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The art of HSEQ

Offshore Engineer • June 2014

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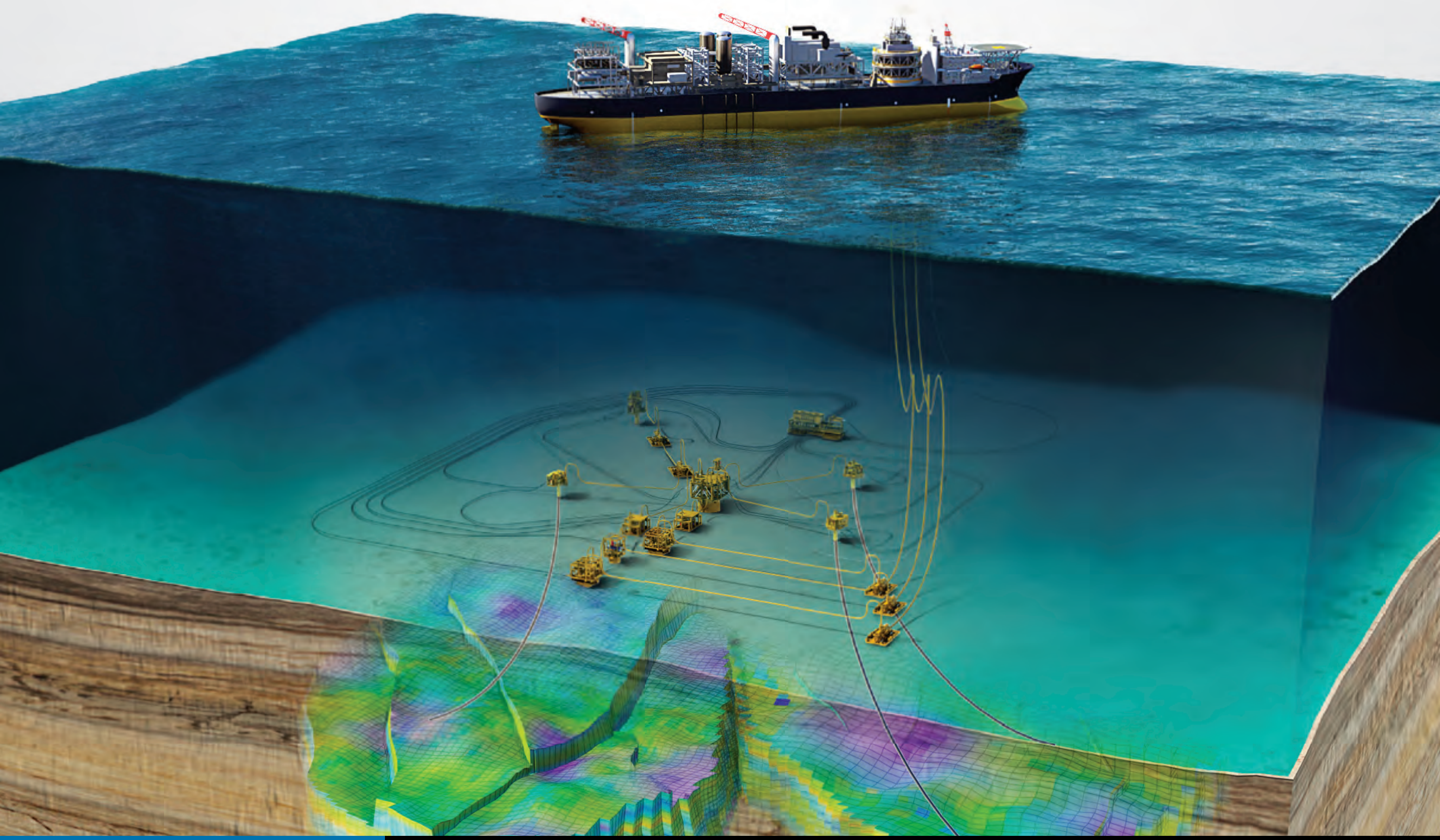

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June 2014

Cover story

The art of HSEQ

ON THE COVER

A watchful eye.
3D animator Sage Hansen's artwork, "Guidance," was on display in NOV's employee art gallery at OTC 2014. The original was acrylic on canvas.

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Volume 39, Number 6 June 2014

Departments & Columns

"How can HSEQ improve in your sector?"

Inspired – Dedicated – Reliable

MARINE CYBERNETICS
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SCANPARTNER REKLAMEBYRÅ

Third-party testing of BOP software

A modern Blow-Out Preventer (BOP) relies on a sophisticated redundant computer system to achieve desired performance and safety. The scope of BOP-HIL testing from Marine Cybernetics is to verify correct functionality according to rules and regulations, user requirements, and to detect hidden software errors and design flaws in the BOP system software.

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Online Exclusives

Managed-pressure drilling riser stack integration

Weatherford examines the advantages of using MPD-ready rigs.

Equipped with MPD technology, the floating rigs of the future will be able to meet deeper drilling challenges.

Safety automation reduces hazard levels

Boosting automation increases the chance at sustaining safety by cutting back on the weakest link in the safety chain: People.

What's Trending

Troubled waters

- Woodside retreats from Leviathan
- Pit halts Snorre production
- Goliat delivery rescheduled

Photo: Snorre B from Norwegian Petroleum Directorate.

People

Cruickshank takes lead at BOEM

Walter Cruickshank was named acting director of the Bureau of Ocean Energy Management, replacing departing chief Tommy Beaudreau.

OE at OTC

OE staff's coverage of Houston's 2014 Offshore Technology Conference includes:

- Mexico's energy reform: challenges and opportunities
- Brazil's PPSA CEO promises local content 'flexibility'
- BSEE announces tech center

Image of Pemex's Gustavo Hernández García at OTC from Barchfield Photography

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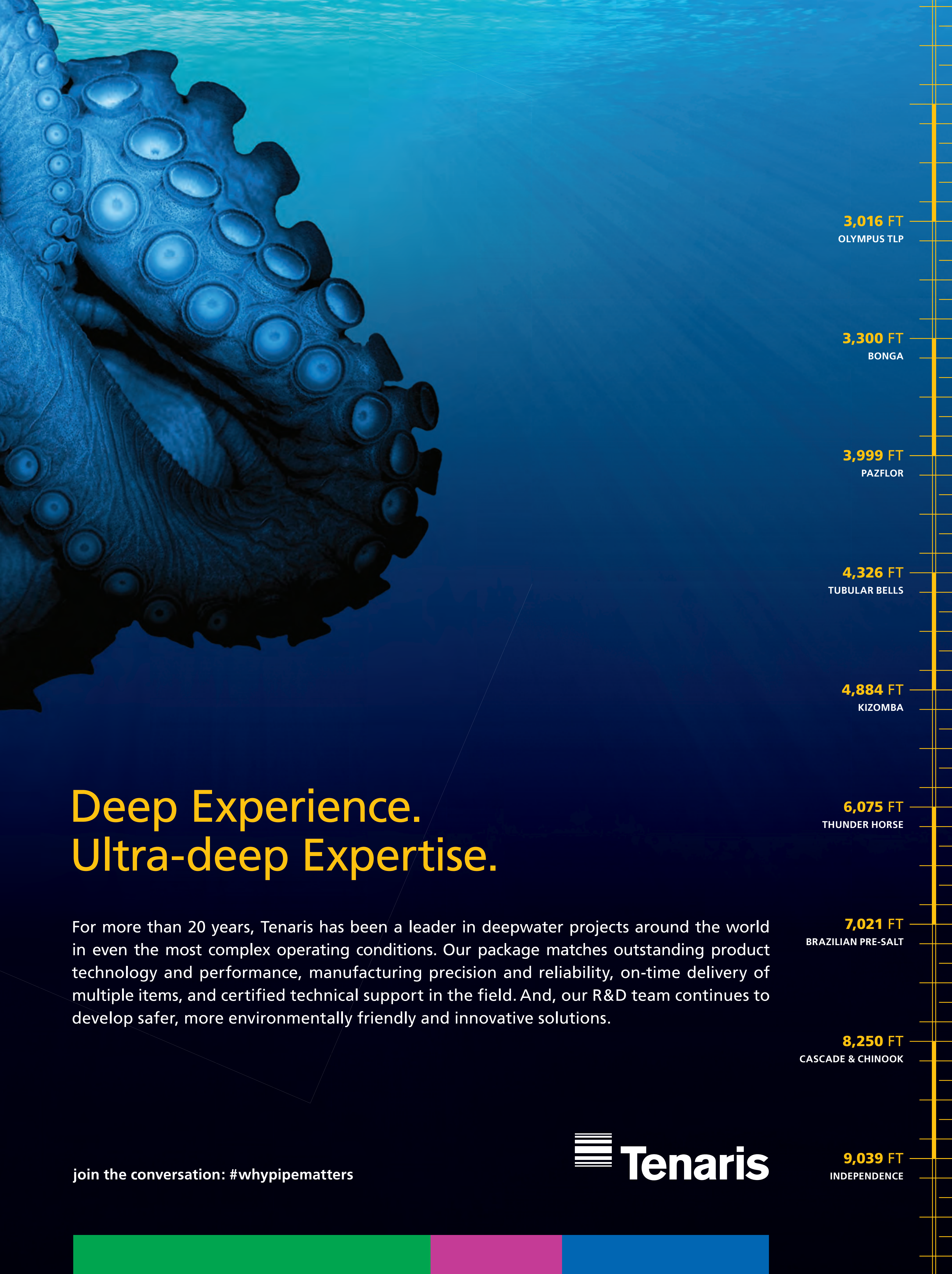
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Voices

Branching out. With safety being so critical to performance, OE asked:

How can HSEQ improve in your sector?

When considering improved HSE performance within the industry, I follow progress on hydrocarbon release reduction, an extremely challenging issue especially with ageing assets. HSE data indicates release frequency plateaued between 2005 and 2013 after an extended period of continuous improvement. I am concerned that an upward trend may be prevalent soon.

Maggie Leitch
Global Technical Safety & Risk Lead
Xodus Group

The industry must better communicate risk awareness, understanding both serious events (e.g. hydrocarbon releases) and near-misses. A recent study showed that, on average, 4-6 significant hydrocarbon releases were recorded per year in 2010-2011 across 30 offshore platforms with one operator.

Frontline personnel and first-line supervisors should be provided with a better understanding of the behaviors and consequences of serious events. This will lead to increased risk perception on the technical complexity of equipment and platform layout, effects of ageing assets on HSEQ risk, and the human and organizational factors that affect unsafe behavior — allowing organizations to learn more quickly, and contribute to the prevention of serious events.

Garry Moon
Principal Consultant
Lloyd's Register Consulting

The development of a positive health and safety culture is a complex, evolving process that forms the foundation which underpins an organization's safety performance. In Expro, we believe a culture of safety starts right at the top - with leadership. Leadership drives an organization's culture and this in turn, drives behavior. Leaders create and influence a culture by setting expectations and standards, and by putting those into practice – talking the talk and walking the walk.

David Ford
Group HSEQ Manager, Expro

There's always room for improvement. In piping connections, for example, there has been an increased focus on cold-work based solutions. Whereas traditional methods such as welding require access to gases and ignition sources and come with complex procedures, such as permits, testing and isolating areas of operation, cold-work solutions deliver a safe, secure and pressure-tight mechanical connection within minutes. Cold-work installation is also the same for all material types (not the case with welding that requires different qualifications). Through a combination of simplicity and innovation, the industry is making significant progress.

Rune Haddeland
CEO, Quickflange

Many of us view behavioral-based safety and stop work authority as strong methods for improving performance as they have yielded very positive results when implemented correctly. However, in recent months I have heard increasing conversation regarding procedural discipline. A cursory review of the top root causes of incidents will typically indicate a lack of adequate content or failure to use a written procedure as major factors. We must lead a change in culture to increase awareness for the importance of procedural discipline. We must encourage our people to intervene or assert their right to stop work when they see a colleague not following procedures.

John Raine
Vice President – QHSSE, Weatherford International

The offshore sector represents an extremely challenging environment. Lifting and handling heavy equipment offshore has proven a problematic task for operators over the years. The HSE Offshore Division receives countless reports of accidents causing injury as a result of poor lifting safety. However in the instance of mud skips, this can be addressed by introducing vacuum fills for the disposal of waste on the platforms, as opposed to manual lid handling and lifts. This method requires less personnel on the drilling deck and therefore reduces the risk of serious hand injuries. Using vacuum fills on drilling mud skips allows for dual operation on a conveyor, eliminating the need for heavy lifting and the associated safety risk. An approach that has been highly-favored within the industry.

Greg Spence
Managing Director, Environstore

Safety is among the top concerns affecting process owners and operators worldwide, but poor safety culture continues to appear among the top five root causes in industry incident investigations. As the industry continues to improve best practices based on lessons learned from terrible industrial accidents, it should strive for consistency in the implementation and enforcement of safety standards. The industry needs to invest to accelerate the development of competence in key disciplines such as: hazard analysis, safety requirement specification and functional safety management. Attract, develop and retain young professionals that can take ownership of the future of safety, culture, processes and technologies. Safety must be in the core values of every company and shouldn't ever be deemed as "too expensive." As the late Safety Expert Trevor Kletz wisely advised the industry, "if you think safety is expensive, you should try an accident."

Luis Duran
Product Marketing Manager Safety Systems, ABB

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

Nina Rach

Colloquy

DNV's Carl Arne Carlsen honored

Dr. Carl Arne Carlsen, senior vice president and previously a member of the DNV executive board, was recognized at the 45th Offshore Technology Conference in Houston, receiving the 2014 OTC Distinguished Achievement Award for Individuals.

The award is in recognition of his "outstanding, significant and unique achievements, and extensive contributions" to the offshore industry, and was presented at the Annual OTC Dinner, 4 May 2014.

The OTC Board said that Carlsen was honored for his significant advancements in the safety and reliability of mobile offshore structures, and the practical applications of risk management.

Over the course of his career, Carlsen's focus on safety led to important developments in the industry. Chief among these is his work in establishing rules for dynamic behavior of jackup platforms, semisubmersible platforms, and for FPSOs in harsh environments. He was also instrumental in developing the IMO/IACS Enhanced Survey Program for oil tankers and carriers.

Carlsen earned an MS degree in naval architecture from The University of Trondheim in 1971, and a PhD in 1975.

"A defining moment for me came in 1980, as a direct consequence of the tragic accident with the Alexander L. Kielland platform that capsized in a severe storm outside Norway," says Carlsen (in which 123 workers died).

Soon after, he was appointed head of classification for mobile offshore units (MOU) at DNV, and tasked with developing new MOU rules to cope with the harsh environment in the North Sea.

Carl Arne Carlsen. Photo by Nina Rangoy; copyright DNV GL.

In cooperation with the Norwegian Maritime Directorate, the new rules were issued in 1981, and they introduced new principles for more robust design, construction and in-service inspection. They were almost immediately adopted throughout the industry, and provided important input to the United Nations' International Maritime Organization (IMO) 1989 MODU Code.

Carlsen also helped promote use of FPSOs in the North Sea, and the first, *Petrojarl 1*, started operating on the Norwegian continental shelf in 1986.

The way to succeed, Carlsen says, is "to be determined to strike the right balance between theory and practice, safety and cost efficiency through respectful involvement of all stakeholders. And you have to work together with really smart and principled people!"

Peer recognition

"Carl Arne Carlsen is a thought leader in the offshore industry. We are proud that he has spent his career with DNV, now DNV GL, and on behalf of all his 16,000 colleagues, I congratulate him with this recognition. Throughout his 40 years in DNV, Carl Arne Carlsen has had almost every possible position in the company. He has been a member of the executive committee; he has been a regional manager, a global network leader, head of R&D, plus a whole range of other positions. Through all this work, he has significantly helped DNV GL fulfill its purpose of safeguarding life, property and the environment," says Henrik O. Madsen, DNV GL Group's CEO.

Carlsen is a Fellow of the Society of Naval Architects and Marine Engineers, and is a SNAME Blakely Smith Medalist. [SNAME is one of the professional societies that planned the first OTC in 1969, and SNAME member Ed Stokes serves as current OTC Board Chair, 2013-2014.]

Peter G. Noble, Noble Associates LLC, and SNAME president, 2013-2014, says Carlsen is "one of the leaders in innovation in our offshore industry. I think what he's really brought is a balance between advanced analysis and practical engineering and experience."

The OTC announced that proceeds from this year's Annual Dinner will be donated to Medical Bridges, a Houston-based organization that provides medicine and medical supplies to healthcare providers in need worldwide. OE

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Opinion

Brian Salerno, BSEE

ThoughtStream

Keeping up with the industry

The pace of innovation in the offshore industry is truly awe-inspiring. It's amazing to look at today's capabilities and think about how they weren't even possible a few years ago. Of course, from the perspective of the regulator, it is also a little daunting. Our challenge at the Bureau of Safety and Environmental Enforcement (BSEE) is to keep current with the aggressive pace the industry is setting, so that we can understand the safety and environmental implications of the technology being used.

Our goal is to ensure that our nation's offshore resources are developed without incident, and I believe that it also a goal of industry. Offshore safety, protection of the environment, developing offshore resources, all of these not only reflect public needs and expectations, but they also represent good business practices. We have all seen how catastrophic events can adversely impact the environment, causing the public to lose confidence not only in the industry's commitment to safety, but also in the regulator's ability to oversee responsible offshore operations. How then do we collectively and appropriately approach the ongoing imperative of integrating new technology into an already complex operating and regulatory environment?

There are several approaches we are undertaking that we believe will allow all of us to meet our mutual goal of safe operations. One change that has already started is the placement of more performance-based language into our new regulations, which will make it easier to establish equivalency to the standard of safety we all envision.

We are pursuing more sophisticated risk-assessment tools to accommodate technological approaches not specifically envisioned in the regulations as they are written today. Although we intend to maintain our hybrid approach to regulations, risk tools will complement established standards in our evaluation of new and emerging technology.

We have also established the Ocean Energy Safety Institute to serve as a forum where industry, government, and academia can come together and explore the implications of emerging technology. The institute will hold forums on topics such as how to best assess and make a determination of best available and safest technology and system reliability. However, the Institute will only be successful with industry participation. It will be open, transparent, and collaborative, but the industry's participation is needed to make that happen.

Our challenge at BSEE is to keep current with the aggressive pace the industry is setting, so that we can understand the safety and environmental implications of the technology being used.

Brian Salerno, director of the Bureau of Safety and Environmental Enforcement (BSEE)

While all of the approaches described above will help us move closer to our goal of no serious incidents on the US outer continental shelf (OCS), our sense in BSEE is that we still need to do more, to work more closely with original equipment manufacturers, participate more fully with standards-setting bodies, and strengthen our ability to assess novel and emerging technologies. That is why we are working to establish a technology center within BSEE. The center will not replace the regulatory processes already in place at the regional level. Permit reviews and deepwater operations plans will remain a function of our region and district offices. But the center will add depth and capacity to the bureau, so that as industry continues to innovate and develop new capabilities, we will keep pace. It will support all of our regional offices and will work closely with the Ocean Energy Safety Institute.

This is an exciting time to be working on the OCS, with an unprecedented level of technological innovation. As we continue to move forward, we must all keep in mind what is at stake and remain committed to safe and responsible operations. OE

***Brian Salerno** is the director of BSEE. Prior to joining the agency, Salerno served as the US Coast Guard's Deputy Commandant for Operations. Over his 36-year active duty career, Salerno attained the rank of Vice Admiral, serving predominately within the US Coast Guard's marine safety program. Salerno is a 2000 graduate of the US Army War College, with an MA in Strategic Studies. He is also a graduate of the Naval War College non-resident program, and holds an MS in Management from The Johns Hopkins University.*

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Global Briefs

A Seismic survey off Canada

Seismic acquisition companies PGS and TGS are collaborating to expand 2D seismic coverage off eastern Canada ahead of a new tenure round in the area. PGS will acquire more than 30,000km of seismic data using two vessels during 2014, and TGS will complete processing by Q3 2015. In June 2014, the M/V *Sanco Spirit* will start seismic and gravity data acquisition in the Labrador Sea and northeast Newfoundland-Flemish Pass areas. In July, the M/V *Atlantic Explorer* will start acquiring seismic and gravity data in the Tail of the Bank area of southeast Grand Banks. The southeast Grand Banks 2D covers 15,000km.

B Statoil starts GOM campaign

Statoil started its latest Gulf of Mexico exploration campaign with a well on the Martin prospect, in about 890m water depth in Mississippi Canyon Block 718. The well is being drilled by the Maersk Developer semisubmersible drilling rig in the Greater Mars basin, about 205km SSE of New Orleans.

C Apache subsidiary sells GOM blocks

Apache Corp.'s Gulf of Mexico subsidiary will sell its non-operated interests in the Lucius and Heidelberg development projects and 11 primary-term deepwater exploration blocks to a subsidiary of Freeport-McMoRan Copper & Gold for US$1.4 billion. Apache has an 11.7% working interest (WI) in the Lucious unit and 12.5% WI in the Heidelberg blocks. Apache's WI in the 11 primary-term blocks ranges from 16.67-60%. None of the company's producing operations are involved in the sale, which is expected to close by 30 June.

D Oil found at Johan Castberg

The fifth and final well in Statoil's exploration program in the Barents Sea around the Johan Castberg discovery found oil. Well 7220/7-3 S was drilled on the Drivis prospect in production license (PL) 532, about 15km southwest of the 7220/8-1 Johan Castberg discovery. Out of the five wells drilled, just two have found oil. Statoil said it will work with its license partners to assess the exploration program results.

E Appraisal at Sverdrup

Lundin Petroleum reported that the latest Johan Sverdrup appraisal well, 16/2-19, intersected 6m of good-quality, oil-filled sandstone of lower Jurassic/upper Triassic age in the Geitungen area in the northeastern part of the Johan Sverdrup discovery on the Norwegian continental shelf. The company said well 16/2-19A was drilled as a side-track and found 13m gross of low to excellent-quality upper Jurassic sandstone in the central Geitungen area. Appraisal well 16/2-19 was drilled approximately 2.1km north of appraisal well 16/2-12 and 3.2km southeast of appraisal well 16/2-9S, both in PL265.

F *P-62* starts production

Petrobras began production from its *P-62* platform at the Roncador field in Brazil's Campos basin, the company announced. The 111sq km Roncador field is in water 1800m deep and is divided into four modules with differing oil densities. Petrobras says the *P-62* FPSO, in 1600m water depth, can process 180,000bo/d and 6 million cu m/d of natural gas. It will eventually tie into 22 wells: 14 production and eight injection.

G FloaTEC installs TLWP in Campos basin

FloaTEC, a US-based JV between a subsidiary of McDermott International Inc. and Keppel FELS Ltd., installed the P-61 tension leg wellhead platform (TLWP) in the Papa Terra field, Campos Basin, in 1180m water depth. FloaTEC will operate the facility for 3 years before handing over to the joint operators of the Papa-Terra JV, Petrobras and Chevron.

H Repsol starts Namibian drilling program

Repsol Exploration (Namibia) started drilling on the deepwater Welwitschia-1 prospect in Walvis Bay, offshore Namibia. Welwitschia-1 is targeting about 1.6billion net risked recoverable resources. Repsol is using the Rowan Renaissance drillship. It is the ship's first drilling program following delivery from Hyundai Heavy Industries (HHI) in Korea. Repsol operates PEL0010 (44%) on behalf of partners Tower Resources' subsidiary Neptune Petroleum (30%) and Arcadia Expro Namibia (26%).

I Total scores off Ivory Coast

Total has made a "very promising" light oil discovery in 2300m water depth as part of an intensive exploration campaign off Ivory Coast. The Saphir-1XB exploration well, the first exploration well on Block CI-514, is the first discovery in the San Pedro basin. Saphir-1XB

was drilled using a semisubmersible to 4655m TD and encountered about 40m net pay containing light 34° API oil, in a 350m-thick interval of thick sands. Total said it plans to drill another two offshore wells, in Blocks CI- and CI-516, by the end of the year. Total E&P Côte d'Ivoire operates Block CI-514 with a 54% interest, alongside CNR International (36%) and PETROCI Holding (10%).

J Statoil exits Angola block

Statoil announced it will divest its 5% participating interest in ENI-operated block 15/06 off Angola to Sonangol EP for US$200 million. In addition to the ownership in four producing assets, Statoil also holds participating interests in Blocks 22, 25 and 40 in Angola's Kwanza basin. As announced in April, Statoil will participate in eight commitment wells in the Kwanza basin, beginning drilling in 2Q 2104.

K Agadir Basin well non-commercial

The FA-1 well in the Foum Assaka block offshore Morocco has been plugged and abandoned after failing to find commercial hydrocarbons. Operator Kosmos Energy said the well was the first in a series designed to unlock the Agadir basin and was drilled to test a salt diapir play concept targeting the Cretaceous interval in a combined structural-stratigraphic trap. Kosmos operates the Foum Assaka offshore block.

L Drydocks completes NDC jackup repair

Drydocks World has completed a major repair and refurbishment of National Drilling Co.'s (NDC) jackup drilling rig Al Ittihad. The repair and refurbishment package on the 61.87 x 51.21m rig included preload, void, bilge and diesel tank steel repair with nearly 125 tonnes of steel used to renew the inside of the tanks. The yard also completed various repair works on the rig's accommodations.

M Joint study agreement signed

RWE Dea and the State Oil Co. of Azerbaijan Republic (SOCAR) have signed a joint study agreement to evaluate the hydrocarbon prospectivity in an area south of the Absheron peninsula, south of Baku in the Caspian Sea. The study area is between Karadag and Hamamdag and covers about 850sq km in shallow water less than 30m deep.

N Barents Super-Tie extension

MultiClient Geophysical (MCG) is extending its multiclient 2D (MC2D) Barents Super-Tie towards the east into the newly-opened Barents Southeast, formerly a disputed zone between Norway and Russia. The new lines will tie the existing Barents Super-Tie in the west to the areas to be covered by the Group 3D Surveys in the Barents South East. In addition, MCG and Sevmorneftegeofizika (SMNG) will reprocess 2D seismic data from the Russian side of the Barents Sea, providing a consistent regional MC2D dataset, and connecting most of the wells in the Norwegian Barents Sea with key fields and wells in the Russian Barents Sea.

This survey will be around 3500 km and will be acquired by SMNG's vessel the M/V *Akademik Nemchinov*.

O US sanctions Rosneft president

The US Department of the Treasury issued sanctions against seven Russian government officials and 17 entities pursuant to the Ukraine-related Executive Order 13661. Among those officials listed was OAO Rosneft President and Chairman of the Management Board Igor Sechin. Sanctions against individuals were designated because those listed were seen as being part of the Russian government's "inner circle." BP holds 19.75% equity in Rosneft, and BP Group Chief Executive Robert Dudley sits on Rosneft's board as a non-executive director. He is not a shareholding member. According to a spokesperson for the US Department of the Treasury, as a US citizen, he is not prohibited from dealing with Rosneft or from sitting on the board.

P TDW completes subsea pipeline intervention

T.D. Williamson (TDW)

completed its largest subsea pipeline pressure intervention to date offshore Indonesia. The scope of work included hot tap and plugging operations, which were carried out for main contractor Timas Suplindo in conjunction with Offshore Construction Specialists, on behalf of Pertamina EP. Work was performed on sections of the pipeline network attached to part of the Lima flow station as part of the subsidence remediation project. The flow station consists of compression, service and process platforms, as well as a platform bridge, flare bridge and tower. The overall goal is to raise the Lima flow station, in the northwestern Java Sea, which has been sinking into the seabed for 17 years.

Q CNOOC begins Kenli 3-2 production

CNOOC Ltd. began production at its 100%-owned Kenli 3-2 oilfields, the company announced on 12 May 2014. The Kenli 3-2 oilfields, located in the southern Bohai Sea at an average water depth of 20m, include Kenli 3-2, Bozhong 34-6/7, the southern part of Bozhong 29-4 and the Bozhong 35-2 oilfields. The primary production facilities include seven offshore platforms and one onshore oil processing terminal. Peak production is expected to hit 35,000b/d. In March, CNOOC announced a natural gas discovery in the nearby Bozhong 22-1 structure in south central Bohai. Gas production tested at 14.2MMcf/d.

R Japan's JX to develop Layang field with FPSO

Malaysia's Petronas has approved Japan's JX Nippon Oil & Gas Exploration's field development plan for the Layang gas field. JX Nippon intends to develop the field off the coast of the Malaysia's Sarawak state on Borneo, and start production with an FPSO in 2Q 2016. Layang field is about 8km east of the producing Helan gas field, in Block SK10. JX Nippon anticipates initial production of 100 Mcf/d of natural gas (17,000 boe/d) and about 7000 b/d of condensate and crude.

S Drilling at Bertam off Malaysia set to start

Lundin Malaysia BV will begin development drilling at its Bertam oil field off peninsular Malaysia this summer. The Bertam field, in the PM307 Block, was discovered in 1995 when Petronas Carigali drilled the Bertam-1 well. Lundin Petroleum acquired the PM307 license block in 2011, and Lundin Malaysia completed the Bertam-2 appraisal well in 2012. Lundin received Petronas' approval for the Bertam field development plan in October 2013.

T Nereus ROV lost in Kermadec Trench off NZ

Hybrid remotely operated vehicle (ROV) Nereus was confirmed lost at 9990m depth in the Kermadec Trench northeast of New Zealand. The unmanned vehicle was working as part of a mission to explore the ocean's hadal region from 6000m to nearly 11,000m deep. Scientists say a portion of it likely imploded under pressures reaching 16,000psi. At the time it was lost, the ROV was 30 days into a 40-day expedition with R/V *Thomas G. Thompson* to carry out the first systematic study of a deep-ocean trench as part of a program under chief scientist Timothy Shank, a WHOI biologist who also helped conceive the vehicle.

Contract Briefs

Technip wins subsea infrastructure contract

Marathon Oil Norge awarded Technip a contract to extend subsea infrastructure on the Alvheim field, on the Norwegian Continental Shelf. The scope of work includes installation, procurement, fabrication, and tie-in of spools and protection covers, as well as installation of one manifold. The subsea operations will mainly be performed with divers in water about 120m deep. Technip's operating center in Stavanger will run the project, which is scheduled to be completed 1H 2016. Offshore campaigns will take place in 2014, 2015 and 2016.

