Required reading for the Global Oil & Gas Industry since 1975

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FPSOs

Offshore Engineer • September 2014

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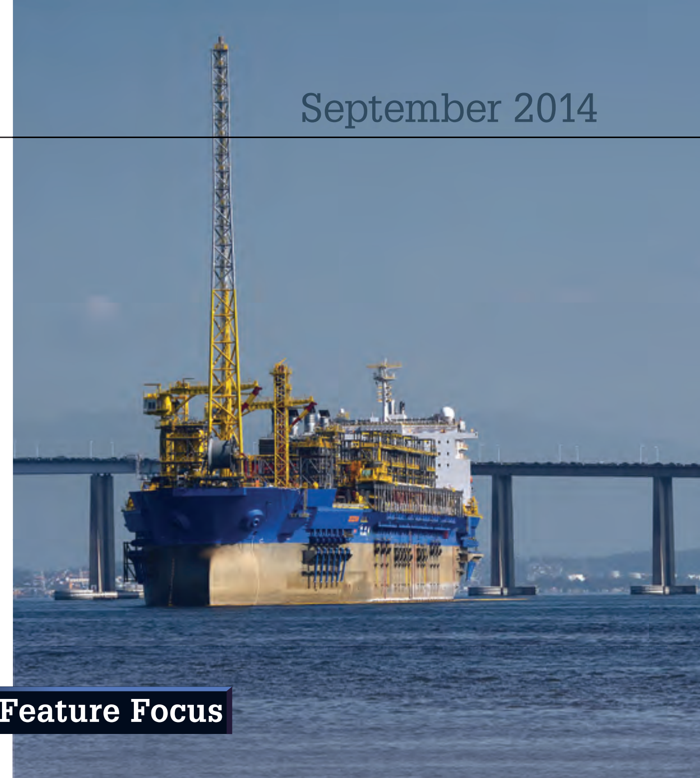


ON THE COVER

Topping off. SBM Offshore shares this photo of the final stages of construction on the *Cidade de Ilhabela* FPSO at its 50:50 joint venture Brasa yard, with partner Synergy, in Niteroi, Rio de Janeiro, Brazil. The 1.6MMbbl-capacity FPSO will be stationed at Petrobras' Sapinhoá field.

4th Annual Global FPSO forum

What's going on in today's FPSO business?

Plan to attend the two day conference and participate in the Mooring Special Session Workshop held on September 23rd from 1:00 – 5:00 p.m.

Tuesday, September 23

Session 1: 1:00 - 1:10 PM
Introduction, Recap & Update from 2013
Arjan Voogt, Marin

New Deepstar Research for Chain Corrosion
KT Ma, Chevron 1:10 -1:25 PM

Update on Regulations and Design Philosophy
Hongbo Shu, Shell 1:25 -1:40 PM

Mooring Replacement Work
Subir Bahttacharjee, ExxonMobil 1:40 - 1:55 PM

A Practical Look into Preventing Mooring line Failure at the Fairlead
Jonathan Miller, InterMoor 1:55-2:10 PM

Coffee Break
Sponsored by:
2:10-2:30 PM

Session 2: Monitoring Mooring Line Failure

Experience with Multibeam Sonar for Dry Monitoring of Mooring Line Failures
Angus Lugsdin, Tritech International Limited
2:30-2:45 PM

Integrated FPSO Real Time Monitoring, Forecast and Advisory System
Yong Luo, COTEC 2:45-3:00 PM

Current Mooring Line Monitoring Approaches
Robert Barker, BMT Scientific Marine Services Inc 3:00-3:15 PM

Panel Discussion and Q&A
David Cobb + Session Speakers 3:15 - 3:30 PM

Coffee Break
Sponsored by:
3:30 - 3:50 PM

Session 3: Turrets & Station Keeping
3:30-3:50 PM

Mooring System Options in Shallow Water
Jack Pollack, SBM Offshore
3:50 - 4:10 PM

Turret Mooring Design for Squall Conditions
Amir Izadparast, Sofec
4:10 - 4:30 PM

Challenges in Deepwater Disconnectable Turret Design Cheryl Smerk, NOV
4:30 - 4:50 PM

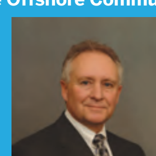
Discussion & Closing Remarks 4:50 5:00 PM

Opening Reception on the Exhibit Floor
5:00- 7:00 PM

Wednesday, September 24

Introductions and Opening Remarks
Brion Palmer, AtComedia
Barry Donovan, Raymond James 7:45-8:00 AM

Keynote: Expectations, Opportunities, Issues in the Offshore Community



Randall Luthi, President, National Ocean Industries Association 8:00-8:40 AM

Session I: The State of the Business
Moderator: Peter Lovie, Peter M. Lovie PE, LLC.

Bigger, More Complex, More Advanced: You Want Us To Do All That And Walk On Water Too?
Thomas Kolanski, BW Offshore

Contracting, Building, Operating And Financing - And Getting Paid For It. Leasing Is Not What It Used To Be!
Puneet Sharma, Modec International

What the FPSO Contractor of the Future Will Look Like
Cobie Loper, SBM Offshore

Operator Comments, Discussion with Audience
Blake Moore, Shell
8:40-10:05 AM

Morning Coffee Break in the Exhibit Hall
Sponsored by:
10:05-10:35 AM

Session II: The Future From Perspective Of Industry Advisors: Expectations, Opportunities And Issues
Moderator: Barry Donovan, Raymond James

Intro: Quiz for Audience
Barry Donovan, Raymond James

Worldwide Projects - A Forward Look At Activity Levels and Trends
Jim McCaul, International Maritime Associates

Financing Activity and Trends in the Offshore Industry
Barbara Gronquist, SVP Shipping, Offshore, DNB Bank ASA

Recurring Legal and Related Trends and Issues in FPSO Market
Kerry Williams, Chamberlain Hrdlicka

10:35-12:10 PM
Closing Discussion; Audience Q&A for Speakers

Lunch in the Exhibit Hall
Sponsored by:
12:10-1:10 PM

Session III: Facing the Realities of Cost and Risk - The Big Debate of 2014
Moderator: Dick Westney, Westney Consulting
Speakers:
Mike Mileo, Chevron
Babu Ramalingam, SBM
Bob Williamson, KBR
Dick Westney, Westney Consulting Group

PROPOSITION 1:
Standard, Contractor-Developed FPSO Configurations and Designs Provide Significant Cost Saving Opportunities That Should Be Taken Seriously

PROPOSITION 2:
FPSO Project Risks Are Being Mis-Allocated Between Owners and Contractors, Resulting In Higher Costs

PROPOSITION 3:
Owners Can Do a Lot More To Drive Cost Reductions (Other Than Squeezing Contractors)

PROPOSITION 4:
The Cost of FPSOs Today Actually Represents Good Value; an Optimum Balance between Capital Cost, Operating Cost, And Production Efficiency

PRESENTED BY: OE

WRAP-UP:
Final Observations from Panel and Audience
1:10-2:55 PM

Coffee Break in the Exhibit Hall
Sponsored by: NOV
2:55- 3:25 PM

Session IV:
Possible Game Changing Developments in the FPSO Industry
Moderator: Jim Wodehouse, Water Standard

The Dockwise Vanguard for FPSO "Drydocking" for on Location Refurbishment and Repair
Ryan Rush, Dockwise

Subsea Processing and FPSOs - Equipment Realities and Changes in Field Developments
Janardhan Davalath, FMC Technologies

Impact of Local Content on Project Performance in Offshore Field Developments
Neeraj Nandurdikar, IPA

Panel Discussion: How Immediate Are These Game Changers For The FPSO World? Others to Worry About?
Session Speakers
3:25-5:20 PM

Sponsored by: NOV
Coffee Break in the Exhibit Hall
10:10-10:40 AM

8:10-10:10 AM
Panel Discussion
Session Speakers

Governmental Regulators Respond - Current Situation Covering FPSOs in US GoM
BSEE and Capt. Nadeau, USCG

The Class Societies React to Current Needs
Ken Richardson, ABS

Opening Discussion with Operators - What We Are Looking For

The Difficult Truths of Deteriorating Confidence in Standards
Peter Noble, SNAME

Session V:
FPSO Operations - Ensuring that Operations are Safe, Reliable and Compliant with Regulations
Moderator: Peter Noble, SNAME

Introductions and Opening Remarks
Brion Palmer, AtComedia
Peter Lovie, Peter M Lovie PE, LLC
8:00 - 8:10 AM

Thursday, September 25

The Forum Reception on the Exhibit Floor
5:30-7:30 PM

Session VI:
Significant FPSO Projects Worldwide
Moderator: Chris Barton, Wood Group Mustang

Noble Energy, Living our Purpose, Delivering Superior Projects
Scott Childress and William Pritchett, Noble Energy

The Mexican Energy Reform Impact on the FPSO Industry
Enrique Garza, Garza Tello & Asociados S.C.

Discussion Panel: Common Trends?
Session Speakers
10:40-11:55 PM

Lunch in the Exhibit Hall
Sponsored by: Industronic
11:55-12:55 PM

Session VII:
Evolving New Business Sectors
Roberto Noce, Moss Maritime/Saipem

Gas Related FPSOs: Gas and Liquids Processing, FLNG: Projects and Mega Projects
Kathleen Eisbrenner, The Next Decade

Arctic Developments - Technical and Commercial Challenges
Hans-Martin Sand, Moss Maritime/Saipem

Challenges with Floating Production and Drilling In Arctic Environments and Solutions to Overcome Them
Fredrik Major, Sevan
12:55-2:10 PM

Session VIII:
The Latest on FPSOs in US GoM
Moderator: Jeremiah Daniel, Walker Ridgebras

Organizer's Closing Remarks
Brion Palmer, AtComedia
3:50 PM

2:55-3:50 PM
Operator and Contractor Panel:
Shell, Petrobras, BW Offshore, Modec International, Saipem, SBM Offshore, Sevan BP

Session IX:
Closing Panel Discussion - What's Ahead, Pulling it all Together - Comments from the Audience, Wrap Up and Closing Remarks
Blake Moore, Shell

2:10-2:55 PM
Decision Processes Affecting Choice of a Development Solution in US GoM. Will There Be Any More FPSOs In US GoM?
Martijn Dekker, Shell

Going First: How It's Going In Operating the BW Pioneer
Paulo Biassotto, Petrobras

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Volume 39, Number 9 September 2014

Departments & Columns

"Has the industry done enough in regards to well control?"

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BPA WORLDWIDE

Online Exclusive

Yea or Nay

Scotland will vote on the independence referendum later this month. Oil and gas consultant Sanjoy Sen will discuss the outcome and what it means for the North Sea sector.

Photo from Scotland's Referendum 2014 Facebook page.

What's Trending

Highs and lows

- Mexico signs energy reform into law
- Majors join FMC Technologies' subsea JIP
- Apache to exit high-profile LNG projects
- Kara Sea spudded despite sanctions

People

Miller named Halliburton president

Halliburton picked Jeffrey A. Miller as its new president. In this new role, Miller will complement the leadership of Dave Lesar, Halliburton's chairman and chief executive officer. Miller has served as Halliburton's executive vice president and COO since 2012.

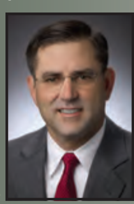

Photo from Texas A&M University.

The hunt for OE October

Next month, OE offers our all-interactive print issue. Ever read one of our articles and wished you could find out more either through extended photo galleries, video, sound bites, and data? Look for special icons indicating interactive content, scan it with the Actable app, which can be downloaded for free via the Apple iTunes store or Google play on any smart device, and enjoy our expanded content options.

White Paper

Understanding Safety Integrity Levels (SIL)

Hear from Scott Safety product experts about SIL compliance, why it is important, and how SIL compliance will benefit you.

Voices

Room for improvement. While much has changed since Macondo, OE asked:

Has the industry done enough in regards to well control?

Can the industry ever do enough? At Aker Solutions, we strive to continually improve the safety and reliability of our well control products and systems. If the industry should focus on one area for improvement, my suggestion would be to re-examine the way we manage the lifecycle of well control products to ensure we keep them operating safely for the duration of their operational life.

Craig Harvey
Chief Engineer, Aker Solutions

During the last 50 years, the industry has improved its drilling systems with advancements made to subsea technical equipment. Whether it is sourcing, producing or shutting down an oil well, each phase has its own unique set of challenges. The key to maintaining control is fixing a potential problem before it fails. Accidents can be managed, but to do so effectively, the industry must maintain engineering integrity of all its operating systems and source out solutions before potential damages can occur. When we realize something doesn't work, we have to fix it rather than deal with it later.

Andy Cates
President, The Subsea Company

We're definitely safer than we were four years ago, but each new well presents its own unique set of challenges. As we explore ever-deeper waters, we may encounter extremely high pressures and temperatures. Industry is continually collaborating and evolving to meet such challenges by adopting the best available and safest technologies for subsea well access and subsea well control.

Randall Luthi
President, National Ocean Industries Association

The thought process needs to begin with what to do to avoid a well control incident. It begins with basic drilling practices and "listening to the well." By keeping your finger on the pulse of the well during drilling operations, many events that eventually lead to a well control incident can be foreseen. This "pulse" is reflected in the basic real time data at the well site combined with other analysis. However, these skills are not that common and rushing can take priority over basic drilling practices. As an industry, we can and must do better at preventing well control incidents.

Pat York
Global Director, Well Engineering, Weatherford

The industry has made major strides through well control initiatives, new regulations, and recommended practices. However the issue is wider than simply well control. DNV GL believes that major accident safety – which has remained almost static in performance – can be enhanced by the same factor of 10 as has already been achieved by the oil and gas industry for occupational safety over the past 20 years. This will require better risk management, more focus on critical safety barriers, and continuing focus on people, plant and process. Safety Case, although not essential, is one way to trigger a reassessment of how we prevent major accidents.

Robin Pitblado
Vice President, Risk Advisory Services, DNV GL

The industry has made incredible progress post-Macondo, starting with the OGP recommendations. IWCF has created additional programs, new syllabi, the training and certification has become increasingly progressive and role-specific. We are introducing enhanced certificate renewal training and focusing more on crew resource management, but the culture around well control still needs to change.

We need to move away from the process of training candidates to pass an exam every two years, to well control process safety becoming part of the daily fabric of offshore life through continuous learning and a philosophy that is promoted throughout the industry from the top down. This cultural step change has still to come.

David Price
CEO, International Well Control Forum

Industry and regulators have significantly enhanced spill prevention, containment and response capabilities. We have developed new standards for blowout preventers, capping stacks and other elements of well control, and two well containment companies can now rapidly deploy advanced subsea containment technology if needed. Likewise, the Center for Offshore Safety, formed in 2011, embodies industry's commitment to continuous improvement in safe operations and safety culture. As the co-chairs of the Presidential Oil Spill Commission recently stated, "offshore drilling is safer than it was four years ago," but we can and should continue to strive toward the goal of zero incidents.

Charlie Williams
Executive Director, Center for Offshore Safety

Our industry and environment changes constantly, which creates a sense of importance for improvement. Taking new technology and integrating it with proven old school methods improves our industry daily. It's not just about improving products, services and methods. It's how we invent better ones while maintaining safety, training and providing cost-effective ways to provide energy worldwide. We work to understand where risks and opportunities may emerge and what's needed to address them and enable new forms of innovation. Improvement isn't just a must. It's a responsibility.

David Wright
President, Wright's Well Control Services

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

Nina Rach

Colloquy

Indonesia tightens cabotage

Cabotage is trade or navigation in coastal waters and traditionally refers to shipping along coastal routes, transporting passengers or goods from port to port in the same country. Laws governing cabotage serve to protect local industries and affect logistics for offshore oilfield development and services.

Indonesia

Indonesia's Ministry of Transportation (MOT) is gradually tightening its cabotage laws for offshore vessels, presumably to encourage the country's ship building industry to grow, and to protect member companies of the Indonesian National Shipowners Association (INSA).

MOT has allowed liberal cabotage exemptions for the past few years for a variety of vessel types in order to maintain hydrocarbon production levels.

Article 8 of Indonesia's 2008 Shipping Law states that sea activities in the country's waters are to be convened only by national sea transport and shipping companies that use Indonesian flagged ships manned by Indonesian crews, effective as of 7 May 2011.

However, local shipyards were unable to produce sufficient vessels, so the government created exemption tables in 2011, allowing certain foreign-flagged ships to continue to operate in Indonesian waters: Government Reg. No. 22/2011 and MOT Reg. No. 48/2011.

The first deadline was December 2012 for two types of offshore support vessels: platform supply vessels (PSVs) and anchor-handling tug supply (AHTS) >5000BHP with dynamic positioning (DP2, DP3). Local shipyards were able to produce enough so that the exemption ran out and AHTS vessels are now subject to cabotage principles.

The next deadline under the 2011 regulations was December 2013 for offshore construction vessels and dredging vessels.

Local yards were able to supply diving support vessels, but not derrick/crane or SURF laying barges, or dredging vessels.

In early March, UOB Kay Hian Securities noted that the shortage of locally-flagged vessels in Indonesia is pushing up dayrates. A growing drilling rig fleet will lead to increased AHTS and PSV demand. UOBKHS analyst Nancy Wei said, "Indonesia's oilfield services sector is still in its infancy and is driven by an upcycle in exploration and production spending and offshore vessel cabotage."

2014 extension

At the end of 2013, MOT announced it would extend exemptions. In March 2014, MOT Regulation No. 10/2014 became the regulation of reference for offshore vessel cabotage.

The current exemptions for oil & gas survey vessels (seismic, geotechnical), offshore construction vessels, dredging, salvaging and underwater works (heavy floating cranes and crane barges >300 tonne) will expire in December 2014.

In December 2015, the current exemptions for jackups, semisubmersibles, deepwater drillships, tender-assist and swamp barge rigs will also expire.

GBG Indonesia wrote: "Indonesia's amendment to its cabotage principles should be interpreted as a measured strategy; flexible enough to allow for a relaxation in deadlines if domestic supply of specific offshore vessels falls short but at the same time strict enough to cease exemptions when the local industry has sufficiently improved upon its production capabilities."

Indonesia's shipbuilding industry is already able to construct 19 types of offshore vessels, and local expertise is growing. However, I don't expect to see many drillships and semisubs to emerge from Indonesian yards in the very near future. OE

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ThoughtStream

Michelle Smidt and Dr. Karen Becker, Queensland University of Technology

Workforce-related risks in oil and gas projects: identification and analysis

As investment in oil and gas projects is set to continue globally, it becomes increasingly relevant for the organizations managing such large scale developments to take measures to limit and prevent schedule and budget overruns. There are concerns that not being able to get the right people at the right time for the right cost could inevitably threaten the overall project delivery.

Risk assessments and registers are by no means new to the industry, or to the people running these projects, however, to date, such assessments have taken a very technical approach and also a limited view of what "risk" encompasses. In fact, many project managers will tell you that at the core of any project delay or project overspending is a personnel issue.

It is these workforce-related risks that our research at Queensland University of Technology (QUT), in collaboration with Air Energi, intended to document in more detail. By doing so, we hoped that more organizations would consider such risks as part of their current assessment process.

Although many of our findings may be unsurprising to those with extensive industry experience, they do confirm the importance and continued impact of these risks, and break them down in a way that hasn't been done before.

In brief, through in-depth interviews with industry experts, our research documented six key areas of people-related risk: project appeal, recruitment, onboarding and induction, retention, demobilization, and compliance. Each of these was further explored to reveal a subset of risks (To read the full findings of the report titled, "Workforce-related project risks," visit the Air Energi website: http://www.airenergi.com/sites/default/files/brochures/prep.pdf).

- **Project appeal:** The attraction of candidates will depend on the attractiveness of the project itself. This includes factors such as duration of project, remuneration and benefits, location, employer brand of operating company, roster, and the phase of the project.
- **Recruitment:** This depends on factors such as clarity of needs, necessary processes and procedures, whether skills are available to meet demand, quality of local talent, reference checks, expectations, and internal client policies and requirements.
- **Induction & Onboarding:** Key issues here are use of a formal induction process, organizational cultural alignment, time requirement, upskilling and training, as well as industry experience.
- **Retention:** Several key issues with retention deal with loyalty, management support and style, career development opportunities, poaching, alignment with company culture, equity, staff versus contractor benefits, personal circumstances and taxation.
- **Demobilization:** This stage presents the highest risk in terms of resources and time invested. Key issues are project completion, continuity, client/labor hire agency relationship, identifying skills and capabilities for future use, succession planning, reputation control, confidentiality and sabotage.
- **Compliance:** Such factors include complying with the legal requirements of the location and country but also internal organizational policies.

However, identifying these risks is just the first step. A critical outcome from the research is the ability for those managing a project to be able to identify the specific issues that present the biggest risks, and proactively take steps to mitigate them wherever possible.

From the findings, we developed a survey to identify which of the six key risk areas are likely to apply to a specific project. The results of the survey combine to produce a results report and an interactive map that illustrates in a very simple way the low, medium and high workforce-related risk areas. It also identifies those areas where there is a high level of uncertainty within the management team about the critical workforce-related risks.

This tool, entitled PREP™ (people risk evaluation of projects), is currently under development, but it is the intention that it will greatly improve how projects are managed and mitigate risks, by not only broadening the view of organizations to consider not only workforce-related issues and technical risks, but encourage them to adapt their current approach to risk assessment in order to better get to the heart of workforce issues. By doing this we believe that many of the current schedule and cost overruns experienced by many of today's oil and gas projects can be significantly reduced. OE

__Michelle Smidt__ serves as a research project officer at QUT. She recently worked on a research project jointly funded by the Australian government and Air Energi investigating people-related risks on LNG projects involving a contract workforce. Michelle was responsible for gathering and analyzing the data which enabled the development of the PREP™ tool. Michelle completed a Bachelor's in English and employee communications in 2011 from Copenhagen University and a Master's of Business HRM at QUT in 2012.

__Karen Becker__ is an associate professor, researcher and lecturer at QUT Business School. Karen is an active researcher in the area of strategic HRM, learning and development, innovation and change in the workplace, and prior to joining academia spent 12 years in corporate HRM and HRD roles, and as an HR consultant. Karen has published over 40 peer-reviewed journal articles and conference papers relating to her research.

Global Briefs

A Chevron quits Anchor-1

Chevron's Anchor-1 well was junked due to mechanical difficulties. Located in Green Canyon Block 807, 131mi. from Louisiana in the Gulf of Mexico, Anchor-1 was abandoned before reaching its geologic objectives due to mechanical issues experienced during tieback, operator Chevron told OE. Results from the Anchor-1 well are anticipated in early 2015. With a 5240ft water depth, Anchor-1 was spud in March 2014, using Pacific Drilling's *Pacific Santa Ana* drillship, and was targeting inboard lower tertiary horizons and a secondary Miocene target.

B BOEM offers US-Mex boundary blocks

Bureau of Ocean Energy Management attracted $110 million during its Western Gulf of Mexico Lease Sale 238 on 20 August. Supermajor BP was the highest bidder based on total number of high bids, totaling $22.8million. Shell had the highest bid for one block, the Alaminos Canyon Block 902, offering $1.75million.

C TGS starts snipe survey

TGS will begin Snipe Phase 52, a new long-offset 2D multi-client survey in the ultra-deep water, US Central Gulf of Mexico in 3Q 2014.

