a job on Chestnut.

The 200,000 bbl capacity Sevan300 *Hummingbird Spirit* was Sevan's second cylindrical unit and the first one in the North Sea. Sevan's first cylindrical FPSO was the *Sevan Piranema*, now *Piranema Spirit* and operated by Teekay Petrojarl, launched in 2007, offshore Brazil, in 1000m water depth. Both were built at Yantai Raffles/Keppel Verlome.

Sevan's third unit was the Sevan300 *Sevan Voyageur*, used by Premier Oil on the Shelley field, from 2009-2010, then on the Huntington field, since 2013, for EON, where it still resides. A Sevan1000 was then used to develop the Eni-operated Goliat field and a Sevan400, built at Cosco, will be used for the



Hummingbird Spirit in harbor.

Dana-operated Western Isles development, due online this year. Sevan has also built cylindrical drilling units.

The *Hummingbird Spirit* was designed to last 20 years and built with aluminum instead of steel, glass-reinforced plastic (GRP), instead of steel, and high-quality cranes, and turbines, MacLean says. Even the topside surface was thicker, to reduce issues with wear.

At Chestnut, the *Hummingbird Spirit* is moored in 120m water depth, using nylon and chain, with suction piles, in three sets of four mooring lines. A handysize tanker is used for offloading.

The *Hummingbird Spirit's* 90% uptime and continued reservoir performance has helped the unit outlast its planned stay, albeit to the detriment of another field. In 2012, Antrim Energy – which dissolved this year – signed a deal to use the unit on the Fyne field from 2016. But, contract renewals with vessel owner/operator Teekay in 2013 (when Chestnut produced 13 MMbbl, reserves were estimated at 18 MMbbl), and again in 2016, meant the unit stayed put. The Fyne license lapsed in 2016.

Renewal

In Q1 2017, with production sitting at 4000 b/d, Centrica had a decision to make: to cease production by the end of the year or reinvest. The firm reprocessed seismic data on the field, using production well data. The result was

the discovery of an area the firm thinks has yet to be swept. MacLean says that a rather different question emerged: “Should we completely redevelop, have a new export route, or new wells?” Although with hindsight, Chestnut would have been a bigger development in the first place, given the economic backdrop, the decision was made to keep the FPSO and drill a new well.

The new development well will be drilled using Paragon Offshore’s *MSS1* semisubmersible, built at the Barreras shipyard in Spain in 1979. It will be the rig’s fourth well on Chestnut, having drilled the second production well, the water injection well and a sidetrack water injector. The unit, which had been stacked since coming off contract with Nexen late-2016, will be drilling from early August to mid-October.

The new, long horizontal well, which will reach about 9200ft measured depth, or about 6850ft true vertical depth subsea, is in an area Centrica believes hasn’t been swept by the current well stock: comprising a vertical well and a long horizontal well. The new well will be drilled using Schlumberger’s Geosphere technology, which has been used on other injectite wells, but is relatively new.

The tool reads 60ft into the formation, which means as Centrica drills it can see the formation around it, with

the data loaded into Petrel and able to give an almost real-time display on top of existing seismic data, to help target shallow sands.

“We are keeping it simple, the difficulty is finding sand,” Campbell says. “Injectites are difficult to predict. You can build a geological model, but every model has risk. Schlumberger’s tool will help mitigate that risk. If we do miss the sand, we can sidetrack. It’s quite exciting technology.”

For the new well, a subsea tree, which was already built (but, surplus to another operator) has been procured and its control system changed out for an Aker Solutions system, to match the existing control systems in the field. The existing wells are in a daisy chain, so the new well will integrate into existing infrastructure.

The one downside is that the flow rate will back out production from the other wells, MacLean says. But, 10,000 b/d of dry oil is preferable to 10,000 bbl of fluid where 80% is water, he adds.

With the additional production expected, Centrica extended its contract with Teekay for the *Hummingbird Spirit* out to 2020. It is planning some work on the FPSO, including the replacement of eight of the 12 mooring lines. Centrica plans to do another four later this year. To extend equipment use, the firm has been using Viper Subsea’s, an Oceaneering company, umbilical support technology. This is used to mitigate degradation in electric supply cores in the field’s umbilicals, i.e. keeping them open, instead of having to replace them.

There’s also the potential for more water injection capacity to be added, and a debottlenecking study will run from this year into next year. But, a decision will not be made until the third well has started producing, MacLean says. Centrica is also assessing the used of drag resistant agent (DRA) in its production pipelines to aid injectivity.

Life after Chestnut

With its learnings from Chestnut and the knowledge of the *Hummingbird*, Centrica is considering its next steps. “The key might be, in the future, to re-develop another location, maybe something near to Chestnut,” MacLean says. “We have organic opportunity for this type of solution and *Hummingbird Spirit* would be a great tool for us to use.” *OE* looks forward to telling you more. **OE**

In-Depth



Juan Carlos Zepeda, president commissioner, CNH, speaks at the Pemex Farm-out day event. Photos from Pemex Flickr.

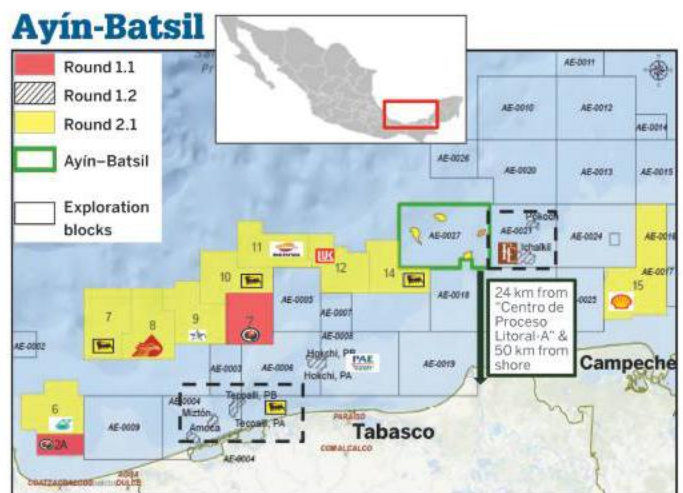
The fruits of Mexico's labor

Mexico's energy reform efforts have been realized with recent successes from prior bid rounds. Now, Mexican national Pemex has added a steady schedule of farm-outs in shallow and deep water. Audrey Leon surveys the plays on the agenda.

Mexico has worked tirelessly over the last three years to bring its energy reform to fruition, and the last piece of the puzzle was its own national oil firm, Pemex. In December 2016, Pemex finally found its first joint venture partner (BHP Billiton) for the Trion field, in the deepwater Gulf of Mexico, through a competitive bid process. Now, Pemex is ready to do the dance again.

At its first-ever farm-out day in Houston, CEO José Antonio González Anaya reiterated his company's and the Mexican government's commitment to making the energy reform work. And one of those ways is through seeking more partnerships to develop existing resources, on- and offshore.

"We have a historic opportunity to use all the instruments and flexibility available from the energy reform, he told the audience. "Before, [only we] were able to explore and produce and commercialize anything to do with oil. Now anyone can



touch it, foreign and domestic. Now Pemex can partner with anyone – foreign and domestic – to do this.”

At the farm-out day event, Mexican officials announced four new farm-out opportunities: two onshore Tabasco, one in shallow water – Ayin-Batsil, in the Campeche Basin, and one in deepwater – Nobilis-Maximino in the Perdido Basin, adjacent to Trion. Mexican regulator, the National Hydrocarbons Commission (CNH), will again run the bidding process for the farm-outs, as they did in 2016 when determining a joint venture partner for Trion.

“Our role is to run the bidding process, and to ensure that this is a transparent and fully accountable process,” said Juan Carlos Zepeda, CNH president commissioner, at the Pemex farm-out day in Houston.

Ayin-Batsil

Pemex E&P Director General Gustavo Hernandez was on hand to add more detail on the plays added to the farm-out agenda. The Ayin-Batsil area, he says, offers 359 MMboe of undeveloped 3P reserves, mostly heavy oil, in shallow water, with multiple fields to develop.

“It’s an important field,” González Anaya said. “There’s a lot of oil.

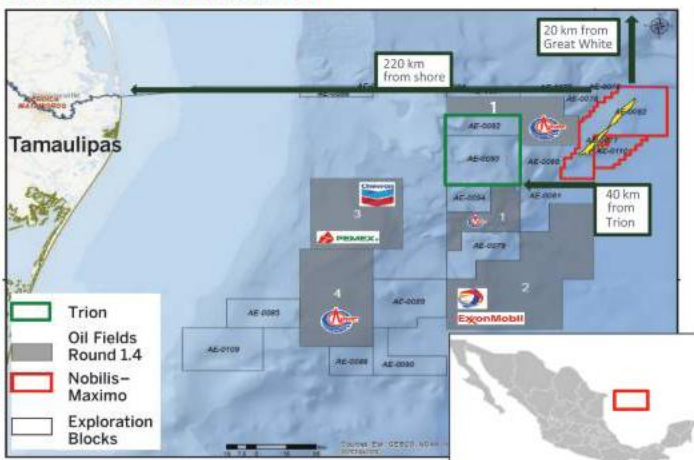
“Why didn’t do this field [Ayin-Batsil] on our own,” González Anaya asked. “The water is a bit deeper than we are used to. We are an expert in shallow water, but most of our fields are in 80-120m water depth. That’s why we left it there to be done.”

The total area of the complex is 1096sq km in water depths ranging 150-170m, deeper than the shallow water fields in which Pemex normally operates, he said.

González Anaya added that there is infrastructure nearby – the Litoral-A central processing platform, which is 24km from Ayin-Batsil and 50km from shore – to plug into production and take production onshore. “You still have to build a 50km pipeline from where we are to the existing infrastructure Pemex has. But the infrastructure is there. That’s why we waited,” he said.

Ayin was discovered in 1991. Initial production rates from Ayin-Batsil, Hernandez said, were between 1200 b/d and .32 MMcf/d (Batsil) and 8200 b/d and .33 MMcf/d (Ayin). There

Nobilis-Maximino



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 | 2014 | 2015 | 2016 | 2017 |
|------------------------------|------------|-----------|-----------|-----------|
| Shallow (<500m) | 76 | 57 | 35 | 13 |
| Deep (500-1500m) | 30 | 18 | 12 | 1 |
| Ultradeep (>1500m) | 12 | 11 | 8 | 4 |
| Total | 118 | 86 | 55 | 18 |
| January 2017 date comparison | 127 | 114 | 72 | - |
| | -98 | -28 | -17 | 18 |

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 2017-21

| Water depth | Field numbers | Liquid reserves (mmbbl) | Gas reserves (bcf) |
|----------------------|---------------|-------------------------|--------------------|
| Brazil | | | |
| Shallow | 14 | 350 | 2649 |
| Deep | 9 | 820 | 1295 |
| Ultradeep | 36 | 11,250 | 13,256 |
| United States | | | |
| Shallow | 4 | 27 | 71 |
| Deep | 20 | 780 | 1277 |
| Ultradeep | 17 | 2089 | 1780 |

West Africa

| | | | |
|---------------------------|------------------|------------------------|------------------------|
| Shallow | 110 | 3524 | 16314 |
| Deep | 24 | 2075 | 3430 |
| Ultradeep | 12 | 1611 | 2398 |
| Total (last month) | 232 (236) | 22,176 (22,240) | 39,821 (39,611) |

Greenfield reserves

2017-21

| Water depth | Field numbers | Liquid reserves (mmbbl) | Gas reserves (bcf) |
|------------------------|---------------|-------------------------|--------------------|
| Shallow (last month) | 877 (887) | 33,163 (33,381) | 320,829 (329,080) |
| Deep (last month) | 119 (121) | 5208 (5208) | 76,071 (78,071) |
| Ultradeep (last month) | 76 (76) | 16,155 (16,155) | 47,097 (47,097) |
| Total | 1072 | 54,526 | 443,997 |

Global offshore reserves (mmbbl) onstream by water depth

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|------------------------|----------------------|-----------------------|-----------------------|----------------------|-----------------------|-----------------------|-----------------------|
| Shallow (last month) | 21,290.9 (21,275.90) | 32,117.92 (32,136.74) | 21,897.92 (24,737.17) | 20,138.7 (17,328.56) | 12,010.12 (12,834.19) | 16,128.42 (15,683.92) | 19,525.56 (20,790.44) |
| Deep (last month) | 960.47 (959.22) | 4215.67 (4215.67) | 1210.15 (1401.45) | 2921.58 (2730.28) | 2382.1 (2628.92) | 4392.71 (4569.01) | 7711.15 (7640.63) |
| Ultradeep (last month) | 2000.69 (2015.69) | 3100.14 (3100.14) | 1653.94 (1653.94) | 4090.4 (4090.40) | 3847.95 (3847.95) | 9459.94 (9459.94) | 5406.84 (5406.84) |
| Total | 24,252.06 | 39,433.73 | 24,762.01 | 27,150.68 | 18,240.17 | 29,981.07 | 32,643.55 |

Source: InfieldRigs

05 July 2017

Pipelines

(operational and 2017 onwards)

| | (km) | (last month) |
|-----------------------|---------------|-----------------|
| <8in. | | |
| Operational/installed | 41,040 | (41,535) |
| Planned/possible | 23,302 | (22,187) |
| Total | 64,341 | (63,722) |

8-16in.

| | | |
|-----------------------|----------------|------------------|
| Operational/installed | 81,476 | (82,300) |
| Planned/possible | 49,065 | (46,890) |
| Total | 130,541 | (129,191) |

>16in.

| | | |
|-----------------------|----------------|------------------|
| Operational/installed | 94,263 | (96,168) |
| Planned/possible | 44,991 | (46,365) |
| Total | 139,254 | (142,533) |

Production systems worldwide

(operational and 2017 onwards)

| | (last month) |
|-------------------------|------------------|
| Floaters | |
| Operational | 298 (308) |
| Construction/Conversion | 45 (44) |
| Planned/possible | 295 (287) |
| Total | 638 (639) |

Fixed platforms

| | |
|-------------------------|------------------------|
| Operational | 9,105 (9041) |
| Construction/Conversion | 72 (90) |
| Planned/possible | 1,372 (1304) |
| Total | 10,549 (10,435) |

Subsea wells

| | |
|------------------|------------------------|
| Operational | 4,879 (5148) |
| Develop | 374 (342) |
| Planned/possible | 6,425 (6330) |
| Total | 11,678 (11,820) |

Rig stats

Worldwide

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|--------------|------------|------------|------------|-------------|
| Drillship | 86 | 58 | 28 | 67% |
| Jackup | 395 | 233 | 162 | 58% |
| Semisub | 109 | 63 | 46 | 57% |
| Tenders | 28 | 15 | 13 | 53% |
| Total | 618 | 369 | 249 | 59% |

North America

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|--------------|------------|------------|-----------|-------------|
| Drillship | 28 | 19 | 9 | 67% |
| Jackup | 24 | 6 | 18 | 25% |
| Semisub | 7 | 5 | 2 | 71% |
| Tenders | N/A | N/A | N/A | N/A |
| Total | 59 | 30 | 29 | 50% |

Asia Pacific

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|--------------|------------|------------|-----------|-------------|
| Drillship | 11 | 5 | 6 | 45% |
| Jackup | 114 | 72 | 42 | 63% |
| Semisub | 30 | 13 | 17 | 43% |
| Tenders | 21 | 12 | 9 | 57% |
| Total | 176 | 102 | 74 | 57% |

Latin America

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|--------------|------------|------------|-----------|-------------|
| Drillship | 21 | 17 | 4 | 80% |
| Jackup | 50 | 27 | 23 | 54% |
| Semisub | 23 | 16 | 7 | 69% |
| Tenders | 2 | 1 | 1 | 50% |
| Total | 96 | 61 | 35 | 63% |

Northwest European Continental Shelf

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|--------------|------------|------------|-----------|-------------|
| Drillship | 1 | 1 | 0 | 100% |
| Jackup | 49 | 28 | 21 | 57% |
| Semisub | 37 | 22 | 15 | 59% |
| Tenders | N/A | N/A | N/A | N/A |
| Total | 87 | 51 | 36 | 58% |

Middle East & Caspian Sea

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|--------------|------------|------------|-----------|-------------|
| Drillship | 1 | 1 | 0 | 100% |
| Jackup | 119 | 82 | 37 | 68% |
| Semisub | 3 | 3 | 0 | 100% |
| Tenders | N/A | N/A | N/A | N/A |
| Total | 123 | 86 | 37 | 69% |

Sub-Saharan Africa

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|--------------|------------|------------|-----------|-------------|
| Drillship | 18 | 13 | 5 | 72% |
| Jackup | 15 | 8 | 7 | 53% |
| Semisub | 3 | 1 | 2 | 33% |
| Tenders | 5 | 2 | 3 | 40% |
| Total | 41 | 24 | 17 | 58% |

Eastern Europe

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|--------------|------------|------------|-----------|-------------|
| Drillship | N/A | N/A | N/A | N/A |
| Jackup | 1 | 0 | 1 | 0% |
| Semisub | N/A | N/A | N/A | N/A |
| Tenders | N/A | N/A | N/A | N/A |
| Total | 1 | 0 | 1 | 0% |

Source: InfieldRigs 10 July 2017

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

were 10 exploration and appraisal wells drilled, from 1988 to 2015, that intended to characterize the block, Area E-0027-M, he added. There are two other fields that comprise the Ayin-Batsil area, including Makech and Alux.

Hernandez said that Ayin is the most relevant field with 60% of the total 3P reserves. Batsil is second in size with 20% of the 3P reserves. Alux and Makech could potentially be developed as subsea tiebacks to Ayin and Batsil, he said. The nearby Litoral-A facility has a storage capacity of 200,000 b/d and 600 MMcf/d, which, as of 2016, had a 75% utilization rate, Hernandez said. Also in the same area, there are two Dos Bocas gas and oil pipelines with 600 MMcf/d capacity, at 80% utilization rate, and a 200,000 b/d capacity with a 10% utilization rate, respectively.

There are also three additional exploratory opportunities, which could offer 224 MMboe of prospective resources (average, unrisks) – Ichal, Ken, and Chelpul – all which have 25-26° API oil.

Nobilis-Maximino

Another opportunity, this time in deepwater, is Nobilis-Maximino, which sits in 3000m water depth in the Perdido Fold Basin, adjacent to previous discoveries Trion and Great White. A total of nine wells have been drilled on the Nobilis-Maximino.

When Maximino was drilled in 2013, Pemex then-described the find as the “crown jewel.” The Maximino-1 probe was one of Pemex’s deepest wells, at 9515ft water depth. Nobilis was discovered later in 2016. The Nobilis-1 exploration well, on the eastern flank of the Maximino field, is 220km off the coast of Tamaulipas at 3000m water depth. Pemex said both exploration wells (Nobilis-1 and Maximino-1) proved light oil of 40° API.

According to Pemex, the main reservoir in Nobilis is in the lower Eocene Wilcox. The Nobilis-101 exploration well, drilled in 2017, tested a separate structural closure to the northeast in the Wilcox. Pemex said it discovered oil in the upper Eocene and Oligocene reservoirs.

The 1524sq km Nobilis-Maximino area has 3P reserves of 502 MMboe of light oil, and estimated production of 300,000 b/d. Nobilis-Maximino is 26km from Great White, and 40km from Trion.

In addition to Nobilis and Maximino, there are two other discoveries: Supremus and Mirus. Pemex said a further 627 MMboe could be had in prospective, unrisks resources in three additional exploration prospects – Chachiquin-1, Maximino-1001, and Maximino-3001.

Maximino, which Pemex called the most second important of the block, has 41 API light oil, with 187 MMboe in 3P reserves. Nobilis is 42 API light oil with 315 MMboe in 3P reserves. Supremus, the only find with heavy oil (28 API), has 98 MMboe contingent resources in the Oligocene. Mirus has 41 API light oil with 73 MMboe contingent resources. Pemex believes that Supremus and Mirus could be developed as subsea tiebacks to Nobilis-Maximino.

The farm-out for Nobilis-Maximino is expected to run in parallel with the next deepwater round 2.4, in January 2018, Pemex said.

A future so bright

SENER’s Aldo Flores-Quiroga highlighted the success Mexico has already enjoyed since the reform passed. “We have done



Pemex CEO Jose Antonio González Anaya speaks at the Farm-out Day event in Houston.

Photos from Pemex Flickr.



Left to Right: Aldo Flores-Quiroga, deputy secretary of energy for Hydrocarbons Mexico (SENER); Pemex's González Anaya; Miguel Messmacher Linartas, Secretary for Income, Ministry of Finance (SHCP); and Juan Carlos Zepeda, president commissioner, CNH.

in three years what no other country has in terms of reform," he said. "Today, we have 54 companies working in Mexico's E&P sector."

As a result of the first five bidding cycles, Flores-Quiroga said that Mexico expects US\$57 billion in investment. They have already signed 49 new contracts and have participation from 17 countries.

Flores-Quiroga also mentioned that the new five-year plan will offer 509 exploration and production blocks, and 82 production fields. "The aim is to present these at auctions by 2019," he said. "We will announce six months before the round. We aim to make the process more standardized."

Of the 509 blocks, Flores-Quiroga said 119 are deepwater blocks with prospective resources of 6594 MMboe and an average block size of 1000sq km. The blocks are in three basins, the Salina del Istmo, Cordilleras Mexicanas, and Perdido. The next deepwater rounds will be scheduled for January 2018 (Round 2.4) and October 2018 (Round 3.2), he said.

There are also plenty of shallow water blocks up for grabs. Flores-Quiroga said that there are 112 blocks with prospective resources of 3555 MMboe with an average block size of 400sq km. The shallow water blocks are in three basins – Burgos (near the US/Mexico maritime border), Tampico-Misantla (offshore Veracruz), and Sureste (offshore Tabasco and Campeche, and home to Eni's Amoca and Talos' Zama discoveries).

Historic finds

No doubt Mexico's energy reform efforts will not only be measured in monetary success but in production volumes as well. Two days after Pemex's farm-out day in Houston, Talos Energy announced it made an estimated 1.4-2 billion bbl, "world-class" light oil discovery at the Zama-1 exploration

well, offshore Mexico. Wood Mackenzie called it one of the 20 largest shallow water finds in the past 20 years, and the first for the private sector.

Zama-1 was drilled in 166m water depth, about 37mi (60km) off Tabasco, in the Block 7 in the Sureste Basin, using the *Ensco 8503* semisubmersible.

The well reached an initial shallow target vertical depth of approximately 11,100ft (3383m). Talos said it hit a 1100ft (335m) oil bearing interval, with 558-656ft (170-200m) of net oil pay in Upper Miocene sandstones with no water contact. The firm said initial gross original oil in place estimates for the Zama-1 well range from 1.4-2 billion bbl. Oil samples indicate light oil, with API gravities between 28-30° and some associated gas.

On the same day as Talos' announcement, Italy's Eni said its Amoca field, inside Area 1 in the Sureste Basin, has 1 billion boe of resources in place. Eni said that the Amoca-3 well proved the presence of multiple significant oil levels in the Orca and Cinco Presidentes Formations. Amoca is 1200km west of Ciudad Del Carmen, in the Bay of Campeche in 25m water depth. The Amoca-3 well was drilled to 4330m total depth and encountered 410m of net oil pay (25-27° API), in several high-quality Pliocene reservoir sandstones, of which 300m were found in the deeper sequence of Cinco Presidentes, in various cluster levels of Pliocenic age with good reservoir characteristics.

The total resource base estimate for Area 1 is 1.3 billion bbl of oil in place, according to Eni. The Italian explorer plans to submit an accelerated and phased development plan in 2017 targeting an early production phase with a plateau ranging from 30-50,000 b/d, with the start of operations planned for early 2019. **OE**

Aerial views of the Turritella FPSO while docked at Keppel's yard.
Photos from Shell.



Testing the waters

In advance of OE's 2017 Global FPSO Forum, held in Houston this month, Audrey Leon chats with the forum's board members to learn what is in store for the FPSO sector and discover how digitalization may play a role.