Transocean nets $953m of contracts

Transocean was awarded contracts worth about US$953 million. Among other highlights in its fleet report, Transocean reported its *Dhirubhai Deepwater KG1* drillship was awarded a three-year contract offshore Brazil at a dayrate of $440,000 ($482 million estimated backlog). The rig's prior dayrate was $510,000. The semisubmersible *Paul B. Loyd, Jr.* was awarded a two-year contract extension in the UK North Sea at a dayrate of $430,000 ($314 million estimated backlog). The rig's prior dayrate was $447,000. Additionally, two other semisubmersibles, *GSF Development Driller II and Sedco 706*, and GSF Constellation II jackup were also given substantial awards. Estimated 2015 planned out-of-service time decreased by a net 84 days (subject to change).

Petrobras inks Saipem contract

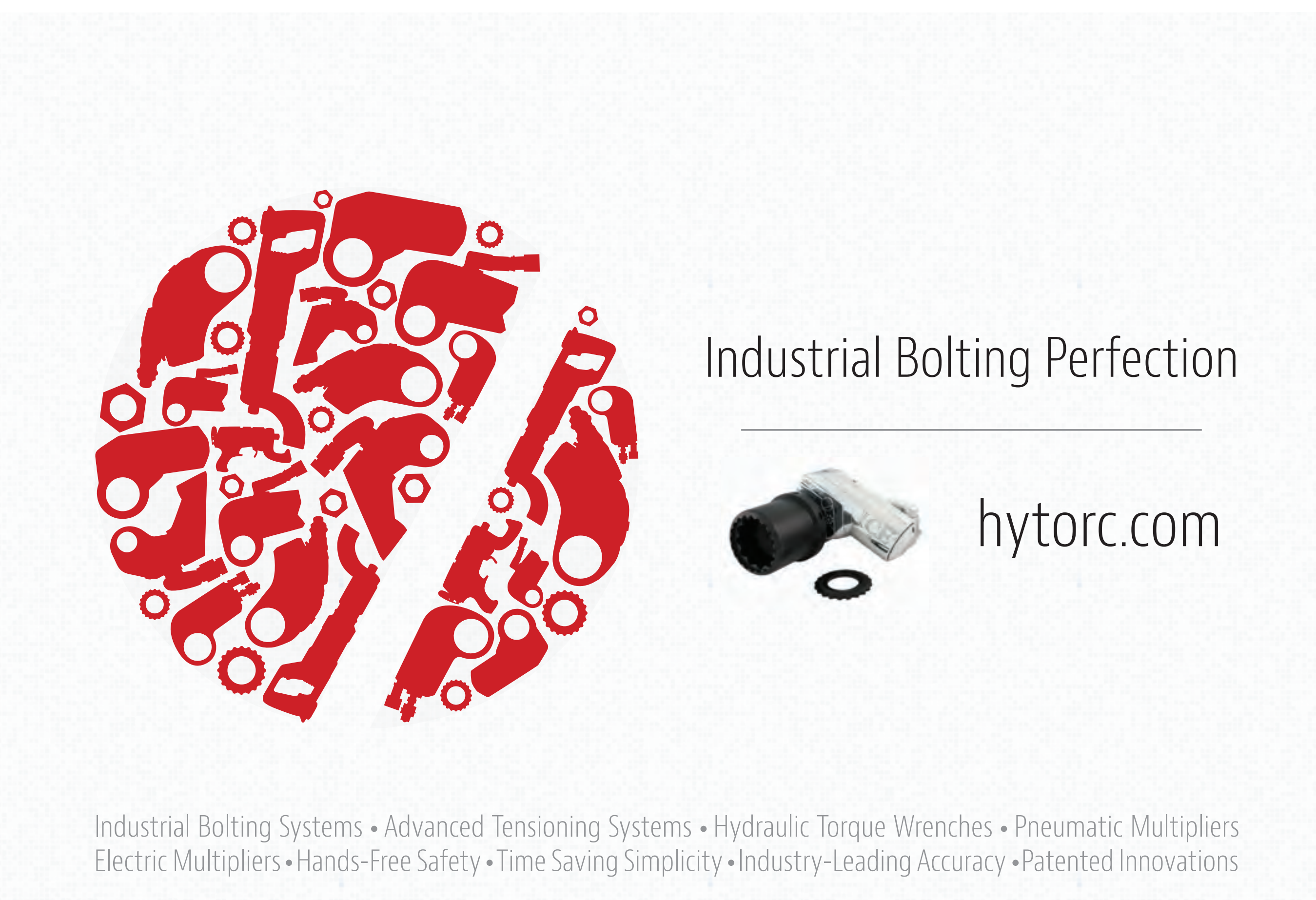
Brazil's Petrobras has awarded Saipem an EPCI contract for the Lula Norte, Lula Sul and Lula Extremo Sul projects, to be developed in the Santos basin presalt region, about 300km off the coasts of Rio de Janeiro and São Paulo states. The work scope includes engineering, procurement, fabrication and installation of three offshore pipelines, with related terminations (PLETs) and free-standing hybrid risers (FSHRs) for the gas export systems to be installed in the Lula field in water depths up to 2200m. The marine activities will be performed mainly by the *Saipem FDS2* crane ship in 1H 2016.

Siemens wins Shah Deniz power project

Siemens Energy has received an order from BP Exploration to deliver customized direct electrical heating (DEH) power supply systems for 10 subsea flow lines, with an option for two additional systems. All the systems will be deployed at the BP-operated Shah Deniz gas field in the Azerbaijan sector of the Caspian Sea to prevent hydrate formation during any process shutdown. The equipment will be delivered at the end of 2015.

ABB inks $20m offshore vessel contracts

Power and automoation group ABB has won contracts worth more than US$20 million to supply electrical power and propulsion systems for two offshore vessels. In addition, ABB will supply complete power and diesel electric system packages, along with fire and gas monitoring and control systems. Both power distribution and propulsion systems will be monitored by ABB's remote diagnostic system■



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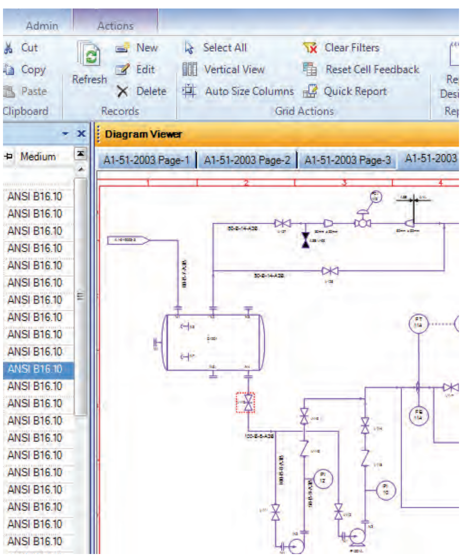

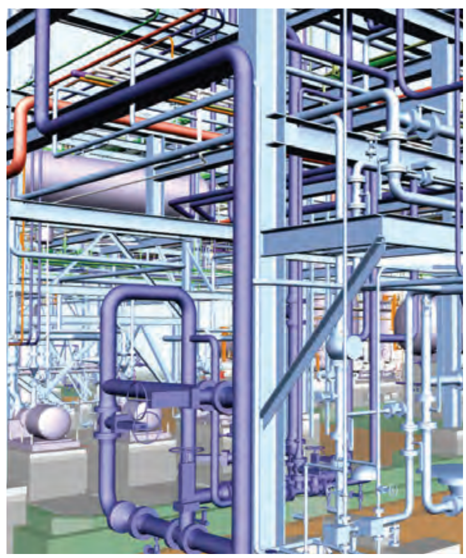

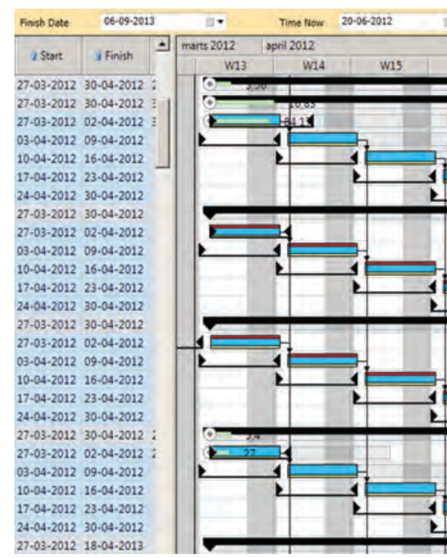

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Eyes on safety

The 45th annual Offshore Technology Conference in Houston brought together US regulators and major operators to discuss advancements in offshore safety since Macondo. Audrey Leon reports.

According to the US Bureau of Safety and Environmental Enforcement's (BSEE) incident statistics database, updated January 2014, nine well control incidents occurred in the Gulf of Mexico, 97 fires and/or explosions, 226 injuries, and three fatalities were recorded in 2013. In all 691 incidents occurred on the US outer continental shelf (OCS), down from 730 the previous year.

Since Macondo, US regulators and the industry have made safety a major discussion topic. At last year's OTC, BSEE set out to engage the industry and encourage discussion of its then-recent Safety and Environmental Management Systems (SEMS) II rule, which aimed to provide greater employee participation in safety decisions out in the field, as well as set oversight guidelines for requiring audits to be conducted by third-parties (OE June 2013).

This year new BSEE Director Brian Salerno discussed the importance of SEMS in his multiple appearances, including at Active Arena: Oil Spill Prevention as well as the lunch event Improving Safety Management and Recognizing Contributions.

"Most accidents we see come from the human element, not just technology failures," he said at Active Arena. "Safety has to permeate through the workforce, and workers need to understand the processes and be good stewards of the company. They should be rewarded by the company for looking out."

Uno Holm Rognli, Vice President of Drilling and Wells, US Offshore, for Norway's Statoil, echoed that sentiment.

"A good (safety culture) takes time to build," he said. "Start with rules and regulations that people understand and want to follow. Risks should be understood and eliminated.

"It should be perfectly OK to say 'I don't understand this,'" Rognli said.

He continued, saying it is important to have stop criteria that prevents mistakes. "Management should make sure we follow these criteria."

BSEE Director Brian Salerno discusses the importance of SEM at OTC 2014. Photo by Barchfeld Photography.

On US regulations, Rognli added that coming from Norway, Statoil is familiar with having detailed regulations. "The company has had no problem adapting to US standards," he said, but he believes it would be harder to go the other way. "We have to ask for permission every time we make a small change."

At Improving Safety Management and Recognizing Contributions, Salerno told the audience that a lot more can be done with SEMS. "None of us should be satisfied that the goal of a widespread safety culture within the industry has been achieved," he said. "Some companies still think they can cut corners or regard SEMS as just a plan on a shelf. As we have seen, in some tragic cases, lives have been lost–needlessly–for failure to follow established safety processes."

He continued: "I'm grateful to those who have taken SEMS and the need for a comprehensive safety culture to heart.

Center for Offshore Safety's Charlie Williams, BSEE Director Brian Salerno, and USCG's Joseph Servidio spoke about safety management at OTC 2014. Photo by Barchfeld Photography.

Quick stats

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

New discoveries announced

Depth range	2011	2012	2013	2014
Shallow (<500m)	105	74	67	12
Deep (500-1500m)	25	24	18	4
Ultradeep (>1500m)	18	37	31	–
Total	148	135	116	16
Start of 2014 date comparison	151	135	98	–
	-3	–	18	16

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

Reserves in the Golden Triangle

by water depth 2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	16	738.25	1,060.00
Deep	16	2,615.00	2,515.00
Ultradeep	45	13,239.75	18,090.00
United States			
Shallow	21	109.25	322.00
Deep	20	1,510.11	1,654.57
Ultradeep	33	4,825.50	4,690.00
West Africa			
Shallow	167	4,576.02	22,537.83
Deep	50	5,886.50	7,170.00
Ultradeep	17	1,835.00	3,210.00
Total (last month)	385 (393	35,335.38 (35,481.53)	61,249.40 (62,172.40)

Greenfield reserves

2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow (last month)	1,284 (1,323)	51,992.51 (54,073.30)	831,554.26 (842,190.49)
Deep (last month)	164 (174)	12,559.48 (13,762.48)	100,059.77 (102,319.77)
Ultradeep (last month)	115 (114)	20,450.75 (20,400.75)	60,257.00 (62,207.00)
Total	1,563	85,002.74	991,871.03

Pipelines

(operational and 2014 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,688	(41,782)
Planned/ possible	24,447	(24,237)
	66,135	(66,019)
8-16in.		
Operational/ installed	78,250	(78,422)
Planned/ possible	49,698	(49,545)
	127,948	(127,967)
>16in.		
Operational/ installed	89,823	(89,859)
Planned/ possible	48,241	(46,246)
	138,064	(136,105)

Production systems worldwide

(operational and 2014 onwards)

		(last month)
Floaters		
Operational	273	(271)
Under development	45	(44)
Planned/possible	330	(331)
	648	(646)
Fixed platforms		
Operational	9,435	(9,509)
Under development	105	(106)
Planned/possible	1,399	(1,382)
	10,939	(10,997)
Subsea wells		
Operational	4,514	(4,501)
Under development	421	(402)
Planned/possible	6,368	(6,367)
	11,303	(11,270)

Global offshore reserves (mmboe) onstream by water depth

	2012	2013	2014	2015	2016	2017	2018
Shallow (last month)	6,013.52 (6,015.41)	23,665.64 (23,595.12)	48,211.78 (48,776.97)	37,696.72 (38,704.23)	35,133.46 (34,484.94)	47,708.06 (49,265.43)	30,510.50 (31,991.23)
Deep (last month)	2,817.87 (2,821.40)	484.30 (471.51)	4,598.44 (4,628.59)	6,424.40 (7,249.37)	3,941.05 (3,547.37)	5,460.09 (6,649.19)	9,767.54 (9,718.46)
Ultradeep (last month)	737.15 (737.15)	2,932.94 (2,937.44)	2,830.93 (2,826.43)	2,168.67 (2,173.17)	5,255.06 (5,255.06)	14,060.03 (14,060.03)	6,759.86 (6,701.05)
Total	9,568.54	27,082.88	55,641.15	46,289.79	44,329.57	67,228.18	47,037.90

15 May 2014

Safety is a shared goal."

Salerno discussed a near-miss reporting system that BSEE plans to develop, which would be similar to that of the aviation industry. "This does not replace required reporting or substitute BSEE investigations," he said. The new program will be headed by the US Bureau of Transportation Statistics to guarantee anonymity; Salerno said this will allow the agency to broaden its understanding of risk, including indicators, and how to mitigate them.

With the opening up of Mexico's oil and gas industry on everyone's minds, the need for close ties to the country arose as a discussion topic during Q&A. Of this, Salerno said: "We have a very dynamic relationship with Mexico. We interact with our counterparts Comisión Nacional de Hidrocarburos (CNH) a lot. With new developments, such as the transboundary agreement, we need to be closer."

US Coast Guard Rear Admiral Joseph A. Servidio, who also spoke at the lunch session, agreed with Salerno, stating "One Gulf, one standard, is the way forward."

Macondo in focus

Salerno mentioned during Active Arena's Q&A session that one main problem with the US government's response to Macondo were the "silos" that existed between government agencies.

"Going back to my coast guard days, prior to Macondo, our mindset was ship-based or shore-based. In the Gulf, there was acknowledgement, but it never mapped into interagency planning.

"That gap has been now closed. BSEE has a strong relationship with the US Coast Guard (USCG), National Oceanic and Atmospheric Administration (NOAA), Environmental Protection Agency (EPA), and others, as well as states, and local communities," Salerno said. "Prior to Macondo, response was a surface construct. Intervention was not readily available. Center for Offshore Safety, the Marine Well Containment Company (MWCC) weren't around."

Jim Raney, Director of Engineering and Technology at Anadarko Petroleum, and past chair of the API Committee on Standardization of Oilfield Equipment and Materials (CSOEM), discussed the joint industry task force that was organized following Macondo. The task force, he said, focused on three items: prevention, intervention, and response. The group looked at equipment including ROVs and subsea control and containment tools.

"We were using the same equipment that we used for the Exxon Valdez spill," Raney told the Active Arena audience. "However, with the creation of MWCC and Helix Well Containment Group, the two are ready to cap and flow with the industry."

Raney said there has been significant progress made to improve spill prevention. And several API standards have been introduced thanks to industry involvement, including API RP 96, led by Chevron, which focuses on deepwater well design and construction, as well as API RP 17W, recommended practice for subsea capping stacks, and API RP 17H, focused on remotely operated tools and interfaces on subsea production systems. API RP 98, focuses on personal protective equipment for oil spill cleanup workers.

Chevron

Responding to what it saw as a need for its own operations, Chevron's Vice President of Drilling and Completions David

Jim Raney, Anadarko, speaks at an OTC session about industry response to Macondo. Photo by Audrey Leon/OE.

Payne showcased the supermajor's new WELLSAFE program, which focuses on process safety for well control.

The WELLSAFE program is based on the US Navy program SUBSAFE, which came into practice following the sinking of the nuclear submarine USS Thresher, which killed 129 crew members in 1963. The SUBSAFE program narrowed focus to the integrity of a submarine's hull, and covered how to react to flooding events.

WELLSAFE mirrors the SUBSAFE model, and is an assurance-based program that includes clear written requirements, shifts the focus from training to education, and offers a continuous certification process. WELLSAFE begins with business unit certification. Payne said it needs a governing authority centralized in global drilling and completions. Additionally, the individual well design needs certification.

"WELLSAFE assures that well design complies. It's like doing an audit every day," Payne said. Each rig is certified by the business unit's wellsite. "We will stop any operation that is not safe and does not meet expectations."

Payne said Chevron knew it needed to put WELLSAFE into action following a January 2012 blowout at the Funiwa Deep 1A natural gas well off Nigeria, which killed two workers and began a fire that burned for 46 days, eventually consuming the KS Endeavour jackup rig owned by Hercules Offshore.

Chevron is rolling out WELLSAFE in stages, Payne said. The supermajor expects to fully implement WELLSAFE for rig operations only in 2015, with the Gulf of Mexico business unit being the first to attain certification.

Statoil

Rognli discussed the Norwegian giant's perspective on spill prevention, saying that prevention starts with well integrity, and by constructing a well that can deal with any pressure. Statoil plans to implement new safety measures including early kick detection, a smart flowback system capable of detecting abnormal flow, and an ECD management system for bottom hole pressure control. **OE**

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	102	99	3	97%
Jackup	414	369	45	89%
Semisub	192	169	23	88%
Tenders	33	22	11	66%
Total	**741**	**659**	**82**	**88%**

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	27	27	0	100%
Jackup	94	79	15	84%
Semisub	30	26	4	86%
Tenders	N/A	N/A	N/A	N/A
Total	**151**	**132**	**19**	**87%**

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	15	13	2	86%
Jackup	112	106	6	94%
Semisub	37	30	7	81%
Tenders	24	15	9	62%
Total	**188**	**164**	**24**	**87%**

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	26	26	0	100%
Jackup	9	6	3	66%
Semisub	39	39	0	100%
Tenders	2	2	0	100%
Total	**76**	**73**	**3**	**96%**

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	47	46	1	97%
Semisub	47	45	2	95%
Tenders	N/A	N/A	N/A	N/A
Total	**95**	**92**	**3**	**96%**

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	102	85	17	83%
Semisub	3	3	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	**106**	**89**	**17**	**83%**

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	30	29	1	96%
Jackup	26	24	2	92%
Semisub	20	17	3	85%
Tenders	7	5	2	71%
Total	**83**	**75**	**8**	**90%**

Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	2	2	0	100%
Jackup	24	23	1	95%
Semisub	16	9	7	56%
Tenders	N/A	N/A	N/A	N/A
Total	**42**	**34**	**8**	**80%**

Source: InfieldRigs

16 May 2014

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

A NEW FUTURE
for managing environmental issues

A new approach to managing environmental issues aims to deliver increased alignment, engagement, transparency, and assurance in relation to managing environmental issues at the Cygnus gas field in the southern North Sea. Jos Tissen and Ian Buchan explain.

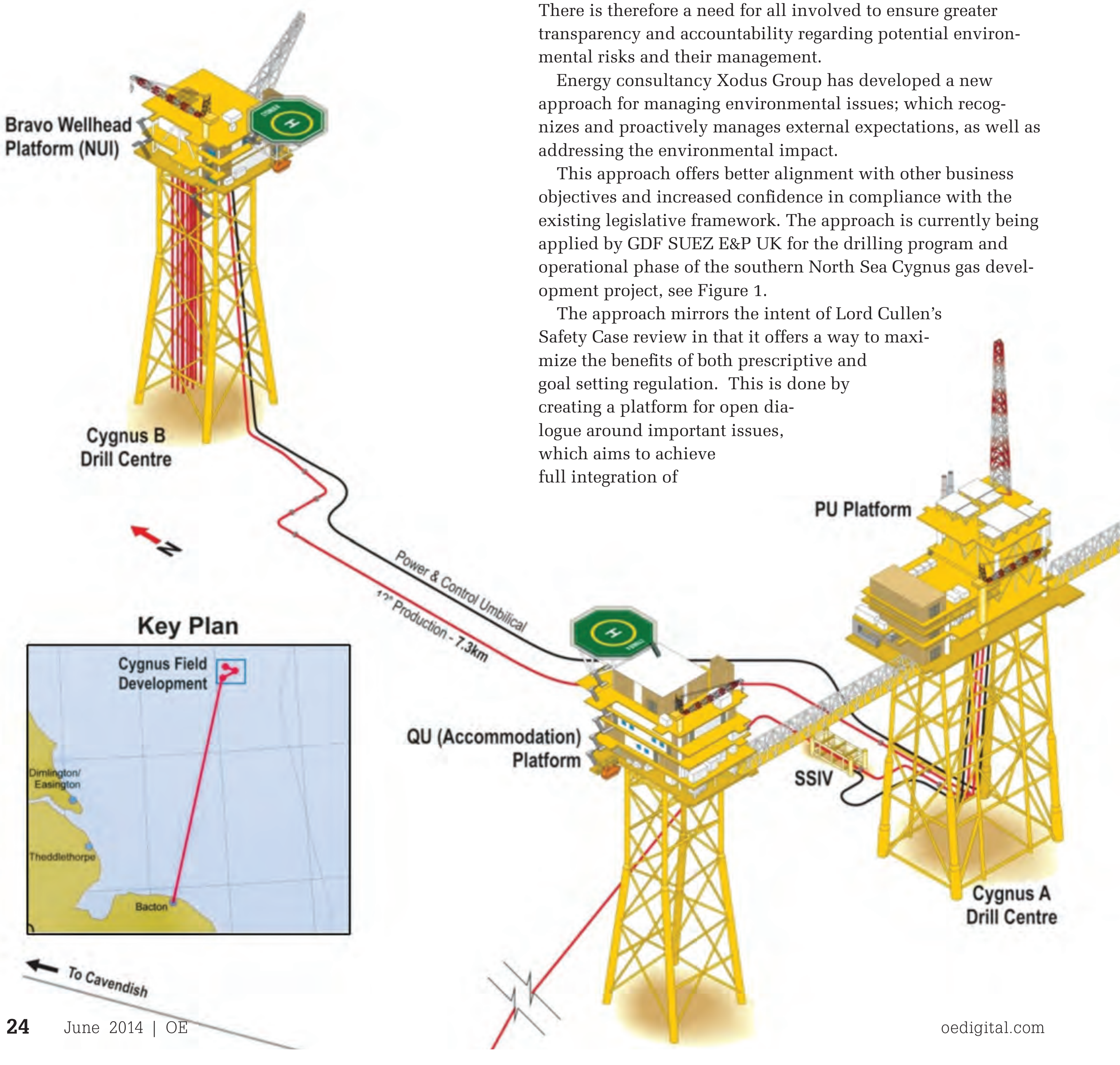
Operators are faced with an increasing administrative and cost burden in managing their environmental risks. The Montara blowout and *Deepwater Horizon* incidents have led to intense scrutiny, exposing conventional management approaches as inadequate.

Also, onshore activities such as hydraulic fracturing attract growing concerns by stakeholders and demand other regulators to review the way they implement environmental regulations. There is therefore a need for all involved to ensure greater transparency and accountability regarding potential environmental risks and their management.

Energy consultancy Xodus Group has developed a new approach for managing environmental issues; which recognizes and proactively manages external expectations, as well as addressing the environmental impact.

This approach offers better alignment with other business objectives and increased confidence in compliance with the existing legislative framework. The approach is currently being applied by GDF SUEZ E&P UK for the drilling program and operational phase of the southern North Sea Cygnus gas development project, see Figure 1.

The approach mirrors the intent of Lord Cullen's Safety Case review in that it offers a way to maximize the benefits of both prescriptive and goal setting regulation. This is done by creating a platform for open dialogue around important issues, which aims to achieve full integration of



environmental management into the operation and maintenance of offshore exploration and production operations.

It is fully aligned with the international standard on environmental management systems ISO14001, which features the continuous improvement concept and includes a commitment to comply with pertinent legislation.

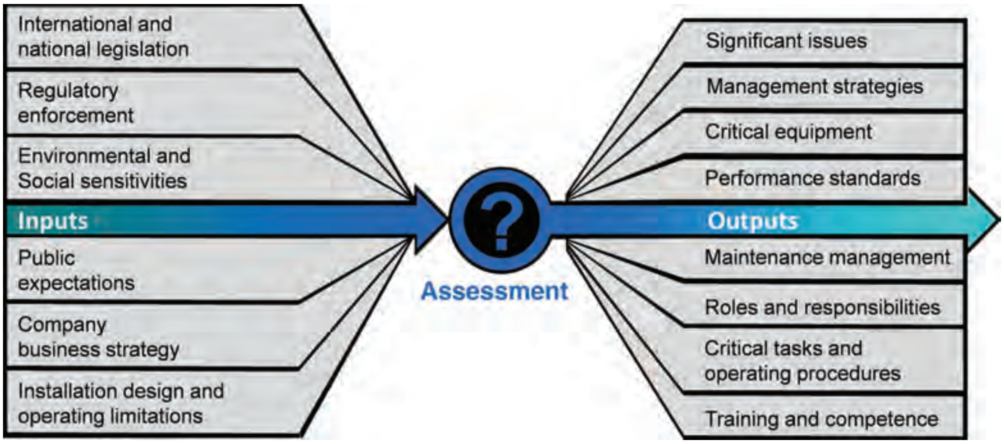


Figure 2: Environmental management plans offer a path towards unlocking the benefits of goal setting regulation and away from prescriptive regulation. Graphic from Xodus.

The environmental management plan

Due to the way the environmental management plans are developed, they offer a structured approach to creating better alignment in the management of environmental issues and increased confidence in compliance with legislative frameworks and corporate requirements.

Central to the method is a single document detailing the technical scope description, purpose, and methodology, as well as the environmental management planning and implementation.

The document is essential to the company's environmental management system, as it bridges the gap between operational objectives and stakeholder expectations, and provides an audit trail between high level objectives and individual tasks and responsibilities, depicted in Figure 2.

The outputs from the assessment, as illustrated, are used to inform and populate the tools, systems, and processes that drive and control operations on the asset. The environmentally critical/important equipment are captured within the maintenance management system, with appropriate levels of maintenance and inspection applied to each.

The roles and responsibilities (either onshore or offshore) that are necessary to ensure that the "issue management" strategies are implemented and followed are captured in the job descriptions for each position. The training and competence requirements for each position, in order that these individuals are able to fulfill their roles and deliver on their responsibilities, are captured in the training and competency management system.

The actions that are required to ensure that the plant and equipment on the asset are operated in line with the issue management strategies are then incorporated into the relevant operating procedures.

The focus of the asset management team, as well as those in compliance assurance roles, is therefore on ensuring that maintenance and inspection routines are carried out, personnel are managed in line with HR processes, and operating procedures are followed.

Plan, implement, check and review

Figure 1: The Cygnus field is the sixth largest gas field in the southern North Sea and the largest to be discovered in the last 25 years within the southern North Sea gas basin.
Image from GDF Suez.

The need for environmental protection is generally not disputed and much has been done to reduce industrial and consumer related pollution. However, building an effective environmental management system according to the "plan, implement, check and review" ISO 14001 cycle is not easy and is not as simple as writing a policy and ensuring its execution. Effectively implementing such a system requires alignment with other company commitments, such as structural integrity and financial liability. In reality, enhancing environmental performance is limited by the opportunities for improvement. Forcing through improvements generally results in tension within the organization, lack of alignment and buy-in, and bulky procedures that gather dust on the shelf.

This approach encompasses a side-by-side assessment of the differing societal perspectives by compiling a list of issues (or environmental business risks) from a comprehensive analysis of interactions between activities and environmental and social sensitivities; the equivalent of a safety HAZID (hazard identification study), with a twist.

For each of the resulting 40-60 environmental issues, an objective assessment of ecological impacts is prepared, while being conscious of the limitations of environmental science, such as its struggle to assess cumulative impacts. On the more subjective side of the equation, the expectations of stakeholders, such as their motivation and influence is considered. Finally, legislation and company standards are reviewed to ascertain any differences in these three assessments.

Two main response strategies are distinguished: impact reduction, which is reducing the physical environmental impact by, for instance, reducing the use of resources, by reducing emissions or discharges, or by reducing noise emissions. The other response strategy is risk communication, which is increasing the acceptance of the risk by better explaining the acceptability of the risk, by challenging the motives of stakeholders, or by sharing control with stakeholders. A combination of the two strategies is often required.

Issue management

One answer may be to shift and widen the perspective of environmental management from impact reduction to issue management, as shown in Figure 3. This can have wide-ranging implications.