The survey, which will take about 100 days, will include 12,000km of data extending to the US-Mexico international boundary, using SeaBird's M/V *Osprey Explorer*, under a contract worth about US$7.5 million, towing 12,000m cable length. Final data will be available in 4Q 2015.

D Hebron GBS towed

The ExxonMobil-operated Hebron oil field hit a milestone in late July when the gravity based structure was towed from the dry dock to the project's Bull Arm construction site. The 180,000-tonne structure arrived 10 hours after tow-out operations began. Hebron is located in 150m of water, is in the Jeanne d'Arc Basin, 350km southeast of St. John's. It is expected to contain 700MMbbl of recoverable resources.

E Alma/Galia development delayed

First oil from EnQuest's Alma/Galia development in the UK North Sea is now not expected until next year.

First production from the field, to be developed using the *EnQuest Producer* FPSO had been expected in 2H 2014. EnQuest said, while progress had been made on the FPSO, at OGN Group's Hadrian Yard in England, sailaway was now weather dependent and would happen in Spring 2015, with first oil in the middle of the year. The subsea infrastructure is already in place, with risers and mooring systems pre-installed.

F PSA investigates platform oil leak

Norway's Petroleum Safety Authority (PSA) is investigating a hydrocarbon leak, discovered and halted at 5am on 7 August, on the Eldfisk field in Block 2/7 in the Norwegian North Sea. The leak led to the discharge of stabilized oil to the sea from the Eldfisk field terminal platform.

The facility was in the process of starting up after an emergency shutdown and loss of power on 6 August, said the PSA. "According to ConocoPhillips, a blowdown valve in the separator was left open during the start-up, so that stabilized oil flowed to the sea via a sea sump and knockout drum."

G Porcupine shows further promise

Antrim Energy said recent evaluations showed frontier exploration license (FEL) 1/13 in the Porcupine basin off Ireland's west coast contains an estimated unrisked prospective resource potential of 1.1 billion boe. FEL 1/13 includes blocks 44/4, part of 44/5, 44/9, 44/10, 44/14 and 44/15: the Skellig Block. The FEL was assigned 17 leads, with a best estimate of 482MMboe (42.7% of the total) assigned to two primary leads, C and M-3. Drilling is set to start in 2015.

H Repsol to drill off Canary Islands

Spain's Repsol could start drilling offshore the Canary Islands this year after Spain's Industry Ministry approved the firm's plans. The move follows the award of environmental permits earlier this year.

Repsol operates blocks 1-9 offshore the Canary Islands, with partners Woodside Petroleum and RWE.

I Liberia opens round

The Liberian Government and the National Oil Company of Liberia (NOCAL) launched a Liberia Basin Bid Round, with four undrilled offshore petroleum exploration blocks offered - LB-6, LB-7, LB-16 and LB-17L. Blocks LB-6 and LB-7 were part of the Liberia Basin 2007/8 bid round. No production sharing contracts for those bid rounds became effective, and in 2013 NOCAL terminated discussions with the designated bidder. Blocks LB-16 and LB-17 were awarded in the Liberia Basin 2004 Bid Round, and are again available for bid.

J Libra drilling begins

Petrobras started drilling the first exploration well on the Libra pre-salt area in the Santos basin offshore Brazil, estimated to contain 8-12 billion boe. The well, 3-RJS-731, being drilled using the *NS-36 (Schahin Cerrado)* drillship, is the first of two wells planned for the first phase of Petrobras' minimum exploration program. It will reach 5850m final depth (including water and sediments), about 170 km off the coast of Rio de Janeiro state and about 5km southwest of discovery well 2-ANP-2A-RJS. The entire minimum exploration program will be completed by the end of 2017, Petrobras says.

K Jupnier gets greenlight

BP Trinidad and Tobago (BPTT) sanctioned its Juniper offshore gas project off the southeast coast of Trinidad.

The project will involve the construction of an unmanned platform and associated subsea infrastructure, with fabrication expected to start by 4Q 2014 and first gas expected in 2017.

The Juniper facility will take gas from the Corallita and Lantana fields. The development will include five subsea wells, in 360ft water depth, with 590MMcf/d production capacity. Gas will be transported to the Mahogany B hub via a new 10km flowline.

L Repsol wins Colombian license

Spain's Repsol won operatorship of the COL4 license, in the Caribbean Sea, with partners Statoil and ExxonMobil Exploration Colombia, in the country's 2014 bid round.

The license award is subject to final approval from the ANH. The entry is an early exploration phase and the initial working commitments include 2D and 3D seismic acquisition.

M Woodside, Noble and Marathon enter deepwater Gabon

Noble Energy and partner Woodside Petroleum signed a production sharing contract with Gabon's Government covering Block F15 in the Gabon Coastal basin, West Africa. The PSC includes a four-year seismic commitment and a future option for exploration drilling.

Additionally, Marathon Oil signed an exploration and production sharing contract for Gabon offshore Block G13, Tchicuate, in the deepwater, pre-salt play. Tchicuate encompasses 275,000 acres and is about 50 miles offshore Gabon and near proven shallow-water, pre-salt oil discoveries.

Early August, Eni made a gas and condensates discovery in the Nyonie Deep exploration prospect in block D4, about 13km from the coast of Gabon. The Italian major estimates initial potential in place is 500MMboe.

N Seismic program for Seychelles

Dolphin Geophysical is using the M/V *Polar Duchess* to acquire a 1500km seismic survey for Ophir Energy and WHL Energy covering the Junon Block, in the Seychelles Exclusive Economic Zone, about 125km southeast of the main Seychelles island of Mahé. This is the second 3D seismic survey in the Seychelles Exclusive Economic Zone, with the previous survey focused on the area northwest of Mahé.

O Oman launches bid round

Oman's Ministry of Oil & Gas (MOG) launched an oil and gas exploration bid round, which includes offshore blocks 18 and 59.

Block 18 is in the north Sohar basin between the Batinah Coast and Makran Acretinanory prism covering 21,140sq km. MOG says about 10,000km of 2D and 2048sq km of 3D seismic has been acquired on the block and three wells drilled in the past, with a number of plays identified.

Block 59 is on the east coast central Oman covering 40,488sq km. The block is covered by 8000km of 2D seismic with several prospects and leads in the area. The deadline for sealed bids is not later than 31 October 2014.

P Kara Sea drilling begins

ExxonMobil started drilling the Universitetskaya-1 well in the East Prinovozemelskiy area, Kara Sea, on 9 August, defying Western-imposed sanctions against Russian state-owned Rosneft.

ExxonMobil is using the semisubmersible drilling rig West Alpha. Rosneft said Universitetskaya contains 1.3 billion tons oe and that about 30 structures have been found in three East Prinovozemelskiy areas in the Kara Sea, with a resource base totaling 87 billion boe.

While previous sanctions forbid the US and EU from business transactions with sanctioned individuals, July's sanctions specifically intend to deny Rosneft from thriving off Western-based oil and gas equipment and technology.

Q Exxon spuds Domino

ExxonMobil started drilling the deepwater Domino-2 appraisal well in the Black Sea Neptun Block offshore Romania, said partner OMV Petrom. Domino was discovered in 2012 about 200km offshore. Domino-2 is being drilled from the *Ocean Endeavor* semisubmersible drilling rig in about 800m water depth. The well follows OMV Petrom's Marina 1 discovery in the Istria XVII offshore Perimeter (shallow water) in the Romanian Black Sea.

R Panyu enters production

CNOOC started production at its Panyu 10-2/5/8 project in the Pearl River Mouth Basin in the South China Sea. The project includes three oilfields – Panyu 10-2, Panyu 10-5 and Panyu 10-8 – with 100m average water depth.

The facilities include one wellhead platform and nine producing wells. CNOOC says there are four wells connected, which are producing about 9000b/d. The project expects to reach 13,000b/d peak production by 2015.

S Macharee-1 spudded

Seadrill's West Cressida jackup rig spud the Mancharee-1 exploration well in Block G10/48 in the Wassana oil field, Gulf of Thailand, said KrisEnergy.

Block G10/48 covers 4696sq km over the southern section of the Pattani basin. The Mancharee-1 well, expected to reach a total depth of 12,420ft, will evaluate a series of stacked sandstone reservoirs of Miocene and Oligocene age.

The plan for the first phase of the Wassana oil field involves 12 to 14 development wells connected to a fixed production platform. First production is expected to start in 2H 2015 at a peak rate of 10,000bbl/d. Gross recovery from Phase 1 is expected to be 13.6MMbbl.

T APAC surveys

TGS will conduct a 3D multi-client survey Nerites Season 2, the largest 3D survey TGS has acquired in the Asia Pacific region, covering 13,000sq km in the Great Australian Bight. Nerites 2 is the second season of the Nerites 3D seismic program over blocks EPP44 and EPP45, which are mainly in the Bight's deepwater Ceduna sub-basin.

Data acquisition is expected to start 4Q 2014- 1Q 2015 by Dolphin Geophysical.

TGS also started a regulatory approval process to undertake a 17,000km 2D multi-client survey in the Reinga, Northland and Taranaki basins, offshore Northwest New Zealand, expected to started in 4Q 2014 and run to 2Q 2015, using the M/V *Aquila Explorer*. OMV's Whio-1 well in exploration permit PEP 51312 in the Taranaki basin was water wet. ■

Contract Briefs

Subsea 7, Tata Steel enter agreements

Subsea 7 and Tata Steel entered multiple contracts, worth about US$13.4 million, in which Tata Steel will supply more than 55km of subsea pipes weighing more than 9000-tonne to four separate North Sea projects.

The contracts include about 28km of carrier pipe, more than 27km of sleeve pipe, girth welding and triple jointing, and the application of glass flake epoxy pipe coating.

Rosneft deals beat EU sanctions

Rosneft and North Atlantic Drilling Ltd. (NADL) agreed multiple long-term offshore drilling contracts, worth about US$4.25 billion, at the end of July, beating the latest round of European Union and US-issued sanctions. Rosneft committed to six offshore drilling units until 2022; five-year contracts for the *West Navigator*, *West Rigel*, and *West Alpha* semisubmersibles; two newbuild CJ-54 class rigs; and a 2.5-year contract for a Gusto-class jackup rig. The rigs will head to Russian waters in 2015-2017, NADL said.

Rosneft, NADL and Northern Offshore also agreed on a 2.5-year deal for the use of Northern Offshore's Energy Endeavor jackup.

Sinopacific enters Mexican market

Sinopacific Shipbuilding Group has been contracted by Mexican shipping company Naviera Petrolera Integral to construct three SPP17A offshore support vessels, marking the Chinese company's first foray into the Mexican market. Developed in-house by Shanghai Design Associates, a branch of Sinopacific, the vessels weigh about 1765Gt each and are nearly 62m-long. The service speed is 12knots.

Arena picks Gulf Island for fabrication

Gulf Island Fabrication received an award letter from Arena Offshore for the fabrication of two jacket/piles and topsides for Arena's projects in the US Gulf of Mexico. Delivery for these units is set for late 2Q 2015.

CNR picks decommissioning consortium

CNR International has picked a consortium of AF Decom Offshore UK and Heerema Marine Contractors to remove and dispose of its UK North Sea Murchison platform.

Heerema-AF Consortium's contract will cover engineering, preparation, removal and disposal of both the topsides and jacket structure of the Murchison platform, together weighing about 37,000 tons.

Murchison stands 254m-high from seabed to flare tip in Block 211/19. The 24,500-tonne Murchison topside has 26 modules for drilling, production and accommodation, supported on a eight-legged steel jacket in 156m water depth.

Megalodon installation contract awarded

McDermott International will provide transportation and installation services to Walter Oil & Gas Corp. for the Megalodon platform in South Timbalier Block 311 in the Gulf of Mexico.

McDermott will provide all materials and equipment to transport and install the six-pile platform in 391ft of water, over an existing well site. The heavy-lift *Derrick Barge 50* will perform a side-lift of the jacket and set the topsides. Installation is expected to start in 4Q 2014. ■

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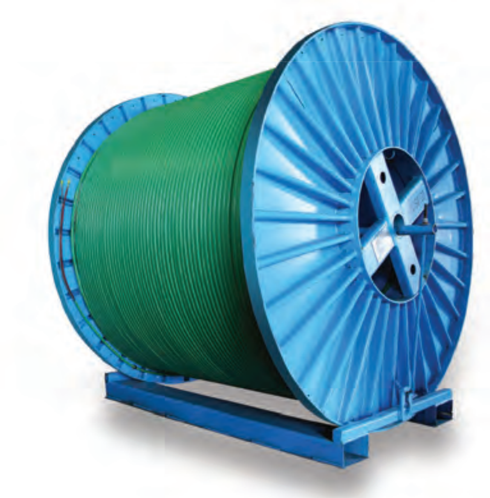

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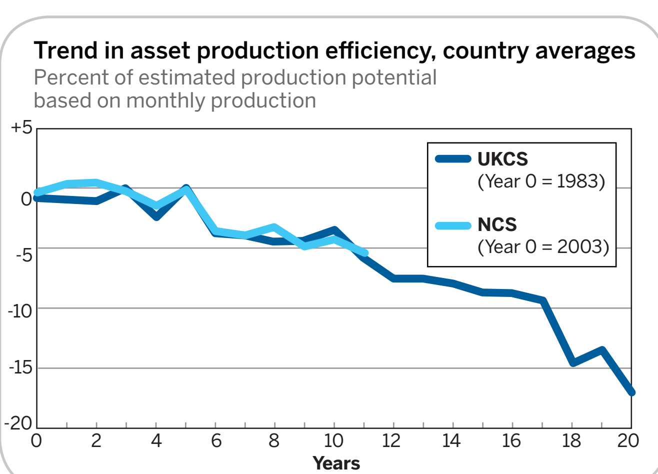
Protecting assets
through better data trending

Elaine Maslin examines how better data trending and a focus on key hubs could help improve ailing production efficiency rates and extend asset life on the UK Continental Shelf and beyond.

NI CompactRIO deployed on a vessel for measurement and control in a DNV certified application. Photo from National Instrument.

Big data has been making headlines, not least in the oil industry. But, is big data—and how to handle it—being used to its full advantage across all areas of the business? Some think not, specifically with regards to maintaining and extending the life of aging production facilities on the UK Continental Shelf (UKCS).

Some 50% of North Sea facilities are at or beyond their expected design life, with many of those now expected to operate for even longer, as drilling, seismic and production technology extends field lives and recovery rates.



Asset production efficiency trends in UK and Norway.
Graph from McKinsey & Company.

Operators have been focused on improving the integrity of these assets, but not all have fully embraced the next step—better aging and life extension (ALE) management, particularly through use of data collection and trending, according to the UK's Health and Safety Executive (HSE).

ALE is a core focus under HSE's Key Program 4, which follows the asset integrity-focused KP3. In a report, concluding its three-year investigation, HSE suggests better data and data trending could help to predict potential future failures and help plan maintenance.

The investigation looked at 33 installations on- and offshore on the UKCS. The final report alludes to insufficient key performance indicators, missing data and engineering drawings in places, and a tendency for audits to follow what happened prior, rather than addressing future needs. Referring specifically to electrical, control and instrumentation (EC&I) systems, the report cited a "widespread fix-on-fail approach."

Such an approach could lead to down time—a sore point on the UKCS. The UK's Department of Energy & Climate Change revealed production efficiency on the UKCS fell from 81% in 2004 to 60% in 2012. The poor efficiency levels are largely (nearly half) due to plant equipment failure and unplanned

Quick stats

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

New discoveries announced

Depth range	2011	2012	2013	2014
Shallow (<500m)	103	74	71	35
Deep (500-1500m)	25	23	19	7
Ultradeep (>1500m)	18	37	32	5
Total	146	134	122	47
Start of 2014	151	135	98	-
date comparison	-5	-1	24	47

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

Reserves in the Golden Triangle

by water depth 2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	15	603.25	1,060.00
Deep	16	2,615.00	2,515.00
Ultradeep	45	13,235.25	18,090.00
United States			
Shallow	23	105.55	352.00
Deep	20	1,510.11	1,654.57
Ultradeep	32	4,300.50	4,290.00
West Africa			
Shallow	169	4,485.47	21,678.05
Deep	50	5,886.50	7,170.00
Ultradeep	17	1,805.00	3,210.00
Total	412	38,094.59	63,504.70
(last month)	(386)	(34,633.63)	(60,788.62)

Greenfield reserves

2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	1214	46,150.75	770,028.05
(last month)	(1238)	(47759.96)	(805426.92)
Deep	161	12,621.98	97,509.77
(last month)	(161)	(12580.98)	(97909.77)
Ultradeep	107	19,520.75	54,507.00
(last month)	(109)	(19880.75)	(57257.00)
Total	1,482	78,293.48	922,044.82

Pipelines

(operational and 2014 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	40,473	(40,348)
Planned/ possible	25,006	(24,740)
	65,479	(65,088)
8-16in.		
Operational/ installed	78,109	(77,889)
Planned/ possible	49,819	(49,475)
	127,928	(127,364)
>16in.		
Operational/ installed	89,771	(89,810)
Planned/ possible	49,233	(48,765)
	139,004	(138,575)

Production systems worldwide

(operational and 2014 onwards)

Floaters		(last month)
Operational	280	278
Under development	41	41
Planned/possible	340	335
	661	654
Fixed platforms		
Operational	9,273	(9,378)
Under development	128	(129)
Planned/possible	1,421	(1,391)
	10,822	(10,793)
Subsea wells		
Operational	4,504	(4,481)
Under development	406	(408)
Planned/possible	6,466	(6,398)
	11,376	(11,287)

Global offshore reserves (mmboe) onstream by water depth

	2012	2013	2014	2015	2016	2017	2018
Shallow	6,015.73	23,677.58	45,505.78	36,289.61	29,783.64	44,054.87	26,930.42
(last month)	(10,494.57)	(6,015.73)	(23,658.35)	(45,585.00)	(36,569.77)	(33,117.01)	(44,387.07)
Deep	2,791.02	484.30	4,423.69	5,618.56	3,612.50	5,266.95	10,882.73
(last month)	(2791.02)	(484.30)	(4,598.44)	(5,843.45)	(3,579.44)	(5,215.54)	(10,597.09)
Ultradeep	737.15	2,932.94	2,817.43	1,908.77	5,207.70	12,210.51	6,986.35
(last month)	(737.15)	(2,932.94)	(2,817.43)	(1,932.29)	(5,193.17)	(12,634.64)	(7,398.10)
Total	9,543.90	27,094.82	52,746.90	43,816.94	38,603.84	61,532.33	44,799.50

4 August 2014

An NOV Hex mud pump. Image from National Instruments.

shutdowns, according to data from the Production Efficiency Task Force (PETF), set up by government-industry body PILOT. Worse, the basin is highly reliant on hubs. If they shutdown, it could impact multiple fields (see panel). Sir Ian Wood's Maximising Recovery report, published earlier this year, also recognizes the need for better asset management, stating a "the need for significantly improving asset stewardship."

A change in mindset is needed, says Tony Hetherington, head of operations, gas and pipelines, at the HSE. While ALE concepts are starting to be recognized and adopted, binary decisions are still being used to manage facilities, despite availability of systems for monitoring and trending data, he says.

"Binary decisions, i.e. assessing a piece of equipment based purely on it meeting its safe operating criteria or not, are no longer appropriate," he says. "Computerized maintenance management systems will give them [operators or duty holders] the data they need, but they are not being used as much as they could be in a structured way across industry, because leadership do not see it as an essential thing to do."

Strategic hubs

Managing assets becomes even more critical when it comes to "strategic hubs" in the North Sea, according to McKinsey and Company, which presented a report on production efficiency at this year's DEVEX conference in Aberdeen.

The McKinsey report found that the two main factors impacting performance are export system dependency and the quality of operator practices and approaches. McKinsey looked at production efficiency correlated with reliability practices in 2005/06 and then again in 2010/11. Best or good practice operators had higher asset production efficiency regardless of the year of study with leading performers also improving in the time period. Through interviews with 50 offshore field managers, McKinsey found that high performing operators were more likely to:

- Challenge and minimize planned downtime—by doing only the most essential activities during turnarounds and post-postponing others until normal operations resume, instead of treating a turnaround as a chance to tackle a "laundry list" of maintenance tasks that has been building up.
- Continually improve reliability by learning from failures—by routinely prioritizing and conducting investigations into root cause failures that result in lost production, then making appropriate changes to equipment, protocols or maintenance strategies.
- Create a culture of responsibility in operations—by instilling a sense of ownership in an asset, supported by widespread adoption of clearly visible and understandable operating standards.

As an example, Hetherington cites an area high up the HSE's importance list; safety critical elements (SCEs), such as emergency shutdown valves (ESDVs). An ESCV will be periodically tested, and if it meets performance criteria, it will continue to be used. Under a binary decision making system, its performance, or the time taken to close correctly, could have lengthened from the 8secs it was designed to close at, to 12 and then 18secs, but still pass its performance acceptability criteria, a phenomena described as "normalization of deviance" by the KP4 report. Another example is water pressure in a dousing system. If the pressure is falling year on year, it could be a sign it is silting up, but it could still pass the binary decision test, Hetherington says.

"If we trend that data now, it will give duty holders time to think about planning to do something about it," he says, enabling better longer term asset management. "What is required now is looking at how equipment is performing over time, and what other parameters are changing, such as production fluid content, to assess how quickly equipment or pipelines are potentially degrading, and so when they might fail, and what the best maintenance or inspection regime might therefore be, and what action can be taken before it fails."

Another example is using data trending to improve structural management, by helping to understand corrosion and fatigue. "If you can lose 50% of your wall thickness through corrosion, and the structure is corroding 2% per year, you know approximately how long you have got to use that facility," Hetherington says. "By

Another key factor is reliance on hubs. Since 2000, indirect hubs and independents (i.e. fields that are tied to and rely on third party hubs for export), have had consistently lower asset production efficiency than direct hubs, and the performance differential is widening, McKinsey says. An outage at an installation housing a major export route has a severe knock-on effect on its dependents. "For instance, when a hydrocarbon leak was discovered at the Cormorant Alpha platform in early 2013, its operator closed the Brent crude oil pipeline which flows through it. The outage affected 27 other fields."

Other recommendations from the report:

- Fix the basics of reliability and maintenance—employing strong operating practices, as well as having clear performance goals, rigorous root cause analysis, staff improvement schemes, and having a "one team" culture. Investing in facility upgrades and integrity-enhancing projects may be necessary as well.
- Establish standards in common operating tasks—including between operators and service companies, with a focus on knowledge sharing in areas such as common reporting and operating standards related to operating practices.
- Regenerate critical infrastructure within prominent hubs.

