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Gulf of Mexico

page 70

- **GoM major projects**
- **Offshore crane update**

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Feature

Asset Integrity

ON THE COVER

Taking care of business. Kiewit Offshore Services is hosting several large projects this year at its Ingleside, Texas yard, including Anadarko's Lucius truss spar, which is under construction. Shell's Olympus TLP set sail to Mars B field in July. The rigs pictured on the cover will eventually find their way to Chevron's Big Foot and Jack/St. Malo developments in the US Gulf of Mexico.

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Volume 38, Number 10 October 2013

Departments & Columns

OE Review

DEEPWATER INTERVENTION

OFFSHORE EUROPE REVIEW

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BPA WORLDWIDE BUSINESS

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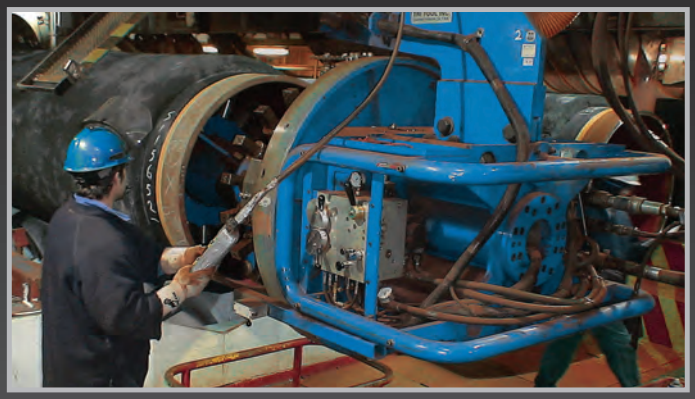

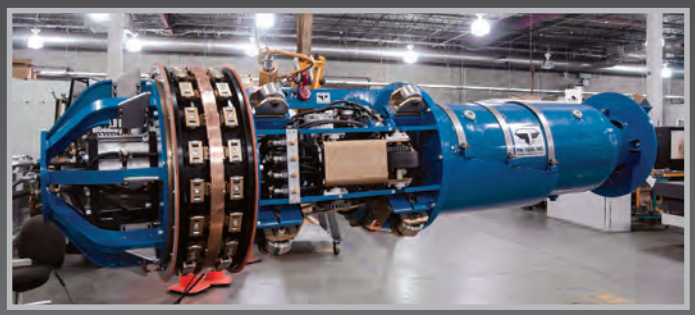

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Myths and misperceptions on RLWI

Various myths and misperceptions surround riserless light well interventions (RLWI) preventing operators from performing these cost-efficient, production enhancing maintenance operations on their subsea wells.

What's Trending

Petrobras talks tech investments

Petrobras President Maria das Graças Silva Foster announced at public hearing in the Brazilian Senate that the company plans to invest R$4 billion in 2013 and R$21.2 billion between 2013-2017 in information technology and telecommunications.

People

The Obama administration selected Coast Guard veteran Brian Salerno as director of the US Bureau of Safety and Environmental Enforcement (BSEE).

Photo: U.S. Coast Guard photo by Petty Officer 2nd Class Etta Smith.

Offshore Europe Review

Online Exclusive

This year's SPE Offshore Europe in Aberdeen was the most successful yet, with more than 63,000 people walking through the exhibition hall and conference doors. As the official media partner for the event over the past 30 years, OE once again produced the show daily from our booth. To see the highlights, look out for our official digital show review, due out mid-October.

Special Content

OE Review: Deepwater Intervention

The global deepwater intervention arena is expected to experience incredible growth over the next few years as more and more wells are drilled and current subsea assets mature. OE examines applied intervention technologies in this and next month's issue. See more on page 77!

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Voices

Regulatory update. Crane rules were updated in August; OE asked,

"How will the US Coast Guard's new rules on offshore cranes affect business in the Gulf?"

The proposed rule's incorporation of API's robust industry standards will ensure that businesses are using safe and proven technologies to design, build, and use offshore cranes. In doing so, the rules will further enhance the safety of America's oil and natural gas industry, which has been a bright spot in our economy and put the US on a solid path toward domestic energy security.

Holly Hopkins,
Senior Policy Advisor,
American Petroleum Institute

It is not clear that the proposed rule will have a significant impact on MODU's, OSV's and floating offshore facilities since the newer specifications and standards for cranes the rule seeks to adopt are already in wide use – although expanding the number of crane certifying organizations as proposed by the Coast Guard should be a helpful change and seems to have worked well with respect to other types of vessels.

Charlie Papavizas,
Partner, Chair, Maritime Practice,
Winston & Strawn LLP

Since [the Coast Guard is] incorporating industry standards that have presumably been used by most of the industry to purchase their equipment, it should have minimal effect.

Alan Spackman
Vice President, Offshore
International Association of Drilling Contractors

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

Nina Rach

Colloquy

Eyes around the North Sea

Many stakeholder programs benefit from oil industry funding and local community approval gives oil companies a social license to operate. Just before the Offshore Europe conference in Aberdeen, I discovered the deep industry connections of the North Sea Bird Club (NSBC).

The first wells were drilled off the UK coast in the 1960s and were almost immediately followed by reports from keen British birders working on the rigs. What started as a pastime, grew into a constructive data collection program with the approval and support of North Sea operators.

The precursor to the NSBC was a monitoring program started by a single oil company in 1971 to record offshore bird sightings on data forms. After collating the data for a few years, it became apparent that migrating land birds were using offshore facilities as staging posts, and that the collected information would be useful in studying bird movements.

The North Sea Bird Club was established in 1979, by a few individuals in the oil industry and at Aberdeen University, who "saw a unique opportunity" to obtain offshore data on birds and other wildlife. NSBC was initially sponsored by eight companies and received data from 41 installations along the coast.

The NSBC issues a bulletin, *The Fulmar*, from its office at the University of Aberdeen's Ocean Laboratory and Centre for Ecology in Newburgh, about 15 miles north of Aberdeen, at the mouth of the River Ythan.

The stated aims of the NSBC are to:

- Provide a recreational pursuit for people employed offshore
- Obtain, collate and analyze observations of all birds seen offshore
- Produce reports of observations and an annual report
- Promote the collection of data on other wildlife offshore.

It would be nice to see this offshore initiative take flight in the Gulf of Mexico and other areas.

The Club is financed by 10 corporate sponsors: BG Group, Total E&P UK Plc, Chevron, Centrica Energy, Marathon Oil (UK) Ltd.; ConocoPhillips, Talisman Energy (UK) Ltd.; Shell Exploration and Production, Europe; and TAQA Bratani Ltd.

NSBC developed a "Guidance for Observers" booklet with advice for offshore workers about keeping records of sightings and guidance on all aspects of wildlife offshore.

NSBC has amassed more than 120,000 records of birds, cetaceans, and insects reported since 1979. Over the decades, the NSBC data has shown that British land birds travel much farther than previously thought.

Early reports

In August 1990, Reuters' Ron Askew reported that North Sea oil rigs "swarm with birds," and that the 200 oil installations in the British North Sea "make a unique network of observatories for studying their movements." Bird watching is a natural recreation during long offshore shifts, and he cited offshore UK fields named for birds: Fulmar, Tern, and Dunlin.

The NSBC recorder in 1990, Sandy Anderson, said that in the club's first decade, its 500 members (roustabouts, engineers, medics, and radio operators) recorded sightings of 206 different bird species offshore, including rarities and even birds underwater.

—A Black-billed Cuckoo seen on an oil rig 180 miles east of Aberdeen was the first British sighting of the species.

—The pilot of an inspection ROV reported: "At a depth of 130m (430 ft), and later at 140m (460 ft), we observed a bird swimming. At first we thought it was a Guillemot, but the shape of the bill later led us to believe it was a Razorbill."

In November 1991, four authors from the University of Aberdeen presented a paper at an SPE HSE conference in The Hague: "The North Sea Bird Club: Ten Years of Recording in the North Sea."

"All over Britain, at strategic points on the coastline, there are bird observatories which record the arrival and departure of migrating birds. The presence of several hundred solid structures up and down the North Sea, which are used by birds en route, represents a huge, unique bird observatory, capable of uncovering facts about bird migration which have long eluded land-based scientists."

Occasionally, birds recovered from UK platforms have been sent ashore via helicopter, such as the Scops Owl found stranded on the Forties Delta platform, 110 miles ENE of Aberdeen, in June 2004.

More recently, in mid-September, a TAQA Bratani observer reported two Great Spotted Woodpeckers on the Tern Alpha platform, raising hope that outdoor activities remain attractive, despite the allure of online pursuits. It would be nice to see this offshore initiative take flight in the Gulf of Mexico and other areas. OE

More: http://abdn.ac.uk/nsbc/

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ThoughtStream

Rear Admiral Wendi B. Carpenter

US maritime strategy:
A time for new beginnings

The imperative for a holistic United States maritime strategy has never been greater. The National Strategy for the Marine Transportation System was published in July 2008 by the previous administration. The White House, the Congress, and the maritime industry should collectively and collaboratively address the ever more pressing need for a national maritime strategy and pass long-overdue legislation to reinvigorate the maritime industry. Key areas include domestic and international commerce, maritime security, marine environmental policy, workforce development, maritime education and training funding, and strengthening our American merchant marine.

All of these intersect with actions, which must also be taken to ensure the strength of our entire transportation industry across intermodal networks, so that we generate the right capability through balanced, long-term investment in infrastructure, technology, the environment, and education. With planned and focused effort, we will generate capability, and while doing so, promote short and long term employment opportunities across various industries, benefiting the economic vitality of the nation and extending positive second and third order effects, including increased tax revenues.

Working closely with US Department of Transportation (DOT) and the Marine Administration (MARAD), a high-level working group should be convened from a broad cross section of individuals such as key members of Congress, leaders from the US maritime industry, labor, US Deparments of Defense (DOD) and Homeland Security, as well other industry experts and educators to develop maritime strategy, policy with executable action plans, and legislation. The Committee on the Marine Transportation System should be widened to include stakeholders from outside of the government and so serve as a central board for the long-term development and oversight of a full-scale effort.

The Jones Act must also be shored-up to properly support our domestic maritime industry – all essential components of national security and capability.

90% of global commerce moves by sea. The sufficiency of the mariner pool to support a large-scale activation of DOD and DOT sealift fleet depends on the health and size of the US-flagged commercial fleet. History has repeatedly proven it is in the best interest of the US to maintain and support a strong active, competitive, and military useful, privately-owned US flag merchant marine. Sealift is the primary means for deploying most of the combat equipment and sustainment for ground forces.

More than 40,000 American vessels of various types, built in American shipyards and crewed by American mariners, operate in US waters in different segments of the industry such as offshore, coastal, inland, and western rivers. The Jones Act results in nearly 500,000 jobs, $29 billion in labor compensation, and more than $100 billion in annual economic output, according to a study by PricewaterhouseCoopers for the Transportation Institute.

The privately owned and operated US merchant marine is responsible for one-third of the shipbuilding industry's activities. The Jones Act ensures that our nation maintains a shipbuilding and repair industry that directly supports over 28,000 jobs in the United States and is capable of building ships domestically for national defense.

We live in uncertain times. In our many US ports and miles of inland rivers and waterways, as well as in the global commons, our merchant mariners are truly a first line of defense, not only transporting economically essential goods and services, but acting as the watchful eyes and ears of security in these vital areas.

Environmental standards, liability, safety, and enforcement are improved by having American-owned vessels and US citizen-crews responsible for safely delivering the goods along our nation's waterways.

Our hope for the future lies in ensuring that the White House will, with the support of the new team at DOT and MARAD, immediately work for creation and implementation of this historic maritime planning team. It is up to us to encourage Congress to support and work ever more closely with leaders of the American maritime industry to create "THE" comprehensive maritime strategy and pass legislation that will not only support, but also spur further growth in our industry The time to act is now. OE

Rear Admiral (ret.) Wendi B. Carpenter *is president of SUNY Maritime College in Bronx, New York. She is a 30-year Navy veteran, having previously served as the commander of the Navy's Warfare Development Command. In 2005, Carpenter became the Navy's first woman aviator promoted to the rank of admiral.*

Initially published in the July 2013 edition of *MarineNews* - www.marinelink.com

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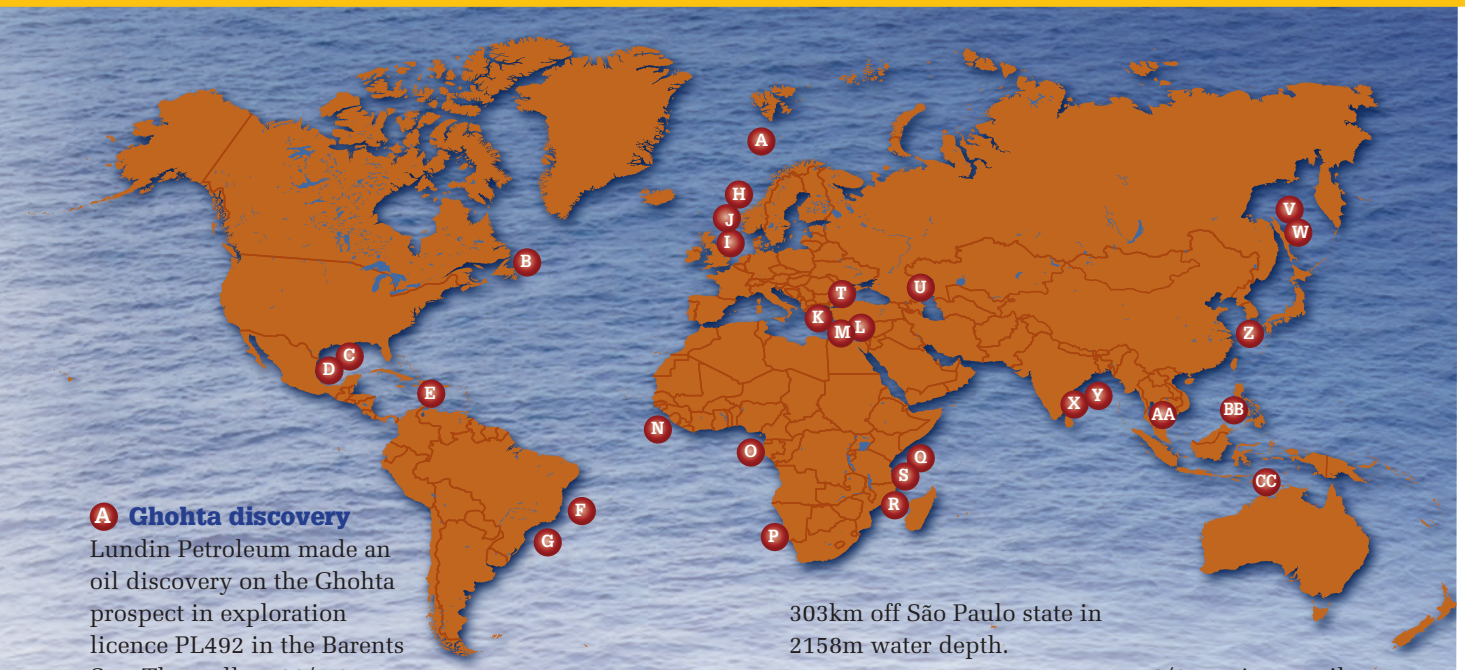

A Ghohta discovery

Lundin Petroleum made an oil discovery on the Ghohta prospect in exploration licence PL492 in the Barents Sea. The well, 7120/1-3, 35km northwest of Snøhvit field, found a 75m oil column in Permian carbonates.

B Statoil strikes oil

Statoil has made a third oil discovery in the Flemish Pass basin, offshore Newfoundland on the Bay du Nord prospect (EL1112), about 500km northeast of St. John's, Newfoundland.

C W&T Offshore subsalt

W&T Offshore, Inc. made a subsalt discovery in a deep-shelf, target beneath its Ship Shoal 349 Mahogany field. The SS 359 A-14 well is producing from the T-sand (in excess of 17,200ft TVD), at an initial flow back rate of 3,030bo/d and 5.6 Mcf/d of gas with 9,400 psi FTP.

D Shell hits pay

Shell found a 36m oil-bearing zone at its Yucatan North-1 exploration well in Walker Ridge 95/96/139/140 blocks, US Gulf of Mexico, 280km south of New Orleans, Louisiana. The well was drilled to 9500m TD.

E PDVSA, Chevron partners

Venezuela and Trinidad and Tobago announced that the Petróleos de Venezuela in partnership with Chevron will concentrate on the Loran-Manatee field (10Tcf reserves), on Venezuela and Trinidad-Tobago's borders.

F QGEP discovery

Queiroz Galvão Exploração e Produção S.A. (QGEP) filed a Notice of Discovery with ANP for well 1-QG-5A-BAS, in block BM-J-2 in the Jequitinhonha Basin off Brazil.

G Petrobras strikes oil

Petrobras found oil in well 3-SPS-101 in the Carioca Discovery Evaluation Plan area, block BM-S-9, Santos Basin pre-salt. The well, Iguaçu Mirim, is located 303km off São Paulo state in 2158m water depth.

H Svale North oil

Statoil, with partners Petoro AS and Eni Norge in PL128, made an oil discovery at well 6608/10-15, Svale North prospect, Norwegian Sea, 9km northeast of Norne field. The well was drilled by the Songa Trym semisubmersible.

I Tolmount gas

E.ON made a gas discovery in block 42/28d in UK's southern North Sea. The Tolmount discovery, 40km off East Yorkshire, encountered a 200ft gas column in the Leman sandstone and test flowed at a maximum stable rate of 50MMcf/d. E.ON said reserves are up to 16Bcm.

J Statoil oil discovery

Exploration well 16/2-18S, located on Statoil-operated PL265 in the North Sea, was drilled west of Johan Sverdrup discovery, about 9km west of well 16/2-6 and 3 km west of appraisal well 16/2-14. A 15m oil zone was proven. The well was drilled to 1,948m TD below mean sea level.

K Croatian survey

Spectrum will acquire 2D seismic off Croatia ahead of the country's latest licensing round, using Seabird Exploration to gather about 12,000km of long-offset seismic data. Acquisition will complete in 4Q 2013.

L Tamar drilling

Drilling on the South West Tamar prospect, off Israel, is due to start late September. A budget of US$122 million has been approved, excluding production tests. The best estimate of the undiscovered resources is 684Bcf at a 90% probability of success.

M Egyptian gas

BP announced a deepwater gas discovery in the East Nile Delta off Egypt. Gas and condensate were found in

honouring the past,
shaping the future

Allseas

38m net of Oligocene sands. The well, Salamat, is 75km north of Damietta and was drilled in 649m water depth, using the *Maersk Discoverer* semisubmersible.

N Lukoil spuds well

Lukoil is drilling the Savannah prospect on Block SL-5-11, using the *Eirik Raude* semisubmersible, in 2000m water depth. off Sierra Leone. Block SL-5-11 covers 4022sq km in Atlantic Ocean. Lukoil holds 49%, Oranto (Nigeria) has 30%, and PanAtlantic has 21%.

O Gabon discovery

Total found gas and condensate at its Diaman-1B well off Gabon. The well, in the Diaba block, was drilled to 5585m TD, finding 50-55m of net hydrocarbons in pre-salt formations. The well, is in 1729m of water, more than 100km off the coast.

P HRT duster

HRT Participações em Petróleo S.A. announced that the Moosehead-1 well, is a dry hole. The Moosehead prospect is in PEL-24, in the Orange basin, off Namibia. The well encountered about 100m of carbonates. Wet gas shows were encountered.

Q FAR Ltd., Ophir JV

FAR Ltd. completed negotiations on joint venture agreements with Ophir Energy PLC on offshore Kenya exploration permit Block L9. Block L9 is a large permit in the heart of the Lamu basin. A series of 2D and 3D seismic surveys have identified several oil and gas prospects and leads with prospective resource volumes in excess of 300 Mmb/o (unrisked best estimate, 100% basis).

R Eni discovery

Eni has made a discovery at Agulha exploration prospect, in Area 4, off Mozambique, opening a new exploration play in the southern part of Area 4. Preliminary estimates show that the structure could contain 5 to 7Tcf of gas in place. The well was drilled in 2,492m of water and reached 6,203m TD.

S Tanzania appraisal

BG Group's completed appraisal drilling of the Pweza-2 well in Block 4, 2km south of the Pweza-1 discovery, using the *DeepSea Metro 1* drillship. This well confirms a 1.7Tcf gross recoverable resource estimate for the Pweza field.

T Romanian drilling

Petroceltic International launched a drilling campaign in the Romanian Black Sea. The campaign started with the Cobalcescu South well using the *GSP Prometeu* jackup. The well is about 170km northeast of Constanta, in the south-west corner of Block EX-28 in 90m water depth. The planned total depth for the well is 3100m.

U Kashagan produces

The North Caspian Operating Co., on behalf of the North Caspian Sea PSA consortium, said the first well was opened and the initial volumes of oil are being produced from the Kashagan field. The first phase of production is from eight wells. Production will be progressively ramped up to the design capacity from 180,000b/d in the first stage, and up to 370,000b/d in the second stage.

V Russia offers blocks

The Russian Federation's Ministry of Natural Resources offered nineteen

new blocks for exploration and production in August, including the Amur-Limanskiy block and Vostochno-Pribrezhnyy blocks in the Sea of Okhotsk. The blocks will be offered for 25 years of exploration and production.

W Rosneft seismic

Rosneft began seismic acquisition over license blocks Lisyansky, Kashevarovsky, and Magadan-1 in the Sea of Okhotsk off Russia. The company is gathering 2D seismic along with a gravity and magnetic survey, using the *Academik Fersman* seismic vessel. The program will cover 10,000km: 5300km on the Lisyansky block, 2000km on the Kashevarovsky block, and 2700km on Magadan-1.

X Deepwater gas

Reliance Industries and BP have made a second deepwater gas condensate discovery in the Cauvery basin off India. The discovery was made in well CYIIID5-S1 on Block CY-DWN-2001/2, in 1743m water depth, 62km off the coast.

Y ONGC discovery

India's Oil & Natural Gas Corp. announced a discovery in block KG-OSN-2004/1, about 21km south of Narasapur, on India's east coast.

Exploratory well KGOSN041NANL-2 flowed gas at 66,601cu m/d through 1/4in. choke. This is the fourth discovery in the block, after Chandrika South, Alankari, and Saveri.

Z Petronas' FLNG

The Kanowit FLNG facility is under construction at Daewoo Shipbuilding & Marine Engineering (DSME) in Okpo, South Korea. The unit is for the Kanowit gas field off Sarawak, Malaysia. The FLNG will be 300m long, 60m wide, and will be moored 180km (112mi.) offshore Bintulu.

It is designed to produce 1.2 million tonne/yr of LNG, boosting Malaysia's total LNG production capacity from 25.7-26.9 million tonne/yr.

AA Salamander hits oil

Salamander Energy encountered oil at its G4/50-5 exploration well in the Surin prospect in the central portion of the Western sub-basin, Block G4/50, in the Gulf of Thailand. Oil was discovered in Miocene fluvial sandstones in the N40 zone from 1525-1533m TVDSS. Oil samples indicate 31° API oil.The well was drilled using the *Atwood Mako* jackup.

BB Otto drilling

Otto Energy Ltd. is drilling two horizontal wells in the second phase of development at Galoc field in SC14C in 290m of water off the Philippines. The wells are being batch drilled in 311 m of water. After drilling, the DOF-operated *Skandia Hercules* construction vessel will install subsea equipment and hook-up both wells to the FPSO *Rubicon Intrepid*.

CC Eni Australia plans

Eni's Australian division, announced that the company plans to spend up to US$230 million drilling in the Timor Sea over the next 18 months. Operations will take place in the Evans Shoal area, the Blackwood area, the Kitan area, in deepwater Timor-Leste, in the Vesta-Swan area, and the Blacktip field.

Contract Briefs

Subsea 7 on Cardona

Subsea 7 was awarded a contract worth more than US$70 million by Stone Energy for Cardona field in the US GOM. Scope includes engineering, procurement, installation, and flowlines commissioning, risers, pipeline structures, and a gas-lift umbilical.

Technip wins Stones

Shell picked Technip to provide engineering, procurement, and installation services covering subsea infrastructure at Stones field in the US Gulf of Mexico. The scope includes installation of the subsea production system and lateral gas pipeline, inclusive of project management, engineering, and stalk fabrication.

Rowan wins Cobalt

Rowan Companies entered into a three-year contract with Cobalt International Energy, L.P. for the *Rowan Reliance*, a new ultra-deepwater drillship under construction at the Hyundai Heavy Industries Co. Ltd. shipyard in Ulsan, South Korea. Delivery is scheduled for October 2014.

Parque das Conchas win

Shell awarded a contract to FMC Technologies to supply subsea systems for the Parque das Conchas Phase 3 development off Brazil. FMC's scope includes seven subsea trees, two manifolds, and associated subsea control systems; tie-in connection systems, subsea distribution hardware, tooling, and services.

Almaco quarters

Estaleiro Enseada do Paraguaçu (EEP) awarded ALMACO Group a contract for the living quarters on six drillships to be used in the Brazilian pre-salt drilling program. Design and fabrication starts in 2013 with the sixth drillship to be completed in 2019.

OneSubsea on Quad 204

OneSubsea has been awarded a £65 million contract to manufacture subsea trees for BP's West of Shetland Quad 204 project. This redevelopment of Schiehallion and Loyal fields involves a new FPSO and a major upgrade to subsea infrastructure.

Bumi Armada win

Bumi Armada Caspian LLC signed a supplementary agreement worth RM567.6 million (US$178.5 million) with OOO LUKOIL-Nizhnevolzhskneft for engineering, procurement, installation and pre-commissioning (EPIC) work in the Caspian Sea's Russian sector.

TWMA lands processing

TWMA was awarded an offshore processing contract in Angola.

The agreement, worth up to US$35million, will see TWMA take the concept through design, installation, and operation of a system onboard a newbuild drillship.

EMAS wins pipelines

EMAS Amc was awarded a contract by VAALCO Gabon, for the expansion of the Etame Marin Field off Gabon, Africa. The EPIC scope encompasses rigid pipelines along with the transportation and installation of flexible pipelines and two fixed production platforms. The contract is worth about US$120 million.

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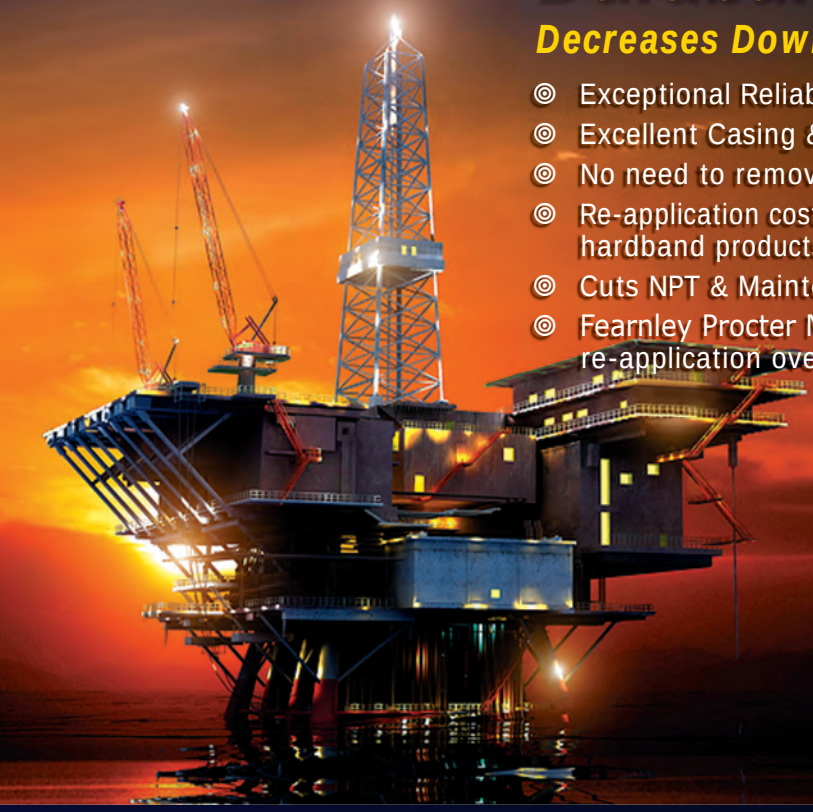

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Corporate foreign policy

Developing economies continue to be a core feature of global exploration efforts. Dr. Peter Davis looks at managing political, societal and ethical risks in such regions.

As Dick Cheney once observed, "the good Lord didn't see fit to put oil and gas only where there are democratically elected regimes friendly to the United States."

As extractive companies increasingly find themselves exploring business opportunities in—to quote Dick again—"places where, all things considered, one would not normally choose to go," they find themselves facing a raft of new and unfamiliar challenges.