By changing the objective of environmental management to issue management, everything that is part of the issue is managed under the heading of the issue, including the

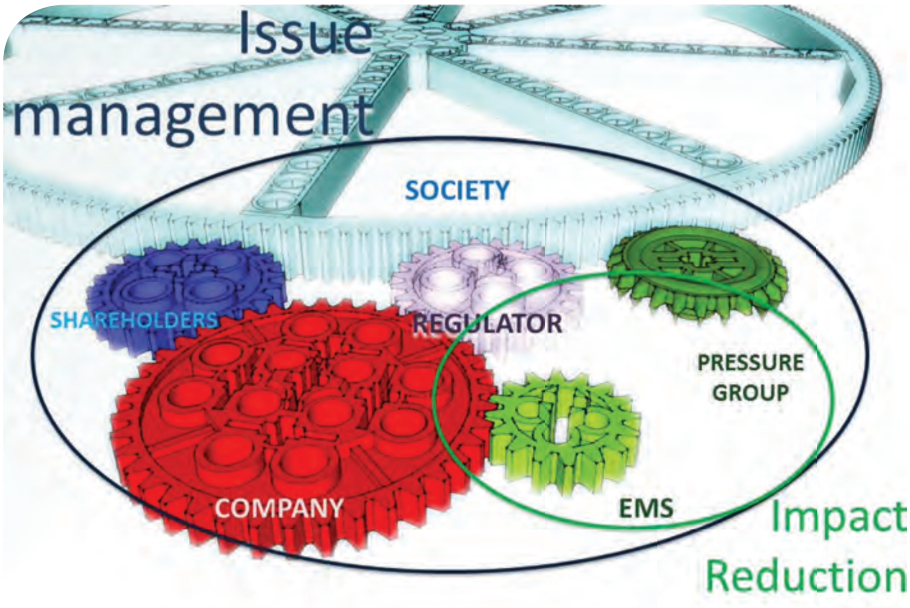


Figure 3: Issue management recognizes society as the bigger force in the equation, driving both the development and the environmental agenda. Graphic from Xodus.

misalignment of expectations between the company's HSE department and operational department, and between the operator and the regulator. This explicit representation creates buy-in, and the formulation of realistic management strategies. By broadening the subject, issues become clearer and their management more focused, while confidence in meeting regulatory requirements and expectations also increases. This can be demonstrated in the following three examples:

- Offshore oil in produced water discharges are currently regulated by a blanket 30 mg/l discharge standard and tolerated exemptions for some gas platforms. Chemical treatment is essential. Monitoring studies have not revealed any concerns, yet the regulator is pressing towards water injection and compliance with the oil-in-water standard. Goal setting regulation has the potential to reopen the dialogue and create alternative solutions.
- Production chemicals are not only screened for their environmental properties, but, in the UK, additional administrative assurance layers are enforced, with little environmental benefit, such as application forms, local impact assessments, and reporting. There is potential to streamline the system and free up resources.
- The *Deepwater Horizon* oil spill disaster has awakened the industry to strengthen its oil spill prevention and response potential. Spill prevention is one of the last remaining areas of UK offshore environmental regulation that is goal setting and the industry has an opportunity to demonstrate to its stakeholders that this is done responsibly.

A risk based approach

The approach aligns with the Oil & Gas UK Environmental Assurance Plan (EAP) initiative. This results in a different management structure where the system is built from the bottom up, i.e. developing issue specific management strategies with input from the line, identifying tasks and responsibilities, and collating those in procedures as and when required. It is therefore specific and responds to real-time changes, and can be applied at any stage of the project development process, from inception to decommissioning, and is fully aligned with ISO 14001.

The most recent example of the application of this approach involved a new regulator (NOPSEMA) in Australia, which had been rejecting a large number of environmental approval applications. The new approach was applied and plan approval given almost instantly. The main barrier encountered before using the approach was to satisfactorily demonstrate to NOPSEMA that proposed operations' environmental impacts were reduced to a level "As Low As Reasonably Practicable" (ALARP). The approach allowed attention to be concentrated on the issues that deserved to be formally addressed (either due to scientific, industry, regulatory or stakeholders concerns), and how they could be managed. ALARP became the by-product of the issue management dialogue.

Conclusion

The concept of a risk-based approach to managing health and safety is not new to the oil and gas industry. A key recommendation from the *Piper Alpha* inquiry was to move the industry from a largely prescriptive safety regime to a goal setting one. The subject approach facilitates a similar shift for the management of environmental issues.

Whilst this is still work in progress, the positive feedback received to date during the process of implementing the approach gives confidence that it will deliver unparalleled levels of alignment, engagement, transparency and assurance on the management of environmental issues pertinent to the Cygnus Field across GDF SUEZ E&P UK, regulatory bodies and other stakeholders. **OE**

Jos Tissen*, principle environmental consultant at Xodus Group, has over 33 years international experience in the oil and gas industry, 27 years of which is in the management of environmental issues. He has mainly worked in Scotland and in the Netherlands. Tissen studied at Middelbare Technische School in Oss, Netherlands.*

Ian Buchan*, environmental manager at GDF Suez E&P UK, has over 20 years' experience in the environmental management of the offshore oil and gas industry in the UK. Experience includes specializing in oil spill response and contingency planning, hydrocarbon release prevention and upstream environmental management and compliance assurance for Offshore Operations. He has a BSc Hons in Marine Biology from Aberdeen University and MSc in Marine Resource Management from Heriot Watt University.*

WORK BETTER

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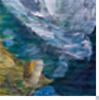

GETTING PFP RIGHT

Picking the right passive fire protection (PFP) product can be a minefield. Richard Holliday assesses the issues.

Passive fire protection (PFP) is often considered a nuisance. It seems to cover every bit of metal on oil and gas platforms, terminals, refineries and petrochemical plants. It frequently gets damaged, and when it becomes loose at height, it can be a dropped object hazard. Poorly specified and applied materials can also increase corrosion risk through corrosion under Insulation/fireproofing CUI/CUF.

In the event of a fire, people need time to escape or tackle it, and PFP buys that time by protecting safety critical elements (SCE's) from hydrocarbon fires. It isn't applied randomly—fire risks are assessed and areas that need protection have the correct type and thickness specified to keep the facility safe. Unfortunately, few asset managers fully understand how this substance came to be there, what it is or how to look after it.

A hierarchy of needs – inherently safer design

When designing or assessing PFP, it is essential to consider more than just the fire rating; virtually all PFP materials sold will have fire certification; but many systems are not fit for purpose or the fire certification is not applicable to the end use. The following aspects should be considered as an order of precedence for a PFP system:

1. Shall not generate hazards, e.g. cause corrosion, leading to leaks or integrity loss.
2. Shall not degrade with time in the environment it is exposed to, including design life and process operating conditions.
3. Shall survive an initial explosion, with resultant overpressure, drag force, deformation of substrates, and impact from flying debris.
4. Shall survive an initial high heat flux, high momentum jet or spray fire that may occur.
5. Shall provide fire protection for the required time and maintain the temperature of the item being protected below its critical temperature.

Generic names and descriptions	Typical uses and considerations
Cement-based ▪ Reinforced concrete ▪ Concrete encased steel ▪ Lightweight cementitious products	Typically now only used onshore due to weight and long term weathering issues. Low-cost, low-skilled application and local supply are main strengths.
Epoxy intumescent (or subliming) ▪ Spray applied ▪ Trowel applied ▪ Preformed (cast or molded)	These are the most commonly-used materials on offshore facilities and are gaining acceptance onshore where harsh environment or weight restrictions are an issue. Typically used on structural steel, but also commonly used on process equipment and divisions. When pre-formed, it is popular for retrofit projects and enclosures.
Syntactic phenolic foam ▪ Wet applied ▪ Preformed (cast or molded)	With much broader temperature operating limits and higher thermal performance these systems have commonly been used on vessels and pipework. Recently gaining acceptance on under-decks where combined fire and thermal insulation is required.
Flexible jackets / blankets ▪ Tailored polymer-coated outer covers with flexible insulation core layers	Most commonly used on valves, flanges and actuators but also used on vessels and pipework. Can be difficult to remove and replace on a regular basis while ensuring integrity is maintained.
Composites systems ▪ Laminated insulation core materials	Used to provide lightweight fire and blast walls and to protect items such as valves, flanges and actuators
Metallic systems ▪ A metallic outer face, typically of stainless steel, protecting an insulating core such as: • Man-made mineral fiber • Alkaline earth silicate. (AES) or refractory ceramic fiber • Cellular glass • Micro-porous & aerogel insulation • Cement sandwich • Dimpled stainless foils	Used to fabricate fire rated divisions and also used on process pipework and equipment such as vessels.
Endothermic wraps ▪ Combined with ceramic fibers ▪ Contained within a polymeric matrix	Commonly used on cables, cable trays and piping.
Rubber systems ▪ Vulcanized rubber bonded direct to steel ▪ Vulcanized rubber manufactured into preformed items	Commonly used in splash zone locations
Penetration sealing systems ▪ Transit frames and blocks ▪ "Witches hat" and bellow-type seals ▪ RTV foams ▪ Intumescent systems	A wide range of available systems covering pipe, cable and duct penetrations. Commonly specified as matching the rating of the division they are penetrating. However, in reality, they are rarely installed as tested and often omits thermal insulation without which they may not survive the fire.

Commonly used PFP for hydrocarbon fire types. Source: MMI Engineering.

PFP types and their use

There are many types of PFP and each has its place and use; however all have strengths and weaknesses (See chart on left).

In some circumstances, combinations of these systems are used – for example combining epoxy intumescent materials applied over cellular glass, either to protect the epoxy PFP from hot or cold substrate conditions or to provide combined fire and

Anomaly level		Description
1	Immediate risk	Condition deteriorated so that there is an immediate risk, even before any fire or explosion
2	Major anomalies	PFP not present, condition degraded or original design so poor that little or no protection offered against identified fire and explosion hazards
3	Significant anomalies	Condition degraded or poor original design such that premature failure is probable for identified fire and explosion hazards
4	Minor anomalies	Individual and small anomalies, possible reduction in protection level for identified fire and explosion hazards but not likely to cause global collapse or pr emature failure
5	Acceptable	Meets or exceeds requirements

Example of anomaly ranking. Source: MMI Engineering.

Fire seal penetration insulation failed.
Photos from MMI Engineering.

thermal insulation.

Today, using asbestos containing materials (ACM) is prohibited; however, its use was common in PFP, even up until the mid-1980s, and care should be taken when inspecting old PFP.

For prevention of CUI/CUF, these systems can be simply characterized into two categories:

1. Fully bonded, joint-less and impermeable systems. These can generally be considered as low risk CUI/CUF systems (assuming compatibility with substrate materials is checked), and there is substantial track record and evidence to show that these perform better than anti-corrosion paint systems.

2. Non-bonded, demountable, permeable or porous systems. In all instances it will be necessary to pre-treat steel substrates with a robust full anti-corrosion coating system. No matter how well you seal it there will be the potential for water vapor to reach the substrate and be trapped there. Coating systems should be suitable for immersion use at the operating temperatures expected.

PFP integrity management

Industry regulations and guidance typically require operators to verify and maintain PFP throughout the life of the facility, which is only possible if good records are maintained. To facilitate this, it is essential to establish a database detailing where and why PFP is used. This would generally include the following steps:

1. Establish an asset register of items requiring PFP. This could include primary and secondary structure, process equipment, pipelines and ESD valves, temporary refuge (TR) and command and control centers, blow-down and flare/vent system, fire zone divisions (walls, decks), and fire pumps.

2. Define the criticality of each item. This would consider facts such as TR impairment, escalation control, loss of production, asset protection, and environmental impact.

3. Establish functional requirements for item being protected. This would include aspects such as structural resistance, hydrocarbon containment, smoke and toxic fume integrity, separation for fire zoning, and fire water demand.

4. Establish hazards and conditions in the area. Blast/explosion hazards, impact, fire hazards (jet fire, diffuse fires, pool fires) and environment hazards (UV, salt spray, heat, vibration).

5. Determine required fire resistance time. How long do you require it to perform the function(s) identified in No. 3 above?

6. Establish fire resistance rating. Consider the structural resistance requirements (including self-weight), integrity requirements and insulation requirements (now commonly known as REI – resistance, integrity and insulation).

7. Establish the maximum critical temperature the item can reach and from this the allowable temperature rise under fire conditions.

Inspection of the PFP is undertaken based on the condition of the PFP, the severity of anomalies and the extent of anomalies.

Armed with the information in the table "Example of anomaly ranking," it is possible to establish a matrix to assess the integrity of the PFP and plan repairs and maintenance.

Against each 'score' will be a series of outcomes, ranging from removal and replacement with upgrade, to future re-inspection.

PFP Inspection

It is essential to understand the modes of failure for each different PFP system and this requires detailed knowledge of both the materials used, their system design/specification and the application principals, which often involves a degree of detective work.

Typical anomalies include: cracking; disbondment; water logging; mechanical damage; loss/removal of material; exposed reinforcement; Corroded or damaged reinforcement; reinforcement not located in correct position or missing; thermal degradations; UV damage; incorrect jointing and sealing details; missing components; exposed top flanges; or missing coat-backs.

For some systems, under certain fire conditions, these may have little effect on fire performance in other cases even a visually small (or hidden) anomaly could lead to rapid failure. It is often the combination of anomalies that determine the severity. There are no simple rules of thumb and the author has personally witnessed a 180 minute fire barrier be destroyed in less than five minutes by a jet fire.

The key to a successful PFP integrity management process is to ensure it is carried out independently; maintenance contractors and PFP manufacturers often offer a "free" service, but do they really understand the hazards and risk? Competence comes from experience and a fire-proofers ticket for attending a two-day training course on one material is no substitute for years of practical experience. OE

Richard Holliday *is principal consultant at MMI Engineering. Holliday is a technical authority in passive fire protection (PFP), thermal insulation, heat shielding, and protective coatings. He has an MSc in Information Systems from Robert Gordon University, Aberdeen.*

Sensory perception

City Technology's John Warburton discusses why gas sensors are so essential to high-performance gas detection while examining how the right sensor solution can deliver tangible savings and value in offshore applications.

Twenty years ago, computers were purchased with little understanding of inner component workings or the clever technology that actually made the device perform so well and effectively. Today, thanks to a an effective global marketing campaign from a leading processing chip manufacturer, we now all appreciate that our computers are only ever as good as their processing capacity, regardless of any other impressive functionality they might offer.

This is a good analogy for the gas detection industry; there is much focus on the gas detection solution itself and all the value such a device can bring, but the sensor component itself is equally important.

No room for failure

Fixed and portable gas detection forms an intrinsic part of offshore safety. The sensors used within such devices have a very hard job to undertake. Not only must they detect gas risks accurately and reliably, but they must do so consistently and in all environmental conditions. Factors like sea spray or salt particulates, cross-sensitive compounds, poisons and temperature, pressure and humidity fluctuations must all be considered and compensated for effectively. A high-quality sensor must be designed in such a way that it can overcome any challenges.

Failure is not an option in such applications: Lives and assets depend on the highest grade of safety provision.

Gas risks are numerous and ever-present offshore, including hydrocarbons like methane, alcohols like methanol, and toxic gases like hydrogen sulphide, sulphur dioxide, nitrogen oxide and carbon monoxide.Standards and minimum provisions vary considerably across the globe. ATEX and EN/UL/FM/CSA regulations are constantly evolving, and they represent a high provision of safety in terms of global standards. As an interesting example, the poisoning of flammable sensors is a recent hot topic in the Asia Pacific region, following the Chinese government's recent announcement of the new flammable gas detection GB153221.1 Standard which becomes effective 2015, designed to enhance safety through more stringent controls over flammable detector performance.

Globally, society is becoming increasingly safety conscious, which has resulted in more stringent insurance criteria. This criteria is a catalyst for greater accountability and protection. As a result, today's sensors need to work harder than ever.

Meeting offshore needs

Maintenance is also a key consideration for offshore applications because of the vessels' distance from land-based resources. The right sensor choice can assist dramatically with this aspect; extended calibration and easy sensor switch-out functions deliver considerable value. Reliability is also essential - a sensor with an inherently stable design can facilitate such ongoing maintenance value, by its ability to compensate effectively for any factors that could be a potential challenge.

One of the most important jobs of a portable gas detector in offshore applications is protection in confined spaces like tanks, pipelines, drains, culverts and hollow platform legs. Fixed gas detection is featured prolifically offshore; flammable, hydrogen sulphide and oxygen detection is required at driller stands, shale shakers and drill floors; compressors, pipelines and seals require flammable detection; drains and run-off gullies must also be monitored for hydrogen sulphide, carbon dioxide, and nitrogen oxide. These are just a few examples.

Geological and environmental impacts

Aside from the obvious associated industry risks, it is worth noting that regional factors can have a big impact on sensor use. For example, in the Caspian Sea, oil and gas demands have led to exploiting sourer wells rich in hydrogen sulphide.

Depending on the geology, varying well constituents will be extracted presenting a huge variety of flammable risks that must be negated. A flammable sensor must be able to cover all these gases, their differences, and compensate accordingly to deliver leading-edge performance. Any sensor manufacturer will tell

In offshore application, the workers' lives and the asset's integrity can all come down to the tiny sensors within a gas detector.

With increased safety regulations, a lot is demanded from gas sensors. Images from City Technology.

you this takes considerable effort, scientific talent and expertise.

Extracted, raw crude can contain a diverse mix of hydrocarbons in varying quantities, from small chains like methane hydrate; to aromatics, like benzene; and alkynes, like butadiene. Flammable sensors must be able to adapt to the different flammability of these hydrocarbons.

Cash is king

Second only to safety, cost is the next biggest factor in selection. A manufacturer should deliver the following essential combination: highest performance/accuracy (in all-weather/temperatures/potential cross-interference conditions); intelligent affordability (real-world value fully aligned with the offshore industry itself); and reliability.

I am often asked what to consider when selecting the right sensor solution. The offshore oil and gas industry provides the ideal context to highlight the core attributes needed, because it represents some of the most challenging locations for gas sensors to work in. There is the potential for ingress by compounds and water vapour/sea spray that must be prevented using filters, sinters and small capillaries. Ambient conditions can change and temperature can fluctuate due to weather systems and the effects of being out on deck and then inside.

Sensors from leading manufacturers should be designed and tested to respond to such conditions and meet the maximum range a device could ever encounter, working between -40°C and 55°C. They should include technologies and components that allow the sensor to adapt quickly to fluctuations.

Other sensor challenges

Humidity is a particular concern for electrochemical cell (ECC) sensors. Shifts can be large depending on climatic conditions. Leading-edge ECC sensors must work effectively across various RH conditions, meeting the demands of even the most challenging locations through their intelligent component design, which must prevent drying out or saturation. A sensor with inherently stable design will also overcome any potential issue created by pressure fluctuations.

Accidents happen and portable devices can easily be dropped. Fixed gas detectors are also subject to vibration from sea storms and on-structure processes, so sensors need to be highly robust and capable of withstanding impacts and mechanical vibrations.

Sensors must also be able to minimize the effects of cross-interference, which could cause inaccurate readings and nuisance alarms. There are various compounds that can impact sensor performance including alcohol-based de-icers and a high performance sensor must be able to perform accurately in the presence of cross-interference compounds.

A sensor specifically designed and tested to meet the needs of an offshore application is a must and it is recommended to work with a manufacturer well-versed in your application. Benchmark recommendation is to request proven data on performance – if a manufacturer cannot prove the suitability of your sensor to your application, this is a red light indicator the sensor is not optimized for such a use.

Reduce maintenance – save money

Various factors combine to make a sensor capable of extending maintenance intervals. The impact of sensor swap-out ease and sensor testing should also be considerations. All aspects will impact any potential saving/value you may be able to leverage.

Something that is often overlooked is the importance of repeatability; you need to be able to rely on your manufacturer's processes and controls so that each sensor you use works exactly as it should, every time. A gas detector cannot afford to lose even a moment's effective detection performance and it uses its sensing capability to fulfil this remit. Just one faulty sensor can really be the difference between life and death, so take a holistic approach to selecting a manufacturer and be sure that their production practices can deliver consistent high quality results. One sure fire way to assess this yourself is to ask to see manufacturing facilities and processes and also failure ppm data (the calculation of how many sensors out of every million are probable to fail). OE

John Warburton *is the Strategic Marketing Manager of City Technology, and , part of Honeywell Inc.,works to deliver sensing solutions entirely optimized and tested to meet the demands of offshore applications.*

Offshore seismic solutions

Five exemplary geophysicists took part in a panel discussing "Emerging Offshore Geosciences Technologies" at the 45th Offshore Technology Conference in Houston, all of whom have dedicated years of service to the Society of Exploration Geophysicists (SEG), one of OTC's sponsoring professional organizations. Nina Rach reports.

Marine streamers

David James Monk, Director of Geophysics at Apache Corp., talked about advances in marine streamer technology and novel acquisition geometries. Broadband seismic allows deeper imaging through the inclusion of lower-frequency data, and "you really want the lowest frequencies you can get," he said.

Acquisition techniques that reduce seismic ghosting (reflections from the sea surface), such as towing streamers at different depths, and using sampling pairs, such as pressure and velocity fields, or pressure and acceleration, ultimately improve data quality.

Simultaneous-source acquisition may become more common offshore, resulting in more data acquired faster.

Monk believes bandwidth will increase to one million channels within a decade. Technology to position streamers has advanced, he said, and may result in shooting "strange geometries that we can't even begin to imagine today."

Monk earned a PhD in physics at University of Nottingham, and worked in R&D on seismic acquisition and processing at Geophysical Service Inc. (GSI) and Halliburton Geophysical Services Inc. (HGS) for 18 years, then served as President at Energy Innovation Services before joining Apache in 2000. Monk served SEG as Chairman (2008-2011), and as President (2012-2013).

Permanent reservoir monitoring

Rocco "Rocky" Detomo discussed using permanent reservoir monitoring systems (PRM) offshore, citng BP's Life of Field Seismic (LoFS) program at the Valhall field off Norway. BP Norge covered a >45sq km area with permanent ocean-bottom cables and ran 15 surveys. Success at Valhall led BP to install PRM on the Clair field off UK, and at the Azeri-Chirag-Gunashli complex in the Caspian Sea. LoFS systems make sense, Detomo said, if companies plan repeated surveys over a field.

He also mentioned several types of seabed geodesic systems to measure subsidence and lateral movements, and suggested that systems could be integrated to provide different types of measurements.

Detomo discussed permanent wellbore sensors, which incorporate distributed acoustic sensing fiber-optic systems that he expects to be deployed more widely. The future should bring improvements in fiber-optics, with more sensors, channels, and receivers. Other promising technologies include autonomous recording, seafloor power solutions, and optical data transmission.

Detomo earned a PhD in experimental nuclear physics at the Ohio State University, after which he worked for Shell and received Shell's 1991 President's Award. He recently formed Omoted Geophysical Consulting. Detomo has served SEG in many capacities, as technical program chair for the 2006 Annual Meeting, Chair of the Travel Grants Committee, Trustee Associate of the SEG Foundation, and travelled as the SEG 2012 Honorary Lecturer in the Middle East & Africa, discussing 4D time-lapse reservoir monitoring. Detomo is Vice-Chair of the SEG subcommittee for the OTC 2015 technical program.

Seabed hardware

Shuki Ronen, Seabed Geosolutions BV, questioned whether PRM is the future of reservoir geophysics.

Non-permanent technology, including streamers and ocean-bottom nodes, can also provide proper reservoir monitoring, especially with faster shooting and better broadband sources.

Sometimes it is a good idea to put receivers on the seabed; sometimes it is not, Ronen has said. "I want to encourage people to know where and when and how to put seismic receivers on the bottom of the ocean."

4D reservoir monitoring often requires seismic surveillance in congested offshore areas, where obstacles deter full streamer spreads. Ronen points out that seabed receivers present fewer safety challenges than surface-towed streamers. Permanent or accurately repositioned receivers also have improved repeatability for reservoir production monitoring. Ronen anticipates more remotely operated vehicle-enabled installations and longer battery life.

In addition to improved P-wave imaging, multicomponent seabed receivers record shear waves, which can help distinguish between effects of fluid change and pore-pressure change.

Ronen earned a PhD in geophysics at Stanford University and works in academia and the oil industry. He was a visiting professor at Colorado School of Mines, and has been a consulting faculty member at Stanford since 2008. He worked at Saxpy Computer, Schlumberger and Veritas DGC in various positions for 18 years, before consulting for Chevron, joining Seabird, and then serving as Vice President for Ocean Bottom Technology at CGGVeritas. Ronen is now Chief Geophysicist at Seabed Geosolutions (JV between Fugro and CGG). He received an SEG Special Commendation in 2002, recognized as one of the four principal developers of Seismic Un*x, and in 2012 served as SEG North America Honorary Lecturer, discussing "Ocean-bottom acquisition and processing: past, present, and future."

Microseismic monitoring

AAPG member Peter M. Duncan, president and CEO of Houston-based MicroSeismic, discussed the achievements and promise of microseismic technology.

"Microseismic monitoring is to [hydraulic] fracing as logging is to drilling," Duncan said. It helps show which parts of a reservoir are draining, and points to the best areas to put future wells. "Optimal well spacing," he said, "is what operators need to know."

He said passive measurement was useful for monitoring production as well as induced seismicity resulting from injection, and would be part of the smart oil field of the future.

Passive monitoring also provides transparency into oilfield operations. "The oil and gas industry recognizes the need to remain good stewards of our environment and are proactive in developing technologies and practices that ensure responsible oversight," said Duncan.

Duncan earned a PhD in geophysics from the University of Toronto and has spent his career at Shell Canada, Digicon Geophysical, ExploiTech Inc, which became a subsidiary of Landmark Graphics, and 3DX Technologies Inc., before founding MicroSeismic. Duncan served as SEG President in 2003-2004, and as Fall 2008 SEG/AAPG Distinguished Lecturer.

4D/4C off Brazil

Paulo Johann, corporate reservoir geophysics manager at Petrobras Brazil, discussed how the company is using PRM technologies.

In 2005, Petrobras ran an ultra-deepwater, 4-C seismic acquisition program in the Campos and Santos basins. It began with a feasibility study that indicated the potential value of multicomponent technology. Petrobras used illumination analysis to design the survey and had fully processed data within seven months.

In late 2012, Petrobras installed the first deepwater PRM system at the Jubarte field, in Campos basin. The Jubarte area is crowded with obstacles, with 60 fields, 567 wells, and 51 platforms, and would appear to be a perfect candidate for PRM because of the complex infrastructure.

A PGS Optoseis system was installed in 1200m-1350m water depth in the south part of the field. The sensor array included 35.6km of seismic cables arranged in two subsea array loops covering 9sq km, containing 712 4D-4C receiver stations at 50m intervals. The objective was to validate the ability of fiber optic sensing technology to detect reservoir impedance changes.

Traditional offshore seismic surveys produce less than 500,000 seismic traces/sq km. High-density surveys provide around 1 million traces/sq km. But the Jubarte PRM acquisition geometry generates more than 3.8 million traces/sq km of multi-azimuth and multicomponent data.

Johann joined Petrobras in 1981. He has been involved with internal Petrobras training programs for new geophysicists and geologists and was PRAVAP (Research IOR Program) coordinator in geophysical technology. Johann earned a D.E.A. and PhD in reservoir geophysics from Paris VI University, as well as MBAs from FGV and COPPEAD. Johann was the first SEG Latin America Honorary Lecturer (2008) and was vice-president of the Brazilian Geophysical Society, SBGf (2003-2005) and SEG (2008-2009). OE

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An automated robotic drilling future

Drilling technology has improved by leaps and bounds in the past 20 years. Yet, Statoil's drilling and well research manager says there's room for a revolution when it comes to efficiency. Elaine Maslin reports.

"I think there's room and need for a revolution in offshore drilling," says Halvor Kjørholt, manager for drilling and well research, Statoil.

Kjørholt, who was speaking at SPE Intelligent Energy International, held in Utrecht in April, says drilling technology, particularly around safety and ability, has improved, but efficiency hasn't. In fact, drilling costs have increased by a factor of five since the turn of the century, he says.

"There has been sizeable technology development in drilling over the last decade," Kjørholt says. "These developments have eased the life on the rig, improved safety, and enabled more advanced wells, but drilling efficiency has not improved much over the last 20 years."

Improving drilling efficiency could help the industry save. Drilling, which is the most efficient measure in increasing recovery rates, accounts for more than half the development cost for offshore projects, he says.

According to Kjørholt, there is room to take 50% out of the time to drill a well—and he has some ideas how this can be achieved.

Kjørholt has six technology aspirations for the drilling industry, from robotics to real-time monitoring. They involve a combination of intelligent solutions and hardware, topside and downhole, all of which are inter-connected with potential synergies.

The six areas are: real-time well diagnostics; drilling sequence automation; downhole pressure control; robotic drill floor solutions, casing while drilling; and real-time reservoir navigation. Not all are entirely aspirational—Statoil is already working with companies to realize robotic drill floor solutions, for example.

Kjørholt outlined each area in more detail:

- **Real time well diagnostics –** Kjørholt would like a software diagnosis tool to give accurate information about downhole conditions. For this, improved and extended instrumentation and data acquisition will be needed, including self-calibration capability. An ultimate version should also indicate potential improvements which could be made during drilling.
- **Drilling sequence automation –** Applying modern control technology used in other industries to run drilling process sequences in an automated mode, would enable the industry to move away from the relatively manual process drilling is today, Kjørholt says. "It's about moving drilling more in the direction of process control."

Statoil is already working with Norway's Sekal to achieve this. Sekal is owned by International Research Institute of Stavanger (IRIS), Statoil Technology Invest, Sakorn Invest, Saudi Aramco, Wellwork

Drililng sequence automation will be tried out on the platform.
Photo by Harald Pettersen, Statoil.

Innovation, and Sekal employees.

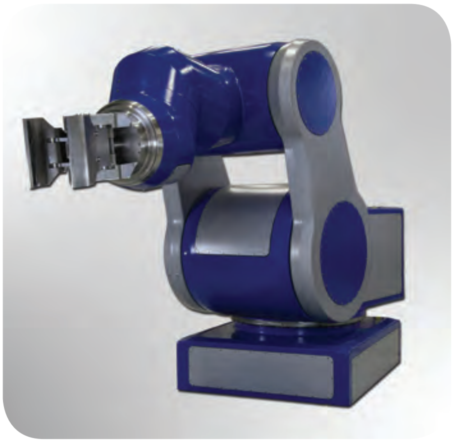
The company has developed DrillTronics, a real-time system to actively control the draw-work, top-drive, and mud pumps to account for the dynamic behavior of the well during drilling operations.

The system monitors, diagnoses, and controls the drilling process, with several automated functions in addition to safeguards and safety triggers. All the functions will be tuned to match, in real time, what the well at any point in time can handle from the real time calculated and calibrated values.

DrillTronics can be run in two different modes, active and passive. In passive mode DrillTronics will calculate and display all limits and the driller may use the displayed limits. These limits will not be used by the drilling control system (DCS). In active mode, all calculated limits will be sent and used by the DCS and hence automated functions, safeguards and safety triggers will all be active. All functionalities are adapted to compensate for rig heave.

A first version of a system using drilling sequence automation is being installed on the Statfjord C platform in the Norwegian sector of the North Sea and will start operating this spring, Kjørholt told SPE Intelligent Energy.

■ **Down hole pressure control, or managed pressure drilling –** This exists already as a service, Kjørholt says. "In the future it could be a more integrated part of the way we are drilling," he says. "I think the way forward is to integrate it into drilling control systems and this way accuracy should be improved, as well being able to detect small, in and out, fluxes from the well. An ultimate form should automated handling of losses and gains, to make sure an event doesn't develop in to a well control situation."