"Given the interconnectedness of the infrastructure we believe that the industry must develop a new operating norm at this hub level. First, production efficiency audits by a new regulator should begin by targeting operators of the most critical pieces of infrastructure," McKinsey says. "The industry should also consider a more collective approach to managing 'system critical' infrastructure." ■

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	105	98	7	93%
Jackup	425	381	44	89%
Semisub	191	162	29	84%
Tenders	33	24	9	72%
Total	**754**	**665**	**89**	**88%**

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	30	29	1	96%
Jackup	93	78	15	83%
Semisub	28	23	5	82%
Tenders	N/A	N/A	N/A	N/A
Total	**151**	**130**	**21**	**86%**

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	14	11	3	78%
Jackup	117	108	9	92%
Semisub	38	30	8	78%
Tenders	24	17	7	70%
Total	**193**	**166**	**27**	**86%**

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	26	26	0	100%
Jackup	9	7	2	77%
Semisub	38	38	0	100%
Tenders	2	2	0	100%
Total	**75**	**73**	**2**	**97%**

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	49	48	1	97%
Semisub	47	43	4	91%
Tenders	N/A	N/A	N/A	N/A
Total	**97**	**92**	**5**	**94%**

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	107	95	12	88%
Semisub	3	3	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	**111**	**99**	**12**	**89%**

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	31	29	2	93%
Jackup	25	21	4	84%
Semisub	18	15	3	83%
Tenders	7	5	2	71%
Total	**81**	**70**	**11**	**86%**

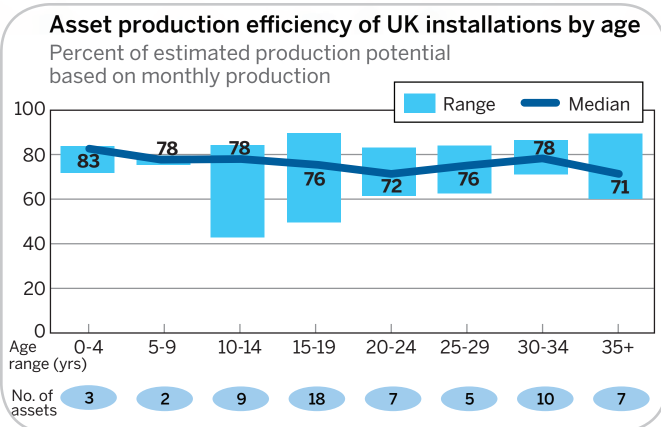
Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	2	1	1	50%
Jackup	25	24	1	96%
Semisub	19	10	9	52%
Tenders	N/A	N/A	N/A	N/A
Total	**46**	**35**	**11**	**76%**

Source: InfieldRigs

14 August 2014

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



Inefficient indirect hubs. Graph from McKinsey & Company.

doing something about that corrosion rate now, maybe painting it more frequently, you could prolong the life of the asset."

In practice

For fire and explosion systems, duty holders have good planned maintenance routines, using data trending, and there are increased inspection and maintenance routines on aging installations, including investment in replacing equipment and work on SCEs, with in-house core integrity teams and "system custodians" for specific SCEs, HSE says.

For structural analysis, concise structural reports are being created from inspection data, with anomaly trend analysis, and the findings reported to senior management (although, for some, not all structural analyses were up to date and some fatigue and redundancy analyses were incomplete or missing), the KP4 report says.

Risk-based assessments were also being performed, but these could be better utilized by looking at near-, mid- and long-term risks, such as managing the effects of changes in fluid properties and quantities, pressures, and souring.

In pipeline management, cross-industry collaboration has improved flexible riser inspection and integrity management, KP4 says. But, it continues, sophisticated corrosion modelling programs need to be validated, at suitable intervals and corrosion threat assessments, could be supplemented by longer-term corrosion mechanism predictions and management, "probably requiring greater integration of predictive information between reservoir and topsides engineers."

Diagnostics

Using computer-based condition monitoring on assets is gaining more interest in the offshore industry, says Tristan Jones, Regional Marketing Engineer, Industrial and Embedded Systems, National Instruments, which supplies software and hardware used by engineers to develop systems that require measurement and control.

Jones says other industries are using more sophisticated data management and monitoring systems to manage aging assets, such as the railways and power generation sectors, by incorporating diagnostic systems. US-based Duke Energy, for example, has around 80 power plants and faces significant challenges with downtime resulting from component failure in older assets. However, for their predictive maintenance, they were spending 80% of their time taking measurements, and just 20% on analytics. They developed a more automated approach, by combining existing data from programmable logic controllers and sensors installed by original equipment manufacturers, with a significant installation of additional measurement nodes to evaluate the health of each asset. The data is aggregated to an enterprise level, with greater visibility, and the engineers can spend 80% of their time on prognosis, and predicting future failures, Jones says.

Another benefit of using automated, computer-based condition monitoring, incorporating data captured from PLCs or sensors installed by OEMS, and then using diagnostic systems, is that expert knowledge can be "harvested" and maintained in the system, and not lost when an expert on a particular piece of machinery leaves the business, Jones says.

Tristan Jones, National Instruments

Equipment uptime can also be increased, without having to send staff onto the drill floor, using automated sensor and diagnostic systems, Jones says. NI supplied a system to NOV for Hex mud pumps for use offshore in Norway. NOV wanted a computer-based condition monitoring system to maintain productivity on the pumps by allowing preventative maintenance, and without needing a human to access the pumps. A number of accelerometers, speed and phase sensors were added to the pumps to monitor vibration, in order to detect valve leaks. An NI CompactRIO system was added to the pump control system to acquire high-frequency data and power the sensors, along with signal processing software and alarm logics, using NI's LabVIEW software. These enabled the team to monitor the pumps' performance and schedule maintenance appropriately.

Different levels of prognostic tools can be added to monitoring systems, depending on requirements. Nick Ward, Senior Product Manager, Predictive Equipment Health Management, Controls and Data Services, at Rolls-Royce, has been looking at higher level prognostic tools, and sets them out into three generations. The first is threshold limiting. If a vibration value of a turbine, for example, goes over a specified limit, an alert is logged, setting reaction time, which, if breached, results in a shutdown. Second generation analysis involves an understanding of what the asset is supposed to do and how it should behave, by assessing live measurement data against stored data (showing what it should be doing) and finding anomalies, before raising an alert. Third generation analysis is a combination of second generation analysis, but incorporating additional factors, for example looking at vibration alone might not trigger an alert, but measurements on vibration, temperature and other parameters might, indicate a failure.

The tools for better ALE management are available, Hetherington says. "The industry, in general, hasn't been taking advantage of the data it collects, particularly on aging assets. The industry is beginning to respond, but we need to keep up the pressure," he says. **OE**

Point by point: The business of FPSOs

In advance of OE's 2014 Global FPSO Forum, Managing Editor Audrey Leon spoke with Peter Lovie, Senior Advisor, Floating Systems for Peter M Lovie PE, LLC, and program chair for Global FPSO Forum; Arjan Voogt, MARIN USA; and Bruce Crager, Endeavor Management, to discuss topics affecting the FPSO sector.

OE: How have you seen FPSOs – both the technology, the attitudes regarding them, and regulatory requirements – change from when you started your career to now?

CRAGER

Bruce Crager, Executive Vice President, Endeavor Management: My first FPSO, *Ocean Producer,* was converted in 1991 when I was SVP at Oceaneering Production Systems. The unit was converted in about 12 months after the engineering was complete. The first client was Amoco in Gabon for a project in 50ft of water, which was the shallowest FPSO installation in the world for many years. The FPSO conversion was about $27 million, including installation. The unit was then moved to Angola where it worked in shallow water for Sonangol P&P for about 18 years. This small FPSO could store about 500,000bbl and process about 20,000bbl. Most of the FPSOs in recent history are much larger, work in deeper water and cost much more. For these reasons, most of the FPSOs leased today, both conversions and newbuild vessels, are contracted initially with much longer term contracts. In addition, the regulatory requirements have become more stringent in the last 20 years, particularly in areas such as the US and North Sea.

LOVIE

Peter Lovie: I got into the FPSO business in Houston in 1995 when I started work for Bluewater of Holland, as their Business Development Manager for North America. After a fascinating seven years at Bluewater with their fleet of turret moored FPSOs for the North Sea and elsewhere, I left to join American Shuttle Tankers as its VP-BD. They were attempting to introduce shuttle tankers in Gulf of Mexico, employing the proven practices of the North Sea's leader in the field. The case for these DP2 tankers was strong: (1) the ultimate in proven safety, (2) ability to work with more uptime in rougher conditions than hawser-moored shuttle tankers, and (3) the cost effectiveness of not having to use support tugs while loading offshore or maneuvering and docking in port.

However we–like our Seahorse Shuttling competitor backed by Conoco–did not succeed in this five-year campaign and the company was absorbed into Teekay.

I had been pretty active in the environmental impact statement (EIS) team effort (1998-2001) for using FPSOs in Gulf of Mexico. Consequently, when the Cascade moved forward, I was working for Devon Energy, which was non-operating partner (50:50 with Petrobras) on this development that contemplated an FPSO with shuttle tanker export.

We felt that there was room to improve terms for the leased FPSO and the partners were persuaded to open up a bidding process, which took a few more months, but saved a nine figure amount. The requirement here was quite different from that in the general industry expectation: storage capacity was less–around 600,000bbl instead of 1MMbbl and now the FPSO had to be disconnectable instead of permanently moored as had been called for in the EIS. At 8200ft the water depth was several times greater than when the EIS was approved in 2001.

DP2 did not win as the shuttle tanker design choice for Cascade. Petrobras opted instead for enhanced maneuverability tankers with bow loading, controllable pitch propeller and bow thrusters, still requiring two tugs for loading offshore, plus tugs in port.

You asked about the regulatory side. I have to say that I found the USCG and Minerals Management Service (MMS) very willing to listen to new directions in these early formative stages, whether from a contractor or an operator, and where we really went after fundamental sound and safe methods and took a lead in it. Maybe this is an American thing–we did not "go cap in hand as supplicants for papal blessing"–but rather it was an attempt to take the lead and get it right.

VOOGT

Arjan Voogt, Manager of MARIN's Houston office: The FPSO community has always been proactive in solving challenges in design and operation together as an industry. The reality that if one of these systems fails all will suffer, is seen by all competitors who work together towards safe and efficient operations. Since the FPSO Research Forum began 17 years ago, many joint industry projects tackled important issues like green water and bow slamming, life cycle management, mooring integrity and safe offloading operations.

OE : Currently, only one company (Petrobras) operates an FPSO in the Gulf of Mexico in the Cascade/Chinook field, and Shell is soon to follow with the *FPSO Turritella* at its Stones development. What's your view of this market? Will more companies follow suit as production heads into deeper Gulf waters or will US regulations interfere?

Bruce Crager: This is correct for the US Gulf of Mexico, but there is another FPSO working for Petróleos Mexicanos (Pemex) in the Mexican Gulf and several more planned, including two at Ayatsil-Tekel. FPSOs are not the only floating production option in the Gulf due the well-developed offshore pipeline infrastructure. Spars, TLPs and semi FPUs are practical options in most locations. However, as we move into deeper water and new areas without pipeline infrastructure, such as the Cascade/Chinook and Stones developments. FPSOs are a very viable option. One significant advantage of FPSOs is the ability to disconnect in the event of a hurricane, which is not common practice for other floating production systems. For these reasons, I expect the use of FPSOs in the Gulf to increase.

Arjan Voogt: As is shown by their track records around the world FPSO can be safe and reliable means to produce and store oil, so I don't see the US regulations block this option for field development. However, the choice for FPSO's is driven by many more factors and with the existing infrastructure and experience in the Gulf of Mexico, it will not be the one solution that fits all.

Peter Lovie: The evidence is not good for there being many more FPSOs in the US Gulf of Mexico. First, taking the broad operating oil company viewpoint, there are multiple factors at play influencing the choice of an FPSO as the development

The Cidade de Ilhabela FPSO berthed at the Brasa shipyard in Niteroi, Rio de Janeiro, Brazil.
Photo from SBM Offshore.

The FPSO Cidade de Ilhabela is in the final stages of construction at the SBM Offshore/Synergy joint venture Brasa shipyard in Niteroi.

Photo from SBM Offshore.

solution: reservoir conditions, bringing the oil inward instead of sending outward to other countries, convenience and cost-effectiveness of the extensive pipeline network, economics and risks versus other development options (semi, spar, TLP or subsea tie-in). All of this gets risked and looked at again and again as reservoir options get investigated. One really has to have worked for an operator to fully grasp it. Gulf of Mexico operators do genuinely consider the FPSO option, but the logic for choosing that solution has not prevailed very often.

The DeepStar-led effort during 1998-2000 to secure an EIS from MMS was driven by avoiding the need for a two-year regulatory delay in securing an EIS for an FPSO-based developments, to try to keep the FPSO option available and on the table. The practical example cited back then was Texaco's Fuji prospect, the leading FPSO prospect in sight at that point. Appraisal later showed that prospect did not contain enough oil and it went away.

An industry study in 2013 involved an informal "focus group" opining on the need for more FPSOs in US Gulf of Mexico. Not one of the ten operators in the project meetings saw a need in a time frame of the next ten years for another FPSO after Stones. The context was the need for offloading in Gulf, which of course, largely hinged on the presence of FPSOs. This is documented in RPSEA project 10121-4407-01.

Ten or fifteen years ago, I was much more optimistic for growth of the FPSO fleet in US Gulf of Mexico, but now have to go with what I see. If you listen to the shuttle tanker people and the FPSO contractors they can be somewhat more optimistic.

OE : In May, OE ran an article about a recent RPSEA study that sought to investigate whether cylindrical-hull FPSOs could be a potential production solution for remote ultra-deepwater Gulf of Mexico operations. Response to the article indicated that not enough was done in the study to both include a disconnectable option as well as account for wave slam loads. Will cylindrical FPSOs ever have a place in the Gulf of Mexico? Or is it just as simple as providing the option to disconnect when storms approach?

Bruce Crager: Cylindrical FPSOs operate offshore Brazil as well as the North Sea. While these are not disconnectable, those in the North Sea work in a severe environment. The industry has proven it can develop technical solutions as needed, and developing a disconnectable concept for round hulls should be possible. The FPSO *Ocean Producer,* converted in 1991, was located in only 50ft of water offshore Gabon and required a simple disconnect capability in the case of extreme storms. While this feature, which was based on remote release of chain stoppers on deck was never required at this location, the disconnect system was activated at each anchor as the vessel left the field. The biggest issue is likely to be how to maneuver a cylindrical hull which lacks propulsion after disconnect.

Arjan Voogt: There is a reason why vessels aren't cylindrical shaped. Disconnecting and moving away for a storm might not be the most practical solution for a cylindrical floater. Offloading the oil and evacuating the platform will be considered as well. Both options have technical and regulatory challenges ahead, but it's definitely possible.

Peter Lovie: I was in the middle of the first FPSO in Gulf of Mexico needing to be disconnectable, and again when it was contracted back in August 2007. Then, another disconnectable FPSO for Stones was contracted by Shell last year (using SCRs).

**honouring the past,
shaping the future**

Allseas

Why should a new round FPSO for ultra-deepwater Gulf of Mexico be any different, and not disconnectable? Regulators at the 2012 and 2013 Emerging FPSO Forums in Galveston spelled out their needs on this. Knowledgeable Gulf of Mexico industry people know about it. The disconnectability issue is a serious fundamental to resolve–no excuse for ducking it if an operator is to take this work seriously.

In my experience the RPSEA business model was well intended, but mulling it over, a year after serving as principal investigator on one of their projects, I believe allowing the free market to sift out the worthwhile new technologies is better than a government assistance plan. The centuries old process of survival of the fit in the marketplace of real needs is sensible, but it can get forgotten with passing years. What I have seen happen is that some operator's technology guy says this new system is going to be great, without ever having to face the real business world. And people tend to think operator guys are always right!

OE: It was mentioned at last year's forum that FPSOs are being designed to operate for 20-30 years, but with most FPSOs being conversions instead of newbuilds, the hull's life span is likely 50-60 years. How is that extra life taken into account before work begins on the conversion?

Bruce Crager: Hull life–assuming proper hull coatings and cathodic protection with regular inspections – can last for a very long time. However, most process systems are designed for a shorter life such as 20 to 30 years. There are extreme examples such as Petrobras FPSO P-34, previously known as the *P.P. Moreas*, which was built in 1959 and first converted to an FPSO in 1979. However, while the hull is now very old, this unit has been upgraded three more times with significant modifications to the topsides and is still operating offshore Brazil.

Arjan Voogt: Not every trading tanker is a good candidate for conversion. The consumed fatigue life can be calculated and taken into account in the design of the conversion. Older vessels that traveled in more harsh environments, will need more time in the yard and more steel replaced before they're ready for a life as FPSO. Many conversion are done on relatively new vessels, just to reduce the time to first oil.

Peter Lovie: This is now a normal part of the design process. It's not unlike the circumstances in the last two decades where semisubmersible MODUs have been modified for deeper water and deeper drilling and their hull lives extended much longer than the original 25 year target. The offshore industry has become much more skilled in dealing with hull fatigue life. There are much better analytical tools and amazing practical gauging methods are now available that were unthinkable a decade or two ago, plus contractors' ingenuity in devising practical remedial measures.

OE:Last year, several speakers brought up factors negatively affecting the FPSO industry. These included increased local content requirements, rising costs, clogged supply chains, and competition. What can be done to overcome these challenges?

Bruce Crager: These challenges are common to other large projects in the offshore industry. The solution will require coordinated efforts between FPSO providers, operators and suppliers to focus on well-defined up front engineering, minimal change orders, and ongoing communication during project execution. One key to successful FPSO start-up is to have the operations team involved early so they can support commissioning as well as long term operation of the vessel. Another issue is the experience level of the companies working in the FPSO industry. Some have little experience and competition is a real concern because there are about 30 owners of leased FPSO units. Many of these only own one unit, but all are actively focused on leasing their FPSO fleet on an ongoing basis and many are trying to win work for more units.

Arjan Voogt: Many FPSO's are designed to changing specification, resulting in multiple iterations. There are often good reasons for this (changing field expectation, financial markets,

'Emerging' no more

The 4th Annual Global FPSO Forum, formerly Emerging FPSO, serves as a rare opportunity to meet and deliberate over topics affecting the global industry. While most conferences are held in Europe and Asia, Global FPSO Forum is held annually in Galveston, Texas. Although the event is held near the center of the oil and gas industry – Houston – the conference tackles issues spanning the globe, hence the new name.

The Global FPSO Forum draws operators, contractors and service providers alike to present new findings and to debate old ones in a convenient setting. The 2014 lineup includes speakers from ABS, BW Offshore, FMC Technologies, MODEC, Moss Maritime, National Ocean Industries Association, NextDecade LLC, NOV, Petrobras, Saipem, SBM Offshore, Sevan Marine, Shell Exploration and Production, Society of Naval Architects and Marine Engineers (SNAME), Tritech International, and Wood Group Mustang.

The Global FPSO Forum will hold a special workshop on moorings on Tuesday, September 23, which will host speakers from Chevron, Shell, ExxonMobil, MARIN, Tritech International, InterMoor, SBM Offshore, SOFEC, and NOV. Topics to be discussed include: changes in design philosophy, mooring integrity, mooring line monitoring, prevention techniques, turrets and station keeping, shallow water mooring systems, challenges in disconnectable turret designs, and case studies.

OE's Global FPSO Forum will be held this **September 23-25, 2014**, at the Galveston Island Convention Center at San Luis Resort. For more information, please visit: **www.globalfpso.com.** ■

other new data), but it increases costs and limits the availability of good qualified engineers.

Peter Lovie: Every time the offshore business gets busy this kind of discussion starts again. It is part of life, how things get difficult and when the going gets tough, the tough get going, to paraphrase Vince Lombardi.

The radical shift to much larger and more complex FPSOs was addressed at last year's forum and will be again this year. CAPEX obviously goes way up when the vessel is so much bigger and badder– but is it really a matter of "cost escalation"? Naturally supply and demand causes some escalation on unit rates as we saw in industry indexes during 2007-2009 when they rose and then came back down. There's a matter of what we define as "cost escalation."

OE: Over the past two years, one topic that continues to pop up in regards to FPSOs – no matter the location – are issues with mooring lines and the degradation of either the ropes or chains. What are some

The FPSO Cidade de Paraty operating in the field.
Photo courtesy of Petrobras News Agency.

FPSO market forecast

Energy analysts Douglas-Westwood estimates in its World Floating Production Market Forecast that US$91 billion will be spent on FPSs during the period of 2013-2017. This marks a 100% increase over the previous five-year period, with the global CAPEX set to double.

Douglas-Westwood attributes the remarkable jump to factors including an increased number of newbuilds and conversions when compared to redeployments; a greater degree of local content requirements that can result in increased costs; and general inflation within the offshore oil and gas industry.

As exploration graduates into deeper waters, an industry-wide scramble to find cost-effective production methods generally follows. The deeper the water, the less options operators have; however, FPSOs are featured globally in some of the deepest projects in the world, including what will be the deepest project in the world: Shell's Stones in the Gulf

solutions that could curb these problems and help keep FPSOs and other floaters on station?

Bruce Crager: The industry has significant experience with mooring systems for both offshore rigs and floating production units, including FPSOs. There are only five dynamically-positioned FPSOs in the world so the large majority are moored. The mooring system normally remains in place during the life of the field. It is possible to inspect mooring systems in-situ using divers and ROVs and the industry has the capability to replace specific components such as chain, wire rope and synthetic rope sections. However, more work is needed to improve the longevity of these components in long life fields, particularly in harsh environments.

Arjan Voogt: As discussed in last year's forum, there are many different reasons why mooring lines break. In the end, an anchor chain is nothing stronger than its weakest link. Mooring systems are designed with this in mind and can maintain station with one line down. The broken line does need to be replaced, though, which often takes many months of planning and preparations. Anticipating line failures in advance and designing the mooring system for a potential line replacement, together with life monitoring of the lines will help keep FPSO's on station. This years' mooring special session (at Global FPSO Forum) will compare competing system to monitor the lines. In addition to this, FPSO operators will present ongoing research in corrosion and failure mechanisms which will help to prevent some mooring line failures in the future.

Peter Lovie: Mooring line failures are not new, and not just with FPSOs. Hurricanes Katrina and Rita in 2005 caused multiple semisubmersible drilling units to break loose and drift in the Gulf. It was these mooring line failures that led to the nightmares in the minds of knowledgeable operators' that one of these MODUs would bang into an FPSO loaded with oil during the hurricane, causing a horrendous oil spill of Valdez proportions. Hence, the 2006 scramble to make FPSOs disconnectable for the US Gulf, and the OTC sessions and panels on this theme in 2007.

Around 2008, the ability to inspect mooring lines on location became much more doable. In 2014, these mooring line failures are widely recognized as a problem by operators, underwriters and regulators, and all working to do something about it. The underwriters see a loss rate of 10 times more with mooring systems than with other offshore underwritings.

Their Floating Unit Mooring Assessment (FUMA) initiative in its 21 July 2014 presentation says that in 2001-2011 there were 23 documented mooring failures, eight of which were systems failures (multiple line damage and drifting), all based on OTC Paper 24025. Their "Moored Floating Unit Portfolio" cites 112 incidents in six years with a total of $2.86billion in claims.

"Houston we have a problem." **OE**

of Mexico. This could be why Douglas-Westwood found that FPSOs represent "the largest segment of the market both in numbers (94 installations) and forecast CAPEX (80%) over the 2013-2017 period. FPSSs account for the second largest segment of CAPEX (10%), followed by TLPs, then spars."

The firm, which analyzed around 1000 FPS projects for the report, found that Latin America accounted for 29% of the forecast installations and 37% of the projected CAPEX, partially due to the fact that Brazilian state-owned Petrobras operates numerous fields in the country's presalt that account for the bulk of the region's FPSO installations. Despite the national's high-profile troubles, including significant financial cutbacks and a scandal related to contractors, Douglas-Westwood expects that it will continue its hold on the region. Beyond Latin America, it noted, "Asia is the next most important region in numerical terms (24 installations, but Africa is so in terms of forecast CAPEX ($18.2 billion)." ■

–Sarah Parker Musarra

Wireless Networking Offshore

Networking technology works, but companies need to know the obstacles in order to avoid snares. Ellen Fussell Policastro reports.