OE: What does the future hold for the floating production/FPSO industry because of the downturn?



Chris Barton, senior vice president, business development – Offshore, Wood Group Mustang: The challenge now is to make deepwater FPSO (floating production, storage and offloading) projects economic. Leaner, less complex designs are the talk of the day. There are a lot of assets out there and operators want to find solutions. As such, operators are considering reutilizing designs and repurposing facilities.

Operators are more willing to look at tiebacks as opposed to standalone developments. Wood Group has developed its "Catalog of Designs" as a means to an end. BP's Mad Dog 2 is a dramatic example of how costs have changed. Estimated at US\$20 billion before the price fall, the project was given the green light at \$9 billion in late 2016, thanks to a significant redesign and negotiating lower prices with suppliers.



David Petruska

David Petruska, segment engineering technical authority - Floating Systems, BP:

In general, floating production/deep-water will be negatively impacted as we remain the high margin barrels these days, but unable to set the price.

We're seeing fewer projects with operators cutting capex and looking to spend where they can get the best rate of return and new production online the quickest.

But, on the positive side, we are seeing that we can get capex cost of such projects in check to meet our economic thresholds.

We will likely see more FLNG and gas handling FPSOs in the future. The next few years will remain tough, but we should see an increase in activity even if oil prices stay about the same as we adjust for the current market conditions. Converted FPSOs could reign (although that has always been the case to some degree) as they allow for lower capex and a significant schedule advantage when executed properly.



Paulo Biasotto, facilities area manager, Petrobras America:

Project development based on floating production/FPSO concepts will continue to face tough competition from onshore projects and other offshore development concepts, e.g. subsea tieback to existing facilities.

However, floating production/FPSO

concepts should still have competitive advantages in some areas based on niche markets characteristics, e.g. proximity to markets, domestic demand and existing infrastructure.



Eric Van Dijk, vice president business development, SBM Offshore:

Obviously, the whole FPSO business has contracted significantly and we now all have to fight for our share of a much smaller pie.

However, there are still significant discoveries that can be developed at competitive cost and these discoveries

often lend themselves for FPSO solutions. FPSOs will play a central role for the foreseeable future both for oil and gas developments.



Blake Moore, independent consultant:

The offshore oil industry is working through a difficult transition to remain economically competitive. With oil prices in the \$40/bbl range and forecasts of \$30/bbl, offshore oil development projects will likely remain challenged. New methods to design, build and operate

offshore floating facilities will need to be developed to dramatically decrease costs if the industry is to recover and remain relevant. The digital transformation we have seen in other industries that have resulted in dramatic changes in the cost structure is a clear opportunity for the offshore industry.

As with any transformation, the industry needs to have a clear driver and companies will need to behave in a much more collaborative way to achieve meaningful change in the cost structure. We have the driver in low oil prices that may

exist for the next decade, but we have yet to see a push to collaborate between companies to drive down prices.



Bruce Crager, executive vice president, Expert Advisory Group, Endeavor Management:

The floating production/FPSO market has been negatively impacted by three events. First, the significant drop and ongoing low oil price, which has slowed new development. Second, there are more FPSOs available today and

coming off contract in the next year than ever before.

It is likely this number will reach 30 out of a total fleet of about 180 vessels. Some of these have already been scrapped and others are unlikely to be competitive, but there are still plenty of FPSOs available. These range from very small storage and/or processing capacity to very large capabilities, so not all available FPSOs will be candidates for any new project.

In addition, there are usually changes to be made when relocating an FPSO, such as process modifications, mooring system changes and riser/umbilical connections. Therefore, many of these existing vessels are not better solutions than a newbuild or new conversion, particularly for a long-life field.

The third event is the significant slow-down in FPSO demand for Brazil. This one region houses more FPSOs than any other area in the world and Petrobras has more FPSOs working than any other company. The combination of low oil price, the "car wash" scandal and changes in Brazilian laws and politics scene has slowed a number of possible projects.

In summary, the FPSO market will remain slow in the next one to two years, until more units are needed for new developments. In the longer term, there will be an ongoing need for FPSOs and floating production systems to develop deepwater fields, as well as those which are marginal or remote.

OE: There is plenty of buzz in the industry surrounding digitalization. How do you see this being applied in the floating production/FPSO industry? And what are the barriers to implementation?

Barton: The rapid progress of digital technology, such as big data and analytics, sensors, and control systems offers FPSO operators the chance to automate high-cost, dangerous, or error-prone tasks. Automation can significantly improve their bottom line.

There are many ways in which automating FPSO maintenance can improve production efficiency. For example, radio-frequency-identification (RFID) tagging of equipment, along with the use of other sensors, can help track activity. Tracking, in turn, enables applications that can monitor equipment condition and support predictive maintenance and automated operations shutdowns. These applications minimize risk of catastrophic failures and process disruptions, while maximizing equipment reliability and production efficiency.

Operators are already using analytical models to predict failures of critical equipment components. It also includes using simulations to test failure scenarios in platform operations and employing text mining for analysis of unstructured input from engineers and operators. In greenfield automation programs, the digital processes are built in during project development to ready the technology for future advances, taking into account



the 5-7-year life cycle of these projects.

For brownfield programs, companies develop overlays (for example, upgrades of wireless and mobile) that pull the required data flow out of the platform to support analytics units. This approach helps to avoid being

locked in by technology choices from the past.

Petruska: The process is starting downhole and will work its way back to the host. Initially, it will be to allow access to more real-time data to make decisions quicker, but it will then lead to more data mining to find other values to augment operations. For the host, one outcome could be fewer workers needed offshore all the way to de-manning for normal operations. Barriers will be not fully understanding the value statement of the technology and cost.

Biasotto: While the digitalization benefits are indisputable, the offshore, and oil and gas industries face some of the key challenges as the industry in general, e.g. lack of standards and regulation for digitalization, digital security and skills. While in the long-term it will require changes in the way we develop and operate floating production/FPSO facilities, in the short-term such changes will need to demonstrate cost savings are effective, otherwise it will fall behind opex reduction needs.

Van Dijk: One of the main opportunities that I see is digitalization enabling remote operations and, therefore, reduced manning. This will result in cost savings on both the opex and capex side and will also improve safety by having less people offshore. I don't think the industry is ready for a major shift yet, but it is just a matter of time before we will see broader applications.

OE: What are some new advances that may change FPSO design, construction, and/or operations?

Barton: More eWorking will certainly start transforming the industry. Wood Group is developing eXpert and eWorkpack and an example of how this technology contributes to conservation.

Petruska: I would like to see risk-based stability used, in order to improve understanding and to see if that could change the design. I suspect we will see more large gas handling FPSOs. Not an advancement, per se, but we will need to understand their design and process safety aspects vs. what we been doing with oil-dominated FPSO field developments.

Biasotto: Digitalization should support a true lifecycle management for floating production/FPSO facilities from design

through operations, and across projects. Nevertheless, this should be supported by well-defined lessons learned, standardization, and integrity management goals rather than simply data accumulation in order to provide real efficiency gains.

Van Dijk: Database driven design is one development that is getting more and more traction. We are moving from 3D design to 6D or even 7D – if you talk to some operators. I still have some doubts about the cost benefits, because man-hours on projects keep on going up despite all this technology. Another interesting application is wireless commissioning and use of RFID technology. I'm convinced that definitely pays off.

OE: Life Extension of existing floating systems is also another big topic for the industry due to the downturn. What are some of the technologies that you have an eye on that could be used in this space?

Barton: Technology advancements and business changes are leading operators to look at extending the service life of their offshore floating facilities. To go beyond the originally approved design life, the operator requires the approval the regulating bodies.

To obtain this approval, the operator needs to demonstrate that the facility can be maintained fit-for-service for the new life span. Developing a life extension plan requires careful re-evaluation of the design and new extrapolations of expected future damage mechanisms, including fatigue and corrosion.

The challenge is to provide assurance that an old design that has been in an operating environment for a prolonged period will meet future needs and can satisfy demanding new regulations and design criteria.

Life extension challenges are to ensure that safety conditions remain satisfactory and that your extended use is approved by the statutory authorities. This requires a rigorous assessment of the integrity of the asset combined with a detailed analysis of potential hazards that could occur when production volumes are maintained. Advanced analysis methods and smart methodologies are being developed to enhance and streamline the analysis process.

Petruska: Better inspection and surveying equipment. Although this is not a technology, but these are rooted in the engineering, i.e. what are acceptable design limits for a life extension vs. a new design.

Biasotto: Risk based inspection (RBI), Condition based maintenance (CBM), inspection techniques, digital asset platforms for management of inspection and maintenance data.

Van Dijk: Life extensions are naturally messy and it is important to know the physical status that a facility is in. Proper asset integrity management will give us a better idea of the scope of life extension projects. Laser scanning of existing facilities will also play an important role in life extensions. **OE**



OFFSHORE ENERGY 17

EXHIBITION & CONFERENCE
(9), 10 & 11 OCTOBER 2017
AMSTERDAM | THE NETHERLANDS



Register now

Offshore Energy attracts a global audience of more than 12,000 offshore energy industry professionals. The three-day event, features an exhibition where over 650 companies will showcase their products and services. The accompanying conference addresses current and future issues in the offshore industry, covering developments in oil & gas, offshore wind and marine energy. See you in Amsterdam!

CELEBRATING
10
YEARS OECC

WWW.OFFSHORE-ENERGY.BIZ

Supported by



Platinum Sponsors



Weathering the storm

Infield Systems' Catarina Podevyn surveys the FPSO market and discusses recent projects awards.



The John Evans Atta Mills MV25 FPSO, operating at Tullow's TEN project, offshore Ghana.

Photo from MODEC.

The leased floating production, storage and offloading (FPSO) sector is integral to the floating production system (FPS) market. With cost reduction high on the agenda of upstream operators, the option of a leased facility is becoming increasingly attractive for key majors and national oil companies (NOCs), which have traditionally favored owned and operated facilities.

Currently, Wood Mackenzie forecasts for up to 14 projects involving leased platforms to see final investment decision (FID) during 2017 and 2018, driven by Brazil's pre-salt developments, including Sepia, where MODEC is currently the frontrunner for the lease award. A number of projects in emerging and remote areas of production, such as SNE (Sangomar Deep), offshore Senegal, and the Sea Lion development, in the Falklands, are also expected to see FID during the next 18 months, with leased production facilities the favored development option.

In terms of installations, conversions are expected to meet over 80% of leased platform demand over the 2017-2021 timeframe. Tanker conversions are often selected for leased FPSO facilities, and have been historically utilized on small-to-medium sized offshore fields. Such facilities have in the main been converted very large crude carrier (VLCC) units, which have been primarily used by small and mid-cap operators developing small-to-medium size offshore fields. We are now seeing a greater use of converted facilities on larger

developments, most notably Petrobras's Libra pilot project. As Petrobras is the leading deepwater operator, Brazil's NOC has also increasingly utilized leased FPSOs, with both SBM Offshore and MODEC historically the contractors of choice. Other key operators expected to employ leased production platforms over the 2017-2021 timeframe include Italy's Eni, UK-based independent EnQuest and Ophir Energy.

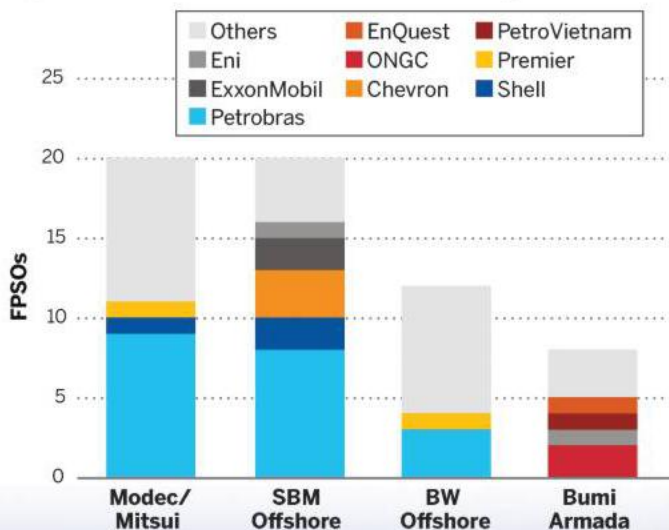
The four main FPSOs contractors (SBM, MODEC, BW Offshore, and Bumi Armada) control more than 60% of the operational leased fleet. MODEC and SBM dominate the supply of high-end FPSO units and have provided the majority of leased FPSOs employed by Petrobras. While they both have experience with engineering, fabricating



and managing top-end units, going forward they will have strong competition from other players.

ExxonMobil's Liza project offshore Guyana has recently been awarded to SBM, with the floater specialist undoubtedly the frontrunner for the second FPSO expected to be installed on the field. The Dutch-based contractor has also looked towards a more standardized approach in response to the prevailing market challenges; developing its Fast4Ward FPSO concept since 2014, while repeatability has been at the core of strategy in the *Cidade de Marica* and *Cidade de Saquarema* FPSO conversions, which were installed on the Lula Alto and Lula Central ultra-deepwater fields, offshore Brazil, during 2016. If SBM is awarded phase 2 of Liza, the same repeatable approach is also likely.

For MODEC, the last decade has seen the Tokyo-based contractor awarded an increasing number of contracts in deeper and more complex waters, with key projects including the VLCC conversion FPSO *Cidade de Mangaratiba MV24*,



Source: Wood Mackenzie

Key leasing contractor's operational, under construction, under conversion and awarded leased FPSOs by operator.

Source: Wood Mackenzie

on the giant pre-salt Iracema Sul field at a water depth of 2200m and the *John Evans Atta Mills MV25* FPSO, which came onstream in August 2016, producing from Tullow's TEN (Tweneboa, Enyenra and Ntomme) fields within the Deepwater Tano contract area, offshore Ghana. With Petrobras contracts increasing, MODEC has also established a strong relationship with Keppel's subsidiary Keppel FELS Brasil. This year is also expected to see the delivery of the *Cidade de Campos dos Goytacazes* FPSO to the Brazilian NOC's Tartaruga Verde field under a 20-year fixed time charter.

The last year has continued to bring financial challenges for BW Offshore, with the company employing financial measures including maturity extensions on corporate bonds and a US\$100 million equity raise. While challenges continue, the company has also looked to diversify; acquiring stakes in the Dussafu field, Gabon, through its subsidiary BW Energy, and on Namibia's Kudu field BW Offshore will be the operator and facilitator of what will be a significant domestic power generation project. This year will also see the completion of the *Catcher* FPSO, which is destined for the Premier Oil-operated North Sea Catcher field. Operator Premier continues to target first oil for later in 2017, despite construction delays.

Unlike counterparts SBM and MODEC, which are focusing strategy towards deepwater FPSOs, all of Bumi Armada's units installed during the previous five years have been in less than 500m water depth. The last year has been a significant period for the Malaysian-based contractor, with a number of key projects starting operations. The Enquest-operated *Kraken* FPSO, which is Bumi Armada's first North Sea facility, saw first oil in June, and the *Karapan Armada Sterling III* FPSO, owned and operated on behalf of field operators Husky-CNOOC as part of the Madura BD project, East Java, is expected to commence production imminently. Operations have also started on the *Armada Olombendo* FPSO at Eni's East Hub development, as well as the *Armada LNG Mediterranea* FSU offshore Malta.

With operators successfully reducing project breakevens, and more standardized working practices, design and manufacturing techniques being introduced, the market's leading leased contractors have managed to weather the worst of the downturn, albeit with varying degrees of success. The remainder of 2017, and 2018 are expected to see a more positive period for leased FPS contractors, with several project awards on the table, while the approaches taken by contractors in recent years as a way to maintain financial health, including SBM's repeatability approach and BW Offshore's business diversification, place these companies in a more robust position going forwards. **OE**



Catarina Podevyn is a senior analyst at Infield Systems, part of Wood Mackenzie. She has managed all published content produced by Infield Systems and is a regular contributor to leading industry publications. Since joining Infield Systems in 2008, Catarina has been involved in numerous bespoke projects and has authored several publications within Infield Systems' Global and Regional Perspectives series, including the Floating Production Systems Market Report, the Deep and Ultra-Deepwater Market Report and latest Subsea Market Report.



Twin FPSOs *Cidade de Marica* and *Saquarema* passing in Guanabara Bay in Rio de Janeiro. Photo from SBM Offshore.



Making MODUs into FPUs

InterMoor tows the *ATP Innovator* FPU from the Gomez field in the Gulf of Mexico. Photo from InterMoor's Flickr.

Mobile offshore drilling units could be a FPU conversion alternative. Karen Boman sets out the details.

In a cash-constrained environment, finding alternative concepts could help make offshore developments float. One such alternative, discussed at this year's Offshore Technology Conference (OTC) in Houston, would see mobile offshore drilling units (MODUs) converted into floating production units (FPU).

The conversion of tankers for floating production, storage and offloading (FPSOs) vessels has been a common practice, accounting for almost two-thirds of operating units, due to the relative economic attractiveness of a tanker hull versus a newbuild FPSO hull, according to Anders Martin Moe,

project development manager for floating production, and Manuel Laranjinha, project manager floaters and drilling, Wood Group, in their OTC paper, *Design Methodology for Converting a MODU into a FPU*. Converting MODUs into FPU has been less common over the past 15 years, but there are examples, including the *P-40* at the Marlim Sul field off Brazil and the *ATP Innovator* at the Gomez field in the Gulf of Mexico.

As operators look to reduce deepwater project costs, conversion of MODUs to FPU might provide the oil and gas industry an answer, the paper authors say. A decline in drilling activity and the subsequent halt or delay of development plans means many MODUs are available that could be candidates for conversion into early production facilities, long-term well-testing facilities, minimum processing facilities and even full processing facilities in oil fields in benign areas, Moe and Laranjinha say.

For its base case, Wood Group used its own MODU design to determine feasibility for converting a MODU to an FPU. The

exercise conducted on the basis of the design focused mainly on weights and hydrostatics stability to determine the maximum topsides payload that could be accommodated without making significant changes to the hull. Wood Group then considered two other cases: conversion of a MODU to an FPU capable of full production without drilling, the other an FPU that had full production with drilling capacity.

A study of the cases shows the conversion of a MODU into a combined production and drilling facility represents the highest risk and possibly the highest cost. The conversion of a MODU into a facility with reduced topsides processing and drilling capability appearing to offer a reasonable balance between risk and cost, Moe and Laranjinha say.

Before undertaking a conversion, several technical and commercial factors must be considered, the authors say. Even if no hull modification is needed, operators will need to verify the hull's remaining design life of the fatigue-sensitive areas such as bracing connections. A MODUs global structure may need to be strengthened when the payload becomes significantly higher than the design values. Such issues are well-known and frequently encountered in the modification, upgrade and life extension of drilling rigs.

Removing existing drilling facilities and integrating a new topsides processing facility present relatively low-risk challenges. But, operators will have to pay close attention during conversion to the riser and mooring system arrangement. For example, only having two pontoons for hanging off and routing risers to topsides will limit field layout.

Commercial feasibility issues include finding a MODU unit

with sufficient payload capacity and in good enough condition to limit the needed conversion/modification workscope for the hull. Finding a field with the environmental conditions, reservoir characteristics, and production requirements suitable for a converted MODU, as well as necessary infrastructure, is also crucial. The cost of acquiring topsides and their integration must be included in decision-making.

Semisubmersible MODUs and FPU's differ not only in their intended purposes, but in their equipment and structure. For example, semisubmersible FPU's do not dry dock for inspections at regular intervals like those for MODUs, which means additional requirements for structural design regarding fatigue are needed. Unlike MODUs, semisubmersible FPU's are very rarely equipped with propulsion equipment, and are typically installed at a field onto pre-laid permanent mooring lines. The two do share similarities in their primary design driver – the weight and footprint of the topsides, though the definition of payload does differ somewhat for both.

The Wood Group authors conclude, saying that the conversion of MODUs into FPU's could potentially open new opportunities for additional lease and operate models within the semisubmersible market.

“Potential commercial gains are very much related to reduced investment and low risk. In the end, one must prove the modification is not only a feasible solution, but also commercially interesting when compared to a traditional newbuild project, proving the modification will have such a reduction on overall capex that it eventually will impact the traditional oil and gas players' medium- to long-term strategies.” **OE**

Innovative. Intelligent. Informed.



With over 35 years' experience in the oilfield we have developed materials and provided engineered solutions to practically every deepwater project around the world.

Our technical, engineering, procurement and manufacturing teams are full of highly qualified personnel, all brimming with ideas. Supported by senior personnel with unrivalled experience we believe we provide an industry-leading service.

Benefit from the best product solutions with Balmoral engineered buoyancy, insulation and elastomer products.

Balmoral Offshore Engineering | balmoraloffshore.com

OE 2017
5-8 SEPT 2017

Offshore Europe
AMSTERDAM, NL

SPE Offshore Europe
CONFERENCE & EXHIBITION

Booth 2C111



BALMORAL

Marginal options for small pools

The UK North Sea's extensive pile of marginal fields offer an attractive prize, if they can be economically unlocked. Steve Hamlen reports.

As oil and gas provinces mature and the largest fields have already been developed, operators look to exploit the remaining smaller reserves. This often involves the use of new technology and more cost-effective solutions. This is certainly the case for the UK North Sea, as the region is looking to "small pools" – marginal fields with less than 50 MMboe.

Chris Pearson, Small Pools Solution Centre Manager for the Oil & Gas Technology Centre (OGTC), is tasked with finding ways to develop them.

There are an estimated 600 marginal fields around the world, according to Pearson's presentation this March, who said this presents a great opportunity to export technology and expertise from the North Sea, because the majority of these fields are located offshore the UK.

There are more than 350 undeveloped discoveries on the UK Continental Shelf (UKCS) and 160 are either in relinquished blocks or areas that have yet to be re-licensed.

Together these represent 3.4 billion boe of technically recoverable reserves that offer the UK industry some US \$228 billion (£175 billion) in potential revenues. So, small pools could be big business and the supply chain could benefit from a push towards bringing some of them onstream.

"It is therefore entirely logical that the boost to the supply chain would almost be instantaneous as industry sanctions their investment in the development of these fields. It is with this in mind that

the OGTC is focused on both near-term development 'wins' and in parallel fundamental research that can transform how we provide energy across the UK," Pearson told *OE*.

"The OGTC has combined funding of \$234.5 million (£180 million) from both the Scottish and UK governments. Our obligation is to match-fund this with industry contribution envisaged as 'benefit in kind' by allowing access and support to oil and gas infrastructure, application of expert knowledge and access to assets that will assist us in achieving our goal."

Around 70% of these marginal fields hold less than 10 MMboe. In addition to their small reserve volumes, other challenges exist, such as, low energy reservoirs, difficult fields, fluid commingling, differential pressure and gas

disposal.

The best solutions on offer to operators come from adopting a "cluster and collaborate" approach, Pearson notes, adding that mapping of these small pools was completed in 2016 and cluster analysis has revealed promising areas of development.

The Moray Firth has 43 discoveries in 11 potential clusters, while the Central North Sea (CNS) has 64 discoveries in 18 potential clusters.

"The majority of the marginal fields are in the CNS. However, in order to achieve the objectives of the Wood Report, the UK needs to develop and utilize existing infrastructure across the UKCS," he says.

Infrastructure access

Access to existing infrastructure offers marginal fields promising development options. The distance from these facilities will help dictate the best development solution, Pearson says.

The OGTC estimates that around 30

discoveries are potentially suitable for extended reach drilling (ERD), at between 0-5km from infrastructure, while 200 finds are suitable for subsea tiebacks (less than 20km), and around a further 120 discoveries would require standalone cluster developments (more than 25-30km away, sometimes less).

The use of existing infrastructure would help to extend the life of the host facilities, which is within the remit of the UK's MER (Maximizing Economic Recovery) strategy.