Most obvious is political stability—quite simply, is the person or government with whom a deal was transacted likely to remain in place? If not, is a likely successor minister or government likely to honor the deals already in place? However, even if a government is stable, and legal, other structures may not be in place.

Regulatory frameworks will often be challenging; in the Democratic Republic of Congo (DRC), for example, mining regulations are virtually non-existent. Similarly, rule of law may be weak, and so contracts and other legal frameworks may not be enforceable in practice.

Getting these issues wrong can be very costly. First Quantum owned the Kolwezi copper and cobalt tailings project in south-eastern DRC. The company had spent a reported US$430 million preparing the commercial production. In early 2010, the company's licence was revoked for rather murky political reasons.

A country's ethical and social norms, ethnicity and religion, also pose challenges. What are the relationships and tensions between different groups? Is it possible to operate to international standards in relation to health and safety?

Is corruption a concern, and if so how can an investor avoid activities that may, for example, lead to prosecution under the US Foreign Corrupt Practices Act? Do local norms disadvantage women, specific ethnic groups, or other elements of society?

Finally, companies have to deal with problems associated with infrastructure. Transport links can often be poor or non-existent, outside major urban centres, and power supplies can be erratic. "Soft" infrastructure will frequently be problematic—in many

BP and Statoil review Algerian security

Dealing security risk, even in more developed countries, was brought into stark light following the January 16 attack on the BP/Statoil operated In Amenas gas plant in Algeria.

Forty people were killed in the attack. Statoil, five of whose workers were among the dead, said in a report, published in September, neither it nor BP could have prevented the attack, but questioned both firms' reliance on Algerian military protection, which had not detected or prevented the incident.

It also said security measures at the site were not constructed to withstand or delay an attack of the scale that occurred.

Statoil has established a security risk management system, but, it says: "The company's overall capabilities and culture must be strengthened to respond to the security risks associated with operations in volatile and complex environments."

Photo: Øyvind Hagen - Statoil

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	2010	2011	2012	2013
Shallow (<500m)	93	105	74	32
Deep (500-1500m)	28	25	23	10
Ultradeep (>1500m)	36	20	34	19
Total	157	150	131	61

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 2013-17

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	22	1,721.75	980.00
Deep	16	3,257.00	2,255.00
Ultradeep	40	12,428.45	17,340.00
United States			
Shallow	27	108.30	1,186.50
Deep	23	1,378.71	1,624.87
Ultradeep	26	3,019.00	3,440.00
West Africa			
Shallow	148	3,416.55	18,047.59
Deep	46	5,454.00	6,320.00
Ultradeep	14	1,900.00	2,650.00
Total (last month)	362 (356)	32,683.76 (32,562.41)	53,843.96 (53,703.96)

Greenfield reserves

2013-17

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow (last month)	1,271 (1,284)	75,101.59 (75,600.19)	813,262.02 (824,193.58)
Deep (last month)	161 (160)	13,657.58 (13,654.58)	80,626.57 (80,326.57)
Ultradeep (last month)	98 (97)	17,551.45 (17,746.45)	66,747.00 (66,847.00)
Total	1,530	106,310.62	960,635.59

Pipelines

(operational and 2013 onwards)

	(km)	(last month)
<8in		
Operational/ installed	41,886	(41,860)
Planned/ possible	24,998	(23,721)
	66,884	(65,581)
8-16in		
Operational/ installed	77,601	(77,688)
Planned/ possible	48,127	(47,837)
	125,728	(125,525)
>16in		
Operational/ installed	89,139	(89,110)
Planned/ possible	48,392	(50,241)
	137,531	(139,351)

Production systems worldwide

(operational and 2013 onwards)

Floaters		(last month)
Operational	273	(277)
Under development	50	(48)
Planned/possible	321	(313)
	644	(638)
Fixed platforms		
Operational	9,688	(9,655)
Under development	138	(145)
Planned/possible	1,465	(1,467)
	11,291	(11,267)
Subsea wells		
Operational	4,385	(4,416)
Under development	410	(411)
Planned/possible	6,197	(6,007)
	10,992	(10,834)

Global offshore reserves (mmboe) onstream by water depth

	2011	2012	2013	2014	2015	2016	2017
Shallow (last month)	10,467.31 (10,471.06)	5,996.47 (6,006.89)	65,183.42 (65,246.75)	29,947.35 (30,610.38)	36,875.97 (36,880.04)	34,291.26 (34,931.09)	52,732.53 (53,788.13)
Deep (last month)	1,312.21 (1,312.21)	1,735.15 (1,735.15)	3,387.61 (3,528.61)	5,710.92 (5,788.99)	4,363.91 (4,144.84)	5,106.65 (5,282.95)	9,303.17 (9,070.98)
Ultradeep (last month)	199.94 (199.94)	737.15 (737.15)	3,243.07 (3,243.07)	2,922.43 (2,922.43)	2,004.29 (1,907.54)	5,678.49 (5,669.67)	15,528.97 (15,789.23)
Total	11,979.47	8,468.77	71,814.10	38,580.70	43,244.17	45,076.40	77,564.67

16 September 2013

countries weak education systems fail to provide companies with adequately-trained potential employees. Commercial and other links, in order to access local goods and services, may also be absent.

Emerging good practice

Operating in countries like this is not new. Those companies who have been doing it for a long time have developed ways of dealing with the challenges they face.

Anglo American, for example, has developed a socio-economic assessment tool (SEAT) to increase site managers' understanding of the needs and priorities of local stakeholders and of their social and economic impacts.

Notwithstanding the difficulties they have recently experienced in America, BP has been a leader in understanding and managing its impacts in emerging economies. In Azerbaijan, for instance, the company invested in a business development center to develop local businesses capable of providing goods and services for BP's operations.

At a global level, approaches have been developed to help companies address issues they face in emerging markets. The Extractive Industries Transparency Initiative was developed to deal with corruption in payments by extractive companies to governments. The Voluntary Principles on Security and Human Rights provides companies with guidance on the use of security forces at their sites.

Corporate foreign policy (CFP) and socio-economic due diligence

There is still a need for a more systematic approach—to place the understanding and management of social, political and ethical issues on an equal footing with more "traditional" issues, such as technical solutions, legal structures and financing, when planning and implementing new country strategies.

In developing new operations, companies are very familiar with due diligence. Yet, why is there no analogous process of socio-economic due diligence? It is at least as likely, probably *more* likely, that a venture in a developing country will be derailed by a problem emanating from local societal issues than from any other cause.

The starting point is to understand the context of the country in which a new operation is planned. Companies do not have to start from scratch. Bilateral and multilateral donor agencies, such as the US Agency for International Development, or the British Department for International Development, will have detailed country plans based on analysis of the country's needs.

The next step is to assess what the likely impact of a country's development challenges will have. Questions might include:

How might a poor skills base in the country hinder potential for expansion?

How might procurement processes or hiring strategies perpetuate labor abuses, gender inequalities and ethnic tensions?

How might a company operate in such a fashion as to support a domestic government's effort to reduce graft and corruption?

How might a lack of capacity in key government

ministries hinder an ability to obtain key approvals or licences for operations?

In what ways might security procedures need to be modified in order to take account of local tensions and efforts to manage them?

By asking questions like these, a company is able both to understand how the development context is relevant to its business, and formulate challenges that need to be addressed. Simply, a company can create a "to do" list of issues which need then to be addressed as part of day-to-day management processes.

The challenge of making CFP work

What stops CFP from being general practice among companies operating in emerging economies seems to be that companies' existing structures do not cope well with understanding and managing complex societal, ethical and political issues.

Many companies, especially those with a strong technological background, such as oil and gas operators and contractors, rely on quantitative systems and spreadsheets to manage their activities. When dealing with essentially qualitative issues, such as politics and society, this approach is not helpful.

Companies also need to consider the skills and aptitudes of their employees. Oil and gas companies generally hire and promote people on the basis of technical competences—be that as an engineer or project manager.

CFP requires people able to cope effectively with less tangible issues, and to take decisions on what will often be incomplete and imperfect information. Managing societal issues also requires the ability to deal effectively with very different and often challenging groups of people—tribal peoples or military forces, for example.

Companies therefore need to hire staff on the basis of their abilities in non-technical, as well as technical, disciplines. Furthermore they need to train and promote on the ability to manage societal relationships effectively, and see this set of skills as being as important as capabilities in other areas.

Developing economies are complicated places. Politics, religion, ethnicity, ethics, and history all conspire to create an environment difficult to understand and in which to operate. CFP, and the process of socio-economic due diligence, are designed to distill that complexity and identify the key challenges.

Companies operating, or seeking to operate in developing economies need to adopt this approach, and to prioritize the management of socio-economic issues, alongside the more usual technical and financial considerations. OE

Dr. Peter Davis *is a member of Henley Business School's visiting faculty. His research focuses on the role of multinational companies in conflict zones, and his book, Corporations, Global Governance and Post-Conflict Reconstruction, was recently published by Routledge. He was educated at the Universities of Oxford and London.*

Structural integrity management – from cradle to grave

Properly implemented, structural integrity management can provide structural integrity assurance from design to decommissioning, explains Mohammad Nabavian of Wood Group PSN.

The concept of structural integrity management (SIM) for offshore installations is maturing, underpinned by the need to assure the reliability of ever-aging infrastructure, cope with the demands of complex life extension projects, and cater for safe and successful decommissioning.

The systems and tools to support SIM need to be robust, practical, and flexible to adapt to what is known about the structure and account for its individual risk profile and ageing characteristics.

Development of SIM systems

Fixed offshore structures are typically designed using industry standard codes (ISO-19902, API, AISC). On the UK Continental Shelf, governmental regulations also play a part in the design process, ensuring hazards, such as the loss of structural integrity, loss of containments, and fires & explosions are identified, and appropriate mitigation measures put in place.

SIM systems can ensure longer term

Aging assets in mature basins like the North Sea means asset integrity is a key industry issue.

asset integrity, taking into account the operations, life extension, and decommissioning phases of the asset life cycle. Thus, a SIM system should be in place from the cradle-to-grave of an asset.

A robust SIM system is designed to ensure:

- Safety of those working offshore
- Continued production
- Protection of the environment
- Legislative compliance
- Industry best practice.

An integrated SIM system accounts for the development of inspection strategies, work scopes, inspection results reviews, and the maintenance of inspection record databases. It also makes for easier identification and management of defect assessments and the development of repair solutions for both topsides and subsea structures.

Change management is required when modifications are made to an installation, normally involving changes in the physical and operational parameters of the asset. These modifications should be designed with an understanding of the complete brownfield environment. At the heart of the SIM system is engineering competence.

Ageing assets

Driven by the UK Health and Safety Executive (HSE), Key Program 4 (KP4) is the next stage in the HSE's aging and life extension inspection program. This means operator's assets are regularly subject to scrutiny by independent safety inspectors to ensure standards are maintained according to UK regulations. The program, which was due to run until September 2013, has the potential to impact the way operators manage the structural integrity of their assets globally.

On average, more than 30% of nearly 7000 platforms in operation around the world have been in operation for more than 20 years. In the North Sea, more than 50% of assets fall into this category. With so many operating beyond their original design life, and yet more discoveries being made, operators are under pressure to extend the life of their offshore assets without compromising asset integrity, reliability, productivity, and more importantly, safety. KP4 is designed to stimulate a common industry approach to managing ageing installations that will ensure safe offshore operations for the long term.

The UK-HSE states that KP4 is not simply about how old an asset is, but about how it is ageing and what is known about that process.

Figure 1 shows a simple "bath tub" curve, which illustrates that, as aging mechanisms—corrosion, erosion, accumulated damage—take effect, there is an inevitable increase in the likely hood of failures occurring.

KP4 has focused operators to take responsibility for managing the risks associated with asset integrity and life extension projects through the use of SIM systems. Operators are also keen to increase the value of their assets, and a robust SIM system is seen as a part of achieving this. If this approach to structural integrity management was adopted globally, there is an opportunity to transfer SIM best practice from the North Sea to operating assets around the world.

Life extension

As assets age, trends show decreasing revenues and increased operational costs. Life extension projects and the implementation of an appropriate SIM system can counter these trends and increase the value and viability of an asset, Fig.2.

For example, asset value may be increased by enhanced oil recovery or tie-back projects, both of which would rely heavily on structural analysis to demonstrate additional capacity from the existing structure. Likewise, elements of operational expenditure could be optimized; such as subsea inspections targeted on critical components, if the behavior of the structure and its risk profile is understood.

Demonstrating the structural integrity of aging assets is of paramount importance when considering life extension. In Norway, an application for life extension is a formal requirement, and in the UK, a safety case must be reviewed when installation design life has been exceeded.

The effects of the *Deepwater Horizon* tragedy in the Gulf of Mexico led to an announcement by the Bureau of Ocean Energy Management, Regulation and Enforcement that all operations and drilling facilities on the outer

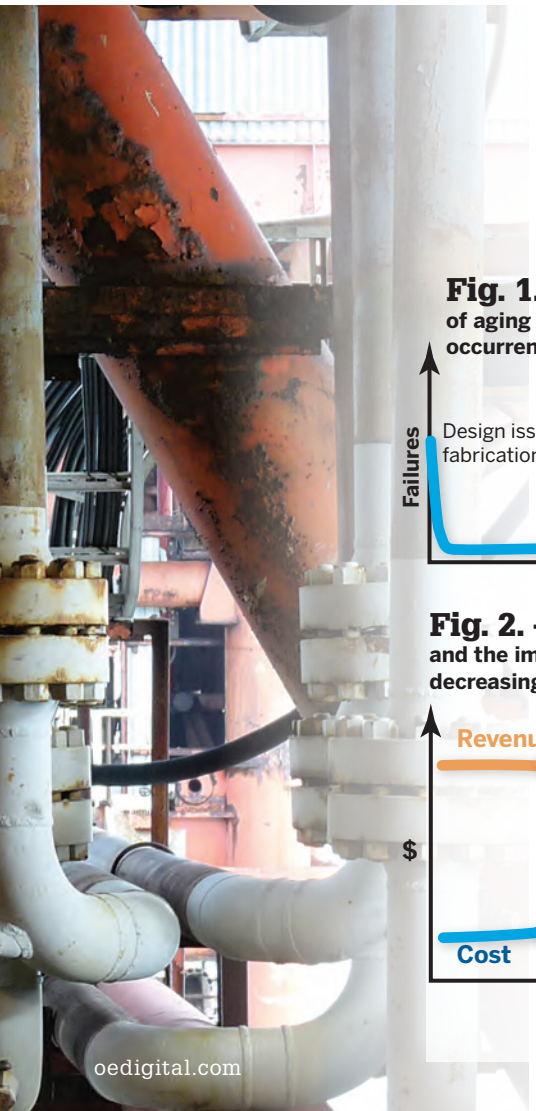


Fig. 1. – This "bath tub" curve of aging assets shows an inevitable increase in the occurrence of failures.

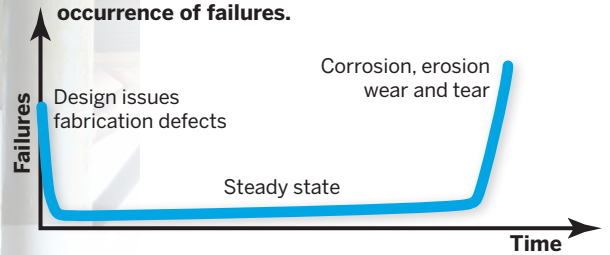


Fig. 2. – Life extension projects and the implementation of a SIM system can counter decreasing revenues and increasing operational costs.

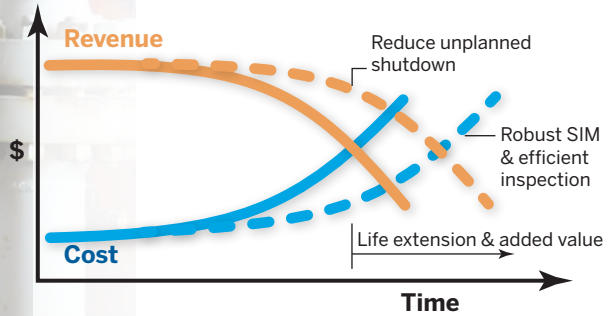
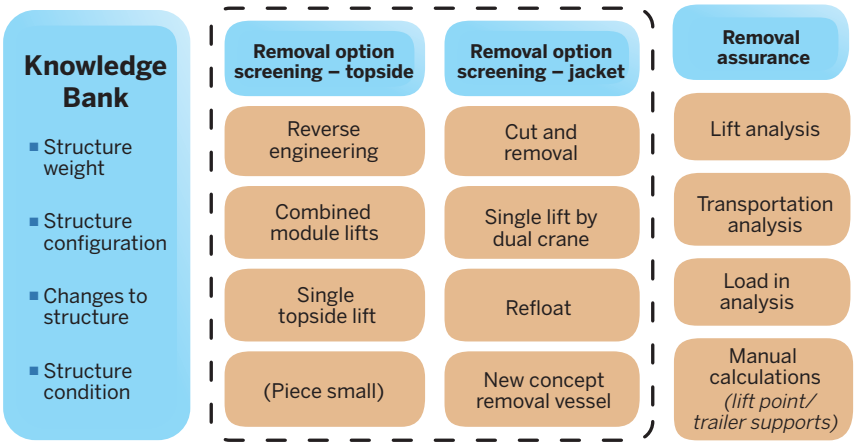


Fig 3. – For decommissioning, SIM is used to take into account the integrity of the topside and the jacket.



continental shelf would be required to develop and maintain a safety and environmental management system (SEMS). The SEMS final rule is designed to improve workplace safety offshore.

The rule will hold operators accountable for overall facility safety, including ensuring that all contractors and subcontractors have safety policies and procedures in place that support the implementation of the operator's SEMS program, and align with the principles of managing safety, set forth in API RP 75, the recommended practice for offshore oil, gas, and sulfur facilities and associated equipment.

Applying a SIM system can help operators manage these challenges, and ensure that the required systems and tools are available for asset life extension or demonstration of enhanced structural capacity beyond the original design values.

The realization of enhanced structural integrity can involve advanced structural analysis techniques such as:

- In-place assessments
- Reserve strength ratio (RSR) assessments
- Boat impact assessments
- Finite element analysis
- Dynamic and post-buckling assessments
- Blast assessments
- Fatigue/fracture mechanics
- Reliability assessments

There are various assessment triggers which can be used to inform the need for such analyses.

Decommissioning

The requirement for SIM does not stop at cessation of production. SIM plays a vital role in the safe and successful decommissioning of offshore infrastructure.

The SIM system provides a central location for platform knowledge, containing information about the structure, its weight, configuration, changes and modifications, and current condition. The retention and availability of this information forms a critical part of decommissioning planning. When considering removal options as part of the decommissioning process, SIM is used to take into account the integrity of the topside and the jacket, so options can be assessed according to the robustness of the structure for safe removal, transportation, and load-in, Fig. 3.

If effectively implemented and maintained, the SIM system is there to provide the required structural integrity assurance from design to complete decommissioning. OE

Mohammad Nabavian *is head of advanced integrity at Wood Group PSN. His experience includes design and analysis of new offshore structures for the North Sea, Middle-East, and deep waters of the Gulf of Mexico, as well as, appraisal of existing mature platforms, involving damage assessment and engineering beyond the confines of current codes. He earned an MSc and PhD from Cranfield University.*

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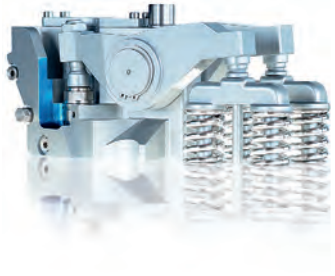

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Asset integrity – a global perspective

Atkins' Ramsay Fraser looks at offshore asset integrity assessment techniques and how acceptance criteria depend on geographic region.

Evaluation of the integrity of an offshore structure is one of the four key functions of an integrity management system – the others being acquisition and management of data; strategy for in-service inspection, mitigation and/or early decommissioning; and program for in-service inspection.

Evaluation requires assessment if an initiator is triggered, such as development projects on existing installations, when new metocean or geotechnical information becomes available and, for older assets, to ensure that degradation due to fatigue, corrosion, and seabed settlement from reservoir compaction is acceptable.

Development projects on fixed installations typically involve a significant increase in topside weight due to new process facilities together with increased wave load due to new risers or conductors.

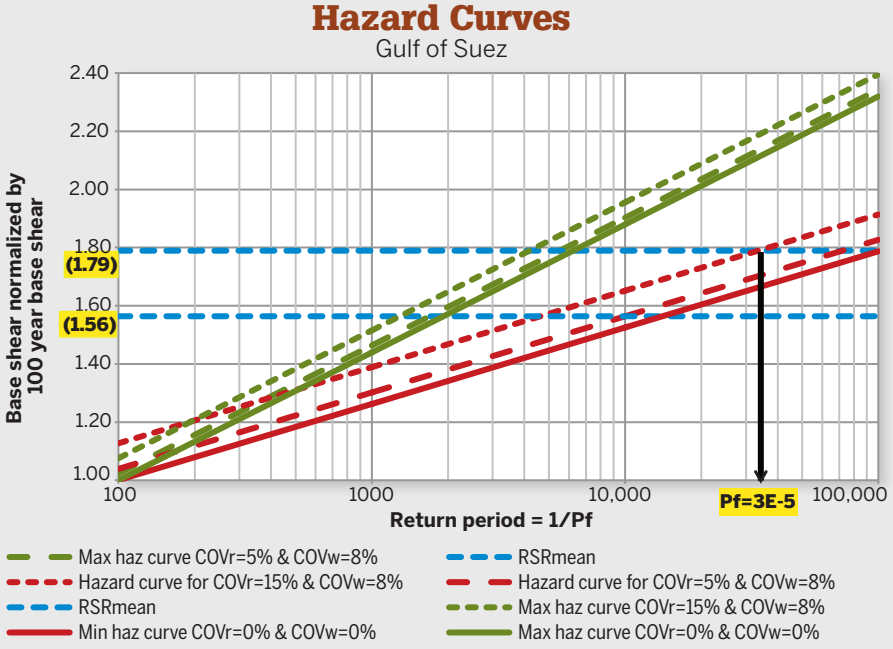
The quantity of metocean data and quality of data processing and modelling has increased significantly in some geographic regions and has resulted in greater awareness of higher assessed probability for wave-in-deck loads during extreme storms and appreciation of the implications of these higher probabilities.

While the assessed loads typically increase due to the above, the latest computer simulation techniques (such as ultimate strength analysis using software such as ABAQUS[1] with the critical components of the structure represented in detail and embedded within the model of the total structure (in order to provide the correct boundary conditions) usually demonstrate that the structure has greater capacity than shown using previously adopted techniques.

The ISO[2] and API standards for offshore structures are currently being updated and one of the outcomes is likely to be greater consistency in the assessment methodology and criteria required for the integrity of offshore structures in all regions of the globe.

Recent assessments of fixed offshore structures by Atkins in the North Sea, Gulf of Mexico, Arabian Gulf, Caspian Sea, and NW Shelf have indicated that to achieve greater consistency:

1) The industry needs to set acceptance criteria based on reliability studies, structural performance around the globe and experience. The criteria need to be straightforward and limited to linear and non-linear methods of analyses and software. Good guidance is required in the codes to allow most engineering contractors to do good work. This guidance should focus on the structural modelling; loading model and material behavior in component design versus system ultimate capacity checks.



Latest computer simulation techniques reveal the local failure mechanisms of an offshore structure when loads exceed the allowable levels.

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2) Engineers performing structural assessments require a deeper understanding of the assessment methods used by metocean consultants and geotechnical engineers.

The acceptance criteria for the safety level of an offshore structure have developed since the early API codes and in particular in the 1980s in the Gulf of Mexico and the 1990s in Europe.

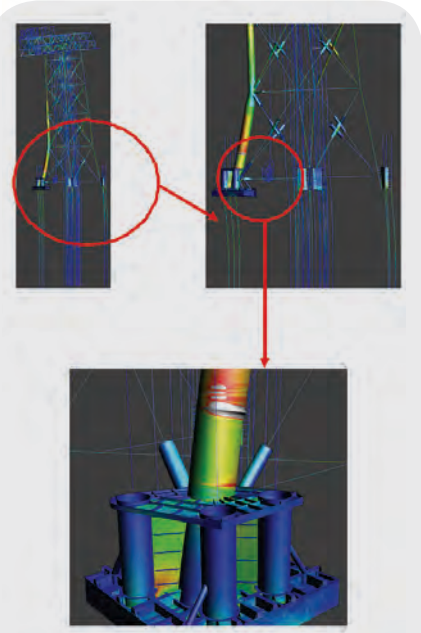
The 1980s developments came together under the umbrella of API in the early 1990s after Hurricane Andrew in 1992 and led to Section 17 being established in API for assessment of existing structures. The work was very focused on the Gulf where platforms are unmanned for the extreme events and for which therefore reduced criteria, based on economics are acceptable, since life safety was preserved. This is unique to the Gulf of Mexico and has often been misinterpreted and applied incorrectly in other parts of the world.

In the mid 1990s, Efthymiou et al[3] showed that different geographic regions have different probabilities of occurrence of an extreme storm load normalized by its 100 year storm load. Regions with fewer larger storms (e.g. cyclonic regions such as the North West shelf) have a greater probability of extreme load than regions with more sustained storm conditions such as the North Sea. The 1990s developments were incorporated in the 2007 publication of ISO 19902.

The ISO 19902 code allows three methods of capacity assessment:

a) DLA (Deign Level Assessment)
b) RSR (Reserve Strength Ratio)
c) SRA (Structural Reliability Assessment).

The DLA determines the forces on each component in the structure from a linear analysis (with non-linear pile-soil interaction) and compares these against the capacities in the code equations for each component and the regional specific load factor γ_E. The RSR determines the collapse capacity of the whole structural system (as a multiple of the 100-year storm load and using mean or best-estimate resistance) and compares against the code requirement. The SRA determines the return period for failure of the structural system (i.e. the reciprocal of annual probability of failure Pf) and compares against the code implicit probability of failure. Assessment by SRA is more structure specific and thus less conservative than the RSR method, which, in turn, is more structure specific and thus less conservative than the DLA method.



Hazard curves showing the relationship between γ_E (DLA), RSR and Pf (SRA) and a consistent level of safety across different geographic regions.

The acceptance criteria for all three methods depend on the geographical region of the installation. However, for a given geographical region, the acceptance criteria for the three methods are related. The (shifted exponential) probability density for the extreme storm load can be plotted as a hazard curve as shown in the figure below. The solid red line represents the hazard curve for the Northern North Sea (NNS) with no uncertainty in load or resistance i.e. it represents the probability of a storm of a given load magnitude occurring in any year at the installation location. The dashed red line represents the hazard curve for the NNS with uncertainty in the load given a specific storm were to occur together with the uncertainty in jacket capacity given the failure mode comprises failure of four or more braces. The dotted red line is the same as the dashed line, but with the uncertainty in jacket capacity given the failure mode is a single leg failure. The dashed dark blue line represents the hazard curve for the Gulf of Mexico with uncertainty in the load given a specific storm were to occur together with the uncertainty in jacket capacity given the failure mode is one of four or more braces failing.

These hazard curves show the relationship between RSR (on the left axis), γ_E for the DLA (on the right axis) and return period for failure of the structural system for the SRA on the horizontal axis. These curves also assume that the members participating in the failure mechanism are dominated by wave load rather than dead load. As described by Efthymiou et al[3], these hazard curves show the relationship between RSR γ_E and return period for structural failure for the NNS for different modes of failure.

All of the above assume sufficient air gap such that wave-in-deck (WID) load does not significantly contribute i.e. the storm load is "wave-in-jacket" (WIJ) only.

However, before these curves can be determined accurately and used appropriately, the metocean data must be analyzed in a specific and consistent manner using the response-based method developed by Tromans & Vanderschuren[4]. Atkins has found that the industry's metocean consultants do not yet routinely use this method and consequently, the resulting calculated structural safety level is not consistent and usually conservative.

The probability distribution for the crest elevation of the extreme waves in a storm together with the measured elevation of the deck above mean sea level are required in order to determine the annual probability of wave-in-deck load.

The figure below shows hazard curves relating return period for failure of the structural system versus the platform's overturning moment (OTM) capacity normalized by the magnitude of the OTM having a return period of 100 years.