Communications will be of the essence for the *Goliat* floating production, storage, and offloading vessel (FPSO) once it starts operating in the northern-most portion of the Barents Sea.

Eni Norge, which co-owns the Goliat field with Statoil, leased the *Goliat* FPSO from Sevan Marine. The cylindrical platform will operate in one of the harshest environmental regions in the world, so it goes without saying reliable operations are vital for the control system.

Along with a new emergency shutdown, process shutdown, fire and gas detection, and power management systems, the FPSO, which is under construction in a shipyard in South Korea, will receive new telecommunication systems to fully support, manage, and monitor offshore operations from the offshore control room to the onshore remote operation center. The contract contains offshore data networks, wireless coverage to surrounding vessels, an onboard radio system, and more than 20 other subsystems.

Goliat is just one of a growing fleet of offshore platforms across the industry discovering the benefits of wireless connectivity offshore. But there are still concerns about malware and hacker snares.

"The major barrier for firms across the sector remains the perceived risk from inadequate data security," said Nick Kamen, head of energy and utilities at Vodafone, a multinational telecommunications firm headquartered in London. "The challenge is how to deliver data security within the framework of an open systems-sharing model, while still providing sufficient levels of protection for sensitive and commercially confidential information using third-party devised systems."

The answer, Kamen said, is to address specific IT system requirements and security needs during the initial analysis and design stages. Despite comments that costs and return on investment posed some risk, the overwhelming message from experienced professionals is improper funding for initiatives is one of the biggest deterrents to success.

Multi-redundancy more reliable

Wireless technology takes on different meanings, depending on its application and location. "Locally, on the offshore platform, wireless is really no different than in a plant," said Jim Gilsinn, senior investigator at Kenexis in Maryland. The difference comes when using wireless to get from the platform to headquarters onshore. "Long-haul wireless, which is usually light and thin, is tightly controlled," Gilsinn said. "Because communication is over longer distances, there's more of a possibility for intrusion."

Self-healing mesh is only for large-scale deployment of WiFi in a manufacturing environment, which has more access points than normal. "The actual access points talk to each other and determine if there are outages or link failures," Gilsinn said. "And they can route around those situations." That's also the case when dealing with wireless links, and not necessarily going directly to a wired access point. The path could be a wireless access point that connects to another

Rendering of the *Goliat* FPSO vessel depicted in harsh weather.

access point, and it's "meshed" back to the hard-wired infrastructure. "You won't find that except on the rig itself, yet even mesh on the rig is limited because of limited bandwidth," Gilsinn said.

WirelessHART (a wireless sensor networking technology based on the highway addressable remote transducer) would be another way to use mesh technology to allow asset management across the network, said Fred Czubba, senior business development manager for the oil and gas industry at Phoenix Contact in Washington.

Communications going back to shore would use long-haul, which requires a license band, where users pay the Federal Communications Commission (FCC) for a certain frequency within a certain range. "Point-to-point is like wire replacement for communication between the offshore oil rig and the onshore control station or network access point," Gilsinn said. Yet multi-redundant networks are a better option than point-to-point for rig-to-shore communication said Gary Williams, product manager of control and safety for communications and security at Schneider Electric. Wireless mesh is only one type of multi-redundant network.

Here's how multi-redundancy works. Say you have a ring of multiple platforms; one is going clockwise and one counterclockwise. "The one at 12:00 wants to communicate to the control room at 6:00," Williams said. It can transmit in either direction. "That's multi-redundant, but it isn't mesh."

Authentication, encryption deter attacks

With security being one of the main concerns of asset owners, it's critical to build a good security system during the network design. One way to do that is to "build in intrusion detection, authentication detection, and encryption," said Soroush Amidi, manager of product marketing at Honeywell Process Solutions. "Then you're able to build a safe network, whether it's in a plant or in the middle of the ocean."

If you don't look at the complete architecture from the design point, "all you're doing is patching," Czubba said. "Going layer by layer through your architecture up front is more effective, he said, "Otherwise, you're just filling holes."

Image from Eni Norge.

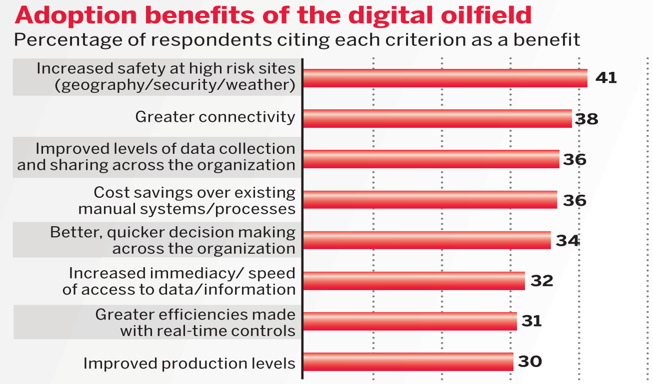
Authentication tools are another way to keep out intruders, asking users to verify their identity. "Most wireless standards have features such as access point broadcasting and service set identifier (SSID). That's great for ease of use, but horrible for security," said Dan Schaffer, business development manager for network and security at Phoenix Contact in Pennsylvania. There's nothing in the standards that stops you from broadcasting your SSID for the whole world to see, and compliance to the standards is not the same thing as security, he said. "You can make uninformed choices and defeat most of the security, encryption, and authentication of your wireless network."

Whitelisting is another way to help ensure a secure network. "It's more of an authorization tool than authentication

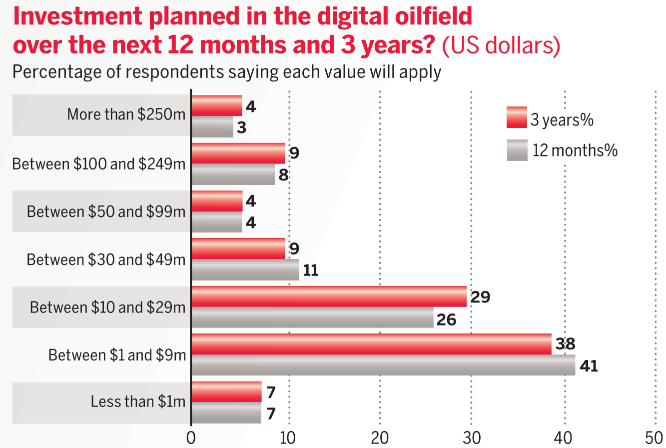
SECURITY, FUNDING PREDICT DIGITAL OILFIELD'S FUTURE

Vodafone, and Huawei, a Chinese networking and telecommunications equipment and services firm, surveyed 120 industry leaders across the globe, revealing an overall positive outlook about wireless communications in securing operations offshore.

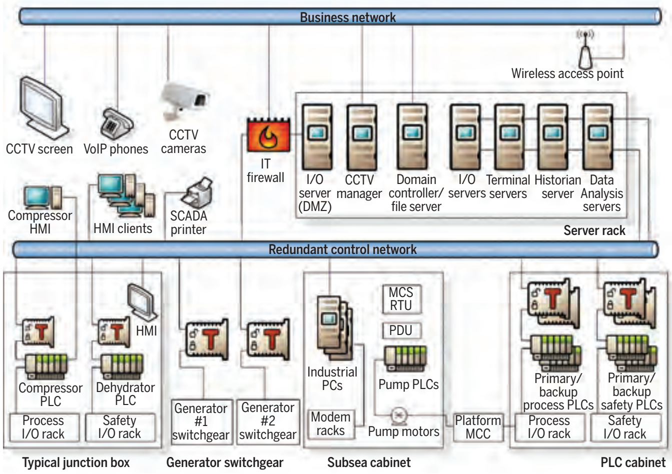
In the survey, 75% of companies said they use wireless technology for communications. Only 33% of respondents reported no experience with a digital oilfield trial. Just over 33% regarded digital oilfields as a way to improve production economics and 66% believed the digital oilfield to be important relative to other strategic business initiatives.



Regarding investments and priorities, 52% said their individual spending would exceed US$10 million, 26% would exceed $30 million, and 11% would exceed $100 million. In order of priorities for investment, security of data and information ranked first, followed by security of people, premises, and physical assets, data collection, data sharing, and finally monitoring and control of maintenance.



Just over 50% reported a concern with the inevitable security surrounding IT and systems, and 75% acknowledged cultural concerns and the internal readiness to adopt automation and wireless technology. Only 33% said they were culturally prepared to adapt to the needs of the digital oilfield. Just under 66% agreed a lack of knowledge of the digital oilfield is hindering cross-industry adoption. ■



Security appliances loaded with a SCADA-specific firewall module protect PLCs, switchgear, and packaged process units.

because it allows an authenticated user to perform a known set of authorized actions," Gilsinn said. Whitelisting works along the lines of known programs can pass through, but if the software is not on the accepted list, then it ends right there. That compares to blacklisting which lets users pinpoint the source of the virus after it's happened. Until a blacklisting tool knows about a virus, it can't block it.

Segregation keeps network clear

With the potential for malware or viruses intruding on the network, even accidentally, operators need to make sure their networks remain segregated so operators on the rig can access the web, communicate with family on Skype, and rest assured all that activity is segregated from the control network, said Graham Speake, principal systems architect at Yokogawa. With the use of more sophisticated technology and firewalls, random checks sometimes occur to make sure nothing unusual is getting into the network. But because of limited manpower and the rigs' remoteness, these checks don't occur on a regular basis, Speake said. Think of the offshore platform, with its several areas of operation as akin to your house with its several rooms, Schaffer said. "Once someone gets inside your house, maybe through an open window in the kitchen, they have unfettered access to other rooms in your house because you don't put up significant barriers in between your rooms."You want to layer your protection and compartmentalize your network so a compromise of one area does not immediately impact other areas," Schaffer said. "That way you are mitigating your damage, kind of like having locked doors between the rooms of your house, or at least a Rottweiler."

Stupid human tricks

While attacks and malicious intrusions are a concern in wireless communications, out on the rig itself, malicious intent isn't quite as problematic. "You're probably less susceptible to the hacker coming in across the network because it's difficult to breach the short bandwidth in the middle of the ocean," Speake said, but it's easy for people to accidentally cause a problem. It's kind of like David Letterman's segment on stupid human tricks, Gilsinn said.

"They could write a password on a sticky note and leave it lying around, or they'll make their password too easy." Or people assume the wireless networks are segregated. "They get bored out there, so they plug in their USB sticks and download web sites for personal use or charge their phone," Speake said. "They aren't necessarily making phone calls but maybe listening to music, and you don't know what's on the phone." While most oil platforms have a separate line accessing the internet that might not be available for the control room. "But they'll find ways," Speake said. "They might hook up a separate wireless hub off of their personal laptop and connect to it from the control room."

The key to isolating traffic is to think about radio frequency (RF) protection and include only what is really needed. "The onshore link should only be used for things that are absolutely necessary, Gilsinn said. "Email is necessary, but web surfing should be limited. The actual process communication should have a higher priority," he said. "You should control network flow going through your wireless link, since it's your sole link from corporate to the outside world." So while you can never eliminate web traffic, you can limit it in terms of the bandwidth it uses.

Standards as an anchor

Knowing which standard to use with offshore wireless technology isn't so easy because such a variety of groups developed independently and represent different industries and needs. Some choices include IEEE 802.11 WiFi for use in wireless local area networks (WLANS) or Zigbee or Bluetooth standards for personal area network systems are intended for short-range communication. Yet, as the automation industry is moving to IP-based technologies, some experts are now opting for standards that allow more system flexibility. ANSI/ISA-100.11a-2011, Wireless systems for industrial automation: Process control and related applications, "has tried to go a lot farther than WirelessHART," Czubba said. "It's object orientated and designed to support a lot more functionality, such as Foundation Fieldbus, which sees use more offshore than onshore. Plus the standard has a high performance and reliability factor."

"One great element about ISA-100 is it allows system flexibility and is aligned to IP networking, Amidi said. "A distributed system allows you to have a central hub from which you can get all your data and manage transmitters."

The standard also allows vendors with big data packets, such as vibration, to use proprietary protocols without having to make changes, Amidi said. They can use the tunneling features of ISA100.

Advanced encryption standards (AES) let you protect data in flight. "AES-256 tells you how big the key is to encrypt and decrypt the data. It's pretty much unhackable," Schaffer said. "The 802.11 Internet protocol (IP) standard will support radios as a way to authenticate. But some of the other industrial protocols, such as Bluetooth, which can be used in industrial settings, have weak or nonexistent authentication," Schaffer said. "You can follow the standards and have a secure system or insecure system based on the choices you make. The standard doesn't demand you use AES-256 encryption. If you choose not to do that, you're still following the standards, but you've severely weakened your security." In such a diverse world of standards for wireless and security, the bottom line is you need to think on an all-encompassing level.

Security standard enables defense

The ISA99 control system security standards played a major role in the development of a new architecture for one company operating a platform on the US continental shelf. By using a Defense in Depth network architecture (an information assurance strategy from the US National Security Agency [NSA]) in accordance with ANSI/ISA-99 standards and the Department of Homeland Security guidelines, the new architecture isolated layers of the business and process control network, using routers and firewall appliances to permit only the minimum traffic that was necessary between these layers.

"The concepts of zones and conduits in ISA-99 (now IEC 62443) are critical to any communications, whether wired or wireless, because these models give you the ability to divide your platform into security zones so you can tailor your defenses to specific areas as well as security capabilities and needs," said Eric Byres, CTO of Tofino Security. The case above is a prime example of using ISA/IEC 62443 zone and conduits with security products, Byres said. "The firewalls give engineers the ability to control what traffic flows into a zone (see graphic), and sends out alarms when it notices suspicious traffic."

Benefits over risks

As users become more educated about the potential for wireless communication offshore and the savings it represents, experts believe they will realize benefits over risks. Even though wireless today sees use mainly for monitoring and reporting and not control, because of security and reliability concerns, in the next five years we will start to see more comfort and use of control in noncritical areas.

Today's use of real-time wireless communication for safety uses should help spur on acceptance. In an emergency, wireless devices can help operators know who's made it to the lifeboats and who hasn't. One helpful tool is as a card helicopter passengers swipe to ensure they're compliant with regulations before boarding the rig. When a person gets off the helicopter, he gets tagged. "We can monitor personnel to find out which floor of the platform they're on. In case of emergency, when somebody has to initiate a rescue, you don't want people searching the platform to find those individuals."

With so many older platforms needing upgrades, wireless will see more use, and more checks will be in place, ensuring devices only connect to other devices, and flagging those from a separate access point, Speake said.

Today's technology will only get more sophisticated as time goes on. The way new engineers interact with technology is quickly evolving, with technologies such as a touch screens instead of a mouse and monitor. Today's workforce has to interact differently and come up to speed a lot faster. In addition to firewalls and levels of encryption, the industry is seeing more use of retina and finger-print recognition and digital video.

There are applications and efficiencies the industry has not seen yet. That is why it is just scratching the tip of the automation-networking iceberg. OE

New technologies for changing environments and reservoirs

SBM Offshore discusses some of the company's developing technologies and how it is working toward unlocking reserves in the Gulf of Mexico

Exploration for fields further offshore and in deeper waters is leading to the development of more complex reservoirs. It is also fueling technology innovation from service providers. Product development is driven by evolving market demand and relies on close collaboration with clients.

Dutch floating production and mooring system provider

TECHNICAL CHALLENGES

Some Lower Tertiary reservoirs appear to be poor quality, leading to low recovery factors. Oil players have launched a series of industry-wide initiatives to sponsor the oilfield service industry to fill the key technology gaps for subsea and well equipment.

Due to the characteristics of the Lower Tertiary reservoirs, SBM Offshore has found that the key challenges include:

- Some of the deepest reservoirs ever developed in the world (many between 8,000m and 10,000m below sea level)
- A thick salt layer making seismic imaging difficult, and drilling and well workovers costly
- Ultra HPHT conditions (up to 20,000psi or more)
- Injection of water and/or gas for enhanced oil recovery (EOR) will require surface pressures of 1000bar or more
- Riser systems required to connect subsea wells to a floating facility are beyond the capabilities of conventional flexible risers
- Prevalent hurricanes
- Exposure to prolonged high currents, known as the Loop Current, or large furrows near the Sigsbee Escarpment where water depth can suddenly drop steeply by 1000m, posing serious challenges for export pipelines
- Difficult seabed terrain

Technical solutions for the Lower Tertiary Paleogene fields

SBM Offshore has developed and qualified a range of new technologies to meet these challenges. In addition, the company is mining existing its technologies to attempt to increase productivity, efficiency and safety. Here are some examples:

1. Disconnectable FPSO with steel risers for early production

SBM is building the FPSO *Turritella* for Shell's Stones development. A Suezmax tanker is currently being converted in Keppel's shipyard in Singapore. It will be the deepest production unit ever installed, and the first disconnectable system with steel risers.

Currently, only Petrobras has an FPSO operating in the Lower Tertiary area on the Cascade/Chinook fields, which is the first FPSO approved for use in the US sector of the Gulf of Mexico.

The FPSOs for Shell and Petrobras are both relatively simple processing units with no reservoir pressure maintenance in terms of water or gas injection. The primary purpose of the early production systems is to allow the operator to gain an understanding of the reservoir performance from a small number of wells, before deciding on the best full field development strategy. An FPSO minimizes the need to run a long export oil pipeline across difficult seabed terrain in ultra-deepwater.

Hurricanes are prevalent in the Gulf of Mexico. To avoid exposure to this risk, FPSOs operating there need to be disconnectable, which is typically achieved by releasing a buoy to which the risers and mooring lines are attached. The buoy then sinks to a pre-determined depth. Once the storm passes, the FPSO returns and the buoy is reconnected so that production can recommence.

However, this type of development has limitations due to the maximum suspended weight that the disconnectable buoy can support; depending on water depth and riser design, a maximum of six to 10 risers and umbilicals can be accommodated. For

Above: FPSO *Turritella* marks Dutch FPSO provider SBM Offshore's introduction to the Gulf of Mexico.
Left: A rendering of FPSO *Turritella.* Images from SBM Offshore.

SBM Offshore was recognized at this year's Offshore Technology Conference in Houston for its Very High Pressure (VHP) Fluid Swivel technology, which allows operators to use floating production storage and offloading (FPSO) units throughout the full development of ultra-high-pressure reservoirs. Previously, full development had not been possible where a weathervaning system was required in conjunction with fluid re-injection into the reservoir.

Back to work in the Gulf of Mexico

The VHP Fluid Swivel technology would be particularly relevant to the Paleogene reservoirs, or Lower Tertiary fields, in the

Stones, SBM, in close collaboration with Shell, has developed the world's largest disconnectable turret, complete with several new components needed to enable the buoy to be safely connected and disconnected. Coupled analyses of steel risers and FPSOs enable SBM to optimize both the riser design and the vessel motions and excursions.

2. Disconnectable FPSO with steel risers for full field development

Full field developments typically require a larger number of risers and umbilicals, which a disconnectable turret cannot accommodate. SBM developed the MoorSpar system, which is supported by a conventional, slender spar-type structure, with the capacity to support more risers and umbilicals. The concept is the result of more than seven years' research, involving extensive model tests. It is ready to enter a major project FEED.

The concept makes use of a yoke on the FPSO, which is elevated on disconnection from the MoorSpar. This simplifies the riser design, as the spar remains floating when disconnected and the MoorSpar size can be adjusted to the riser loads. Moreover, when connected, the yoke decouples the FPSO motion from the risers, enabling the use of simple steel catenary risers instead of the more expensive lazy wave configurations.

The current industry pressure limit for an FPSO fluid swivel is 520bar, however, this is inadequate to allow water and/or gas reinjection into Lower Tertiary fields; pressures are needed well above this level. The solution from SBM is the VHP Fluid Swivel. The 830bar swivel design successfully passed a full qualification program. Long duration endurance runs equivalent to five years in North Sea conditions were undertaken. The swivel design can accommodate operating pressures up to 1,000bar (14,500psi). Further tests during 2014 will complete qualification at this pressure.

Launched in 2009, the development program has resulted in a patented technique to allow the swivel seals to accommodate much higher pressures. The resulting VHP fluid swivel is suitable for water injection, gas injection or WAG service. The high-pressure rating of the VHP Fluid Swivel has been achieved by limiting the pressure differential across individual seals in the swivel. An Oil Pressurization System (OPS) supplies two pressurized fluid barriers for this purpose: 860bar between the isolation and primary seals (first barrier), and 430bar between the primary and secondary seals (second barrier). There is ambient pressure between the secondary and tertiary barrier. The VHP OPS thus limits the pressure differential over any seal to 430bars, which is within the qualified capacity of the seals.

"The VHP Fluid Swivel demonstrates that our continued innovation is successfully bridging the technology gaps identified with our clients," SBM Offshore Group Technology Director Michael Wyllie says.

3. Deep draft semisubmersible

For deepwater fields in harsh environments, SBM's DeepDraft vessel holds the world record water depth for a floating ptoduction semisubmersible. Independence Hub semisubmersible FPU has been installed in the Gulf of Mexico, in 2415m water depth, since 2007. Its daily gas production capacity is 1 billion scf/d. ■

SBM Offshore's Very High Pressure Fluid Swivel, which was recognized at OTC 2014.

US Gulf of Mexico. The US Bureau of Safety and Environmental Enforcement says that there are about 90 announced Gulf of Mexico deepwater prospects, "with operators setting and surpassing records in water depth and length."

Currently, only two Lower Tertiary fields are in production today due to the extreme challenges of these reservoirs, which are characterized by extreme water depth and high-pressure/high-temperature (HP/HT). The Lower Tertiary formation in the Gulf of Mexico is situated approximately 280km offshore and runs 125km wide and 480km long.

Paleogene-aged sandstone reservoirs typically lay between 8000m and 10,000m below sea level. The extreme depths result in pressures in excess of 1400bar (20,000psi) and very high temperatures that test the limit of what the industry is capable of operating in today.

Until recently, no technology has existed to overcome the inherent difficulties that come with the ultra-deep fields, which range from 1500m to potentially as deep as 4300m.