Indeed, some of the undeveloped discoveries are being assessed for suitability for ERD by the UK's regulator, the Oil and Gas Authority (OGA)," Pearson says.

"Other fields will benefit from a reduction in the entire lifecycle cost. This does include how we design, build and install systems for a lower cost that we currently achieve. We are designing the next stage of those projects to find a suitable field trial to demonstrate where the utilization of those technologies would be appropriate."

With regard to potential standalone projects, Pearson adds: "There is a varied set of solutions, such as remotely operated unmanned and light-manned systems. There is no single approach that can deal with the entire range of reservoirs properties currently undeveloped, so we are supporting a number of concepts to test feasibility, alignment with our objectives of MER, plus the economic value returned from supporting a reduction in life cycle costs for the developments."

Licensing options

The OGA is putting a strong focus on mature areas and relinquished blocks in the upcoming 30th Licensing Round. The OGA will also release data packages on the aforementioned 160 unlicensed discoveries, while also looking at models "from cooperation to unitization" in



Chris Pearson

order to “facilitate joint area development plans,” the OGA says.

Alignment of license terms is also on the cards, such as expiry and timing commitments, “to induce synergies for exploration and development campaigns.”

Earlier this month, the OGA unveiled measures designed to make data openly available and stimulate interest in the UKCS ahead of the 30th Round.

“Data and technology are key to unlocking as many of these undeveloped discoveries as possible,” says Gunther Newcombe, operations director, OGA. “That’s why we’re making this data openly available; to provide useful insights into each discovery and the potential these may hold. We want to see swift deployment of technology to help unlock many of these discoveries.”

New technology

The use of new and immature technology will be critical to unlocking the potential of marginal fields on the UKCS, playing a major role in reducing costs of and extending the reach of small pools projects, Pearson says.

In terms of cluster technology, the OGTC is looking at mechanical hot taps, mechanically connected pipelines and multi-use pipelines. For standalone options, the OGTC is mulling “tiebacks of the future” and not-normally-manned facilities, which are designed for disassembly.

The search for new technology relies heavily on communication and the exchange of knowledge, Pearson says.

“Collaboration is part of our DNA in the OGTC. We simply could not achieve our aims without building and nurturing collaborative behaviors across all of our activities. It can always be improved and is always open to challenge,” he says.

An OGTC call for proposals for ideas to unlock small pools was launched this May, with some £1 million funding available to take ideas forward.

The OGTC is also looking at standardizing the subsea development lifecycle approach to support rapid engineering and delivery of a project; full interconnectivity between modular subsea components; the re-use of subsea equipment from one field to another; interoperability with present and future systems; and the use of a range of key supplier specific subsea

components. Other, more conceptual ideas include gas to power, at site, potentially tying in with offshore wind grids, filling in for spare capacity.

Design and efficiency

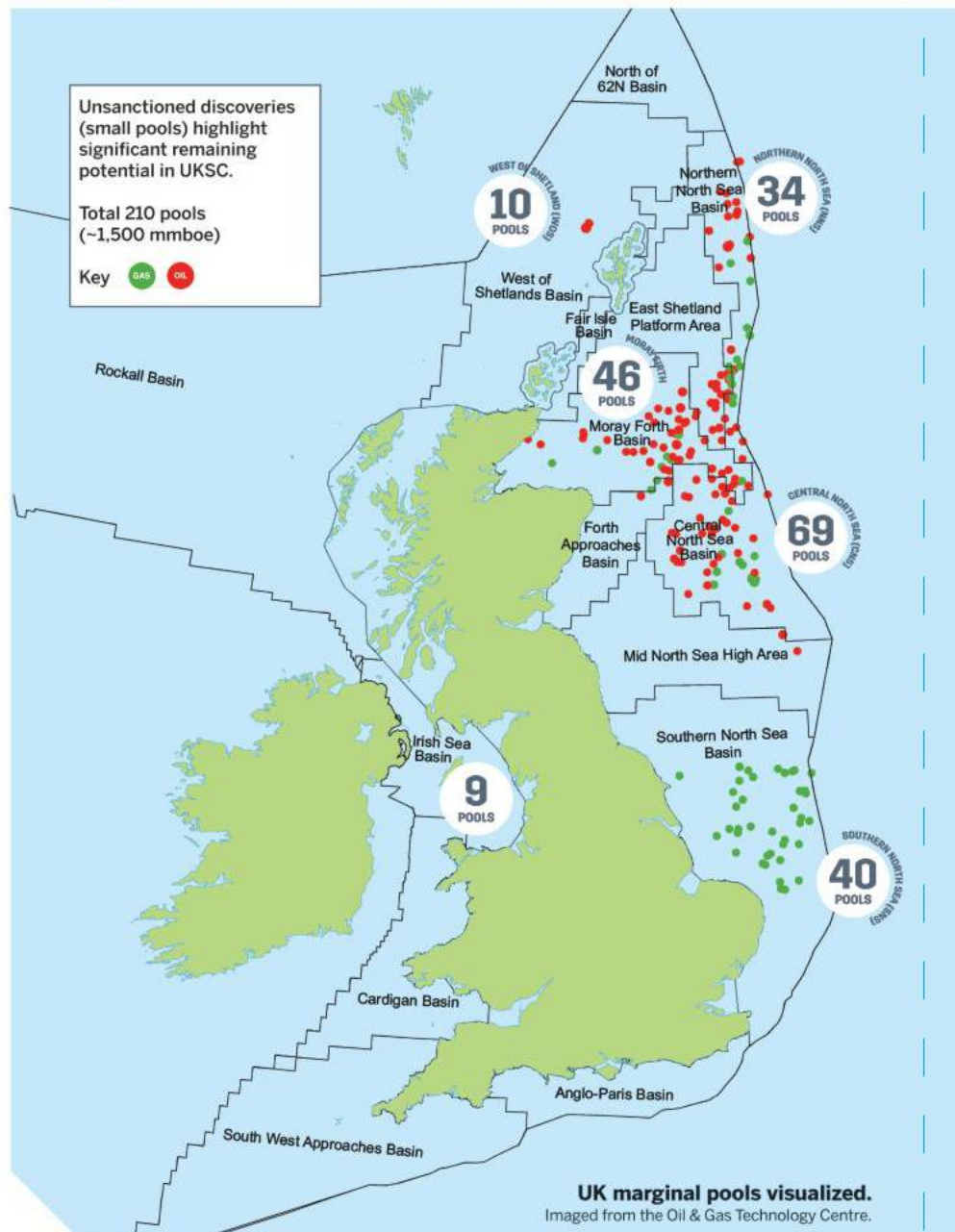
Industry body Oil & Gas UK is also pushing operators to adopt leaner designs using industry standardization for marginal developments.

Indeed, since the oil price crash of mid-2014, many UK operators and contractors have realized that collaboration is essential to driving down project costs, while development designs must be optimized to make

them economically viable. During the March presentation, Oil & Gas UK cited four recent case studies when operators looked for more efficient designs and streamlined solutions.

The first saw an FPSO riser system cost \$10.1 million (£7.75 million), a 25% cost saving; the second achieved a saving of 18%, with a subsea pipeline tieback costing US\$16.9 million (£13 million); a third saw a subsea manifold and bundle costing \$33.7 million (£26 million), a 15% saving; while the fourth, another subsea tieback cost \$18.8 million (£14.5 million), a 28% saving. **OE**

Small pools solution center – delivering information



North Sea honey bee

Finding a way to tap the North Sea's estimated 3.4 billion of resources currently locked up in marginal pools has become a perennial problem. Elaine Maslin looks at a past solution and ideas for today.

More than 300 discovered fields are sitting untapped across the basin, more than 150 of which are unlicensed. Many contain just 0-3 MMboe (150), with 80 containing only 4-6 MMboe. But, most of them are close to existing infrastructure, says Gordon Drummond, project manager, National Subsea Research Institute (NSRI).

Some of it is about development cost. According to NSRI research into small pools, based on a US\$60/bbl oil price, the minimum viable field size that could be produced economically was 11.1 MMboe. If the capex could be reduced by 25%, fields as small as 9.1 MMboe could be produced, and even 5-8 MMboe, with 50% cost reduction.

However, small fields have been produced before. Indeed, Centrica's Chestnut field was thought to contain just 7 MMbbl when the *Hummingbird Spirit* FPSO started up in 2008, and the field is still producing today, now that data suggests the field is larger than previously thought.

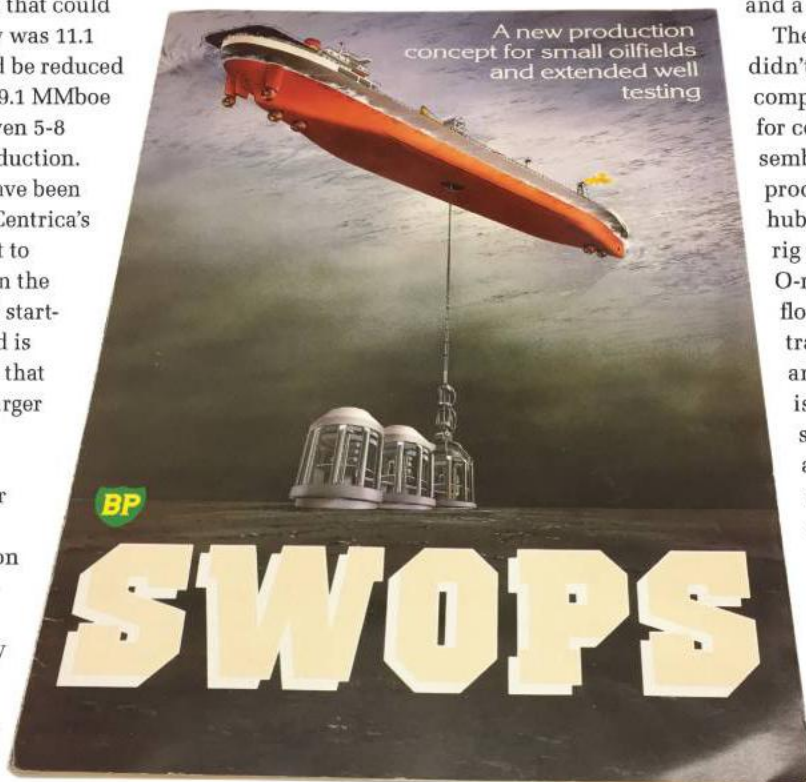
Another earlier and more radical solution for marginal fields was the single well oil production system (SWOPS), developed and deployed by BP in the 1980s and very

nearly an option for Chestnut.

It was technically advanced for its time and arguably the first floating offshore production system (FPSO), before FPSOs were invented. But, its commercial model didn't stack up. The unit, named *Seillean*, Gaelic for "honey bee," spent too much time transiting its oil cargo to shore and not enough producing to make it pay.

Seillean started work for BP in 1989, on the Donan and Cyrus fields. It was then sold in 1993 to Reading & Bates, under a move by BP to rent rather than own assets. Next, the unit moved to Brazil to perform deepwater well tests (following some modification work) for Petrobras.

After being acquired by Noble Drilling – and renamed *Noble Seillean* – she was sold to Paragon Offshore, and renamed *Paragon FPS01*, and moved to the US Gulf of Mexico. Paragon decided to scrap her, along with three other units, early 2016.



An original brochure, from when SWOPS was first unveiled. OE Staff photo.

A honey bee

Sandy Meldrum, who worked on the system, outlined SWOPS at a Society of Underwater Technology (SUT) event in Aberdeen earlier this year.

"It (*Seillean*) was a means of producing oil from small offshore fields that would be uneconomic to be developed through conventional means, fixed or floating," he says. It was a production system with a riser system and storage capacity.

The 250m-long, 37m-beam fully DP unit, for 75-200m water depth, and 4.5m significant wave height, was built at Harland & Wolff in Belfast. It had 51,000cu m storage tanks (320,000 bbl) and 15,000 b/d process equipment – later upgraded to 25,000 b/d. The unit had two moonpools, for the riser system and remote operated vehicle (ROV – a low spec work class Scorpio), and a derrick for riser handling, and a tensioning system.

The riser system was a 5.5in outer diameter bore drill pipe made up of 32ft long pipe joints, with 5000psi operating pressure. This was new and meant the safety joint was needed – and was indeed used. It was later upgraded when it went to Brazil, Meldrum says.

Pipe handling and tensioning facilities were in one moonpool, with a surface tree on a wireline BOP system, with a swivel joint for 360 vessel rotation. This connected to a connection package, a flex joint, to allow 15-degree offset, and a safety joint.

The riser connect package didn't need guidelines, and comprised a collet connector for connection to the tree assembly (a flowline stab base, production tree, and re-entry hub installed using a drilling rig on the wellhead), a conical O-ring interface, providing flow paths for hydraulic transfer between the riser and tree assembly, valves for isolation and flushing, and shearing the wireline, and a diver panel for recovery of the riser connector package if the safety joint got separated. A re-entry hub would fit on top of the production tree via the collet connector, and incorporated a mandrel onto which the riser connector package locks.

If a second well was being produced it could be connected to the flowline stab base with a flowline and control umbilical. Direct hydraulic controls via an umbilical (with 23 hydraulic lines and two riser flushing cores) were used in conjunction with the riser package. Acoustic monitoring was used to relay pressure information from the tree/flowline back to the vessel.

In the early days, the plan was for the vessel to go between 4-5 fields. But, some of the wells didn't live up to expectations, Meldrum says. BP, at the time, was in the process of moving from using its own rigs to using contractors instead.

Meldrum says that compared with an FPSO that stays on station, the SWOPS vessel had to leave once it was full to offload. "There was a lot of down time," he says. Gas was dealt with through flaring.

Other options

Other existing ideas for how to produce these fields have included production buoys, "FPSO light" concepts, such as Amplus' versatile production unit (VPU) (*OE*: May 2016 – Small is beautiful), subsea production systems with subsea storage, such as Kongsberg's subsea storage system concept (*OE*: August 2016 – *Tanked up*), now owned by NOV. According to an NSRI study, out of these, production buoys were deemed as having the potential to be profitable after five years. Subsea production was thought to have the potential to get "above the line" after five years, while FPSO light struggled to wash its face – based on \$60/bbl prices.

Ian Dring, an executive at Sea Captaur, which has developed a production buoy concept (*OE*: August 2016), says there's an opportunity for such a technology. He says, of 347 undeveloped fields on the UKCS, 130 contain more than 6 Mmboe and 155 are currently unlicensed. He suggests using an unmanned buoy type system, with subsea oil storage and a shuttle tanker to offload oil periodically. It could also be used for late life field extension, when larger facility such as an FPSO is no longer viable, or as an early production system for a larger field.

John Woods, of Aberdeen-based Offshore Production Buoy (OPB), says: "There are a lot of assets (fields) out there that need these solutions." OPB has a ca.28m-diameter, 12m-high

column shaped buoy design for 30,000 bo/d (40,000 b/d liquids) process capacity, and 9 MMcf/d gas handling, for work in 100-400m water depth via catenary or tension tethers.

The buoy would contain controls, power generation (including for up to six ESPs and water reinjection if needed) and de-gassing equipment, with a typically 200,000 bbl subsea tank and offloading system. Gravity and temperature-based separation would be used, with the liquids heated and degassed. Gas would be used for heating the tank and process equipment space to reduce corrosion. But, this limits the system to 9MMcf/d, Woods says. "There's a gas oil ratio sweet spot. This would be for fields where you're not sure what the production will be, they are stranded, end of life production or a stand in for an FPSO," Woods says.

While the buoy has been designed to be reusable, the subsea storage system would be unlikely to be reused, says Woods. With the design assessed and review by design house ODE, OPB is now looking for field studies in the North Sea.

Commerciality

While some of the issues are around technology – including flaring, water handling, sand management – ultimately, one of the biggest blockers, as with *Seillean*, will be the commercial model. With the existing small pools, there's little incentive for those that hold them, or those without infrastructure, to go after them. With 120 players on the UKCS, finding commercial alignment is difficult, compared to the Dutch shelf, where there are four players, one of which is the national oil company, says Chris Pearson, from the Oil & Gas Technology Centre in Aberdeen. "It's classic market failure," Drummond adds. "It's now 80% owned by 20%, it's lots of people owning a few and no appetite that's killing us."

There could be a change. Pearson says that the UK regulator, the Oil and Gas Authority, is starting to take a "use it or lose it" approach to those sitting on these assets and not doing anything with them. One operator was said to have half a dozen of these opportunities but would not put them across infrastructure other than their own. "This could help us, but it's a big challenge," Pearson says. **OE**

Back to the future

A concern on the UK Continental Shelf is that untapped fields could be stranded, if existing infrastructure, such as export pipelines, is removed.

The situation could have applied to a new hub being developed by Independent Oil & Gas (IOG), if not for a decision to recommission a 90km-long decommissioned southern North Sea (SNS) gas pipeline – saving £100 million and two years' work, IOG CEO Mark Routh told an East of England Energy (EEEGR) event in Norwich.

IOG is acquiring the Thames Gas pipeline, which took gas into Bacton, England, to transport some 500 Bcf from its Blythe, Elgood, and Vulcan gas hubs. IOG plans to drill 10 wells, lay over 70km of new connector pipelines and install up to five new platforms for these hubs. The Harvey asset, between Blythe and Vulcan, is likely to also be part of the project.

"We saw a pipeline was empty and, if we recommissioned it, we would have a pipeline that could start to unlock these stranded assets," Routh said. Acquiring the pipeline from Perenco, Centrica and Tullow cost £1, with IOG taking on all future liabilities, which amount to several million pounds.

Environmental surveys started in February, and in July, a field development plan was submitted.

Work to recommission a 60km section of the 24in Thames pipeline is underway, with plans to send intelligent pigs down it to assess its condition. A solution to any problems could be a 16in run through the current pipeline, which would be subject to more rigorous inspection than many other pipelines in the SNS, Routh said. "Pipelines are usually over-engineered – some of the 1960s pipelines are still flowing gas safely more than 20 years beyond their initial design life."

The project will be the first recommissioning of a decommissioned SNS pipeline. IOG is inviting the supply chain to work on the basis of payment on production, estimated at 150 MMcf/d at its peak by 2020. ■

Nightmares on wax

Waxy crude on the Pil and Bue project and topside constraints has led VNG Norge to explore pipe-in-pipe heating systems. Elaine Maslin reports.

Pil and Bue, or bow and arrow, are oil and gas discoveries in Blocks 6406/11 and 12 on the southern part of the Halten Terrace in the Norwegian Sea. Both discoveries were made in 2014, and contain a total 80-155 MMboe.

But, to produce these fields, operator VNG Norge, faces a number of challenges. “The Pil and Bue fields are quite waxy, with a high pour point [the point at which a liquid loses its liquid properties],” Alireza Forooghi, lead flow assurance engineer, VNG Norge, told the Underwater Technology Conference (UTC) in Bergen in June. “The fluids form strong gels during shut down. A 30km journey to the topside facilities

makes it even more challenging.”

VNG Norge looked at a standalone development, using a floating production vessel, but chose the tieback option to Statoil’s Njord A facility. The next closest host for a tieback would be Shell’s Draugen platform, some 65km away. But, while Njord A is closer, it also has process constraints, including gas compression ullage, surge volumes to accommodate slugging and liquid handling for pipeline depressurization.

The flow assurance challenge could be tackled using heated pipelines. Most existing waxy crude developments are onshore, Forooghi says. Those offshore are mostly non-gel forming and the few that

are use short, dual multiphase flowlines to a dedicated floating production vessel.

VNG Norge’s subsea concept for Pil and Bue is 6-8 wells, with a 36km multiphase flowline to a production template, gas and water injection flowlines, served from the Njord A topside, to an injection template, close to the production template.

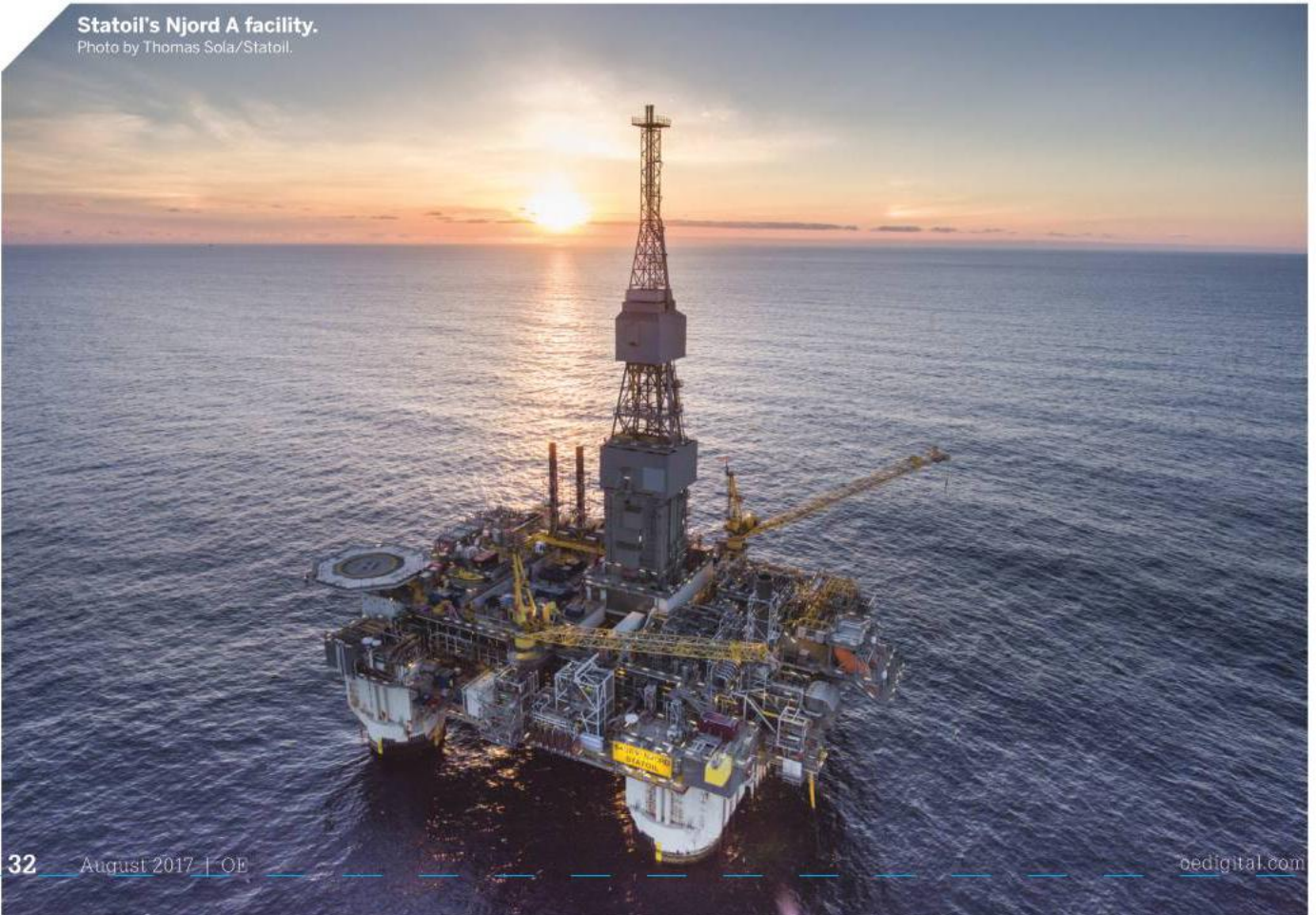
For the Pil and Bue flowline, VNG Norge screened three options: pipe-in-pipe (PIP) without active heating, which would rely on pipeline depressurization for hydrate management and continuous wax pour point depressant injection; electrical heat trace (EHT) PIP technology; and direct electrical heating (DEH) of the pipeline.

Forooghi says that early in the project lifetime hydrate formation pressure will not be reached, when the flowlines are depressurized. But, there would be issues with low pressure startups, due to the amount of liquids left in the line after depressurization, leaving gelled segments that would need 200-400 bar pressure to restart the line – without active heating.