The blue line represents the hazard curve for WIJ load on the platform while the green line represents the

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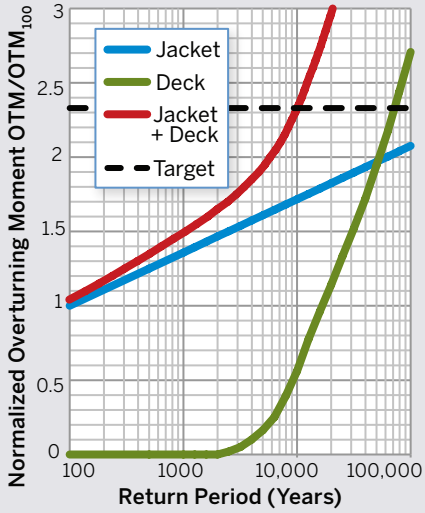


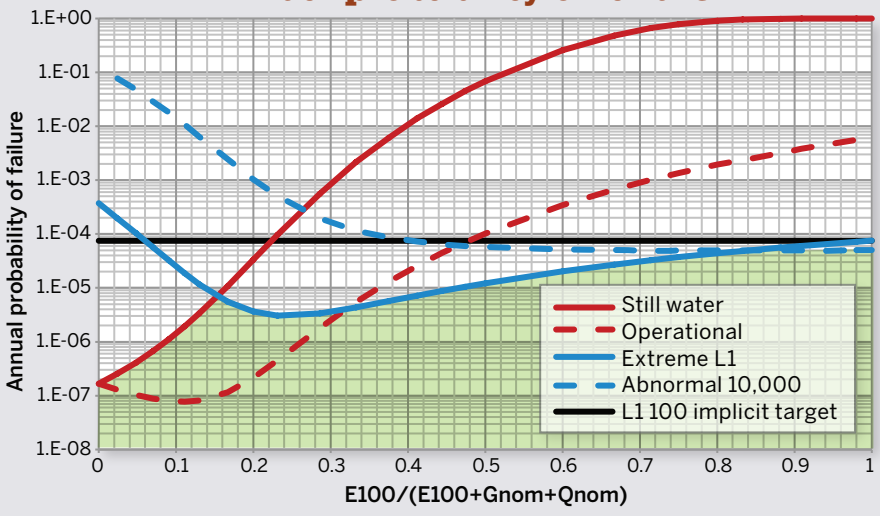
OTM hazard curve for wave-in-jacket and wave-in-deck.

hazard curve for WID load on the platform. The red line represents the hazard curve for combined WIJ and WID load on the platform. This curve shows that once the return period is sufficient for WID load to occur, the OTM capacity required increases rapidly in order to achieve a sufficient return period for failure of the structural system. This is to be expected due to high WID loads acting at a significant lever arm from the legs at the lower elevation of the jacket.

The red dotted hazard curve on the earlier diagram was calculated from base shear and thus it would be steeper if it were based on OTM and consequently the code implicit return period to failure would reduce to slightly below 10,000 for NNS jackets designed to ISO 19902 with γ_E=1.35 and a single leg mode of failure.

The hazard curves give the capacity required in order to achieve a specified return period for failure of the structural system. If significant additional topside load is to be added to a platform, then an additional check on the reliability of the jacket and foundations is required for the still water condition.

The plot below shows the annual probability of failure for a structural component when it is designed to an ISO code utilization ratio of 1.0 and subjected to loads ranging from 100% dead load to 100% wave load. The plot shows that the code equation for the L1 condition governs the Pf for high proportions of wave load, the abnormal 10,000-year code equation governs for members with more than 80% of their load being due to wave load and the still water code equation governs for low proportions of wave load. This plot illustrates that compliance with the ISO code for operational conditions results in excessive conservatism for structural components with a low proportion of storm load in comparison to components with higher proportions of storm load.



Annual probability of failure for a structural component designed to an ISO code utilization ratio of 1.0 and subjected to loads ranging from 100% dead load to 100% wave load.

Atkins has applied the above methodology to assessment of jacket structures in many global regions. Although some further work is required to establish complete consistency across all regions, the next revision of the ISO code may well achieve this. OE

Note: This is a shortened version of Fraser's article. Read the full version at www.OEDigital.com.

Ramsay Fraser *is Atkins' technical director for offshore structures. Having originally managed Atkins' Aberdeen office across all disciplines, Ramsay now has a global role which sees him work on projects with Atkins teams from across the world. He has a BSc and PhD in Engineering from the University of Aberdeen.*

Acknowledgments

This article is based on technical developments by Atkins' offshore structures team and in particular, Mark Manzocchi. Also, BP UK structures team has shared relevant data for this article with Atkins.

In addition, we have benefited from technical discussions with Pat O'Connor, Dr Mike Efthymiou, Dr Peter Tromans, Dr Richard Gibson, Dr Graham Stewart and Prof Richard Jardine.

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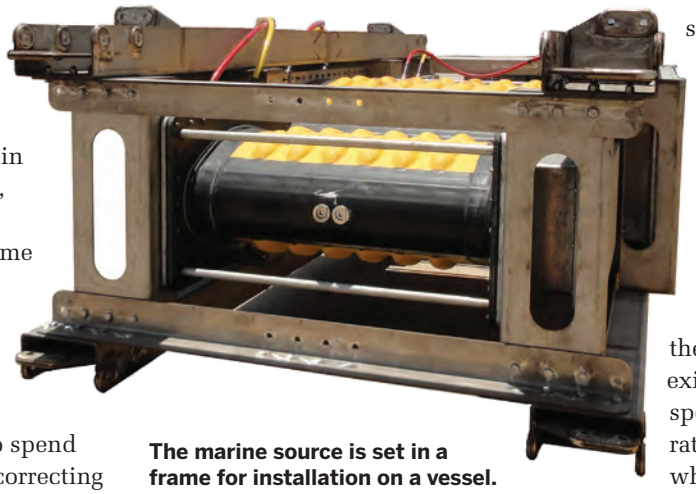
New marine vibrator offers improved performance

Houston-based Geokinetics showed its latest source advance in their booth at the SEG Convention this September. Bill Pramik, Geokinetics' vice president explains the technology.

More and more, the oil and gas industry is being asked to reduce its impact on the environments in which it works. In one sense, this is ironic, because the industry recognized a long time ago that reducing its environmental footprint has a positive effect on profitability. In simple terms, if the environment is minimally impacted, there is no need to spend time, resources, and money correcting problems. Nonetheless, the industry also recognizes that it has a responsibility, as good corporate citizens, to perform work in a manner consistent with environmental best-practices and guidelines.

Geokinetics has been proactive when it comes to protecting the environment. In many areas, the company's internal policies are more stringent than prevailing regulations and it constantly monitors performance looking for improvement opportunities. One such opportunity being developed by the Technology Research and Development team in Houston is the Geokinetics Marine Vibrator. It is a major step forward to the goal of being good environmental stewards.



The marine source is set in a frame for installation on a vessel.

Seismic acquisition

So exactly what is a marine vibrator? As the name implies, it is a seismic vibration source that's used in the water. In much the same way that Vibroseis trucks are used to acquire land seismic data, marine vibrators can be used to collect seismic data in the marine environment. That, of course, raises the question: Why would we want to do this?

There can be little doubt that humans have an impact on the environment. These impacts can be divided into three basic categories: good, bad, or inconsequential. Which category an impact falls into depends on the nature of the impact and somewhat from the perspective it is examined. In the seismic industry, "inconsequential" environmental impact is the goal. There is some environmental impact from operations; the goal is for that impact to have no consequences or, at least, the smallest consequences practical.

Offshore, where seismic companies acquire ocean bottom and transition zone seismic data, the source of choice for over 50 years has been the airgun. Before that, dynamite and other explosive charges were detonated in the water as the energy source. The airgun was hailed as a safer and "friendlier" seismic source and was quickly adopted by the industry. Now, 50 years later, airguns are beginning to lose their status as an environmentally-friendly source.

The relevant literature is full of statements regarding the harm that seismic airguns might do to the environment. Many of these statements are based on incomplete, incorrect, or anecdotal reports about environmental damages caused by airguns. The truth is that there are very few scientific studies about the impact of airguns on the environment, and those that exist generally focus on one or two specific species (e.g. cetaceans), rather than the environment as a whole. Nonetheless, it is prudent that we begin looking at alternate seismic energy sources for the marine environment.

A marine vibrator will probably never replace airguns as the energy source for marine seismic acquisition, just as land vibrators have not replaced explosives for land acquisition. However, there are a number of situations where a marine vibrator can be advantageous. Some of these advantages relate to environmental concerns, others involve seismic data quality and acquisition efficiency.

Differences

One of the major differences between airguns and vibrators is the sound pressure level that is transmitted into the water. It is like comparing a shotgun blast to the hum of a room air conditioner. The shotgun, like the airgun, releases all of its acoustic energy in a single pulse with a very high sound-pressure level, but with a very short duration. In contrast, a room air conditioner, like a marine vibrator, has a very low sound-pressure level, but it runs for a relatively long period of time.

In seismic exploration, what is important is the total amount of energy output by the source. For example, if the airgun has a sound pressure level of 100 and lasts for 0.1 seconds, the total acoustic energy would be 10. If a marine vibrator has a sound pressure level of 1 and lasts for 10 seconds, the total acoustic energy would also be 10. For seismic data acquisition, these two sources provide the same energy for seismic imaging, but the vibrator is 100 times quieter. Intuitively, this has a much smaller environmental impact.

Geokinetics' Marine Vibrator

The Marine Vibrator project dates back 20 years, to 1994 when the initial concept was proposed. A set of prototype vibrators was built and tested in 1999 to provide a "proof-of-concept." From a geophysical perspective, these tests were very successful, collecting excellent quality seismic data. However, the prototype vibrators were finicky and broke down often. There was a hiatus in vibrator development until 2007, when a renewed interest came from recognizing their potential benefits for shallow-water operations.

An improved driver for the vibrators was developed and another set of vibrators was built. These new vibrators have been undergoing testing and continued development since that time.

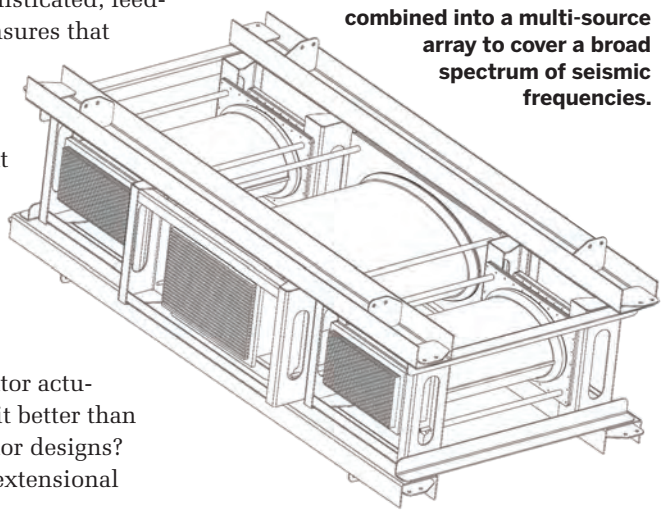
Along with drivers, many other vibrator components and functions have been improved. Changes to the internal springs' configuration have increased energy output. Modifications to cooling and pressure compensation systems have improved reliability. The addition of a very sophisticated, feedback-control system ensures that the vibrator's output is the preferred signal. These and other refinements ensure that the vibrator will be a robust and efficient seismic acquisition tool.

Design

So, how does the vibrator actually work, and why is it better than previous marine vibrator designs? The vibrator uses a "flextensional transducer." This vibrator type has distinct advantages over previous marine vibrator designs, which mimic traditional, land vibrators, using large plates or diaphragms to induce pressure waves into the water. This idea works well for higher frequencies, but fails at lower frequencies. The reason this approach fails is because a vibrating plate or diaphragm is only good at generating frequencies proportional to the diameter of the plate. As frequencies go lower, the wavelength gets longer, and the ability of a vibrating plate to generate pressure waves at that lower frequency decreases.

A solution is to effectively change the vibrating plate into a vibrating balloon. Now, instead of moving the plate back and forth to make the acoustic wave, we inflate and deflate the balloon very quickly. As the balloon changes volume, the water near it cannot flow around it because the balloon is expanding in all directions. A vibrator that changes volume will improve low frequency acoustic energy generation. This is one of the principles of the new vibrator's flextensional design. Because of this design, the new vibrators are much more efficient at generating lower frequencies for seismic data.

The vibrator's drivers have also been improved. Previous marine vibrator designs have used either conventional hydraulics (like land vibrators) or magnetic voice coils (like home stereo speakers). Hydraulic systems are limited, because the servo-valves that control motion have reaction-time limitations. Magnetic coils don't suffer these same limitations, but are inherently weak and don't generate much force.



Three marine vibrators can be combined into a multi-source array to cover a broad spectrum of seismic frequencies.

Because of these limitations, Geokinetics used something radically different: Terfenol-D. Terfenol-D is a highly magnetostrictive metal. When a piece of Terfenol is placed in a strong magnetic field, it changes its shape, or size, or both. And it does this with a lot of force. Terfenol-D is an ideal way to power the marine vibrator with a strong, reliable, driving force that will stand up to the rigors of round-the-clock seismic acquisition.

The new marine vibrator is a broadband, marine seismic source that can generate acoustic energy for seismic exploration from 5Hz to over 150Hz. Because of its configuration, it can efficiently operate in water depths as shallow as 1m without suffering the energy losses that airguns experience in shallow water. The instantaneous sound pressure levels generated by the vibrator are a small fraction of those generated by airguns and, because of this, the vibrator is a more "environmentally sensitive" acoustic source. Marine vibrators will not replace airguns for marine seismic acquisition, but they were never intended to. They are another tool for the seismic industry as it continues to adapt to the changing environmental standards. OE

Bill Pramik *is the vice president of Acquisition Technology at Geokinetics, Inc. where he oversees research and development of new seismic acquisition hardware and methods including recording technology, seismic sources, and seismic receivers. Pramik was employed by PGS for 15 years, and served 3 years as their Vice President of Geophysics and Quality before moving to Geokinetics 2010. Prior to that, he worked for Amoco Production Company for 16 years, including a 6 year assignment to their Research Center. Pramik received his Geophysics degree with a minor in Mathematics from Virginia Polytechnic Institute, where he was awarded a 2-yr Amoco Foundation Scholarship.*

Growing the Caspian's small rig market

The Caspian Sea is experiencing growing drilling demand and attracting interest from major oil companies.

By Victor Schmidt

The Caspian Sea is a land-locked interior basin with established oil and gas production that has seen increasing activity since the bordering nations gained independence from the former USSR in the late 1990s. Five nations surround the sea: Russia, Kazakhstan, Turkmenistan, Iraq, and Azerbaijan. National oil companies (NOC) control the drilling market, so there are limited opportunities for competitive drilling. But with the entry of international oil companies, drilling demand is increasing and requiring additional rigs.

The total number of drilling units is small, only 28 rigs in all, according to Rigzone. The fleet is composed of 7 semisubmersibles, 11 jackup drilling rigs, 2 inland barges, and 8 platform rigs. The State Oil Company of Azerbaijan Republic (SOCAR) controls 17 of the rigs: 3 semisubs, 6 jackups, and 8 platform rigs. Add in Kazakhstan's one inland barge and the NOC-controlled component rises to 18 rigs, or 64% of the rigs in the Caspian.

The remaining third is the competitive fleet, which includes four semisubs, five jackups, and one inland barge. Parker Drilling operates a competitive inland barge, *Parker Rig 257*, that can drill to 30,000ft in 18ft of water. Teniz Burgylau operates the other barge, a non-competitive submersible - *Caspian Explorer*, dedicated for the Zhambyl project off Kazakhstan. That rig is for near-shore work in up to 8ft water depth, for drilling to a maximum 6000ft drilled depth.

Caspian Drilling Co. Ltd., based in Baku, Azerbaijan, controls the semisub market with four rigs and it is building a fifth, a Keppel FELS DSS 38M design with a 3000ft water depth rating and 40,000ft drilling depth. Keppel Caspian Shipyard Co. in Azerbaijan is building the US$800million rig, which is scheduled for delivery 4Q 2016. The semisub will have an 800m, eight-point mooring system to hold the vessel on station during the Caspian's high-speed winds, and 7m-deep pontoons for transit through shallow-draft channels.

The jackup market is divided between four players: Russia's Eurasia Drilling Co. Ltd. (EDC, with 3 jackups); Dubai-based Momentum Engineering (1 jackup); Iran's North Drilling Co. (1 jackup). In addition, Kazakhstan's Teniz Burgylau LLP, a subsidiary of national company KazMunaiGas JSC, is building a new independent-leg, cantilever jackup of KFELS B design. The rig will be rated to 262ft water depth for drilling to 20,000ft, but the rig is upgradeable to 400ft water depth. The Keppel Kazakhstan yard in Aqtua, Kazakhstan is building the US$240million jackup for delivery in 1Q 2015.

Eurasia Drilling added the *Neptune* jackup to its fleet in early July and is building an additional rig that will enter the market next year. According to news reports, Lukoil president Vagit Alekperov said that Lukoil intends to drill the Khazri structure in the Caspian Sea at the end of 2013, using the *Neptune* jackup. The company also plans to use the rig to drill the Titonskaya structure in 2014.

Aside from the NOCs, several major oil companies are actively exploring and developing drilling plans with their local partners for the Caspian including Statoil, ExxonMobil, Shell, CNPC, Lukoil, Conoco Mubaddala, Total, Petronas, Dragon, and Turkmen Exploration. OE

Eurasia Drilling speaks

Eurasia Drilling's CFO W. Richard Anderson visited *OE's* offices recently and provided an update of their operations.

OE: How are your Caspian offshore operations faring?

WRA: Eurasia bought Transocean's *Saturn* rig for US$260 million in 2011. The jackup, a Keppel FELS CS Mod V design, is on a three-year contract (US$208,000/d) with Petronas for drilling off Turkmenistan. Petronas is a major client, who just signed a new three-year deal developing an offshore oil field off Turkmenistan. Offshore operations are about 5% of our revenue and about 15% of our bottom line, so they are a meaningful share.

Ice is a concern in the Caspian, but the operators of Kashagan field (in the Kazakhstan sector) have built berms in the shallow waters to protect the rigs from wind-blown ice. We'll soon have four jackups in the Caspian, which will allow us to work in most of the sea.

OE: How are the rigs delivered?

WRA: Our new Caspian Sea rigs will come in by the Volga River and canal system. These are jackups of Super 116E Lamprell design and are being built in Sharjah, UAE. The first, *Neptune*, was commissioned in July and is on contract to begin drilling in late August. It should be on contract for the next five years at good day rates. The next jackup, to be called *Mercury,* is scheduled for delivery in November 2014. Both rigs can drill to 30,000ft.

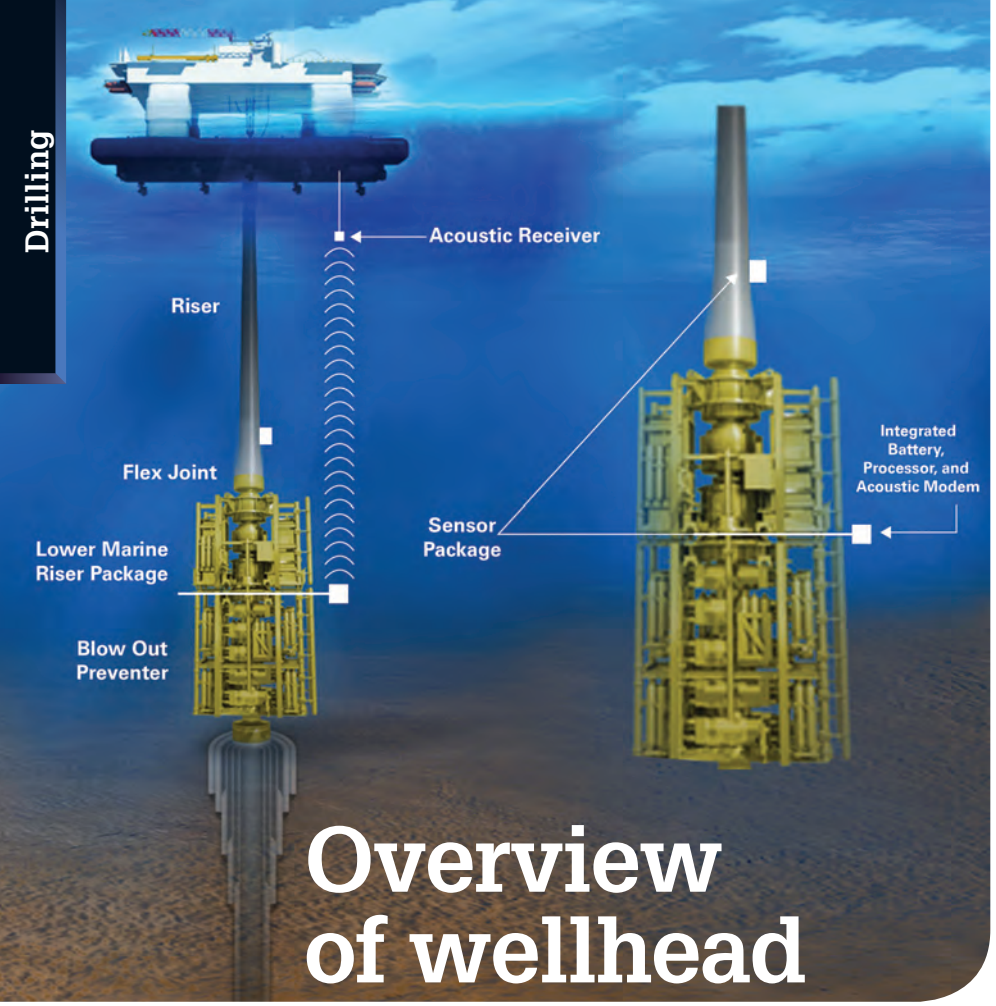
OE: What about areas east of the Caspian?

The *Saturn* jackup is drilling for Petronas off Turkmenistan.

WRA: Gas exploration is active onshore in Turkmenistan, but Chinese competition makes it tough to get a start there. Petronas and Dragon are our major clients offshore Turkmenistan. The Chinese are building a jackup in Astrakhan (Lamprell), but it isn't ready yet.

OE: What are your plans for expansion?

WRA: We have designs to move into Russia's northern offshore waters. Three major contracts were signed recently by operators for exploration in those northern seas [that will lead to future drilling]. ■



Overview of wellhead fatigue monitoring

By Paul Forman, Dan Walker, John Henderson and Jim Maher

Wellhead fatigue is acknowledged as a technical challenge in the oil and gas industry. In an effort to advance industry capabilities and better inform operational decisions, BP is developing a system for instrumentation and data interpretation to provide enhanced insight regarding wellhead loading on a real time basis.

The following activities were taken to define the system concept:

- Comparison of historical data to original analysis results.
- Correlation of BOP motions/accelerations to stresses at particular points of interest.
- Simplification of processes to calculate fatigue.
- Dialog with the instrumentation community regarding capabilities of various equipment types.

These activities led to development of simpler, more robust system concept that provides better data, faster. Prototypes are currently in development. The system is not dependent on specific mechanical or control details of the BOP, and can therefore be retrofitted to existing BOPs.

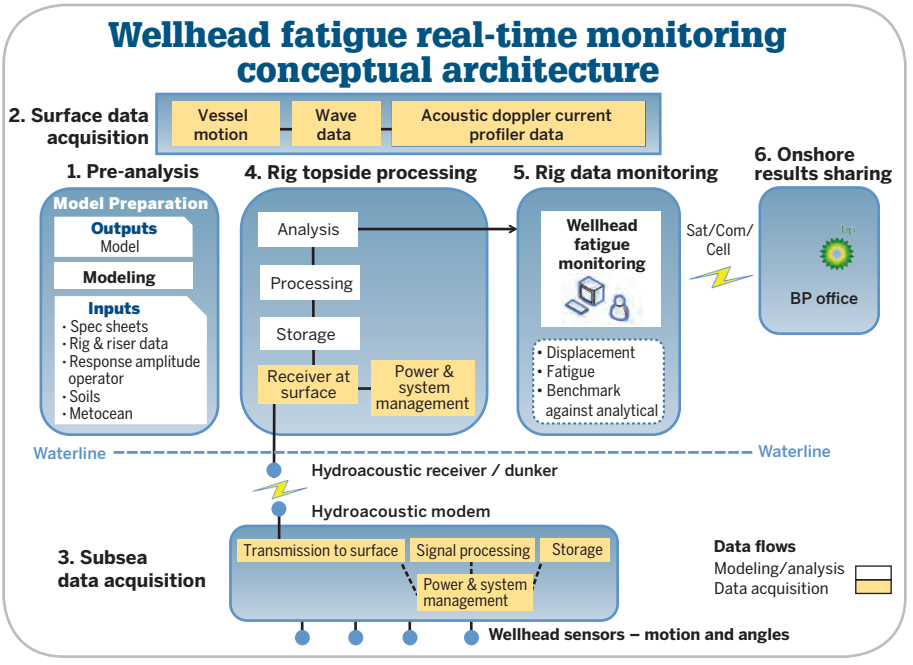
History

The original and current riser instrumentation systems are "data loggers." These self-contained systems were designed to obtain better understanding of vortex induced vibration (VIV) on deepwater risers. Their use has been extended to measure BOP accelerations, which can be used to estimate wellhead fatigue.

However, there is significant delay between measurement and availability of data for interrogation. Therefore operational decisions are often made based on extrapolation of pre-analysis results. Real time systems have been proposed but rely on the use of cables to carry the high-bandwidth data to the surface for processing. Cables can impact riser running and are susceptible to the major hydrodynamic loads in the splash zone.

Historical data comparison

BP's riser monitoring database dates back to the early 2000s and includes data from the deepwater Gulf of Mexico and the North Sea, as well as more recent data from the Mediterranean, Caspian Sea, and other areas. This database was analyzed to better understand how well standard industry analytical methods predict riser and BOP motions. The conclusion is that although the analytical predictions are conservative, they are adequate for riser dynamics. However, the predictions are generally more



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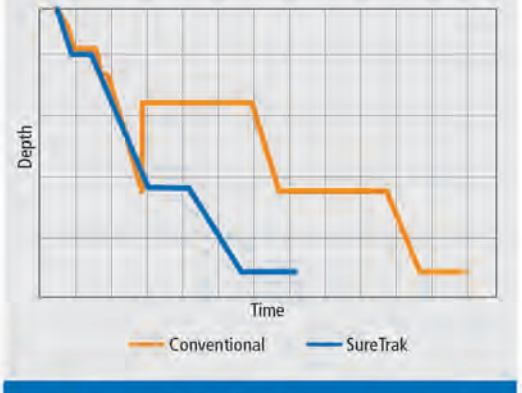

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conservative for BOP dynamics and typically lead to higher fatigue loading predictions than would be calculated from observed BOP motions.

Fig. 1 illustrates a common data disparity, in LMRP RMS accelerations vs. wave height. Original predictions are in blue and summary statistics for the observed BOP motions are in red. Although some scatter is expected, in an accurate prediction the observed data points would spread equally above and below the blue analytical prediction line. Instead, the data is bounded by the analytical results and most data is well below the line.

The location of the majority of the data points below the blue line indicates substantially less loading was accumulated than originally predicted. The highlighted band for Seastate 3, for example, shows less than 10% of the originally predicted loading.

Similar comparisons were performed on other data from a variety of regions with similar results. However, there were cases in which more vibration was observed than was predicted. Practical mitigation options exist to reduce the accumulation rate for those rare circumstances.

Based on this analysis, a real time system concept was developed to:

Maximize safety and operational efficiency by more accurately calculating the fatigue loading on the wellhead.

Provide rapid feedback on events resulting in greater than anticipated loading to inform timely operational decisions.

Displacement to stress correlation and calculation simplification

Most riser instrumentation systems were designed to detect stresses along the riser above the flexjoint (i.e. above the LMRP/BOP). These complex systems require resolution of riser dynamic modes and allocation of various amplitudes to the participating modes. Additionally, a large number of sensors (8-10) and full-time series data is required at the point the computations are performed. Wellhead loading is traditionally calculated by imposing the time-series data on a finite element analysis (FEA) model. This process is computationally intensive and typically performed when a large data set is available for processing. The complexity and need for large amounts of data in this method negates the use of a real time system.

Due to a near-linear relationship between wellhead and BOP stresses, the number of sensors and amount of data can be reduced. A portion of the processing can also be performed on the sensor prior to transmission to the surface. Therefore, data transmission needs are reduced and the need for a cable is eliminated.