Robotic Drilling System's drill-floor robot.
Photo from Robotic Drilling Systems.

■ **Robotics –** "In the future we will see more robotics replacing the mechanical solutions we have today," Kjørholt says.

Here, Statoil is also already working on solutions, this time with Norway's Robotic Drilling Systems (RDS). The firm, behind the seabed rig concept—a seafloor drilling rig—recently had significant investment from Norwegian drilling firm Odfjell. The company agreed to participate in a new share issue of NOK50 million in RDS, and an additional NOK35 million in a future share issue.

RDS describe the unit as the world's strongest fully electric robot for the oil and gas industry—"a new generation handling tools, for the pipe-deck and drill-floor on new builds and retrofits, consisting of robotic technology for fully unmanned drilling operations."

A full-scale prototype has been in testing over the last two years, with support from Statoil, Forskningsrådets Demo 2000 program, Innovation Norway, and two other oil companies. Odfjell says a full-scale test is planned for 2015, with a final offshore test in 2017.

"With a payload capacity of 1500kg at 3m reach, the robot will be capable of handling most tasks done today by air-tugger, other lifting apparatus and/or rig personnel," RDS says.

The ultimate solution must be unmanned and efficient drill floor with high reliability, he says. "A fully electric solution is seen as fast, accurate, and easy to maintain, as it could be built, to an extent, from standard components.

RDS' robot is to be moved to an onshore test-rig for testing later this year, Kjørholt says.

Robots use NASA technology

Massachusetts-based Energid Technologies is working with Robotic Drilling Systems by providing its robotics software, Actin. It says beta deployments, software testing in which a sampling of the intended audience tried the product out, are anticipated next year.

The robot control software, used by NASA and DARPA, will program, monitor, and control the robot RDS is developing for offshore drilling operations.

Energid says its software provides a level of autonomy, flexibility, and safety, not before seen in the energy industry.

The companies says it will simplify the interface to the end-user, whether a rig operator (simply monitoring rig operations) or a developer (with the ability to create complex motion sequences for the robots).

"I never thought it would be possible to create sophisticated, multi-robot, hand-off procedures, using a simple drag-and-drop interface, especially when dealing with the number of axes that we are, but with the Actin software that's exactly what we're doing," says Roald Valen, Control Systems Manager for RDS. ■

■ **Making the well as you drill –** "This has been a long-wanted solution, providing we have full capability to steer and log," Kjørholt says. "I see this as a way to build robustness in to the well. The ultimate aspiration is to drill, line, and cement sections in one run."

■ **Real-time reservoir navigation –** "Being able to make a 3D image ahead and around the bit is an enabler for optimal well placement and enabling better understanding of the reservoir," Kjørholt says.

These solutions alone could improve efficiency. But, Kjørholt says, using all of them would have the biggest impact. "My view is an integrated effect will be bigger than the sum of the components," he says. "For all these areas, developments are ongoing, but there's still a long way to go."

There is also "one final piece missing," Kjørholt says—competency. "Future solutions will need new competency. It will be important to seek that also outside the traditional drilling environment," he concludes. OE

Archer's modular Topaz makes its North Sea debut

Statoil's Heimdal platform. Photo by Øyvind Hagen – Statoil.

Archer's new vertical drilling rig is due to debut in the Norwegian North Sea later this year. Meg Chesshyre found out more.

Drilling specialist Archer's new VDD (vertical drilling rig) 400.2 offshore modular rig, the Archer Topaz, will be deployed for the first time in the Norwegian North Sea later this year. Carrying out plugging and abandonment operations on a modular rig is also a first for Archer and the industry as a whole.

The rig is in the final stages of commissioning at German rig manufacturer Max Streicher's facility at Deggenau in Germany, and ready for transportation to Norway. The design and construction of the rig has been carried out over about 18 months.

"All of Norway's oil and gas industry focuses on us," comments Dr. Peter Romanow, head of drilling technology at Streicher.

The new rig is scheduled to mobilize for a program for Statoil, and partners Total, Centrica, and Petoro, in the Heimdal field in August, and to be operational by November. The contract is for permanently plugging and abandoning 12 gas wells on the Heimdal platform in the Norwegian North Sea. The contract period is 34 months, with four option periods of three months each. Total contract value, including the startup, operating and decommissioning phases, is estimated at US$115 million.

The low persons on boar (POB) required to operate the Archer Topaz made it a viable option for Statoil for deployment on the Heimdal field center, where installation upgrades are under way to keep the field operational as a gas processing and distribution hub up until 2030. First gas from the nearby Valemon field, to be exported via the Heimdal platform, is expected this coming December.

The modular offshore rig, Archer's second, has been designed and built in cooperation with Max Streicher and is in line with current NORSOK regulations, the standards developed by the Norwegian petroleum industry. It is easy to transport, install, and dismantle, and is highly automated. The rig up time is around three weeks and there is a self-erecting mast system. The pipe-handler operates fully automatically, the pipe-handling crane, which has been adjusted to the limited space on the Heimdal platform, is partially automated. The modular-designed pipe deck, with its support structure, weighs about 200-ton and can be loaded with rods and pipes up to 150-ton. The deck will be delivered in about 30 modules.

"The fact that it is NORSOK compliant means we can basically operate anywhere in the world at the highest level of safety," explains John Lechner, president North Sea and executive vice president with Archer. The high level of automation results in a minimum POB and a much safer operation. "It gives us the advantage of what you would see on a seventh generation semisubmersible, as far as automated handling and safety systems are concerned."

He stresses the advantages of the modular system in terms of flexibility of operation. "We believe this is a first class rig, safe and an efficient alternative to more conventional solutions for mature installations in the North Sea." With a modular solution, the cost is low because the POB is low, and the cost of installing the rig is much lower than other solutions.

An unexpected additional benefit of the modular system arose, when there was major flooding in the Deggendau region last year, as the manufacturer was able to send some of the modules to other subsidiaries, in order to catch-up. It also means that testing and commissioning can be carried out in parallel.

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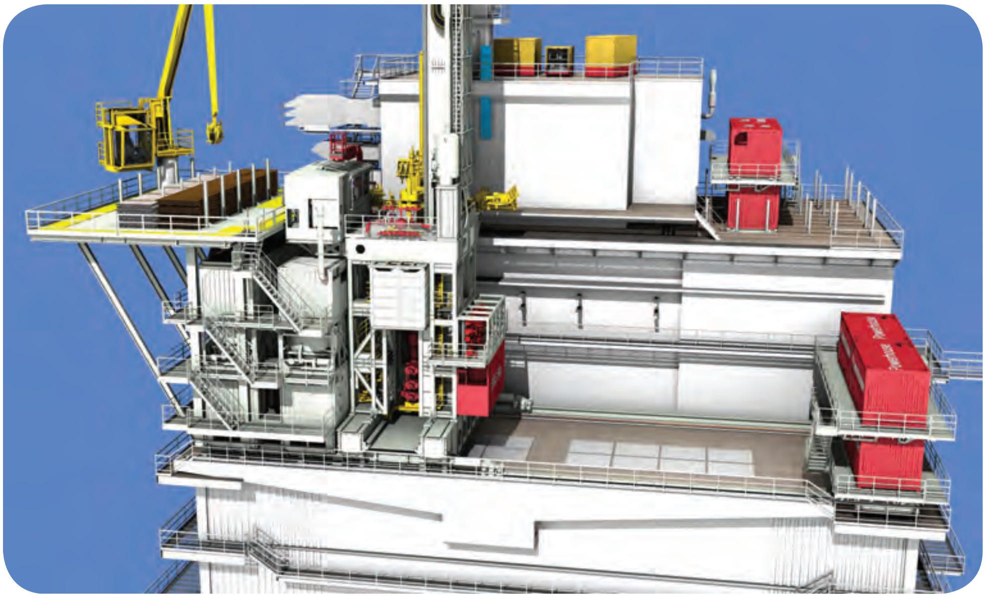

The Archer Topaz modular rig, as it will look when installed on the Heimdal platform. Image from Archer.

It is easy to integrate the modular rig onto a platform and easy to re-use. There is no need to refurbish outdated platform drilling rigs in situ. The structure can be re-configured to reach other well slots. Its small footprint makes it appropriate for aging platforms with restricted space, and its integrated power generation and mud system allow for autonomous operations, Archer says.

The VDD 400 range features a 400-ton pull capacity, a 100-ton pushing capacity, a maximum 12-ton module weight, two direction skidding, and a compact 145 x 12m footprint, without power supply. The mast height is 28m and the drilling depth 5000m. The hydraulically driven VDD 400.2 has automatic pipe-handling for tubular sizes 2½-in. to 20-in., and is suitable for operation in hazardous areas. The hydraulic power enables precise control, and despite small components, high power can be transmitted. The rig and mud package weighs 490-ton, the power package 128-ton, and the pipe deck and pipe-handling crane 220-ton.

The new modular rig follows Archer's first modular rig design, VDD 400.1, the Archer Emerald, which was a breakthrough when it was launched in 2012. The Archer Emerald is currently operating offshore New Zealand in the Tasman Sea on Shell Todd's Maui A offshore platform. It successfully completed its first year without any LTIs (lost time incidents) in February.

The two projects differ in that for Maui Archer had to supply its own power, but was able to use an existing pipe deck, whereas on Heimdal a power supply is available, but it was necessary to supply a pipe deck. Lechner says there have also been some ergonomic learnings from Maui for Heimdal, in terms of maintaining equipment in a compact space offshore.

Archer's modular rigs (MDRs) are designed to stand alone, can be rigged up on most offshore installations, and can perform most drilling operations normally performed from a platform, including drilling and workover operations, completions, snubbing services, casing drilling, and plug and abandonment, Archer says. They are rack and pinion driven, modular drilling, and intervention rigs, a concept proven by Streicher on land rigs in Europe, but a new concept for the North Sea.

This modular rig package can be tailored to meet well-specific requirements and provides operators with an alternative to both mobile offshore drilling units and traditional platform drilling rigs on existing and future installations. Using an MDR, in both greenfield and brownfield environments, negates expensive CAPEX investments and/or costly re-activation projects, Archer says. Renting an MDR also negates operating, maintenance, and re-certification costs on existing drilling facilities.

Archer secured a contract this spring for the provision of drilling services with Talisman Sinopec Energy UK using the Archer Emerald. This contract will be the first operation using the modular rig on the UK continental shelf. The initial two-year contract is worth about $96 million. Mobilization is due to start in 1Q 2016, following a period of rig interface modification. The platform-based modular drilling activity will form an integral part of the Talisman UK Montrose Area redevelopment project, aimed at prolonging the life of aging assets and extracting further reserves from the Montrose reservoir.

Lechner thinks that once both modular rigs are working in the North Sea in a year and a half's time—one a piece in the Norwegian and UK sectors—"We'll be able to showcase the technology, show that the work can be done with a very low POB, and to the safety standards that we are talking about."

The modular rig suitability assessment comprises a desk top feasibility study, an offshore site survey verifying the findings of the desktop study, a FEED study, detailed engineering, and finally the offshore construction project, where engineering teams are mobilized to conduct the interface activities to install the MDR on the platform. This activity is conducted off the critical path, ahead of mobilization, to mitigate any exposure to delays during MDR mobilization.

Archer's rig manager for the Heimdal project, Bjørn Christensen, says that Archer personnel are currently being trained up for Statoil's Heimdal project.

Archer has more than 8100 employees over 100 locations, including the North Sea, Middle East, Asia, Africa, Europe, North America, Gulf of Mexico, and South America. In addition to its two modular offshore rigs, it is operating on 33 offshore platforms and owns and operates 77 land rigs. **OE**

The Archer Topaz modular rig, nearing completion in Germany. Photo from Archer.

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West Africa gets some TLP

Deeper and more difficult reservoirs are demanding different concepts offshore West Africa, including tension leg platforms. Jérôme Iacovella and Pauline Beraud discuss the options.

The Moho Nord TLP design.
Image from Doris Engineering / F. Lucazeau.

The wellhead platform with tender assisted drilling (TAD) has been the preferred concept for many developments in the benign environmental conditions found in West Africa and southeast Asia for many decades.

Replacing the fixed jacket used in shallow water with a tension leg platform (TLP) allows the wellhead platform concept to be extended into deeper waters.

The first TLP installed in about 150m water depth on the Hutton Field in the North Sea in the early 1980s has now been decommissioned. The second, installed five years later in the Gulf of Mexico (GOM), was the Jolliet tension leg wellhead platform (TLWP). It was four times smaller than Hutton, with a displacement of only 16,600-tonne, and is still producing.

Since then, 15 TLPs have been installed in the GOM and five TLWPs have been installed in southeast Asia and West Africa, mostly with tender assisted drilling. Two TLWPs that will use semi tender assisted drilling (STAD) are currently under construction: the Papa-Terra TLWP for Petrobras in Brazil and the Moho Nord TLWP for Total in the Congo.

A TLP is a floating platform, vertically moored by means of tendons and anchored with driven piles. The tendons are typically steel pipes, which are kept in tension at all times by the buoyancy of the hull. The structure is vertically restrained by the tendons and the high axial stiffness virtually eliminates all the vertical heave, pitch and roll motions induced by the environmental conditions. A TLP has a very limited storage capacity and as a consequence can only be used in areas where the production can be exported directly through a pipeline or via a storage unit, such as a floating storage and offloading vessel or a floating production, storage, and offloading (FPSO) vessel.

In West Africa, oil storage and offloading is generally required, which means that an FPSO is the obvious choice for a host platform. The only exceptions are where an export pipeline is installed and a compliant piled tower (CPT) or smaller FPU barge without storage can be used. With a host platform, the two main field development alternatives are then:

1. subsea wells tied back to the host platform through flowlines with umbilicals
2. surface wells on a dry tree wellhead platform installed close to the host platform with fluid transfer lines (FTLs) and minimum processing facilities.

For the shallow depth Oligocene and Miocene reservoirs found in West Africa, the subsea tieback is often the more economical solution. In the deeper and more difficult reservoirs, where the wells can be drilled from a single drill center, a wellhead platform offers several advantages that can make this the most economical concept.

First, direct access to the wells facilitates well intervention operations and gives better control over the production for reservoir management, which can increase the oil recovery rate. Second, drilling operations can be done directly from the platform with a dedicated drilling/workover rig or with a self-erecting derrick equipment set (DES) installed

Hutton TLP legs–the first TLP installed–at Scotland's Cromarty Firth, post field decommissioning.

and supplied by a tender vessel.

When the surface wellhead platform with dry trees shows an advantage over the subsea trees then there is a choice between three concepts; the deep draft semi, the SPAR and the TLP. In West Africa, the long period swells have an adverse effect on the dynamic behavior of the deep draft floaters, like the semi and the SPAR, and the TLP becomes an obvious choice. The only drawback with a TLP is that it is designed for a given payload, which implies a good evaluation of the weight from the start, including any future modifications, and accurate weight control throughout the project.

Doris Engineering has been developing the TLWP concept for more than two decades, analyzing pros and cons, adapting technology, and proposing innovative solutions for the particular West African environmental conditions found in the Gulf of Guinea.

Exxon Mobil showed the way when they installed the first two TLPs in West Africa. The Kizomba A TLWP was installed in 2004, on Angola's block 15, 300m from the host FPSO. The key parameter for this concept development selection seemed to be the need to develop the early-Aptian reservoir and the requirement for careful reservoir management with frequent well interventions. The TLWP hosted the production dry trees and subsea wells were dedicated to gas and water injection. The same development scheme was retained for Kizomba B, which followed in 2005.

The Moho Bilondo development

The Moho Bilondo field, offshore Congo, has been developed in two phases. In 2004, Doris Engineering performed a conceptual study of a TLWP with tender assisted drilling for the Moho Bilondo development that was compared to a solution with two subsea drill centers tied back directly to the FPU barge. On this occasion, the subsea solution was selected and the FPU was installed and brought on-stream in 2008. Nevertheless, this early work proved the feasibility of a number of key technical issues and laid the foundations for the future development.

In 2011, for the Moho Nord development, Total again included the TLWP in the concept screening process when looking at how to produce the Albian reservoirs, which are deep formations more than 3000m below mudline. The complexity of these reservoirs imposed a high level of reservoir management with a need for frequent well intervention. It was this requirement that led the project team to select the TLWP concept, with dry trees that would allow drilling and coiled tubing operations to be performed simultaneously.

Doris Engineering has been involved with this project since the conceptual and the pre-project studies and subsequently as the engineering subcontractor of Hyundai Heavy Industries, which as the successful bidder of the compensated call for tender (CCFT). During these engineering studies, the following new features have been introduced by Total to make the Moho Nord a unique TLWP concept:

- Semi tender assisted drilling (STAD) unit is positioned on the east side of the TLP and the derrick equipment set (DES) sits on skid beams that run in the North South direction to allow the coiled tubing (CT) to be run underneath the Substructure.
- The DES substructure has a clear height of 13m and the main BOP is placed below the upper deck to allow enough clear space for a stand-alone coiled tubing tower to operate independently without interfering with the drilling operations.
- The drilling riser system has been designed to jump from one well to another without being pulled out of the water. The drilling riser is hung off at the mezzanine deck in a slot with a skidding system and is only disconnected from the wellhead at the seabed when moving to the next target.

These innovations combined can provide a significant saving in the drilling durations with an associated saving on the overall drilling costs.

In the benign environmental conditions found in West Africa and southeast Asia, the TLWP with tender assisted drilling (TAD) has been found to be an interesting solution in deep waters. It is a robust concept when dry trees are required to improve reservoir management and facilitate well intervention operations and with the recent innovations in the drilling and well intervention systems it may become the cost effective solution for other similar developments in the future. OE

Jérôme Iacovella *joined Doris Engineering in 2000 as a naval architect. He is now heading the naval architecture and marine operations department. He has been particularly involved in the development of Moho Nord TLP project for Total.*

Pauline Beraud *joined Doris Engineering as a naval architect in 2006. For more than three years she has been involved in the development of Moho Nord TLP project. She holds and engineering degree from ENSTA Paris Tech.*

After being abandoned in 1998, the Republic of Benin's only oil field is due to resume production, using a minimal facilities conductor supported platform design. Elaine Maslin reports.

Benin's minimal facilities

Benin has a 171km-long coastline, which runs along the Gulf of Guinea between Nigeria to the east and Togo to the west.

The country's main offshore sedimentary area consists about 3500sq km on the continental shelf (up to 200m water depth) and 8000sq km in deep water (200-3000m).*

But, to date, the country has produced just one oil field, Sèmè, and it has been shut-in since 1998. Now, Sèmè is being brought back to life, with the help of a conductor supported platform (CSP).

The Sèmè field was discovered in 1968, it sits at 40m water depth, 15-20km offshore. First production was in 1982, via three platforms, and, after 1988, two monopod towers were added. However, operations at the field ceased in 1998 (A Historical Dictionary of Benin by Mathurin C. Houngnikpo and Samuel Decalo, 2013).

Post-1998, Nigeria-based South Atlantic Petroleum (SAPETRO) took over a 100% interest and operatorship in Block 1, containing Sèmè, under a production sharing contract with Benin's government. SAPETRO says Sèmè had produced more than 20MMbbl up to 1998.

The company says it acquired 350sq km seismic data over the acreage in 2007, and by the end of 1Q 2009, SAPETRO had drilled two appraisal wells; Central Sèmè West 1 (CSW-1) and the Central Sèmè East (CSE), in the central part of the Sèmè structure, to confirm the existence of by-passed oil.

SAPETRO had been considering a standard jacket design, but brought in UK-based Aquaterra Energy, which offered a design based on its unique minimum facilities Sea Swift CSP design, a solution created for marginal fields in shallow, benign waters, and able to be installed using conventional drilling and handling techniques from a jackup drilling rig, without the need for additional heavy lift vessels.

Subsea structure ready for installation using the Noble Tommy Craighead jackup drilling rig.

Sea Swift

The general Sea Swift CSP design concept is a topside structure, to house wellheads and Christmas trees, supported on conductors, which are braced by a subsea structure, into which the conductors are drilled, cemented, and grouted, to provide structural support and stiffening.

"The primary driver for using a CSP is to make marginal fields economically viable by providing a minimum facilities platform on which dry trees are installed," says Richard Miller, operations director, Aquaterra Energy. "The CSP concept is that a jackup drilling rig can drill the wells while also installing the CSP subsea structure and topsides using its top drive and heavy lift package."

The Sea Swift design is a scalable system to meet each specific application, he says. "One of the primary drivers of the CSP design solution is what rig is contracted to drill the wells—the operational capacity of the jackup drill rig. Bathymetry, metocean and soils data are also important considerations, defining the design."

Miller says a CSP could be used in up to 80m water depth, depending on such factors, and Aquaterra Energy has already designed and installed a Sea Swift CSP in 65m with a 450-tonne topside.

A key part of the design is using NOV's XLCS high-fatigue resistant conductor connectors, which enable conductors to be run and installed to the required depth,

CSP (conductor supported platform) topsides being loaded onto the Industrial Force vessel at Sfax, Tunisia, for transportation to Cotonou, Republic of Benin.
Photos from Aquaterra

using standard techniques employed on a traditional jackup, while providing the necessary structural integrity needed.

Aquaterra Energy's Sea Swift CSP design was first used offshore West Africa in 2007—two Sea Swift CSPs, Solha and Airoga, were installed offshore Angola. A third CSP was installed for Petronas offshore Malaysia last year. This installation was in 65m water depth. Its topsides, comprising four decks (weather, mezzanine, main and lower), has an operating weight of circa 450-tonne, sitting on four, 36in. by 2in. thick wall, structural conductors, with five internal conductors. It had two, 300-tonne, subsea structures and the CSP catered for 16 oil production wells, 11 with gas lift and 12 water injection wells, connected to an 8in. export riser.

The Malaysian CSP was a wellhead support structure and was operated in conjunction with a mobile oil production unit (MOPU), which housed the water injection and downstream production facilities and electrical power generation, Miller says.

Sèmè

The Sèmè CSP will be used to flow up to five wells, in 26m water depth, to an onshore processing facility 15km away.

The CSP consists of a 220-tonne integrated topside, riser guides, boat landing, and a 121-tonne subsea structure. Its topsides and subsea structure were built by Tunisian fabricator, Socomenin, at their Sfax facility, under supervision by Aquaterra Energy. Production will be controlled from an onshore facility at Cotonou, Benin's largest city, via an integrated fibre optic communication and power cable.

The topside structure comprises cellar and production decks, including a large control room, which houses transformers, to step down the incoming 11Kv power supply used by the electrical submersible pumps deployed into the wells, controlled via variable speed drives, and motor control centre.

The wellheads and Christmas trees will be accommodated on the production deck and four, structural, 30in., 1½in. wall thickness, conductors support the topsides, while also housing the well casings. Riser guides, providing support and protection to the export riser, power cable and sea water caisson, are run and supported from two conductors.

While the Sèmè CSP sits at 26m water depth, with a 12m air gap, the design had to take into consideration softer soil conditions than on the Malaysian CSP. On location at Benin, it is not until 15-20m deep that stiff clays are found to provide support, requiring 80m of conductor to be installed below the mudline, despite the shallow water depth.

The subsea structure comprises four leg cans and cross members, bracing the four structural conductors, and increasing the fatigue lives of the conductors caused by the environmental loading effects caused by wave action on the risers.

The topside process piping includes a pig launcher and multiphase flow meter complete with test facility for each well, and a common manifold, which takes the un-processed three-phase crude off the platform to shore via the 8in. pipeline. Access for personnel is via boat, using a boat landing platform, and a secure entrance hatch. CCTV systems, looking inward and outward, have been installed, and the platform is fitted with navigation aids.

While the CSP topside would normally be installed by the jackup completing the drilling operations, an available pipelay vessel was used for the Sèmè field topside installation.

"As the project had the opportunity to utilise the infield pipelay barge, the topsides was installed by the barge; this in turn reduced the lift weight constraint caused by the jackup lift and skidding capacity required for the installation," Miller says. "The subsea structure was installed by the rig (the Noble Tommy Craighead)."

Installation of the Sea Swift CSP on Sèmè started at the end of March, with installation completed by the end of April. OE

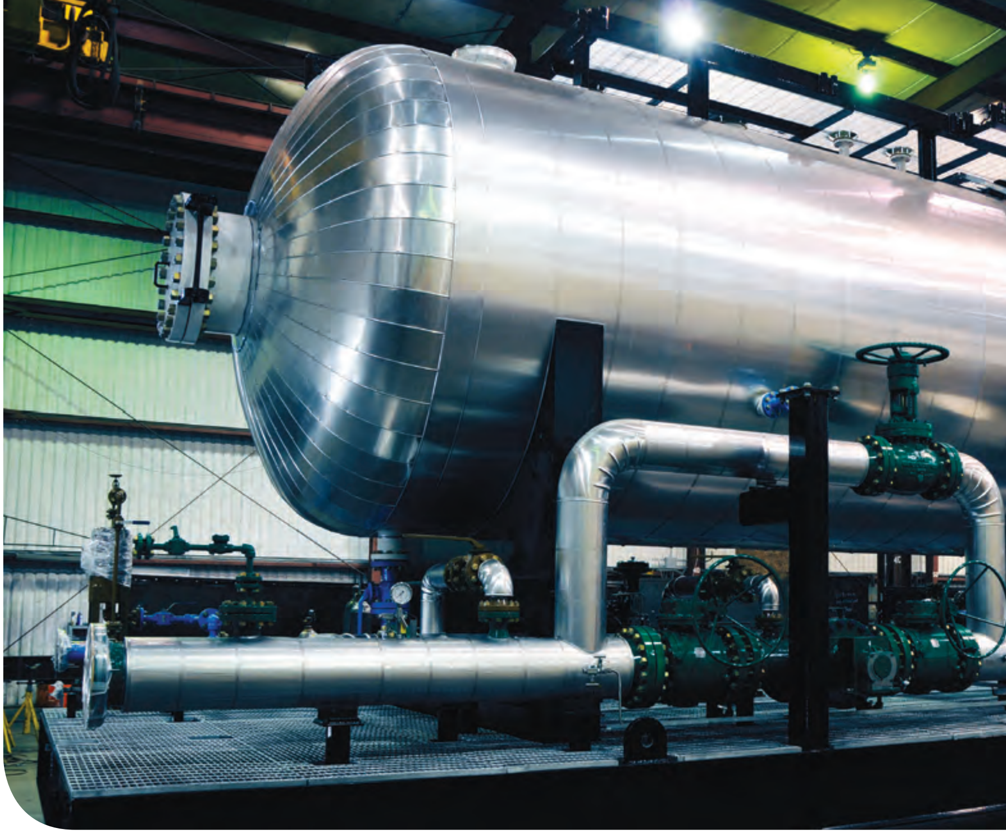
* Project Completion Report, Benin. Petroleum sector technical assistance project. February 1990, World Bank.)

FURTHER **READING**

Produced water treatment technology helped make Sèmè possible, see page 44.

Subsea structure on the quayside at Sfax ready for loading.

Produced water was one of the reasons for Benin's only offshore field, Sèmè, being shut in after 14 years of production. Vince Buchanan explains how technology is helping the field return to production.



TECHNOLOGIES allow Benin field to produce oil for first time in over a decade

By the end of this year, for the first time in over a decade, the Sèmè field in the Republic of Benin, West Africa, is due to be operational.

The field was shut-in after 14 years of production, during which time more than 21MM bbl were produced. At the time of field dismantlement, Sèmè was delivering several times more water than it was producing oil and it was no longer economical.

Chemical injection technology and oil recovery in water treatment systems will enable the field to produce a peak 6000 boe/d and it is estimated that an additional 16 years of production can be achieved.

The field

Sèmè is the only producing field offshore the Republic of Benin. It sits in the Gulf of Guinea and consists of three platforms, one well head and two production facilities. The field produced 7627 boe/d at its peak in 1984, but, at the lowest in 1997, just before abandonment, it was delivering only 1207boe/d.

Benin, which shares a border with Nigeria, started producing oil in the 1970s, but output remained low and stopped by the end of the 1990s, when the price of oil became uneconomical and funds for operations dried up.

South Atlantic Petroleum (SAPETRO) took over the block in 2004, and earlier this year awarded ProSep, through Procegas, a US$5.1 million contract to provide both the oil and water process packages.

Challenges

A major issue to overcome was limited storage at the site. The tankage available was only sufficient to store the produced oil with no real facility at site for water storage and every three to four months tankers would have to collect the oil. Using the tankers to transport the water to a disposal site as well as the additional cost for utilizing that site would have made the project not economically feasible. Local disposal wells were not a viable solution due to environmental concerns. The only solution available was to dispose of the produced water into the ocean.

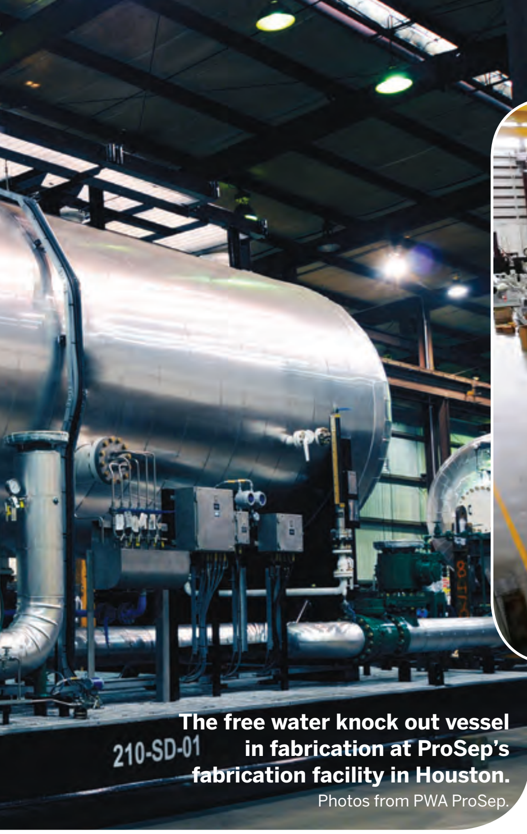
A 1.5km subsea pipeline will be used to move the produced water from the onshore separation facilities offshore. The onshore water treatment plant is designed to meet the standard water quality for the Gulf of Guinea of 20ppm oil in water. This solution allowed this project to become economically feasible.

Oil train

To meet the final oil specification of 0.5% basic sediment and water (BS&W), an oil train was developed consisting of a free water knockout (FWKO) feeding two trains of scavenger heat exchangers and thermal electrostatic treaters. This system was developed to provide an efficient and environmentally sound method for heating the process. This was by reducing the total heat load and recapturing energy already expended by cross exchanging the dehydrated oil with oil coming from the FWKO.