In a DEH PIP, the flowline forms part of an electrical circuit. A number of variations exist, where the inner pipe and outer pipe form a circuit (end-fed PIP), or where a piggy back cable providing power is used completing the circuit

Statoil’s Njord A facility.

Photo by Thomas Sola/Statoil.



at both ends of the flowline. Center fed (or closed circuit) systems also exist, where power is supplied from a mid-line connection along the pipe, then forming an electrical circuit with the inner and outer pipes.

Closed circuit (or center fed) DEH PIP has been used in the US Gulf of Mexico on the Oregano and Serrano fields, since 2001. This was a first for the technology, Forooghi says. Open loop, or piggy back DEH applications, have also been used on various Norwegian fields, including the first DEH application of any kind on Asgard, in 2000. Center fed systems have been used on Na Kika (2004) and Habanero (2003), both in the US Gulf of Mexico.

EHT PIP has also been used, Forooghi says, on Total's Islay project in 2011. EHT uses trace heating elements, i.e. cables, helically wound around the pipe. This is an option gaining traction, Forooghi says, with others looking at it for Norwegian developments, including Tommeliten Alpha, and it's an option for Snadd, as well as Total's Zinia 2 project offshore Angola.

"DEH PIP has some real advantages," Forooghi says. "It has relatively high thermal performance in the system, the flowline size is not limited. It can be laid in S-lay and J-lay, it is field-proven, operational and possible to repair if the system fails. The disadvantages are that it has relatively high-power demand, and while it's applicable in short flowlines, longer flowlines need to be divided into sections, and it requires a relatively high number of bulk head and water stops to make it," although this is the same for EHT, he says. It's also exposed to relatively heavy wait-on-weather for offshore operations and welding, he says.

The advantages of EHT are relatively high thermal and electrical efficiency, he says. "It has a good level of redundancy through using a number of heat traced cables. It can be tested onshore for faster offshore installation. The main disadvantage is the limitations in size of pipe. The biggest flowline size to date in 12in and it is limited to reel lay or towing to field and it's not repairable.

"EHT is the best option for Pil and Bue, because we only need it in shut-down and start-up. During normal operations, we will be running quite hot. In late field life we are planning to have gas cap blow down, when might be required to be used

Drying out

Norway's Minox has a DryGas compact gas dehydration concept. It is a two-stage gas dehydration process based on the firm's Minox Deoxygenation technology. The technology - initially designed for topsides has two separators with static mixers upstream. Glycol (TEG or MEG) is used to extract moisture from the gas - including a conventional TEG regeneration. The system use less glycol than conventional dehydration systems and would be a lot more cost effective solution than injecting glycol for flow assurance with an untreated gas.

Minox has completed full-scale testing of the system at Statoil's K-Lab, at Kårstø, Norway, supported by Statoil and the Research Council of Norway (Demo2000 program) and is awaiting a report. The next steps will be adding a glycol pump and optimizing how much glycol is needed. To take the system subsea, which the firm plans to do, will involve a full redesign tailor-made for the subsea environment, says Minox CEO Bjørn Einar Brath.

Brath says that the system is already half the weight and size of a comparable system. Traditional systems consist of large contactor towers, absorbers, extending up through multiple topside decks, where the wet gas reacts with TEG as it passes through the absorber. The conventional towers are sensitive to movements of the installation, which can be a problem on floating installations, and require larger volumes of TEG and the energy.

The firm has been making systems using similar technology for water deaeration for topsides since the late 1980s and it is used by nine major operators now.

ExxonMobil has also been working on gas dehydration technologies. Earlier this year it unveiled its cMIST technology, which dehydrates natural gas using an absorption system inside pipes, replacing the need for conventional dehydration

on a continuous basis."

VNG is running a competitive front-end engineering and design (FEED) study between Subsea 7 and TechnipFMC, following which it will look to qualify the technology for Pil and Bue, due to new elements in the system for the development.

This is likely to be around the challenges of using this technology on a 34km tieback - when previously it's been limited to shorter lengths (6km on Islay), due to short heating circuits.



Minox's system. Photo from Minox.

tower technology. It is an inline technology that could be deployed onshore, offshore and, potentially, subsea.

cMIST removes water vapor from natural gas with a 70% reduced footprint and 50% of the weight of traditional systems, the firm says. At its core is a "droplet generator," used to break up conventional solvent into tiny droplets that become dispersed in the gas flow, increasing the surface area for the absorption of water from the gas. This is followed by an inline separator that coalesces the water-rich glycol droplets and moves them to the outside wall of the pipe for effective separation from the dehydrated natural gas. The water-rich glycol is regenerated using a conventional system and sent back to the droplet generator to be used again. ExxonMobil has licensed cMIST technology to the Chemtech division of Sulzer. ■

This could mean a move towards using higher voltage cables, which would be exposed to relatively high temperatures. "The overall system behavior will need to be designed and simulated to design life," Forooghi says.

Development engineering work is being supported by Norway's Reinertsen. The subsea production systems contract was awarded to TechnipFMC and Aker Solutions. A contract for engineering, procurement, construction and installation is due to be awarded in Q4 2017. **OE**

Let's get connected

Sometimes seen as the weak link in the system, subsea connectors have come a long way. With new challenges, larger throughput requirements, new materials and methods this is an ever-evolving technology, says

Hydro Group Systems' Bill Milton.

Subsea electrical and optical systems connection has been developed from decades of research and development, looking for cost savings, performance enhancements and ways to address environmental challenges.

Engineers and scientists have been supporting military operations and pushing oil and gas activities deeper, farther and faster. This in turn has helped the telecom industry maximize throughput of data, reduce downtime and lower the cost of systems at sea.

All such developments must include connections to communicate, supply power and monitor status. These connections have also evolved and are being made from new materials for new environments and new system requirements. In many cases the connector industry is trying to keep up with the

system advances and, in some cases, is even getting ahead of the market need.

However, as metal, plastic and new exotic material housings improved, so did system requirements, with a desire for more data or power conductors in the connectors. This then drove the need for smaller conductors and higher-density connectors with acceptable dielectric materials.

As engineers worked on materials to house the epoxy – rubber, glass to metal seals or plastics inserts – we found that the increased power capability and huge increase in data transfer capability is critical in the progress of undersea systems. This new ability, to power larger systems and multiple systems with one input cable and connector plus the ability to add more sensors, is smarter and can handle faster data rates and increased bandwidth requirements.

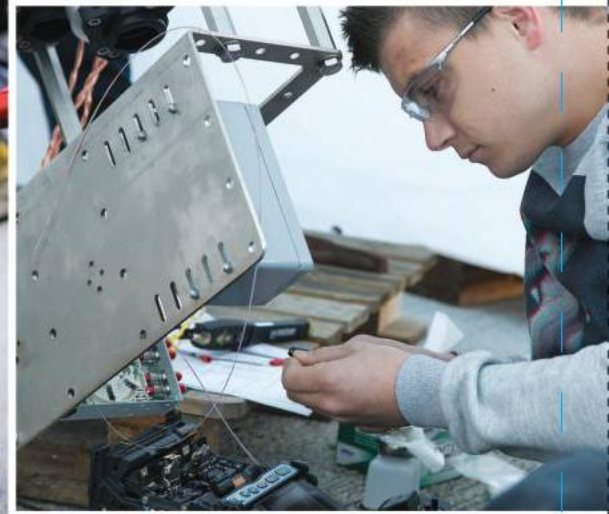
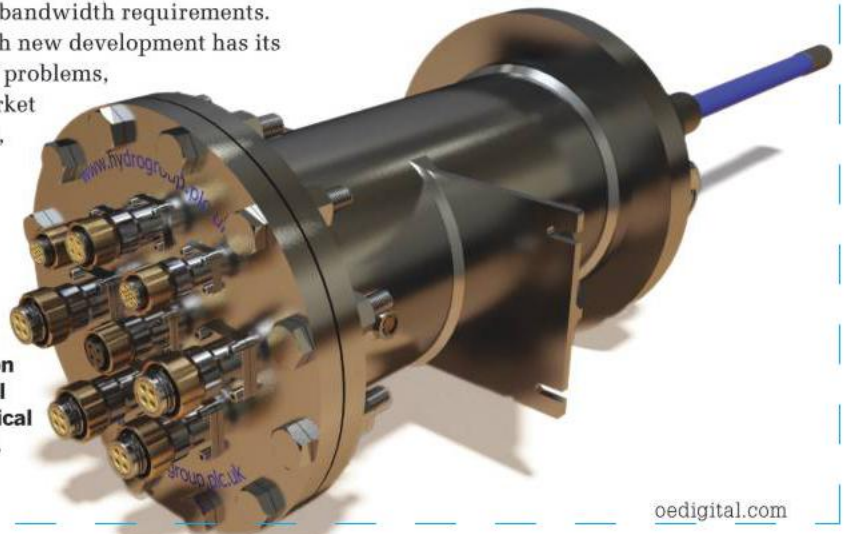
But, each new development has its own set of problems, in one market or another,

such as the military with concern over the submarine safety. Such problems led to the need for specific guidelines for designers and manufacturers of connectors to develop qualification testing to ensure specified requirements were met not only in performance and environmental testing, but material certification tests too. Products were now required to be “qualified” to a specification.

A subset of this trend is in fiber optic components, which we're seeing being continuously developed for use with increasing bandwidth in data and faster speeds to get data from point to point. As the components and systems are developed, the interconnection is also modified to attach elements of the system together.

The fiber challenge was very difficult

Subsea electrical umbilical termination unit coaxial and electrical connector.



Left: Cable end preparation – prior to termination. Above: On-site splicing of fiber optic terminations.

Photos from Hydro Group Systems.



Subsea turbine – medium voltage termination.

in the beginning and is still a stubborn medium today. It has enabled faster data transfer speeds, from kbits/sec to Tbits/sec, reduces cable size and weight, greatly reduces the number of repeaters required to carry the signal long distances and has little or no impact from interferences.

But, with ever deeper water requirements, explosive shock critical material needs and harsher environmental conditions to be met, each day is like the first in developing these new connectors for fiber systems. We are constantly working on the capability to tighten tolerances for superior alignment of the fiber termini and to reduce data loss, as well as techniques to polish the fiber without changing the characteristics of the light path. In the first systems, the insertion loss for a termini was in the 3dB (decibel) range and now we can achieve less than one tenth of a dB in loss.

Materials such as high density plastics and ceramics have been introduced to improve performance in the connector shell and termini alignment.

What will be the next new material to allow smaller fiber termini? How many fibers can we put into one connector and perform to the requirements? When will we find the solution to using fiber for power efficiently? These and many other questions are being asked daily, as technology moves forward for the subsea market.

But, with a seabed filled with dry mate connectors, wet mate connectors, electrical and optical connectors, there's another broader goal: to develop this technology for multipurpose use across an array of projects, and to make them far more reliable, while reducing costs.

This will again mean new technology requirements. In some cases, it is viable to use induction coils for power connections and with some power levels we can also transfer data on the power line without the use of a connector – this technology is one that is in use and in continuous development.

The use of acoustic data transmission from subsea components in some systems eliminates the need for connectors and

will be looked at for many systems once the data rates can be achieved at a much higher level than they are today. But, the frequency range and distance limitations are a challenge, and the fact the signal is transmitted, which can be detected by others, is a potential security problem.

Some of the latest technologies include radio frequency signals and Wi-Fi transmission over very short distances between subsea connectors, and they offer some promise.

As in the past, there will be challenges along the way. In the past, some have not met performance expectations, there have been design errors, manufacturing flaws and some anomalies resulting in failure and/or catastrophic failure. Nonetheless, there are many submarines, oil and gas systems, telecom systems and oceanographic systems in use with no connector failures or limited connector failures worldwide.

All in all, connectors are currently the best solution for subsea connections, be it dry mate or wet mate. Whether the solutions for the new challenges we face look or act like a connector, as we know it today, is a different matter, but it will still play the same role in connecting subsea components.

To achieve our goals, communication between engineers, system designers, project managers and program offices is crucial. Connectors should be considered in the initial design stage and not as an afterthought when completing the system.

It is possible the connector can be bought off the shelf, just as it is possible that it will need to be developed or modified to meet specific system requirements. But, there is positive progress being made in this bespoke technology and it will continue. **OE**



Hybrid coaxial and electrical connector.



William (Bill) Mildon is president of Hydro Group Systems in Pinellas County, Florida, a subsidiary of UK-based Hydro Group. Bill has held

a number of senior positions, most recently as technical director at Nest Technical Services. He has lead teams in submarine penetration designs, under water connectors and numerous fiber optic inter-connect products.

Design once, build many

Rob Gill and Steve Henzell explain how WorleyParsons intends to make wellhead facilities production cheaper and faster with a design one, build many ethos.



The pressure to reduce the cost of new developments has never been greater for North Sea operators. The combination of low oil prices, decreased North Sea development opportunities and increased competition from the US shale industry means that

our industry's being forced to adapt to new ideas.

One development concept that's starting to gain traction is the use of low-cost wellhead platforms for the development of small satellite fields. These are typically newly discovered fields close

Varying water depth



Minimal scalable facilities. Images from WorleyParsons.

to an established host platform, which can provide control and power and also carry out fluid processing.

While wellhead platforms have long been a favorite in the shallow waters of the southern North Sea, up until now, the preferred option for the development of satellite fields in deeper water has been to use a subsea manifold with a tieback to the host facility. Subsea manifolds are tried, tested and trusted, but, WorleyParsons has carried out a number of studies showing that they don't necessarily provide the best value solution for a multiple well development. The difficulties and additional costs associated with maintenance and future well intervention operations can all contribute to increased costs over the lifetime of a project.

With 30+ years' experience in the design of unmanned wellhead platforms, WorleyParsons has accumulated a reference list of more than 500 installations, which are currently operating throughout the world. The WorleyParsons team has combined this experience with ideas borrowed from the shale industry – where standardization and modularization of equipment is the key to low-cost field development – and they have come up with a new concept in wellhead platforms suitable for installation in deeper water and able to withstand North Sea conditions.

The new design uses piled foundations, can be deployed in water depths of up to 120m, and provides space for a maximum of 12 well slots. No accommodation has been provided for personnel who will gain access for four-monthly maintenance visits by vessels equipped with a "walk-to-work" gangway. The platform design includes a 5-tonne crane and sufficient deck space to allow full access for future well intervention. WorleyParsons has also designed the new platform for construction within their covered yard near Stavanger, Norway, and with one flat side to permit installation by either barge launch or jackup platform to widen the choice of installation contractor.

The platform is designed with a "design once, build many" approach to capture economies of scale and efficiencies more closely associated with a production line than a North Sea construction yard. The design borrows from the philosophies that WorleyParsons has previously followed in both the Persian

Gulf and in the Gulf of Thailand, and uses a minimum number of different profiles to reduce procurement and stockholding costs.

Topsides and jacket weights are comparable to more traditional North Sea designs at around 650-tonne and 3500-tonne, respectively, for a 100m water depth platform. With almost all of the topsides and much of the jacket being identical for any platform regardless of water depth. However, there is scope for significant savings in project schedule by both reducing set up times and by allowing construction to start in parallel with detailed design. The design is so standardized that water depth, seabed conditions and well slot arrangement are the only pieces of information required to completely define an individual platform so further reducing project schedule and minimizing construction risk.

WorleyParsons sees an immediate market for at least 20 low cost modularized platforms in the Norwegian sector of the North Sea alone, and is currently talking to a number of operators who have been carrying out studies to assess their viability. They also see applications in UK waters where the upcoming 30th licensing round will be targeting small pool discoveries which will require especially low-cost development schemes. **OE**

Rob Gill is a process engineer by background and has 30 years of technical, management, M&A and business development experience in the oil, gas, petrochemicals and manufacturing industries. Rob holds a BSc. in Chemical Engineering from Loughborough University and an MBA from INSEAD.

Steve Henzell is a process engineer by background and has over 30 years' experience in oil and gas design and operations. He is an authority in the design of well-head platforms and provides leadership in the areas of concept and front-end engineering design within the WorleyParsons Group. Henzell holds a BE in Chemical Engineering from the University of Queensland and is a Chartered Engineer in both Australia and the UK.

FURTHER READING



Less is more www.oedigital.com/drilling/item/13155-less-is-more

Going modular

Offshore structures for multiple uses were investigated by Mirco Busetto, head of basic design Offshore Business Unit, Fincantieri, at this year's Offshore Mediterranean Conference (OMC) in Ravenna, Italy. Elaine Maslin reports.

Fincantieri has developed a modular concept, called floating modular platform technology (FMPT). It is based on a hexagonal semisubmersible structure (although there's potential to make a gravity-based version), which could be scaled in size, both in terms of individual unit but also by linking multiple units together to create larger platforms or islands.

The firm's research suggests such units could be used for conventional energy production, residential use, renewable energy, aquaculture, and as bases for deepsea mining. They could be used for short-term developments, for wind farms or other forms of power generation, and longer term, such as industrial or tourism uses. Medium-term uses could be aquaculture, marine energy, or artificial islands for logistic purpose.

A key part of the concept is that it could be built at "any shipyard" and that the design could be adapted to different uses, i.e. a base design could be customized to a variety of uses, says Busetto. "The modularity allows for different water depth and different distance from land," he says. "It could be a fish farm or crew accommodation, a drilling and production platform or a base for mineral processing."

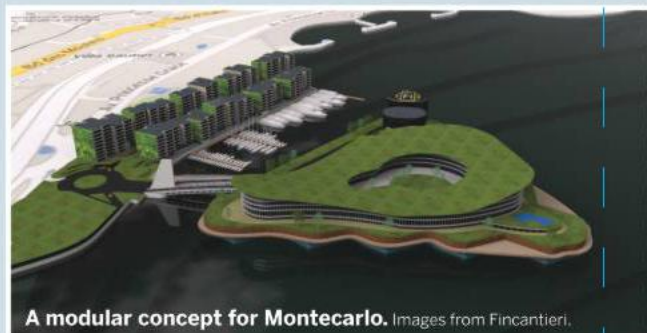
At its narrowest and widest points, the hexagonal structure would be 50m by 60m – although Busetto says the size could be bigger. It would have a 12m-draft and would be 10m from the main deck to the water line.

Ideas Fincantieri has been looking into include a residential project just off Montecarlo. It would create a 6ha "artificial island," the benefit of which would be having no contact with the seafloor, therefore limiting damage. Another application could be a wind generation platform. Fincantieri has called this concept "Seaflower." It would have a mooring chain spread system in 50-200m water depths, a draft of 12m and 20-year design life for a North Sea site.

"Another application is offshore power generation, or offshore gas field, gas-to-power production." This has been looked at for offshore Mozambique, where getting gas from deepwater (1000m) offshore gas fields to markets poses a challenge, while wave heights for a one-year average are 4.3m, or 6m for a 100-year storm.

Three FMPTs could be used, two for power generation (60MW each), with power transported to shore via electric export cables. The third unit would hold the crane, flare, living quarters and helideck. The concept could offer a first phase of development before full field development, Busetto says. Additional facilities could then be added over time. One of the critical points is that connections between the modules have to withstand environmental forces during a 100-year storm condition or during application, he says.

Fincantieri also sees synergies with wind and wave power, but also solar and microbial fuel cells, which could be added to projects to improve economics, Busetto says. ■



A modular concept for Montecarlo. Images from Fincantieri.



FMPTs for a gas to power project offshore Mozambique.

C- Room for improvement

While UK North Sea production efficiency has made improvements since diving to a dire 60% in 2012, more can still be done, says Gordon Lawrence from Asset Performance Networks.

Production efficiency has come under the spotlight on the UK Continental Shelf (UKCS) – and not for good reasons. Even before oil prices collapsed in mid-2014, the watershed Wood Review found that “Production efficiency... has fallen from 80% a decade ago to 70% in 2010 and to an average of 60% in 2012.”

The Wood Review cited poor asset stewardship and “poor project management, planning and execution

efficiency...” as contributors to this efficiency loss. Oil & Gas UK’s Efficiency Task Force determined that most of the production loss referred to in the Wood Review could be attributed to “unplanned plant losses and planned shutdowns...” It subsequently issued a pamphlet offering “Guidance for the Efficient Execution of Planned Maintenance Shutdowns.”

In June, the Oil and Gas Authority (OGA) published the UKCS Production

Efficiency in 2016 report. It finds that production efficiency – measured as the percentage of production compared to the maximum theoretical production of an asset – has now risen to 73%. But, this is still far below an 80% target and the report highlights that “Plant losses continue to be the largest loss category in 2016, representing 60% of total losses.”

Scope change after scope freeze

■ Between scope freeze and turnaround start ■ During turnaround

Figure 1: Onshore facilities

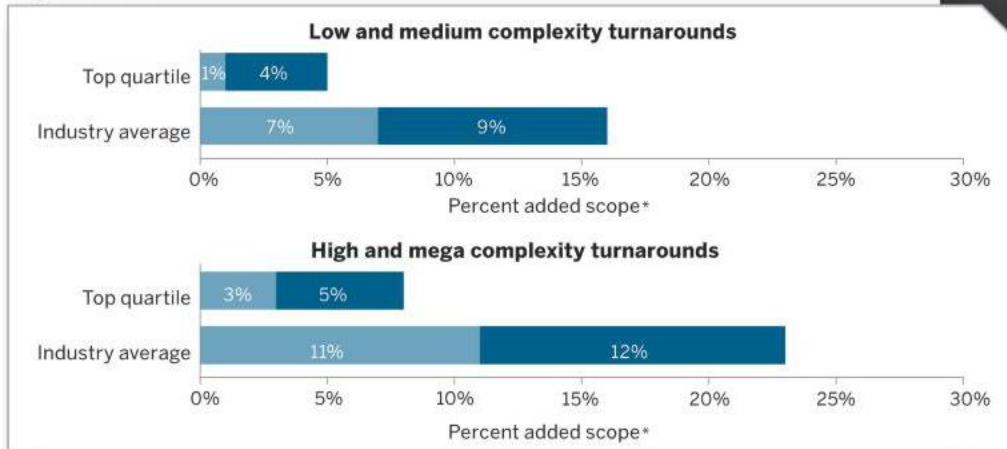
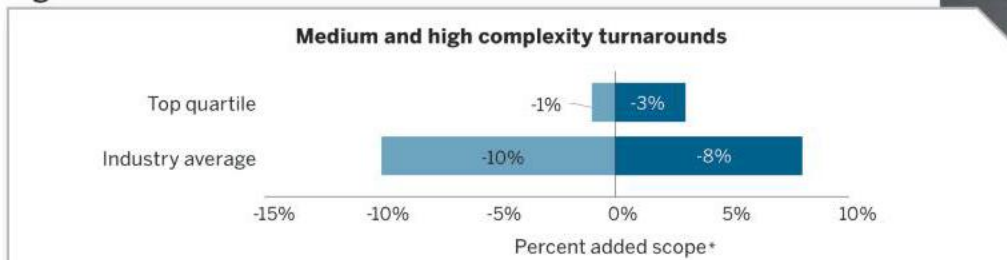


Figure 2: Offshore Facilities



* Percent added scope is determined as a percentage of total direct and material cost

Source: AP-Networks Turnaround Data

Research carried out by Asset Performance Networks indicates that there are a number of areas where plant losses could be reduced by transferring lessons from onshore maintenance turnarounds to their offshore counterparts.

Extending intervals

Historically, much of the offshore industry has focused on 12-month intervals between turnarounds. One exception to this has been West Africa, which focuses more on 48-month cycles. But, in the last decade, there has been a trend, particularly in the Norwegian sector, and more recently in the North Sea, to try and stretch the interval from 12 to 24, 36, or even 48 months.

However, there are obvious, practical limitations to how far the interval can be extended, including:

- There is a limit to the amount of time that an item of regulated equipment can go without statutory inspection, as laid out in the relevant “written scheme of examination.”

- There is a limit to the amount of time that some equipment can go before it requires cleaning.