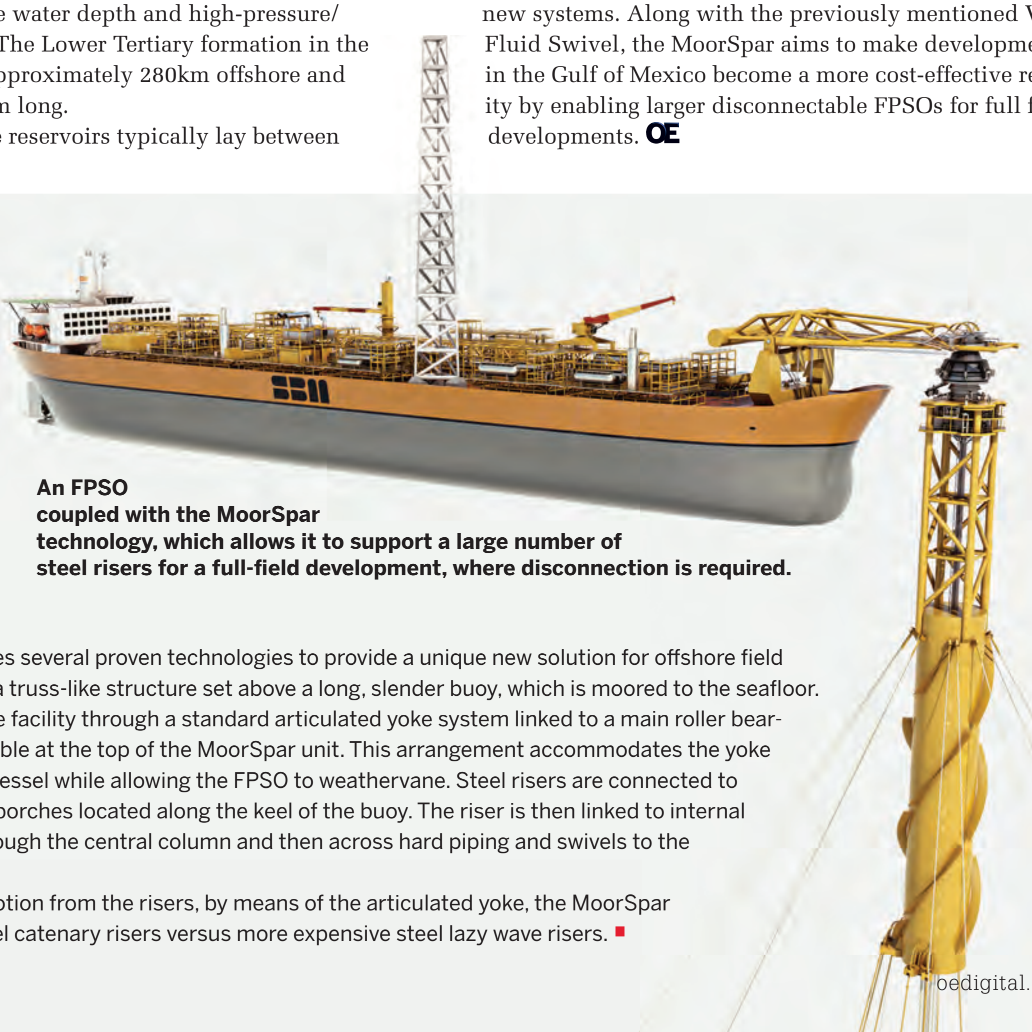
New technology developed by SBM Offshore will enable FPSOs to be widely used for the extremely challenging Lower Tertiary fields. These solutions are applicable for both early production and full field developments.

The FPSO *Turritella* for Shell's Stones development marks SBM Offshore's first move into the region. Due to start operations in 2016, it will be the deepest production unit in the world at 2900m. For SBM Offshore, the list of industry firsts for *Turritella* also includes the first disconnectable turret with steel lazy-wave risers. As a consequence of the combination of water depth and steel risers, the buoy has the biggest displacement to date. Fitted with a very complex mooring system, it will have a processing capacity of 60,000bpd and 15MMscfd. For this turret, SBM Offshore developed and qualified several new components related to the buoy pull-in and latching systems, as well as a new design for the massive buoy.

The company is also attempting to address the remaining technology gaps in the industry with the development of its two new systems. Along with the previously mentioned VHP Fluid Swivel, the MoorSpar aims to make developments in the Gulf of Mexico become a more cost-effective reality by enabling larger disconnectable FPSOs for full field developments. OE

THE MOORSPAR SYSTEM

This technology permits an FPSO to take a higher riser load, and yet still allow disconnection to sail away from hurricanes. The MoorSpar system can be advantageous for high pressure and high temperature reservoirs as it avoids the need for flexible jumpers or risers.



An FPSO coupled with the MoorSpar technology, which allows it to support a large number of steel risers for a full-field development, where disconnection is required.

The system device combines several proven technologies to provide a unique new solution for offshore field developments. It consists of a truss-like structure set above a long, slender buoy, which is moored to the seafloor.

FPSOs are connected to the facility through a standard articulated yoke system linked to a main roller bearing situated below a gimbal table at the top of the MoorSpar unit. This arrangement accommodates the yoke roll and pitch motions of the vessel while allowing the FPSO to weathervane. Steel risers are connected to the MoorSpar facility at riser porches located along the keel of the buoy. The riser is then linked to internal piping, which is routed up through the central column and then across hard piping and swivels to the FPSO.

By decoupling the FPSO motion from the risers, by means of the articulated yoke, the MoorSpar enables the use of simple steel catenary risers versus more expensive steel lazy wave risers. ■

The *BW Pioneer* FPSO, currently in Petrobras' Cascade/Chinook development in the Gulf of Mexico, can process 80,000bo/d.
Image from Petrobras.

DNV GL launches regulatory roadmap for US floaters

Raja Roy examines DNV GL's first comprehensive overview on how to properly comply with US Coast Guard requirements to operate FOIs, FSOs and FPSOs in US waters.

The roadmap document called "Verification for compliance with United States regulations on the outer continental shelf" follows from the US Coast Guard's (USCG) policy letter last year, accepting approval plans and inspections from the class societies DNV GL, Lloyd's Register, and ABS as basis of USCG approval. However, differences in the accepted rules and standards, and the subsequent variety in the complementing requirements from the CFRs (code of federal regulations) led to uncertainties among operators, both about requirements and final approvals.

This roadmap removes the uncertainty factor. By including all the relevant information in a single document, it is a clear path for compliance.

Background

The USCG, within the Department of Homeland Security, has broad authority under the Outer Continental Shelf Lands Act to regulate safety of life and property on US Outer Continental Shelf (OCS) facilities and vessels engaged in OCS activities, and the safety of navigation. The USCG is also responsible for security regulations on OCS facilities, as specified under the Maritime Transportation Security Act. Other regulatory agencies, such as the Bureau of Safety and Environmental Enforcement (BSEE) also share jurisdiction over OCS activities.

Commercial vessel safety standards for US-flagged vessels, Mobile Offshore Drilling Units (MODU), undocumented floating facilities, and fixed facilities are published in chapter 1 of Titles

33 and 46, CFR. The regulations provide detailed guidance for the design, construction and operation of these units.

However, USCG has recognized that the design and technology of offshore facilities continues to advance at a rapid pace, and that existing US regulations (CFRs mentioned above) do not address the current state of technology. Under 33 CFR 143.120, the USCG has the authority to accept alternative design and engineering standards if an equivalent level of safety is provided.

USCG has recognized that design and technology of offshore facilities continues to advance at a rapid pace, and that existing US regulations do not address the current state of technology.

Accordingly, the USCG published CG-ENG Policy Letter No. 01-13, which prescribes alternate design and equipment standards for floating offshore installations (FOI) and floating production, storage, and offloading offshore units (FPSO) located on the US OCS. In general, the policy letter requires the floating unit to be classed by a classification society (DNV GL, ABS and Lloyd's Register) that is accepted by the USCG, and establishes requirements to be met in addition to the classification society's rules.

A floating facility meeting the design and construction requirements of this policy letter is considered meet a level of safety equivalent to that prescribed by 33 CFR 143.

Objective of the regulatory roadmap

As there are differences in the class society rules, which form the basis of the equivalencies, and the complementing requirements from the CFR, there remained an uncertainty on the requirements and the final approvals. To remove this uncertainty factor and in order to establish a clear path of compliance, DNV GL created a roadmap and a class notation (US) in the interest of the operators and engineering houses.

A matrix of requirements

The document titled DNV GL SE-003, outlines a regulatory roadmap for owners and operators of FOI, FPSO and FSO units wishing to engage in OCS activities in the US Gulf of Mexico. The roadmap uses DNV GL classification rules and services as a building block, and identifies additional USCG design and equipment requirements for these units that are not otherwise covered by the rules.

Compliance with the appropriate DNV GL classification notations and supplemental USCG design and equipment requirements described in this service specification provides an equivalent level of safety to the USCG's design and equipment requirements prescribed in the CFR.

Contents of the document

The document outlines a DNV GL class-based verification scheme for US compliance for offshore objects of the following types: FOI, FSO, and FPSOs.The document is divided into two main chapters and an appendix:

- Ch.1: General information about principles, procedures and legal provisions for meeting an equivalent level of safety to the USCG requirements (as documented in their policy letter No. 1-13) for FOIs, FSOs and FPSOs meant to operate on the US OCS.

- Ch.2: Design and equipment requirements for meeting an equivalent level of safety to the USCG requirements for FOIs, FSOs and FPSOs operating in the US OCS. This chapter contains compliance matrices for FOIs and FPSOs which specifies a list of supplemental USCG requirements beyond class requirements in a tabular format. The chapter also includes an informative section on equivalencies and design considerations.
- Appendix A: USCG Policy letter No. 1-13.

USCG acceptance of the DNV GL plan review and inspections is predicated on the basis that such actions are in accordance with the relevant class notations and additional USCG requirements described in CG-ENG Policy Letter No. 01-13. The USCG will make decisions concerning equivalencies, or resolutions of apparent conflicts in or among the applicable requirements.

DNV GL main class and additional US notation for an FPSO:

Normally for an FPSO (with US flag or foreign flag), the following minimum class notations will be proposed under DNV GL class.

1A1 production and storage Unit POSMOOR offloading

USCG's and the Bureau of Safety and Environmental Enforcement's (BSEE) main concerns for FPSOs operating in the OCS are for evacuation and seeking shelter during a hurricane. Therefore the FPSO will require a valid tanker certificate for evacuation during a hurricane situation. Therefore such FPSOs / FSOs require a detachable/disconnectable turret that can be relatively quickly disconnected in the event of a hurricane or extreme weather.In such situations, the vessel will adopt the tanker mode and move out to seek shelter. Therefore, the 1A1 notation (typically for mobile offshore units as opposed to permanent offshore installations) is the mandatory notation together with POSMOOR for passive mooring. Double hull requirements in 33 CFR 157.10d(c)(1)(i) and 33 CFR 157.10d(c)(2)(i), and the requirements in 33 CFR 157.10d(c)(3) and 33 CFR 157.11(g)(2) must be met. DNV GL-classed FPSOs complying with the relevant sections of the OSS document for meeting the class notation, together with the supplemental USCG requirement as documented in the compliance matrix, will be awarded the additional notation of Production and Storage Unit (US).

Supplemental USCG Requirement for FPSO

Chapter 2 contains supplemental requirements by the USCG that are otherwise not required under normal DNV GL class rules for the relevant FPSO notations.

These have been arranged by discipline in a tabular format noting the area of discipline, a description of the requirement for clearer understanding and the item number in the policy letter for easy reference.

The main areas that have been documented for USCG supplemental requirement for FPSOs are as follows:

1. Stability: highlighting USCG's requirement for intact and damage stability and MARPOL annex 1 requirement; MODU CODE requirements; demonstration of safe disconnection procedure for severe weather, etc.

2. Piping systems: on arrangements; pollution prevention; ballast piping; and transfer system
3. Hazardous locations: Zone 1 and 2 definitions
4. Electrical and instrumentations: requirements on emergency generator loads, detection of conditions of disconnection, non-acceptance of ATEX certification, etc.
5. Fire and safety: USCG requirements on fire extinguishing, detection and wellhead protection.

BSEE requirements:

The other regulatory agency that share jurisdiction on OCS activities is BSEE, which has its own requirements. BSEE requirements that are related to structures, mooring and foundation are covered under a platform verification program as defined in 30 CFR 250 sub-chapter I. The verification program needs to be performed by a nominated CVA (DNV GL has such authorization). The CVAs responsibilities during design, fabrication and installation are defined in 250.915, 250.916, and 250.917.

As specified in 250.916 for design verification for floating facilities (FOIs and FPSOs) the CVA needs to ensure that the requirements of the USCG for structural integrity and stability have been met. Besides the structural integrity and stability requirements, BSEE mandates specified independent assessments for the following:

- drilling, production and pipeline risers and riser tensioning system
- turrets and turret-hull interfaces (for FPSOs)
- foundations and anchoring systems
- mooring or tethering systems.

Therefore, for these units with DNV GL class including the US notation, most of the BSEE requirement for the structural integrity and stability inclusive of mooring, turret and hull interfaces will be satisfied. Of these, the mooring component of particular interest to both BSEE and USCG is the usage of polyester ropes in the OCS. DNV GL have an extensive qualification program for polyester ropes and components as well as for the suppliers of that component, and standards which meet BSEE NTL requirements. Both DNV GL's standard and its qualification procedure have been used in recent projects for the mooring verification program.

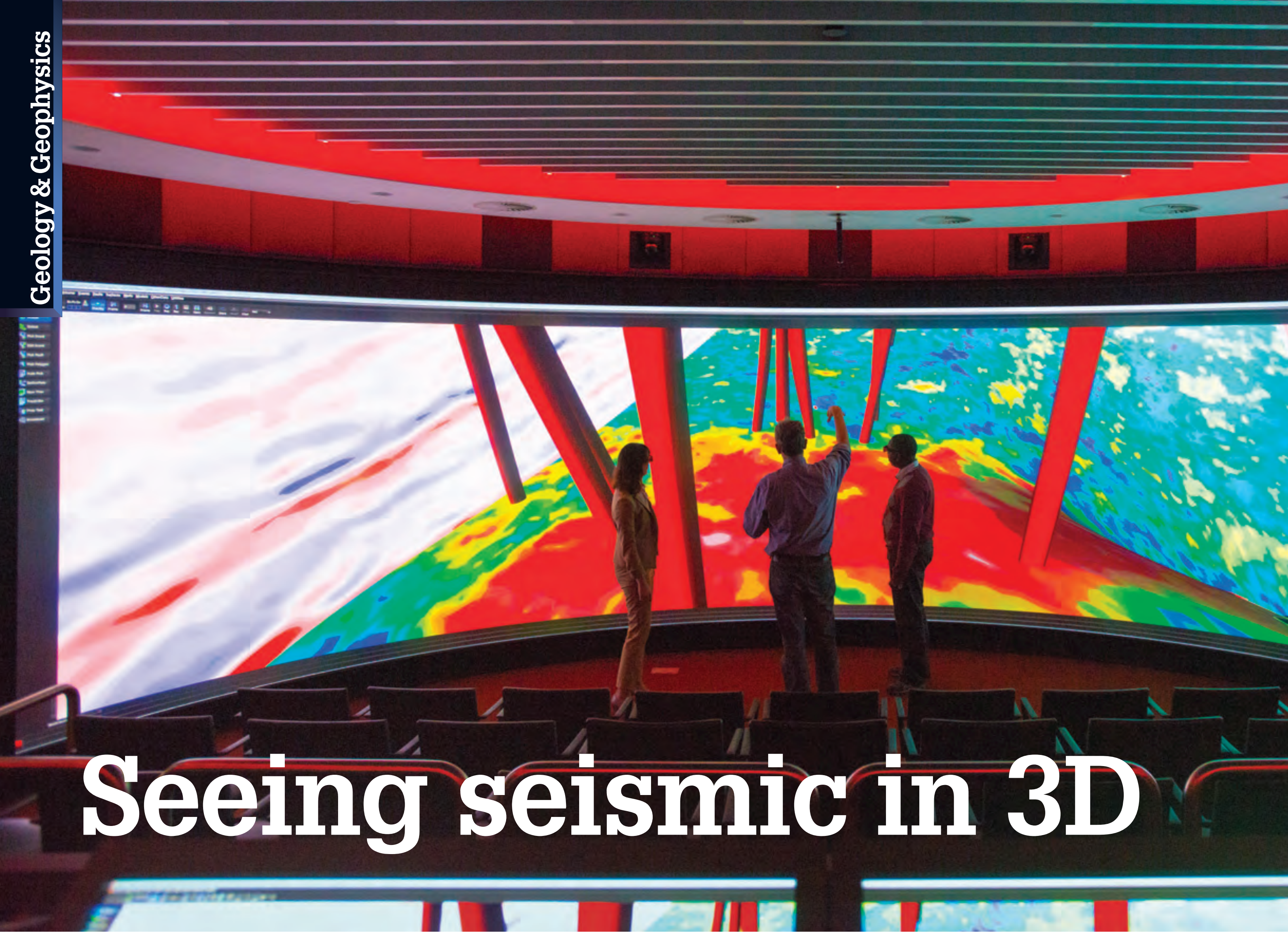
The above assessments can be performed under the CVA scheme using the applicable international standards mentioned in 250.901, 2007 NTL G14 and equivalent DNV GL standards (which have been accepted by BSEE under the scheme for previous GOM projects).

DNV GL's work in the Gulf of Mexico

In 2008, DNV was the classification society and CVA for the first FPSO (*BW Pioneer*) in the US GOM, for the Cascade and Chinook field and is currently working on a classification and CVA project for a floater in the GOM for Delta House. OE

***Raja Roy** is a principal engineer at DNV GL. He has 22 years of relevant experience in structural engineering for fixed and floating offshore platforms and vessels.*

His expertise includes regulatory coordination for coastal and shelf state requirements for offshore projects and project management for multidisciplinary classification/verification projects.



Seeing seismic in 3D

Shell's GeoSigns has helped the company find reservoirs like the pre-salt West Boreas field in the Gulf of Mexico and there is more to come. Elaine Maslin reports.

Four years ago, Shell decided to take a new approach to its seismic imaging. The supermajor wanted to bring a plethora of applications—seismic and non-seismic—together under one platform, incorporating state of the art visualization technologies.

The outcome was GeoSigns, a constantly-developing suite of applications incorporating subsurface interpretation software and visualization technologies, which "visualize and extract information from data rather than simply averaging it through various processing steps into a single data point."

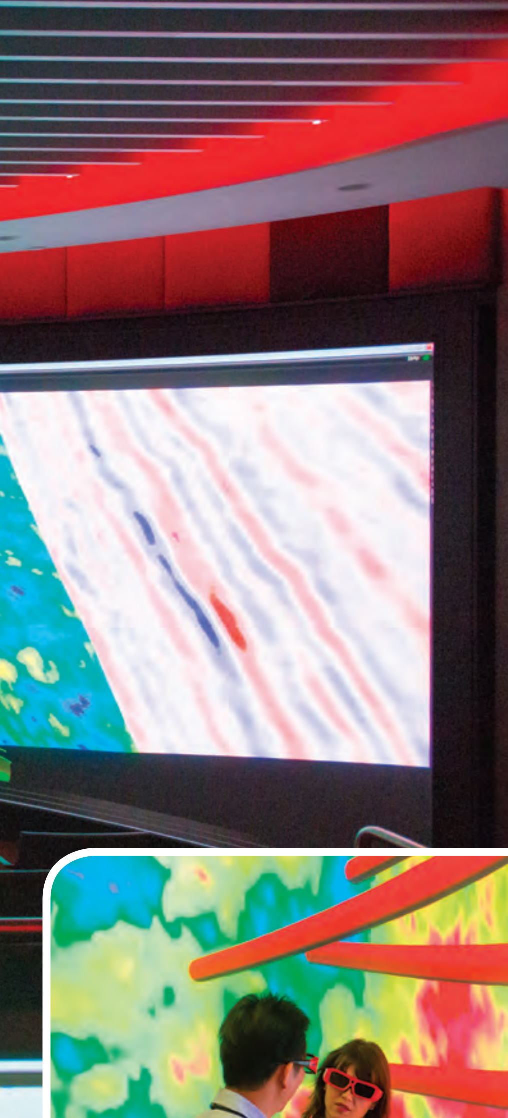
For Shell, it is all about technology and novel IP and the possibilities breakthrough innovation can offer in the subsurface. The opportunities have already been demonstrated. Bettina Bachmann, Shell's Vice President, Subsurface and Wells Software, has been involved in GeoSigns from its inception. An early indicator of its use was on the US Gulf of Mexico Deimos field.

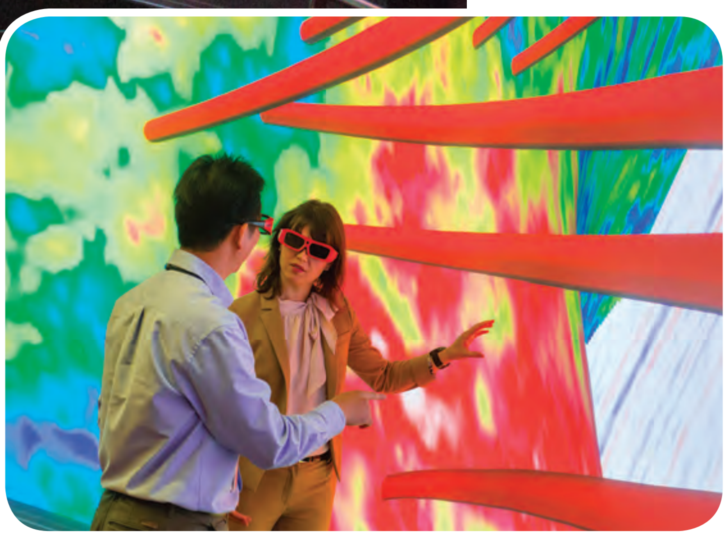
"We drilled a well in 2004 (on Deimos) on the basis of very good seismic," she says. "It was in the Tertiary Gulf of Mexico where we understand the plays. The quality of the seismic was very good, but the imaging around salt domes has always been difficult and is an ongoing challenge for all companies operating in this space." The well showed no sign of oil or gas and the exploration program was suspended.

But Shell didn't give up. It re-surveyed the area using wide-azimuth seismic acquisition, with ocean bottom sensors, which helped to illuminate the area under the Deimos salt structure from all directions. "Shell has been pushing the limits around that space for a while," Bachmann continues. "We used wide azimuth, processed the data in a different way, and used some of the functionality that is unique in GeoSigns, in terms of displaying this information and giving the user access to better imaging under the salt dome. In 2009, we re-drilled the well in a different location, much deeper, under the neck of the salt dome, and it was a discovery, confirming the existence of the West Boreas field." Soon after another field, South Deimos, was discovered based on the same data. Together, the two discoveries added more than 150MMboe to Shell's resources.

"The discoveries were clearly attributed to the improved imaging and interpretation capability," Bachmann says. Two specific areas helped. First, the use of wide azimuth seismic. Now common practice and widely used, it was not so at the time Shell drilled Deimos. "Shell was one of the first," Bachmann says. "We used ocean bottom seismic so you can record the waves from the seismic and avoid disturbance, and having the experience of how to do that helped."

The second issue is handling the "enormous" amount of data received, processing it properly and interpreting it correctly using high-performance computer power. This is where GeoSigns





Shell's iScope facilities enable the company to collaborate with colleagues around the world in real time and see seismic in 3D.
Photos from Shell.

comes into its own, Bachmann says. "The challenge for us is the sheer amount of data, which is difficult to handle. An awful lot of it you don't even want to look at because it doesn't add any value." Through processing, about 60-70% of the seismic data is discarded, with the remainder worked into a final processed picture to hand over to the seismic interpreters.

Selecting what data you want and then utilizing it and displaying it is key, Bachmann says. For example, GeoSigns is able to display butterfly gathers so that a viewer can look at different azimuths while keeping the view of the gathers intact, she says, giving the viewer access to five dimensions.

The principle behind GeoSigns was initially called an exploration integrated workspace, or EIW. The idea was to bring all the applications together in one space, e.g. they can be accessed from a common point from multiple locations. This would also bring data, which may have been stored separately and used in different ways, through different workflows together under one workflow.

GeoSigns includes 29 of Shell's major proprietary technologies, as well as applications bought from the marketplace. "Two-hundred different applications were pulled together in to the different product lines and we simplified the way they are operating and the way they are accessed. This meant there was much more data but it also integrated, so 2D and 3D data can be integrated," Bachmann says.