Points of interest for wellhead fatigue are typically in the vicinity of the low pressure housing (LPH) or at the first connector (~30ft below mudline). The stress-displacement relation at the first connector is almost perfectly linear. The relation at the LPH is close to linear and can be approximated by a linearity assumption. Fig. 2 shows the full displacement time series plotted against the full stress time series, thereby eliminating the time dimension and illuminating the

Fig. 1 – LMRP RMS accelerations vs. wave height

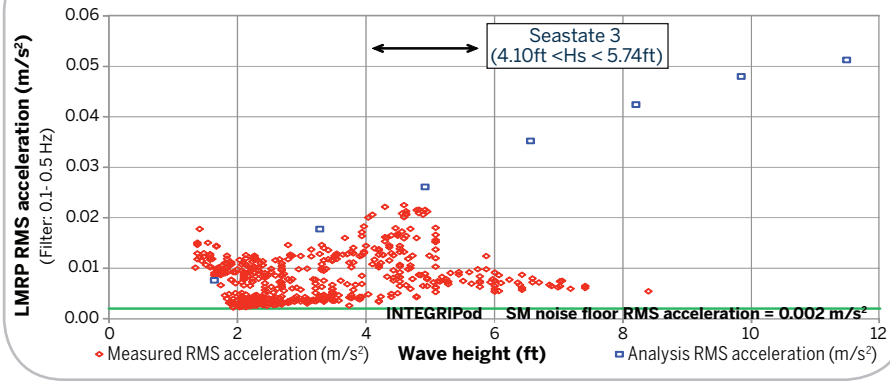
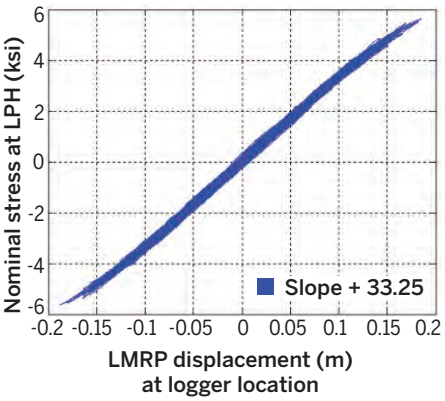


Fig. 2 – Stress vs. Displacement at LPH



displacement-stress relationship.

A linear slope can be determined from Fig. 2 and used to recreate the stress time series as long as the displacement time series is known. In Fig. 3, this slope is used as a transfer coefficient and the two signals look the same, demonstrating that the displacement data can be used to approximate the stress signal.

Fatigue calculations are performed using either time domain or frequency domain. If using time domain, a linear transfer coefficient can be used in conjunction with the sensor displacements and the resulting signal can be processed to obtain cycle amplitudes. The histogram is transmitted to the surface for further fatigue processing. If using frequency domain, transfer functions can be derived based on the results of the pre-analysis. Suitable wideband frequency-domain fatigue methods are available to process the signals. Transmitting the spectrum to the surface is advantageous as it can be used for diagnostic purposes. The amount of data transmitted is reduced by at least a factor of 10 and perhaps as much as 100, depending on the method used. This is an advantage since acoustic transmission at low bandwidth is more battery efficient and more reliable.

Instrumentation capabilities

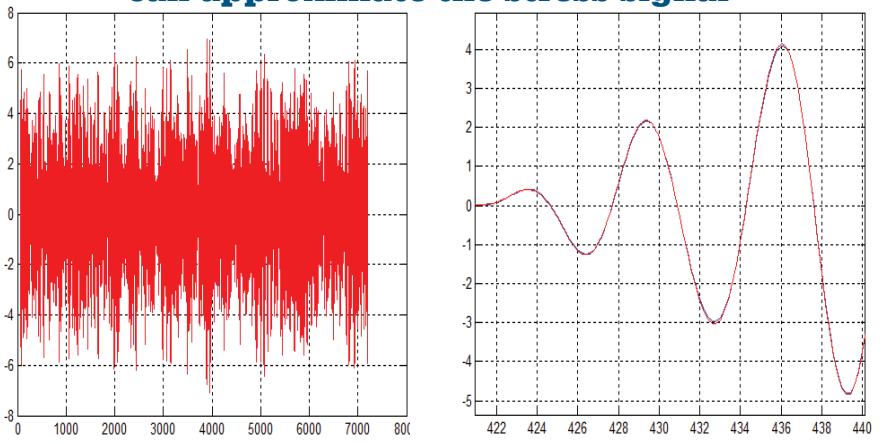
A survey of current industry capabilities was conducted in order to assess how these findings could be combined with equipment to create a more optimal system to achieve the operational and knowledge-generation goals. The intent of the survey was to collect information on advances in a broad range of industry niches, including subsea positional survey, dynamic positioning/beacons, drilling riser angle measurement systems, etc. The concept is to combine technological advances with the improved algorithms to provide an improved system.

Two of the most relevant equipment advances are:

1. **Acoustic systems** – Given the data simplifications, an acoustic modem can be used to transmit data. This has several advantages including near real time data without the need for a cable and minimal interfaces with the BOP/riser mechanical systems. The latter is important because this system can be retrofitted onto existing facilities.
2. **Low power sensors** – MEMS (micro-electro-mechanical systems) accelerometers reduce the power requirements by 50-100 times. This allows systems to be deployed for 1-2 years at a time, operating continuously without needing a change-out operation. However, there is a reduction in resolution.

Although the above improvements are enabling, the following improvements provide substantial increases in potential functionality of such a system:

Fig. 3 – Displacement data can approximate the stress signal



Blue curve - time [s] vs. BM stress [ksi] Red curve - time [s] vs. displ.[m] * (BM stress[ksi]/displ.[m] slope)

1. **Optical modems** – High bandwidth downloads through short distances of water have progressed recently. Although the system described results in little need for full-time series data, there is an advantage in the ability to periodically download full data for diagnostic purposes. An optical modem and associated ROV download device can enable this without introducing significant complexity.
2. **Processing capabilities** – The miniaturization of processing and storage advances the use of on-board algorithms.
3. **Improved error rejection algorithms** – Many algorithms from digital signal processing and inertial navigation can assist with identifying errors at an early stage. This is important for on-sensor processing because errors are less visible. Moving beyond the traditional "person in the loop" processing will require the use of additional algorithms.

Synthesis, system definition

Based on the improvements and simplifications listed above, it is possible to assemble a system with the following features:

- Real time feedback suitable for operational decision making by the drillers.
- Correlation information suitable for building knowledge base.
- Elimination of the cable – reduces operational challenges and cost.
- Reduction of ROV change-out operations – reduces operational cost and schedule challenges due to unavailability of ROV support.
- Reduce processing time and costs.
- Completely independent of BOP mechanical systems – can be retrofitted on any BOP.
- Install topsides or by ROV.

Conclusions

A real time system to measure wellhead loading is in development. This system will provide data that more accurately reflects the loads on the wellhead. Additionally, there is a reduction in the amount of data and a simplification of the data processing. This allows for more rapid data transmission to the surface without the need for a cable. This system will help inform operational decisions in a more accurate and timely manner. OE

Paul Forman *is Vice President for Wells Engineering in BP Exploration Operating Co. Ltd. He is responsible for strategic direction and business delivery of Wells Engineering. He leads a team of engineers in the organization's drive for consistency, rigor and standardization in how BP conducts engineering design for well construction across the full lifecycle of the well. Forman has 24 years' industry experience and earned a BS in Engineering at RGIT (now Robert Gordon University), Aberdeen.*

Dan Walker *is Global Wellhead Integrity Program Manager for BP America Inc. He graduated from The University of Oxford in Engineering Science, completing a M.Eng in 1999 at St. Catherine's College and D.Phil at Magdalen College in 2003. He was recruited by BP as a technical specialist in the area of offshore hydrodynamics. Walker has worked in Azerbaijan, Russia, Alaska, Norway and Trinidad, and has covered technical areas in BP ranging from deepwater oil and gas exploration and production to offshore wind projects. Walker has also worked for BP in the Gulf of Mexico and Angola and continues his role as relationship manager for BP's engagement with the University of Oxford.*

John Henderson *is a senior drilling engineer working in BP's Global Wells organization and is currently based in the UK. He has worked in various operational engineering roles in the North Sea, Middle East, Africa, and South America. Most recently he has been involved in the subsea wells development planning for Shah Deniz Stage 2 project in the Caspian Sea. Henderson has 28 years of industry experience.*

James Maher *is a consultant focused on innovative solutions for floating systems, risers, and equipment for the floating drilling and production industry. He has founded several deepwater technology companies and has been involved in the development and commercialization of many technologies. He was involved in the development of several generations of spar technology, in his role as the Spar Product Manager for Technip and other engineering management roles. Maher has a BS in Mechanical Engineering and a BA in Government Studies from the University of Notre Dame and an MSE in Civil Engineering from Purdue University.*

Michelle Edwards *is a technical writer and editor for Barrios Technology. Dr. Edwards has worked in biotechnology where she assisted in the management of a small start-up company. She then moved on to NASA's Johnson Space Center where she led a team in the development of an architecture to identify and analyze risks to humans from long duration space flight. Dr. Edwards has a B.A. in biology and a Ph.D. in neuroscience.*

Singapore's newest shipyard at Tuas

Sembcorp has completed the first phase of its state-of-the-art shipyard on Singapore's west coast. Nina Rach reports.

Mr. Wong Weng Sun, President and CEO, Sembcorp Marine

Sembcorp Marine celebrates its 50th anniversary in 2013, and continues to expand and upgrade its facilities, laying the foundation for long-term, sustainable growth.

The company is building Phase 1 of an expanded yard in Singapore, at Tuas. The entire 206-hectare new facility will be developed in three phases over 16 years.

The Tuas yard joins Sembcorp Marines's current Singapore properties: Jurong Shipyard, Jurong SML, Sembawang Shipyard, PPL Shipyard, and SMOE.

Sembcorp Marine has also established a global network of shipyards including P.T. Karimun Sembawang Shipyard and P.T. SMOE in Indonesia, and the new Estaleiro Jurong Aracruz integrated facility under construction in Brazil. It has also invested in Indian yards: Pipavav shipyard and Sembmarine Kakinada, and several yards in China, the UK, and the US.

Sembcorp Marine President and CEO Mr. Wong Weng Sun presented details of the new Tuas yard in Singapore and the new yard in Brazil at the Offshore Technology Conference in Houston this year and spoke with OE. Wong believes the new efficiencies in the Tuas yard could bring cost savings of up to 20%. The company is investing more than US$1.5 billion to build the two state-of-the-art shipyards, geared for the offshore oil and gas industry.

Tuas-Phase 1

Commercial operation of Phase 1 facilities at Tuas began in August 2013, with all four drydocks busy with repair jobs in late September. More ships are expected to be rerouted to the Tuas yard from Pulau Samulun, an offshore island in Jurong Industrial Estate, separated from mainland Singapore by Selat Samulun. This is Jurong Shipyard's main repair facility.

The Tuas project was first announced in November 2009, but the new shipyard had been envisioned for decades,

View of the new yard at Tuas View Extension, with Finger Pier #1, Wharf #1, and Drydocks #1 and #2 at left; Finger Pier #2, Quay #2, and Drydock #4 at center.

and is built on reclaimed land at Tuas View Extension, with new docks and quays. This gave the company the luxury of designing from the ground up, without having to retrofit enhancements into pre-existing structures. With space at a premium, the company planned an efficient layout, with integrated, work-effective operations. New automation and abundant overlapping crane coverage is particularly impressive.

The new yard covers 73.3 hectares, equipped with four very large crude carrier (VLCC) drydocks of 1.55 million deadweight tonnes (dwt). The total quay and wharf length is more than 3.8km. The yard contains state-of-the-art production technology and workshops for ship repair, rig repair, upgrading, and ship conversion, such as floating production storage and offloading (FPSO) conversions. The Tuas yard is capable of servicing a range of vessels, including VLCCs, mega containerships, liquefied natural gas (LNG) carriers, passenger ships, and offshore vessels.

With the addition of Phase 1 facilities, the Group's ship repair and ship conversion & offshore capacity will nearly double from the previous 1.9 million dwt.

Costs for Phase 1 were higher than the original target because certain building works (including the dormitory) were brought forward.

Computer-aided rendering of the new facilities at the Tuas shipyard.

Tuas-Phase 2

In December 2012, Sembcorp Marine acquired a 34.5 hectare site at Tuas View South Extension for the second phase of Tuas yard development. This is adjacent to and north of the Phase 1 yard. It will be developed over 4-5 years.

Sembcorp Marine's Tuas land tenure for both Phase 1 and Phase 2 is 30 years, plus 30 years leasehold.

Executive direction

Mr. Goh Geok Ling is the Chairman of the Board of Sembcorp Marine, appointed in February 2006. He also serves as Chairman of Jurong Shipyard, Sembawang Shipyard, SMOE, and is a director of Sembcorp Industries. He holds a Bachelor of Engineering from the University of Sydney, Australia.

Mr. Wong Weng Sun is the President and CEO of Sembcorp Marine, appointed in May 2009. He is also the Managing Director of Jurong Shipyard and sits on the boards of several of the Group's subsidiaries, including Jurong Shipyard, Sembawang Shipyard, SMOE, and PPL Shipyard.

Mr. Wong is the President of the Association of Singapore Marine Industries and is also on the boards of the Maritime and Port Authority of Singapore and the Singapore Maritime Foundation. Mr. Wong serves on advisory panels and committees at the School of Mechanical and Aerospace Engineering, Nanyang Technological University and at the Centre of Innovation, Marine and Offshore Technology, Ngee Ann Polytechnic. He holds a Bachelor of Mechanical Engineering (Marine) and an MBA from Oklahoma City University. OE

Drydock #3, Wharf #2, Finger Pier #3 at near right; Quay #1, Wharfs #3 and #4 in background at right.

Crane transfer operations

"The safe transfer of personnel is a key challenge in the offshore environment," says Reflex Marine founder & CEO Phillip Strong. The company organized a 3-hour seminar on crane transfer safety at EnerMech in Aberdeen prior to the start of SPE Offshore Europe 2013, in response to a recent North Sea incident where four offshore workers were killed in a ditching accident. In addition to lectures, attendees participated in hands-on, practical review using a FROG-3 unit.

The company unveiled its newly developed FROG-XT crew transfer device at the Offshore Europe conference this year, showing a prototype at Stand 1B85.

The FROG-XT's stainless-steel frame encloses seats that are equipped with safety restraints and shock-absorbing springs. (Photo: Reflex Marine)

Reflex Marine specializes in crane transfer and offshore access with two products, FROG and TORO, driving improved safety standards. The FROG-XT is an evolution of the current FROG hard capsule, based on 20 years of experience, with more than 650 capsules in use worldwide. The stainless-steel frame encloses seats with safety restraints and shock-absorber springs, and has self-righting buoyancy panels. The unit can accommodate a full-size, horizontal stretcher in emergencies—a massive improvement over the rope baskets of yesteryear. ■

Golden rules for safe crane transfers

Reflex Marine and partners Seacor Marine and Sparrows Offshore joined together to create a set of 'golden rules' for safe crane transfer practices offshore. "These rules reflect what's been learned from millions of transfers in varied conditions around the globe, with a focus on those few that go wrong," the company said (www.reflexmarine.com/industry-expertise/golden-rules). "Crane transfer may seem a simple operation, but a wide range of variables is involved, and considering them carefully will help you to achieve a safe transfer every time." The company hopes the rules will eventually become a part of established industry best practices.

Understand your risks

Reflex Marine says it is necessary to perform a risk assessment to ensure you understand site-specific risks. Consider the vessels, cranes, transfer equipment, weather, and sea-state and crews involved. Identify the key risk drivers. Extra scrutiny is required for personnel lifting.

Be familiar with your conditions

Check prevailing weather and sea conditions, including tides and currents. Discuss vessel positioning and station-keeping with the vessel master and crane operator (identifying specific risks or concerns). Understand the limits of your equipment.

Know your vessels

The vessel is major consideration with attention paid to station-keeping and stability. Maintaining a large, clear landing area, free from adjacent obstacles, will reduce risks. Crew competence and familiarity with the installation and communications (particularly radio and hand signals) are also key factors.

Know your cranes

Knowing the limitations of your cranes is important. Cranes should be well maintained with all appropriate

certification in place. The crane location is also important, as is the lift height, the line of sight to the vessel, and the choice of slow or fast line. Understand the function of the crane's emergency lowering systems and ensure they can be operated in the event of a prime mover failure.

Know your transfer device

With a wide range of carriers on the market, Reflex Marine says to select the one best suited to your operating envelope and risk levels.

Be familiar with your crews

Training and competence of vessel and installation crews should be addressed by company procedures. Crane operators and vessel masters have particularly important roles to play. Appropriate personal protection equipment (e.g. hard hat, safety glasses, safety footwear, and personal floatation devices) should be worn by all passengers.

Plan your lift

Dangerous collisions can happen. Pay attention to conditions such as the transfer device being misaligned with the crane hook as harsh weather can make the problem worse.

Where possible, perform lifts over water and retain a good line of sight of the carrier. Note, good communication (including radios and hand signals), between the vessel and crane operator, is essential.

If in doubt, stop

If there are still doubts about safety after trial transfers without passengers, Reflex Marine says suspend operations.

Safety factors in personnel transfer

Marine personnel transfer is an operation that spans many units, with clear communication and planning proving to be key factors.

To best understand the risks involved, Reflex Marine independently compiled a personnel transfer incident database. No such industry research previously existed.

"Operators around the globe are becoming much more aware of the new choices in logistical support. Going back 10-15 years, the first choice was nearly always the helicopter," Strong says.

Based on the data compiled from publicly available data, industry partners, and operators, the database compiles incidents occurring over the last 20 years, from 1993 to 2013. Reflex Marine acknowledges that the database might not capture all incidents due to sourcing and information constraints.

Over the course of their research, analysts found that the vast majority of personnel transfer incidents (68%, according to their database) occurred on the vessel, with a particularly high level of incidents or collisions occurring during pick-up, when falls are more likely to result in serious injuries or fatalities.

In analyzing the results, the company compiled incidents by category and completed root causes analysis to isolate the most dangerous aspects of marine personnel transfers. Categories are: Passenger falling in transport; lateral impacts (also known as "swing" or "the pendulum effect"); vertical impact (such as heavy landings); trips or entanglements; unknown; deck crew; immersion. In doing so, they found the key risks involved passenger falls (more than 50%) and lateral impacts (40%). Heavy landings, by contrast, were likely to result in minor injuries. Immersions had the lowest incident rate (less than 10%), but incurred a high potential for fatalities.

Root cause analysis indicated that faulty equipment design was a major cause (30%), followed by crane operation errors (just under 25%). Analysis of the data helped Reflex Marine understand potential issues and malfunctions to attempt to best protect passengers during such transfers by addressing the incident categories.

To give examples across all categories, the company's devices are designed to float and self-right, and include four-point seat harnesses; spring loaded seat bases; shock-absorbency features; and have been confirmed by Motor Industry Research Association (MIRA) that their devices provided "excellent protection against back injury even in the heaviest of landings."

To avoid the prominent risk of the swing factor caused by dynamic motion, Reflex Marine has outlined the points of highest risk and impact.

For more information on company services, history and safety practices, please visit www.reflexmarine.com. ■

Recognize complex operations

Make sure to recognize and manage risks, as many factors can complicate transfer operations. Common factors include lifts from moving structures (e.g. mono-hull vessels and floating platforms), extreme weather, poorly specified vessels, inexperienced crews and poor installation layout. Where appropriate, seek expert advice.

Emergency planning

Crane transfers can also be used for managing emergencies, such as medical evacuations.

Integrate crane transfers into your emergency planning and perform drills to confirm your capabilities. OE

Lightning protection eliminates strikes to offshore structures

by Peter Carpenter, Lightning Eliminators

According to the US National Weather Service, lightning strikes occur worldwide as often as 100 times per second. Not only are lightning strikes more frequent than many people realize, but they are highly unpredictable and can cause great damage, especially to locations with flammable materials or highly sensitive electronic equipment. For this reason, the oil and gas industry is particularly vulnerable to the dangers of lightning.

Though lightning is less likely to strike over open water, there is still a risk to rigs and platforms—a risk that is only growing. In fact, changes in global weather patterns are producing a large number of lightning strikes in areas where lightning has historically been scarce. Lightning's effects are on the rise worldwide and are expected to strike with more frequency. Areas and industries that have previously not seen its devastating effects will almost certainly be impacted in the future.

A single lightning strike can cause catastrophic damage, costing millions in downtime, product loss, and liability. For example, a storage tank in Kansas City in 2008 caught fire to 1.2 million gallons of gasoline after a strike, and in 2012, in Malaysia a similar incident resulted in a US$40 million loss. Before installing lightning protection, an ExxonMobil facility in Singapore lost nearly a day of work each week due to crewmembers being forced to safety zones when the region's lightning alarm activated.

According to the National Lightning Safety Institute, lightning damage and related losses exceeded $5 billion in 2009. Even though private home insurance claims for lightning strikes are down, the total paid out by insurance companies has gone up—largely due to electronic devices' sensitivity to lightning's secondary surges. Reports from Lloyd's and the Insurance Information Institute suggest that lightning-related losses rose 15% from 2009 to 2010. With lightning events on the rise and these potential losses looming, many industries are searching for proactive ways to mitigate their risk and protect their facilities from loss and damage.

A common misconception is that offshore rigs and platforms are "grounded" to the ocean and therefore not in danger from lightning. However, the truth is that the advanced electrical and electronic systems on offshore rigs can be particularly vulnerable to both direct strikes and secondary surges—and of course, personnel are in danger as well. Upstream operating companies such as Transocean, Chevron, Texaco, ExxonMobil, and BP are looking for solutions to avoid downtime, without compromising productivity and safety during bad weather.

Though lightning is less likely to strike over open water, there is a growing risk to rigs and platforms.

Protecting structures

Lightning protection is not a new concept, dating back to the 1700s when Benjamin Franklin experimented with kites and keys. Traditional lightning rods work by collecting lightning; they attract strikes and convey the energy to the ground rather than to the structure they are protecting. This technology has been used for more than 200 years, and has been very effective in protecting buildings and other structures from the physical effects of direct lightning strikes, such as fire.

Of course, *attracting* lightning is not ideal for facilities that have flammables and other sensitive materials, where using an attractor carries the risk of ignition or damage to electronic systems. Fortunately, there is an alternative. Charge transfer technology *prevents* direct lightning strikes to protect these valuable assets. Lightning Eliminator's dissipation array system (DAS) prevents a strike from occurring within a zone of protection by collecting the induced charge, developed by storm clouds, and transferring the charge through an ionizer into the surrounding air.

The DAS system is available in varying shapes and sizes but typically consists of a large radius hemisphere with an array of many thin, metal splines with sharpened tips distributed evenly over the hemisphere's surface. The DAS system is usually installed on the top of the structure to be protected (Fig. 1).

This technology is based on the hypothesis that producing positive space-charge in the region around the

Fig. 1. A DAS system includes a large-radius hemisphere with an array of many thin, metal splines with sharpened tips distributed evenly over the surface.

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DAS reduces near-surface, electric-field strength to levels below which lightning streamer formation is likely (Fig. 2). With no streamers emanating from the structure of concern, the lightning leader is more likely to connect to streamers originating from either unprotected adjacent structures (man-made or natural) or from any air terminals installed on these unprotected structures.

The principle is consistent with Gauss' electric field divergence law, which states (in one dimension) that the vertical growth of the electric-flux density is proportional to the space-charge density. If this space-charge density is positive near the surface (which is the typical case during a negatively-charged leader approach), then the electric field increases to its peak strength near the leader tip from a surface value near the protected equipment that is lower than if the space charge were not present.

As a result of this lower near-surface field strength, there is less likelihood of streamer formation near the protected equipment, and hence less likelihood of leader-streamer connection. The principal of operation rests on the DAS being able to rapidly emit ample space charge during the time of leader approach. Accordingly, the DAS design attempts to maximize space-charge emission, but without generating streamers of its own.

Browns Ferry example

A study was done at the Browns Ferry Nuclear Plant (BFN). BFN is an excellent test case for this lightning protection technology, since the science and methodology for protecting any facility is the same.

In 1998, a DAS was installed on the off-gas stack, replacing a traditional lightning protection system. Prior to DAS installation, lightning was repeatedly attracted to the off-gas stack and equipment on the stack and around its base was routinely damaged.

As part of an internal review process, BFN consulted a database of lightning activity to determine the number and location

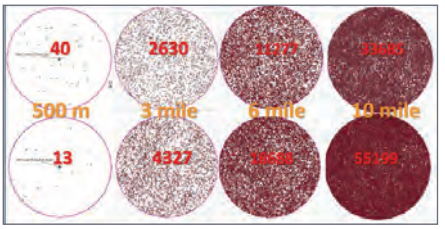


Fig. 3. Browns Ferry historical strike data shows reduced lightning after DAS installation: top row is 3 years prior; bottom row is 3 years post-DAS.

of lightning strikes around the off-gas stack in the three years before and after DAS implementation. They compared the number and location of lightning strikes within 500m, 3mi., 6mi., and 10mi. radius of the off-gas stack for these periods (Fig. 3).

The weighted data for strikes showed that although lightning frequency increased nearly 65% in the 3-, 6-, and 10mi radii around the stack, in the three years *after* DAS implementation, an 80% reduction in lightning strikes was realized within 500m of the stack. The result has been no lightning strikes to the off-gas stack since installation.

Recent work

More recently, an analysis of the physics behind charge transfer technology and DAS was presented at the 2012 International Conference on Lightning Protection (ICLP). A paper titled *Lightning Protection of Tall Structures*, in which the charge transfer system is called an LPAS, concludes the following:

An array of thin metal splines with sharpened tips evenly distributed over a large-radius, hemispherical surface (LPAS) can control the process of lightning discharge into the protected tall structure by injecting the corona space charge into the air-gap cloud structure.

The presence of the corona space charge in the gap smoothes the redistribution of voltage across the gap, so the initiation of the upward leader from the structure becomes impossible under the influence of only the electrical field of a thundercloud.

The even distribution of the total corona current among the multitude of the array's splines increases on orders of magnitude the total corona current required for ignition of the streamer flashes leading to the start of the upward leader. Such high current can be produced only by the electric field of the fast-moving and not too distant downward-stepped leader.

The LPAS of a large diameter and the thousands of splines decreases the equivalent radius of attraction several times compared with the lightning rod of the same height. That results in a decrease of the total number of lightning strikes to a tall structure by an order of magnitude.

To date, Lighning Eliminators (LEC) has installed over 3000 lightning protection solutions in more than 70 countries and throughout the United States, including recent work on offshore platforms in Mexico, Egypt, Nigeria, Malaysia, and South Korea. The company is currently experiencing the most growth outside of the United States, in countries like Qatar where companies are being proactive about the future dangers of lightning, including on and offshore facilities.

Lightning threats to the offshore community are very real. Thermodynamic processes generally start near shore with the potential to evolve into open water events. Rising temperatures worldwide are causing this increase in the frequency and severity of lightning strikes.

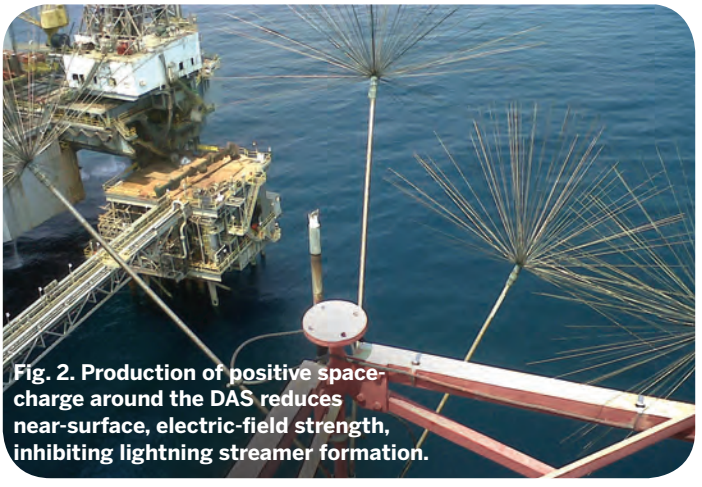


Fig. 2. Production of positive space-charge around the DAS reduces near-surface, electric-field strength, inhibiting lightning streamer formation.

Offshore protection

In 2012, LEC produced lightning protection solutions for nearly a dozen different companies' offshore platforms and rigs. Many of these included the DAS no-strike protection system to prevent future costs associated with lightning strikes.

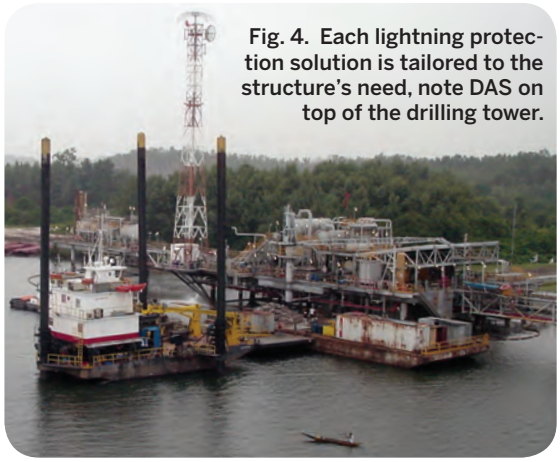


Fig. 4. Each lightning protection solution is tailored to the structure's need, note DAS on top of the drilling tower.

The system currently has over a 99% reliability rate.