- As the interval increases, the opportunities to tie in new capital investment works become fewer.

- There comes a point when repairs to worn or broken equipment cannot wait any longer without affecting safety or production.

As efforts to extend intervals offshore continue, operators are coming up against another limitation, which has a significant impact. The North Sea industry has been developing and expanding for about 50 years. Numerous

firms operate different assets, including platforms, pipelines, distribution hubs, treatment facilities, and onshore receiving stations. Over time, these assets have become more and more interconnected, to the point where the shutdown of any one asset for maintenance can have a significant “knock-on” effect on the other, interconnected assets.

The next concern with extending the interval is whether, by extending it, the turnaround duration is increased by an unacceptable amount. Data from the Asset Performance Networks databases indicate that the duration does appear to increase, by about 15%, when one moves from a 12-month interval to a 24-month interval. But considering that one has just doubled the interval, this seems a relatively small increase



Photo from iStock.

in duration. On an annualized basis, a turnaround of 26 days each year versus a turnaround of 30 days (15% longer) every two years represents the asset being shut down for 7% of the year versus 4% of the year. The advantage of extending the interval appear to be outweighed by increased turnaround duration.

Reducing scope

As well as extending the turnaround interval, an obvious step in reducing production loss is to reduce the duration of the turnaround itself. This can be by focusing only on scope that is “necessary” for safe and uninterrupted operation and deleting “discretionary” scope.

Data gathered by Asset Performance Networks indicates that offshore turnarounds tend to include significant “discretionary” scope. Figure 1 shows the average volume of scope added to onshore turnarounds after scope freeze and before the turnaround, as well as scope “discovered” during the turnaround. Figure 2 gives the equivalent data for offshore turnarounds. This data shows that there is a significant “reduction” in scope during the execution of offshore turnarounds. When interviewed about this reduction, offshore teams explained that they had “discovery” work, just like onshore turnarounds. However, offshore they were able to cut discretionary scope to not only accommodate the discovery work, but also to ensure that the turnaround duration was not excessively threatened. This is clear evidence that offshore turnarounds contain a lot of “discretionary” scope.

A decade ago, the onshore industry also had a culture of pushing “discretionary” scope into the turnaround. They managed to move away from this attitude by implementing some

changes. Firstly, they communicate a tight focus on what the turnaround is intended to accomplish. A very specific and clear “premise” document defines why the turnaround is needed. This naturally leads into a clear definition of the criteria for including scope in the turnaround. In the upstream industry, this premise document is generally not written in as clear a manner as those in the refining industry. Offshore premise documents tend to focus on total shutdown duration, no accidents, and other lagging performance indicators. What is missing is a clear definition of “why” the shutdown needs to take place and hence what scope is “necessary” vs. “discretionary.”

Secondly, the onshore industry has begun using Risk Based Scope Review (RBSR). Prior to freezing the scope, all scope items are “challenged” on whether they meet the scope criteria and, in the case of preventive maintenance, on whether the cost of including the item in the turnaround is less than the risk of it breaking during the subsequent turnaround interval, coupled with the lost production and cost of repairing it when it breaks. Asset Performance Networks has helped teams to reduce scope by typically 10% to 20% using this method. Offshore teams tend not to have the same rigor in challenging scope and the tendency is to include scope based on personal preferences and say-so. After both these actions, onshore teams retain their gains by ensuring that the scope control process, post scope freeze, is rigorous and firmly enforced.

Changing the goal

The focus on scope encourages onshore teams to ask, “How much time do we need to implement this scope of work?” Conversely, many offshore teams still

focus on, “How much scope can we implement in the time given to us?” This attitude is inadvertently enabled and encouraged by the fact that the offshore turnaround duration is rarely set by the team based on the scope of work. Rather, the durations for offshore turnarounds are generally imposed on the turnaround team by senior management and are based on market expectations, not on practical, scope based need.

The path forward

It is the view of Asset Performance Networks that addressing the following issues could have a major impact on production efficiency in the North Sea.

- Focus on interval calculations that take into account what the entire interconnected asset network is doing, not just the asset itself.
- Set out a clear premise explaining “why” the turnaround is needed, and hence what the scope criteria are.
- Challenge scope inclusion, using RBSR methods.
- Allow turnaround durations to be set according to the needs of the scope, not the desire of the market. **OE**



Gordon Lawrence is the manager of Capital Project Consulting in the Amsterdam office of Asset Performance Networks. He is a

chartered engineer, a registered engineer with FEANI and a Fellow of the UK Institution of Chemical Engineers. He holds degrees in chemical engineering, biochemical engineering and business administration, with over 30 years' experience in project management and maintenance turnarounds in the process industries.

Efficiency guidelines

Industry guidelines designed to boost production efficiency in the UK Continental Shelf have been published by Oil & Gas UK. “Guidelines to Maximise Compression System Efficiency” aims to address gas compression losses, which accounted for more than 40 MMboe in unplanned production losses in 2015.

The document, devised by the Production Efficiency Task Force (PETF),

sets out recommendations and good practice for improving compression system performance, covering areas such as:

- Compression system maintenance
- Integrity assurance
- Equipment and process condition monitoring, and,
- Training and competency

It is recommended that companies have a “lessons learned” process to ensure continual improvement of maintenance

procedures. A basic review would involve an assessment carried out after the execution of each maintenance activity, improving efficiency by providing a real-time response to any issues which arise.

PETF chairman and Operations Director of North Sea Midstream Partners Matt Nicol said: “We have made great progress but still have more to do to achieve the PETF’s 80% production efficiency target. I encourage all operators to utilize this gas compression best practice guide.” ▪



OE 2017
5-8 SEPT 2017
Offshore Europe ABERDEEN, UK

SPE Offshore Europe
CONFERENCE & EXHIBITION

REGISTER FOR
FREE NOW AT
[OFFSHORE-EUROPE.CO.UK/
OFFSHORE
ENGINEER](http://OFFSHORE-EUROPE.CO.UK/OFFSHORE-ENGINEER)

FIND SOLUTIONS TO ALL YOUR OFFSHORE TECHNOLOGY AND BUSINESS NEEDS

- 56,000 attendees from 100+ countries
- 1,500+ exhibitors offering live demos, consultations and interactive sessions
- 20 International pavilions
- Free to attend **technical conference and keynotes**: discover **game-changing technologies** and **industry developments**
- **MyEvent online planner** and **networking opportunities** on the day: it is now even easier to make the connections that matter
- The only industry event worth attending: 13,000 of our visitors **don't attend any other exhibition**



"SPE Offshore Europe is an important event to be at and see the latest technology and thinking in our industry."

CHIEF OPERATING OFFICER,
XCITE ENERGY RESOURCES



**NEW
FOR 2017**

Organised by



Reed Exhibitions
Energy & Marine



**Decommissioning
Zone 2017**



Mining for ideas

With its remote and harsh operations, mining has similar characteristics to oil and gas exploration. Could the industry learn from mining's efficiencies? Innes Auchterlonie and Andrew Woodward explain.

We've heard a lot about how the oil and gas industry could learn from other sectors. One sector the industry could learn from is mining. The industry operates in similarly harsh environments, remote locations and experiences fluctuating commodity prices, like oil and gas. It also has a long history of operational improvement projects, due to the challenging economic conditions in which it operates.

We studied 26 improvement project case studies, carried out during 2009-2012, by a range of global mining organizations. They included below ground and open cut mines, extracting everything from precious metals and stones to iron ore, oil sands, and copper. We then compared these approaches with current UK Continental Shelf (UKCS) trends. There were similarities and differences.

Lean mining

From a functional perspective, most mining improvement projects focused on contract and vendor management, working capital reduction, materials and inventory management and throughput.

As an example, a copper mine in Australia that focused on the reduction of working capital and spare parts inventory achieved annualized savings of US\$9 million, with \$15 million in cash release.

We spoke with leaders from some of

the major oil and gas operators and suppliers in the UKCS to get some understanding of where the oil and gas industry was in relation to their counterparts in mining in these areas.

Many complained that vendors treated them as cash cows, while suppliers said operators were forcing them into blanket rate cuts. Both views may have an element of truth and have unfortunately led to an erosion of trust and an unwillingness to share risk. In comparison, the successful initiatives from mining focused heavily on win-win scenarios, aware that a strong, responsive supply chain would be key to future success.

Inventory and materials management

The challenges around working in harsh remote environments, coupled with the need to have spare parts at



Photo from iStock

the right place and at the right time, were strikingly similar. Mining companies focused on modeling spare parts requirements and developing processes to ensure stores were properly handled, with shared key performance indicators (KPIs) across the operational organization. Having spares in the right place was viewed as critical to above ground up time and therefore a high priority.

There is no doubt that our industry recognizes the problems in this area. Indeed, Oil & Gas UK launched the Inventory Management Work Group to improve performance. However, the head of Supply Chain at a major stated to the authors of this article: "We have trouble sending the right stuff offshore. When we realize that it's wrong we have problems sending it back. When it is sent back, we're often not sure where it's gone. The problems this causes for projects and maintenance is huge."

The mining sector has been quite successful in standardizing parts, which has helped their inventory control massively. We realize that with aging existing assets, this is easier said than done, but that's not all that could be done. Standard naming conventions, location codes and track and trace systems employed in other industries have brought great benefits. Engagement with the supply chain to help find solutions that are broadly applicable will also be key.

Performance

The main thrust of the mining projects focused on working practices and staff performance, rather than technology or investment.

Recurring themes were applying lean management principles that carefully analyzed the root cause of each problem, developed a financial business case, designed an improved way of working, and implemented it.

For example, a diamond mine in South Africa focused on improved operator working practice around the maintenance of processing machinery, resulting in daily production figures increasing 15%.

Across the 26 improvement projects, roles and responsibilities for performance were defined, more effective processes with key performance measures designed, and shared targets across the operational organization agreed on. Almost every mining project was driven from the production area, rather than head office and, most importantly, responsibility was given to the actual workforce performing the task. In total, these 26 mining projects delivered \$300 million in cashable savings and even more if the cash release is included from a reduction in stocks and working capital.

Here is where the big difference between mining and the UKCS oil and gas sector is clear. While there have been pockets of activity in this area, the main focus for operators has been in the application of technology to solve problems. In fact, a study by business consultancy PwC found that operators prioritized the use of technology significantly over and above all other improvement initiatives.

The use of technology can bring improvement and we should embrace it where it is necessary. However, during our study we found that no operator has undertaken any significant work to

understand human performance offshore. In addition, of the 26 mining case studies and \$300 million in savings, no capex was introduced and there had been little or additional application of technology. It was all achieved through process improvement and increases in performance of the human mechanism.

Some great advances in production efficiency have been made. Oil and Gas Authority (OGA) figures published in June this year showed production efficiency (PE) has risen for a fourth consecutive year, reaching 73% in 2016, though missing the PILOT (an industry/government task force subsumed by the OGA) target of 80%.

There's also been significant reductions in lift costs from an average of \$29.3/boe in 2014, to \$17/boe in 2016. However, it could be argued that a considerable proportion of this can be attributed to rate cuts (43% of UK O&G business reported cutting pay in 2016 (CITY. A.M)), suspended programs (O&G UK noting a reduction in summer maintenance in 2015) and staffing reductions (15% of operator staff from 2014-2016, Aberdeen and Grampian Chamber of Commerce).

We understand that much of what we discovered in mining isn't new, and much of it plays a part in the long-established operational excellence programs embedded across some of the oil majors, with some success. Yet, many of the principles we've described that have had remarkable success in mining and many other industries are still not broadly adopted in our own.

We have to ask ourselves whether we are making real change in how we conduct business that will see a long-lasting reversal of the steadily increasing costs we saw before the downturn. **OE**



Innes Auchterlonie is managing director of IMRANDD, an asset integrity consulting practice based in Aberdeen. Innes has an MBA in oil and

gas management, having graduated with a distinction from Robert Gordon University in 2015.

Andrew Woodward has a consulting practice specializing in Lean management and production systems.

Designs on the future

Diamond Offshore is championing a new Floating Factory concept meant to meet future deepwater challenges, but drumming up support during the downturn may be tough. Karen Boman reports.

Photo from iStock.

Offshore drilling contractors have sought to meet future deepwater drilling demands by enhancing current capacity, but the idea of re-designing deepwater rigs altogether has not been a major focus of discussion. Diamond Offshore's Floating Factory rig concept could change that conversation.

Diamond says it designed the concept with input from operators and service companies to address the entire well lifecycle requirements expected from 2020-2030 and beyond. It says the Floating Factory aims to improve deepwater drilling by creating efficiencies, enhancing safety, reducing overall well costs, and allowing for the future optimization of 12,192m+ long well designs in greater than 3962m water depth.

The concept, using lean methodologies, combines improved safety with automation and robotics to reduce bottlenecks and minimize controllable flat time for the entire well lifecycle, with a reduction in well duration and cost by 15-30%, says James Hebert, director of operations and technical support at Diamond, in a SPE/IADC 2017 paper, *The Floating Factory Concept*:

Engineering Efficiencies Up Front to Reduce Deepwater Well Delivery Cost.

Deepwater drilling efficiency will need to be improved to meet the challenges of exploration in plays such as the Gulf of Mexico Lower Tertiary/Wilcox trend. These challenges include complex sub-salt imaging capability, reservoir depth, high-pressure, high-temperature (HPHT) reservoirs, distribution of sand, flow capability, and cost-effective drilling and completion, Ken Richardson, EVP Offshore for classification society ABS, told *OE*.

Current floating rigs "drill" only about 20% of the time, with the balance characterized as "flat time." Flat time can include tripping, drill-line slip and cut, and the sequential rigging up and rigging down of equipment. This leaves considerable room for improvement through enhanced and new rig designs and equipment, said James C. West, senior managing director and partner with investment banking firm Evercore ISI, in a 22 June report.

While the timing for the Floating Factory may not be right for some in the industry, Diamond still believes in the concept.

"From our perspective, we're still looking at the Floating Factory concept," said Diamond President and CEO Marc Edwards, in a Q1 2017 earnings call in May. "We've got the final designs in place. We've spoken to a number of yards. We've got a full-scale prototype that has been constructed and has been tested. And, that's the way we see the market changing moving forward.

"Because the pressure from our clients is to materially take down deepwater cost through efficiency gains, and something like the Floating Factory is what is going to be required to deliver on that opportunity."

Design and features

The Floating Factory rig is a variation of Diamond's patented Huisman 12000 rig design. Huisman conducted the basic vessel design, and is designing all the mission critical equipment except for the subsea gear. No other contractors are involved in the basic design phase.

"The objective here is that vessel and equipment are designed simultaneously to optimize the whole drilling unit," Anne de Groot, project director with Huisman, told *OE*. It took about a year and a half to design the rig, which is based on a previous design for Noble Drilling's *Globetrotter* rig and on Diamond Offshore's operational experiences, de Groot says.

There's not yet a contract in place to build one of the rigs, but Huisman is conducting engineering for Diamond in preparation for construction, with the goal of readying the Floating Factory rig for work in 2020, de Groot says. In May this year, ABS announced it had approved the basic Floating Factory drillship concept.

A typical sixth generation floater has 2900sq m of free deck space, a 15-20m elevated drill floor, and measures 230m by 42m. In comparison, the new design offers 4600sq m of free deck space, a drill floor on the same level as the deck, and measures 216m by 38m.

The Floating Factory rig features an all-robotic drill floor, with tools that use condition-based monitoring and offline tool maintenance apps, West said in Evercore's report. The rig has a casing running tool integrated into the well center, with automated changes to the casing clamp, and uses a fully automated pipe handling system. The center of gravity on the rig also is reduced, and the weight is pushed outward. This

reduces vessel roll, which is crucial for dealing with bad weather.

A dual multipurpose tower capable of handling 55m stands of pipe has replaced the standard derrick and sub-structure, reducing connection times, as the design is believed to be able to trip at speeds of 1524m/hr. The hoisting system is also designed for 1500-ton static hook load compared to an average of approximately 1250-ton for sixth generation drillships, West said.

The design eliminates the potential for dropped objects by using welded connections and an open character philosophy, or more open space for procedure prep. A dual mud pit system allows for mud and completions fluid to be treated simultaneously. The Floating Factory also will have three rooms with three medium-sized engines in each versus older generation designs that have three rooms with two large engines a piece. This should allow optimal engine loading, reduced fuel consumption and lower engine wear and emissions output, West said. The rig can be fitted with a 15,000psi or 20,000psi blowout preventer, de Groot says.

Building a better mousetrap

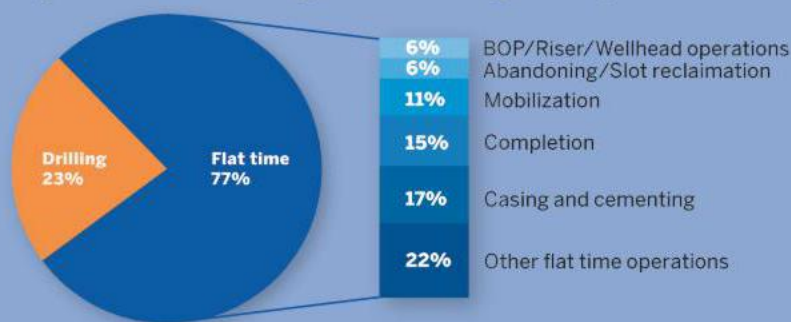
Instead of looking at new designs, the focus of rig construction in the past has been on building bigger rigs, Leslie Cook, principal analyst, upstream supply chain with Wood Mackenzie, told *OE*. To boost capacity for sixth- and seventh generation rigs, drilling contractors added greater top drive and mud pumps capacity, and dual, larger blowout preventers with more shear rams. More storage capability was added to allow more equipment to be stored onboard.

Strong demand for rigs in 2000-2014 contributed to a lack of new innovation in rig design, West said. Then when the downturn hit it was all about survival. "We're finally at a period where rig companies are turning towards the future and the innovation that is necessary to compete," he added.

Shipyards also drove the design of drilling units instead of the drilling contractors who had to work with them. This has led to a situation that is not accepted in other, more competitive sectors of the offshore industry, de Groot says.

Getting a new floating rig design off the ground in the next three to five years will be challenging, Cook says, due to the lack of appetite for newbuild rigs, and the difficulty rig contractors will

Sample customer's 2013 global floater rig activity time breakdown



Drilling days saved with the floating factory in a GOM deepwater well

| DMPT efficiency aspect | Quantification assumptions | Floating factory savings (days) |
|--|---|---------------------------------|
| Spud to BOP run sequence | Increased offline casing and BOP handling | 1.4 |
| Unrestricted hi-speed tripping <i>Where surge and swab is not a limiting factor</i> | Hi speed tripping of drill pipe d BHA only • 5,000ft/hr in open water and riser • 4,000ft/hr inside casing down to 16in OD | 4.2 |
| Restricted tripping <i>Where surge and swab is a limiting factor</i> | 180ft stands saves 2 connections per 1,000ft • Tripping inside 16in and smaller casing • Ability to run 16in casing from setback vs from main deck • Large bore or specialty tools | 8.3 |
| Reduced drilling connections | 180ft stands saves 2 connections per 1,000 -ft | 0.7 |
| Dual multi-size power slips | Pipe OD range from 3.5in to 9.75in do not require insert changes. Case slips can be installed quickly. | 1.7 |
| Drill-line slip & cut | Slip & cut is not required | 2.1 |
| Total days saved | | 18.4 days |
| Percentage of total well time saved | | 16% |

Drilling days saved with the floating factory in a GOM deepwater well

| Floating factory efficiency aspect | Estimate assumptions | Floating factory savings (days) |
|--|--|---------------------------------|
| Increased deck storage area | Improved logistics by increasing the amount of materials and equipment which can be stored on board improving off-line rig-up & rig-down capability. Also decreases risk of potential weather related NPT. | 4 to 7 |
| Increased POB | Provides space for extra 3rd party personnel to support the off-line rig-up & rig-down activity. | 2 to 4 |
| Dual mud system | Allows off-line handling, storage and treatment of drilling, completion fluids, including spacers & flushes. Provides for safe and off-line cleaning of shaker pits, mud pits and suction piping. | 1 to 7 |
| Direct crane access to a large drill floor area | Improves the ability to be assembled and tested off-line and placed on the drill floor as a larger system as compared to handling with drill floor tuggers. | 1 to 2 |
| Off-line rig-up & rig-down of completion equipment | Supports the ability to rig-up & rig-down items such as lift-frames, surface flow trees, and hoses off-line while deploying the subsea trees. | 1 to 2 |
| Total days saved | | 9 to 22 |

Source: Company Reports, Evercore ISI Research

Floating Factory concept.
Photo from Diamond Offshore.



face in convincing shareholders that more newbuild rigs is a good strategy. According to Wood Mackenzie, the marketed utilization for the global floating rig fleet is 60%, while total utilization for floating rigs is around 40%.

The downturn – which has forced drilling rig contractors and many others into a period of harsh self-reflection – will provide a fantastic opportunity for new technologies over the long-run, Matt Adams, senior analyst, Douglas-Westwood, told *OE*. However, Adams doesn't expect the Floating Factory to be added to the existing fleet any time soon. Instead, drilling contractors will mainly focus on improving efficiency and desirability of their existing fleets before looking to new designs.

“From a capex perspective, it would likely make more sense for contractors to retrofit/upgrade their existing idled units, rather than come up with new rig designs and start a new ordering cycle,” Adams says. By doing that, they can both help operators, by bringing down well costs and improving project economics, and help themselves by increasing the

likelihood of picking up contracts.

Focus on efficiency

Drilling contractors have been looking to upgrade their current fleets to reduce non-productive time when rigs are on contract, and increase their likelihood of being picked up for new contracts. Over the past year, drilling contractors have primarily focused on reducing operational, maintenance and repair costs, which account for 25% of daily cash costs, so they can continue to work through the low day rate, low oil price environment.

To reduce costs, contractors are leveraging Big Data and analytic tools, Cook says. The oil and gas industry has lagged in adopting these kinds of Silicon Valley technologies, but is now looking at putting sensors on equipment and using predictive analysis to accurately predict when equipment needs to be changed, or which parts of the drilling and operations processes need to be improved. Examples of these efforts include EnSCO's new asset management system, Diamond's pressure control by the hour, Noble Drilling's digital rig solutions, and

Transocean's performance dashboard.

“In the context of the price environment, it appears that the rig contractors are looking to provide the best value for money for their clients – providing faster drilling, higher spec rigs,” Adams says. “I would infer that their strategy, while rig day rates are low, is to show operators ‘how good it could be,’ getting them to pick-up cheap, high spec rigs so that when/if day rates recover, operators choose to stick with the high spec rigs due to greater efficiencies, rather than going for cheaper but lower spec rigs.”

Of course, Diamond believes the Floating Factory could aid in creating further efficiencies. Edwards said in the Q1 call that while the dual derrick system brings the most advantage, creating a 6-10% efficiency gain, the Floating Factory could potentially do better than that, however. “We've done some [deepwater operations plans] with our Floating Factory designs and over and above the dual derrick rigs, we can put a further 20-30% efficiency gain on drilling the wells out there,” Edward said. “So, that itself is quite compelling.” **OE**

E-BOP

A subsea electric blowout preventer made waves at UTC in Bergen. Elaine Maslin sheds light.

Norway's Electrical Subsea & Drilling (ESD) has been awarded the Subsea Upcoming Company of the Year at the Underwater Technology Conference in Bergen for its work on subsea electric blowout preventer (BOP) controls.

Since the 2010 Macondo disaster in the Gulf of Mexico, ESD, based near Bergen, has been working on its all-electric BOP concept that it says will make drilling safer and much more cost-effective. The core components of the technology are electro-mechanical actuators, integrated with well barrier utilities, and a new control system including condition-based monitoring (CBM).