The skid-mounted FWKO is fully automated and was provided to remove the bulk water from the process. As the name implies, only free water is removed from the production inlet stream, leaving the emulsified water in the outlet oil, to be treated downstream. The design allows the user to adjust the interface level so retention time can be adjusted to the current flow conditions of the water and oil.

ProSep's thermal treaters combine both heating and coalescing capabilities in one process unit. The design allows the heating section to meet the treating viscosity requirements of the coalescing section with electrostatic coalescing



The free water knock out vessel in fabrication at ProSep's fabrication facility in Houston. Photos from PWA ProSep.

The oil separation train in fabrication.

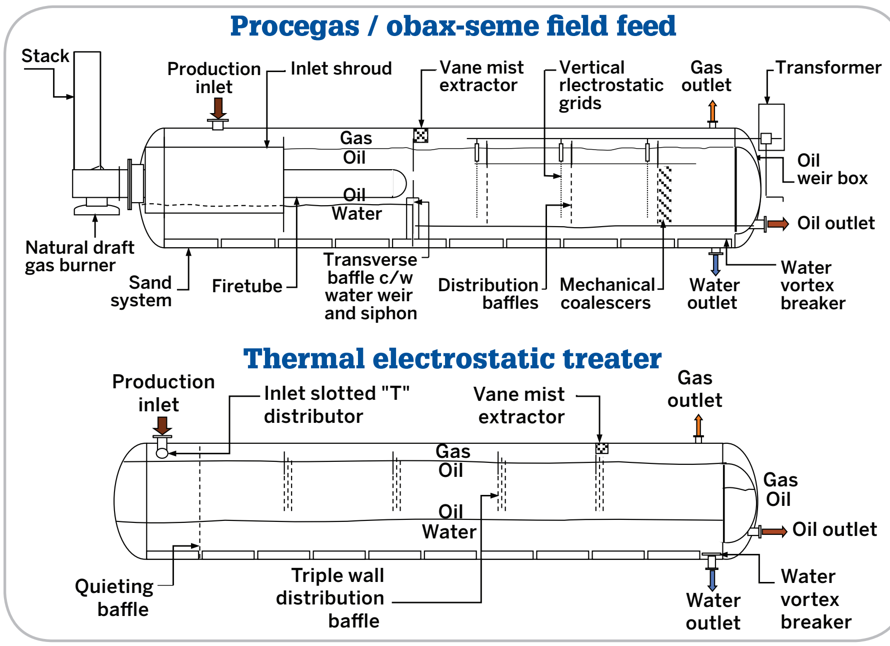
elements. The treating temperature for a thermal treater is considerably higher than that for an FWKO, in order to meet the stricter water content specification of 0.5% BS&W, by removing the remaining emulsified water from the process stream.

Water treatment

ProSep was tasked with treating 11,000bbl/d of water with a 2000 ppm inlet 100 ppm inlet solids. Charge pumps will be provided to pump the water from the storage tank to the first water treatment vessel, which is a corrugated plate interceptor (CPI).

CPIs are designed to provide the same removal efficiency as a traditional gravity separator in a much smaller vessel, making them ideal for fixed-platform as well as land-based installations. In this application, 95% of solid particles greater than 5micron will be removed from the inlet stream.

As the water exits the CPI, there is a secondary stage of treatment; an induced gas flotation (IGF) vessel. To recover oil and condition water for overboard discharge, re-injection or further polishing through filtration, ProSep's ProFloat Flotation Systems is used for efficient removal of oil and solids (capacities from 3000-100,000bbl/d of water, with a separation efficiency of up to 98%), while completely containing the process. This is where the stringent discharge quality of 20ppm of oil in the water will be met, which is now common law environmental regulation in West Africa following years of pollution.



The vessel schematics. Image from PWA ProSep.

Legacy

The government's requirement is that the field needs to have at least 20 years life expectancy. But, after five years, SAPETRO need to start producing from a second block, as the amount of water produced from the current block will continue to increase while the oil decreases. After five years, there will be less than 1000bo/d so the longevity will need to come from another block.

This is the first time ProSep technology will be used in West Africa. The contract includes training local staff. About 20 workers are expected to be involved in the operations and maintenance, on and offshore. Almost 1000 Benin workers will be involved in the construction phase and around 50 people will be working on the operations.

Sèmè is due to be operational by the end of this year. In May, the fabrication will be taking place in the US and the preparations will be taking place at the field in Benin. **OE**

__Vince Buchanan__ is ProSep's Oil Technology Manager, based in the company's Houston office. He has worked for ProSep since its inception in 2005 and has over 40 years' experience in the oil and gas industry.

FURTHER **READING**

Read more about the Sèmè minimal facilities, conductor supported platform, see page 42.

BP applied a "less is more" approach to enhanced oil recovery, and, in doing so, won a Distinguished Achievement Award from Houston's Offshore Technology Conference. Sarah Parker Musarra reports.

Low-salt solution

One of Clair Ridge's jackets is shown on an installation barge in 2013. Photo from BP.

Endless calculations are made to determine how many barrels of oil can be produced in a day to estimate when production will peak, or, even more importantly, when it will begin to peter out.

As greenfields age browner, various enhanced oil recovery (EOR) techniques are trotted out to try to recapture the magic once more. This is especially important since the US Department of Energy places the percentage of oil recovered from a given reservoir at somewhere in the 20-40% range, with EOR techniques providing an additional 30-60% recovery.

However, when the second phase of the Clair field—known as the Clair Ridge development, located 75km west of Shetland and estimated to recover 640MMbo—begins production in 2016, BP's reduced-salinity water injection LoSal EOR will be employed to boost oil production from day one.

With this decision, BP is changing the traditional field development model: Production decline is no longer the trigger for EOR.

"There's a saying the best time to plant a tree was 20 years ago; the second best time is now. A similar principle applies to EOR," Raymond Choo, deployment manager for BP's EOR Technology Flagship program, said.

Scan the video icon with the Actable app on your smart phone to learn more about BP's LoSal EOR and how it applies to the Clair Ridge development.

The first of its kind

"It's groundbreaking. No other company

EOR challenges and opportunities

Enhanced oil recovery, or EOR, was described as the holy grail at the DEVEX conference in Aberdeen in early May.

The prize is significant, particularly in the North Sea. There, EOR is attractive because it enables operators to "find" more barrels of oil in a basin in which new discoveries are becoming increasingly small.

In 2012, while annual production was close to 500MMboe, only 150MMboe was approved under new projects and only 50MMboe was found through exploration.

Yet, while EOR might be where the industry can find more barrels more easily, there are also many challenges, from corporate support for large, costly schemes, which could takes years to pay off, to supply chain and even logistical considerations.

BP has been running EOR projects in the North Sea for a number of decades, including its Distinguished Achievement award-winning LoSal EOR technology. "EOR works in the sub-surface and tends to grow with time," but, "the size of the prize, and access to infrastructure and injectant supply are critical (to its success)," Euan Duncan, lead reservoir engineer, BP, told a Society of Petroleum Engineers (SPE) talk in Aberdeen in April. "Confidence in the process is also critical."

Duncan says large projects and long-term outlooks are required to make EOR projects a success. For example, to use polymers for

BP's Quad 204 redevelopment will use a new FPSO and polymer injection is being investigated for EOR. Photo from BP.

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Monitoring | Modeling | Completions | Control has installed low-salinity water offshore for EOR," Nnaemeka Ezekwe, BP's LoSal EOR deployment manager said.

BP estimates that an additional 42MMbo will be recovered from the UK Continental Shelf's largest undeveloped hydrocarbon resource by using LoSal EOR, part of the company's suite of Designer Water technologies.

The supermajor was recently honored for Clair Ridge LoSal EOR at Houston's Offshore Technology Conference in May with its second Distinguished Achievement award in four years.

BP Chief Operating Officer, Reservoir Development & Technology James Dupree, pictured right, accepts the Distinguished Achievement Award from Offshore Technology Conference chairman Ed Stokes on 4 May 2014. Photo from Barchfeld Photography.

Better water through chemistry

One common oil recovery method is water injection or waterflood, which has been used in the industry in various forms since around the 1930s. Water of some sort, typically de-oxygenated, high-salinity water, is commonly injected in drilled injection wells to flood the reservoir, increase pressure in depleting reservoirs, and stimulate production.

However, significant oil was still being left in the reservoir, despite the high-salinity water injection. It's chemistry, explained Ezekwe. BP examines why the oil molecules would stick to the reservoir's rock surfaces. With the reduction of salinity, ions are reduced, and more oil molecules are freed.

BP said that LoSal EOR, its designed low-salinity water, positively impacts pore-scale displacement, and pushes this "bound oil" through to the production well by relaxing what the company calls "bridges." These bridges are actually double-charged, or divalent, ions, such as calcium and magnesium. These ions compress to the surface of clay through electrical forces in presence of high-salinity water.

In reducing the salinity, the bridges expand and relax. Monovalent ions replace the divalent ions, and, free of bridges, more oil molecules can be released.

Seawater has differing levels of salinity, although the Office of Naval Research places the average at around 35,000ppm. LoSal EOR is significantly less; BP quantifies it as a few thousand ppm.

"If you remove most of the salt, you will be able to increase oil production, greatly reduce scaling and reservoir souring risks," Ezekwe said.

During LoSal EOR's 2008-2009 field trials at Endicott field in Alaska, oil and water – those two famously incompatible liquids - met with good results: increased oil production similar to that found during LoSal EOR's lab testing.

"Low-salinity water was injected in one well, and the incremental oil production observed in another. Endicott proved up the laboratory trials at full scale," BP said.

From Clair to Clair Ridge

At the time of its 1977 discovery through to its 2005 production commencement, Clair, located in around 150m of water, also marked several firsts. It was the biggest field in the UK Continental Shelf, and featured the first steel jacket in the West of Shetland area. It has produced 100MMbo, with production peaking in 2007 at 50,000bo/d.

The Clair Ridge development will consist of two bridge-linked platforms. Pipeline infrastructure connecting it to Shetland is also in the scope of work. The jackets were installed in August 2013; the topsides are planned to be installed in 2016. Peak production is expected to hit 120,000bo/d.

The US$7 billion investment includes $120 million for desalination facilities to incorporate LoSal EOR into the development plan.

BP operates Clair Ridge with 28.6% interest. Its partners include ConocoPhillips (24%), ChevronTexaco (19.4%), Shell (18.7%) and Amerada Hess (9.3%). **OE**

EOR in the UK North Sea, there would need to be major investment in manufacturing capacity, potentially a new plant. It is also crucial that infrastructure—platforms and pipelines—are available and maintained long-term so that EOR projects can be adopted, he says.

BP has used miscible gas, using water alternating gas (WAG) on Magnus (Northern North Sea), Miller (central North Sea).

Miller was the first, starting in 1998, drawing on technology BP had used in Alaska. "Miller had good reservoir properties but also high residual oil saturation," Duncan said, but the suffered with WAG compressor failures. BP also looked at using CO2 injection on Miller, but it was too late in the field's life to make the project work economically, Duncan said.

In 1999, BP installed a WAG compressor on the Ula field in the Norwegian North Sea, for miscible gas EOR. The project increased over time, more injectors and wells were added, and it is likely the Ula project will be expanded again in 2019, Duncan said. In 2001, Magnus also had WAG compressors installed and the platform is due to undergo a maintenance campaign in 2016 to extend the facility's lifetime (OE: October 2013).

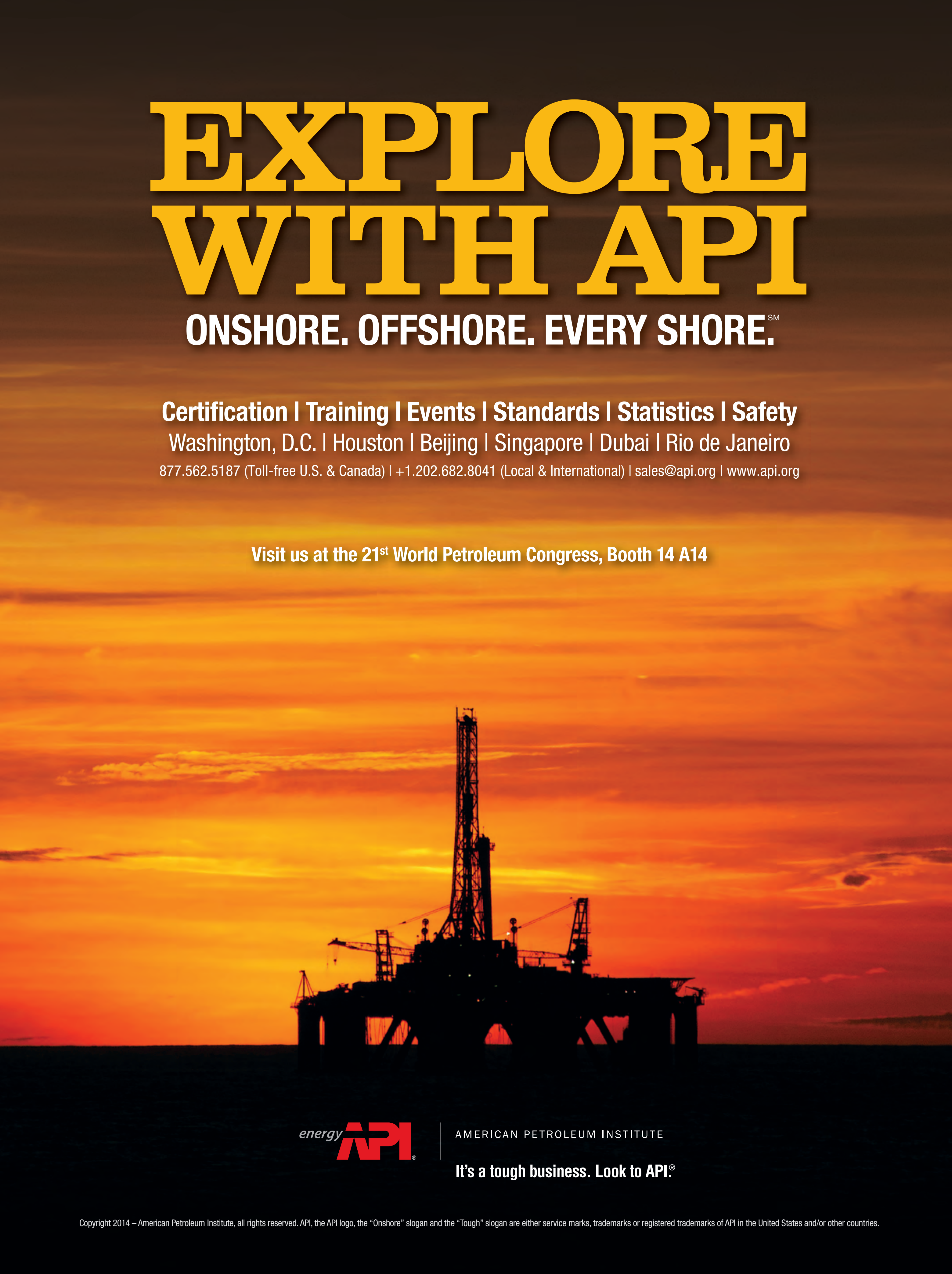
"The main lesson for us has been the importance of asset integrity, fiscal relief (tax allowances), and getting the compressors and economics right," Duncan said. If the industry is to further use EOR, collaboration between operators, to create clusters, enabling large-scale projects, would help, Duncan said. The industry could also draw on initiatives like IFP Energies nouvelles' EOR Chemical Alliance.

BP's next EOR schemes are polymer flood on the Schiehallion and Loyal fields, part of the Quad 204 redevelopment, with startup in 2017, and LoSal EOR on Clair Ridge, due on stream in 2016.

To date, there have been limited offshore polymer flood applications, which will mean a learning curve for BP, and the wider industry. Issues around offshore polymer use include making sure there is an adequate supply chain to supply the amount of polymer required and then understanding how best to handle the product, taking it offshore either as powder to be mixed, or ready mixed, and understanding how it behaves during these processes.

BP is also researching brackish water, which is only slightly salty. "Our focus within BP is on water-based EOR, LoSal, and from that other technologies and different waters to inject to influence the pore scale," Duncan said.

—Elaine Maslin■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EOR evolution

Repsol's Elena Escobar discusses drivers for and challenges associated with applying enhanced oil recovery methods on offshore fields.

Efforts surrounding the research and development of technologies for oil recovery are currently being centralized in order to ensure continued production of crucial sources of hydrocarbons worldwide. As a result, it is expected that enhanced oil recovery (EOR) processes will have a much more important role in supporting the development of giant reservoirs located in offshore fields.

Offshore areas are of high interest to Repsol, with large reservoirs recently being discovered in Venezuela, Brazil, Gulf of Mexico (GOM) and Alaska. Currently, the daily production of the offshore fields, where Repsol is participating with other partners, is about 260Mboe, and located mainly in Trinidad & Tobago, GOM, Brazil and Spain. Repsol's offshore production is expected to increase significantly in the next five years due to two developments: the Shenzi development field located in the GOM, which has reserves of about 400MMbbl, and various carbonate reservoirs in offshore Brazil, holding more than 2 billion bbl in reserves. To support the technical needs associated with the development of these fields, Repsol has invested in different strategic R&D projects in the EOR area.

Worldwide EOR application

EOR processes are defined as the injection of fluids into the reservoir in order to reduce oil saturation and increase the oil recovery factor. The most common EOR recovery processes are the injection of thermal fluids such as steam to reduce the viscosity of heavy oils into the reservoirs; as well as the injection of water soluble chemicals such as polymer, surfactant and alkali to improve the recovery factor mainly in medium and light oil reservoirs. Miscible and immiscible gas injections, such as hydrocarbon (HC) gas, CO_2, N_2, and air, are also widespread in medium and light oil reservoirs. Figure 1 shows the world daily EOR production, locations and production rates of the main EOR projects.

With the exception of the thermal projects in the Zulia state in Venezuela and the hydrocarbon injection projects in the North Sea, most of the large EOR applications are performed in onshore fields. In the past, Repsol examined the recovery processes applied to its offshore reservoirs with similar characteristics to Repsol's mature reservoirs such as Teak, Saaman and Pui, which are located in Trinidad & Tobago.

For this study, Repsol used the C&C DAKS database, 2013, and applied the following filter: offshore fields, sandstone lithology, oil API gravity < 220, porosity < 40% and permeability < 1000 mD. As a result, Repsol obtained a sample of 220 fields. Of these, 132 reservoirs (66% of the total) had secondary oil recovery processes, waterflooding, and hydrocarbon gas injection processes applied. However, only 14 reservoirs (6%) reported EOR applications; ten miscible CO_2 and HC gas injection and four polymer injections (most at pilot test level).

Another search was done by filtering offshore fields only. In this case, 441 reservoirs were identified with only 17 fields (4%) reporting any use of EOR applications. These EOR fields are in a water depth ranging from 200-4800ft.

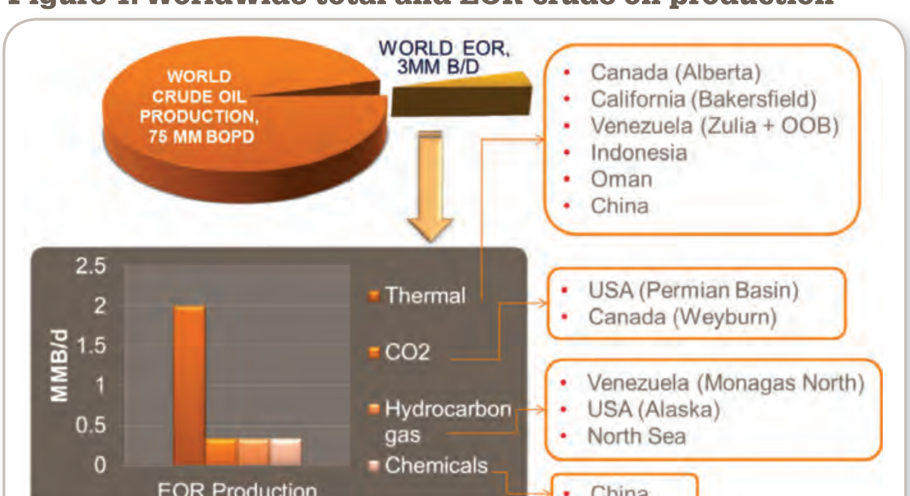
Drivers and challenges

The drivers of offshore EOR applications include: a continued increase in oil prices over the last seven years; the decline in secondary oil recovery of large reservoirs in the North Sea; the discovery of large offshore reservoirs in presalt Brazil; as well as major advances in the development of EOR chemicals (surfactants and polymers).

Compared with onshore field conditions, applying EOR processes to offshore projects is more challenging. For example, due to the spacing between large wells and the fact there are much fewer wells, sweep efficiency is much lower. It takes longer for reservoirs to respond to the EOR process being applied. Furthermore, there are limitations of offshore facilities in terms of space, weight and power supply. In addition, many offshore structures are old, therefore, safety restrictions to implement new processes are higher than onshore. As a result, offshore EOR applications have higher capital and operating costs than those for onshore, resulting in a reduced number of potential EOR technologies that can be applied offshore. For instance, air injection processes are considered too risky from an operational point of view to be implemented at offshore conditions.

Compared to shallow water conditions, the commercial development of heavy oil resources in deepwater offshore reservoirs still poses many unresolved

Figure 1: Worldwide total and EOR crude oil production



Sources: World crude oil production from JPT, Jan., 2014.
Koottungal L., "2014 worldwide EOR survey", O&G Journal, April, 2014.

technological challenges. Most new offshore EOR projects are aimed at light and medium oil fields due to the higher market value of these fluids, and because they are easier to transport from the reservoir to its final destination. The production of deepwater, offshore heavy oil fields is severally impacted by the low temperature of the sea water (around 4^{o}C in the sea floor) making it difficult to pump the oil to the surface as its viscosity is increased due to heat loss along the production well to the surface. Moreover, the high heat loss and fuel costs make transporting steam into the reservoir for the steam injection process very expensive and inefficient.

The picture is different for developing heavy oil fields located in shallow water, close to shore, such as on eastern cost of Maracaibo Lake (60m water depth) in Venezuela, with more than 40 years of successful offshore, cyclic steam stimulation (CSS), in fields like Bachaquero, [11.7^{O}API, 6621million stock tank bbl (MMstb) OOIP] (Escobar et. al. 1997).

Current applications

A number of field examples show the increasing importance of offshore EOR application.

Offshore EOR projects have been applied in North Sea fields since 1976 (Awan, Teigland, Kleppe 2006). EOR offshore processes in this region have been focused on five technologies and 19 field application projects such as hydrocarbon gas injection (six miscible field applications); water-alternate-gas (WAG) injection (three miscible and six immiscible field applications); simultaneous water & gas (SWAG) injection (one field application); or microbial enhanced oil recovery (one field application). WAG appears to be the most successful EOR technology applied in the North Sea.

Since 2003, China National Offshore Oil Corp. (CNOOC) has implemented EOR chemical flooding in offshore heavy oil reservoirs in Bohai Bay, China (Xiaodong, et. al. 2011). Polymer flooding is an important technology for the strategic development of these kinds of fields with three existing polymer EOR projects on heavy oil fields. The projects have been implemented to improve mature water flooding. The total oil production improvement was more than 6MMstb by the end of 2010.

In 2011, Petrobras implemented the first EOR pilot project of CO_2 and natural gas injection in pre-salt Brazil, at miscible conditions, through a WAG scheme injection (SantÁnna Pizarro, Moreira Branco 2012). The pilot is being carried out at Lula Field (28-300API), deepwater (1800-2400m), in the Santos Basin. The source of CO_2 is the associated natural gas produced with the oil in the field. Early results show that the tested EOR process has the potential to be successful.

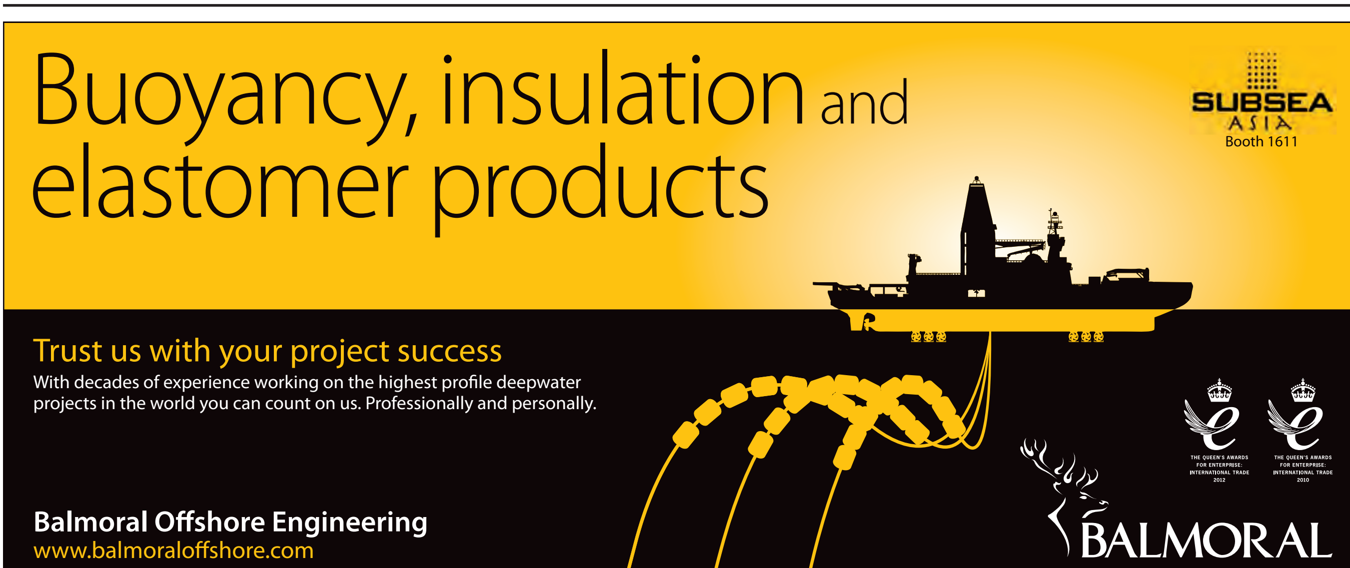
Additionally, Repsol and Petrobras have evaluated different chemical EOR technologies (i.e. polymers, surfactants, and low-salinity water flooding) for the Albacora-Leste field in deepwater (about 2300m), off Brazil (Abdelmawla 2013). Albacora-Leste is a turbidity reservoir, with very high salinity (80,000-90,000ppm) formation brine. Currently, Repsol and Petrobras are working together to go ahead with a chemical EOR pilot test.

Di Pietro et al. (2014) evaluated recoverable crude oil resources associated with CO_2-EOR to 531 offshore oil fields in GOM. The research mentioned that there is a great opportunity to economically apply CO_2-EOR in major offshore reservoirs in the GOM. The study also recommend designing CO_2-EOR in the conceptualization stage of the development plan for new deepwater offshore projects, which could greatly reduce the overall cost and make the application of these processes more attractive in the future.

Conclusion

Various factors are driving the search for increased EOR such as successful secondary recovery methods, new important offshore discoveries, as well as efforts to reduce the production decline of mature offshore fields in the North Sea, GOM and China. To enable the economic transformation of these resources, further development of oil recovery and flow assurance technologies are necessary. OE

***Elena Escobar** is manager of an R&D strategic project on thermal EOR and has worked at the Repsol Technology Center (CTR) as a consultant for oil recovery since 2007. Over the last 27 years, Elena has been involved in enhanced oil recovery (EOR) projects for different oil companies and research institutes. During that time, she has also been a technical leader for different thermal and gas EOR projects and pilot projects. From 2007 to 2009, Elena had also served as mentor of the Repsol reservoir knowledge community. Elena has a PhD in Petroleum Engineering from Texas A&M University.*



DEH: Going with the flow

DEH cable being placed into the traditional protection system, which is a labor and time intensive process.

Images from Nexans.

Using the electrical resistance in flowlines is helping to inhibit hydrate and wax formation.

Exploration and production in harsher environments and deeper waters, far from the shore, pose flow assurance difficulties for operators.

The mix of high pressure and low temperature, in deepwater environments, make pipelines susceptible to hydrate and wax formation, leading to plugs in the flowline and slowing or potentially blocking the flow of oil and gas.

Wax is found in most oil and gas fluids. The cold temperature of the pipe wall causes deposits of the wax to harden and stick to the surface. These deposits increase the viscosity of oil, eventually creating a blockage.

Hydrates are crystalline, ice-like water molecules composed of water and gas, such as methane or carbon dioxide.

They form from the substantial amount of water that is typically present in the untreated well steam—ranging from 10% to as high as 80% in a tail production period. At high pressures they can start to precipitate at temperatures as high as +25°C.

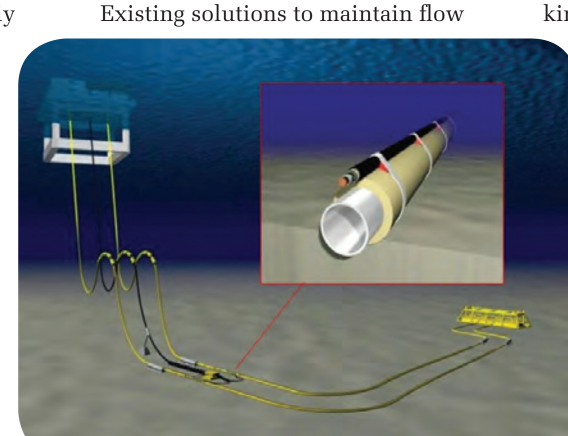
Problems start when they clump together into a slush-like material. They typically form and join together during shutdown situations, but may also form during normal operation, especially if there is a long tieback.

Existing solutions to maintain flow assurance when hydrate and wax formation is possible, is to use a combination of chemicals and pressure evacuation. This involves injecting chemicals into the well stream and removing them topside. Thermodynamic chemical inhibitors work by lowering the temperature at which hydrates form.