Of course, the potential danger isn't only from direct strikes. Secondary surges also wreak havoc on electrical instruments and equipment and protecting this sophisticated equipment is a concern in the energy industry. Dynamic positioning, drilling instrumentation, and other rig management systems are essential to the facility staying online, and are vulnerable to lightning effects. Systems that work to prevent, rather than attract, lightning take these secondary surges into account as well.

The meantime-between-failure for sensitive systems is an important consideration in damage mitigation and loss calculation. The voltage needed to run instrumentation controls decreases as the systems become smarter and more efficient, although they become more intricate and vulnerable. The risk of a high-end secondary surge damaging equipment and affecting the operations also rises. Because not every case is the same, work with offshore rigs and platforms begins with a risk assessment. LEC engineers interview key personnel, review schematics and wiring diagrams, and inspect in situ grounding practices. Last year, vulnerability studies based on International Electrotechnical Commission (IEC) and National Fire Protection Association (NFPA) guidelines and standards resulted in solutions for nearly a dozen companies' offshore platforms and rigs.

Each lightning protection solution can be different as well, tailored to specific needs revealed in these site surveys. Some rigs may only need surge protection devices, which have become critical to protecting power distribution and low-voltage instrumentation and control. Others may require a no-strike system that will provide security against lightning strikes on the helipad, drill derrick, or jackup legs (Fig. 4).

In implementing these solutions, engineers work to improve the level of safety for the workforce, protect the vessels and facilities against direct strikes, as well as secondary surges, reduce downtime and associated costs, and extend facility life through preventative measures. Protecting a vessel from lightning strikes also works to protect systems that otherwise would have lost a considerable portion of their lifespan. In today's uncertain economy, many companies are looking for cost-effective protection as a way to extend the lives of older vessels and work toward being more risk averse with new construction.

The reliability rate of over 99% comes from data from over 3,500 systems. Results like these have led to some of the world's largest offshore producers to look into protecting themselves from the negative effects of lightning, providing a critical safety net for their equipment, personnel, and bottom line. OE

FURTHER READING

Drabkin, M., Mui, C., Ong L.; *Lightning Protection of Tall Structures*, 2012 International Conference on Lightning Protection; Vienna, Austria; September 2-7, 2012.

Peter Carpenter *has more than 26 years experience in electronic engineering and lightning protection. Since 1988, he has been the director of applied engineering at Lightning Eliminators and Consultants. He has assisted in many field evaluations to solve past bonding, grounding, power conditioning, and lightning-related electronic failures. Carpenter studied electrical engineering technology at Cerritos College, Norwalk, California.*

JDR Cable Systems is now producing production umbilicals and power cables at Hartlepool.

Fabrication grows in North-east England

By Elaine Maslin

Increasing construction and installation activity globally is driving a demand for fabrication and manufacturing capabilities.

With its shipbuilding and petrochemical heritage, northeast England is rising to meet the challenge.

From a cluster of towns centering on Newcastle, Darlington, and Teesside, umbilicals for Australia's Wheatstone and Angola's Lianzi developments will be made at a new umbilical manufacturing plant.

J-lay towers for newbuild cable-lay vessels, destined for Brazil, are being fabricated in the area, alongside launch and recovery systems (LARS) for the global market.

Deepsea mining technology, to be used offshore Australasia, is being developed and manufactured here.

Martin Moon, managing director of Darlington-based Subsea Innovation, says: "The strength of the northeast is that it has always had a strong engineering background. I moved here 35 years ago to work in the shipyards, and the area still has the highest percentage of naval architects in the world, even though it is not building ships anymore."

This has resulted in high levels of investment in the area in recent years.

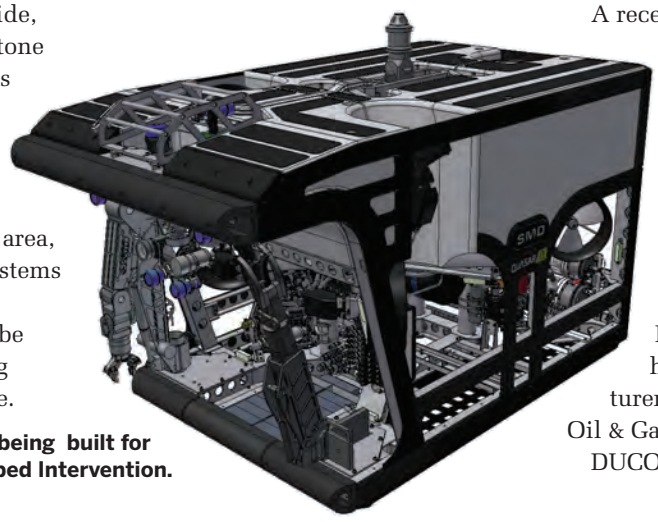
In 2011, JDR Cable Systems opened a £40 million (US$62 million) subsea production umbilical and subsea power cable quayside manufacturing plant at Hartlepool.

The same year, the site produced 200km of subsea array cables each for the London Array and Greater Gabbard offshore wind farms, southeast England. It is now shipping subsea production umbilicals, in carousels carrying up to 4000-tonne each, to southeast Asia from the facility.

A recent order will see JDR creating 10 custom-designed umbilicals, totaling 13km, for Swiber Offshore Construction to install on Brunei Shell's Champion field, offshore Brunei.

Further umbilicals manufacturing capability is being created by DUCO, at Walker Riverside, Newcastle, also home to umbilicals manufacturer Wellstream, now part of GE Oil & Gas.

DUCO, a subsidiary of Technip, is



SMD's Quasar ROV, currently being built for Modus Seabed Intervention.

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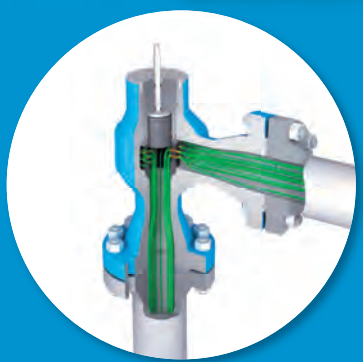

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IHC Engineering Business' designed the Hi-Traq inter-array cable trenching machine.

building its Newcaflex manufacturing facility—a 57.8m-high building housing a vertical helix machine to manufacture umbilicals.

Newcaflex already has an order backlog out to 2016, in addition to work at its existing facility, with projects including Chevron's Wheatstone and Lianzi project umbilicals, and 50km of umbilicals for Total's Moho Nord development off Congo.

When it opens, early in 2014, Newcaflex will compliment a recently opened 14,500sq ft research and development facility, also at Walker, home to about 30 engineers and containing test rigs for umbilicals, for its offshore operations.

The region's strength in subsea equipment, from ploughing and trenching systems to remotely operated vehicles (ROVs) and autonomous underwater vehicles (AUVs), is also attracting investment.

Subsea Innovation, a specialist in launch and recovery systems, tether handling systems and other subsea related equipment, led by Moon, has plans to add 40,000sq ft to its office and workshop space by this time next year.

Darlington-based Modus Seabed Intervention, founded in 2008, launched a new AUV division, after buying a Remus 100 AUV, and has employed senior ex-navy staff to lead it. Modus is also due to take delivery of a 150hp Quasar ROV later this year.

The Quasar, built at Newcastle-based Soil Machine Dynamics (SMD), will be the first work class system to use SMD's DVECS-S control system, along with technology developed by subsea vehicle software firm SeeByte, which together reduces pilot work-load and enables mission repeatability through auto-position controls, navigation map trail, cruise-control, advanced waypoint tracking, chart overlay, auto fly follow, and survey.

It was designed to work in high current areas and mostly targeted for offshore wind farms, but also oil and gas fields for survey, construction support, and IMR of subsea infrastructure.

Peter Imlah, technology director, says: "With technology like SeeByte, you can also better integrate control systems, allowing programming from point A to B, which, using sonar, the vehicle can then navigate. The long-term aim is to reduce the manpower needed to operate an ROV. For every ROV you need a team of 6-7 people. There will be more automation of activity, more reliability, and less maintenance."

SMD itself is a key tenant in the region, designing and manufacturing ploughing and trenching equipment, ROVs, used globally, and now also deepsea mining technology.

It is currently completing production of three, heavy-duty, deepsea mining machines—an auxiliary machine, a bulk cutter, and a collection machine, incorporating technology from Caterpillar and Sandvik, for Canadian operator Nautilus to carry out copper, silver, and gold mining on the seabed off Papua New Guinea.

Another firm meeting new markets is IHC Merwede subsidiary IHC Engineering Business, based in Stocksfield. It has designed a new trenching system, Hi-Traq, specifically for the burial of onshore wind farm inter-array power cables.

TAG Energy's production hall on Teeside creates offshore wind farm monopile and transition pieces with a 24/7 operational linear manufacturing line.

Product and systems development is a strong focus for the region, which is looking to build on its subsea expertise.

Plans were launched earlier this year for a new national subsea engineering center, the Neptune National Centre for Subsea and Offshore Engineering, to be led by Newcastle University, as part of a drive to develop new materials and technologies.

The region has applied for funding for new hyperbaric testing facilities, for

subsea equipment.

Valves manufacturer Bel Valves, at St Peters, Newcastle, is part of the group bidding for the hyperbaric facilities and is another company expanding.

Alison Ennis, Bel Valves marketing manager, says the company was early to focus on critical subsea applications, focusing on high-pressure high-temperature (HPHT), hydrogen sulfide, and deepwater, as well as developing all electric subsea systems, including single actuators for valves.

High-pressure fields, particularly, have driven change, she says, with a need for high-integrity, pressure-protection systems (HIPPS). Bel Valves has worked closely with BP in this area, including on the development of a subsea HIPPS for the Shah Deniz II project.

To meet demand, the company, owned by British Engines, plans to increase its premises by 30%, by relocating sister company hydraulics firm Rotary Power, freeing-up 12,500sq m.

This will enable it to create a dedicated test facility focusing on deep water, and HPHT. The next step, says Ennis, is moving in to even higher pressures, such as 20,000psi pressure through the pipeline.

"We are starting to look at limit of tolerance of metal itself," she says. "Pressures have continued to increase, which has meant products have got bigger and they cannot fit in the manifold. Then if they can get it in, they can't get it out because it is heavy. We are looking at redesigns and alternative design metallurgy."

Northeast England is still also home to large-scale fabrication, although not on the same scale as in the past. This summer, OGN, based at the Hadrian Yard, completed its first project, Apache's Forties Alpha satellite platform. It is now working on the Monarb (Montrose/Arbroath) platform jacket for Talisman Sinopec Energy UK.

OGN wants to move into industrial-scale production of jacket-based foundations for the offshore wind sector. However, the market has yet to fully emerge for offshore wind jackets and a new manufacturing facility to do the work requires US$100 million investment.

OGN, which can handle facilities weighing up to 13,000-tonne, is looking to work outside the North Sea, and looking to smaller work it could do at its Lowestoft yard, which has until now been dormant, says the firm's Carl Jepson.

Another fabricator, TAG Energy, has made the move into the renewables market. The company opened at the 42-acre, former Furness and Swan Hunter shipyard on the River Tees in 2007, in order to build a topside for a deepwater semisubmersible.

The project was dropped by the client and TAG decided to refocus on renewables, raising £20 million in grants and equity funding to develop new facilities, with further £15 million invested since then.

Last year, TAG became the first company in the UK to start manufacturing offshore wind turbine monopiles and transition pieces, with a 24/7 operational linear manufacturing line.

Alex Dawson, CEO at TAG, would like the site to be producing 60-100 monopiles and transition pieces per

year. Diameters of the foundations have grown from 3-4m, when they were first being built, to 6-7m today. Dawson says designs for monopiles with 10m diameter are now on designer's drawing tables.

There had been a move to use of jackets, but monopiles have been supporting turbines of up to 28-30m and are being extended to 35-36m, carrying bigger turbines, he says.

Bigger turbines are coming. In August, the National Renewable Energy Centre (Narec), at Blyth, just north of Newcastle, took delivery of a 7MW Samsung wind turbine nacelle, which will be used to commission Narec's £47 million (US$73 million) independent 15MW capacity test facility, before a six-month testing program begins on the nacelle.

Heavy engineering is not limited to jackets and wind turbine foundations. Allerton Steel, in North Yorkshire, works across industrial sectors, with a heritage in crane manufacturing. However, recent growth, particularly in the last five years, has come from the oil and gas sector.

From working on one to two oil and gas projects a year, oil and gas projects are now a permanent feature in the workshop and the sector accounts for 60-70% of the company's turnover.

These have mostly been structural elements, for topsides or jackets, but now Allerton is moving into mechanical plant, from J-lay towers to ROV launch and recovery systems and even an offshore wind turbine pile gripper for an installation vessel, recently installed.

Paul Denning, a director at Allerton, says the company's workshop is close to capacity and the firm is considering expansion.

It is a common theme in the north-east. Oilfield services firm Archer recently agreed a 10-year lease on a 22,000sq ft premises, and fluid transfer system FES International moved to a new manufacturing site in January, and is already considering further expansion.

Tekmar, a subsea cable protection specialist, is adding 75,000sq ft to its 27,000sq ft facility.

Skills in the region are attracting firms to make their first step into the area, including JDR but also Marine engineering business Houlder, flexible pipe specialist Flexlife, and London Offshore Consultants.

Allerton Steel constructs a J-lay tower at North Yorkshire.

"It is a resilient region with a good solid engineering base and with people who travel all over the world with their discipline and trades," concludes Moon. **OE**

North Sea renewal

After two years of planning, BP is about to launch a major renewal program on its North Sea Magnus and ETAP facilities. BP explained the program—and its long term aims—to Elaine Maslin.

Operators in the North Sea are tackling a thorny problem—how to maintain and sustain production on facilities reaching or past their design lives.

Industry initiatives, through the Health & Safety Executive (HSE), government/industry group PILOT and Oil & Gas UK, have focused on overdue safety critical maintenance, hydrocarbon leaks, and maintenance backlogs.

Now, attention is falling on production efficiency. According to Oil & Gas UK (O&G UK), in 2011 (the latest available data), North Sea production efficiency fell to 63%, compared to about 80% in 2004. O&G UK expects this to fall again to 60% in 2012.

COSL Rival Flotel

The difficulties facing operators are underlying integrity and reliability issues, and large workscopes, due to the age of facilities, with limited bed space available (persons on board or POB) for staff to carry out the work.

Enrique Sandoval, program manager, BP North Sea

The discovery of additional resources is also extending the lives of these assets, further increasing offshore scope, and demand for bed space.

Enrique Sandoval, program manager, is leading BP's North Sea renewal program. This is a multi-year multi-billion dollar investment across BP's UK sector fixed platforms, so far including Magnus and ETAP.

"If we continue at the current pace, we will not be able to catch up and plant operating efficiency (OE) will decline, leading to the need for a big intervention," he says.

"That means a lot of people on offshore facilities, without disrupting operations; shutting-in a field for a year is not necessarily a prudent decision. Renewal is finding a way of maintaining production, but significantly increasing the amount of work that can be done offshore."

What BP is doing BP's renewal program will address integrity and reliability and, ultimately, establish a more sustainable operating model (SOM).

Work on the renewal program started in 2011, with an overall review of the issues and opportunities across all BP's North Sea assets.

Magnus and the Eastern Trough Area Project (ETAP) are the first two assets identified for the program, starting with the Magnus Life Extension Project (MLXP), with work scheduled to start in 1Q 2014.

The appraisal phase for the ETAP Life Extension Project (ELXP) started in late 2012. The project team is currently evaluating potential vessels that could be used to deliver the project, mid 2015.

Appraisal of Clair, a third North Sea asset, will start in 4Q, this year.

The renewal program will be carried out through: specific interventions, to give a short term increase in engineering and POB capacity, to enable fabric maintenance work offshore and improvements in business processes, to reduce the requirement

for work, and to increase the work that can be delivered within the POB constraints.

An accommodation vessel will be used, with flotel, jackup, and walk-to-work options available. Additional work will help increase production, through well servicing, drilling, and OE improvement modification/maintenance, to be performed prior to, during, and/or following the campaign.

To establish a SOM, work will also be carried out to address specific issues, such as valve procurement and management and efficient maintenance of rotating equipment.

Magnus Life Extension Project (MLXP)

Magnus was discovered in 1974. It is in 186m water depth in block 211/12, 160km northeast of the Shetland Islands.

It had 1.6billion bbls initially in place and has been producing for 29 years, with peak production in 1990, at 176,000 b/d, 12,000 b/d gas condensate and 60MMcf/d gas. It has an estimated 900MM bbls recoverable and 500Bcf gas.

BP's estimated cessation of production date is currently 2027.

The facility comprises a central, conventional-steel, combined drilling and production platform, with 190 beds. The field contains a number of subsea producing wells.

Gas export is via pipeline to the

BP's renewal program addresses integrity, reliability, and establishes a more sustainable operating model.

Brent Alpha platform. Oil is exported via a pipeline to the Ninian Central platform.

Intervention

The MLXP workscope is non-shut-down-dependent and is mainly fabric maintenance, modification projects, and general maintenance.

The scope will use 143 POB, over and above the existing core crew, working a 24-hour day over 12 months (totaling circa 500,000 productive man-hours). About 30% of the extra 143 POB will be "green hats" initially, requiring close supervision—strict processes of control of work (CoW) and simultaneous operations (SIMOPS) will be followed.

The increased staffing requires a flotel alongside, to allow for 450 POB in field at a time, increased helicopter operations, and additional attendant vessel operations.

BP will use the 1976-built semi-submersible flotel *COSL Rival*, with a maximum 400 POB, expected to arrive in field in Q1 2014, and remain at Magnus for 12-13 months.

Drilling operations will be paused during the campaign to simplify management and interfaces.

The three main projects included in the intervention are: accommodation refurbishment; drilling upgrades, which consist of a blowout preventer (BOP) controls upgrade, BOP crane upgrade,

The Magnus platform.

cooling upgrades; crane replacement, and boom rest change out.

Sandavol says: "The main challenges will be the readiness in an extremely busy environment; live-operations environment; aligning and integrating BP and contractor workforces, on and offshore; sourcing, attracting, training, mobilizing, and retaining a safe and efficient offshore team; minimizing non-productive time and improving productivity in all offshore activities; and scope prioritization and control of change.

"The renewal program, with all the life extension projects within it, will need a lot of technical people," he says. "As we are not building any more beds, we will need to make sure all the bed space is used optimally."

The MLXP will also introduce new technology to improve operational efficiency.

BP is using R2S, developed by Aberdeen-based Return To Scene, an asset integrity and management tool using spherical photography—a visualization technology to provide a video of all areas of the platform—to create a "walk through" visual record of the facility. This can be used to view job sites, carry out initial access surveys, and allow personnel to familiarize themselves with key areas, without having to make a visit offshore.

The tool also reduces costs by enabling improved planning efficiency—for installation of scaffold, for example—communication and project management.

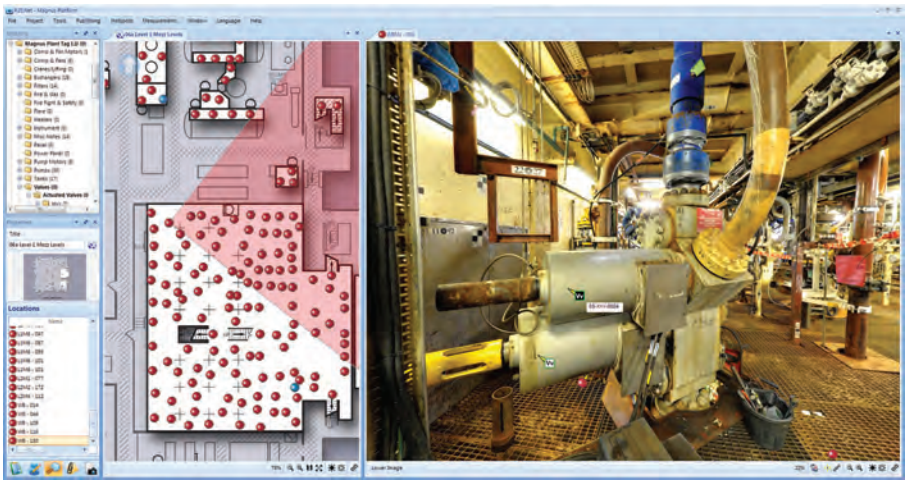
A number of other technology options are being considered to reduce the execution time to do work (painting and inspection techniques).

ETAP Life Extension Project (ELXP)

ETAP started production in 1998. It is in 95m water depth in blocks 22/24a and 22/24b, 240km east of Aberdeen in the central North Sea.

It is an integrated development of nine oil and gas reservoirs, with six fields operated by BP and three operated by Shell/Esso.

It is currently the largest producer for BP in the UK and Norwegian North Sea region. It is also one of BP Group's top 15 fields, in terms of value. Peak production was in 2000, at 217,000b/d



BP has used the R2S visualization and asset integrity management tool on the Magnus platform.

and 360MMcf/d gas. Its expected field life was 20 years, but continued reservoir delivery has led to potentially extending the economic life of the asset to 2030.

The ETAP central processing facility (CPF) comprises a production drilling riser platform, bridge-linked to a quarters and utilities (QU) platform, with a capacity for 117 POB. A normally unmanned installation, with maximum 12 POB, stands about 20km to the east. Oil is exported via the Forties pipeline system to Kinneil. Gas is exported via the CATS pipeline to Teesside.

Sandavol says OE of the ETAP facilities has been significantly impacted by underlying reliability issues. The asset is also aging, compounding the performance decline, and contributing to an overall decline in operating efficiency.

Intervention

The ELXP's main aim is to restore ETAP's operating efficiency and develop a SOM. The ELXP will include adding a new accommodation facility, to increase bed space by a minimum of 25 new beds.

In total, BP expects the project to spend about 400,000 direct man-hours, mostly on fabric and equipment maintenance-related work, with some like-for-like replacement of operating equipment.

The ELXP intervention will use a mobile accommodation unit alongside the QU platform, to provide access to the CPF, and support 24-hour manning. An option for an accommodation vessel has been identified.

Crucial to the entire program is planning, says Sandoval:

"We started in 2011 and will only begin work on Magnus in early 2014," he says. "It takes roughly three years to plan properly—to identify what the right work is, then how to do it around [a] live plant."

The team has learned from work on the ongoing Andrew Area Development, which is using a flotel to aid processing facility modifications

on the North Sea Andrew platform, as part of work to tie-in the Kinnoull oil field. However, in Andrew's case, the platform has been shut down.

SOM projects

The next challenge is to achieve a sustainable operating mode on the facilities.

"What has happened before is we, as an industry, keep doing the same thing again and again, and expect different results," says Sandoval. "We cannot keep doing this, we need to find ways of doing things offshore differently. This is where we need technology, such as R2S.

"We also need to revisit how we work," he says. Specifically, he wants to look at how job functions could be more flexible, so that one bed space occupant could fulfil multiple roles, instead of working in silos.

A program with the SOM appraisal work will look at technology use, organizational structure, recruitment and reward strategy, leadership capability, roles and responsibilities definition, and clarification.

Eastern Trough Area Project central processing facility.

Sandoval also thinks more can be done in specific areas to realize a SOM, such as valve maintenance and procurement, rotating equipment, and controls and instrumentation, which can then be duplicated geographically. "There are tens of thousands of valves offshore and they are crucial," he says. "Production losses can be down to valves. We decided how to look in to that common equipment type.

"How do we define what valves we use, how we buy them, how we get contractors in place, and how we make sure there are enough suppliers in place? Also, how do we then manage how we operate and maintain them in a consistent way?

"This is not about fixing specific equipment issues, but about creating a systematic model that identifies and proactively fixed gaps in the processes and systems to enable a long-term solution, minimizing overall production losses and increasing reliability in the long term," says Sandoval.

In addition, SOM projects will look at right-sizing and technical suitability of facilities and aspects of obsolescence.

SOM work will also move into looking at the effectiveness of root-cause failure analysis, risk and vulnerability management, personnel issues, and plant criticality.

Together, these initiatives aim not only to renew the Magnus, ETAP, and other North Sea facilities, but also to find better ways to maintain and sustain facilities' OE improvements and service requirements, following a flotel or any other vessel intervention. OE

Shallow water subsea systems improve NPV

Shallow water subsea systems can be an ideal solution for improving marginal field net present value. Jerry Streeter, Field Development Manager, for FMC Technologies, Inc., explains.

Very little has been published recently on shallow water subsea production systems (SWSPS) even though they were the foundation used to develop deepwater subsea systems. The large number of SWSPS in place worldwide and their many years of successful operation demonstrate the reliability that can be obtained with this equipment. SWSPS are now being seriously considered and installed by operators of all sizes (fully integrated, independents, and national oil companies) to boost mature field production rates by exploiting the reserves in close proximity to existing infrastructure that were previously considered uneconomical.

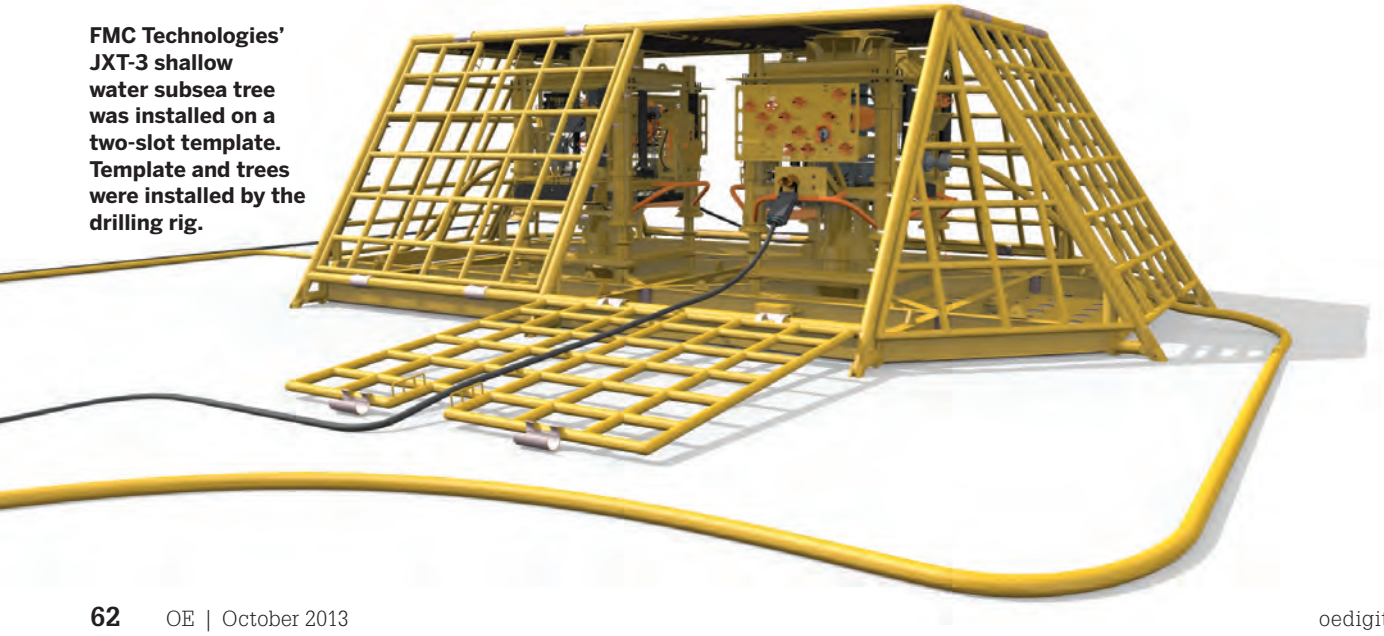
In cases where the reserves are in less than 130m of water and located within 10km of the processing facility, subsea production systems specifically designed for shallow water could make the reserves economically attractive to develop. Shallow water systems, run on 11-7/8 or 16-in. high pressure drilling risers using mudline suspensions systems or 13-5/8-in. wellheads, are specifically designed for wells drilled from jackup drilling rigs. Their functionality and lower costs make them ideal for smaller, short-life fields.

To fully appreciate the impact that a shallow water subsea system can have on a field's economics it is necessary to understand how a shallow water subsea system reduces costs and shortens time to first production.

Drilling and completion

The first option usually considered for developing stranded reserves is to drill additional wells from the existing platform. Often the challenge of this option is that the platform slots are full, so to drill a new well one of the producing wells would have to be plugged and the well sidetracked to the new target; taking this action lowers the net gain in production as the current production is now lost. If the new target doesn't produce as expected, reduced production could be the net result. A second option is to install a wellhead platform over the new well's bottom hole location and drill a vertical well. A third option is to modify the platform to support new well conductors. These options avoid the lost revenue associated with abandoning a producing well, but they do incur the costs of building a new platform or modifying the existing platform and a delay in getting production on stream while the platform – or platform modifications, are designed, fabricated, and installed. Even if the platform has an open slot, reaching the stranded reserve could entail drilling an expensive highly deviated well, which could also be an extended reach well.