The subsea industry, particularly in Norway, has been moving towards all-electric controls for subsea production systems for some time, driven by ultra-long tiebacks, to avoid the need for long and expensive hydraulic production control umbilicals and improve subsea control system reliability. In the OG21s strategy document – Norway's Oil & Gas Technology Strategy for the 21st Century – all-electric subsea wells are listed as one of the prioritized technology needs.

All electric controls for well access systems, however, are relatively new to the industry and subsea drilling.

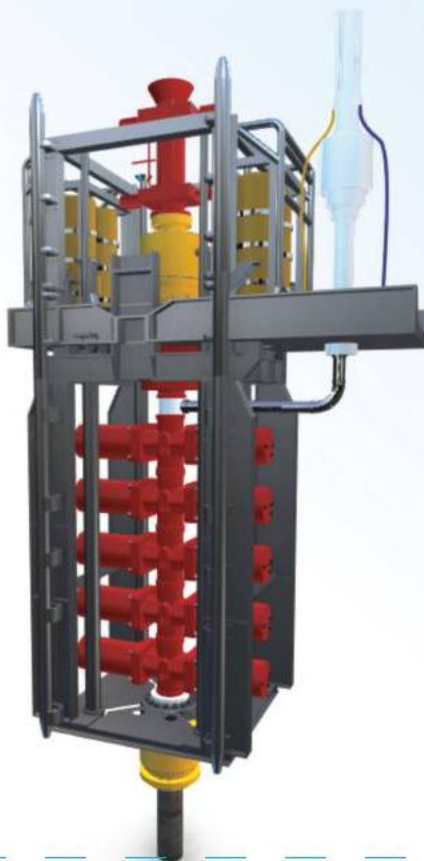
“After Macondo, regulatory authorities will be phasing in new requirements for the drilling industry, some of which will be difficult

to satisfy with current BOP technology,” says former Drill-Quip and Cameron exec John Dale. “A change from electro-hydraulic to all electric BOP control system technology, will provide much better CBM and maintenance data resulting in quick turn-around between operations and exact position monitoring of well barrier elements.”

According to Dale, the benefits include: high actuator force output, monitoring and control of applied force, no discharge of hydraulic fluid to the environment, improved redundancy, facilities for mechanical override and increased reliability through system simplification with the elimination of critical error sources. Reduced weight through removal of hydraulic equipment, real-time monitoring of available back-up power using batteries instead of hydraulic accumulators are other benefits.

“When it comes to ultra-deep high pressure and high temperature drilling, current BOP technology is stretched to the limit,” he says. “The increased BOP stack weight affects drilling rigs, handling equipment and subsea wellhead integrity. Our all-electric BOP will make it possible for existing drilling vessels to operate in much deeper waters, without major modifications.”

The award was made by GCE Subsea, Sparebanken Vest, CONNECT Vest and the Underwater Technology Foundation. ■





SEPTEMBER 13-14, 2017
MARRIOTT WESTCHASE
HOUSTON, TEXAS
www.iotinoilandgas.com

Sponsors as of 7/7/17 include:



Also featuring:



September 12, 2017
Marriott Westchase - Houston, TX
www.blockchainoilandgas17.com



September 15, 2017
Marriott Westchase - Houston, TX
www.wearablesoilandgas17.com



T: 1-855-869-4260 | info@energyconferencenetwork.com

Internet of oil things

The Internet of Things is becoming ever more embedded in the oil psyche. Steve Hamlen reports.

The increasing use of sensors coupled with the progress in data collection and management not only offers the oil and gas industry great cost reductions, but also the chance to fully embrace the march towards “Industry 4.0” – where computers and automation merge, where the Internet and manufacturing are part of one digital supply chain.

“This is the Internet of Things (IoT), where computers and automation come together in an entirely new way, with robotics connected remotely to computer systems equipped with machine learning algorithms that can learn and control the robotics with very little input from human operators,” Dave Mackinnon, head of Technology

Innovation at Total E&P UK, told delegates the Subsea North East Conference & Exhibition in Newcastle, England, mid-June.

Mackinnon described this as a clash between two worlds where you can no longer be in just the machine camp or the Internet camp. In the near future, you will need to be in both or face serious challenges to survive.



Mackinnon

– or become subsumed in an ecosystem in which they play a smaller role,” Mackinnon said.

Industry 4.0 is this merging on computers and machines. The pre-cursors, he says, were:

Industry 1.0 – Steam, which produced

the first machines that mechanized some of the work that people did. Industry 2.0 – Electricity, which created the assembly line and the birth of mass production. Industry 3.0 – Computers, which brought about the beginnings of automation and saw robots and machines starting to replace human workers on those assembly lines.

Digital supply chain

Mackinnon believes that the oil and gas industry is heading towards a digital supply chain that will revolutionize the sector. However, such a system is well advanced in many other industries, so oil and gas must play catch-up.

He used the example of a supermarket planting a lettuce in one country and tracking it all the way from harvest to transport to being placed on a shelf in a UK store – all tracked and traced from start to finish.

“Can we do that,” Mackinnon asked the audience, before citing other examples, such as Nike, which allows a customer to choose a training shoe

Autonomous PSVs on the horizon

French offshore industry vessel operator Bourbon has agreed a memorandum of understanding (MOU) with Automated Ships Ltd. (ASL) to support the building of the world's first autonomous, fully-automated and cost-efficient prototype vessel for offshore operations.

The project, which ASL launched with Kongsberg last year, will see the development of a light-duty, offshore utility ship to service the offshore energy, hydrographic & scientific and offshore fish-farming industries.

It could also be used as a ROV and AUV support ship and standby vessel, able to provide firefighting support to an offshore platform working in cooperation with manned vessels.

Bourbon and ASL are to join forces to secure the subsidies to finance the effective construction of a prototype vessel, called Hrönn.

ASL had foreseen a catamaran style design, but, since project launch in November 2016, has opted for a steel monohulled vessel, to provide more payload capacity and greater flexibility in the diverse range of operations.

Bourbon's entry to the Hrönn project comes after the firm joined forces with Kongsberg to develop digital solutions for next generation connected and autonomous vessels. The two companies will execute joint projects to develop new ways of efficient operations in the offshore services industry, with a fast time-to market.

Hrönn's Sea trials will take place in Norway's officially designated automated vessel test bed in the Trondheim fjord and will be conducted under the auspices of DNV GL and the Norwegian Maritime Authority (NMA). The Hrönn will ultimately be classed and flagged, respectively.

"We are pleased to be collaborating with such expert partners in the development of Hrönn, a vessel that will show how digitalization and autonomy have the potential to revolutionize the offshore services market," said Stene Førsund, EVP Global Sales and Marketing, Kongsberg Maritime. ■



Hrönn Photo from ASL.

online, customize it with regards to colors, laces, size and then click for delivery. All of this data is stored and managed.

Mackinnon suggested that this has great potential in the oil and gas industry, such as tracking and tracing the life-cycle of a subsea Xmas tree. Collecting and using the data of when and where it was manufactured, who bought it and where it was used, including any maintenance work required, will help any future buyers of the hardware make an informed decision: "This is Industry 4.0," he says.

The elements of the digital supply chain were described as: End-to-end digital engineering (product customization); IoT-enabled manufacturing (shop floor to top floor); IoT service implementation (embedded/cloud); and IoT service operation (product usage data).

"As an oil and gas major in the North Sea, how are we involved in manufacturing and how do we extract value," Mackinnon asked.

Total's objectives, he says, were to: reduce overall costs (capex/opex); deliver on-time and on-budget; facilitate future technology; understand and manage risk; and in the North Sea, go smaller and deeper to "push the HPHT

[high-pressure/high-temperature] envelope."

The driver to this strategy is to ensure industrial knowledge transfer to help spur innovation and technological progress. Towards this goal, Total has launched its second Plant 4.0 start-up incubator, joined by Air Liquide, AREVA, Eiffage, Solvay and VINCI Energies.

"This is the very first multi-corporate Plant 4.0 start-up incubator in the world. The partners' common goal is to accelerate the deployment of digital technology

in industry," Total said.

In the same way that the telecommunications sector achieved the triple play of merging the telephone, television and Internet into one service, so it seems the oil and gas industry is beginning to understand the benefits of the IoT and Big Data. If it makes sense and saves money, then the opportunities will be seized sooner rather than later, especially with the industry keen to trim spending, improve efficiency and produce new technology. **OE**

Virtual metering

NEL's Damian Krakowiak examines the potential of virtual flow metering technology and how better testing could enable its adoption.

With the variety of technological solutions for multiphase flow metering, many companies are now providing software solutions for establishing average flowrates for specific applications. Increased demand for real-time flow rate representation for both oil reservoir management and fiscal allocation are the main driving forces for the development of software-based solutions to estimate well flowrates.

Measurement of production is essential to best optimize the hydrocarbon production strategy from wells. This is achieved by performing a well test, the data from which is used to optimize the well's production rates. Installation of physical multiphase flowmeters can be quite often problematic (calibrating, post-installation tuning, maintenance) and very expensive, however.

Virtual flow meter (VFM) systems can be an effective alternative for multiphase flowrate measurements and can be used as a backup for the existing systems. However, there is little understanding of the measurement uncertainty of VFM systems in industry. Validation of VFM systems is crucial and, although recent studies describe overall performance of virtual measurement systems, they do not evaluate the models which drive VFM systems in great depth nor over wider

range of multiphase flow conditions. To provide confidence to end users, more knowledge on the performance of VFM systems is essential.

Virtual flow meter system

In the last five years, several VFM systems have been installed in most of the major producing areas, including the Gulf of Mexico, North Sea and East Asia.

VFM systems models are based on data from existing instrumentation within the system such as pressure



Validation needed. Photo from NEL.

and temperature sensors, choke valve feedback, and control valves feedback. Various mathematical models are created to ensure that together they fit and fully represent the overall system adequately. There are different approaches that can be taken to create a complete model of multiphase flow. VFM models can be created by including steady-state or transient flow simulations that are based on data reconciliation and data validation techniques. Appropriate modeling can be achieved by basing models on single components such as: reservoir, choke, valves, orifice, venture, and flowlines. Another method is based upon the complete network model that consists of many components interconnected together.

As shown in Figure 1, VFM systems can also operate in conjunction with other modeling systems, for example, well and pipework flow simulation software can be integrated with the system to facilitate real-time modeling. VFM systems can also be linked to statistical analysis methodologies, which can assist real-time trend identification.

Most of the existing virtual flow meter models are based on the principles of conservation of momentum as well as on mass and energy equations. The correct application of these equations ensures that each instrument will be also "checked" for its operational health. In addition to the measurement values from the existing instrumentation network, full data analysis and reconciliation will show live respective uncertainties for each measurement. This will be used to determine if individual instrument measurements are within uncertainty limits by changing the instrument state to alarm state.

In turn, this will help predict instrument behavior and aid decision-making on routine maintenance, highlighting any instruments that are not working or not performing within expected uncertainty.

Validation and verification

Like most measurement technologies, VFMs require period verification or calibration. On average, instruments are calibrated at

yearly intervals, or when there is a significant change in process conditions or well performance. Calibration involves comparing the VFM predictions with physical flow measurements. This can normally be accomplished by performing a well test, i.e. routing the flow from the well through a test separator or a multiphase flow meter for a set period of time. If necessary, model parameters will then be adjusted to minimize the differences between the predicted and measured flow.

Previous research

Research Partnership to Secure Energy for America (RPSEA) completed an evaluation into flow modeling in 2011 [1]. The RPSEA project planned to complete

a detailed study into the available VFM packages and to complete and evaluation using field data. There were three stages to the project. The first evaluated VFM systems 'out of the box'. This meant they were not tuned before use. The second stage was to evaluate how the quantity and quality of data affects the VFM. The third and final stage was to evaluate the importance of different modelling techniques used with the VFM.

The RPSEA project originally had eight suppliers involved. It's important to note that only seven suppliers completed stage 1, two completed stage 2, and only one completed stage 3. According to the RPSEA report, the dropout rate was so high amongst the VFM suppliers due to a lack of funding for the suppliers involved. Also, there was a lack of interest from suppliers when it became apparent that the RPSEA project could only supply simulated data, and not actual field data.

The development of VFM technology has been proceeding very quickly in recent years. However, it is generally agreed that further testing and development is required for VFM to constitute a viable replacement for physical metering. Presently, they are best used to supplement physical metering – usually in one or more of the following circumstances:

- As a back-up when the physical metering system is not functioning
- To perform meter verification on the existing system
- As extra measurement redundancy to reduce the uncertainty, and contribute to the application of flow modeling and statistical analysis techniques – such as data reconciliation.

Impact on industry

Validated virtual metering systems can be extremely important in helping improve multiphase measurement. Correctly designed and tuned VFM Systems can not only support flow assurance management by ensuring successful and economical flow of hydrocarbon stream from reservoir to the end point but also greatly improve preventative maintenance.

This could extend the performance and lifecycle of all assets and also reduces safety and environmental risks, as well as operational problems, which could cost industry tens of billions of dollars every year. An accurate multiphase measurement system could

potentially increase recoveries and in conjunction with tuned virtual measurement system models these recoveries may be increased. **OE**



Damian Krakowiak is a project metering engineer at NEL, a technical consultancy, R&D, testing and calibration organization across

all areas of flow measurement. He has an MSc in applied instrumentation and control systems (oil & gas) from Glasgow Caledonian University.

REFERENCES

1. Toskey, E. Research Partnership to Secure Energy for America, Evaluation of Flow Modelling – Improvements to Deepwater Subsea Measurement. Report No: 07121-1301-Task4. 2011

Production & Drilling Chokes \ Compact Ball & Check Valves
API Piping Accessories \ Pressure Relief Valves \ Valve Manifold Packages

High Pressure System Relief



Four CRV40 4" orifice PRVs installed within a CORTEC compact MPD system complete with stand-alone hydraulic controller.

Succeeding in the harshest mud pump, MPD & frac system relief requirements



CRV26 Pneumatic PRV

CORTEC's PRV line offers unparalleled levels of safety, reliability and rapid response functionality. Our models and control panels are purpose-designed and manufactured to suit the end user.

Complete with gantry systems and a full line of service tools for field-friendly operations, CORTEC is equipped to provide a PRV system to outfit your project.



The Standard in Non-Standard Valve Production

www.uscortec.com

Houston 985.223.1966

Port Allen 225.421.3300

Houston 713.821.0050

CORTEC proudly designs, manufactures, assembles, and tests all products in the USA.






 AA-0001
 100-0014


 800-0008
 100-0014


 01-1400
 100-0014

Improving maintenance

Karen Boman speaks with Prasantha Jayakody of Bsquare about the benefits of condition-based maintenance and the challenges of implementation in the oil and gas industry.

Reducing non-productive time related to equipment maintenance and breakdowns is necessary during the downturn as companies seek cost reductions. To achieve these goals, the industry is looking to shift from reactive or even preventative maintenance to data-enabled maintenance, which is automated and gathers information in real-time. Data-enabled maintenance includes predictive maintenance, predictive diagnostics, and condition-based maintenance (CBM).

CBM is a bit of a general catch-all term that encompasses several different data-driven maintain/repair concepts. It should be viewed as a “maturity model” as predictive maintenance can be done without CBM, but CBM can’t be done without adaptive diagnostics (AD), says Prasantha Jayakody, senior product manager for Bsquare Corp., an Internet of Things solution provider. CBM builds on AD, which gathers existing structured and unstructured data to create a comprehensive view of maintenance activities and recommend the best fix. CBM uses analytical software to determine equipment condition in real-time, based on equipment operating use and sensor data combined with the equipment’s AD history.

CBM is one of the tools oil and gas companies could use as they seek to digitalize their businesses. Currently, the industry is hoping to leverage digital

tools to glean more insight from the massive amount of data gathered in operations (OE: June 2017).

One example of industry’s interest in CBM is drilling contractor Transocean and GE Oil & Gas’ announcement in January that GE would provide CBM and maintenance services for pressure control equipment on seven of Transocean’s rigs over the next 10-12 years. The agreement, signed in late 2016, leverages GE’s digital capabilities to shift from event and calendar-based maintenance to condition-based monitoring and maintenance. Working with GE on parts forecasting and service scheduling will allow Transocean to optimize operations by proactively planning and minimizing between-well maintenance, GE said at the time.

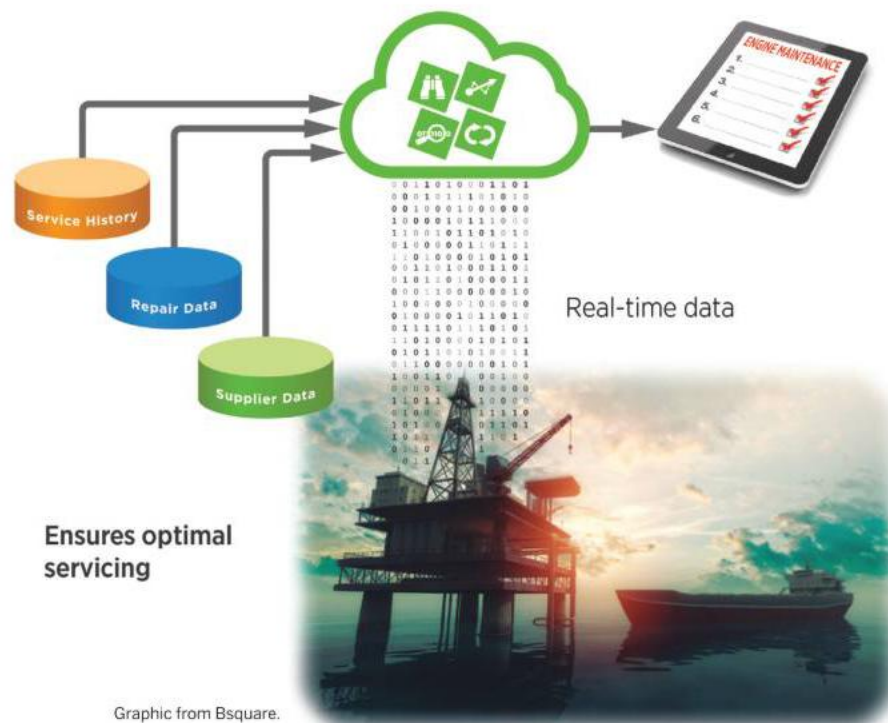
OE: How did the offshore oil and gas industry view CBM prior to the 2014 oil price downturn? How has the view changed post-downturn?

Prior to the 2014 oil price downturn, CBM was commonly viewed as a ‘nice-to-have’ and while most firms recognized the benefits of data-driven maintenance, few firms pursued it. With oil prices north of US\$100/bbl, companies could afford to run to failure or practice interval based preventative maintenance without serious repercussions to the bottom line. In the years following the price downturn, operating budgets were slashed while companies focused on projects with reduced scope and the highest return on capital. With operating budgets greatly reduced, redundant roles were eliminated across maintenance and reliability teams and basic equipment maintenance became the status quo.

OE: What are some other factors spurring greater interest in the offshore oil and gas industry to consider the wider use of CBM?

Safety and reliability are some of the biggest forces driving CBM adoption across the industry. The environmental and financial impact of catastrophic failures is a top concern of management teams and are central to safe, efficient operations. The complexity of offshore facilities balanced by a streamlined workforce presents an opportunity to leverage data to make sure work is performed on the right equipment at the right time. Riding on top of these forces

Condition-based maintenance (CBM)



Ensures optimal servicing

Graphic from Bsquare.

is the remote nature of offshore facilities. In the event of equipment failure, spare parts or intrinsic knowledge may be hundreds of miles away, so performing repairs should be done with the proper teams onsite during a time that will have the least amount of impact on ongoing operations.

OE: Why do you think that producers have failed to adopt the architecture they need? Will this prevent them from reaping the full benefits of CBM?

Data is not the issue; modern offshore facilities generate vast amounts of data from thousands and thousands of sensors. But, identifying which data is useful and what is noise is one barrier to adoption. (McKinsey reported that less than 1% of the sensor data on offshore rigs is used in the decision-making process). Another obstacle is managing this data and the costs associated with moving it to the cloud where advanced analytics and machine learning can be performed. With edge (fog) computing, much of this analysis can now be performed onsite avoiding costly cellular/satellite transmission fees while simultaneously reducing latency. Additionally, we're starting to see organizational changes across teams and hybridization between operations technology, engineering technology and information technology. Small project teams are being assembled to address critical issues and are driving scalable change across companies.

OE: What kind of challenges must the industry address for CBM to significantly impact subsea production?

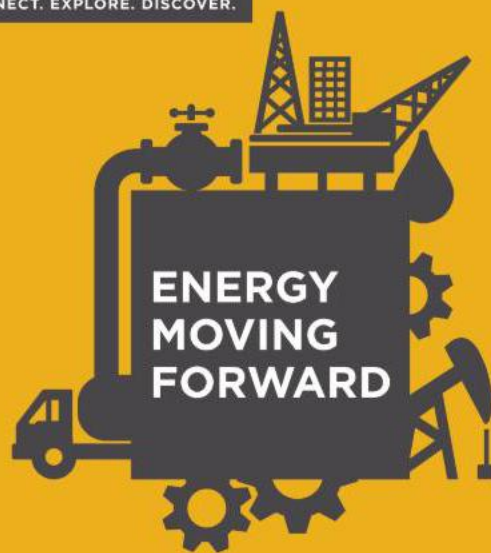
The benefits of CBM are magnified in subsea production, given the limited accessibility to equipment. However, companies need to up their CBM smarts to coordinate maintenance across subsea equipment – equipment needs to be grouped together and machine learning behind CBM analysis needs to optimize the maintenance interval across the entire group of equipment. Additionally, companies need to look beyond CBM and leverage predictive failure technology to decrease downtime of subsea equipment even further.

OE: What other challenges face the oil and gas industry in adopting CBM?

Scalability is a challenge for CBM for several different reasons. In modern rigs, data collection is natively built into most of the equipment, but it becomes more difficult in older installations. Granted, equipment doesn't have to be replaced outright as data collection technology can be retrofitted to older equipment, but this retrofit still requires planning and capital. Secondly, the ideal scenario for CBM is when you can compare performance characteristics and operating parameters across several identical pieces of equipment. It's not realistic to have a single make and model of a given type of equipment across all sites but some level of uniformity is required. **OE**



Prasantha Jayakody is a senior product manager for Bsquare. He has over 20 years' experience in the software industry, working with companies across several industries. Prasantha graduated from the University of Pennsylvania with a BA in mathematics and a BS in computer science.



The Future of Energy Is...

Connecting with colleagues from around the globe through focused business to business communication.

Exploring the latest industry equipment, products and services with hands-on access.

Discovering cutting-edge industry innovations and technical knowledge from industry leaders at our world-class exposition.

In 2017, LAGCOE strengthens its long-standing history of commitment to promote the growth of the energy industry. LAGCOE sits at the heart of America's Energy Corridor and provides a hospitable and inspiring community in Lafayette, LA in which to connect, explore and discover **Energy Moving Forward**.

REGISTRATION NOW OPEN!

ORGANIZED BY



OCTOBER 24-26, 2017 LAFAYETTE, LOUISIANA USA
LAGCOE.COM/REGISTER

Brazil

Turn the page

After years of turbulence fueled by scandal and debt woes, Brazil and its oil company Petrobras detailed how they intend to get back on the right track. Melissa Sustaita reports.

“Were trying to put the country back on track,” said Fernando Coelho Filho, Brazil’s Minister of Mines and Energy, at his first-ever visit to the Offshore Technology Conference (OTC) in Houston earlier this year.

Coelho Filho said that the Brazilian government is working to improve the country’s business environment to allow investors and more companies to be able to operate.

The country recently eased criteria for oil and gas companies to participate in pre-salt auctions, which are also on track until 2019, allowing companies other than Brazilian national company Petrobras to operate blocks.

“We do want more investors. We do want more people coming to Brazil,” Coelho Filho said. “Bid rounds, like the one that we are trying to host in the second semester, [will] be responsible for the Brazilian recovery, and the economy recovery that we need to put Brazil back on track.”

He told the audience that there are many other issues that need improvement, and that the Brazilian government is working on solutions.