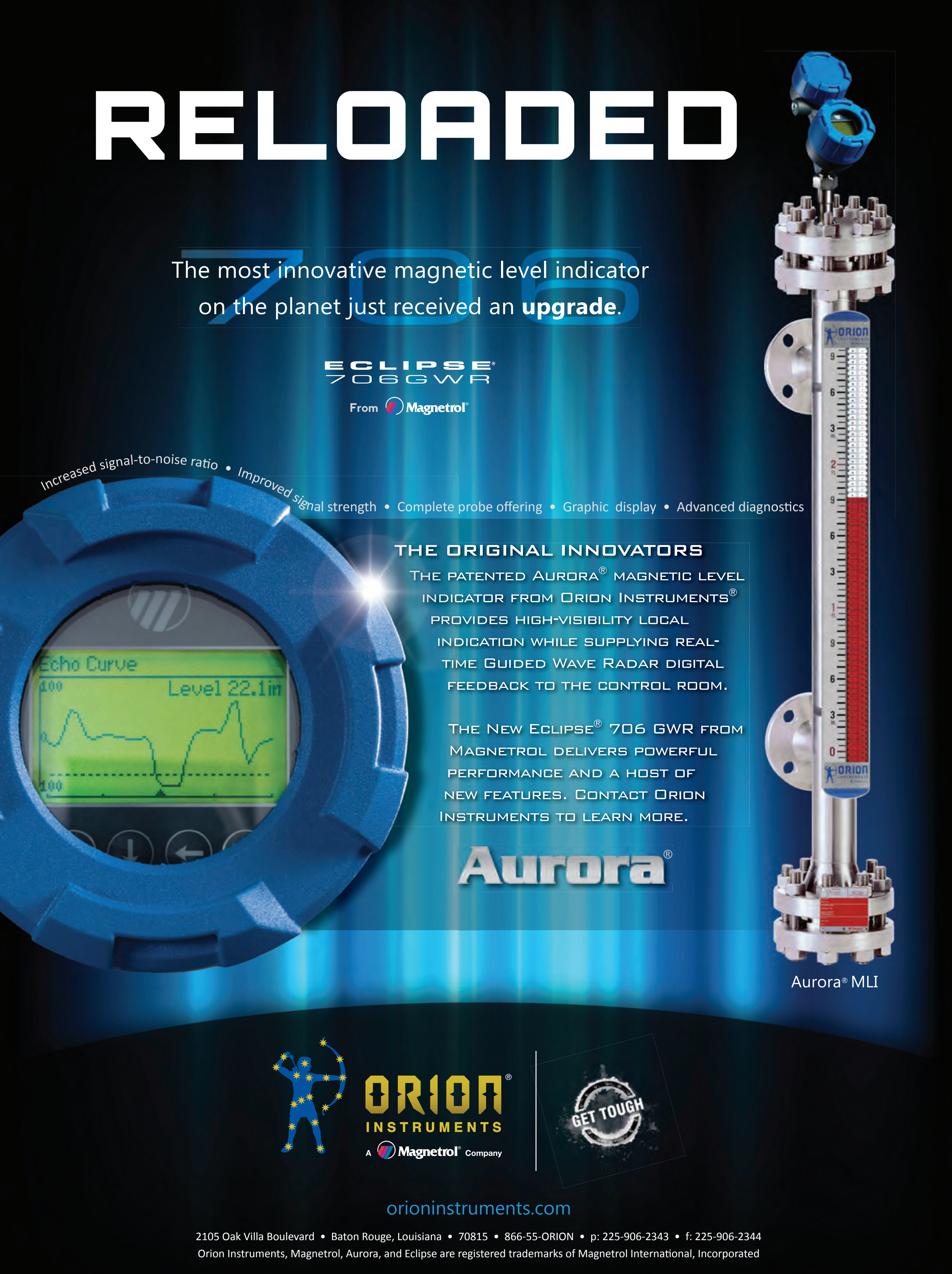
Other chemical inhibitors can be used in smaller volumes, but are less effective if the fluid has a long way to travel through the pipeline. For example, kinetic hydrate inhibitors, which benefit from being both cheap and effective, can only prevent hydrate formation for a short period of time and are more suited to moderate water temperatures.

Direct electrical heating (DEH) systems offer an alternative solution to the problem of wax and hydrate formation, reducing the use of chemicals.

Originally started as a joint industry project, which sought to find solutions to hydrate formation using direct heat rather than chemicals, DEH was first tested at the Åsgard field in the Norwegian Sea



Nexans' DEH system, showing the piggy back cable, which completes the circuit, strapped to the flowline.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in 2000, following a long development phase in cooperation between Statoil, SINTEF, Nexans and others.

How does it work?

In a DEH system, an electric alternating current (AC) in a metallic conductor generates heat. The flowline to be heated serves as an active conductor in the electric circuit, formed by the dynamic riser cable, the feeder cable, the piggyback cable (PBC), and the flowline.

AC current is supplied from the topside power system via the riser cable. Subsea, the riser cable is connected to the feeder cable in the subsea junction box. Using the feeder cable, one of the conductors in the riser cable is connected to the flowline near end, while the other conductor is jointed to a PBC. The PBC is strapped to the flowline along the entire length to be heated, and connected to the flowline at the far end. The flowline, then becomes the primary return conductor in the system, and is heated due to its own electrical resistance.

For safety and reliability reasons, the flowline is electrically connected to the surrounding seawater (i.e. it is an "open system") through several sacrificial anodes. These aluminum anodes are rated for both corrosion protection and sufficient grounding of the system during the expected lifetime of the flowline and the service life of the heating system. The AC current does not influence the internal corrosion of the flowline.

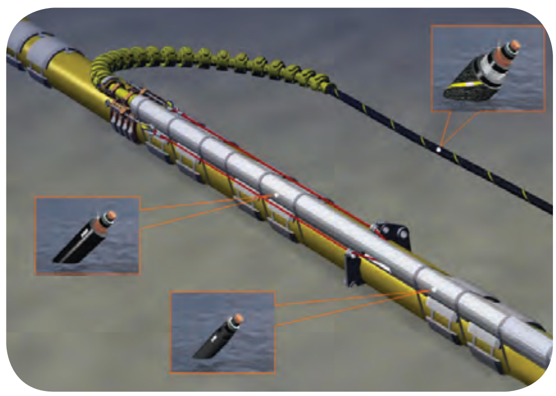
During operation, power is fed to the far end of the flowline through the PBC and returns through the steel flowline and seawater. At each end of the flowline, where the current enters and leaves the pipe, additional anodes are mounted to form a well-defined, low impedance path for the current to the sea, known as the current transfer zone.

The current that needs to be supplied in a DEH system will vary according to many different criteria, including the temperature that needs to be maintained and the magnetic and electrical properties of the pipe. For the Åsgard installation for Statoil the system current is over 1000 A.

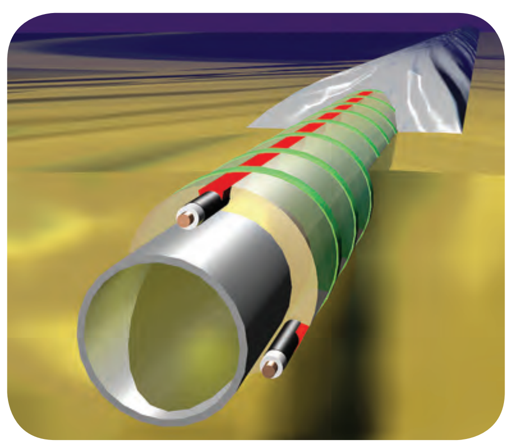
DEH systems can be used continuously to maintain the temperature of the flowline above the hydrate formation temperature, for example in wells that are far from the platform or in deep waters. DEH systems can also be used intermittently, for example during a planned or unplanned shutdown, when the temperature in the flowline decreases, increasing the risk of wax and hydrate formation.

Examples

The Åsgard field is in the Norwegian Sea some 200km west of Nord-Trøndelag. At Åsgard, there are six pipelines heated by DEH and tied back to a floating platform. DEH is used to heat the flowlines from +6°C up to +27°C in order to prevent hydrate development.



The new integrated protection system.



The DEH system on Skarv.

Nexans supplied a dynamic riser cable with four power cores rated for 12kV with 1600sq mm copper conductor and hydraulic tubes. The system included the world's first coupling between high voltage cable and pipeline on the seabed, according to Nexans.

The next installation took place in 2001, at the Huldra field, also operated by Statoil, on a 16km-long flowline. Here the DEH system is used to maintain the flowline above +37°C in order to prevent wax formation.

In 2007-2008, Nexans supplied the world's longest DEH system to the 42km long Tyrihans flowline for Statoil. New S-lay methodology was used for installation and a coaxial design was developed for the riser cable and the feeder cable. Also a new concept for fault detection by optical fiber break monitoring was developed and introduced in the piggyback cable in the Tyrihans project.

Protecting your DEH system

Most DEH systems today have been installed in particularly demanding locations, such as the North Sea, where the sea conditions are rough and the weather is severe. Therefore, the cables in these systems need to be able to withstand severe mechanical loads, particularly from trawl impacts which are common in the North Sea.

Nexans has developed a polymer-based integrated mechanical protection system (IPS) for the piggyback cable. A polymer IPS has a long design life, even when immersed in seawater. It is made up of interlocking segments of polymer with hollow cores to absorb heavy impacts, such as trawling and dropped objects.

Future projects

In March 2014, Nexans announced the award of the DEH systems contract from BP for the Shah Deniz field, in the Azerbaijan sector of the Caspian Sea. DEH systems will be provided for 10 subsea flowlines. Altogether 130km of subsea pipelines will be heated. First delivery of the system will be in July 2014. The second delivery will be in June 2016.

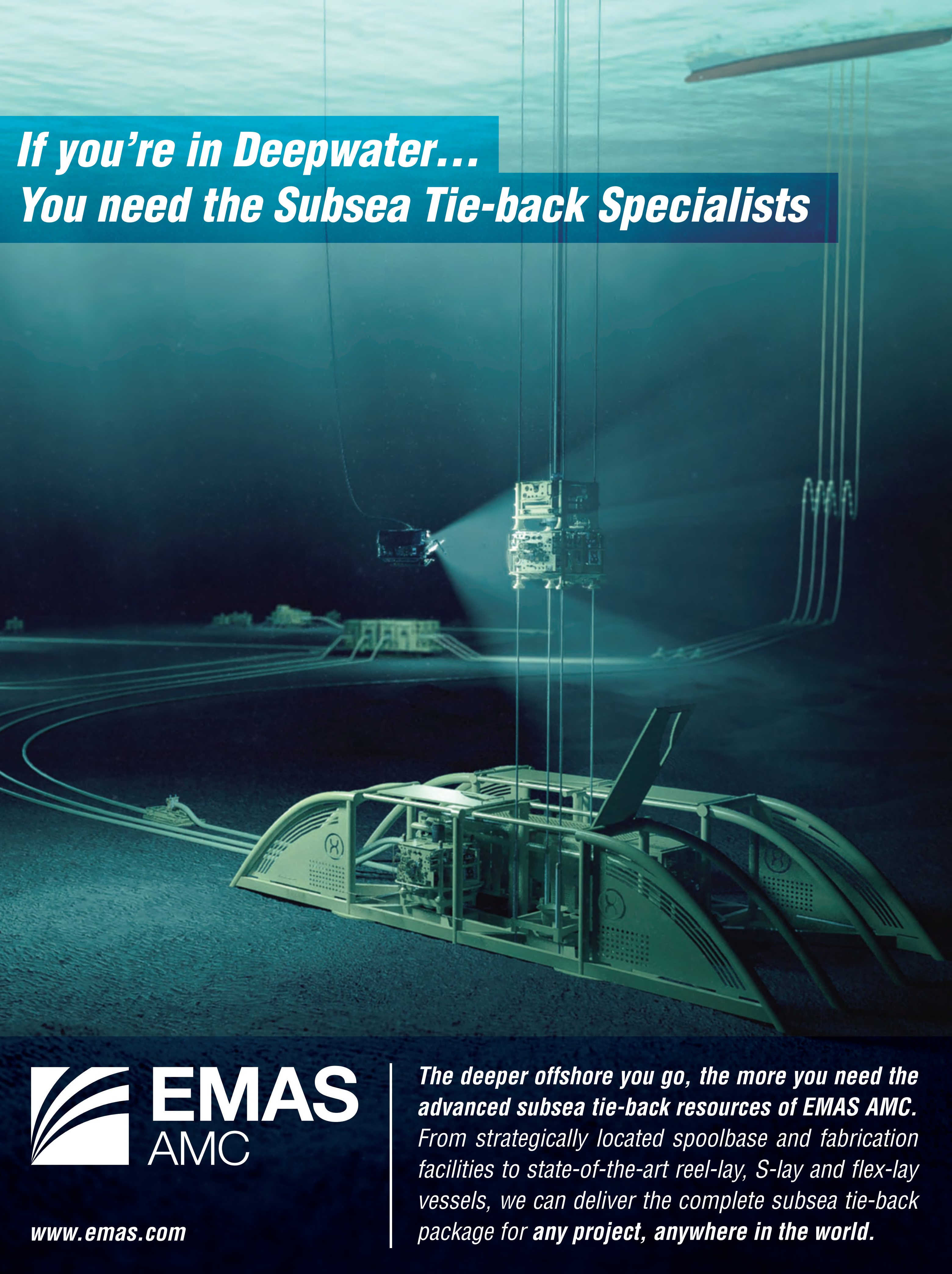
Nexans is taking DEH into deeper waters at Chevron's Lianzi field. The DEH system for Lianzi will be deployed for the subsea pipeline serving the Lianzi oil field development, between the Republic of Congo and the Republic of Angola.

Lianzi is tied back to the Benguela Belize Lobito Tomboco, in Angola block 14m, in 390-1070m water depth, making it the deepest DEH system installed.

The contract, which is with Subsea 7, covers the delivery of the complete DEH system, including riser cable, feeder cable, a 43km-long piggyback cable, and all associated subsea accessories. Delivery is scheduled for this summer.

Conclusion

Overall, Nexans has delivered more than 225km with DEH Cables to heat 19 flowlines around the world. Nexans-produced systems provide flow assurance for 10 of the 11 DEH fields in operation today globally. **OE**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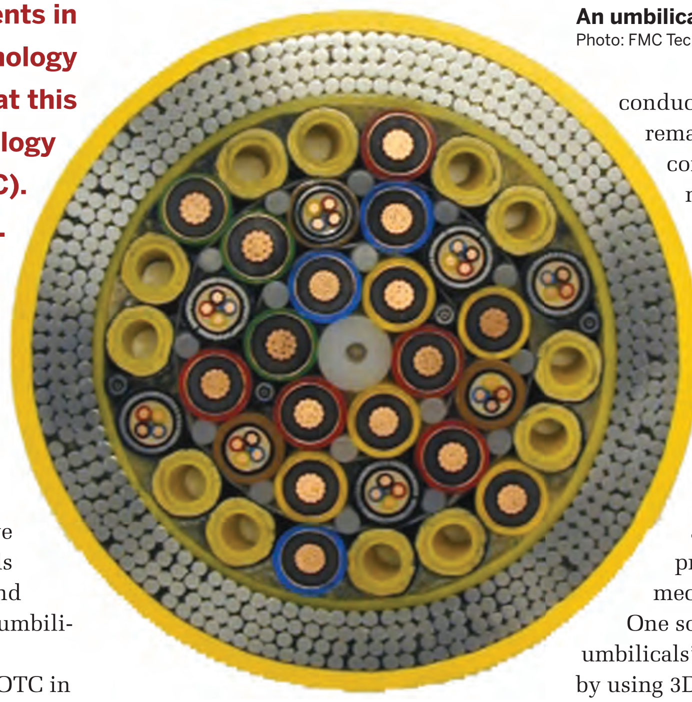
Innovating subsea umbilicals

Recent developments in subsea umbilicals technology were highlighted at this year's Offshore Technology Conference (OTC). Greg App reports.


An umbilical cross-section.
Photo: FMC Technologies.

Umbilicals are literally the lifeline from the surface to the majority of subsea structures that make offshore exploration and production possible. However, multiple factors associated with ultra-deepwater environments have posed various challenges in regards to the construction, installation, and preservation of traditional subsea umbilical systems.

A technical session at the 2014 OTC in Houston included presentations discussing some of the more pertinent technological innovations regarding this essential component of the offshore industry.

Carbon nanotube composite cables

Terry G. Holesinger of the US Department of Energy's Los Alamos National Laboratory presented key findings of his team's progress regarding the continuous research and development of carbon nanotube (CNT) composite cables for ultra-deepwater oil and gas field.

Long-term applications of this technology includes the possibility of subsea floor power distribution, ultra-deepwater dynamic power umbilicals, and improved efficiency in regards to hangar penetrations.

Some more immediate applications regarding deepwater include the improvement of downhole electrical submersible pumps (ESPs), operation at lower voltages to improve reliability, and increasing electrical transmissibility through the wellhead space.

"There is an ever-increasing need in the field of deepwater exploration for the development of conductors that are superior to copper and able to transmit more power to the subsea floor," Holesinger said. "Experimental procedures regarding the development of CNT composite conductors are extremely promising."

CNTs aim to fill the demand for a superior conductor that can operate at the extreme temperature and pressures that characterize deepwater exploration.

In fact, the authors of OTC paper "Carbon nanotube composite cables for ultra-deepwater oil and gas fields" note that the conductivity of various experimental cables were shown to have a higher specific conductivity that exceeded all metals except sodium (DePaula, Holesinger, Pappas, Rowley and Sperling).

"To date, we have successfully produced wires that display high conductivity values for CNT coatings. Additionally, these conductors are much lighter compared to pure copper wires and offer additional advantages for applications needing lightweight materials," Holesinger continued.

Since their discovery in 1991, CNT conductors have been known to have remarkable properties: electrical conductivity, strength, and thermal conductivity. "The challenge now is to produce these CNT products on a larger scale so they can be utilized by the deepwater offshore industry," Holesinger said.

Instability of umbilicals

McDermott Subsea's Miguel Pereira presented research regarding the company's approach to the key challenges presented by the structural mechanics of umbilical systems.

One solution is to simplify the umbilicals' installation analysis method by using 3DUST, an in-house umbilical simulation tool capable of suitable finite element meshing of geometrics, analysis of material assignments, and defining boundary conditions while presenting relevant results. Pereira and his co-authors P. Ramar and M.A. Dixon discuss in their OTC paper "Instability of umbilicals" that this method has already been applied to many deepwater umbilicals in West Africa, the Gulf of Mexico, and Brazil.

The paper states the installation of offshore umbilicals without compromising their functional and structural integrity is a key challenge for the umbilical installation contractors and manufacturers. (Dixon, Pereira, Ramar). "A balance has to be struck between greater cross-section requirements…and stricter installation constraints," Pereira told the OTC audience during his presentation. "The key factors that define this balance involve the quantity and size of chemical, power, and signaling lines within a single umbilical, as well as the amount and size of equipment through which the umbilical travels during the installation process."

Pereira, Ramar, and Dixon propose a new method for assessing the effects of the installation procedure in regards to the structural integrity of the umbilical system by using the 3DUST umbilical simulation program. This method models the installation of the umbilical system by simulating loads that occur during the installation process These loads include bend radius, contact force, tension, and squeeze loads from caterpillar tracks and tube internal pressure.

The US DOE's Los Alamos National Laboratory in New Mexico.
Photo: Los Alamos National Laboratory.

Assessing fatigue life of flexibles and umbilicals

DNV GL's Mayuresh Dhaigude presented progress highlighted in the OTC paper "developments in computational methods for assessing fatigue life of flexibles and umbilicals," written by Dhaigude and P.P. Sharma. "Flexible risers and dynamic umbilicals are being used increasingly in harsh environments which require reliable prediction of fatigue life," Dhaiguda said. While it is extremely important to be able to predict fatigue life to ensure continuous and efficient operation, these predictions are extremely difficult due to layered construction and helical components such as tensile armors and steel tubes. In the presentation, Dhalgude and Sharma outlined an efficient fatigue analysis scheme involving cross-sectional analysis techniques required for fatigue stress calculations in helix elements subjected to bending, tensile and pressure loading, with special attention given to the effects of friction stresses caused by the stick/slip behavior of helix elements in bending.

"This analysis scheme will enable operators to establish fatigue damage and fatigue life by considering corresponding probability of occurrence for short term conditions," Dhaigude said. The program being used to accomplish this analysis scheme is called Helica, an umbilical analysis tool whose calculation efficiency is due to analytical calculation of helix bending stresses assuming loxodromic helix geometry. Helica is capable of being applied to umbilicals and flexible risers while featuring a load sharing analysis for combined loading. Additionally, Helica can calculate cross sectional stiffness properties, consistent fatigue stresses on the umbilicals, capacity curves for an umbilical cross section in compliance with applicable design codes, and both long- and short-term fatigue life expectancy. As factors such as installation, power efficiency, and simulation techniques are continually being developed to address and predict the various challenges facing the successful operation of subsea umbilical systems, it will be extremely interesting to observe how the offshore oil and gas industry adopts and applies these new technologies to reach new production and exploration depths. **OE**

Cutting through the dark

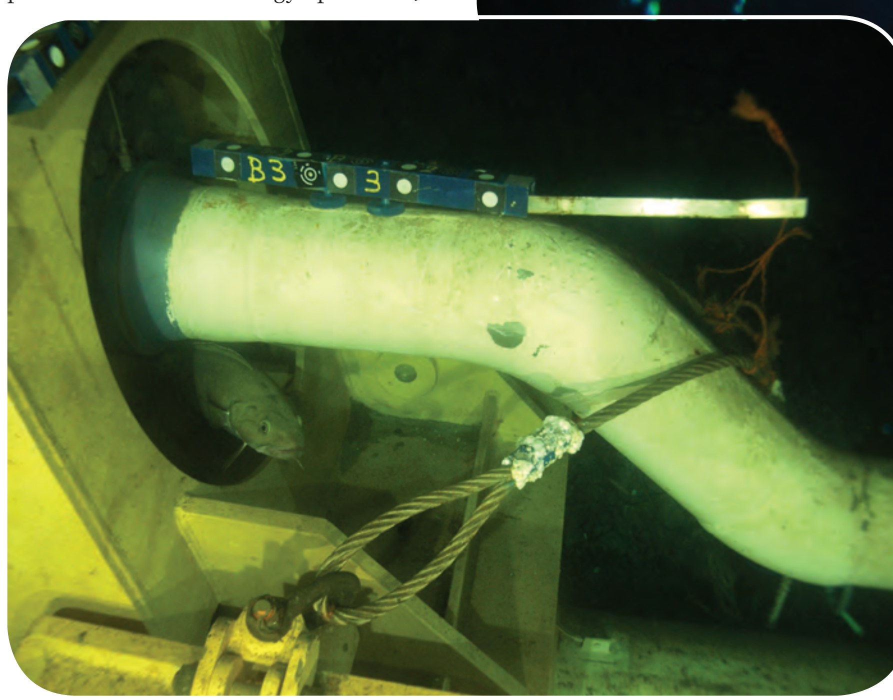
Some service providers are looking to the past to provide new solutions for subsea metrology operations. Greg App reports.

In an effort to overcome the challenges presented by subsea metrology operations, the oil and gas industry has relied on a number of techniques characterized by a wide range of technical capabilities and limitations. Some methods, such as the use of long baseline acoustics, are technologically advanced but susceptible to underwater noise and time sensitivity. Others, such as the use of a diver taut wire, rely on very basic technology that has remained virtually unchanged for decades. The use of a diver taut wire, while conceptually simple, requires an intervening human element to perform potentially dangerous work. In order to complete these subsea metrology operations more safely, accurately, and cost effectively, many companies are combining modern technology with a process known as photogrammetry, a concept that dates back to the mid-19th century.

Savante

The goal of photogrammetry is to retrieve 3D measurements from a 2D image. If the scale of a photograph is known, the distance between two points that lie on a plane parallel to that of the photographic image can be determined by measuring their distance on that image. Thus, it is possible to construct a dimensionally accurate 3D image of an object given multiple photographs from different angles. While the fundamental idea of photogrammetry is about as old as photography itself, this methodology was not applicable to subsea metrology until the advent of digital camera technology. Several companies are providing products that fuse this measurement technique with modern technological developments.

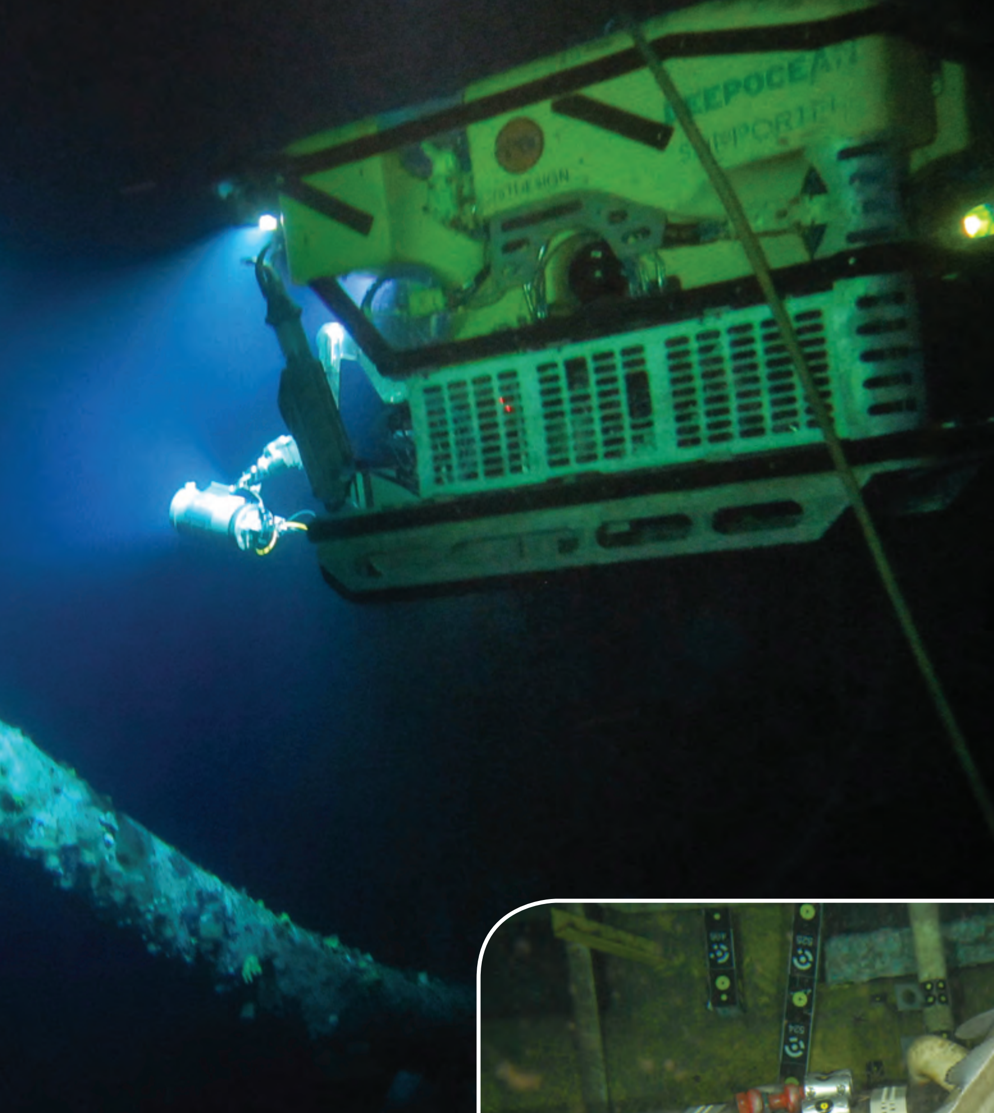
One such example is the Savante VOXEL subsea laser system, a laser-aided photogrammetric package capable of generating extremely accurate distance and angle measurements from video and/or digital images obtained from harsh environments which cause image distortion (such as underwater conditions present in subsea metrology operations).



Parker Maritime utilizes lasers for projecting a point pattern on subsea structures.

The VOXEL system, which is designed to operate with an image produced by any subsea digital camera, utilizes 3D triangulation in conjunction with multi-variate camera lens calibrations to translate between the position of various laser illuminated pixels and individual volume elements. These volume elements (dubbed "VOXELS" by Savante) constitute the surface of the object while lasers illuminate it.

Savante's laser-aided photogrammetry



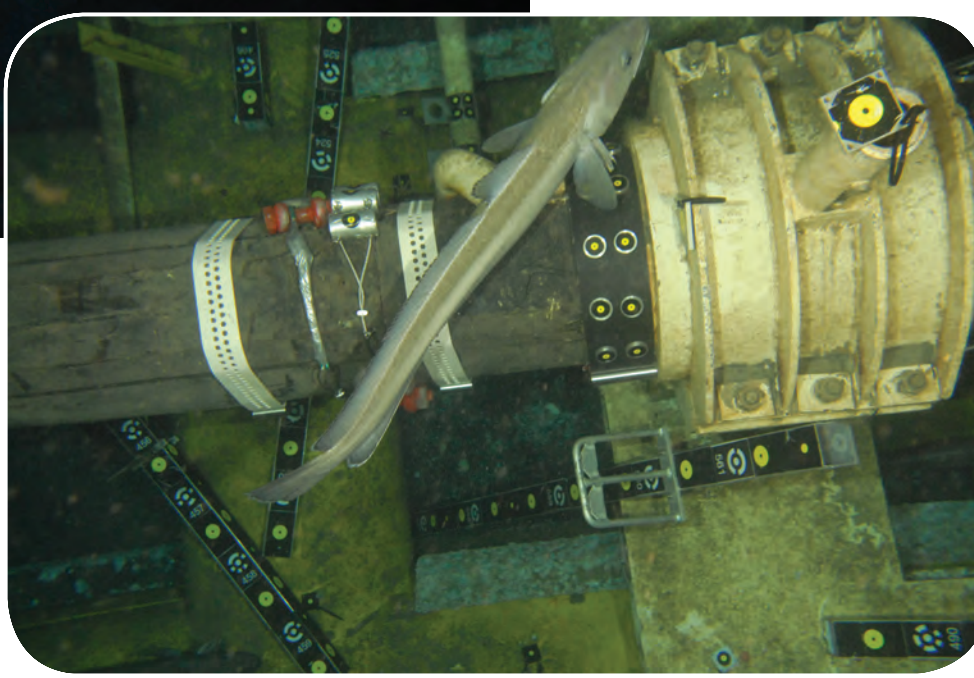
Maritime's Single Camera Metrology System (SICAMS) can be used to measure a variety of subsea elements.
Images from Parker Maritime.

techniques can render dimensionally accurate 3D images in regards to construction, seabed mapping, and damage analysis.

Parker Maritime

Parker Maritime's single camera metrology system (SICAMS), developed in 2007, has been used to measure a variety of subsea elements including shipwrecks, structural dents, caissons, spools, and piping. This system retains its own standardized hardware (including its own camera) to optimize the software's ability to generate accurate 3D renditions based on obtained 2D images. SICAMS has an enhanced blunder detection and reporting tool built into the processing software, which allows for a more accurate 3D rendition of the object being observed. Similar to Savante's VOXEL technology, SICAMS often relies on laser scanning to optimize results. "We utilize lasers for projecting a point pattern on subsea structures for special applications," says Rolv Johannessen, Marketing Manager of Parker Maritime. "A set of coordinates can be given for each laser point on the object being observed."