GeoSigns incorporates subsurface interpretation software based on seismic data, but it also integrates non-seismic methods, such as gravity and magnetic survey data, as well as "search engines." The Trap Search Engine automatically and rapidly scans large seismic datasets and finds suitable traps that interpreters might miss. The Seismic Well Tie fits seismic to well logs, aiding more accurate drilling predictions.

When GeoSigns was introduced, a new, Windows-based operating environment was introduced as well, which, it was felt, many people use and can interact with in an easier way. New hardware was also brought in, which meant applications, processing power and data are stored centrally. "We moved away from people having all the computer power under their desks, and instead we are using shared and centralized computer power, which means data and applications are stored and held somewhere so you can utilize and leverage much more shared hardware capability," Bachmann says. "It also means individual users have greater computing power as and when they need it."

GeoSigns is not a finished system, however. It is constantly being upgraded. For example, Shell is working with NVIDIA and Intel to develop and improve the processing and visualization of data for its subsurface applications. It is working with such companies to extend the amount of data that can be displayed in real time.

The amount of data itself is also a moving target—how much is being stored and used, Bachmann says. "We see data increasing and becoming a bigger challenge," she says. "It is still an acceptable challenge in areas like the offshore Gulf of Mexico, where you have very high-pressured fields, deep underneath the ground, so you find substantial volumes of hydrocarbons in a small space. When you start to go on land, [they are] very different fields you are looking at in order to make the economics work. They are bigger, cover a larger area, and you have to acquire more seismic. It is a completely different challenge to offshore."

But, while a large amount of the seismic data is currently thrown away, thanks to increased computing power, Bachmann suggests more will be used. "In the future we expect we will want to keep more and more of this data. Acquisition methods will probably, at least in the immediate future, not necessarily increase the data we have. But we will want to utilize a lot more of that data in the processing. Software is constantly operating at the limit of what it can do. But there is always more ground to cover. The trick for us is in the extraction and making sense of it.

"There is still a long way to go. The industry is still drilling dry wells. The industry's understanding of the subsurface is still very incomplete and there are still a lot of uncertainties. This is where investing in computer power gives us the ability to solve equations that comes out of physics to solve this much better."

Integrating and utilizing different data sets, handling big data and improving processing, using techniques such as elastic and full wave form inversion, will play a key role in the future, Bachmann says, with GeoSigns as the hub of it, for Shell.

"GeoSigns is an integration of a number of different exploration technologies and software that existed but were fragmented before," she says. "We have leveraged IT capability much more than ever. We have new applications and a new operating environment and new hardware." OE

Breaking barriers

Jerry Lee discusses new and improved drill bit designs and technologies with several leading companies

MicroCORE cuttings are not impacted by the shearing process of the cutters and provide an undisturbed structure for analysis in any formation type. Photos from Tercel Oilfield Products Ltd.

The MicroCORE Bit, developed in collaboration with TOTAL, allows the continuous generation of micro-cores, while drilling. The core, broken by the bit, is carried to the surface through the annulus along with the drilled cuttings.

Rising energy demand has resulted in the need to reach reserves in more complex formations. The more complex the formation, the more issues that arise that must be addressed before production can begin. Those complex challenges must be met by similar caliber innovation and development from the industry. Currently, there are several companies who have introduced or are developing new drill bit technologies and innovations to overcome some of those challenging issues facing the industry today.

Tercel

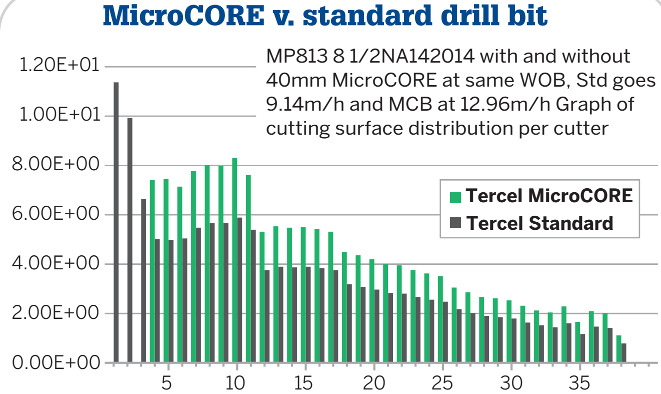
Tercel Oilfield Products Ltd. has been testing and qualifying its latest innovation since 4Q 2013. Improving upon their previous MicroCORE designs, Tercel's product line, featuring the new Phoenix cutters, began commercialization in the last couple of months.

Though the MicroCORE design has been around since 2007, Tercel's innovation is focused on enhancing the rate of penetration (ROP) performance by optimizing the arrangement of cutters on the face of the bit. By improving the energy distribution to the more efficient cutters, the weight on bit is used more effectively in the cutting process, resulting in an average increase in ROP of 36-40% and up to an 82% increase in recent Bakken shale applications, says David Morrissey, Vice President of Sales and Marketing.

The design may be applied to any fixed cutter drill bit. The MicroCORE cutting structure removes the inefficient center cutters on the bit, develops a core by cutting around the center of the hole, and provides an efficient method of evacuating the undisturbed core fragments to surface. These core fragments never see the shearing action of the cutters and provide a high quality sample for analysis on the surface.

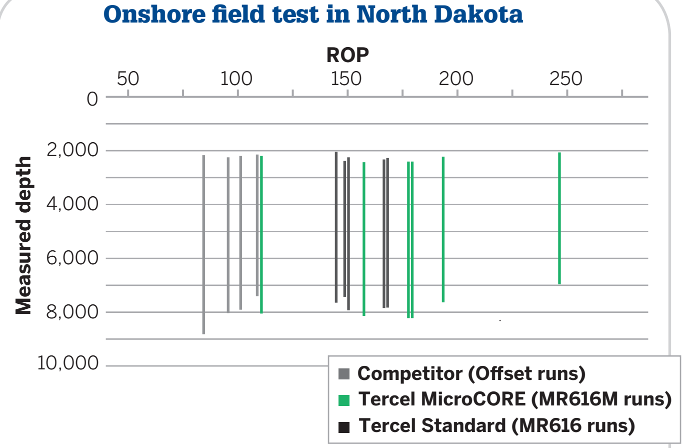
Tercel's field tests have shown that the process of drilling the core and the more efficient cutting structure work to

MicroCORE v. standard drill bit



The MicroCORE cutting system delivers more energy to the cutters than traditional cutting structures. Redistributing wasted energy allows for higher ROP and better quality boreholes. Source: Tercel Oilfield Products USA LLC

Onshore field test in North Dakota



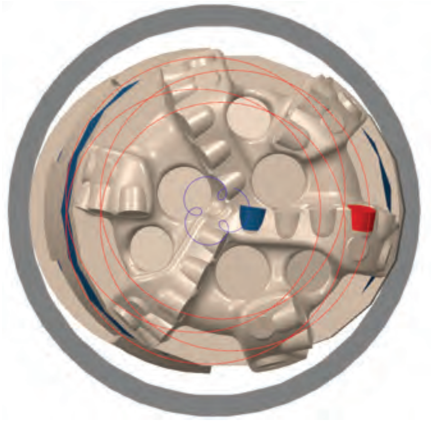
Field test results compared MicroCORE to competitor offsets and Tercel standard drill bits. Source: Tercel Oilfield Products USA LLC stabilize the bit in the hole and reduce vibration, increase stability, steerablilty and durability resulting in lower repair charges as well.

With greater energy focused on the cutters they must be able to efficiently manage the influx of energy. Now standard in all Tercel fixed cutter drill bits, the Phoenix premium PDC cutters meets this challenge and improves upon previous standard cutters in both shock and abrasion performance. Operators no longer need to choose between improving impact shock or abrasion resistance. The Phoenix series cutter allows simultaneous improvement of both properties, prompting better ROP performance, longer depth drilled and less repair charges. Produced using "low cobalt content, the [cutters] strength is really in [performing] in a dynamic thermal environment," Morrissey says.

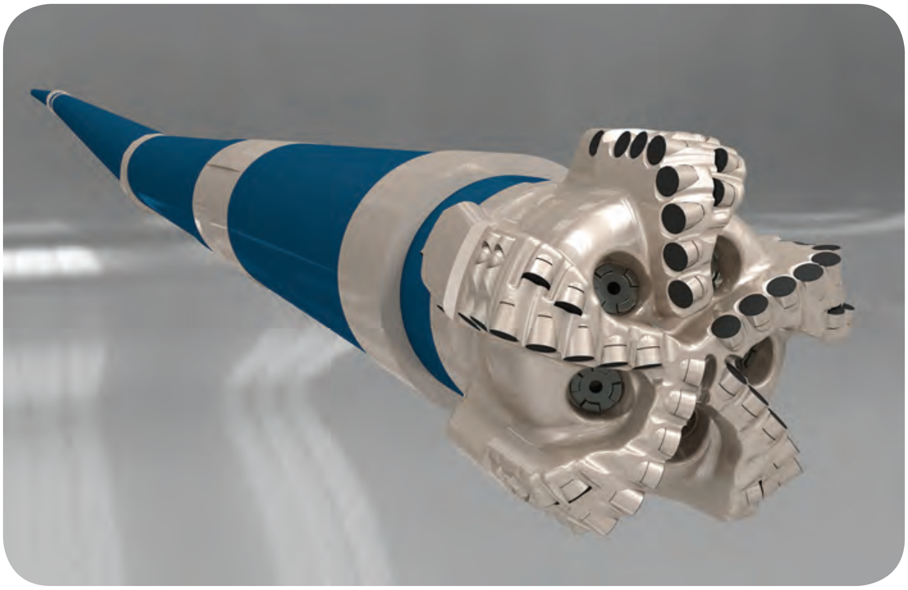
Application of the new product line has seen success in three subsalt wells in a development project off the coast of Brazil, outperforming competitor drills bits in the same formation. Future application will likely be seen in offshore fields of Malaysia.

NOV

At NOV, product development is often an evolutionary process, says Tony Watts, engineering manager. A performance issue is identified, analyzed, and a solution is developed. One problem ReedHycalog has identified facing drilling engineers is the eccentric and off-center drill bit motion on bent housing motor BHA's when performing directional drilling operations. Not only does this cause the hole to be drilled larger, but also results in the bit cutting unevenly. For over three years, the Bent Housing Motor project engineers have been developing a solution. Understanding the issue, NOV engineers have developed a proactive approach, whereby the bits are designed to adapt to the non-axial rotational movement and cut the formation accordingly. Using NOV's in-house software, models of how the drill bit rotates are constructed, allowing the path of each cutter to be traced. Individual cutter contact with the formation is then modeled so that the cutter layout is optimized. This produces a directional bit that cuts all portions of the bottom of the well and in a more predictable manner. During tests in the Epping Field, North Dakota, the new design produced more footage than the offset well using a competing bit. The new bit is designed to work with a broad base of motors, however, it may also be customized for a specific motor. If progress continues as expected, commercialization of the new product may begin 4Q 2014.



Trace of cutter movement during eccentric and off-center drilling. A center cutter is traced in blue, and an outer cutter is traced in red.



Model of a bottom hole assembly with a bent housing motor.
Images from NOV.

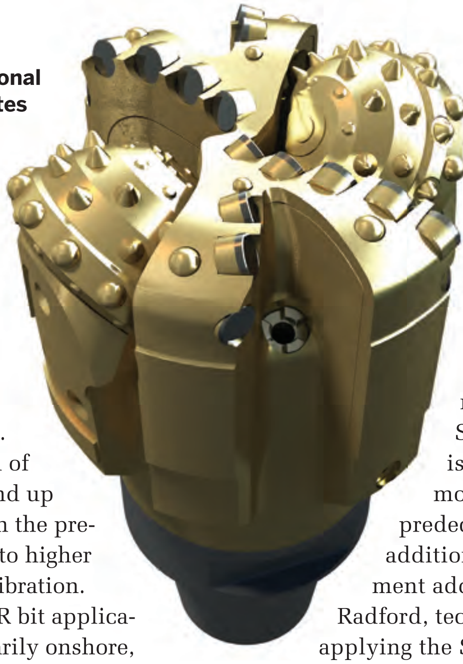
After continuous improvement, NOV has also re-introduced the FuseTek drill bit. A hybrid that incorporates both PDC and diamond impregnated technology into the same bit, the FuseTek bit is designed to drill zones that are interbedded with hard and soft layers. By combining the two technologies, engineers have increased the durability of the bit. The PDC cutters can cut through the soft layers until they eventually fail as the bit drills hard layers. Then, the diamond impregnated portion continues to drill through the harder lithologies. This will save the driller from unnecessary nonproductive time when tripping in and out to replace bits. At an offshore well in the Iwafuneoki Field in Japan, during 4Q 2013, application of the FuseTek drill bit saw a 174% increase over the average interval drilled by competitor bits in the same well, and an 84% increase in footage over the next best performing bit.

Baker Hughes

Baker Hughes Inc. (BHI) has been busy this last year introducing and developing new technology for the oil and gas industry.

BHI will add to its unique line of hybrid drill bits with the introduction of the Kymera FSR. The hybrid drill technology was first introduced in 2011 to target hard interbedded formations. Having succeeded in their original goal, the line has expanded its capabilities to drill in medium to soft regions, such as carbonate or sandstone as well. Additionally, success has been realized using Kymera bits as pilot bits for all concentric expandable reamers, including the BHI GaugePro XPR and Echo lines.

Though it may seem counterintuitive to use roller-cone bits in what seems like a fixed cutter situation, test runs have shown increased performance using the Kymera FSR directional hybrid drill bit. Instead of simply having a crushing role, the roller cone portion of the bit increases stability by distributing the weight of the bit and controlling the penetration depth of the cutters. By controlling the bit in such manner, not only is stability increased, but durability also increases by reducing vibration and preventing twist off and downhole tool failure, says Allan Holliday, product manager for Kymera drill bits. Kymera



The Baker Hughes Kymera FSR directional hybrid drill bit creates fewer torque fluctuations and tolerates more weight on bit for faster drilling.

FSR bits also incorporate a new line of tungsten carbide cutters in its design. The new generation of cutters is sharper and up to 30% tougher than the previous lines leading to higher ROP and reduced vibration. Current Kymera FSR bit application has been primarily onshore, however, expansion to commercial offshore application will begin in about six months, Holliday says.

BHI has also recently commercialized a new line of cutters, the StayCool multidimensional cutter. In design for nearly two years, and introduced in October 2013, the StayCool cutters are constructed with a groove in the body. In contrast from the shearing motion of the traditional smooth faced cutter, the grooved contour of the cutter produces a scooping motion. By introducing the groove to the cutter design, the cutter produces less frictional heat which results in less thermal degradation, longer durability, and greater efficiency of the bit. In comparison, the StayCool cutter runs about 50% cooler than its standard counterpart in laboratory testing, and similar results in field applications; increases in average ROP, about 15%, and average footage drilled, about 12%, have also been seen, says Barzin Chiniwala, cutter product manager.

Improvements have been made to BHI's SlickBit anti-balling coating technology. The coating long ago proved its value in preventing bit balling but was sometimes lacking in durability. Now an enhanced flouropolymer-based compound, maintaining the SlickBit designation, is much tougher and more durable than its predecessor due to the addition of novel reinforcement additives, says Steven Radford, technical advisor. By applying the SlickBit coating to the drill bit, cuttings are less likely to adhere and ball up, allowing the driller to drill faster and longer, reducing bit trips. Application in the Gulf of Mexico has shown increased ROP for one driller by 68% in water-based mud (WBM) over the same bit, uncoated, run on a sidetrack of the same well. They also observed that a coated bit in WBM drilled 72% faster and 3.5 times longer than the average of uncoated bits in OBM in this area. The same operator, in a different area saw bits coated with the improved SlickBit coating drilling 57% faster in WBM without shale balling, compared to offsets in OBM. And in a 54 bit sampling of bits in one area in Alaska, prone to shale balling, the coated bits drilled 45% further. With this new BHI bit coating, BHI says operators are now seeing significant cost saving through fewer bit trips, reduced NPT, faster ROP, and eliminating the cost and challenges of using oil based mud.

Baker Hughes' StayCool multidimensional cutter technology reduces the drilling day curve and costs. Images courtesy of Baker Hughes.

Baker Hughes' StayCool multidimensional cutter technology minimizes friction on the cutter face, improving rates of penetration.

Halliburton

Set to launch early in the coming year, Halliburton Drill Bit Services' new cutter technology will boast higher abrasion resistance, impact resistance, and thermal mechanical properties, according to Brad Dunbar, product manager for Fixed Cutters Drill Bits for HDBS.

With the use of data from offset wells, engineers were able to identify areas of improvement and refine their designs with the ultimate goal of producing more efficient drill bits with the capability to drill longer intervals and a higher rate of penetration.

Changes in the chemistry and manufacturing processes used to develop this new technology have resulted in a number of new patents. Featured alongside proven technology, the new cutters have increased its abrasion resistance by 20-30% as compared to previous products, Dunbar says.

In terms of removing thermal mechanical, abrasion, and impact damage as barriers to performance, "the goal of PDC manufacturing is to push those three boundaries," Dunbar says.

Development for the yet-to-be-named PDC cutter began nine months to a year ago, and it is currently in the validation and testing phase. For the purpose of collecting larger amounts of data in a shorter amount of time, current application of the new technology is limited to onshore sites. However, when the new product line, featuring the new cutters, is released, interested companies can expect them to be marketed for both onshore and offshore drilling operations. OE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Claudio Paschoa discusses Stinger conical diamond technology with João Pedro Tocantins, Senior Product Engineer from Schlumberger's Smith Bits.

Stinger technology aims to optimize pre-salt drilling

Smith Bits' innovative Stinger conical diamond element increases drilling speed and improves stability, showing good potential for tackling the complex pre-salt formations. This Smith Bits technology is focused on rock destruction efficiency to increase drilling performance. The Stinger element is located at the bit's center and enables high-point loading to fracture rock more efficiently for increased durability and rate of penetration (ROP).

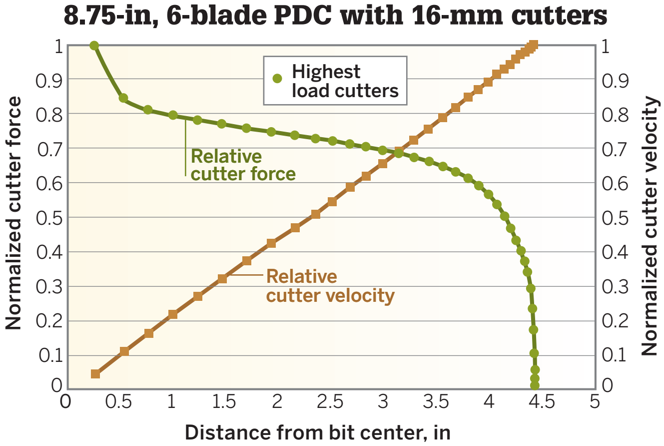
OE: Could you tell us what led to the development of the central Stinger?

A common challenge to conventional PDC bits is that they are inefficient at removing rock from the center of the borehole, because the rotational velocity of cutters decreases with their proximity to the center of the cutting structure; rock removal by the center-most cutters is much less efficient, especially in hard formations. Because the center cutters bear the highest load, operational and formation changes can cause large variations in depth of cut (DOC), including bit torque fluctuations.

This results in decreased drilling efficiency at the center of the bit's cutting structure, which can cause low ROPs, destructive lateral vibrations, and cutter damage. To decrease damage and increase performance at the center of a PDC bit's cutting structure, bit design engineers conceived a center-placed conical diamond element (CDE).

To position the element in the bit, engineers removed the center cutters. The absence of these cutters allows a stress-relieved column of rock to develop while drilling, which continuously fractures and crushes, thereby improving drilling efficiency. The Stinger technology is a new line of PDC drill bits that incorporate the conical diamond elements called Stingers in the center of the bit. This product was intended for applications where impact damage to conventional PDC cutters is prevalent–For example: the pre-salt formation offshore Brazil–and the main limiter for performance.

Cutter force and velocity plot for conventional 8.75-in, 6-blade PDC with 16-mm cutters



This plot shows typical forces and cutter velocity, from bit center to the gauge. The center. Most cutters experience the highest loads and have the lowest rotational velocity, subjecting them to more stress.

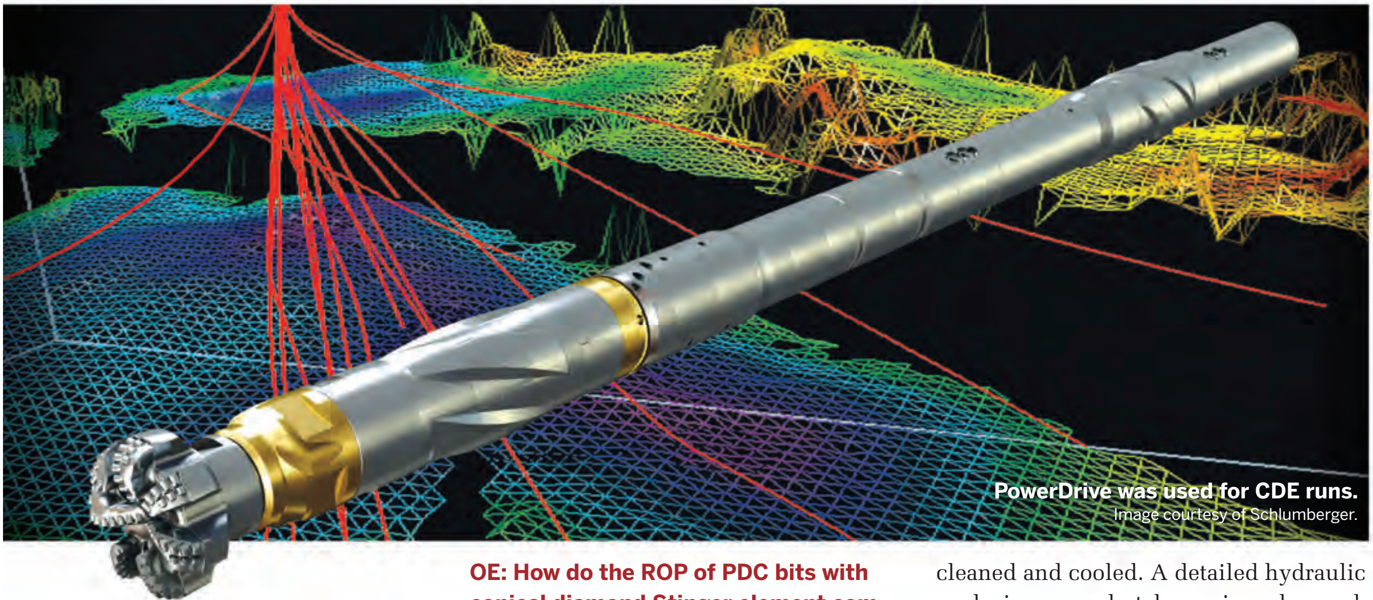
The CDE, centrally placed in a PDC drill bit cutting structure, increased ROP and stability. Images courtesy of Smith Bits, a Schlumberger company.

OE: Are PDC bits still dominant in the drilling market?

Yes, with continuing advances in synthetic diamond cutter technology and improved bit stability, PDC bits have become the dominant force in the worldwide drilling scheme. In 2004, total footage drilled by diamond bits (54%) surpassed that of roller cone bits (46%) and the trend has continued. Due to its reliability the system Turbine + Impregnated bit have been used quite frequently in the pre-salt formation offshore Brazil.