A fourth option is to use a shallow water subsea production system. As in the wellhead platform case the well's surface location is directly over the bottom hole target location. This vertical, or slightly deviated well, reduces drilling time and expense, as well as the cost of modifying the platform, and



FMC Technologies' JXT-3 shallow water subsea tree was installed on a two-slot template. Template and trees were installed by the drilling rig.

eliminates the risk of taking a producing well out of production.

Shorter time to first production

While the period of time necessary to design, fabricate, install, and commission a well protector tripod platform will vary greatly around the world, 12-18 months from contract placement to commissioning is a typical duration for these activities. In some cases, the wells can be pre-drilled; however, it isn't unusual to wait for the platform to be installed before drilling the wells to minimize pre-investment. Producing a stranded reserve through a new wellhead platform potentially means production won't start for 18-24 months after project sanction.

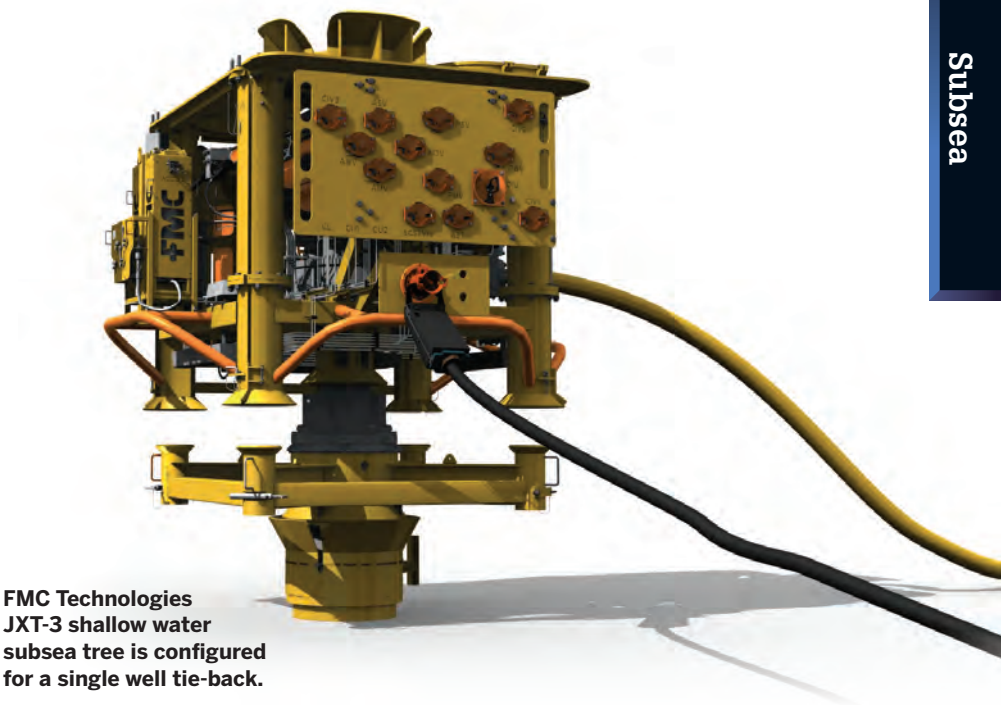
With no pre-investment, a shallow water subsea system can be installed and commissioned in as little as 9-12 months after project sanction. With minimal pre-investment, production can start as soon as six months after project sanction. FMC Technologies has implemented a stocking plan for long-lead equipment to reduce delivery times even further. With minimal pre-investment, an operator can drill and complete a well with a single mobilization of the jackup drilling rig.

Reduced installation costs

Installing a new wellhead structure entails mobilizing a derrick barge to the location for the installation work. Within the past year, IHS Petrodata reported the global average rate for a derrick barge is the range of US$300,000 to $350,000 per day. Shallow water subsea production systems are designed to be installed from the drilling rig, thus the cost of the derrick barge is eliminated from the capex. This is also true for decommissioning costs. The shallow water subsea system components are recovered by the drilling rig when the well is plugged and abandoned, eliminating the costs of the derrick barge to salvage the wellhead platform.

Field architecture

To achieve maximum cost benefit of using a shallow water subsea production system, the seabed architecture must be planned specifically for shallow water fields. A single well tie-back using direct hydraulic controls is the simplest form of subsea tie-back. Direct hydraulic controls are an excellent, safe means of controlling the production tree for tie-backs to 8km (5mi.). Most applications include electrical conductors in the umbilical for instrumentation mounted on the tree. Chemical injection to prevent or remediate hydrate and wax issues is accomplished via one or more chemical tubes in the control umbilical.



FMC Technologies JXT-3 shallow water subsea tree is configured for a single well tie-back.

Multiple well developments also hold the potential to achieve considerable cost savings using shallow water subsea systems, though it is imperative to keep the seabed architecture synergistic with jackup rig operations. When developing the seabed architecture, consideration must be given to the rigs being considered for drilling. Shallow water seabed architecture differs significantly from its deep water brethren as the shallow water seabed architecture must consider the time necessary to move a jackup from one location to another. In fields drilled with a floating rig, the rig can easily and quickly move a few hundred meters to keep the well's surface location directly above the bottom hole location. As a result, the favored seabed layout is a central manifold with production trees and injection trees spaced around the manifold. Flowline jumpers and umbilical flying leads connect the tree to the manifold and control system distribution skid. A dual or single flowline transports production from all wells to the processing platform, with subsea chokes mounted on the trees to balance production flowing pressure and rates from each well in the flowline. Jackups aren't able to easily and quickly move a few hundred meters to a new well, so drilling templates are used to cluster wells into drill centers under the rig's cantilever deck to avoid moving the rig to a different location for each well. Care must be taken that the center point of each well is within the working envelope of the cantilevered drilling and Texas decks of the proposed drilling rig. Two-, three-, and four-well templates are quite common; some rig cantilever deck windows and template layouts can accommodate as many as six wells.

In addition to wellhead locations and geometry, another important consideration is the method of connecting flowlines and pipelines. The common default practice for subsea systems is to use diverless hydraulic connectors, such as FMC Technologies' U-Con connection system, for connecting flowlines, jumpers, and spools to the subsea hardware. For the shallow water system discussed, saturation diving techniques allow these connections to be made using conventional pipeline flanges; swivel flanges and mis-align ball flanges; studs; and nuts installed

Traditional platform versus shallow water subsea system

Item	Platform Option (US$000,000)	Subsea Option (US$000,000)
Drilling	67.5	67.5
Wellhead Platform	60.0	
Subsea Trees, Control System, Control Umbilical		18.1
Flowline	81.1	81.1
OPEX	12.3	13.4
Workover	11.3	11.3
Total CAPEX	208.6	166.7
Total OPEX & Workover	23.6	24.7
NPV	54.0	119.0

Table compares CAPEX, OPEX, and NPV values for a conventional tripod platform and a shallow water subsea system.

with nut-tensioning equipment at great cost savings. Before selecting the optimum approach, the total installed cost, availability of divers in the region of the installation, and client safety requirements must be considered for each project.

A single well tie-back using direct hydraulic controls is the lowest cost option for a subsea production system. Sometimes it is advantageous to apply this principle to multi-well developments. One seabed architecture that has been used several times to simplify operations and reduce CAPEX is one in which the trees are placed on a template, then each tree is connected to the host facility with a discrete umbilical and discrete flowline. The higher cost of multiple flowlines and a control umbilical can be offset by the cost savings of a direct hydraulic control system over a multiplex control system, as well as the elimination of the subsea control module and the subsea choke. The number of wells, offset distance, and flowline diameters ultimately determine if this approach is cost effective.

NPV comparison

We can use a very typical three-well brownfield development to demonstrate the NPV improvement that can be realized by using shallow water subsea production systems. The shallow water field development team at FMC Technologies was asked to evaluate and recommend the most economically attractive method of producing a set of wells. The client had previously installed tripod wellhead platforms in a similar water depth in another district and wanted to determine if a shallow water subsea approach would be economically attractive in this

field. Therefore, the base case was to install three tripod wellhead platforms and produce the wells to an existing host facility in the vicinity. FMC Technologies was asked to develop capex budgets and schedule estimates for this base case, as well as a subsea alternate, so an economic evaluation could be completed. The following table summarizes the capex estimates and forecast NPV for each option.
The base case assumes drilling starts in Month 1 of the development process and all the wells are drilled with the same rig consecutively. Wellhead platform and pipeline procurement begins after drilling and first production occurs in Month 34. The subsea case uses the same timeline and cost assumptions for drilling. Procurement of the subsea system also starts after drilling, but due to the shorter delivery time of the subsea equipment first production occurs in Month 16. Both cases use $20,000 per well per month for opex. The subsea case has an higher total opex because production starts earlier and the model stops production in Month 239 in both cases rather than extending the analysis for 240 months from the time each well comes on production. Well intervention occurs after ten years of production and both cases assume a drilling rig will perform the intervention. In this case ,the subsea option had a lower capex and, due to the shorter time to first production, produced a significant improvement to NPV.

In many cases, shallow water subsea production systems can deliver a robust, cost-effective solution for marginal oil and stranded gas reserves. If operators attempt to offset declining production rates in mature fields by producing untapped reserves in the vicinity of their existing production facility but find conventional methods uneconomical, they should consider contacting a shallow water expert.

Companies like FMC Technologies have teams of experienced field development specialists dedicated to assisting operators develop their marginal oil and stranded gas reserves located in less than 130m of water. OE

Jerry Streeter *is a Marine Technology Society Fellow, and a past president and a former chair of the Offshore Technology Conference Program Committee. His involvement in offshore pipeline and subsea field developments projects began 35 years ago. Innovative application of technologies has been a mainstay of his career. His recent project work includes leading technical teams to conceptualize development plans for shallow water oil and gas fields and prove their commercial viability. Previously, he has led conceptual, FEED, and detail design efforts for the KivuWatt Gas Extraction Facility in Lake Kivu, Rwanda. This project combined oil and gas production technologies with gas-processing technology and the logistics of design for a facility to be constructed on a lake 1300km from the nearest port.*

Deepwater drivers

A high level of investment creates an opportunity for new entrants into the pipelay vessel market, says Douglas Westwood's Singapore-based analyst Thom Payne.

About 32,000km of offshore pipelines are expected to be installed over the next five years, representing a 22% increase over the past five-year period.

Not only is the offshore construction industry faced with the challenge of installing unprecedented volumes of pipe, it is also handling increasing water depths, high pressure, high temperature, and corrosive environments. New flow assurance technologies have also been designed to optimize productivity of subsea developments and keep installation engineers on their toes.

With about 66% of forecast kilometers to be installed in water depths beyond 500m, deepwater is fast becoming the norm for the offshore pipeline industry. The limits of the industry's technical capabilities are continually being tested, with all eyes now on Technip's reel-layer, the *Deep Blue*. The vessel was recently contracted by Shell to lay the world's deepest pipeline, in 2,900m water, to support the development of the Stones field in the Gulf of Mexico.

Including this record-breaking project, North America will account for 16% of deepwater pipelines—the third-highest of all major regions, behind Latin America with 26%, and Europe with 18%. Deepwater is generally defined as greater than 200m.

Brazil in particular drives demand for deepwater activity, with the country accounting for 60% of global

Newbuild - the *Sapura Diamante*, being built by IHC Merwede, for delivery 2014 to TL Offshore, a subsidiary of SapuraCrest, for the installation of flexible pipelines offshore Brazil. It is one of two identical 550-ton pipelaying vessels being built by IHC at the Krimpen aan den IJssel yard, Netherlands.

ultra-deep pipelines in depths greater than 1,700m. Brazil will also account for 58% of the world's flexible flowline demand over the next five years, with more than 3,300km of anticipated pipe to support the development of Petrobras' pre-salt fields in the Santos basin.

However, while the deepwater sector grabs industry headlines, conventional pipelines in less than 200m of water will remain a significant market with over 12,500km of anticipated projects to be laid over the 2013-2017 period.

Some 73% of the shallow water pipeline segment will be accounted for by the Middle East and Asia's support of fixed-platform infrastructure projects such as ADMA-OPCO's long-awaited Um Lulu development. Comprising of 215km of infield and export pipelines, the contract was awarded to the National Petroleum Construction Company (NPCC) earlier this year. The proposed Trans-ASEAN gas pipeline (TAGP) project could add up to 4,500km of mostly shallow water pipelines to the global network.

However, such ambitious construction plans are subject to supply chain capacity. The offshore sector faces a major challenge in ensuring such adequate capacity is available to prevent the rampant price inflation which caused severe slowdowns, delays and even cancellations during the 2006-2008 period.

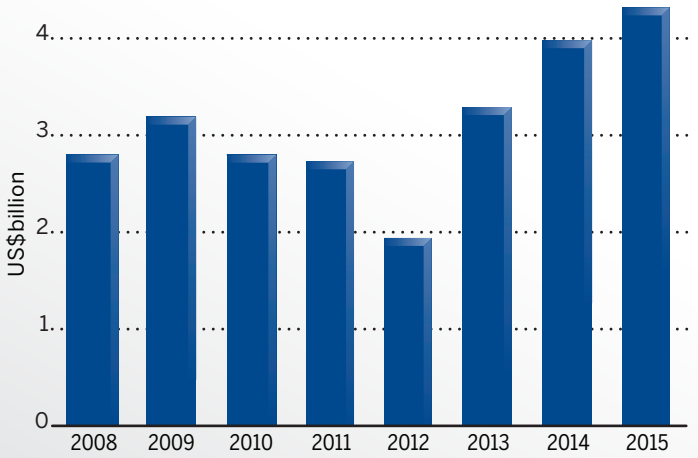
With pipelayer demand, vessel days are expected to jump from 15,500 days in 2013 to 22,700 days by 2017, an increase of 46%. Currently, there are approximately 28,680 potential vessel days available to work in the global market; however, only around 35% of that capacity is suited to the rigors of deepwater operations. The scale of the task becomes especially clear when combined with the anticipated global deepwater demand growth of 114% over the next five years.

Subsea 7 has already taken significant steps to close this gap, investing just under US$1 billion on three state-of-the-art, 550MT top-tension capacity flexlayers in July 2013. Subsea 7 began a joint venture between Technip and DOF Subsea, spending US$1.1 billion on four similar vessels. As it stands, the current order book will provide an additional 3,000 vessel days, but despite this multi-billion dollar investment, DW Energy Group predicts that up to 13 additional high-end pipelayers of various types will be required to satisfy global exploration and production plans over the next five-to-seven years.

With such unprecedented levels of demand expected, and the established contractors already at capacity and investing at record levels, it seems there is ample opportunity for new players to gain a share in the offshore pipe and subsea umbilicals, risers and flowlines (SURF) sectors.

We have already seen significant strides made by relative newcomers such as EMAS and SapuraKencana in the technically-challenging North Sea and Brazilian markets. The wider industry eagerly awaits to see how the rest of the supply chain will react. OE

Offshore pipelines subsea vessel operations expenditure



Global offshore pipelines subsea vessel operations expenditure 2008-15.
Source: Douglas-Westwood's world subsea vessel operations market forecast.

Thom Payne *joined Douglas Westwood as an analyst in 2006. He is involved in research, market modelling, and analysis for a range of sectors throughout the upstream oil and gas supply chain. He holds a law degree from the University of Kent and an MA in political sociology.*

Suppliers benefit from pipelay demand

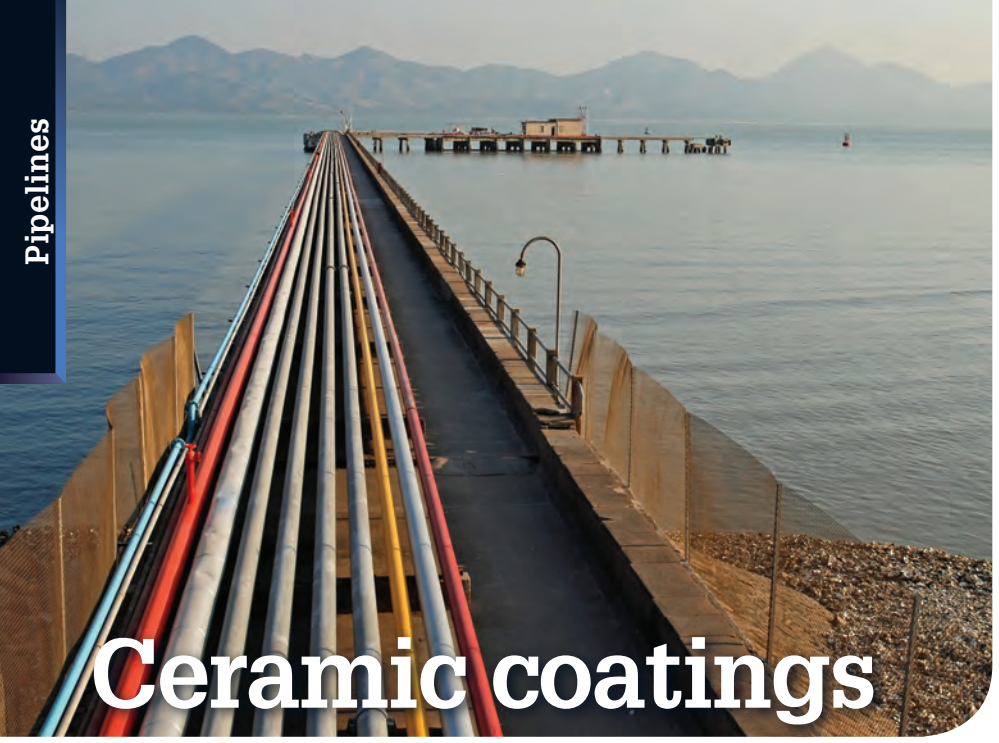
IHC Engineering Business, part of IHC Merwede, is benefiting from a demand for greater capacity in the pipelay market.

It is currently working on five orders from Seabras Sapura for 550-tonne capacity vertical flex lay systems (FLS) to be installed onboard fully integrated IHC Merwede newbuild vessels. These are due to be deployed globally, with delivery of the first vessel due in Q2 2014, to enable activity to start on Petrobras projects in Brazil.

The 550-tonne capacity FLS system consists of a twin, four-track tensioner system, with a maximum dynamic line tension of 600-tonne. It can accommodate a product range from 50mm to 648mm, and has a primary and secondary abandonment and recovery system and tower tilt functionality.

For these projects, IHC EB subcontracted some of the scope to SAS Offshore, based in Alphen, Netherlands, which is providing 300-tonne four-track tensioners.

This year IHC EB has already supplied McDermott with a 300-tonne capacity vertical FLS, to upgrade the horizontal FLS of the *North Ocean 102* for work in the North Sea, and, early next year, it will deliver a 300-tonne capacity system to SapuraKencana for Petrobras operations. Sea trials were recently completed on a 450-tonne capacity reel lay system on Technip's flagship vessel *Deep Energy*. Once in service, *Deep Energy* will be one of the fastest pipelay vessel ever built.



Ceramic coatings can prevent corrosion

Corrosion has long been the bane of the oil industry. Now new approaches and coatings are resolving the difficulties and providing intriguing possibilities for offshore pipelines, explains Tony Collins of EonCoat.

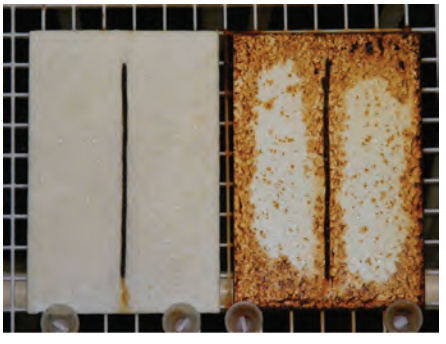
In the oil and gas industry, corrosion accounts for over 25% of failures, according to a recent National Association of Corrosion Engineers (NACE) International report. Corroded pipe repair or replacement costs the industry over US$7 billion per year, based on estimates from NACE. This figure can double when lost revenue, productivity, and spill or leak cleanup costs are tallied.

As deepwater exploration accelerates, protecting offshore pipelines from seawater corrosion is becoming more vital than ever to preserve deeper and more costly oil and gas assets. While offshore pipelines supplement corrosion protection with cathodic protection, the main defense against corrosion remains external pipeline coatings, particularly fusion-bonded, epoxy-powder coatings.

"Corrosion is a major industry challenge," says Scott Justice, Tank Division operations manager of Bolin Enterprises Inc. (BEI), a Casey, Ill.-based pipeline and tank maintenance contractor serving the oil and gas industry.

While traditional corrosion protection has relied mostly on short-lived, physically-bonded coverings of substrate surfaces such as tapes, elaborate three-part coating systems (zinc, epoxy, and urethane), and cathodic protection, these merely attempt to lengthen the time before the steel asset inevitably rusts.

Now a growing number of proactive, oil and gas industry maintenance professionals are turning to a new category of tough, chemically-bonded, phosphate ceramics (CBPC) that can prevent corrosion, extend equipment life, and minimize the cost and production downtime required to recoat, repair, or replace corroded equipment.



EonCoat is a true ceramic coating that delivers a tough-as-nails, corrosion resistant coating that can stand up to just about any application in the industrial or commercial sector.

EonCoat is resistant to high temperature, abrasion, chemicals, UV sunlight, and other environmental factors.

New approach

"What caught my eye about [CBPC coating] was its unique adhesion and chemical properties," says Justice, who visited Wilson, N.C.-based EonCoat LLC to view its corrosion testing lab, processes, and procedures for its CBPC coating. "If its hard outer shell is breached or knocked off, it still has corrosion protection where traditional coatings do not. Whether its coating is aged, beaten, or banged around, it still protects the surface. If you remove the outer ceramic shell, the chemical bond with the substrate still stops corrosion at the surface."

In contrast to typical paint polymer coatings that sit on top of the substrate, the anti-corrosion coating bonds through a chemical reaction with the substrate, and slight surface oxidation actually improves the reaction. This makes it impossible for corrosion promoters like oxygen and humidity to get behind the coating the way they can with ordinary paints. The corrosion barrier is covered by a true ceramic shell, which resists corrosion, fire, water, abrasion, chemicals, and temperatures up to 1000°F.

While traditional polymer coatings create a film structure, which mechanically bonds to substrates that have been extensively prepared, if gouged, moisture and oxygen will migrate under the coating's film from all sides of the gouge. Moisture and heat are then trapped by the film, creating a "greenhouse effect," promoting corrosion and blistering. By contrast, the same damage to the ceramic-coated substrate will not spread corrosion because the steel is essentially alloyed. Its surface oxides have been converted into an inert, electrochemically stable metal incapable of supporting oxidation.

Ceramic coatings such as this consist of two, non-hazardous ingredients that do not interact until applied by a plural-component spray gun like those commonly used to apply polyurethane foam or polyurea coatings. Since the components are not mixed and do not meet prior to application, the need for hazardous volatile organic compound

(VOC)-generating ingredients is eliminated, as are hazardous atmospheric particles and odor. This means that the work can be done in occupied areas.

"The results of the corrosion tank test were impressive," says Justice. Among the corrosion tests frequently run by the manufacturer of the CBPC product is one where the ceramic coating has gone more than 10,000 hours with no corrosion in a salt spray ASTM B117 test. "If the coating works as well as we hope, it could help to stop or minimize corrosion and extend the longevity of a range of oil and gas assets," adds Justice.

Independent electrochemical corrosion potential testing of the CBPC product also indicates its usefulness for offshore pipeline corrosion protection. Steel plates coated with EonCoat were placed in a beaker of saltwater by Dr. Ki Yong Ann, Dept. of Civil and Environmental Engineering, in a lab at Hanyang University, Seoul, Korea. When voltage was run through the solution and the corrosion rate determined by measuring current leakage across the coating in ma/sq m, the coated plates were found to have no corrosion potential. Any result below "2" is considered to have no corrosion potential, and the coated plates tested at 1.15 the first time, and 0.85 the second time.

For submerged offshore pipeline applications, an anti-fouling topcoat can be added to the CBPC coating, which enhances appearance and reduces barnacle growth.

Unlike organic, carbon polymer-based paints and coatings, which may give a foothold for corrosion causing microbes to grow, ceramic coatings are completely inorganic, so they are inhospitable to mold or bacteria. "Since EonCoat is inorganic, it cannot sustain mold or bacteria growth," says Justice.

While not widely considered, the Achilles heel of many traditional corrosion coatings may be in how exact the environmental conditions must be during their application to meet specifications. "A lot of coating products fail due to changes in temperature, humidity, dew point, and other atmospheric factors during application," says Justice. "As conditions change seasonally throughout the year, it can be difficult to provide perfect coating conditions."

Protective ceramic coatings can be applied on hot or cold surfaces, from 40-150°F in 0-95% humidity, excluding direct rain.

"Since the ceramic coating takes changes in temperature, humidity, and dew point out of the equation during application, it can be reliably used in tough environmental conditions that might otherwise compromise the corrosion protection of typical coatings," says Justice.

Cutting downtime

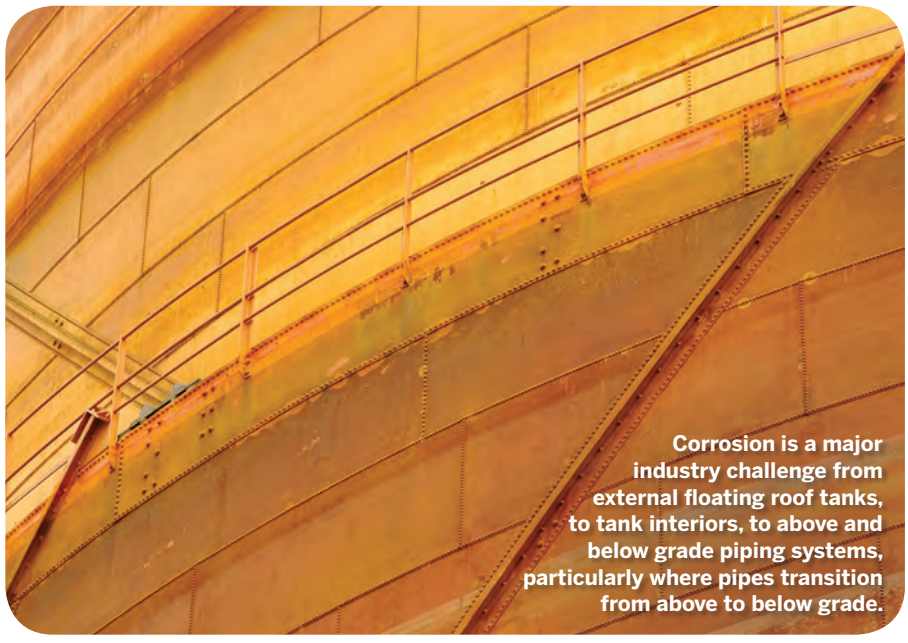
Shane Bartko, a director at TKO Specialty Surfaces, a Calgary, Alberta-based tank, pipeline, and structure maintenance contractor, has used the ceramic coating for corrosion control on a variety of oil and gas projects. "To keep a corrosive coating working well, you want one that will be resistant to high temperature, abrasion, chemicals, UV sunlight, and other environmental factors," says Bartko.

The time saved on a corrosion coating project with ceramic coating comes both from simplified surface preparation and expedited curing time. "With a typical corrosion coating, you have to blast to white metal to prepare the surface," says Bartko. "But with the ceramic coating, you typically only have to do a NACE 3 commercial brush blast." Bartko explains that on coating projects using typical polymer paints such as polyurethanes or epoxies, the cure time may be days or weeks before the next coat of three coatings can be applied, depending on the product. The cure time is necessary to allow each coat to achieve its full properties, even though it may feel dry to the touch.

In contrast, ceramic coating is applied in a single coat, with almost no curing time necessary. Return to service can be achieved in as little as one hour.

"With the ceramic coating for corrosion protection, we're able to get facilities back up and running right away after spraying, sometimes in an hour," says Bartko. "That kind of speed in getting an oil and gas facility producing again can potentially save millions per day in reduced downtime. It makes sense to use the ceramic coating anywhere steel is used and may corrode, from pipelines and processing to storage." OE

Tony Collins *is CEO of EonCoat, LLC, concentrating his time on commercial applications of Ceramicrete technology. Collins founded Turbine Generator Maintenance, Inc., an independent service provider for gas and steam turbines, in 1986 and sold it in 2007, after amassing customers in 47 states and 15 countries. Collins earned a BS in Mechanical Engineering (1978) from Georgia Institute of Technology.*



Corrosion is a major industry challenge from external floating roof tanks, to tank interiors, to above and below grade piping systems, particularly where pipes transition from above to below grade.