Due to the complex nature of SICAMS, Parker provides internal training to their engineers in conjunction with external training regarding the related software. "It is mandatory that our engineers have a dimensional control and understanding regarding surveying techniques," Johannessen says.



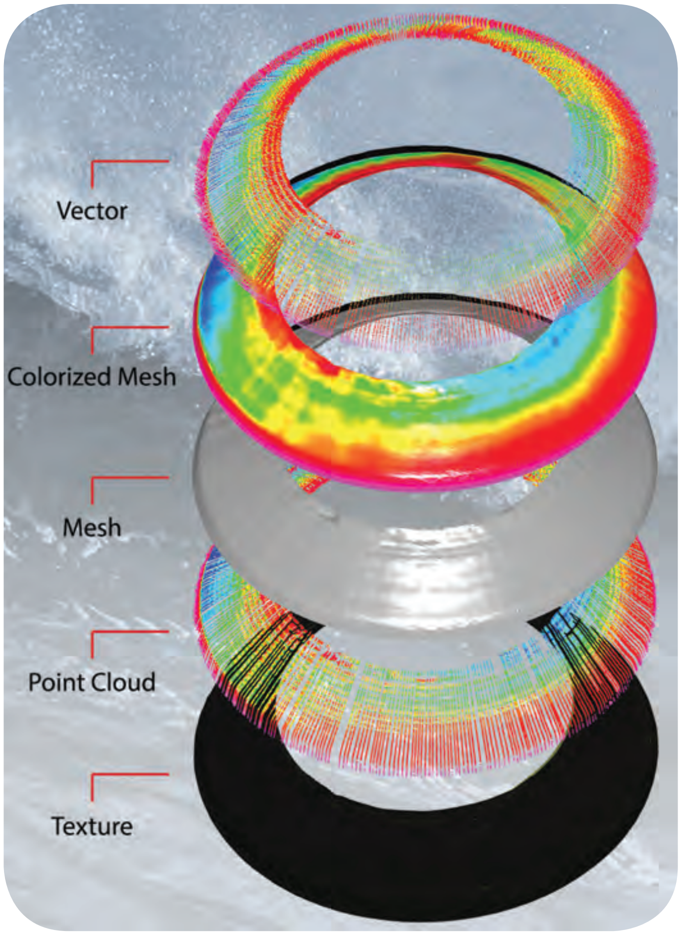
Laser aided photogrammetry is largely immune to subsea factors that have traditionally hindered subsea metrology operations.

Dimeye Corp.

DimEye Corp.'s patented I-Photogrammetry and video laser scan (VLS) technology can be used to address complex metrology projects, including reverse engineering of in situ components, measurements of defects and anomalies such as pipe dents on flex joints, metrology of closing spools and jumper hub alignment studies.

I-Photogrammetry can be used in conjunction with any digital camera; the user simply needs to capture the necessary photographs before sending them online to DimEye for 3D modeling. However, the photographs need to meet various requirements that enable DimEye to create a digital 3D interpretation.

"In certain situations we are able to provide training classes for other companies to complete basic measurement tasks," says Arnauld Dumont, Owner, DimEye Corp. "However, we prefer to use our highly trained technicians to complete most measurement applications. In order to ensure accurate



DimEye's VLS (Video Laser Scan) technology is capable of capturing thousands of images from HD video in a matter of seconds.
Images from DimEye Corp.

results, operators must have a basic understanding of photogrammetry, our data processing software and our VLS software."

Dimeye's VLS system combines the benefits of photogrammetry, high-definition video recording and laser technologies. The main advantage of this system is that it does not need stability or ideal environmental conditions (temperature and salinity) to operate effectively. Additionally, the use of video prevents the need to stop multiple times to take photographs at various angles, which in turn reduces the duration of the operation.

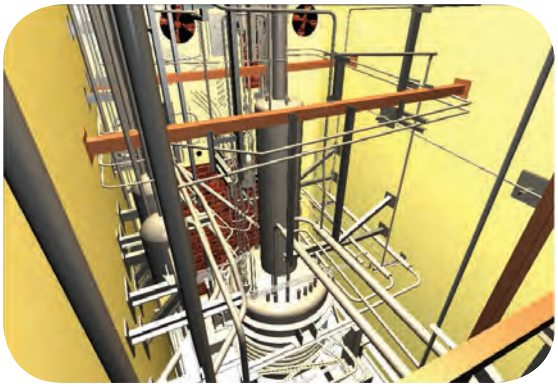
DimEye also provides ROV deployed VLS hardware for rental in addition to offshore support services for hardware/data capture integration.

The future

Even with the addition of modern technological developments, the use of subsea photogrammetry is not without limitations. "The biggest challenge regarding subsea photogrammetry is visibility," Johannessen says. "The general consensus is that when the ROV can 'see,' SICAMS can be used."

This limitation is directly related to the depth at which SICAMS and other subsea photogrammetry techniques can be used. Johannessen expects that the industry as a whole will respond to this challenge by enhancing their equipment to withstand greater depths, where there is less light and greater pressure (SICAMS is currently limited to 1000m depth). "We expect inertial navigation systems (INS) to play an even bigger role in the future, either as a stand-alone tool or in combination with the current SICAMS hardware and software capabilities."

The use of INS is relatively new to the subsea and offshore industry. Previously, it had been used primarily for military operations, but it has recently been made more available for civilian use. Rather than rely solely on visual data for obtaining measurements, INS relies on motion to provide dimensional analysis of a given subsea area. This method uses three orthogonal accelerometers located on a subsea vessel (such as an ROV), which measure linear acceleration in the X, Y, and Z direction. Analysis of the results provided by the accelerometers enables an operator to determine position and orientation of the subsea vessel, assuming that the initial values position and velocity are known. The primary advantage of this technology lies in the fact that it can address problems related to line of sight and poor visibility, with the latter being an unavoidable issue at great depths. However, without definite external reference points, this method is prone to small errors regarding acceleration measurements.



DimEye can provide accurate 3D CAD Models based on images taken from any "off the shelf" camera.

Dumont sees advancements in optical and processing technology having a significant impact on the future of subsea metrology operations, with his company DimEye playing a role in its development.

"In terms of applications where we can provide relevant analysis, we see these developments in optics providing even more accurate results for metrology applications subsea," Dumont says. "We are also working to develop real-time processing of our data in the field. We are leveraging the rapidly evolving technology industry that also provides more powerful processing tools at a rapid pace."

The combination of traditional photogrammetry with modern day technology seems to have provided the industry with an efficient method that excludes the element of human risk while maintaining reliable accuracy in subsea metrology operations. While various limitations remain, current software and hardware developments seem to indicate this could be a viable solution for subsea measurements. OE

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Southeast Asia's NEXT FRONTIER

After 50 years of sanction-driven isolation, Myanmar's reserves offer an exciting and challenging exploration opportunity and could be southeast Asia's next oil and gas frontier. Elaine Maslin reports.

Dockwise floatover installed the Shwe development topsides using COOEC's HYSY229 installation launch barge. First production was in January this year.
Photo from Dockwise.

Myanmar has been producing hydrocarbons longer than many. The country, sitting between India and China, exported its first barrel of oil from an onshore field in 1853.

Today, its hydrocarbon potential, especially offshore, is again attracting attention. After emerging from decades of sanction-driven isolation, due to military rule, the country is hoping to attract new investment in its upstream sector, especially offshore, where it lacks experience.

In January 2013, the Republic of the Union of Myanmar's Ministry of Energy put 30 offshore blocks up for tender (19 deepwater and 11 shallow) in its 2013 Offshore Licensing Round. In March, preferred bidders on 20 of those blocks were announced.

The attraction for foreign investors is that Myanmar's gas reserves have not yet been fully surveyed with modern seismic technology, making it an exciting and challenging country for exploration, says London-headquartered law firm Berwin Leighton Paisner.

"Myanmar has spent 50 years in isolation from the global economy," says a World Economic Forum (WEF) report, New Energy Architecture: Myanmar, produced in collaboration with Accenture and the Asian Development Bank (ADB), and published mid-2013. "If the country continues its political and economic reforms, Myanmar has the potential to emerge as southeast Asia's next frontier."

Erling Vågnes, senior vice president for exploration in the Eastern hemisphere at Statoil, which was one of the winners in the 2013 offshore licensing round, says: "This is a large and virtually unexplored area in a basin with a proven petroleum system and thick sedimentary deposits. This is a long-term opportunity with high subsurface risk, but with high-impact potential."

Myanmar wants to increase production to meet domestic requirements. Pre-2011, due to international sanctions, the government had limited access to finance, so it agreed to natural gas export contracts with Thailand and China, limiting domestic supply, the WEF says.

The country's emergence from sanction-driven isolation could also reignite the potential for an LNG export project, similar to one backed by Japan and South Korea, but cancelled in 2007, suggests Berwin Leighton Paisner.

Offshore potential

According to the WEF report, Myanmar has 7.8Tcf proven natural gas reserves (BP Statistical Review of World Energy, 2012) and it exported about 303Bcf in 2011.

The Myanmar offshore can be geologically divided into three basins, according to a presentation by Zaw Min Aung, assistant executive geologist offshore, at state-owned Myanma Oil and Gas Enterprise (MOGE), which is responsible for the country's upstream activities.

Aung was speaking at February's Myanmar Oil and Gas Week in Yangoon. He said the three offshore basins are the Rakhine, Moattama, and Tanintharyi. The first offshore drilling was in 1965, in the Rakhine and Moattama. The first major discovery was the Yadana gas field in the Moattama area in 1980.

Existing projects

According to Aung's presentation, there are 26 shallow water blocks and 25 deepwater blocks. Eighteen are active, operated by seven companies, under production sharing contracts. These are: Daewoo International (Blocks A-1, A-3, AD-7), MPRL E&P Pte (Block A-6), Petro Vietnam (M-2), PTT Exploration and Production International (PTTEPI) (Blocks M-3, M-11, M-9, MD-7, MD-8), Total E&P Myanmar (TEPM) (Blocks M-5, M-6), Petronas Carigali Myanmar Ltd.

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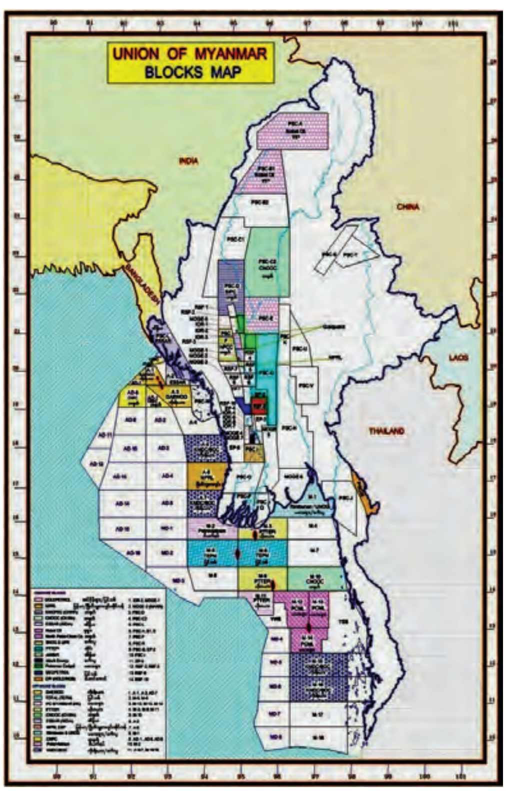
An ACE Winches floatover installation package on board the *S45 Barge* for work to install the ZPQ platform offshore Yangon, Myanmar. Photo from ACE Winches.



Myanmar's on- and offshore acreage.
Image from Republic of Myanmar Ministry of Energy.

(PCML) (Blocks M12, 13 and 14), and CNPC (AD-1, AD-6, AD-8).

Existing production comes from the Yadana and Yetagun fields, which accounted for 95% of Myanmar's total gas production in 2011 (ADB, Myanmar Energy Sector Initial Assessment, Manila, 2012). This year Shwe, operated by Korea's Daewoo International, came on stream, exporting gas to China, with some domestic supply. Sawtika, operated by Thailand's PTTEPI, is also due to come on stream this year. It will also export gas to Thailand, with some domestic supply.

Yadana

Yadana, discovered in 1980 and in production from 1998, is in the Moattama offshore area, in Blocks M-5 and M-6. Reserves are estimated at 6.5Tcf, according to the Ministry. The facilities comprise three well head platforms, housing 17 wells in total, with process, quarters, flare, and medium compression platforms (one each), connected to shore with a 216mi, 26in. pipeline. Partners on Yadana are Total (31.24%), UNOCAL (28.26%), PTTEPI (25.5%), MOGE (15%).

Yetagun

Yetagun, discovered in 1992, is in the Tanintharyi offshore area, in Blocks M-12, M-13 and M-14. Yetagun is Myanmar's second largest gas field behind Yadana. Its reserves are estimated at 4.16Tcf, gas and condensate, according to the Ministry. Production started in 2000.

The facilities comprise a wellhead platform with 10 wells, processing platform, floating storage and offloading facility, compression platform and booster compression platform. A 126mi, 24in. pipeline is used for gas export. The partners are Petronas (40.75%), Nippon (19.4%), PTTEPI (19.4%) and MOGE (20.45%).

Shwe

Shwe is in 110m water depth, in blocks A-1 and A-3, in the Rakhine offshore area, in the Bay of Bengal. Its reserves are estimated at 4.5Tcf. Offshore facilities comprise a processing platform with 11 wells, and the Mya-North subsea well head, with four wells. Gas export is via a 110km-long, 32in. pipeline.

First gas from Mya-North, part of the Shwe development, was in summer last year. On 16 January, operator Daewoo International announced first gas from Shwe, from the first of 11 production wells. Daily production was recorded at 200MMcf, this is due to increase to 500MMcf as the other wells come on stream.

Dockwise was the transport and installation contractor for the 22,000-tonne Shwe jacket, with distributed systems foundation, and 30,000-tonne topsides, constructed at Hyundai Heavy Industry's fabrication yard in Ulsan, South Korea. Dockwise installed the topside through a floatover using COOEC's HYSY229 installation launch barge.

Cable supplier JDR delivered a 13,650m-long production control umbilical for the Mya-North tieback, manufactured at JDR's Sattahip, Thailand facility. FMC provided a subsea control system on the five-slot subsea manifold, in 186m water depth, 12km from the Shwe platform. In June last year, KCA Deutag secured a two year operating and maintenance drilling services contract for the Shwe platform with Daewoo International.

Partners on Shwe are Daewoo International (51%), ONGE (17%), GAIL (8.5%), KOGAS (8.5%), and MOGE (15%). According to a note by KDB Daewoo Securities, dated December 2013, Daewoo International plans to start exploring the AD-7 Block, in the Rakhine offshore area, in 2015. The note says: "If the block's recoverable reserves are at least 3-4Tcf, a gas liquefaction plant may be built (or a piped natural gas facility if production is smaller)."

Zawtika

Zawtika is in the Moattama offshore area, in Block M-9 and a small part of M-11, in the Gulf of Martaban, in the Andaman Sea, about 300 km south of Yangon. The development, encapsulating the Zawtika, Kakonna, and Gawthaka gas and condensate fields, comprises three well head platforms, with a total 35 wells, an integrated processing and quarters platform

(ZPQ), and a 230km-long, 29in. pipeline to shore for export. According to operator PTTEP, Zawtika will initially produce at 300MMcf/d.

Technip performed front end engineering on the M-P project. Larsen & Toubro fabricated the wellhead platforms. The 16,500-tonne ZPQ topside was contracted to SMOE Pte in Singapore.

In Q4 last year, operator PTTEP completed a floatover installation of the ZPQ topside, performed by Saipem using the S45 barge, with an ACE Winches' floatover installation package. PTTEP then started hook-up and commissioning works, construction work of onshore pipeline and facilities, and a development drilling campaign. First gas of the Zawtika project was expected by the end of 2013, but is now expected this year. Partners on Zawtika are PTTEPI (80%) and MOGE (20%).

PTTEP said in January it plans to drill more appraisal wells on Zawtika and carry out exploration activities in Block M3, where a discovery has already been made and is earmarked for domestic supplies, according to a MOGE presentation. "The company will also continue its exploration activities in M11, PSC G & EP 2 and MD-7 and MD-8 for possible future development," PTTEPI said.

The future

Chevron, BG Group, Statoil, Woodside Energy, Shell, and ENI, were among the preferred bidders in the 2013 Offshore Licensing round, announced in March.

More than 60 proposals from 30 companies were submitted for the round, comprising 42 proposals for shallow water blocks and 22 proposals for deep water blocks.

In total, 30 production sharing contracts for offshore blocks had been due to be awarded in the round. In March, 20 shallow and deepwater blocks were offered, with ratification expected following detailed agreements with the Ministry of Energy, and more blocks expected to be offered.

Those selected were:

- **Shallow water**

BG Group and Woodside Energy, block A-4; Chevron, Block A-5; Woodside Energy and BG Group, Block A-7; Oil India Limited and Mercator Petroleum, Block M-4; ROC Oil Co. and Top Oil, Block M-7; Berlanga Holding, Block M-8; Transcontinental Group, Block M-15; Reliance Industries, Blocks M-17 and M-18; Oil India, Mercator Petroleum, and Oilmax Energy, Block YEB.

- **Deepwater**

BG Group and Woodside Energy, block AD-2; Ophir Energy, block AD-3; Woodside Energy and BG Group, block AD-5; Shell and MOECO, blocks AD-9, AD-11, and MD-5; Statoil and ConocoPhillips, Block AD-10 (Bay of Bengal); ENI, Blocks MD-2 and MD-4; Total, Block YWB.

Statoil said its deepwater Block AD-10, awarded in 50/50 partnership with ConocoPhillips, covers more than 9000sq km, about 200km offshore, in about 2000m water depth. The award represents a new country entry for Statoil, which now operates in 34 countries.

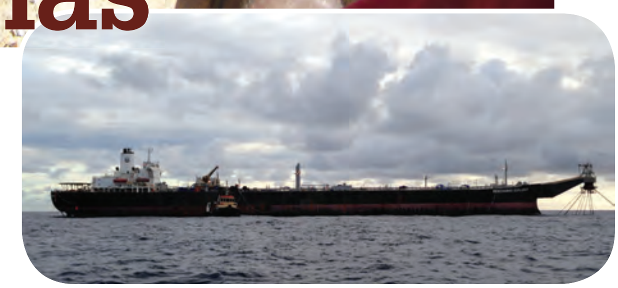
Statoil has committed to environmental and social impact studies and acquiring new 2D seismic during the first study period of 2.5 years. After this the partnership will decide whether or not to enter a three-year exploration period, the firm said.

BG Group and its bidding partners said it was committed to a 3D seismic acquisition program in each block, expected to start in 2014/15, with options for future drilling. OE

The microbial influenced corrosion that was encountered on chain links. Photo from Chevron.

Upgrading Benchamas

In order to improve mooring integrity, Chevron and Technip developed a plan to change out the mooring system at its Benchamas FSO off Thailand. Audrey Leon reports.



The *Benchamas Explorer* FSO located in the Gulf of Thailand. Photo from Chevron.

Mooring line failures are a major concern for the offshore industry, especially with a rise in the use of floating units expected over the next five years. Douglas-Westwood projects that a total of 139 floating production units will be installed between 2014-2018.

At the SNAME conference in Houston this past February, Kai-Tung Ma, a technical team lead of mooring and geotechnical engineering at Chevron ETC, discussed the company's mooring line swap out on the turret-moored *Benchamas Explorer* FSO in the Gulf of Thailand. The FSO began serving the Benchamas field in 1999, which is located 364km south of Bangkok at a water depth of 71m. The vessel's mooring system was designed to last 10 years, with no winch installed to service the mooring lines.

After an incident where a similar vessel experienced a major failure with its wire ropes in 2009, Ma said that Chevron decided to replace the *Benchamas Explorer*'s chain-wire-chain system with new sheathed spiral-strand wire ropes.

The goal of the project was to safely change the ropes while not interrupting production. Ma said it was unsafe to replace the mooring lines from the turret because it would have required a large winch, and would have required the field to shut down for hot work, i.e. welding. Chevron worked with contractor Technip to design a surface mooring connection tool (SMCT), which was welded to the back of an anchor handling vessel. This technique was adapted and improved from a previous project Technip carried out on the Alvheim field in 2006.

For the SNAME paper, Life extension of mooring system for *Benchamas Explorer* FSO, Ma and his co-authors Rachel Price, Dennis Villanueva, Philippe Monti, and Kevin Tan wrote, "The (SMCT) tool allows deck crews to retrieve and hold a mooring line above the water surface for disconnect, reconnect, and repair purposes. The apparatus is designed to allow for easy surface connections when installing or replacing mooring lines and reduces the need for complex underwater mooring line connection processes with ROVs and divers."

The *Benchamas Explorer* FSO had nine mooring legs, secured by driven piles in a 3x3 configuration. Ma and his co-authors discovered that there were many existing issues with the mooring system. Leg #5 had been installed slack, which resulted in higher tensions on legs #4 and #6. The use of computer models helped determine that if leg #5 were shortened by 13 links of 117mm chain, legs 4, 5, and 6 could be brought to the same load.

Additionally, the chain-wire-chain arrangement kept the majority of the wire buried in mud. Inspection showed that the wire rope, after 13 years in service, was well-preserved and protected by the soft mud with little corrosion. "The soft clay protects the steel," Ma said during his presentation. "It stays on the surface of the chain because it's sticky."

No broken wires were observed, however the rope did appear greasy near the bend stiffener, Ma and his co-authors wrote. Testing found that no corrosion was found on the segment 1 chain, but an unusual pattern of corrosion was seen on the segment 3 chain near the touchdown point, Ma said. It was later determined through testing that two types of bacteria, which can cause Microbially Influenced Corrosion (MIC), were present. Ma and his co-authors concluded that the metal loss was due to MIC.

Ma said that fortunately for Benchamas project, the mooring system was designed with alternating lighter and heavier sections of chain, with the heavier chain intended to reduce vessel excursions by providing weight. Since only these larger chains were affected by the MIC, there was no adverse impact in the maximum tension or minimum fatigue life of the mooring system, and the MIC did not obstruct the project in any way.

Ma said this project highlights how important design is in the early stages, saying that the field would have benefited from an original design life of 20 years, instead of 10, by choosing sheathed wire ropes over low-cost options.

"Upgrades in the operation phase tend to cost more than initial execution phase," he told the audience at SNAME. "Don't be cheap in the beginning." OE

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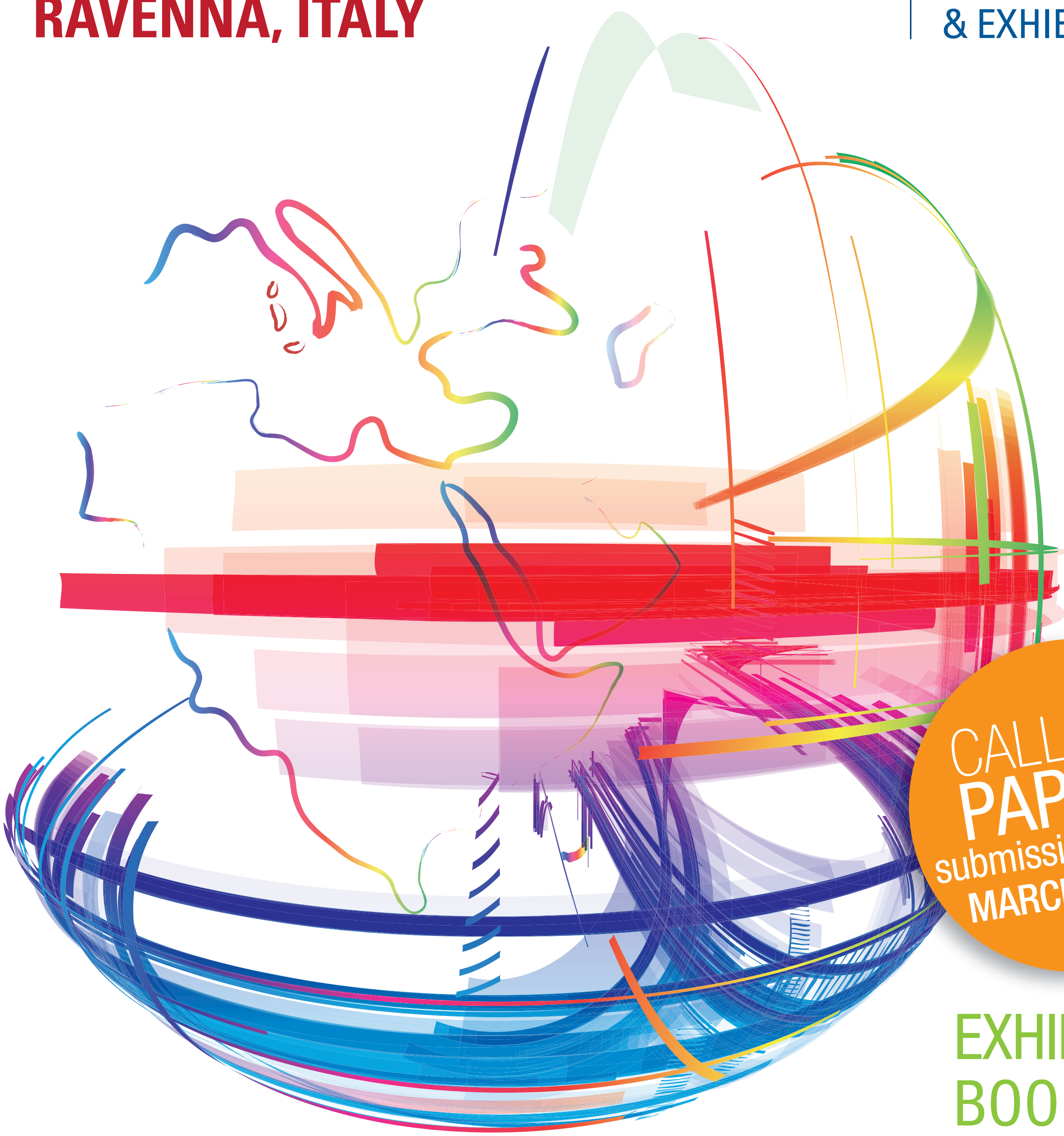

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Photo from Farstad.

Tough tonnage

New anchor handling tug supply vessel orders have slowed, but the market is starting to turn a corner. Elaine Maslin reports.

Depending on which analyst's data on anchor handling tug supply vessels (AHTS) you look at, the size of the fleet varies. What has not been in doubt is its growth trajectory.

A 2013 report by Ocean Shipping Consultants, "Offshore Support Vessels and Mobile Rigs: Global Prospects to 2025," put the AHTS fleet at about 2850 vessels and said this number was expected to grow by 41% to 3900 vessels, by 2025, matching a 41% projected growth in mobile drilling units to 1110. Newbuilding levels were forecast at about 120 a year, with about 30 units forecast to be scrapped each year.

A report by finance firm Cleaves Group in 2012 had been just as buoyant. It said, since 2005, the AHTS fleet had doubled, while the PSV fleet increased by about 30%.

However, the growth rate has slowed. Confidence declined as activity and rig requirements slowed—the main driver for AHTS vessels.

Offshore support vessel (OSV) operators (AHTS and PSVs) have also seen reduced margins.

David Palmer, of Pareto Securities, told the IBC 6th Annual Offshore Support Vessels Conference, in Singapore, in April, that it was becoming "increasingly challenging" to make money in the OSV sector, Palmer says.

DOF's *Skandi Iceman*, built by Vard for DOF. Photo from Vard, by Harald M Valderhaug.

"Global OSV companies' forward EV/EBITDA estimates have been flat over the past six months," he says, reflecting investor concerns about the overall level of E&P spending and offshore fundamentals.

"In 2013, the markets for PSVs and AHTS vessels were moving in the right direction, but on average the earnings in the spot-market did not give owners a sufficient return on their investments," said Norway's DOF AS, which operates 20 AHTS vessels, and has a further three on order, in its 2013 annual report.

DOF says AHTS units are exposed to volatile North Sea spot market rates. "Only about 50 of the 300 PSVs in the North Sea are trading in the spot-market, while 60% of the AHTS fleet depends on the spot-market," the firm says.

Last year also saw a drop in newbuild activity. In the first seven months of 2013, 54 vessels were delivered, according to an RS Platou September 2013 presentation, implying an annual rate of 93 vessels.

Palmer says the AHTS orderbook is "distinctly light," falling more inline with rig utilization rates, which he expects to continue to be muted, rather than newbuilds.

Norwegian shipbuilder Vard's yearend 2012 order book listed eight AHTS newbuilds, compared to five at yearend 2013, with no new orders in 2013.

Vard, owned by Italy's Fincantieri, cited the reasons in its 2013 annual report: "There is some uncertainty surrounding oil companies' continued willingness to grow their exploration and production spending, as cost in the oil and gas industry is on the rise and many players are refocusing their activities."


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Swire Pacific Offshore's latest D-Class AHTS, Pacific Dragon. Photo from Swire Pacific Offshore.

Vard's Niteroi yard. Photo from Vard.

Turning a corner

The fall in orders could signal a rebound in the market, suggests Vard: "An increasing rig count, coupled with limited fleet growth, is the best indication that a long-awaited rebound in the market for large AHTS could finally materialize in 2014. AHTS demand is further bolstered by an upswing in offshore construction activity as a result of high committed upstream investments, and by increased offshore activity in the Arctic regions, including drilling campaigns offshore Greenland and in the Kara Sea, all of which require modern, high-end tonnage suited to harsh environments."

Palmer agrees that the fall in orders means that market demand/supply fundamentals are "starting to look really compelling," particularly for shallow-water assets supporting jackups.

According to the RS Platou presentation, AHTS demand generated by jackups is estimated to have grown rapidly. Specifically, the new generation of jackups, which are larger than previous generation jackups, are generating the demand, requiring vessels with 120-tonne bollard pull.

In France-headquartered vessel operator Bourbon's 2013 annual results conference call in March, CEO Christian Lefévre, said the AHTS fleet is roughly 1400, with 388 more than 25 years old and only 97 on order, offering favorable market conditions for those with new generation units.