OE: Has thermal damage when drilling in highly abrasive formation been decreased by using the PDC bits with conical diamond Stinger element and why is it less susceptible to this kind of damage?

Yes, this happens because the PDC bits with conical diamond Stinger element fails the rock through crushing action. The load is concentrated at a single point, which significantly reduces the required load to fracture the rock. The effect of this single-point loading is compounded with a Stinger element because the column of rock that the bit allows to develop is isolated and



thereby unconstrained, making it easier to destroy. The unique combination of the Stinger geometry and its cutting action reduce frictional heat resulting from improved wear resistance. The enhanced stability provided from the center-placed element will deliver a better load distribution throughout the cutting structure, which will decrease and share the wear evenly among all cutters.

OE: Are the PDC bits with conical diamond Stinger element more resistant to impact damage in non-homogeneous formations and formations with chert and pyrite inclusions?
Yes, once PDC cutting elements are worn or damaged, ROP drops and ring-out on the bit body may occur; a bit trip is therefore necessary. The Stinger element proved to have superior impact resistance when compared to PDC cutters. The CDE placed in the center of the bit increases bit stability and decreases vibration. This will provide a better protection to the cutting structure of the bit and increase durability. This feature will prolong the bit's cutting structure life; therefore, the bit will drill longer footage and reduce the number of trips.

OE: In the heterogeneous carbonates formations, common to Brazil's pre-salt, what are the main challenges faced by drill bits?
The main challenges found in drilling throughout the pre-salt carbonates are the low penetration rates, poor bit cutting structure durability and additional problems related to drilling dynamics, such as torsional and lateral vibrations.

OE: How do the ROP of PDC bits with conical diamond Stinger element compare to that of other PDC and impregnated bits when drilling in Carbonate formations?
The ROP is a lot higher compared to an impregnated bit. Comparing to a conventional PDC bit, the ROP will be also higher because the PDC with the Stinger element will deliver a more aggressive cutting mechanism at bit's center. Also the ability to keep the cutting structure alive and sharp in high weight-on-bit (WOB) applications for a longer period of time will aid in improving the aggressiveness of the bit (improved ROP) and help reach section total depth (TD) in one run.

OE: What are the cutting mechanisms found in PDC bits with conical diamond Stinger element, which allow them to continue cutting when encountering nodules impregnated with hard silicate inclusions?
Crushing (Stinger) and Shearing (PDC) action. Stinger and PDC cutting elements can provide independently complete bottom-hole coverage. The PDC bit with a Stinger element will deliver a more stable cutting structure design that will be less vulnerable to lateral and torsional shocks and vibrations. The Stinger element is expected to absorb or share the impact loads while encountering very hard layers or inclusions and protect the PDC cutters from catastrophic failure.

OE-How do the hydraulics work and what are its advantages?
Placing the Stinger element in the center of the cutting structure makes it essential that nozzle orientation and the resulting flow field are optimized. This will ensure the Stinger element is efficiently cleaned and cooled. A detailed hydraulic analysis was undertaken using advanced computational fluid dynamic (CFD) software to accurately simulate the flow around the Stinger element (cross flow). In the course of each new bit development, nozzle positions are adjusted and fine-tuned to maximize cleaning of the Stinger element and the bottom hole around the bit's center.

OE: Could you tell us about your experiences with the bits in different Brazilian pre-salt formations?
The primary reason behind using the PDC bits with conical diamond Stinger element technology was to face the hostile environment from pre-salt reservoir rock, whose composition of organic microbiolites carbonates and other sediments could possibly offer different heterogeneous characteristics such as the presence of hard silicate nodules and low porosity layers. We have tested one unit so far in Campos basin offshore Brazil. Overall result was very promising showing a huge potential for this technology. The Central Stinger design drilled 234m until section TD throughout hard limestone with an average ROP of 15.4m/h setting the highest ROP and the lowest cost per meter in the field. We have learned a lot throughout this run and have been modifying latest designs applying lessons learned in order to optimize cutting structures and improve performance. Further tests into the pre-salt environment, this time offshore Espírito Santo basin, are ongoing at this very moment.

OE: Can you tell us about the different drive systems and drilling parameters used with the central Stinger in Brazil's pre-salt?

The PDC bits with conical diamond Stinger element design drilled the second part of the 8 ½-in. section with excellent performance, presenting minimal wear after drilling 234m at an average ROP of 15.4m/h. Vibration levels were kept within an acceptable range throughout the run. The changes in lithology encountered were effectively drilled at high rates, since bit cutting structure was kept sharp until the end of the run. The PDC bits with conical diamond Stinger element design was used with a rotary steerable BHA and the following parameters were used:

- WOB: 9 – 52klbs, average 37klbs;
- RPM: 45 – 180, average 136 RPM;
- Flow rate: 580 – 650, average 645GPM;
- Drilling ROP: 15.4m/h.

OE: What were the lessons learned from drilling with the bits in Brazil and how have operators reacted to the results?
The main lessons were related to hydraulics, bit design, cuttings quality, stability and vibration (S&V) and the need for more impact resistant cutters. The most important knowledge gained from drilling runs can be summarized as:

Hydraulics: Maximize HSI (recommendation: HSI > 2.5hp/in^2) to ensure good bottom hole cleaning, better cutter refrigeration and cutting structure durability.

Bit design: The center-placed Stinger element has proven to increase stability and reduce vibration levels; The CDE also has proven to improve drilling efficiency at bit center, increasing the ROP; All versions tested presented minimum wear in the cone area.

Cuttings: Good cuttings size generation confirming that the conical diamond element was crushing the rock into larger-than-normal fragments (desirable feature for geology evaluation).

S&V: The PDC bits with conical diamond Stinger element design clearly showed better dynamical behavior than conventional PDC bits.

Cutters: Impact damage was the main failure mode, therefore bigger bevels and cutters with more resistance to frontal impact load should be considered.

OE: What future developments do you foresee in PDC bits with conical diamond Stinger element technology and its uses?
Currently there is an ongoing project to investigate different uses of Stinger elements in new concepts of drill bit cutting structures. We are also investigating the use of different shapes in Stinger insert to further improve side impact resistance over conical Stinger inserts while maintaining aggressiveness and also the use of high frequency downhole measurements for the next iterations. Reducing the development cycle and identifying optimum parameters and procedures are also necessary along with working to improve the durability on Nose/Shoulder area. **OE**

João Pedro Tocantins is a Senior Product Engineer for Smith Bits, a Schlumberger company, located in Brazil. His focus includes continuous product development for Brazil, drilling optimization and technical support for all bit types. He joined Schlumberger in 2006. João Pedro Tocantins earned his Bachelors in Civil Engineering from Pontifícia Universidade Católica do Rio de Janeiro (PUC-Rio) and his Post Graduate Diploma in Petroleum Engineering from Pontifícia Universidade Católica do Rio de Janeiro (PUC-Rio).

The perils of offshore power quality

Unacceptable power quality can have significant impacts on safety, the productivity of operations and profitability. Ian C. Evans explains.

Electrical power quality is routinely taken for granted by oil and drilling industries irrespective of the fact that it is absolutely fundamental to the safety and operational integrity of drilling rigs, offshore platforms and installations worldwide, without exception.

Electrical variable speed drives; DC drives (SCR drives in offshore parlance) drives and AC variable frequency drives (VFDs) are fundamental to most operations. However, their use significantly degrades the quality of electric power, increases equipment failure, and disrupts control systems, resulting in production losses and compromised safety.

The electrical power quality offshore is rarely monitored and, even after a serious incident or disaster, it is rarely investigated nor considered to be a contributing factor. Rules and recommendations for the limitation of harmonic voltage distortion have been in place for many years, via the marine classification bodies, IEE (Institute of Electrical Engineers) and the IEC (International Electrotechnical Commission) but often given scant regard. Harmonic voltage distortion offshore can exceed the recommended limits by a factor of 4-7 times.

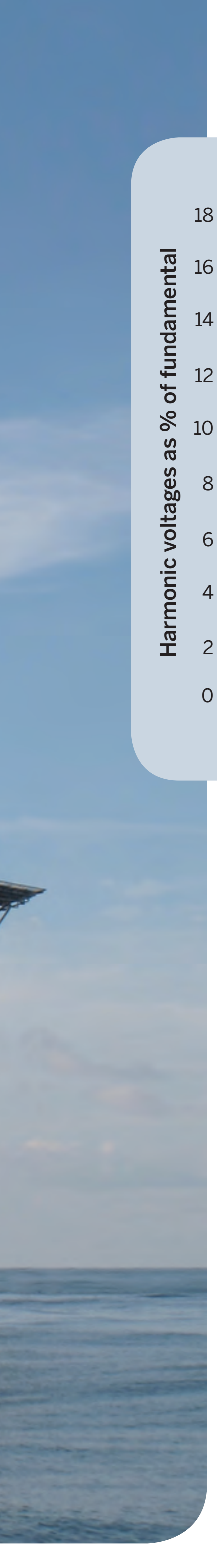
US$100 millions are lost annually across the industry, directly and indirectly, due to poor power quality. The industry is often unaware of where the damage or disruption to equipment originates. Little or no training is provided for rig electricians and little or no harmonic or power quality measurements taken.

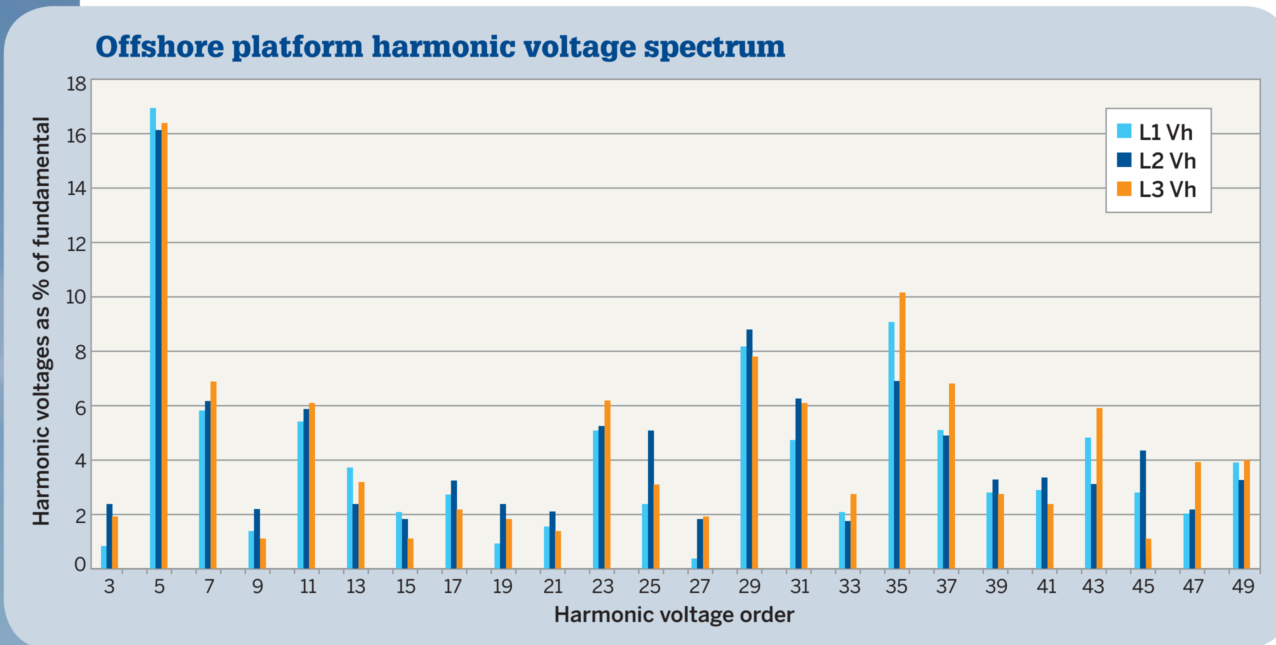
Left: An Ex motor. Above: Typical jackup type drilling rig. Photos from Harmonic Solutions.

Some consequences of poor power quality can appear relatively minor (e.g. the repeated failure of control relays, VFD capacitors or electric motors) but are often expensive operationally. The potential for something more serious also lurks.

In July 1988, the world's worst oilfield disaster, as far as human life was concerned, occurred off Scotland on the Occidental platform, Piper Alpha. 167 men perished. The Cullen Enquiry failed to establish the initial source of ignition which ignited the escaping condensate. Some engineers now believe that harmonic voltage distortion could have been a significant contributory factor, but this was never considered by the commission. At that time there was only rudimentary harmonic measurement equipment available and problems of harmonics were largely unknown to most of the industry.

The reader may start to come to the





Illustrates an installation where the THDv measured on a 690V drilling package was 27.1% (18.9% above the 21st order, due to the use of a number of 24-pulse variable frequency drives). The recommended THDv limit was 5%.
Source: Harmionic Solutions.

conclusion that the quality of electrical power therefore requires serious consideration by safety and regulatory authorities worldwide, including in the EU and the US. However, the new European Directive, (2013/30/EU), governing the safety of offshore oil and gas installations, ignores it.

The author has been in discussion with UK's Health and Safety Executive (HSE - HID Energy Division, Offshore) since 2006, regarding offshore power quality. Two years ago HSE drafted, with assistance from the author and others, a document entitled "HSE information sheet - Harmonic Voltage Distortion in Electrical Systems. Offshore Information Sheet No. xx/2011." The draft document stated: "The objective is to limit the THDv (total harmonic voltage distortion), most commonly to 5% or 8%. To achieve this, the magnitude of the harmonic currents drawn by the non-linear load(s), which otherwise flow in the system, has to be reduced significantly." (This compares to THDv levels up to 35% witnessed by the author on many installations). The draft document concluded saying: "This guidance is issued by the HSE. Following the guidance is not compulsory and you are free to take other action. But if you do follow the guidance you will normally be doing enough to comply with the law." The draft HSE Harmonics Information Sheet was circulated to all Duty Holders in the North Sea and beyond.

However, earlier this year HSE stated: "We no longer have plans to publish detailed information on the subject of electrical power system harmonics. HSE's Energy Division published its new 'Offshore Oil and Gas Sector Strategy 2014 to 2017' in March." No reason was forthcoming from HSE as to why this important safety document, discussed for three years, was shelved.

The new document does not address power quality, and they explain this as follows: "This sets out the key major hazard risks in the offshore oil and gas sector and the objectives we are setting both for the industry and ourselves as the safety regulator. We are directing our limited resources primarily towards these objectives. That is not to say that we deny the potential that poor electrical power quality (in all its forms) has for being a factor in major incidents offshore and we will continue to probe this in our assessments of safety cases, inspections and incident investigations." This means that HSE permit the Duty Holders to continue to police themselves with regards to harmonics and power quality. This is not an approach that gives confidence that the very real problems will be addressed.

There are also serious, related concerns regarding the use of explosion-proof motors of all protection concepts. All induction motors require thermal derating in the presence of harmonic distortion of their voltage supplies, but there is a "complication" regarding fixed speed explosion-proof motors based on IEC standards; these motors are only certified for use on pure sinusoidal supplies (i.e. 0% THDv).

The IEC standard relating to electrical machines, IEC60034-1, specifies the

A spokesman for the HSE said: "HSE electrical inspectors for offshore oil and gas installations are aware of the problems that may arise from poor electrical power supply quality. However, our experience is that electrical power supply quality has not been identified as a significant factor in any incidents investigated by HSE to date. Duty holders are required to ensure their plant and installations complies with relevant standards to ensure safety, so far as is reasonably practicable. HSE inspectors can and do, in inspections and assessments, require evidence that electrical power quality meets the relevant standards. Also, when potentially relevant, electrical power quality is considered in incident investigations."

A WEG EExd motor. Photo from Harmonic Solutions.

requirements regarding 2-3% harmonic voltage factor (HVF), due to the effects of harmonics on winding temperature. IEC 60079-1 (hazardous area equipment) however does not currently have any requirement for HVF regarding compliance testing or certification for any explosion-proof motor protection concepts. It is a similar situation for NEMA/UL explosion-proof motors under standard MG-1.

If these motors are subject to voltage supplies with >0% THDv they are "operating outwith the conditions envisaged when they were certified." This does not necessarily mean the motors are unsafe (although under certain conditions they could be), but it does mean that the operator has lost any third party (e.g. NEMA/UL/ PTB, CSA, BASEEFA et al) verification as to their safety.

There is a second serious and practical consideration regarding 'flameproof motors' (i.e. EExd in IEC codification), which rely on the principle that no matter what happens inside the flameproof enclosure (e.g. an internal explosion) it cannot transmit to the surrounding hazardous area. While that statement may be perfectly valid for sinusoidal voltage supplies it is not valid for harmonically distorted voltage supplies.

A flameproof motor relies solely on motor enclosure and flame paths in the end housings to contain any internal explosion in the event of gas or vapor entering the machine. However, in the presence of harmonics, most notably on motors with deep bar or double cage rotors, the rotor temperature rise can be excessive and well outside the motor temperature class. High rotor temperatures can affect the bearings as the lubrication degrades, exposing them to excessive wear. They can also degrade the flame paths so that if there was an internal explosion (which is more likely due to high rotor temperatures anyway) it might not be contained as expected – with potentially disastrous consequences. In order to overcome this "deficiency," the standards authorities now place the sole responsibility on the duty holder operators to maintain their harmonic voltage distortion at a safe and acceptable level (i.e. 5-8% THDv as stipulated on the now HSE-shelved Harmonics Information Sheet), so that explosion-proof motor safety is not compromised.

The author is unsure how the same authorities would view the reality of these motors being regularly subjected to the 20%-35% harmonic voltage distortion often seen offshore.

PTB (the German explosion-proof equipment test authority) were given details of the harmonic spectrum above (Fig. 3). They calculated an additional 25°C temperature rise on explosion-proof motors with single cage rotors, subject to voltage supplies, with this harmonic spectrum. PTB were unable to calculate the more significant additional heating effect on explosion-proof motors with double cage or deep bar rotors, such as those used in compressor motors.

The importance of acceptable power quality should now be appreciated. Offshore safety authorities, marine classification bodies and standards authorities worldwide need to adopt a more rigid, policed approach to offshore harmonics and power quality. The current rules and recommendations are not fit for purpose to address our 21st Century requirements.

Unacceptable power quality can have significant impacts on safety, the productivity of operations and profitability. The cost of mitigation required to ensure prevention is only a tiny fraction of the possible financial losses.

The quality of electrical power is crucial to the industry, including future subsea installations. It should not be ignored or abused. Offshore electronic equipment is ever-more sophisticated, demanding a higher level of power quality for its reliable operation than in the past. The future for subsea systems, we are told, is "all electric," yet many in the industry seem to lack understanding as to the impact and importance of acceptable electrical power quality on electrical and control equipment offshore.

An acceptable level of power quality is now absolutely fundamental for safety and operational integrity of offshore industries worldwide, and will be increasingly important in future. This needs to be recognized, appreciated, and reinforced by governments, EU committees, standards authorities, offshore safety bodies, and duty holders alike, and urgently addressed. OE

Ian C. Evans majored initially in electrical drives and marine/ offshore power systems. In the late 1980s he campaigned successfully for the introduction of safe and certified explosion-proof motor/VFD packages. Since 1995 he has specialized in harmonics and power quality, for marine vessels, drilling rigs and other offshore installations, both as a consultant and via Harmonic Solutions (Oil & Gas) and Sentinel Power Quality FZE. Evans wrote the harmonics guidance notes for the US marine classification body, published in 2006.

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

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

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

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

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

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

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

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S31OS1

Closed-loop drilling

An in-depth look at NOV's closed-loop drilling automation system, which could help develop North Sea and Arctic assets.

Automation is a growing force in the offshore oil and gas industry. Its potential to increase safety, optimize operations, improve quality, and reduce risk is a strong driver for an industry with ever-rising costs.

The drivers for technology adoption are strongest in operations where efficiencies, quality, and consistency are of utmost importance.Tony Pink, vice president, Dynamic Drilling Solutions (DDS) – Services, National Oilwell Varco (NOV), says well construction north of the Atlantic Ocean and in the Arctic is challenging and expensive, as well as being in a harsh environment.

"Automation would enable operators to reduce or eliminate the need for manpower on the rig floor, reduce risks, and improve project economics through enhanced equipment performance," he says. "By using high-speed downhole data integrated with a comprehensive drilling model, drilling speed can be significantly improved and managed from a remote operations center to offer well consistency and repeatability."

NOV has developed a closed-loop drilling automation system. Closed-loop systems use sensor output, or feedback, to control the machinery and ultimately processes. Used in drilling automation, the direct closed-loop control of machines performs drilling optimization tasks by using high-speed downhole and surface data. In other words, the system allows surface equipment on the rig to be controlled in response to downhole data.

NOV's automation system incorporates intelligent applications, or software, using the closed-loop control of the drillstring to improve drilling performance with control of downhole weight on bit (DWOB), automated steering, stick-slip mitigation, equivalent circulating mud density (ECD) management, and mechanical specific energy parameter optimization.

In NOV's system, downhole data is measured by a downhole drilling dynamics sub and is then transmitted to the surface via wired drillpipe. Surface and downhole acquired data is interpreted and analyzed by software applications, and commands are then distributed to the rig's control system to adjust the appropriate machine functions. The system also includes along-string drilling dynamics subs. Pressure measurements from this sub enable better understanding of the borehole condition and reduce the risk of breaking down the formation or poor hole cleaning.

Key components in NOV's automated well construction system are:

- Downhole data acquisition (DAQ) tools

The BlackStream enhanced measurement sub and BlackStream along-string measurement sub tools are drilling dynamics DAQ tools that provide real-time and memory data of the following parameters: DWOB, downhole torque, rotational velocity, lateral/torsional/axial acceleration, internal pressure, annular pressure, and temperature. The drilling dynamics subs are designed for use in the bottom-hole assembly (BHA) and the drillstring, respectively. The BlackStream measurement while drilling tool provides real-time inclination, azimuth, and gamma ray measurements.

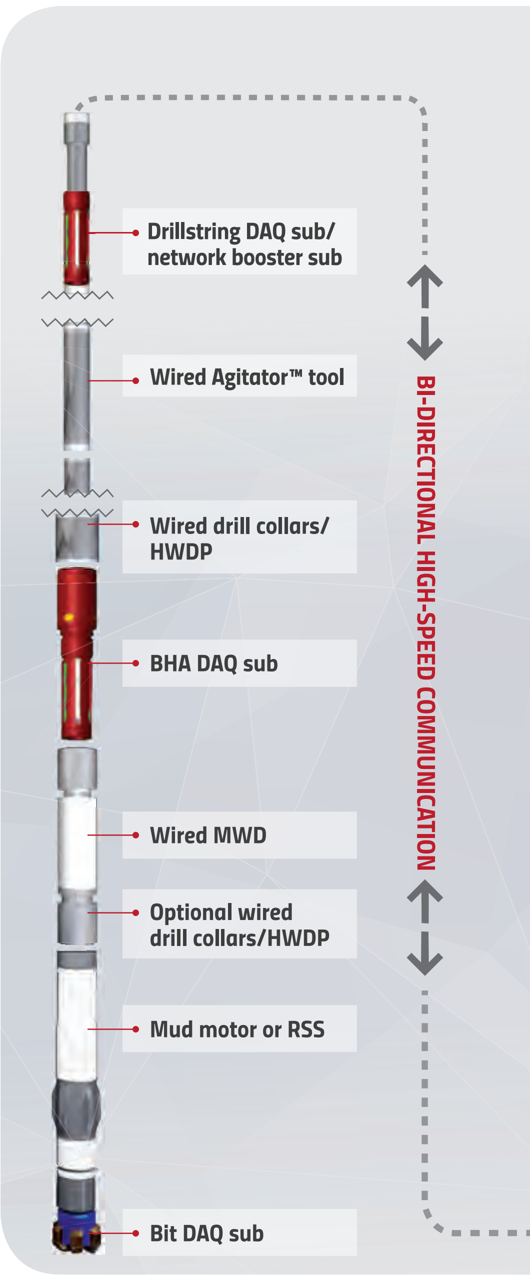
- High-speed telemetry network
- The IntelliServ high-speed telemetry network consists primarily of wired drillpipe and network boosters subs, enabling bi-directional data flow along the drillstring. The network capacity is 57.6Kbps. Currently, BHA interfaces exist for communication with most of the major service providers.
- Control system add-on and data visualizationNOV offers the Amphion, Cyberbase, and NOVOS control systems that can enable the add-on necessary to facilitate the drilling automation system. The add-on enables the TrueDrill DWOB controller, which is a real-time supervisory control engine that utilizes rig equipment to deliver the desired DWOB.
- Well construction applications

The add-on does more than just enhance control; it enables data visualization and software applications. Current applications deliver rate of penetration (ROP) optimization, risk management, dynamics mitigation (SoftSpeed II stick-slip service), and steering optimization.