GOM major projects have blossomed- a picture IS worth a thousand words

By Bruce Crager

The US Gulf of Mexico (GOM) has clearly returned to the spotlight as one of the hottest offshore regions in the world. The impact of Macondo appears to be in the past and the number of both drilling rigs and major production projects are increasing. As an example, the Kiewit Offshore Services yard in Ingleside, Texas, recently had a unique display of floating production systems under construction in early June which included:

Shell Olympus TLP – The unit is now located at Mississippi Canyon 807 in about 3000 ft of water. This is the largest TLP in the GOM, weighing in at a massive 120,000 tons, and Shell's sixth TLP in the region. The unit is the second in the Mars field which covers Mississippi Canyon Blocks 762, 763, 764, 805, 806, 807, 850, and 851; and is expected to extend Mars production to at least 2050. The hull was fabricated in South Korea, transported on the *MV Blue Marlin* to Kiewit, and the topsides were installed there before tow-out to the field, where it arrived on July 20. Production is expected to start in early 2014 with a capacity of up to 100,000boe. Olympus will have a platform rig with slots for 24 wells and six subsea tiebacks. Initial production will be from six subsea tiebacks in the West Boreas and South Deimos fields. Shell is operator (71.5% WI) with BP as the partner (28.5%).

Anadarko Lucius Spar – The hull for this unit was fabricated in Pori, Finland, and arrived at the Kiewit yard in June on the *Mighty Servant I*. This cell-spar hull weighs 23,000 tons with a length of 605ft and diameter of 110ft. The topsides, which are being fabricated at Kiewit, weigh another 15,000 tons and will be set in nine lifts with the heaviest being 10,250 tons. This deepwater field will require some of the largest installation vessels in the industry. The large offshore lift will require Heerema's *Thialf*. The hull was recently installed in 7100ft of water in Keathley Canyon 875 in September, where the Balder installed the nine mooring legs. Other vessels to be used include the *Solitaire*, *Castorone*, *AEGIR*, *Deep Energy*, *Audacia*, *Iron Horse*, *Orion*, and *Deep Blue*. The production capacity of the spar will be 80,000bo/d and 450MMcfd. Production is expected to commence during the second half of 2014. Anadarko is the operator (27.8

L to R: Shell Olympus, Delta House FPS decks (on ground), Kiewit Heavy Lift device, Anadarko Lucius (Spar hull on Mighty Servant I at bulkhead; main topsides just beyond, sub cellar deck and work deck father back), Chevron Big Foot hull and Jack St Malo TLP.

% WI) with six other partners.

Chevron Big Foot TLP – This unit will be installed in Walker Ridge (WR) 29 in about 5,300 ft. of water and is expected to come online in 2014. The hull is an extended TLP with a production capacity of 75,000 bo/d and 25 MMcfd. Total expected project cost is over US$4 billion. The TLP will include a platform rig on deck, using two high-pressure drilling risers, and has capacity for 15 production/injection top-tensioned risers. Chevron is operator (60% WI) with partners Statoil (27.5%) and Marubeni Oil and Gas (12.5%).

Chevron Jack/St. Malo FPS – This semisubmersible floating production system will be installed in WR 758 in about 7000ft of water. The overall development cost is estimated at $7.5 billion with production ramping up in 2014. The FPS has a production capacity of 170,000bo/d and 42.5MMcfd with provisions for future water injection of 200,000b/d. It will produce from three fields: Jack (WR 758, WR 759), St. Malo (WR 678) and Julia (WR 584, WR 627, WR 628, WR 540, WR 583) using multiple subsea centers. Chevron is operator of Jack (50% WI) and St. Malo (51% WI), while ExxonMobil (50% WI) is operator for Julia.

LLOG Delta House FPS – This semisubmersible is similar in design to LLOG's *Who Dat* FPS, although the *Delta House* unit is approximately 40% larger in size and throughput capacity. The FPS will be installed in Mississippi Canyon (MS) 254 in 4500ft of water. The facility has a payload capacity of 9300 tons and production capacity of 80,000bo/d, 200MMcfd, and 40,000bw/d with peaking capacity up to 100,000bo/d and 240MMcfd. The hull is currently being built at Hyundai Heavy industries in South Korea and the topsides are being fabricated at Kiewit. Subsea wells will be tied back from MC 255, MS 300, and MS 431, and the FPS is designed to accept production from other subsea tiebacks in the future. The hull is designed to accommodate up to 20 steel-catenary risers (up to nine fields with dual flowlines). First oil is expected in the first half of 2015. LLOG is the operator and partners are Ridgewood Energy, Red Willow Offshore LLC, Calypso Exploration, Deep Gulf Energy II, Houston Energy, and ILX Holdings LLC, an affiliate of Riverstone Holdings LLC.

In addition to the projects above, there is one other record-setting project under construction just a few miles away from the Kiewit yard, which is also in the fabrication stage for the GOM. It is for **Walter Oil & Gas' Coelacanth project**, which is in Ewing Bank 834 in just under 1200ft of water. This water depth would not be unusual if developed with a floating production system, but Walter has committed to build the third-largest, fixed platform in the world. Those in greater water depths are Shell's Bullwinkle, installed in 1353ft of water in 1988, and BP's Pompano, which was installed in 1994 in 1290ft of water. Both are also located in the GOM. Walter decided to use a fixed platform with surface wells and a platform rig due to concerns over flow assurance with subsea tiebacks, the high cost and limited availability of moored drilling rigs, and the medium size topsides of about 3500 tons having a capacity of 30,000bo/d, 15,000bw/d and 60MMcfd. The jacket and topsides will be built in the Gulf Island Fabrication facility at Ingleside, Texas, which was originally developed for the Bullwinkle project. The jacket is a massive 31,000 tons.

There are a number of other projects moving forward in the GOM, but it is unique to see this many deepwater production assets in one place at one time, such as recently seen at Kiewit's Texas facility. A picture truly is worth a thousand words! OE

Photo: Kiewit

The USCG defines a crane as an offshore pedestal with a minimal lifting capacity of 5 tons. (Photo: Huisman)

Offshore cranes receive regulatory update

The US Coast Guard updated decades old regulations regarding offshore cranes and inspection practices. Anthresia McWashington takes a look at the changes to come.

The US Coast Guard (USCG) recently proposed revisions to the design, certification, inspection, and testing of cranes installed on Mobile Offshore Drilling Units (MODU), Offshore Supply Vessels (OSV), and floating Outer Continental Shelf (OCS) facilities. The USCG also proposed bringing in organizations other than USGC marine inspectors to certify, inspect, and test cranes.

The regulations proposed in May will affect businesses that own OSVs with cranes that have a minimum lifting capacity five tons (10,000 lb); businesses that own MODUs with cranes; and businesses that own 18 floating OCS facilities. In all, 2 cargo gear organizations, 19 crane manufacturers, and about 7 classification societies will be affected by the changes.

Until the passage of the 1996 Coast Guard Authorization Act (*Pub. L. 104-324*, 110 Stat. 3901), the USCG could only delegate marine safety functions related to vessel plan review and inspection to the American Bureau of Shipping (ABS), and the International Cargo Gear Bureau (ICGB). Section 607 of *Pub. L. 104-324* amended *46 U.S.C. 3316* to allow delegation of these functions to international classification societies.

Revisions also authorize the USCG to approve organizations other than the ABS and the ICGB as crane-certifying authorities.

The USCG expects that the additional classification societies will reduce crane operational down time, and allow greater flexibility in scheduling crane inspections and meeting required standards. Before any classification society can be delegated authority under this amendment to act on behalf of the USCG for any purpose, the statute requires that the classification society be recognized by the USCG.

According to the USCG, using outside organizations for crane approvals and inspections has proven successful on other USCG inspected vessels. The USCG has verified that these organizations have personnel who are specifically trained and qualified to witness tests of cranes and conduct crane inspections, and that these inspections can be scheduled more conveniently than inspections by the USCG.

ABS Vice President of Offshore Technology Bret Montaruli, said that this update in crane regulations is essential in improving day-to-day operations offshore.

"The USCG is introducing new regulations to address safety issues because it is important in a rapidly-changing market to make sure rules are in line with industry needs," Montaruli said. "ABS takes a similar approach, gathering input from industry experts to develop guidance like *Guide for Certification of Lifting Appliances* to help companies work safely as the work environment and the government rules change.

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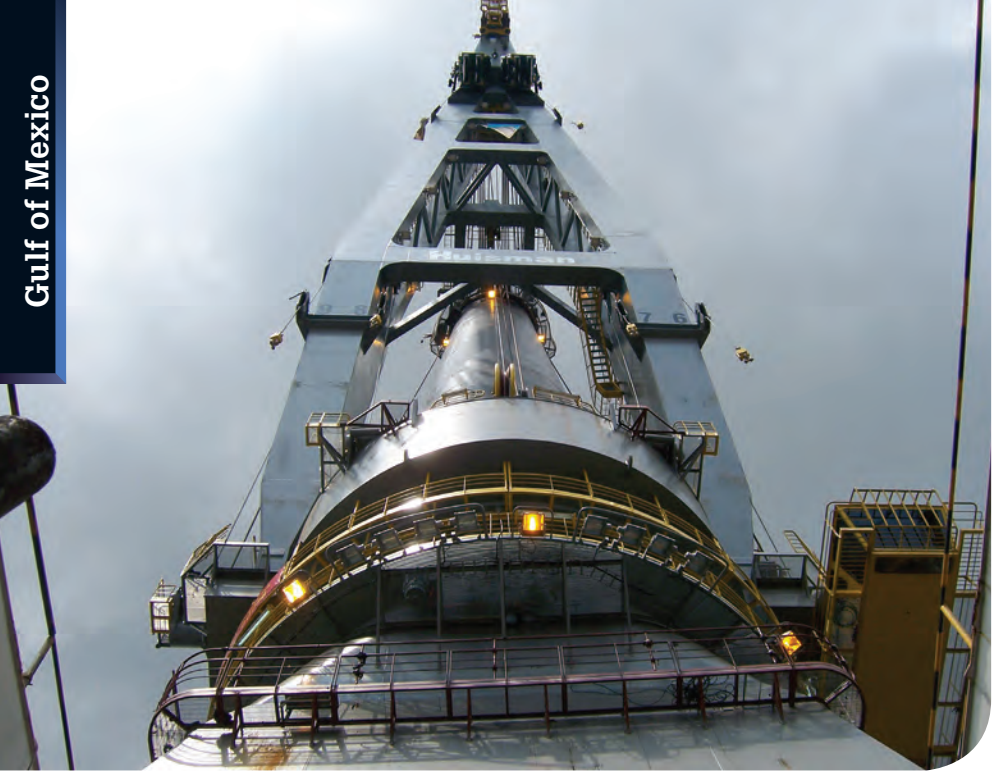

Subsea 7's construction vessel Seven Borealis had its 5,000mt offshore mast crane installed by Huisman in Schiedam, Holland, in 2011. (Photo: Huisman)

"It is an ongoing effort to keep pace with changes in the industry and to make sure the framework is in place for publishing Guide and Rule updates when they are needed," he said.

In addition to expanding the number of crane-certifying authorities, the proposed revisions include an explanation of the term "crane,"—defining it as offshore pedestal cranes with a minimal lifting capacity of five tons that would be listed in the Crane Record Book (CRB).

Comments regarding the new proposals closed on August 12, and despite some companies' concerns that sections of the revisions regarding crane regulations are inconsistent, the USCG insists that the current regulations are outdated and scarcely used within the industry, indicating the necessity for revisions.

As an example, Alan Spackman, IADC vice president of the offshore division, pointed out a conflicting statement in the USCG's clarification of the types of cranes that will be affected.

"They [USCG] define cranes as having a lifting capacity of more than five tons, but later state that they want something less than five tons," Spackman said. "We're just trying to get clarity as to what they actually want the records on, and make sure that the regulations are clear."

American Petroleum Institute (API) spokesman Brian Straessle said that API agreed that the new rule is necessary; however, the organization believes a few technical edits would help clarify certain requirements.

In a August 12th letter to the USCG, API's Director of Standards, David Miller said: "This proposed rule is necessary to enhance the safety of offshore cranes by ensuring that industry uses the best available and safest technologies for the operation, maintenance, design, and construction of cranes used on MODUs, OSVs, and floating OCS facilities.

"The proposed rule would also align Coast Guard regulations with Bureau of Safety and Environmental Enforcement requirements for cranes used on offshore fixed platforms.

"Additionally, the proposed rule would provide owners and operators of vessels the option and flexibility of using additional organizations and associations for the certification of cranes."

According to the US Federal Register, the USCG points out that current regulations reference the first edition of API's *Recommended Practice for Operation and Maintenance of Offshore Cranes*, published in October 1972, and the second edition of API's *Specification for the Offshore Pedestal Mounted Cranes*, published in February 1971.

The USCG's proposal updates these regulations by adopting more recent editions of the API Spec. 2c and RP 2D standards.

The proposed rules would also cause affected parties to include training, purchase API standards, and inspecting or reviewing operations in order to be in regulation. The USCG projects the costs of the proposal to be highest in the first year of compliance, at about US$886,000 (undiscounted 2011 US$), with additional annually recurring costs.

For the 10-year period of this analysis, the USCG estimates the annualized discounted cost of this proposed rule to be $445,000 at a 7% discount rate for a total of $3.12 million over 10 years, and $435,000 at a 3% discount rate for a total of $3.71 million over 10 years.

If approved, the implementation of these regulations could take place at any time; however, Charlie Papavizas, partner in the Winston and Strawn LLP law firm, said that there is no certainty to when updates will be put into effect.

"In my recollection, these regulations were first required in the 2010 Coast Guard Act," Papavizas said. "Updates will be enforced immediately upon effective date of the rule—sometime in the future after comments are received and analyzed." **OE**

FURTHER **READING**

1. *Guide for Certification of Lifting Appliances*, American Bureau of Shipping.

2. 1996 Coast Guard Authorization Act (*Pub. L. 104-324*, 110 Stat. 3901), United States Coast Guard.

3. *Recommended Practice for Operation and Maintenance of Offshore Cranes.* API.

4. *API Specification 2c*, API.

5. *Recommended Practice 2D Standards*, API.

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OE REVIEW

DEEPWATER INTERVENTION

INSIDE

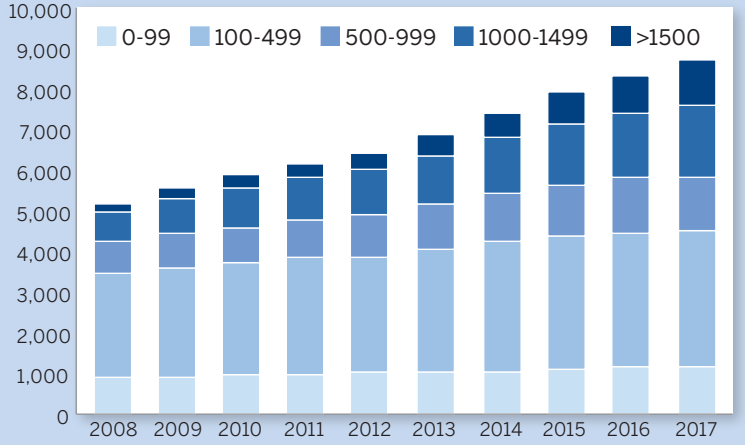
Pictured is *Helix 534* onboard Dockwise's *The Mighty Servant*. Read **OE Review**'s next Deepwater Intervention installment in November.

New frontiers: Depth drives intervention

*Growing numbers of subsea wells in increasingly deeper waters will continue to drive the market for well intervention capabilities. Infields' **James Hearn** outlines the market.*

Depleting oil and gas reserves within established shallow water areas and rising global energy demand over the past decade has led to oil and gas operators pushing the boundaries of exploration into ever deeper and more challenging waters.

Figure 1 – Global well intervention demand (vessel days) by water depth (m)



This drive toward deeper waters has led to significant new discoveries and has been one of the key industry trends of recent years.

Infield Systems forecasts that this deepwater trend is likely to continue for the foreseeable future, as the industry expands into new frontier regions, such as South and East Africa and the South China Sea.

The ever-increasing movement of offshore activities toward deeper waters has been driven by technological advances, particularly in the subsea production industry.

Subsea technology has helped unlock huge reserves of oil and gas, and reduced costs to develop deepwater fields.

There are more than 5,000 subsea wells in operation globally. Current growth in the number of subsea wells being installed shows no sign of abating and helps to fuel the need for associated services, such as subsea well intervention.

Well intervention remains an emerging market and is not yet common practice in many regions, with the exception of the North Sea and US Gulf of Mexico. However, as the operational base of subsea wells increases recovery rates from subsea wells are

typically 10-30% lower than platform-based wells—there is a key need for operators to improve recovery through the use of well intervention techniques.

On a global basis, the majority of well intervention activities are carried out in shallow water areas, and this demand mirrors the operational base of global subsea wells, with areas such as the North Sea containing a significant number of wells. Consequently, the region has the most developed well intervention market.

Future growth in intervention demand is anticipated to be driven by activity in the deepwater sector. During the 2013-2017 forecast period, deep and ultra-deepwater well intervention demand is expected to rise by a compound annual growth rate (CAGR) of 8% and 18%, respectively.

Infield Systems believes that the significant rise in the number of deepwater well installations will help boost the share of global intervention demand taken by deepwater activities to 29% during the 2013–2017 period, a rise of 8% above the 21% share estimated in 2008-2012.

Infield Systems expects deepwater well intervention demand to stem primarily from activities in the African, Latin American, and North American markets. In combination, these three regions are anticipated to account for more than 91% of total global deepwater intervention demand throughout the forecast period.

A handful of countries within these three regions, including Brazil, Angola, and the USA, are expected to account for the majority of demand. These three countries are at the very center of the deeper waters and should continue to provide significant long-term intervention opportunities.

With a 31% share of demand, the majority of future deepwater well intervention demand is set to come from the Brazilian market. Much of this activity is being driven by Petrobras fields located in the country's pre-salt basins.

Demand from the US GOM is expected to account for the second largest proportion of deepwater intervention opportunities, at 23%. The key difference between the two areas is that there is already an established base of deepwater intervention vessels working in the US GM.

Well Ops *Q4000* vessel has worked exclusively in the region since it was delivered in 2002, and its success has led Well Ops to order a sister vessel the *Q5000*. The *Q5000* will enter service in 2015 alongside the *Q4000* and the newly acquired *Helix 534*, a former drillship unit that has been converted into a well intervention vessel in order to serve the growing demand in the region.

With a 20% share of demand through the forecast period, the third largest market for future deepwater intervention activities is Angola. Total, the largest subsea well operator in the country recently contracted the *Skandi Aker* to perform intervention activities in the country on an initial two-year contract, which began in early 2013.

As the number of subsea wells continues to increase, with more and more coming on-stream across the globe, deepwater intervention demand is expected to continue its recent growth trend. This expected growth could offer an increasing number of opportunities for specialized well intervention vessels to enter the market, especially as rig day rates continue to climb towards US$600,000/d for an ultra-deepwater unit. OE REVIEW

Since joining Infield Systems in 2011, ***James Hearn*** *has primarily been responsible for the development of the company's offshore drilling rig database. Most recently James has worked on a variety of research and bespoke client projects, and recently authored the updated version of the company's* Well Intervention Global Perspective Report.

Figure 2 – Deep and ultra-deepwater well intervention demand (vessel days) by region

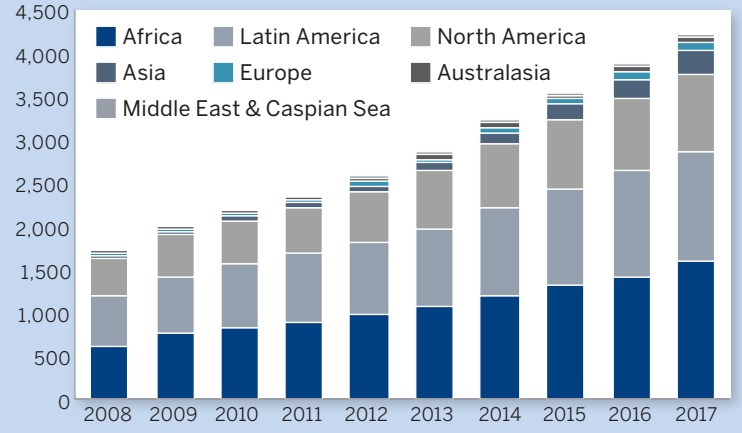
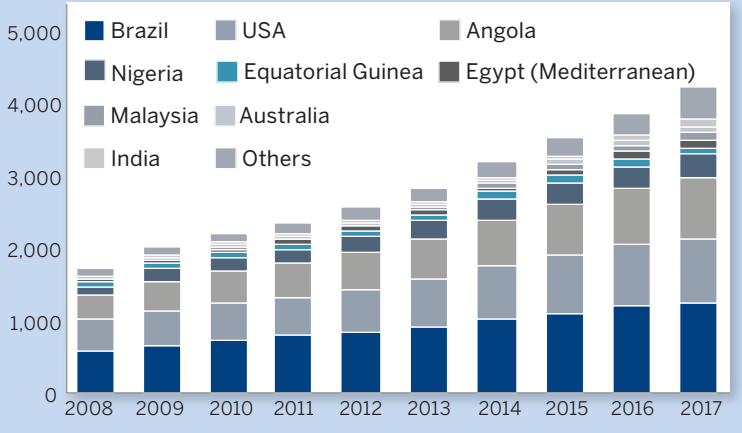


Figure 3 – Deep and ultra-deepwater well intervention demand (vessel days) by country



Anadarko warms to RWLI

Welltec and operator Anadarko describe a riserless light well intervention (RLWI) operation in deepwater Gulf of Mexico.
By ***Ole Eddie Karlsen and Steve Ashcraft***

Milling bit packed with set asphaltenes.

A recent operation in deepwater in the Gulf of Mexico demonstrated that asphaltenes can be removed on e-line as a riserless light well intervention (RLWI) operation.

As the industry is striving to find new resources to meet the growing demand, exploration and development is moving into deeper waters. According to Strategic Offshore Research Ltd. more fields are currently being developed from subsea than from platform; a trend which is also true for Anadarko. Anadarko currently has 30 dry tree wells and 64 subsea wells. Moving forward, the company expects that wet trees will become a larger percentage of their total wells.

There may be misperceptions about riserless light well interventions (RLWI) that lead operators to choose other technology solutions for subsea wells. Welltec makes the case for RLWI in an online exclusive on **OEdigital.com**.

Subsea wells pose technological challenges to increase hydrocarbon recovery. Interventions are a prerequisite for optimizing production over the lifespan of the well; however, wet tree wells have traditionally been intervened less than their dry tree equivalents. This has led to a significant difference in recovery rates, where subsea wells typically produce 10-30% less.

In the Gulf of Mexico, reservoirs are characteristically small, deep and complex. But, the potential for improved oil recovery is large: approximately 30 billion bbl estimated original-oil-in-place in discovered fields at abandonment (Li et al, 2010).

With a growing number of subsea wells, the economic gains from RLWI operations are obvious. To realize this potential, Anadarko is currently exploring the possibilities, learning more about the technology by testing it on selected wells. Well selection is of utmost importance to Anadarko, as not all their subsea wells are suitable candidates.

With the current technology, 80-90% of the intervention scope can be performed using RLWI, includling complex mechanical manipulations and clean-out operations. RLWI makes well maintenance operations, like well stimulation, sand, scale and debris handling, and replacing hardware, feasible. Frequent subsea interventions lead to enhanced recovery and will close the gap between production rates on dry tree and wet tree wells. To date, more than 2,000 RLWI operations have been performed worldwide in more than 400 wells with a very high degree of efficiency and cost-savings.

In the Gulf of Mexico and the North Sea, operators regularly perform RLWI operations and recently this trend has expanded to other regions such as Asia Pacific, West Africa, and Latin America. The RLWI method is less expensive, inherently safer, and leaves a smaller carbon footprint than conventional interventions. In addition, the quick mobilization and higher scheduling flexibility makes this method highly attractive, especially to operators with a large number of subsea wells.

RLWI operations are performed with e-line tools, allowing lightweight "heavy" workovers performed from monohull vessels. The e-line tools are deployed in a subsea lubricator through open water from the vessel down to a subsea stack, and landed on the production tree. As this method has no connection to surface, it eliminates the risk of blowouts, thus increasing the safety of the operation. With thorough planning including cable simulation and proper downline management, the method is even applicable in deepwater; in fact the case at hand set a new world record water depth for RLWI e-line operations of 3991ft (1216 m).

The use of e-line tools offers robotic precision, efficient operations and fast rig up/rig down, return-

ing the well quickly to production. No fluids are introduced, which diminishes the risk of reservoir damage, and surface read-outs allows the crew to monitor the operation in real-time. All tools are equipped with passive fail-safe mechanisms that prevent the tools from getting stuck in case of power-loss. Often a Welltec Release Device run on battery is incorporated into the toolstring, which auto-releases the tools after a set time interval with no cable power creating a fish. In fact, the latter is mandatory in operations on the Norwegian Continental Shelf.

Welltec introduced the original Well Tractor and thus has nearly two decades of experience with this type of conveyance. The lightweight design of the Well Tractor and the innovative nature of Welltec meant that it was only natural to be part of the select few that set out to pioneer rigless and riserless interventions when RLWI possibilities were first explored back in 2000.

During this specific intervention, two e-line tools were employed: the Well Tractor and the Well Cleaner RCB. The Well Tractor is a conveyance tool that enables interventions in all environments. It extends the reach of intervention tools and provides pinpoint accuracy irrespective of the well inclination. During milling or cleaning operations it functions as weight-on-bit and counters the reactive torque from the rotation.

The Well Cleaner RCB is a unique tool that incorporates built-in bailers to capture debris. RCB means reverse circulating bit; it is a system that allows debris to pass through the milling bit and into the bailer sections of the toolstring.

In November 2012, Anadarko initiated its first RLWI operation. The purpose was to set a subsurface safety valve (SSV) across a failed, closed, surface controlled subsurface safety valve (SCSSV). The downhole conditions were unknown, as the well had not been re-entered since it was put on production.

During the initial slickline gauge run, the toolstring kept hanging up after only about 1000ft. (305m) in the well. The first attempted to remove the blockage was with chemicals. However, as this was unsuccessful, it was decided to deploy a Well Tractor and Well Cleaner RCB to try to remove the obstruction.

The toolstring tractored past the slickline hold up depth (HUD), cleaning while moving at 10 f/h. and continued down to 5727 ft (1746 m) , where an obstruction was encountered and the toolstring became stuck. The toolstring was worked free and pulled out of the hole. At surface the bit was found to be packed with solid debris, while the bailer sections were filled with dense, hard-packed asphaltenes. These had not been anticipated in the well.

Thus, Anadarko decided to cease operations pending analysis of the recovered samples. As "asphaltenes" is a common denominator for a class of aromatic-type substances, which are defined on the basis of their solubility, proper analysis is necessary

Bailer section packed with dense asphaltenes after the filter is removed. Asphaltenes set once exposed to lower temperature; when in the well under a certain temperature the asphaltenes are stickier.

in order to determine the appropriate action.

The analysis confirmed that the material recovered was primarily asphaltenes with some entrained oil and Anadarko suspects that these will continue throughout the well. The only intervention option with the current technology is thus a coiled tubing (CT) clean-out with a riser and rig, and at this point it is uncertain if production will be restored.

Based on the experiences with this case well, Anadarko would like to see development of CT technology for use with RLWI to address larger deposits of asphaltenes. The RLWI method is still under evaluation by Anadarko and they see a potential for addressing more discrete deposits with downhole millers like the Well Miller and Well Cleaner.