Palmer says there are currently 2022 AHT/AHTSs in total, with 165 (8%) on order, of which 118 units are scheduled for delivery by end 2014. Of the total fleet, 543 (28%) are older than 25 years and mainly "non-competitive," consisting 412 small AHTSs (29% of the small-size fleet) and 131 mid-size AHTSs (24% of the mid-size fleet).

Challenges and opportunities, from Indonesia to Brazil

Norway-based Farstad Shipping has 30 AHTS vessels in its 59-strong fleet, with a further two due for delivery between February 2014 and July 2015. Far Sirius, one of the largest AHTS in build, according to RS Platou, is due for delivery in April. Far Sirius is a UT 731 CD design, with 24,000 BHP, and 259-tonne bollard pull, being built by Vard at Langsten.

In its 2013 annual report, Farstad said it expects a "slight improvement" in the market in 2014, but it says this will vary between geographical markets. An improvement in the North Sea market will depend on tonnage moving to other markets. It says the Indian Pacific markets are characterized by overcapacity, while the Brazilian market, West Africa, and the Gulf of Mexico offer potential positive developments.

Solstad Offshore, also from Norway, has 20 AHTS. In its 2013 report, Solstad said demand for more traditional AHTSs did not increase as expected in 2013, but there were several signals indicating increased demand in 2014, aided by more rigs coming into operation, especially in the North Sea, West Africa and the US Gulf.

Norway-based Siem Offshore has 10 AHTSs, two on contract for seasonal operation in the Kara Sea, during 2014 and 2015, with options for 2016 and 2017, and none on order. In a March presentation, CEO Terje Sorensen said the North Sea spot market for high-end AHTS would improve due to the increasing number of rigs operating in the region, and that the market was relatively stable for high-end units.

Siem also says several AHTS with less than 15,000 bhp are due to leave the North Sea for shorter term contracts during 2014, further improving the market. There is also increasing demand in the US Gulf of Mexico, West Africa, and Oceania, and a positive outlook in Brazil, and in harsh or remote areas, such as the Barents Sea, Kara Sea, Canada, and US Alaska, Siem says.

Sophisticated tonnage

Palmer predicts that larger players will

According to shipbrokers Westshore, there are a number of new rigs coming into the North Sea that will drive activity. The first of Maersk Drilling's four XL Enhanced jackups (OE: May 2013), the Maersk Intrepid, is enroute to work for Total's Martin Linge in the Norwegian sector. The next in the quartet will arrive 4Q 2014. Other rigs coming in are Noble Corporation's Noble Sam Turner jackup, to work in Denmark, Diamond Offshore's *Ocean Patriot* semisubmersible, to work for Shell, and Prospector Offshore's new Prospector I jackup to work for Total. Later in the year, Odfjell's semisubmersible *DeepSea Aberdeen* will be coming to work for BP west of Shetland, and Songa Offshore's CAT D *Songa Equinox* semisubmersible will arrive to work for Statoil.

Bourbon's ice-class AHTS.
Photo from Vard.

deal with the market landscape by focusing on more sophisticated tonnage, as their cost structure becomes too expensive for the lower-end assets.

In September 2013, Vard delivered what it called one of the most sophisticated AHTS vessels built, the *Skandi Iceman*. Built to ice class and equipped for multi-role operations in harsh and arctic areas, it is 94m-long, 24m beam, and has a rated bollard pull capacity of 280-tonne.

Bourbon's latest order is a Vard Design designed, 270-ton bollard pull AHTS, 93.6m-long, latest generation vessel, also able to work in arctic conditions, scheduled for delivery from Vard Brattvarg in Norway in Q1 2016.

Swire Pacific Offshore (SPO) has been expanding its fleet, focusing on deeper waters, where it expects demand to be greatest, with a string of eight new, 240-tonne bollard pull, D-Class vessels. The first was launched in February 2013, and the eighth, the *Pacific Dragon*, in April. The Havyard-design D-Class vessels were designed to operate in harsh deep water environments, and built to clean-class SPS 2008 and ice notations.

SPO has also set up offices in Latin America, Canada and East Africa in order to explore opportunities in these regions.

DOF, through its Brazilian subsidiary Norskan Offshore, has eight-year contracts for two of its three in-build vessels, *Skandi Urca, Skandi Angra*, and *Skandi Paraty*, and a four-year contract for the third, all with Petrobras, offshore Brazil. The vessels are among some of the larger AHTS vessels currently being built.

Skandi Angra, due for delivery in September, is being built at Vard's Niteroi yard, to an STX AH 11 design, has 25,800 BHP, and 250-tonne bollard pull. Vard is also building the *Skandi Urca*, to the same design.

There may also be continued corporate activity in the market, says Palmer. There are over 600 OSV owners in the world, and the largest owner controls only 7% of the fleet, he says. The top 15 PSV owners own ~800 AHTS globally (44% of the total PSV fleet); while the top 15 AHTS owners own ~700 AHTS globally (32% of the total AHTS fleet).

"With such a fragmented market landscape, players are looking for consolidation and M&A to grow." Recent deals have seen Tidewater buy Norway's Troms Offshore Supply, Fairmount Marine and Fairmount Ocean Towage Company bought by Royal Boskalis Westminster, Australia's Mermaid Marine buy Jaya Holdings, and Jaccar Holdings make an offer for Bourbon.

Palmer concludes: "We are generally positive on the OSV market – but there is a need to be selective on markets, assets and projects. We still see a flatter and longer up-cycle, but with the caveat that, if the oil price doesn't increase, we will see pressure from customers for lower rates and pressure on utilization.

"Oil companies are starting to focus on cost efficiency and cut discretionary spending, but still require near-term production to support their cashflows. As such demand for jackups remains strong. We see a new investment cycle evolving post-2016 due to a tighter supply-demand balance in the energy markets as a result of these spending cutbacks." **OE**

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Spotlight

By Sarah Parker Musarra

OTC 2014: Viking Life Saving Equipment showcases safety solutions

Image of Viking helicopter lifejacket from Viking Life Saving Equipment.

Denmark's Viking Life Saving Equipment kicked off OTC announcing a new Statoil contract to maintain marine safety equipment aboard 36 of Statoil's North Sea platforms. Viking is forming partnerships on the other side of the world, too. Following the passage of the Mexican energy reform, Viking is looking to build on its existing partnership with the Mexican Navy. "Mexico is a very important market for the future, just as Brazil was 4-to-5 years ago," Viking Vice President Benny Carlsen told OE, noting that Viking has worked with several Norwegian companies that have set up shop in Brazil.

Viking launched a best practice guide for OTC, its Offshore Safety Agreement, detailing the company's safety solutions, explaining what to look for in safety equipment, and explaining how to choose the most pertinent items after conducting studies and reviewing results. The guide is also available for download on its website. While HSEQ technology will forever be a race to the latest and greatest, Viking finds that small details can make the huge differences: "Our suits used to be orange. Now they are yellow; the yellow color is more visible at longer distances," Carlsen said. With helicopter and boat transportation remaining areas of elevated risk, Viking showcased its transportation suits and lifejackets at the conference, implementing tracking devices, and thermal liners that regulate body heat. *—additional material provided by Audrey Leon*

www.viking-life.com

OTC 2014: 3M Cubitron II bonded abrasive grinding and cut-off wheel

Image of Cubitron II from 3M.

Among all the booths at OTC, 3M's "Innovation Lab" was easily sighted.

It was the one with the welder decked out in safety gear, grinding away at a piece of carbon steel while an on-looker timed him. With the company's Cubitron II bonded abrasives disc, the welder completed his task in less than half the time compared to when he used a conventional disc. According to 3M, the disc features precision-shaped grains that cut faster, stay sharper longer, and require less pressure than conventional grinding wheels, and 3M says other products require up to three times the amount of pressure to match the cut of Cubitron II abrasives. Image of Cubitron II from 3M.

www.3M.com

OTC2014: GE Oil & Gas 20ksi BOP program

Image of GE Oil & Gas control system from GE Oil & Gas.

Upstairs at GE Oil & Gas' booth, Vice President & CEO – Drilling & Surface Andrew Way and GM – Engineering Dave Balevic introduced the company's new blowout prevention (BOP) program and components: its 20ksi BOP deepwater drilling program; SeaOnyx control system, and the 2014 OTC Spotlight.

While developing these products, Way and Balevic explained that GE Oil & Gas mined existing technologies and sourced knowledge from its other business units. GE Oil & Gas' new BOP system will make it possible to work in subsea formations up to 20ksi and 350°F. It can withstand what Balevic referred to an "industry-leading 2.5 million pounds" of force. GE's **SeaOnyx control system** is designed to minimize downtime, while the SeaLytics BOP Advisor software provides real-time performance monitoring and maintenance data.

"The majority of downtime isn't due to

BOP equipment, it's due to the supporting systems," Balevic said.

GE Oil & Gas also announced that it had secured its first two contracts for the SeaLytics system, from Houston's Atwood Oceanics and Brazil's Queiroz Galvão Óleo e Gás.

www.ge-energy.com

OTC2014: 3M Novec engineered fluids

Image of Novec engineered fluids from 3M.

Past the welding demonstration in 3M's "Innovation Lab," conference attendees found a cellphone submerged in a clear liquid that looked like water. With a 3M employee on-hand to supervise, passers-by retrieved the phone from the liquid, often with pleased, yet slightly-baffled looks on their faces. Not only was the device functional, neither the phone nor their hands retained any dampness or residue.

The cool, curious liquid may seem unusual, but 3M insists most have been around it before. Used to clean electronic devices and minimize their heat, 3M says its Novec fluids are also "used to safely extinguish fires in places that house our American treasures," such as the Alamo and the US Library of Congress. It even safeguards Benjamin Franklin's library and the 24ft-long squid in the Smithsonian. Non-toxic, non-flammable, and with high thermal stability, the environmentally friendly liquid can be used in heat transfer, lubricant and coating deposition, and precision cleaning.

www.3M.com

OTC2014: Cyberhawk ROAV

Image of an ROAV from Cyberhawk.

Winner of OTC's Stand-of-the-Day award among a field of 3000+ exhibitors, Cyberhawk commanded a fair amount of foot traffic.

Having worked with major companies around the world and being the previous recipient of an Oil and Gas UK Award for offshore inspection in the North Sea, the UK-based company educated attendees on the benefits of using its **remotely operated aerial vehicles (ROAV)** for offshore inspection.

Cyberhawk's ROAVs can be deployed in helicopter-constrained situations to monitor flare booms, drilling derricks, and vent stacks. ROAVs are unmanned and battery-operated, which means that personnel are not entering dangerous or risky locations for inspection. Additionally, the asset remains online and producing during inspection, and site reports are produced the same day.

Thermal imaging and close-up, high-definition photographic images from all angles are available for detailed analysis. Trained inspection engineers and pilots with hundreds of hours of experience in what the company calls "GPS-denied" environments operate the units.

—additional material provided by Audrey Leon

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Activity

Oil industry bikers raise millions in Texas

The BP MS 150 is a two-day fundraising cycling ride organized by the National Multiple Sclerosis Society: Lone Star Chapter. This ride is the largest event of its kind in North America, and the top fundraiser for the society, but it's one of more than 100 Bike MS rides staged around the US. For teams to become "National," they need to participate in at least four events. (National teams: BP America, Chevron, ConocoPhillips, and Marathon Oil.)

This two-day, 180mi.journey from Houston to the Texas capitol in Austin, has breakpoints positioned every 8-15mi. and an overnight celebration in LaGrange.

2014 marks the 30th Annual BP MS 150 Houston-to-Austin Bike Ride. Since it's a fundraising event, not a race, it attracts both novice and experienced cyclists.

Ride Marshals are registered cyclists who act as both Good Will and Safety Ambassadors for the recommended training rides and the BP MS 150. They are passionate about safe cycling, and are trained in CPR, first aid, and bike mechanics.

Team BP – BP became the title sponsor in 2001, furthering its commitment to the MS movement. Team BP averages more than 700 cyclists at the annual BP MS 150, and has raised over US$11 million to date.

Team Shell Cycling – Team Shell is a group of 267 Shell employees, retirees, contractors, friends, and family members who promote employee wellness, safe cycling, and are good ambassadors for Shell in the community.

Mark Poindexter, Team Captain and Sponsor, said the team had more than 50 volunteers, in addition to the 256 riders, and has nearly met its 2014 goal of $250,000. www.shellcyclingteam.com

ConocoPhillips – The ConocoPhillips team was led by Stephen Moskowitz this year, and included 251 riders. What started as the ConocoPhillips training series is now known as the Ready-to-Roll (R2R) series, and Team Shell and others take part in the practice rides. ready2rollcycling.com

Schlumberger Cycling Club – SCC was founded in 1996, has about 250 members, and has been recognized by the BP MS 150 with the Platinum Safety Award. The club organized 14 training rides from January to April, averaging more than 100 riders at each, and had 178 riders this year, with Theresa Hartman as team captain.

Celebrating 30 years
HOUSTON » AUSTIN
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BP MS 150 | 30th Annual Ride | Est. 1985

Team member Bill Sass completed his 14th BP MS 150. His perseverance and determination to complete the course on a hand cycle is truly uplifting (see p.5). www.slbcycling.com

Marathon Oil – In 2000, 12 employees formed the first MS 150 team, which grew to 101 riders in 2014. The Marathon Oil team went "National" in 2010, and won the National Rookie Team Award that year, for being the largest.

Alison McCaslin was Marathon's team captain this year, her 9th ride. She told OE that the Marathon team is consistently a Top 25 Fundraising Team, and has raised over $1.4million locally since 2000. Their participation shows how Marathon employees strive to make a difference in their communities, she said. "We ride for those who can't."

ExxonMobil – The ExxonMobil Cycling Team has raised more than $4million for the National MS Society since it started in 1999. The team participates in the BP MS 150 because they "want to experience a great, organized ride, and to help fund research, advocate for change, and help people with MS and their families lead powerful lives. We believe in the work they do and want to be part of it."

Team captains are Joshua R. Lowry and Stephanie Freeman. www.emcycling.com

Industry – 2014 top fundraisers include ($, #riders): Team BP ($1.11million, 655); ConocoPhillips ($461k, 251), ExxonMobil ($365k, 216); Bechtel Cycling Team ($268k, 100), Anadarko ($262k, 168), Team Shell Cycling ($236k), CGG ($225k, 91), Baker Hughes Express ($189k, 166), National Oilwell Varco ($174k, 123), and Marathon ($154k, 101).

Other teams (#riders): Apache (52); BG Group Bike Team (47); BHP Billiton Pedal-up! (36); Team Cameron (91); Cheniere (6); Diamond Offshore Drilling (27); Team DNV-GL (35); Team DOF Subsea (10); Team Dril-Quip (54); Team EMAS (19); Team Emergent Technologies (27); Team Energy XXI (56); eni petroleum cycling team (26); Team EOG (45); Exterran (59); FairfieldNodal (11); Team Fluor (72); FMCTI Cyclers (131); Team Fugro (79); Team GE (51); Halliburton (107); Team Hess (106); Team KBR (38); Kongsberg (15); Lloyds Register (28); Maersk Oil (24); Marathon Oil (101); McDermott (4); Team Murphy (22); Team Nabors (32); Newfield Exploration (34); Noble Drilling (55); Noble Energy (79); Team Oceaneering (85); Oiltankers (16); Parker Drilling (2); Phillips 66 (62); Precision Drilling (9); Repsol Riders (41); Riley Exploration (15); Team Sasol (12); SBM Offshore (42); Team Seadrill (20); Team Shawcor (16); Simmons and Co. (49); Statoil (99); Subsea 7 (86); Superior Energy Services (27); Team TOTAL (81); Team Vantage (21); Team Weatherford (52); Team Williams (23); Team Wood Group (105); TeamOXY (50); Transocean (72); Viking Oil Tools Cycling Team (4); and WorleyParsons (43).

MS – Multiple Sclerosis is a progressive neurological disease that affects people in different ways, including paralysis, loss of vision, and impaired memory. Living with MS means living with uncertainty.

In its history, the ride has raised nearly US$185million for research aimed at treating and eventually curing MS, as well as services for those living with MS, including scholarships.

Take the ride of your life next year, 18-19 April 2015. *–Nina Rach*

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Activity

DNV GL acquires Marine Cybernetics

DNV GL Group COO and Executive Vice President Remi Eriksen, left, shakes hands with Stein Eggan, chief executive officer of Marine Cybernetics, following the acquisition announcement at Houston's OTC 2014. Photo from DNV GL.

At Houston's Offshore Technology Conference in May, leading maritime and offshore classification society Oslo's DNV GL announced it acquired Marine Cybernetics. Notable for introducing Hardware-In-Loop testing to the industry, Trondheim's Marine Cybernetics was established in 2002 as a spin-off from the Norwegian University of Science and Technology (NTNU).

"We share a similar philosophy for providing advanced services within testing, verification and technical advisory," DNV GL Group Executive Vice President and Chief Operating Officer Remi Eriksen, said, calling Marine Cybernetic's third-party testing and verification of computer-based control systems "second to none."

DNV GL also announced that it will be rolling out HIL testing globally.

"DNV GL and Marine Cybernetics have a good strategic match - with common values, an aligned strategic focus as well as complementary services and competencies," he said. "DNV GL's ability to fulfill its purpose of safeguarding life, property and the environment is significantly strengthened by this acquisition."

Eriksen called the acquisition a "strategic investment" that addresses the industry trend of increasingly complex and interconnected computer-based control systems. "We see that an increasing number of incidents - many of them severe - are caused by software-related issues. To ensure step change in the safety and efficiency of offshore and marine operations more emphasis has to be put on software quality," he said. Marine Cybernetics will become an independent business unit within DNV GL. Following the deal, Norway's Kristian Gerhard Jebsen Group (KGJG) announced it will increase its stake in Marine Cybernetics to 30%, with the investment being used to co-develop the company with DNV GL, which retained 70%. ▪ *–Sarah Parker Musarra*

Safety steps recognized

Industry excellence in health and safety was recognized at the UK Oil and Gas Industry Safety Awards in Aberdeen at the end of April. The event recognizes and honors the companies and people who embody the spirit of safety and innovation across the sector.

Step Change in Safety Team Leader Les Linklater presented the Services to Safety Award posthumously to Steve Walton, a safety leader in the industry who understood the importance of people in the safety equation. Walton passed away last year and the award was presented to his widow Marie.

"Steve played a pivotal role in introducing countless safety measures and as one of the first elected safety representatives to sit on the Step Change in Safety Leadership Team; he played his part at the highest level," said Linklater. "He is a great loss to the industry and we remember him today because of the difference he made."

All winners were presented with The UK Oil and Gas Industry Safety Award medal, designed by sculptor Marian Fountain. Nominations for the 2015 awards will open in January 2015.

The category winners were:

- The UK Oil and Gas Industry Safety Award for Safety Leadership: Paul Craig, safety manager, North Star Shipping (pictured)
- The UK Oil and Gas Industry Safety Award for Safety Representative of the Year: Bob Egan, trade foreman, Petrofac Limited
- The UK Oil and Gas Industry Safety Award for Preventative Safety Action: Derek Smith, rigger/deck crew – Clyde, Wood Group PSN, Talisman Sinopec Contract
- The UK Oil and Gas Industry Safety Award for Most Promising Individual: Ruth Pirie, QSHE advisor, Fisher Offshore
- The UK Oil and Gas Industry Safety Award for Innovation in Safety: The North Sea Production Company
- The UK Oil and Gas Industry Safety Award for Workforce Engagement: Andy Nolan and the HSE&A Department, Talisman Sinopec Energy UK
- The UK Oil and Gas Industry Safety Award for Health: Well Track by Sodexo
- The UK Oil and Gas Industry Safety Award Ideas in Safety Prize: Bronson Larkins, intervention engineer, BP

Paul Craig, safety manager, North Star Shipping.

Linklater added: "Offshore safety has improved significantly over the last decade and these awards are all about showcasing steps forward. In addition to celebrating our achievements in the field of health and safety, these awards have also given us the opportunity to pause for reflection and a reminder the sector must continue to be ever vigilant." ▪

–Elaine Maslin


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Spotlight

By Elaine Maslin

Big game hunting in the intervention business

Owen Kratz marks his 60th birthday this year, but he's far from settling down. The CEO of Helix Energy Solutions Group, including the business unit Well Ops, has the global intervention business in his sights, with an expanding fleet and a passion for the industry.

It is not quite the game warden job he had always wanted, and set out to Kenya to find after completing a degree in biology and chemistry in New York. Luckily for Helix, Kratz's career changed when he met a North Sea diver from Rhodesia, who persuaded him to take the same path. In 1984, Kratz joined Cal Dive, which eventually became Helix Well Ops, as a dive superintendent.

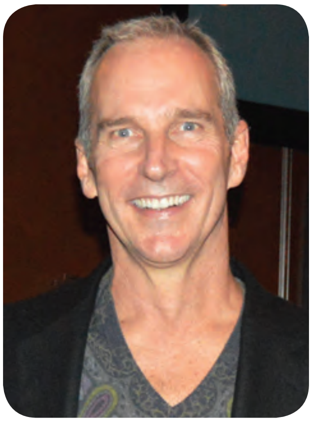
What fascinates—and drives—Kratz is the industry's changing nature and needs. "There are a lot of different things these intervention vessels can do. But, maybe five years from now there could be a decommissioning vessel. I see light intervention vessels, wireline vessels, top hole drilling vessels, vessels specializing in just doing production enhancement. Some of them could also do well start up and clean up."Then there is decommissioning. Decommissioning is changing faster than we can design for. Probably 80% of the intervention market has historically been decommissioning, where producers felt most comfortable trying it out, and there is a big back log in decommissioning, and post-Macondo, going forward, you may not be able to decommission as you used to."

Not only that, but Xmas tree design has changed, and continues to change, he says. There had been a shift from vertical to horizontal trees to facilitate completion and recompletion operations. Now companies are going back to vertical trees, partly because of increasing pressure requirements and to allow tree recovery and repair without pulling the completion. "This is why I like intervention," Kratz says. "It is constantly changing and you have to figure out where the market is going. You have to look at all the solutions a company is going to need."

However you look at it, there will be a need for more vessels, led by the ever increasing numbers of subsea, especially deepwater, wells.

Helix Wells Ops currently operates five vessels (three light well intervention and two heavy intervention), capturing about 50% of the global fleet. They are the *Seawell, Well Enhancer* and *H534* (a converted drillship) monohulls, the *Q4000* semisubmersible, and the chartered *Skandi Constructor* and *HPI* monohulls.

> "This is why I like intervention, it is constantly changing and you have to figure out where the market is going."
>
> **Owen Kratz**



In addition, it has on order the *Q5000* and the larger *Q7000* semisubmersible, both being built by Sembcorp Marine's Jurong Shipyard subsidiary in Singapore, and due for delivery in 2015 and 2016 respectively. The *Q5000* has a five-year contract, with options, with BP. Helix Well Ops will also operate intervention services on two newbuild monohulls being built for Siem Offshore, for client Petrobras, on a four-year contract, with options.

Kratz thinks Helix will build at least one more, giving a total of 10 vessels, before 2018, and that the global fleet will add up to about 20, maintaining the company's 50% market share, by vessel numbers.

Norway's Island Offshore currently has three vessels, Malaysia's Bumi Armada has the *Synergy,* in partnership with Fugro, and Aker Solutions has the *Skandi Aker*. FTO Services, founded in 2012 as a joint venture between FMC Technologies and Edison Chouest Offshore, is also bringing out a vessel.

"There is a lot of difference in the market and not one right solution, that is why we have our fleet," Kratz says. "We are not trying to come up with a product, we are a solution provider."

What surprises Kratz is the time it has taken the industry to adopt intervention technologies, and now the interest in using it. Instead of having an under-utilized specialist vessel, the firm is having to aggressively build up its fleet to meet demand.

"We knew it (the *Q4000*, delivered in 2002) would be required eventually," Kratz says. "Once you go deep, the only way to develop is with subsea wells and if you have subsea wells you would have to be able to access them. That's why we started to position ourselves in deep water, but it was way too early."

Others see the opportunity too. "There are a lot of people trying to figure out how to use it," he says. "There is a lot of reinventing the wheel. We have had the dubious honor of learning from mistakes over the last 20 years." OE

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- ☐ 02 Engineering or Engineering Mgmt.
- ☐ 03 Operations Management
- ☐ 04 Geology, Geophysics, Exploration
- ☐ 05 Operations (All other operations personnel, Dept. Heads, Supv., Coord. and Mgrs.)
- ☐ 99 Other *(please specify)*________________

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

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

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

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

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

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

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Numerology

180,000 The production rate, in bo/d, of Petrobras' P-62 FPSO, located in the Campos basin. See page 16.

1500kg The payload capacity of Robotic Drilling Solutions' prototype fully-electric robot. See page 34.

-40°C is the low end of the temperature range in which gas sensors can operate. See page 30.

139FPUs are projected to be installed between 2014-2018, Douglas-Westwood projects. See page 66.

20-40 The percentage of oil recovered from a reservoir, according to the US DOE. See page 46.

75MMbo/d

is the total amount of crude oil produced worldwide. See page 50.

2850AHTV are estimated to be currently operating *(Source: Offshore Support Vessels and Mobile Rigs: Global Prospects to 2025).* See page 70.

22,000tonne The weight of the Shwe jacket in the Bay of Bengal, Myanmar. *Photo from Dockwise.* See page 62.

12-14 months The long-lead MPD infrastructure was permanently built into the rig, enabling it to rapidly transition from "open to atmosphere with RGH" to full MPD capability, **sparing 12-14 months in future rig up time.** ***(Source: Weatherford)***
See page 9.
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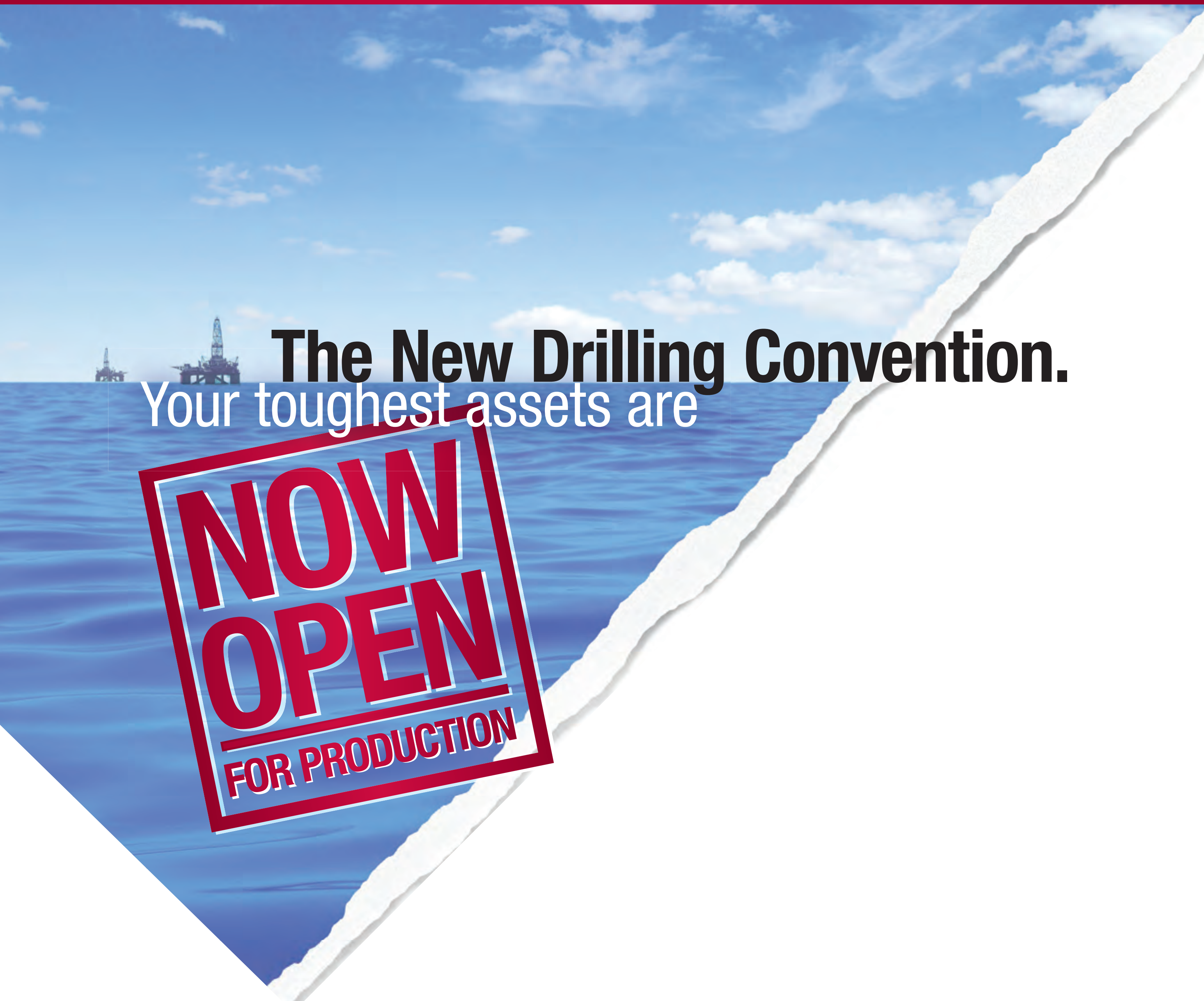

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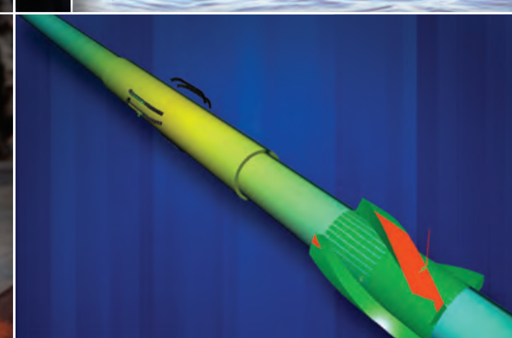
DUAL-REAMER RATHOLE ELIMINATION SYSTEM



i-DRILL system design ensures reamer placement does not interfere with RSS directional capabilities.

Dual-reamer system enlarges rathole, avoids a run, and saves 16 hours on a deepwater rig.

Rhino RHE rathole elimination system enlarged 178 ft of rathole while drilling a deepwater well in the Gulf of Mexico, saving 16 hours of rig time. The Rhino RHE system's dual-reamer process uses a hydraulically actuated reamer positioned above the MLWD tools to open the pilot hole and an on-demand reamer located near the bit to enlarge the rathole. The dual-reamer system eliminated a dedicated rathole cleanout run.

Read the case study at

slb.com/RhinoRHE

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