“We are far, far away from doing everything we want, but we already [made] our first step. We now have a very clear calendar of the dates when the auctions will take place,” Coelho Filho said.

Brazil’s upcoming auctions for pre-salt areas are in place for 2017 until 2019. A total of four bid rounds will be held this year: the 14th bidding round, second production sharing bidding round, third production sharing bidding round, and the fourth marginal fields bidding round.

The 14th bid round of concession auctions will focus on the East Margin, which is set for 27 September, while the second and third bidding rounds for pre-salt blocks under production sharing contracts are scheduled for 27 October.

The offshore areas include Sergipe-Alagoas, Espirito Santo, Campos, Santos, and Pelotas. Brazil will offer 287 blocks at a total area of 122,622sq km. The acreage also includes onshore basins.

Sergipe-Alagoas will offer 11 blocks at a total area of about 7700sq km in ultra-deepwater, with an estimated 15 billion bbl in place.

The Espirito Santo basin includes seven ultra-deepwater blocks at a total area of about 5000sq km.

The ultra-deepwater Campos basin has 10 blocks on offer, at a total area of some 5500sq km,



Fernando Coelho Filho, Minister of Mines and Energy, speaks at OTC 2017 in Houston.

Photo by OTC/Scott Morgan.



Petrobras CEO Pedro Parente speaks at a luncheon at OTC 2017 in Houston. Photo by OTC/Edmund Fountain.

with an estimated 13 billion bbl in place.

The Santos basin has 76 blocks, both in shallow and deep-water, at a total area of about 20,000sq km.

The Pelotas basin will offer six blocks at a total area of about 15,000sq km in deepwater.

In 2018, Brazil's 15th bid round will focus on the Equatorial Margin and will offer the offshore areas of Foz do Amazonas, Ceara, Potiguar, Campos, and Santos. The year will also include the fourth production sharing bidding round with areas available in Saturno, Tres Marias, Uraipuru, and Campos; in addition to the fifth marginal fields bidding round covering marginal oil and gas accumulations in mature basins.

The 16th bidding round in 2019 will include the offshore areas of Jacuibe, Camamu-Almada, Campos, and Santos. The 2019 bidding rounds, which will also focus on the East Margin, will include the fifth production sharing bid round covering the areas of Aram, Southeast of Lula, south and southwest of Jupiter, and Bumerangue; and the sixth marginal bid round will cover marginal oil and gas accumulations in mature basins.

Coelho Filho said that the auctions are expected to raise about US\$2.6 billion (BRL \$8.5 billion) in signing bonuses. The auctions for 2017-2018 may bring in about \$61 billion (BRL \$200 billion) over the next 10 years. For 2019, Brazil is expecting to see approximately \$21 billion (BRL \$70 billion) of investments until 2027.

Petrobras CEO Pedro Parente's message was in sync with Coelho Filho, as Parente told the OTC audience that the company is also on a mission to get back on track.

Parente said that Petrobras is adopting a new strategy, creating opportunities for both industry operators and suppliers, as well as expanding partnerships with universities and research institutions that will include cutting-edge technological development with lower costs and greater production growth.

Petrobras experienced an increase in gross debt, reaching more than six times the level of 2009, and much above the industry level. Parente said that due to the debt interest rates, Petrobras is not able to invest as it would like to.

Under the company's new strategic plan for 2017-2021, Petrobras is working on a new pricing policy, increased capex productivity, increased opex efficiency, and is seeking partnerships and divestments.

"We are intensifying our partnerships with operators, with service companies, and with research institutions," he said. "We really feel good about partnerships in the E&P area. We have more than 130 partnerships."

Parente said that partnerships will boost the company's activity in upstream, including: taking advantage of technological knowledge, help with lowering research costs, faster production growth, lower capex, lower lifting costs, and reduce the breakeven of production in Brazil.

He gave an example in which it took 300 days for Petrobras to develop its first pre-salt well. Now, Petrobras can now develop a pre-salt well in less than 90 days.

In its divestment process, the Brazilian giant has changed its target to reach \$21 billion in 2017-18 across its business, a 54% increase from its 2015-2016 target of \$13.6 billion.

Petrobras also intends to reach a total production of 2.8 MMboe by 2021 in Brazil, and 3.4 MMboe internationally. "In reality, Petrobras was a victim of this huge scandal that we've seen in Brazil," he said. "We're working very hard to leave this in the past." **OE**

FURTHER READING



Brazil reveals 14th Round terms Brazil's National Petroleum Agency has published the final bidding terms for the 14th Round for oil and gas blocks set for 27 September. <http://bit.ly/2uN9eaE>

Brazil

Pioneering under pressure

Petrobras' insatiable deepwater production plays a significant role when it comes to driving global subsea systems demand. Elaine Maslin speaks with the firm's subsea systems executive manager Cristina Pinho.

As executive manager, production development and technology – subsea systems at Petrobras, Cristina Pinho has an enviable position. She's line of sight on some of the world's largest subsea developments – including the giant pre-salt, multi-floating production unit Libra project. She's also working for a firm that has been a global leader in subsea technology development.

Today, the focus is, however, on cost. “Four years at US\$100/bbl contributed to a vicious behavior in the oil and gas industry,” she told the Underwater Technology Conference (UTC) in Bergen, mid-June. “It's time to re-think and pursue projects with break even at \$35/bbl again.”

The industry will also have to work hard not to slide back into bad habits. She says projections suggesting project costs will increase 7%/yr from 2018-2023 as oil demand increases. “If this happens, cost will be at the same level as 2014 again. We should work to keep costs low, to at least the same level as 2006. How?”

It's a tough question, but she's been working on some

answers, not least on Libra. Pinho, who studied mechanical engineering at the Federal University of Rio de Janeiro, became a manager of production operations for Petrobras in 1997, managing the P-07 and P-20 platforms. She's held various roles, including general manager of exploration and production facilities and general manager of operations and maintenance. Pinho also holds two MBAs.

Petrobras is important for the global subsea market. South America accounts for 17% of global demand for subsea trees, Pinho told the UTC, with Petrobras accounting for 90% of that demand. Subsea scope cost is also important to Petrobras, amounting to 37% of project cost, she says.

Yet, while there are just four main subsea system suppliers, most with modern facilities in Brazil, the buyer market is fragmented, she says, which doesn't induce industrialization or standardization.

In this context, Petrobras sees increasing productivity and reducing the total cost of ownership of subsea systems. It

“We have to think differently.
Today, what we really need is to be simpler.
We need the size of things to be diminished
to have safer installation.”

– Cristina Pinho, Petrobras



has been working on a continuous cost reduction program, PRC-Sub, since 2012, focusing on design engineering, operation, process safety, contracts and service level. It is similar to and follows another project focusing on well cost reduction (PRC-Poço).

On PRC-Poço, Petrobras found that well construction cost was driven by was rig time. “On subsea the most important element is the equipment, at 70% of the cost,” says Pinho, speaking with *OE*. “Flexible lines are a large part of Brazilian subsea production, so these were targeted, optimizing the subsea layout.” This includes using single lines for water and gas injection, saving some 132km of flowline being used on a typical subsea layout.

Overall, the cost reduction work has seen a 40% decrease in flowlines and other optimization applied on subsea equipment, she says. She said this was achieved through working with research institutes, suppliers, installation contractors, and others, and that Petrobras sees more potential by working this way. Other areas that could reap savings include reducing inspection and monitoring frequency.

On Libra, Petrobras and its partners are working on “Libra 35,” a project seeking a \$35/bbl break-even price for Libra, something the firm has said is achievable.

The cost reduction work so far has saved Petrobras US\$500 million across the business, with a forecast \$4.5 billion expected to be saved by 2026. But to achieve a 30-40% reduction in total life cost, subsea systems need a different approach, Pinho says. This includes promoting the integration of different disciplines – reservoir, wells, subsea, topside, flow assurance – to generate options that can be evaluated in a fast way. Pinho says that Petrobras developed a tool to help evaluate options.

Petrobras already has the benefit of scale, she says. “We moved on standardized control systems for Xmas trees so now we can mix trees from different suppliers with control systems from different suppliers, giving us flexibility. But, there is room to move more profoundly on standardization of equipment. Now we have to do this,” she says.

Petrobras has been working with flexible lines for 30 years and has now made a standard “menu” of flexible lines and then tries to select from this menu. “It allows us to move to a different type of contract, to frame agreements,” Pinho says.

But, there’s a flip side to the standardization coin. “Sometimes we standardize the wrong things,” she says. This could be when moving to ultra-deepwater fields, with high-pressure and high-temperature, and just increasing the size of equipment. This very quickly turns into oversize equipment that’s difficult to install.

“We have to think differently,” Pinho says. “Today, what we really need is to be simpler. We need the size of things to be diminished to have safer installation.”

To add to the challenge, there’s a tight schedule. Petrobras has a lot of projects coming online in the next 5-10 years, Pinho says. The work will include making the most of suppliers and contractors, “especially when they are merging, making alliances, trying to get synergies.” This “new shape of the market,” is exciting for Petrobras, Pinho says. “As Petrobras,



The Libra EPS FPSO.
Photos from Petrobras.

we should provide the right environment to make it happen – to be open to discussion to new ideas and solutions for our projects and to find a way to have companies participate from the beginning of a project.”

The big project, of course, is Libra. It’s also a new frontier in terms of Petrobras’ approach, with partners and with suppliers, says Felipe Moreira Matoso Ribeiro Gomes, general manager for subsea engineering, Petrobras.

“I think it will be very exciting. To begin this project with other participants,” Pinho says. “We are starting the pre-salt again,” Gomes says. “And then use what we learn for the future.” Libra is being developed in a phased, or modular way, starting with an early production system, to know about the reservoir and flow assurance. Second semester 2017, Libra was due to start production from an early production system – the *Libra Pioneer* floating production, storage and offloading vessel, with one well.

But, it’s not all about reducing cost. There are challenges where new technology might have a place, however. “Recently, we are facing problems with CO₂ (i.e. on Libra) and we are working hard with suppliers of flexible lines to find different solutions,” Pinho says. This could be new materials, include composites, Gomes says. “This is something we really want from industry, to prove equipment with composites,” Pinho adds.

Artificial intelligence, big data and machine learning could also help the oilfield. “We need to know more about these to understand how we can apply them in our operations,” Pinho says. “In the last five years, a lot of effort has gone into our integrated operation room, where experienced people work together, monitor the operation, and help with logistics and solutions when something happens. We are still putting energy into this, but it never ends. We should understand how we can manage integrated operations with the data we get from the fields and from our history, how we can have the benefit of all this. We have a mountain of data we can work with. We are starting in exploration, looking at what is best information to lower the risk of the exploration phase.”

Predictive maintenance, inspection work, monitoring, improving the productivity of tools will also all come under this scope, Gomes says. And it goes beyond software. Hardware like subsea robotics can play a greater role. “We used to inspect pipes with divers, we can now do this with tools and robots,” Gomes says. “And there is room for us to improve the use of robots, to be more predictable and efficient.” **OE**

Brazil

Pre-salt prevails



Peregrino A platform. Photo from Statoil/ Øyvind Hagen.

Brazil is slowly emerging from one of its worst economic crises with the country's oil and gas sector no exception, says the EIC's Pietro Ferreira.

Brazil's most important oil and gas player, Petrobras, plans to invest US\$74.1 billion by 2021 under its revised investment plan. It is progressing with several of its pre-salt projects.

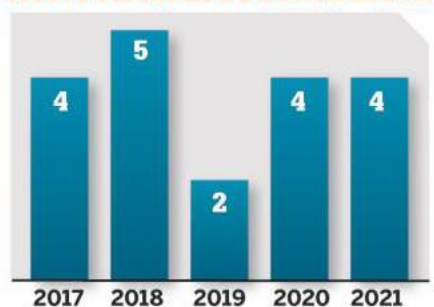
The much-delayed bidding process for the charter of a 180,000 b/d floating production, storage and offloading (FPSO) vessel for the Libra pre-salt field (pilot project) seems to be nearing its conclusion. BW Offshore, MODEC and SBM Offshore submitted bids to Petrobras in May and, at the time of writing, a technical evaluation was underway. Commercial proposals were due to be revealed in July, with an award expected in September or October. A tender process for the *Libra 2* FPSO, the second permanent unit at the field, is planned to be launched this year, with a contract award in 2018.

Another major pre-salt project involving an FPSO is *Sépia*, where a 180,000b/d unit will be deployed. MODEC was revealed as the lowest bidder in May, having offered a day-rate of approximately \$720,000. An award is expected to be announced soon.

Meanwhile, a tender process for an FPSO for the *Búzios* pre-salt field started during Q2 2017. Petrobras is understood to have invited major floater specialists to bid for the field's fifth FPSO, which will have oil and gas processing capacities of 150,000 b/d and 6 MMcm/d, respectively. The bidding deadline is 15 September.

Petrobras is also looking for two smaller production units to replace existing semisubmersibles and FPSOs at the Marlim field in the Campos Basin. The company is seeking expressions

New Petrobras FPSOs in Brazil



of interest from potential bidders with tender documents for the 100,000b/d *Marlim 1* FPSO expected to be released in late 2017.

Statoil

In May, Heerema Fabrication Group (HFG) was awarded a contract by Norway's Statoil to

provide a 9300-tonne jacket for the WHP-C platform, which will be installed as part of the second development phase of the Peregrino heavy oil field. Kiewit will supply the platform's deck (with Wood Group providing engineering and procurement services) while Cameron Sense will provide the unit's drilling package.

Karoon

Australian oil company Karoon is looking to install a 40,000 b/d production unit at the Echidna oil field, in the shallow waters of the Santos Basin. A tender for a six-year charter contract is expected to be launched in the coming months and it is understood that Karoon will welcome bids offering an FPSO or a semisubmersible unit connected to an FSO.

Market perspectives

The local oil and gas market is eagerly anticipating three bidding rounds for exploration and production blocks taking place in September and October. The first, scheduled for 27 September, will offer 287 exploration blocks in 11 basins across the country. The second and third bidding rounds, both scheduled for 27 October, will offer eight pre-salt blocks. Petrobras has already signaled its intention to bid for three such blocks and the local industry expects other IOCs to follow suit. **OE**



Pietro Ferreira works as a regional analyst at the Energy Industries Council (EIC) regional office in Rio de Janeiro, Brazil. He is a graduate in International Relations. His activities involve researching and analyzing project information on the South American energy market.

7th Annual



Gearing Up For The Future

AUGUST 29-31, 2017

Omni Riverway, Houston, TX

The Digital Revolution is Now



The drive toward digitalization isn't just for the automotive industry. This year's forum discusses the use of smart tools, software, and automation technology to lower costs and improve efficiency on FPSO projects from start to finish.

Join us for this year's half day workshop:

Planning for the Digital FPSO

Tuesday, August 29th
1:00pm - 5:00pm

Increase your awareness and understanding of the technology and trends for "digital" applications for FPS/FPSO configurations. Learn the proven and potential benefits as well as how to identify and mitigate potential risks.

REGISTRATION:

Use code **FPSOEHPI** to receive complimentary access to the exhibit hall and a reduced conference rate.

For information on exhibit and sponsorship opportunities please contact:

Jennifer Granda | Director of Events & Conferences
Email jgranda@atcomedia.com
Direct +1.713.874.2202 | Cell +1.832.544.5891

globalfpso.com

Hosted by:



Sponsored by:



Organized by:



Produced By:



Solutions

NOV adds new Lift Frame

National Oilwell Varco (NOV) has introduced a new compensated coiled tubing lift frame (CCTLF) to the Devin product line of intervention and stimulation equipment.

The new CCTLF has been engineered to support today's ultra-deepwater string weight and enhance operational performance. The lift frame provides a designated work window between the topdrive and landing string for subsea completion and intervention activities. Weight is distributed evenly across the top section, down two legs, and back to center at the bottom section, allowing for well center rig-up of coiled tubing, wireline, and slickline. The system can be rigged up both as a backup or primary compensator.

The new frame introduces a fully automated motion-compensation operating mode, which includes auto-tide adjust with manual override capabilities, that eliminates the need for system adjustments once rigged up. Remotely operated hydraulic control systems yield increased safety and flexibility, while real-time system monitoring via hand-held units provides system displays on the rig floor and in the drill shack. Having access to this data and understanding critical parameters enables rapid responses to potential problems.

www.nov.com/CCTLF



Belzona unveils corrosion protector

Belzona Polymeric has unveiled the Belzona 3412, an encapsulating membrane that can be brushed or spray applied to complex metallic and painted surfaces to protect machinery and equipment from severe corrosion. Belzona 3412's water-excluding corrosion inhibitors allow it to provide

protection against galvanic, crevice and many other types of corrosion. It also protects against aggressive environmental factors such as UV resistance. The company said it is the ideal solution for flange protection.

The isocyanate-free system coating comes in two colors, grey and orange. The grey blends into metallic substrates; the bright orange enhances the visibility of Belzona 3412 and highlights areas, which can be peeled and inspected. When used with Belzona 8411, a release agent/corrosion inhibitor, Belzona 3412 can be cut and peeled back during required maintenance or to check the status of the substrate, before being fully resealed with an extra layer. Depending on the temperature and humidity of



the environment, the material takes between one and four hours to become touch-dry, meaning minimal downtime for the coated equipment.

www.belzona.com



Inmarsat launches fourth satellite

Inmarsat has launched its fourth high-speed broadband communications satellite, the Inmarsat-5 F4, in its Global Xpress constellation. The fourth satellite adds further capacity to the GX network, as well as in-orbit redundancy that further upgrades the reliability and resilience of Inmarsat's service offerings. The other three satellites in the constellation have been delivering global coverage to users on land, at sea and in the air since December 2015. Boeing has served as the company's satellite manufacturing partner for the Global Xpress project; SpaceX has been Inmarsat's launch partner.

www.inmarsat.com

Vortec shows off new A/C vests



In an effort to combat heat stress, Vortec has introduced the Personal Air Conditioning Vests (PACs), which help circulate cool air to minimize temperature-

related stress and fatigue, thus improving comfort and productivity. Vortec PACs use a vortex tube to reduce the temperature of the air circulating through their vests, which diffuses the air flows around the

worker's torso.

The circulating air is up to 60°F cooler than ambient, keeping workers cool even in oppressive environments, the firm says. Durable, plasticized vests are available in three sizes and provide continuous cooled or warmed air through its perforated lining. They do not restrict movement, do not absorb sweat or other contaminants, and can be worn under other protective clothing. Dual action PACs can easily switch from cold to hot, to provide comfort in all seasons, and amortize the investment in this PPE.

www.vortec.com



Ampelmann designs new gangway

Ampelmann released its latest gangway for personnel transfer: the A-type Enhanced Performance (AEP). Now providing clients with 10% greater workability in sea states up to 4m significant wave height; the AEP also has the ability to use smaller vessels to obtain similar performance (compared to current A-type).

The AEP features an advanced motion compensation control system with precision controls to enable fast landing and comfortable people transfers. The system significantly improves operational up-time on projects year-round and provides benefits to operators in rougher waters, including the North Sea and the coasts of South America and the Middle East.

The AEP can also be used to ensure comparable workability on a relatively small vessel, where bigger vessels were needed before, saving cost for Ampelmann's client by allowing flexibility in positioning on the vessel.

www.ampelmann.nl



Delmar updates RAR Plus, MOORMax

Delmar Systems unveiled the new RAR Plus, a next generation rig anchor release (RAR), which adds key features such as a manual backup release method and increases the ultimate and release load ratings. The RAR Plus transmits both direct and indirect line tension measurements from internal sensors for real-time display onboard the rig in a user-friendly graphical user interface.

The RAR Plus is a key component in the new Delmar MOOR-Max Releasable Mooring System, which Delmar says provides a revolutionary mooring system for MODUs to avoid storms or improve rig move efficiency. The company said the mooring system combines proven acoustic mooring release technology with efficient proprietary methods that come from over 40 years of rig move experience.

www.delmarus.com

GustoMSC offers new jackup for wind installations

GustoMSC has debuted the NG-20000X, a self-propelled jackup design characterized by a high variable load and large water-depth capability, offering a new approach for wind turbines with capacities beyond 10MW. The NG-20000X features a telescopic leg crane, which offers a hook height when extended of 1250-tonne at 160m, and offers an increased hoisting capacity when retracted of 2500-tonne at 120m. The design addresses the spiraling trend of growing crane weights due to the increasing requirements related to the heavy foundations and high installation heights, while staying close to the proven design technology at the same time, said Jan-Mark Meeuwisse, commercial director, GustoMSC.

Based on GustoMSC's leg encircling crane designs, the NG-20000X design offers a proven variable speed drive jacking system and a large unobstructed deck area. Its variable load capacity of 16,500-ton allows the contractor to make a roundtrip carrying six complete sets of wind turbine components with a turbine weight of 1000-ton, or carrying seven pieces of 900-ton jacket foundations, optimizing the cost per installed turbine or foundation. www.gustomsc.com



Activity

SNC-Lavalin completes Atkins takeover



Heath Drewett, president, Atkins, and Neil Bruce, SNC-Lavalin president and CEO, discuss their plans for the company following the acquisition close. Image from SNC-Lavalin's YouTube channel.

Montreal-based engineering and construction (E&C) firm SNC-Lavalin has closed its £2.08 billion (US\$2.6 billion) acquisition of UK-based engineering firm Atkins Global.

SNC-Lavalin President and CEO Neil Bruce says the acquisition of Atkins

establishes the company as a top three E&C provider within the industry.

The acquisition of Atkins creates a global fully integrated professional services and project management company – including capital investment, consulting, design, engineering, construction,

sustaining capital and operations and maintenance. The new combined company will have over 50,000 employees and annual revenues of approximately \$9.2 billion (C\$12 billion).

Heath Drewett, group finance director and executive director of Atkins, now becomes president of Atkins, SNC-Lavalin's fifth business sector, and a member of SNC-Lavalin's executive committee, reporting directly to Neil Bruce.

"Joining SNC-Lavalin will provide us with the ability to offer our clients and employees the enhanced scale, capabilities, expertise and other benefits that come with being part of a larger and stronger global company," Drewett said. "At the same time, we look forward to bringing our own unique project management, design, consulting and engineering capabilities to SNC-Lavalin's clients. The result will be a more agile and responsive company that better meets client needs and creates cross-selling opportunities."

Centrica, Bayerngas Norge to form JV

Centrica and Stadtwerke München have agreed to combine Centrica's European oil and gas exploration and production business with Bayerngas Norge.

The new joint venture company will be owned 69% by Centrica and 31% by Bayerngas Norge's existing shareholders, led by SWM and Bayerngas, and could ultimately be listed on the stock market.

The JV will comprise Centrica's assets in the UK, Netherlands and Norway and Bayerngas Norge's assets in the UK, Norway and Denmark.

Once combined, the JV would have 2016 year-end 2P reserves of 409 MMboe, 2016 year-end 2C resources of 216 MMboe (66% gas reserves) and expected combined 2017 production in the range 50-55 MMboe from 27 producing fields. The company's assets will include a UK onshore terminal at Barrow-in-Furness.

The deal, which is expected to realize cost savings of £100-150 million, is due to close in Q4.

GE, Baker Hughes complete merger

GE Oil & Gas and Baker Hughes also completed their planned merger, which will create an entity that offers GE's digital solutions and Baker Hughes domain expertise as oilfield services provider. The new company will trade under the stock symbol BHGE.

"Disruptive change is the world's new normal," said Lorenzo Simonelli, president and CEO of Baker Hughes, a GE company. "We created BHGE because oil and gas customers need to withstand volatility, work smarter, and bring energy to more people—and our offering to them is now different than any other in the industry. Ours is a new company that brings together over a century of experience and is built on invention, execution and the quality of our people and culture."

TFKable to acquire JDR

Global producer of wires and cables Tele-fonika Kable (TFKable) will acquire subsea umbilicals and power cables supplier JDR Cable Systems.