The case example was Anadarko's first attempt at RLWI operations and it was achieved in a world record water depth for RLWI e-line operations of 3991 ft (1216 m). It was also the first time asphaltenes have been recovered using e-line cleaning tools. OE REVIEW

Ole Eddie Karlsen *is VP of global subsea operations at Welltec Norway. He has more than 20 years of experience in the oil and gas sector, with previous roles at Vetco Gray and ABB Offshore Systems.*

Steve Ashcraft *is a senior staff production engineer with Anadarko Petroleum Corporation, currently assigned to the Lucius facility. He has 18 years industry experience in drilling, completion and production operations. His offshore assignments include Snorre A tension leg platform (TLP), Valhall, BC-10, Terra Nova, Boomvang Spar and Marco Polo/K2 TLP.*

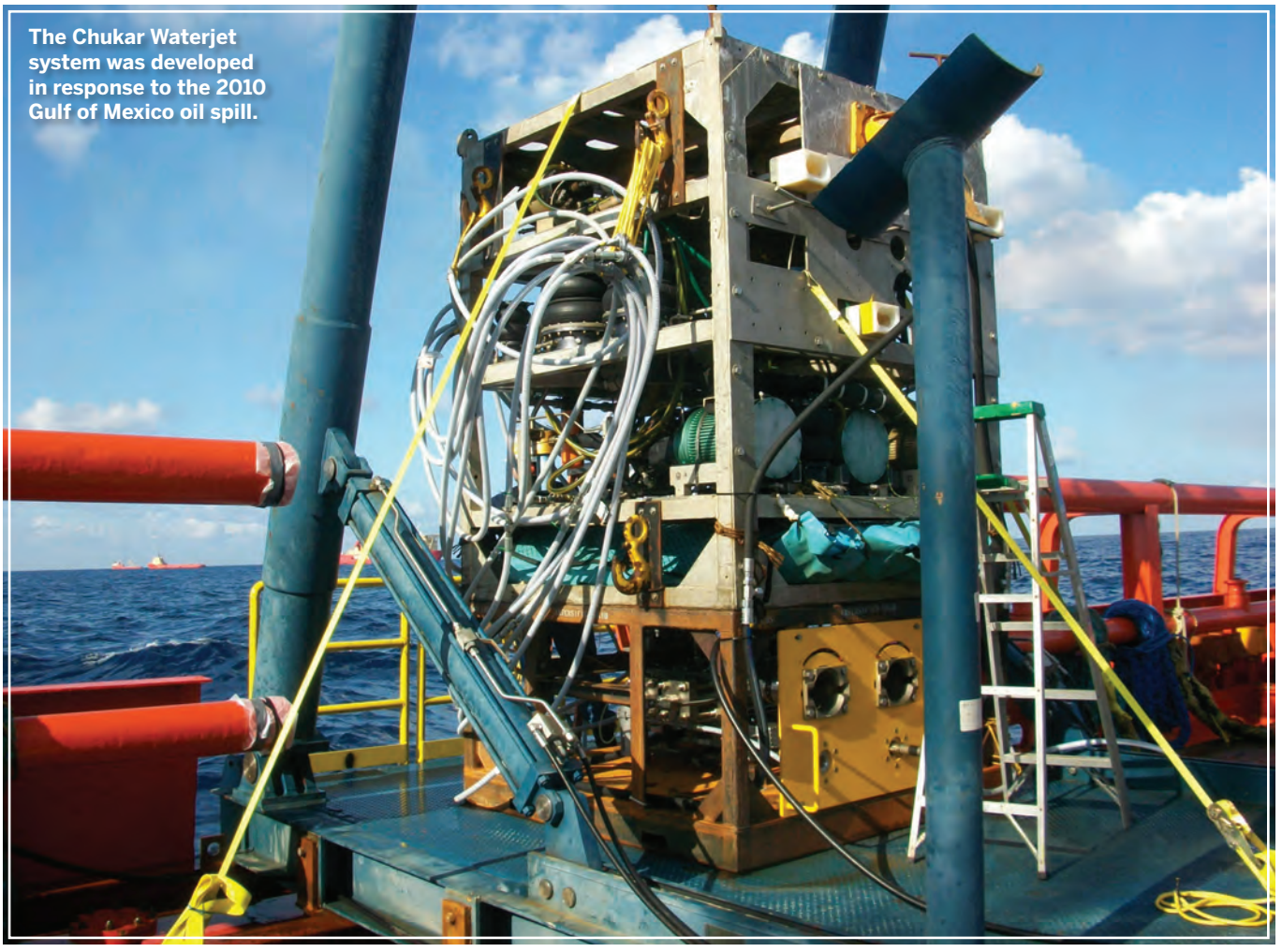
Subsea waterjet cutting goes ultra-deep and ultra-high pressure

Waterjet cutting went deepwater during the BP Macondo crisis. Now it is ready to go even deeper.

By ***Elaine Maslin***

Ultra-high pressure (UHP) waterjet technology has been used since the mid-1980s in the marine environment.

Its use is well established for surface preparation and corrosion removal, as well as for cutting, both in manufacturing processes and on infrastructure. UHP waterjet has also been used underwater, but until recently, this has only been to a depth of about 365m, due to the



The Chukar Waterjet system was developed in response to the 2010 Gulf of Mexico oil spill.

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inability to deliver abrasive to greater depths, as well as pressure loss inside the hose or high pressure tubing.

In 2010, Chukar Waterjet developed a waterjet system used at 1430m (5000ft) on the Macondo well in the US Gulf of Mexico. It needed to remove accumulating hydrates that were making it difficult to cap the well. Other methods of removing the hydrates, including using methanol dispersant, had been unsuccessful.

Chukar used seawater pressurized by a hydraulic waterjet intensifier pump, in conjunction with a methanol dispersing system, to remove the hydrates from the bottom and the inside diameter of the spool as it was being lowered into place. The sealing surface was then able to go over the flange and mate with the lower marine riser (with the spool acting as the connector), which the valve system could be mounted onto.

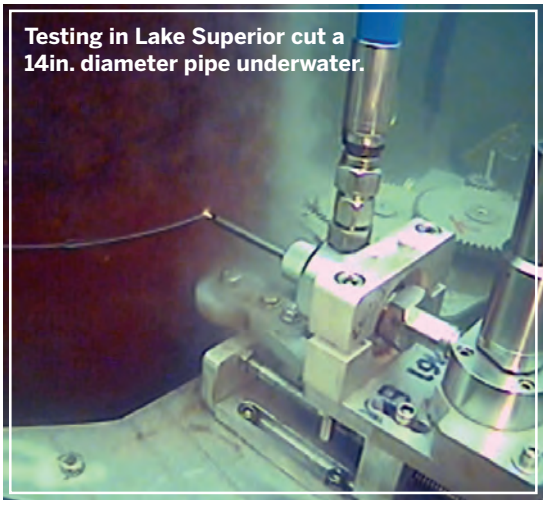
The system operated for extended periods while at 1430m deep and 3° Celsius (37° Fahrenheit), with ambient pressures of 150 bar (2100 psi) and exposure to salt water and methanol.

Chukar has now extended the depth at which its UHP waterjet intensifier technology can work to more than 3000m, for both cutting and hydrate removal.

In April, the latest system performed a successful test cut in in Thunder Bay, Lake Superior, Ontario. An UHP waterjet pipe cutter was used to cut a 14in.- (356 mm) diameter, ½in. (12 mm) thick steel pipe, in under 20 minutes.

Warren Christopherson, operations manager at Chukar Waterjet, says that saws designed for pipe cutting, including diamond-wire saws, can cut off pipes or other offshore structures, but they can bind, because they must enter into the saw cut gap (kerf) to complete the cut.

"Attempts to cut off the riser pipe at the Macondo oil well in 2010, with the use of a diamond-wire saw, were unsuccessful because the saw became stuck in the full flow pipe," he says. "After the saw was dislodged, a shear was then used to cut off the riser, leaving a jagged cut."



Testing in Lake Superior cut a 14in. diameter pipe underwater.

Underwater welding and flame-cutting techniques are well established, but safety risks have placed increased pressure on dive operators to minimize reliance on both, he says.

The system developed by Chukar is able to carry enough abrasive on the waterjet skid in order to provide cutting of 50m (160ft) of 12mm-thick steel, independent of depth, in a single deployment.

The process of abrasive waterjet cutting typically involves a UHP (3900 bar) stream of water with an abrasive, such as garnet, added. Without abrasive, water-only waterjets are typically used for cleaning or for cutting soft materials.

Using waterjet tooling, either hand-held or using an ROV, the UHP stream is directed to a surface or cutting area, for cutting holes or linear cuts, and cutting pipes from the inside or outside.

The system, controlled from the surface, is deployed with an umbilical cable, providing power and communication, using either a diver or ROV to aid skid and tooling placement, depending on water depth.

For coating removal or hydrate remediation, seawater or methanol is pressurized to 3900 bar by an intensifier-style pump, to create a uniform application to remove coatings like epoxy or concrete without damaging the substrate.

For cutting applications, seawater is pressurized to ultra-high pressure by the intensifier-style pump, and abrasive is added to create a cold-cutting tool, effective at cutting most material, including up to 250mm steel.

Chukar's system is powered by a 150hp electric motor, running at 3000 volts and is aimed at cutting and cleaning, decommissioning, maintenance, and salvage, as well as emergency response use. Sea water, plain water or methanol can be used, along with abrasives added for cutting applications. OE REVIEW

During testing, the skid was deployed at Lake Superior.

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SPE Offshore Europe – Standing room only

The strength and the level of activity in the oil and gas industry was clear at this year's record-beating 40th anniversary SPE Offshore Europe.

The event attracted more than 63,000 people—a number significantly higher than the anticipated 50,000 and a 25% increase compared to 2011's show.

As the official media partner for the event over the past 30 years, OE produced the show daily for SPE Offshore Europe 2013 straight from our booth. If you missed a copy or would like to go back and read our coverage, please visit oedigital.com/oe-oe. And be on the lookout for our official digital show review supplement, due out mid-October.

Conference chairman Malcolm Webb said that the UK oil and gas industry is the country's greatest industrial success story in more than 100 years and this year's SPE Offshore Europe served to underline that fact.

That success is clearly anticipated to continue, and was highlighted by the show's theme—The Next 50 Years.

Egbert Imomoh, SPE President for 2013 said: "I was honored to be part of this hugely successful event and to witness the busy exhibit halls, full keynote, and technical sessions all week long.

"Rightfully so, a note of sobriety ran through the event, with respects paid to those who lost their lives in the Shetland helicopter crash, but it is through these exchanges that we learn and become a safer, more productive industry."

Vasyl Zhygalo, senior exhibition director, Reed Exhibitions, said the 40th anniversary of the event had been a fantastic success. "Our conference and exhibition have been successful in equal measure. There has been an outstanding line-up of top industry speakers with standing room only at many of the key addresses and presentations.

"We've also been overwhelmed at the response from exhibitors many of whom have been queuing to sign up for 2015."

And so to the next SPE Offshore Europe—the date is set: September 8-11, 2015. OE

GMS unveils S-Class jackup

By Elaine Maslin

UAE-based GMS Offshore Contractors is introducing a new class to its fleet, to further expand the business.


Duncan Anderson, GMS CEO

The S-Class will be a new self-elevating, self-propelled DP2 jackup barge, bridging the gap between the firm's existing smaller K-Class and large harsh weather E-Class jackups.

It will be a harsh weather barge, but smaller, cheaper and more utilitarian than the larger E-Class, Duncan Anderson, CEO at GMS, told OE during SPE Offshore Europe. The S-Class will be aimed at use for well services in the oil and gas market and for offshore wind farm maintenance in northwest Europe, Middle East, South East Asia, and West Africa.

Anderson said there is a demand for units larger than the K class, but not as large and requiring as much man-power as the E-Class. After six years talking to clients, the S-Class

The new S-Class, to be built by GMS.

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was designed to meet those needs. "We have designed a workhorse," says Anderson.

The S-Class will have DP2 and be able to operate in up to 65m water depth. The jacking system will be based on a two layer system with a 90 ton per pinion load. The unit, with four thrusters (two 1000kw and two 800kw) and four 1250kw generators, will have 800sq m deck space, a 150 ton main crane, and 15 ton auxiliary crane, and will be able to accommodate up to 150 people.

GMS plans to order three S-Class units, with options for a further three.

GMS is also investing in its existing fleet. Its third E-Class, GMS Enterprise, is due to enter service next year, taking the fleet to 10. GMS Enterprise, capable of working in up to 85m water depth, will have a 400 ton main crane and 60 ton auxiliary hoist.

The company's main focus is on maintenance programs, well servicing and offshore wind, mostly on long term contracts.

A key area in the Middle East is brownfield work. GMS works on the prolific Zakum oil field, northwest of Abu Dhabi and producing since 1968. Anderson says, to date, Zakum has only produced about 8% of its reserves. Two GMS barges have been working on the field for the last 14 years.

Recent investment has been the result of a takeover by Abu Dhabi-based Gulf Capital in 2007. At the time, the company had just three jackup barges. It now has nine, as well as an accommodation barge and two anchor handling vessels.

Of the K-Class barges, four operate off Abu Dhabi, two off Saudi Arabia and one offshore Qatar. The two E-Class units are working in northwest Europe. Since August last year, GMS Endurance has been working for ConocoPhillips on the "V fields" in the southern North Sea on an asset life extension program. The second, GMS Endeavour, has been working offshore Germany on the Dolwin wind farm transformer substation. OE

OE@OE hosts seminars

As part of SPE Offshore Europe 2013 ExxonMobil Fuels & Lubricants and Caterpillar Marine & Petroleum Division (CAT) joined forces for an interactive breakfast seminar, hosted by Offshore Engineer's Paul Hutton.

Maintenance and engineering professionals from across the oil and gas sector gathered to hear Peter Longstaff, industrial lubricants manager for ExxonMobil Fuels & Lubricants and Will Watson, offshore oil and gas product marketing manager for CAT, discuss how advanced technologies can enable oil and gas companies to improve the safety, environmental care and performance of their operations.

Offshore Engineer and subject matter experts from GL Noble Denton also took part in two live discussion and Q&A sessions during Offshore Europe.

These were looking at the various requirements and global best practices for maximizing performance and efficiencies across the lifecycle of a floating production system.

All three events were filmed live—watch out for the full video highlights on oedigital.com in coming weeks. OE

Wordle: OE staff members compiled their notes from SPE Offshore Europe 2013 and discovered the conference's most talked about themes.

The *Offshore Engineer*-hosted interactive breakfast seminar during Offshore Europe.

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Championing pipe-in-pipe technology

By Audrey Leon

McDermott International's director of global subsea engineering, Mark Dixon, made the case for pipe-in-pipe technology during at a presentation on Emerging Technologies in the Subsea Sector at SPE Offshore Europe 2013.

While pipe-in-pipe is not a new technology, having been introduced nearly 20 years ago, many in the industry remain skeptical, Dixon said.

"It has a great track record...it is seen as too new or too costly," he said. "It's about creating value proposition. The value is enhanced lifecycle of the project."

Pipe-in-pipe technology consists of a flowline in center with installation in annulus between pipe. Use of space age materials, Dixon said, which can be thin and compact, can minimize the size of the product.

Mark Dixon, McDermott International's director of global subsea engineering speaks at a presentation on Emerging Technologies.

"The ability to insulate pipes drops as you go deeper," he said. "Pipe-in-pipe becomes independent of water depth to achieve high performance, although it comes at a high cost.

"The materials are more expensive, along with a second pipe," he said. "You have to weld that up, it's heavier. This is where cost increases come from, but you get performance benefits."

Dixon said that the number of projects have steadily increased, with 3-8 occurring per year. The areas with the highest incidence of pipe-in-pipe are the North Sea and North America. Dixon said the Asian market is not as familiar with this type of technology.

In addition to advocating for pipe-in-pipe, Dixon argued for greater communication within the industry to safely introduce new technologies.

"If we can overcome skepticism, we can progress technology at an appropriate pace," he said. "Communication needs to be open enough to see what's coming down the line, without operators disclosing things they aren't comfortable with." OE

Step up and be counted

By Audrey Leon

A ditching incident in the North Sea that killed four offshore workers on August 23 set a somber tone at SPE Offshore Europe 2013 with many sessions beginning with a moment of silence for the fallen.

Ken Robertson, production services manager for Shell UK Ltd, stressed the importance of participation among UK workers in order to improve safety conditions, during the Step Change in Safety panel discussion.

Robertson, who serves as Step Change in Safety leadership team co-chair, said one current challenge is employee participation in the workforce-elected safety representatives program, as required by the UK Heath and Safety Executive (HSE).

"We all need to step up and be counted," he said. "Ask yourself what is your level of involvement?

Ken Robertson, production services manager for Shell UK Ltd.

What are you doing to be personally involved? Step up or step back."

Robertson advocated for improved communication not only between regulators and industry, but also among stakeholders.

When asked if too cozy a relationship exists between regulators and drilling companies, panelists from Fairfield Energy and HSE denied the charge.

"A mature relationship with anyone, whether it is two businesses, or a business and a regulator, it is about working in partnership, but recognizing that there will be a point in that process where tough challenge is what that relationship is all about," said Judith Hackitt of HSE. "It's about knowing how to strike a balance. If we were to adopt a stand off approach (as a regulator), I don't think we would make as much progress as we have.

"What makes us unique in the UK is that relationship between regulator and industry enables us to work both in partnership, but recognize when we're able to be the enforcer," she said.

Ian Sharp of Fairfield Energy said: "It may seem cozy, but it is a respectful relationship. When you have a respectful relationship you can engage in the difficult conversations. I know for a fact (the relationship) is not cozy." OE

Hayward predicts geopolitical, price, technology trends for next decade

By Nina Rach

Former BP CEO Tony Hayward, now CEO of Genel Energy, gave the keynote speech at an Offshore Europe conference session on independent oil companies. Hayward focused on geopolitics, prices, and technology, while explaining the role of the independent in challenging conventional thinking.

Tony Hayward

Geopolitics has defined the field of play, he said, influenced by OPEC, "the most successful cartel in history," the collapse of the Soviet Union, and the opening-closing of Venezuela.

Technology is the lifeblood of our industry, and he said innovation has been characterized more by incremental moves than major step-changes. Sharing and plagiarism of technology hardware is rife, but the real value is expertise and deep familiarity with play concepts and how to efficiently use available technologies. Hayward cited shale development, where hardware may be openly available, but expertise is necessary to achieve success.

IOCs have been successful in opening new plays through innovation and low-cost development and he explained why:

- High oil & gas prices have made risk capital readily available.
- Hardware and experienced staff are freely available.
- Independents are nimble, willing to take risks, carry little-to-no political baggage, and have realistic expectations.

In the next decade, Hayward predicts that OPEC will remain in place; Russian state dominance will preclude outside investment; and turmoil in the Middle East will continue, but the area will hold many opportunities for IOCs. The US will not become energy-independent, but Hayward expects North America to become a net exporter. The US$100 barrel is the new norm, and the sector will continue to attract capital. US natural gas prices will settle at $4-5/Mcf, and it is inevitable that the link between oil and gas prices will break down. Given the global gas glut, revisiting gas- to- liquids seems inevitable, but GTL needs a breakthrough technology, he said. Supermajors will continue to dominate Arctic exploration, deepwater Gulf of Mexico and West African development, but other markets are open for IOCS to flourish.

Session chair James Paton said IOCs will beat costs by collaboration and shared infrastructure. Most discoveries are likely to be less than 10MM bbl, and the secret to success in any mature basin is to "make the pie as big as possible" and devise a fair (equitable) strategy to divide it.

Simon Flowers, Wood Mackenzie, said "The entrepreneurial approach, seen over the last 10 years, will keep independents ahead of the competition." OE

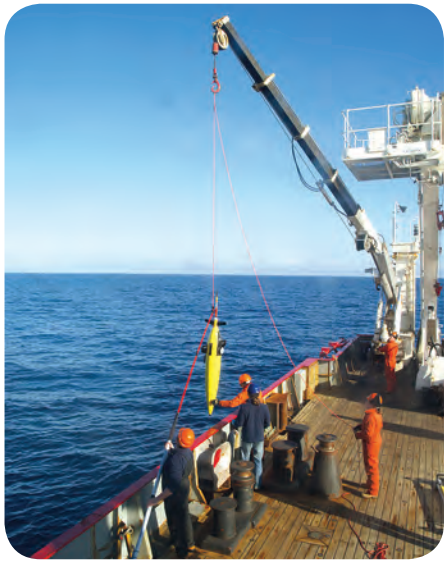
Solutions

Distribution manifolds

Three styles of modular fluid distribution manifolds were launched by **Parker Hannifin**. Two of the manifolds, the Hi-Pro Distribution Manifold (up to 6000 psi) and the Hi-Pro Air Header Manifold (up to 800psi), are based on ball valves for quick on-off control. Parker's third option, the H-Series Distribution Manifold (up to 6000psi), provides a compact manifold body that accepts a user-defined choice of five or 10 metal-seated needle valves.
www.parker.com

Low energy AUV

Kongsberg Maritime launched the Kongsberg Seaglider™ AUV at AUVSI 2013. This AUV is a low-cost device, with long endurance, and capable of deployment durations in excess of nine months. The technology uses changes in buoyancy for thrust, combined with an extremely hydrodynamic shape resulting in low-energy requirements, hence its ability to partake in much longer missions than propeller-driven AUVs. Full production of the AUV is expected by December 2013, although there is capacity for delivery of special orders before this date.
www.km.kongsberg.com



Lighting for harsh conditions

MacArtney introduced the new LUXUS Compact Low Light Camera, designed for use in harsh and turbid conditions, where light is limited or artificial. The housing for the LUXUS Compact Low Light Camera is made from sandblasted titanium and features a depth rating of 4000m. The camera consumes 2 W and can handle DC power units from 12-24V DC. It has universal mounting brackets, a compact LED, pistol grip, and a compact media controller.
www.macartney.com

Increased operational safety

Germany's **Raytheon Anschütz** released its latest gyro compass, the Standard 22, which ensures accuracy and reliability under all environmental conditions. Operational safety was dramatically increased due to a patented data transmission technology that completely replaces the use of slip rings. The solution offers a series of universal course converters: serial/360° synchro converter, serial/universal synchro converter and serial/universal step converter. These converters are enabled to retain existing equipment and can be used to replace virtually all available gyro compasses in the market.
www.raytheon-anschuetz.com

Ball and Taper

First Subsea Ltd. launched its Series III Ballgrab ball and taper mooring connectors. The connector's male mandrels are in compliance with the ABS 2009 approval for specialist subsea mooring connectors. First Subsea is the first manufacturer of offshore mooring connectors to achieve ABS type approval for the design and manufacture of large-scale forgings over 500mm in diameter. The firm recently won a contract from Technip for a platform moored in Anadarko Petroleum Corp.'s Heidelberg field development in Green Canyon Blocks 859, 860,903, 904 and 948 in the Gulf of Mexico.
www.firstsubsea.com

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Activity

Ocean Installer, McDermott alliance ends

Stavanger-based Ocean Installer AS and Houston-based McDermott International, Inc. mutually agreed to dissolve their North Sea project-specific alliance that the two companies entered in December 2012.

McDermott said that opportunities under the alliance have not materialized, however, the relationship between McDermott and Ocean Installer remains amicable. In recent months it has become apparent that the long term strategic aims of both companies are not aligned.

"We had different strategies," said Ocean Installer CEO Steinar Riise. "As you may-have seen of their recent press releases, McDermott has a lot of changes going on. Their strategy did not fit with ours."

Riise said the dissolution of the alliance will not impact any of Ocean Installer's current contracts.

Steinar Riise, Chief Executive Officer of Ocean Installer

Ocean Installer and McDermott entered the alliance to pursue and execute North Sea rigid pipelay projects. The partnership was projected to pave the way for a more permanent relationship.

The end of the alliance has not deterred McDermott from pursuing future partnerships, the company said in a press statement: "McDermott may undertake timely and appropriate strategic partnerships with leaders and niche players in the industry in support of reaching global tier-one status in subsea project execution."

Ocean Installer maintains focus on expansion. The company established a Houston office earlier this year.

"Houston is an extremely important market because of the resources there. We strive to become a global service provider and Houston is a part of that," Riise said. OE

A new company, **DNV GL Group**, has been formed following the merger of DNV and GL Noble Denton. DNV GL Group is now a major ship and offshore classification society, providing technical assurance and risk management services to the oil and gas industry and expertise in wind, power transmission and distribution. DNV GL employs 17,000 people across 300 sites in more than 100 countries. The merger had to be approved by competition authorities in South Korea, USA, EU, and China.

Directors of Aberdeen-based **Bridge Energy** have approved a £103 million takeover bid from Norway's **Spike Exploration**. The deal would see Spike acquire the entire issued share capital of Bridge Energy at a premium of about 41% to Bridge's share price on its last trading day. Spike Exploration was set up in 2012 with US$300 million backing from Norwegian private equity firm HitecVision.

The **University of Stavanger** has been chosen as the home for a new Norwegian national research center for increased oil recovery. The University of Stavanger (UiS), the International Research Institute of Stavanger (IRIS) and Institute for Energy Technology (IFE) are the main partners in the new research consortium. Associate Professor Merete Vadla Madland will be the president of the new center. It will be funded by the Norwegian government with NOK50 million over the next five years.

Abu Dhabi-based subsea engineering and diving services firm **DCN Global** has been bought by **Fugro Subsea Middle East**. The company, which will be renamed **Fugro Subsea Services** (Middle East), has primarily operated in the Middle East, Caspian, and African regions. DCN Global employs about 39 people with about 170 contract staff. Annual revenues are about US$30 million. Fugro Subsea Services (Middle East) will continue to work with DCN Diving in the Netherlands.

Entries are now open for the **2014 Offshore Achievement Awards**, hosted by SPE Aberdeen and supported by Offshore Engineer and TAQA. For more than 27 years, the awards have recognized outstanding success and innovation in the oil and gas sector. Last year's awards ceremony attracted a record 530 industry professionals. This year, two new categories have been introduced—the Inspiring Leader and the Environmentalist awards. Deadline for entries is December 1. The awards will be held at the Aberdeen Exhibition and Conference Centre on March 20, 2014. For more information go to: www.spe-oaa.org.

(L-R) SPE Aberdeen chairman Anthony Onukwu with Ian Phillips, SPE board member responsible for organising the OAAs, and Pete Jones of principal sponsor TAQA.


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Spotlight

By Sarah Parker Musarra

IMarEST President's Commendation Award travels to the Gulf

Leslie (Les) Douthwaite, Honorary Secretary of IMarEST's US Gulf Coast Branch, was recently honored by the institute's highest award. OE discusses his career and commendation.

In Houston on August 21, at The Institute of Marine Engineering, Science and Technology's (IMarEST) First Offshore Oil and Gas Engineering conference, Les Douthwaite received the President's Commendation Award, an annual international award recognizing exceptional service to the organization.

Douthwaite was named the honorary Secretary of IMarEST's US Gulf Coast Branch about four years ago.

Founded in London in 1889, IMarEST is "the first institute to bring together marine engineers, scientists, and technologists into one international multi-disciplinary professional body." Chairman of the local branch, Alan Mills, presented the award to Douthwaite saying the US Gulf branch grows at a particularly fast rate, making Douthwaite's service all the more essential.

> "Marine engineering is a highly-skilled profession because a ship is like a floating town…It is what I'd call a noble profession."
> – Les Douthwaite

Les Douthwaite, honorary secretary of IMarEST's US Gulf Coast branch, was honored with the President's Commendation Award on August 21. Pictured from left to right: Americas Division President Paul Jukes, Douthwaite, US Gulf Coast Branch Chairman Alan Mills. Courtesy IMarEST

Douthwaite supports the local chair by organizing branch meetings; and conducts the intensive and time-consuming professional review interviews required for chartered engineer registration for new members.

"[It] is by far the most demanding role on any branch committee," Mills said. "The fact that Les has, for so many years, gone above and beyond what many would do is precisely why he was singled out for recognition of his tireless work and selflessness."

Giving back to IMarEST is something Douthwaite feels strongly about, as IMarEST helped him navigate his professional career as a young engineer.

"We all used to go to the Liverpool branch meetings as young marine engineers-to-be; we were very much on the learning curve," he said. "Now that I have a little more time, I'd like to give back to the institute and to promote it [in the US], particularly to young members. I'm paying back what I got out of it."

Douthwaite joined IMarEST in December of 1961, while serving as a cadet with the British Merchant Navy, when the organization was known as the Institute for Marine Engineers. He was later elected Fellow of the Institute.

"Marine engineering has been a part of my life since I was 16," said Douthwaite, a native of West Kirby, Cheshire. It was at that age that he began apprenticing for Liverpool's Blue Funnel Line. While steaming around the Far East, and during summer breaks from Newcastle University, Douthwaite worked his way up to second engineer for the company within eight years. Upon graduating, he was recruited by Lloyd's Register, starting as a surveyor and retiring as the quality manager for the Americas. He retired in 2010, having worked 47 years for only two companies.

"Marine engineering is a highly-skilled profession because a ship is like a floating town," Douthwaite said. "Not only do you have the main propulsion engines and their support systems, but you've also got power generation systems, electrical systems, sanitary and water systems, and the galley. You're a jack of all trades. It is what I'd call a noble profession." OE

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Numerology

30% of 7000 platforms around the world have been in operation more than 20 years. ▶ See page 24.

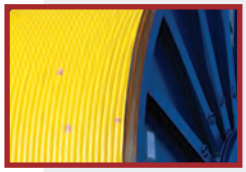
2050 The life-of-field date for Shell's Mars development. ▶ See page 70.

30,000 ft The drilling depth of Parker's inland barge Rig 257. ▶ See page36.

100

The number of lightning strikes per second that occur globally, according to the US National Weather Service. ▶ See page 48.

US$230million The amount Eni will spend to drill in the Timor Sea over the next 18 months. ▶ See page 14.



200 km The length of subsea array cables produced by JDR Cable Systems in Hartlepool in 2011 for wind farms off England. ▶ See page 52.

32,000km of offshore pipelines are expected to be installed over the next five years ▶ See page 66.

66.8m New world record for freefall lifeboat drop. *(Source: Norsafe ASA)* ▶ Watch the video on OEdigital.com

5tons The lifting capacity of a pedestal crane, as defined by the US Coast Guard ▶ See page 72.

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Read the case study at
slb.com/RhinoRHE

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