Both companies have a long history of collaboration, with TFKable being JDR's business partner providing water blocked power cores for its cable and umbilical systems. JDR's subsea systems, used in the global offshore oil, gas and renewable industries, allow its customers to power and control their offshore operations, and will enhance the range of cable solutions TFKable can provide to its customers, the company said.

The transaction, which is subject to receipt of required regulatory approval and consents and other customary closing conditions, is expected to close in Q3 2017.

Meanwhile, JDR has officially opened a 4000sq m European service center in Newcastle upon Tyne, UK.

The new center aims to deliver greater service value for clients and facilitate continued growth.

The multipurpose center includes a workshop, warehouse, visitor center and state-of-the-art offices. The facility – which will house up to 50 staff – will also serve as the central base

for JDR's European service operations and the company's sales and marketing functions.

The location was strategically selected for its proximity to projects in the North Sea and Europe, JDR's manufacturing facility in Hartlepool and the local supply chain, allowing JDR to rapidly respond to client needs and provide additional service value.

AFGlobal acquires Advanced Measurement

AFGlobal has acquired Advanced Measurement (AMI), a provider of automation, controls and data management systems.

AFGlobal says that this acquisition enhances the company's current upstream drilling, completion and production smart technology, providing better answers and efficiencies for its clients.

"AMI's offerings will help broaden our reach as an OEM," says Curtis Samford, president and CEO of AFGlobal. "This

strategic technology addition will serve as an important vehicle for us to further develop more advanced control and data management offerings, enhancing our ability to help clients achieve stronger production gains and make better real-time decisions."

Helix, GATE ink subsea MOU

Two Houston-based companies, Gibson Applied Technology & Engineering (GATE Energy) and Helix Energy Solutions robotics subsidiary Canyon Offshore signed a memorandum of understanding to jointly offer subsea blockage prevention, detection and remediation solutions to the offshore oil and gas industry.

The parties anticipate this alliance will offer effective and integrated blockage solutions using GATE Energy's flow assurance engineering and patented technical solutions, combined with Canyon Offshore's world class vessel and ROV assets.

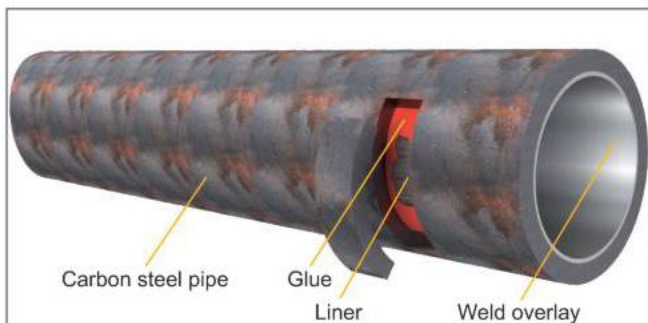
GeoSea to acquire offshore wind installer A2SEA

Belgian firm GeoSea moved to acquire full ownership of offshore wind installation and service firm A2SEA from Denmark's DONG Energy and Germany's Siemens, who stated that owning the group is no longer within the scope of DONG's core business, prompting the move to sell.

A2SEA, which has been owned by DONG and Siemens since 2009, will continue to operate out of Denmark.

"The activities of A2SEA represent a strong and complementary fit with GeoSea's operations," said Luc Vandenbulcke, managing director GeoSea. "The combined organizations will be well positioned to provide a broader range of integrated services and solutions to offshore wind energy customers."

The transaction, which is conditional upon authority approval, is expected to be completed in Q3 2017.



GluBi® pipe

Innovation for the oil and gas industry

BUTTING has developed a glued mechanically lined pipe that can be laid by the reel-lay process, without using internal pressure or increasing the wall thickness of the liner: the GluBi® pipe!

Take advantage of our know-how and contact us!

BUTTING Group
 Thomas Schüller
 Phone: +49 5834 50-375
 thomas.schueller@butting.de



BUTTING
 www.butting.com

ATL SUBSEA

COLLAPSIBLE FLUID CONTAINMENT BLADDERS

IN SUPPORT OF: EXPLORATION • PIPELINES • DRILL RIGS
 • BOP SKIDS • ACCUMULATORS • SUBMERSIBLES

- 20+ YEARS OF SUBSEA BLADDER SERVICE
- CONSTRUCTED FROM DURABLE, REINFORCED SYNTHETIC ELASTOMERS; MAXIMUM RELIABILITY & LONGEVITY - REUSABLE
- WIDE SELECTION OF FITTINGS & ATTACHMENTS
- FLEXIBLE MATERIALS COMPATIBILITY EXPERTS

MADE IN THE USA

RUGGED, COLLAPSIBLE CONTAINERS FOR SUBSEA FLUID STORAGE & DISPENSING OF:

- MONO-ETHYLENE GLYCOLS (MEG) • HYDRATE INHIBITORS • BIOCIDES
- NAPHTHENATE • ANTI-CORROSION TREATMENTS • ETHANOL
- LUBRICANTS • SALT DEPLETERS • PIPELINE MAINTENANCE COCKTAILS

800-526-5330 atlinc.com
 RAMSEY, NJ USA +1-201-825-1400 atl@atlinc.com

EXPEDITED DELIVERY AVAILABLE!

Editorial Index

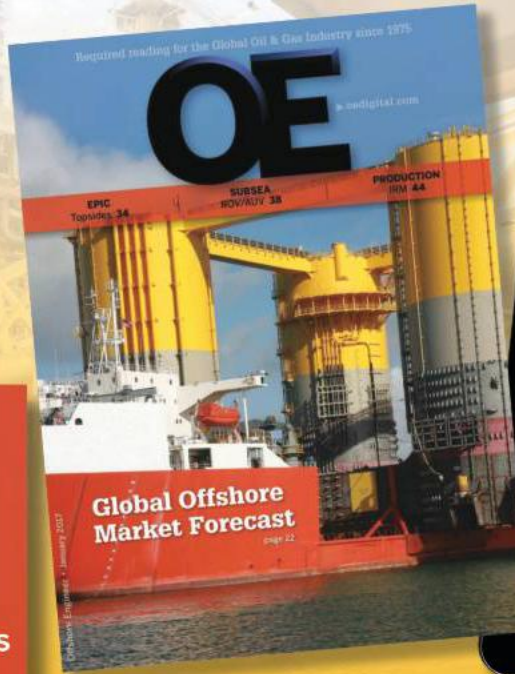
| | | | | | |
|--|----------------|--|------------|---|--------------------------------|
| ABS www.abs-group.com | 44 | GE www.ge.com | 52, 62 | Paragon Offshore www.paragonoffshore.com | 15, 30 |
| AFGGlobal www.afglobalcorp.com | 63 | Geoje Shipyard www.shi.samsung.co.kr | 8 | PEMEX www.pemex.com | 16 |
| Air Liquide www.airliquide.com | 49 | Glasgow Caledonian University www.gcu.ac.uk | 51 | Petrobras www.petrobras.com | 12, 21, 24, 30, 54, 55, 56, 58 |
| Aker BP www.akerbp.com/en | 11 | GustoMSC www.gustomsc.com | 61 | Petronas www.petronas.com.my | 12 |
| Aker Solutions www.akersolutions.com | 15, 33 | Harland & Wolff www.harland-wolff.com | 30 | PGNiG Upstream Norway www.norway.pgnig.pl ... | 11 |
| Ampelmann www.ampelmann.com | 61 | Heerema Fabrication Group www.hfg.heerema.com | 58 | Premier Oil www.premier-oil.com | 10, 14 |
| AREVA www.areva.com | 49 | Helix www.helixesg.com | 63 | PwC www.pwc.com | 43 |
| ASL www.aslmarine.com | 49 | Huisman www.huismanequipment.com | 44 | Qatar Petroleum www.qp.com.qa/en | 12 |
| Asset Performance Networks www.ap-networks.com | 38 | Husky Energy www.huskyenergy.ca | 10, 12, 25 | Queiroz Galvão Exploração e Produção www.qgep.com.br | 10 |
| Atkin www.atkinglobal.com | 62 | Hydro Group www.hydrogroupplc.com | 34, 35 | Research Council of Norway www.forskningssradet.no/en | 33 |
| Baker Hughes www.bakerhughes.com | 63 | Immarsat www.immarsat.com | 60 | Robert Gordon University www.rgu.ac.uk | 43 |
| Bayerngas Norge www.bayerngasnorge.com ... | 62 | IMRANDD www.imrandd.com | 42 | RPSEA www.rpsea.org | 50 |
| Belzona Polymetrics www.belzona.com | 60 | Infield Systems www.infield.com | 24 | Samsung www.samsungshi.com | 8 |
| BHP Billiton www.bhpbilliton.com | 16 | Inpex www.inpex.co.jp | 3, 8 | SBM Offshore www.sbmoffshore.com ... | 21, 24, 58 |
| Bluewater www.bluewater.com | 14 | INSEAD www.insead.edu | 37 | Schlumberger www.slb.com | 15 |
| Bourbon www.bourbonoffshore.com | 49 | JCG Corp. www.jgc.com | 12 | SeaCaptaur www.seacaptaur.com.au | 31 |
| BP www.bp.com | 11, 20, 30 | JDR Cable Systems www.jdr-cables.com | 63 | SENER www.sie.energia.gob.mx | 18 |
| Bsquare www.bsquare.com | 52 | Karooon www.karoongas.com.au | 58 | Sevan www.sevanmarine.com | 14 |
| Bumi Armada www.bumiarmada.com | 24 | Keppel Verlome www.damenshiprepair.com | 14 | Shell www.shell.com | 8, 10, 33 |
| BW Energy www.b-wenergy.com | 25 | Kiewit www.kiewit.com | 58 | Sierra Oil & Gas www.sierraoilandgas.com.mx .. | 10 |
| BW Offshore www.bwoffshore.com | 10, 24, 58 | Kongsberg www.kongsberg.com | 31, 49 | SNC-Lavalin www.snclavalin.com | 62 |
| Cameron www.cameron.slb.com | 46 | Kufpec Norway www.kufpec.com | 11 | SOFEC www.sofec.com | 12 |
| Centrica www.centrica.com | 14, 30, 62 | Loughborough University www.lboro.ac.uk | 37 | Sparebanken Vest www.spv.no | 46 |
| Chevron www.chevron.com | 10 | Lukoil www.lukoil.com | 12 | Stadtwerke Munchen www.swm.de | 62 |
| CNOOC www.cnoccltd.com | 25 | Maersk Oil www.maerskoil.com | 12 | Statoil www.statoil.com | 10, 32, 58 |
| CONNECT Vest www.connectvest.no | 46 | Mexico's National Hydrocarbons Commission www.gob.mx/cnh | 17 | Subsea 7 www.subsea7.com | 12, 33 |
| ConocoPhillips www.conocophillips.com | 12 | Minox www.minox.no | 33 | Sulzer www.sulzer.com | 33 |
| Cosco www.en.cosco.comcol/col786/ | 14 | MODEC www.modec.com | 24, 58 | Talos Energy www.talosenergyllc.com | 10, 19 |
| Dana www.dana-petroleum.com | 15 | National Subsea Research Institute www.nsri.co.uk | 30 | TAQA www.taqaglobal.com | 12 |
| Delmar www.delmar.com | 61 | NEL www.tuvnel.com | 50 | TechnipFMC www.technipfmc.com | 8, 12, 33 |
| Diamond Offshore www.diamondoffshore.com .. | 44 | Nexen www.nexencnooltd.com | 15 | Teekay Petrojarl www.teekay.com | 14 |
| DNV GL www.dnvgl.com | 49 | Nike www.nike.com | 48 | TFK Cable www.tfcable.com | 63 |
| Douglas-Westwood www.douglas-westwood.com | 46 | Noble Drilling www.noblecorp.com | 30, 44 | Total www.total.com | 8, 11, 33, 48 |
| Dril-Quip www.dril-quip.com | 46 | Norwegian Maritime Authority www.sjofartsdire.no/en | 49 | TPAO www.tpao.gov.tr/tp5 | 12 |
| EIC www.the-eic.com | 58 | NOV www.nov.com | 31, 60 | Transocean www.deepwater.com | 52 |
| Eiffage www.eiffage.com | 49 | Ocean Installer www.oceaninstaller.com | 12 | Tullow Oil www.tulloil.com | 10, 25 |
| Electrical Subsea & Drilling www.esdrilling.no/about-esd | 46 | Oceanering www.oceanering.com | 15 | Underwater Technology Foundation www.utc.no/utf | 46 |
| Endeavor Management www.endeavormgmt.com | 22 | Offshore Production Buoy www.opb.solutions .. | 31 | University of Pennsylvania www.upenn.edu | 53 |
| Eni www.eni.com | 10, 14, 19, 24 | Oil & Gas Authority www.ogauthority.co.uk | 28, 38, 43 | University of Queensland www.uq.edu.au | 37 |
| EnQuest www.enquest.com | 24 | Oil & Gas Technology Centre www.theogtc.com | 28 | VINCI Energies www.vinci-energies.comen | 49 |
| Evercore ISI www.evercore.com | 44 | Oil & Gas UK www.oilandgasuk.co.uk ... | 29, 38, 42 | Viper Subsea www.viperinnovations.com | 15 |
| ExxonMobil www.exxonmobil.com | 10, 25, 33 | OneSubsea www.slb.com | 12 | VNG Norge www.vng.no/en | 32 |
| Federal University of Rio de Janeiro www.ufrj.br | 56 | ONGC Videsh www.ongcvidesh.com | 10 | Vortec www.vortec.com | 60 |
| Fincantieri www.fincantieri.com | 37 | Ophir Energy www.ophir-energy.com | 24 | Wood Group www.woodgroup.com | 12, 20, 26, 27, 58 |
| Fugro www.fugro.com | 12 | Pancontinental Namibia www.pancon.com.au .. | 11 | Wood Mackenzie www.woodmac.com ... | 19, 24, 46 |
| GATE Energy www.gateinc.com | 63 | Panoro Energy www.panoroenergy.com | 10 | WorleyParsons www.worleyparsons.com | 36 |
| GCE Subsea www.gcesubsea.no | 46 | | | Yantai Raffles www.cimc-raffles.com | 14 |

Required reading for the Global Oil & Gas Industry since 1975

OE

Offshore Engineer

- Actionable Intelligence, on and for the global offshore industry
- Field development reports
- Global coverage with regional updates on key exploration areas
- Case studies on new technology



SUBSCRIBE FOR FREE!

FAX
this form to
+1 763.746.2785

or
visit us at
www.oedigital.com

1. What is your main JOB FUNCTION (check one box only)

- | | |
|--|--|
| <input type="checkbox"/> 50 Engineering | <input type="checkbox"/> 54 Field Operations |
| <input type="checkbox"/> 51 Exploration, Geology, Geophysics | <input type="checkbox"/> 55 Consulting |
| <input type="checkbox"/> 52 Drilling, Production, Operations | <input type="checkbox"/> 56 HR, Staff Recruitment |
| <input type="checkbox"/> 53 Executive & Other Senior, Mid-Level Mgmt | <input type="checkbox"/> 99 Other (please specify) _____ |

2. Which is your company's PRIMARY BUSINESS ACTIVITY (check one box only)

- | | |
|---|---|
| <input type="checkbox"/> 20 Oil / Gas Company, Operator | <input type="checkbox"/> 33 Service, Supply, Equipment Manufacturing |
| <input type="checkbox"/> 24 Drilling, Drilling Contractor | <input type="checkbox"/> 34 Finance, Insurance |
| <input type="checkbox"/> 30 Pipeline/Installation Contractor | <input type="checkbox"/> 35 Government, Research, Education, Industry Association |
| <input type="checkbox"/> 25 EPC, Main Contractor, Subcontractor | <input type="checkbox"/> 99 Other (please specify) _____ |
| <input type="checkbox"/> 36 Engineering, Consulting | |
| <input type="checkbox"/> 31 Ship/Fabrication Yard, FPSO | |
| <input type="checkbox"/> 32 Marine Support Services | |

3. Do you recommend or approve the purchase of equipment or services?

(check all that apply)

- | | | |
|---------------------------------------|--|--------------------------------------|
| <input type="checkbox"/> 700 Specify | <input type="checkbox"/> 701 Recommend | <input type="checkbox"/> 702 Approve |
| <input type="checkbox"/> 703 Purchase | <input type="checkbox"/> 704 N/A | |

4. Which of the following best describes your personal area of activity?

(check all that apply)

- | | |
|---|--|
| <input type="checkbox"/> 101 Exploration Survey | <input type="checkbox"/> 107 Support Services, Supply Boats, Transport, Support Ships etc. |
| <input type="checkbox"/> 102 Drilling | <input type="checkbox"/> 108 Equipment Supply |
| <input type="checkbox"/> 110 Production | <input type="checkbox"/> 109 Safety Prevention and Protection |
| <input type="checkbox"/> 103 Subsea production, construction (including pipelines) | <input type="checkbox"/> 111 Reservoir |
| <input type="checkbox"/> 104 Topsides, Jacket Design, Fabrication, Hook-Up & Commissioning | <input type="checkbox"/> 99 Other (please specify) _____ |
| <input type="checkbox"/> 105 Inspection, Repair, Maintenance | |
| <input type="checkbox"/> 106 Production, Process Control Instrumentation, Power Generation etc. | |

YES! I would like a FREE subscription to **OE**
 No thanks

How would you prefer to receive **OE**?

*Print Digital

*Print Delivery Option restricted to USA, CAN & Mexico. All other regions will receive the digital edition - your email address is required for proper processing.

Name: _____

Job Title: _____

Company: _____

Address: _____

City: _____ State/Province: _____

Zip/Postal Code: _____ Country: _____

Phone: _____

E-mail address*: _____

By providing your fax and/or email address, you are granting AtComedia permission to contact you regarding your subscription and other product offerings. May AtComedia contact you about other 3rd party offers for:

Email: Yes No Fax: Yes No

Signature (Required): _____

Date (Required): _____

Please Note: Only completed forms can be processed. Your signature does not obligate you or your company any way.

ATCOmedia
Atlantic Communications Media

What's next

Coming up in OE September

- **Feature – Subsea Processing**
- EPIC – Asset Integrity
- Subsea – All-Electric Subsea & Inspection, Repair, Maintenance
- Production – Heavy Oil
- Drilling & Completions – Riserless Drilling
- Regional Overview – NW Europe Review

Bonus Distribution

SPE Offshore Europe
Aberdeen, UK
5-8 September 2017

Offshore Energy
Amsterdam, The Netherlands
9-11 October 2017

Never miss an issue! Sign up for *Offshore Engineer* at OEdigital.com today!

Two pump stations during system integration testing prior to final delivery. Another pump module is shown next to the pump station.

Photo courtesy of Schlumberger.

Ad Index

| | |
|---|------------|
| API api.org/Standards | 4 |
| ATL Subsea atlinc.com | 63 |
| Balmoral balmoraloffshore.com | 27 |
| Butting www.butting.com | 63 |
| CORTEC www.uscortec.com | 51 |
| Deepwater Intervention Forum deepwaterintervention.com | 13 |
| Global FPSO Forum globalfpso.com | 59 |
| IoT in Oil & Gas Conference www.iotinoilandgas.com | 47 |
| LAGCOE lagcoe.com/register | 53 |
| NOV nov.com/stories/wellstreamprocessing | OBC |
| OE Subscription oedigital.com | 65 |
| Offshore Energy www.offshore-energy.biz | 23 |
| OneSubsea, a Schlumberger Company onesubsea.slb.com/standardization | 9 |
| Petroleum Exhibition & Conference of Mexico (PECOM) pecomexpo.com | IBC |
| Siemens www.siemens.com/turboshow | 6 |
| SPE Offshore Europe offshore-europe.co.uk/offshoreengineer | 41 |
| SpirStar spirstar.com | 7 |
| TechnipFMC TechnipFMC.com | IFC |
| Tradequip www.tradequip.com | 5 |

OE

Advertising sales

NORTH AMERICA

Audrey Leon
Phone: +1-713-874-2205
aleon@atcomedia.com

UK/FRANCE/SPAIN/AUSTRIA/ GERMANY/SCANDINAVIA/FINLAND

Brenda Homewood
Phone: +44 1622 297 123
Mobile: +44 774 370 4181
bhomewood@atcomedia.com

ITALY

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

NETHERLANDS

Arthur Schavemaker
Kenter & Co. BV
Phone: +31 547-275 005
Fax: +31 547-271 831
arthur@kenter.nl

ASIA PACIFIC

Audrey Raj
Phone: +65.9026.4084
araj@atcomedia.com

24th Annual

PECOM

Petroleum Exhibition & Conference of Mexico

An **OE** Event

March 13-15 2018

**Promoting new businesses,
operations and technologies
within Mexico's energy
and petroleum sectors.**

Parque Dora María,
Villahermosa, Tabasco, Mexico

PRESENTED BY

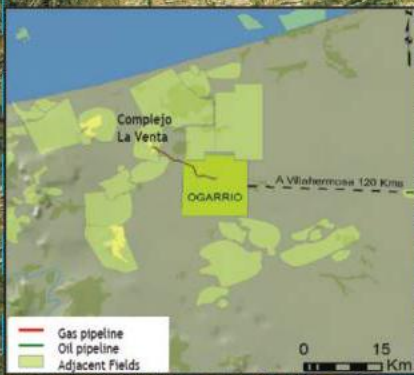
ORGANIZED BY



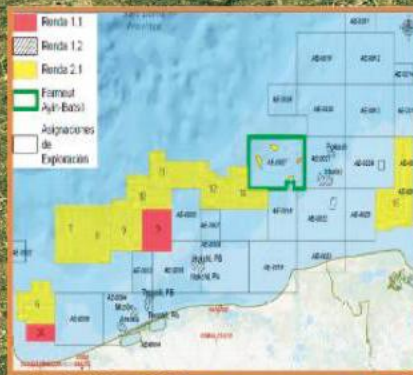
Now more than ever **PECOM**, due to our long-standing relationship with Tabasco's government and business leaders, is your gateway to Mexico's energy industry. With Mexico's state-owned oil company Pemex announcing new partnership opportunities – both onshore and offshore Tabasco – the time is right to share your expertise and technology with **PECOM's** attendees.

New Business Opportunities in Tabasco

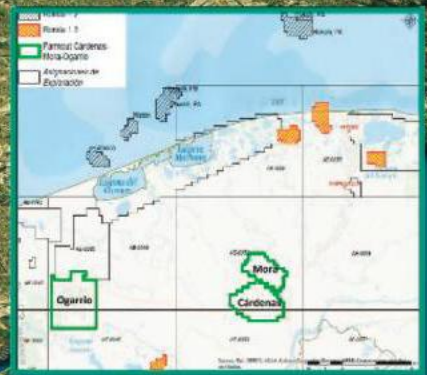
OGARRIO



AYIN - BATSIL



CÁRDENAS - MORA



The farm-outs announced by Pemex give the opportunity to share knowledge and best practices for mutual benefit. This is an exciting time for Mexico's reformed energy sector. If your company sees Mexico as part of its business plans, make sure you participate at **PECOM 2018**.

For information on exhibit and sponsorship opportunities please contact:

Jennifer Granda | Director of Events & Conferences | Email jgranda@atcomedia.com | Direct +1.713.874.2202 | Cell +1.832.544.5891

pecomexpo.com



Injecting Value into Water Treatment Technologies

2-in-1 module combines produced water and seawater treatment for the BW Offshore Catcher FPSO

Just 31 miles from fabrication to shipyard, we delivered a 2-in-1 module that combined produced water and seawater treatment for the Catcher Development FPSO to ensure reservoir well injectivity.

As an integrated partner, we also supplied **Bondstrand® fiberglass pipe** and an **APL™ turret** and **mooring system** to complement the water treatment module.

We're proud to have delivered a custom solution to BW Offshore that will help to unlock the full value of this challenging development in the coming years.

Learn more at nov.com/stories/wellstreamprocessing