The data flow and automation process is as follows:

1. Data from the BHA and drillstring are transmitted to the surface via the telemetry network and combined with surface data in the rig's control system. The data is validated and analyzed on a fixed time interval.

2. Control logic computes the required



SWOB set point to deliver the desired DWOB determined by the drilling program plan or optimization applications. Auto driller parameters such as RPM and differential pressure can also be recommended by the optimization applications.

3. The autodriller receives the SWOB set point as a request, analyzes it in the context of its current operational state and safety case, and makes a decision whether to implement the requested SWOB set point or not.

The NOV DDS optimization team has already demonstrated consistent ROP improvements of 20-30% with occasional improvements of 100% (Pink et al. 2011).

"Drilling automation improves drilling stability, reduces risk, and increases ROP. These improvements will also help extend drill bit and BHA life and reduce the number of expensive trips due to bit or downhole tool failure. In harsh drilling conditions and complex drilling environments, the system can deliver knowledge and performance to help contractors and operators achieve their goals safer and more efficiently," Pink says.

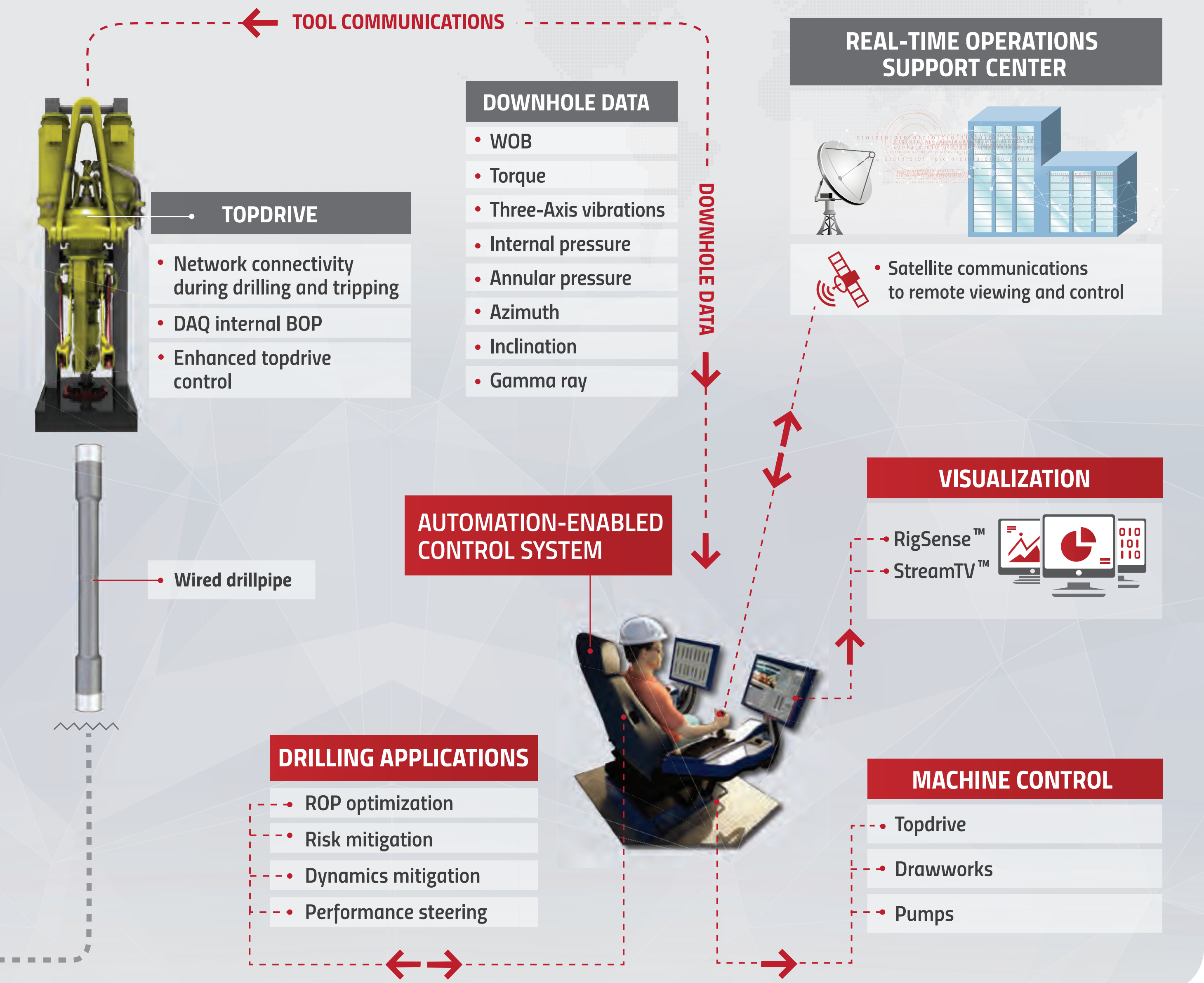
The system has been through three onshore field tests and it has been used on two onshore commercial wells.

"The early results have demonstrated that these technologies can deliver significant performance improvements," Pink says. "The largest observed benefit however was more cultural than technical; the high-speed downhole drilling dynamics data allows the driller and the customer representatives to maximize the performance of the rig without compromising safety or the reliability of the equipment. High-speed downhole data means the rig and drilling system can be used in a less conservative way—the equipment can be pushed to a higher limit because of clear visualization of the downhole environment. This safe and controlled lack of conservatism could significantly improve well delivery times and reduce the cost of field development."

Three major projects are being planned in Norway with Total, ENI, and Lundin. **OE**

This article is based on a presentation by Tony Pink, National Oilwell Varco, presented in March 2014 at the SPE workshop, In Arctic Norway, and a presentation at the IADC's conference in Vienna in June 2014.

NOV's Closed loop drilling system



Managing the process and the power systems that serve it through a single integrated control system can cut costs while giving a much better overview of the total plant. Laya Sathyadevan explains.

Electrical Integration – bringing process and power together

Traditionally, the systems that serve process automation and power automation within the same plant are separated, both by a lack of common communication and architectural standards as well as organizational differences between departments.

Intelligent electronic devices (IEDs) are microprocessor-based controllers of power system equipment. They can communicate with the automation system as well as with each other to give an overall picture of what is happening to the process or power supply system. IEC61850 communication interface can efficiently handle this data over Ethernet. Exchanging the same amount of data between plant devices using traditional communication interfaces will require extensive cabling.

Imagine a typical small oil platform with a 10-bay medium voltage electrical system. Signalling between the bays, to and from the automation system and for other tasks, can require around 980 wired connections. When we also consider the large number of available protocols, the bandwidth and cost-efficiency of this approach is very limited, and could result in solutions having to be implemented on a project-by-project or even device-by-device basis. Furthermore, multiple systems mean multiple databases, additional engineering tools, different operator stations, and more system administration and maintenance.

Today, this barrier is a costly reality for many operators of offshore platforms and FPSOs, which may use a large number of communication protocols, such as Modbus and Profibus. If a device needs to be integrated to the control system, it could require a solution designed just for that single device. Transferring data such as valve positions and thermal alarms between the process automation system and the power automation system will require a lot of hard wiring.

Electrical integration

This barrier is one that can be eliminated through electrical integration, which means integrating process automation and power automation into the same plant control system. This integration is based on devices that use IEC 61850 interfaces to transfer control or power data, saving up to 30% on cabling costs compared to hard wired systems. This creates a single automation environment that unifies the control of process-related equipment as well as protection, control and monitoring of substation equipment and power transmission and distribution. Integrating the process automation system with the power automation system allows a single overall strategy in the areas of engineering, operations and maintenance.

The economic benefits of electrical integration can run into millions of pounds, either through increased production or reduced operating costs. IEC 61850 interfaces also support redundancy, making the integrated power and control system more tolerant of failures. During the lifetime of an oil and gas platform, various components of the integrated power and control system will have to be exchanged or replaced. Over time, the system may also cope with integration of new components from the same or new suppliers or it may have to be extended. Irrespective of these changes, interoperability must be maintained. The data structure of IEC 61850 has been specifically designed to achieve this.

One drawback of this integrated system approach is that IED attributes, such as parameter settings, are managed by tools specific to each IED manufacturer. This means that using IEDs from several vendors will increase the number of tools needed to support the system.

Electrical integration based on open standards

The difficulties of electrical integration have been largely removed with the advent of IEC 61850. Acknowledged as the global communication standard in substation automation, it represents a huge step forward in simplifying the integration of protection and control IEDs.

With its standardized model of the IED and its data and communication services, IEC 61850 ensures interoperability between electrical devices from different vendors and is able to replace all the

Managing the process and the power systems through a single integrated control system can cut costs and give a better overview of the total plant.
Image from ABB.

typical protocols found in the substation automation domain. Based on Ethernet technology and providing flexible and open system architecture, IEC 61850 makes the application future-proof over entire system lifecycles.

Electrical integration extends the typical scope for asset management tools from just instrumentation into electrical power generation and distribution as well. The resulting architecture provides operators and maintenance personnel with current process information plus all relevant electrical asset information. All information sent via IEC 61850 interfaces is available as real-time data. This can be customized so that, for example, the IED sends data only every five minutes. The architecture also offers remote access to all equipment diagnostics from the same maintenance workplace.

To achieve this, IEC 61850 uses a mainstream communication technology, manufacturing message specification (MMS) over Ethernet. This standard specifies two main types of communication; vertical communication between the control system and the IEDs and horizontal communication from IED to IED.

Vertical communication uses the full MMS stack and is intended for the vast amount of data shared between the control system and the IEDs. Horizontal communication uses the special generic object orientated substation event (GOOSE) messaging, a data transfer method that removes the delays inherent in traditional hard-wire signals, allowing high-priority data to go directly between the IEDs.

Savings

Major benefits of electrical integration include reduced investment cost through one integrated system, improved operator effectiveness and collaboration across all areas of the plant and reduced maintenance costs through using one common maintenance strategy for the entire plant.

It can also provide an enhanced energy reduction program by improved visibility into power consumption. For industries such as oil and gas, 24/7 availability and reliable electrical supply are paramount. Integrating the electrical system into the Integrated Control and Safety System (ICSS) using IEC 61850 technology gives the user an excellent overview of a platform's electric power assets, as well as a large amount of data that allows ready diagnosis of faults.

The main objective of a power management system is to avoid blackouts, especially those with in-house generation, critical loads or insufficient supply from the electrical grid. One critical functionality of a power management system is load-shedding; keeping critical loads running should incoming power be lost. Non-critical loads are shed to keep critical parts of the plant running.

With electrical integration, load-shedding applications are now easier to design and can have an even faster response time compared to hard-wired solutions. Systems that can help achieve this include ABB's System 800xA, the first process-control system on the market to support the IEC 61850 standard. Its AC 800M controller functions, as an IED, allow it to communicate horizontally with other IEDs via GOOSE. Load-shedding can be implemented using an Ethernet-based solution, which means faster trips, monitoring of trip data quality and reconfiguration of trip logic without re-wiring. This allows a faster response to power glitches, giving increased plant uptime by preventing blackouts.

Cutting the cost of power

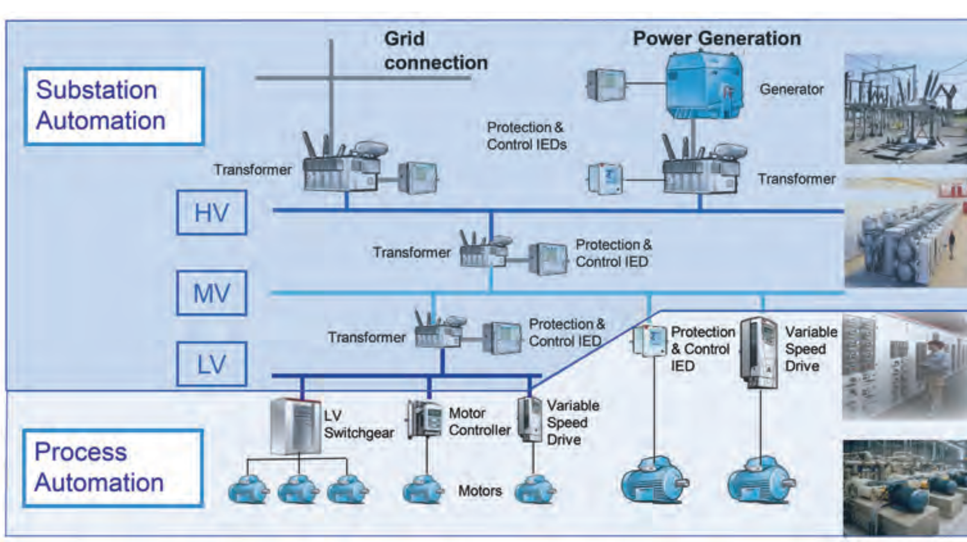
With access to all critical electrical data, cost-sensitive producers can reduce their total consumption of electrical power significantly. An integrated system enables plant operators to see and understand power usage in a more coordinated manner, allowing new energy-saving opportunities and allowing existing reduction programs to be improved. An increase in power consumption by a unit or area due to equipment malfunction and wear can quickly be remedied, while better visibility of power consumption and costs allows easier energy audits and benchmarking.

Integration in action

An example of electrical integration in action offshore is an ICSS for an FPSO operating in the Jordbaer field in the Norwegian sector of the North Sea. Based on ABB's System 800xA, this uses 14 AC 800M and AC 800M HI controllers in redundant configurations, providing an integrated solution for hull side (vessel control and safety) and topside (process control and safety).

The days of treating control and power as two separate entities are surely numbered and the progressive company seeking to cut costs and gain better visibility will increasingly come to see them as inextricably linked and part of a greater whole. OE

***Laya Sathyadevan** is an oil and gas systems engineer at ABB UK. She is currently working on QGC project in Australia and BP Caspian project where IEC 61850 communication is used to integrate process and power automation systems. Sathyadevan has a Master's degree in Control Systems from Imperial College London.*



The control of drives, intelligent MCCs, medium voltage switchgear, protection and control IEDs integrated on the same system increases visibility of the process, asset management of electrical devices, better interfaces with process control and improved operational procedures.

The push for uniformity

Stephen Whitfield examines well control standards in the US and Europe.

Since the Macondo blowout devastated the Gulf of Mexico in the spring of 2010, governments and industry organizations around the world have recognized the need to prevent potential blowouts through better well control standards. While there is still no universally-accepted regulation for everyone to follow, organizations around the world are getting closer to that goal.

Well control in the US

The approaches from both industry and government with regards to well control have been slightly different.

The American Petroleum Institute held a forum on offshore well control equipment in New Orleans this past January, and out of that forum came a new standard for subsea capping stacks aimed at improving their ability to control a potential spill.

This new standard, otherwise known as RP 17W, addresses both new capping stacks and existing ones, suggesting that they should "use field proven and qualified equipment components where possible" and "provide a means for circulating trapped gas from below the top barrier component."

The API also recommended that the stacks themselves have the ability to check pressure below a wellbore's mechanical closure device. In the case of a blowout, they should be able to inject both hydrate inhibitors and chemical dispersants into and have some outlet for diverting the flow of fluids from the main bore.

Of course, the API standard is only a recommendation, not a binding law. In governmental channels, the push for uniform well control policy has continued at a steady pace.

In 2012, the US Bureau of Safety and Environmental Enforcement (BSEE), an agency of the Department of the Interior, hosted a forum in which federal officials, industry leaders, and top names in academia talked about the steps they could take to improve blowout preventer safety – the failure of the *Deepwater Horizon*'s BOP was cited as the main cause of the Macondo incident.

Blowout preventers are part of a comprehensive well control policy that the Bureau of Safety and Environmental Enforcement is currently crafting.
Photo from GE Oil and Gas.

Since then, the BSEE has been working on a comprehensive well-control bill, but there is no timetable for when this bill will begin moving through the necessary legislative channels.

David Smith, the head of BSEE Public Affairs, acknowledged that the demand for such a policy has been noticeable.

"While [the BOP] was a point of failure in the *Deepwater Horizon* tragedy," Smith said to OE, "a number of barriers failed as well and it was the combination of failures that ultimately resulted in the loss of well control and the explosion. Therefore, as BSEE undertook this rulemaking, we diligently worked to ensure it would address well control in a more comprehensive way."

Europe

In March 2009, a year before Macondo, the International Association of Oil and Gas Producers (OGP) held a drilling standards workshop.

The organization recognized a few major concerns within the industry with regards to well control equipment – namely, that there were very few internationally recognized standards to follow.

In a presentation from that workshop, OGP acknowledged four API standards – RP 53, RP 59, RP 64, and RP 16Q as "the only practical documents available to … install, test, and use well control equipment."

That presentation cited the need for a set of international standards because of the increasing number of drilling contractors from Europe and Asia that do not follow API standards.

Five years later, there is still no set of internationally recognized standards on well control, but there are a host of organizations around the world working to increase awareness of proper well control procedures in the wake of Macondo.

Last year, the European Union announced its Directive on the Safety of Offshore Oil and Gas Operations as a direct response to *Deepwater Horizon* and other incidents. The directive sought to address what it called "the existing divergent and fragmented regulatory framework applying to the safety of offshore oil and gas operations" between its member states.

The EU directive touched on a wide range of issues, including response and liability in the case of a blowout and, as the name would suggest, preventative measures. Most importantly, it called for independent, expert regulators to assess the capacity of wells in each of its countries with well operations.Under the directive, EU countries that are not land-locked have until June 2015 to implement the directive into law.

By 2016, the European Commission will report on the progress of the implementation of this directive to both the European Parliament and the European Council.

International organizations

Elsewhere, other organizations are leading the way in researching the possibility of a uniform standard and educating others about well control.

The International Regulators' Forum (IRF) has already officially supported the International Organization for Standardization (ISO) standards system. However, ISO standards are far from a be-all, end-all, and the IRF's Offshore Safety Conference in Perth last fall featured several proposals on potential safety and environmental regulations.

One in particular, a joint presentation from the Netherlands Oil and Gas Exploration and Production Association and the country's State Supervision of Mines, dealt with possible ways to deal with blowouts.

The presentation, titled "Emergency Response in Case of a Blowout in Shallow Waters," highlighted the communication between government and industry in the Netherlands as a key.

The Norwegian headquarted DNV GL has done plenty of work on blowouts recently – in 2012 and 2013, the organization evaluated the possibility of further automation of BOP systems with the hopes of developing a new guideline. While that effort did not ultimately lead to anything, DNV continued its work, shifting focus to wellhead fatigue in a new joint industry project (JIP) announced in early July.

The JIP, which features contributions from companies like BP, Chevron, ExxonMobil, Marathon, and Shell, will provide funding to various studies that asses current practices for assessing fatigue. These studies are expected to be completed in the first half of 2015.

On another note, the British-based International Well Control Forum (IWCF) has been at the forefront of the movement for stronger, consistent well control standards, and in the last couple of weeks the organization has launched two initiatives.

First, the IWCF started an online awareness course aimed at educating those currently working in the industry and those planning to enter the industry. The program details what to expect in the lifecycle of a well, as well as potential hazards to look out for and industry methods for dealing with blowouts.

The other initiative, announced in early August, aims to improve the quality of well control training through a series of technical taskforces.

Among the areas of focus are drilling, well intervention and completion, quality of training, crew resource management, enhanced certificate renewal, High Pressure High Temperature.

The IWCF said these taskforces will consist of board members, member center representatives, and independent industry specialists. Additionally, it will begin a new introductory online course. OE

As the industry advances into ultra-deepwater, an increasing number of tight tolerance wells require an efficient system for determining early influxes or losses during drilling, tripping, and cementing operations. Scott Hilliard of Statoil and Florian Le Blay, Soufian Berhil and Eric Villard of Geoservices, a Schlumberger company, present a new early detection flow monitoring system and setup for floating rigs.

Well surveillance in ultra-deepwater

As part of the FLAG service, a Coriolis flowmeter installed in the return flowline continuously measures the actual flow. Photo from Schlumberger.

With the increase in ultra-deep, high-pressure high-temperature (HPHT) wells, new drilling technologies are crucial. Monitoring active pit volume and the mud level in the flow line are standard ways to detect influx or "kick," the most dangerous hazard encountered during drilling HPHT wells in ultra-deep water. However, detecting gains or losses using the active pit is delayed due to the length of the flow line and the communication chain on the rig.

Active pits are commonly located far from the wellhead at the end of the flow line after the gumbo box and shakers. Pit transfers and other operations can influence the volume and require constant communication between the driller, mud loggers, mud engineers, and the derrick man. With the time required for detecting influx and the influence of the communication chain, additional volumes can build up before the decision is made to shut in the well.

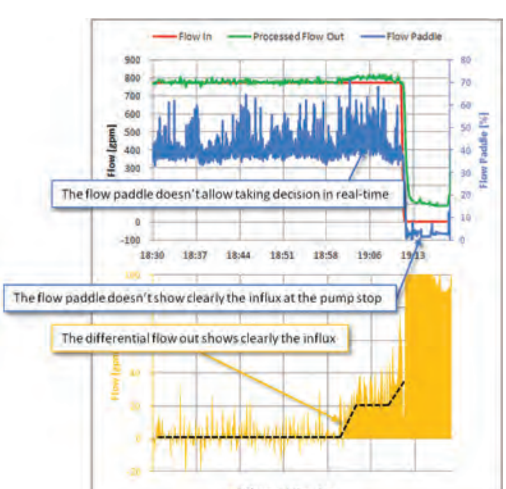


Fig. 1: Comparison flow paddle vs. differential flow out. Images from Statoil and Schlumberger.

Sensor types

The use of the flow paddle on the flow line to detect gains and losses has shortcomings, so in the 1990s, improved flow sensors were introduced on some rigs to measure flow from the well more accurately. Two types of sensors are now common: the electromagnetic sensor and the Coriolis flow sensor.

Although the size and configuration of the electromagnetic sensor make it the best option for flow measurement, being restricted to conductive fluid, or water-base mud (WBM), made the Coriolis flow sensor the preferred option because it works with any kind of drilling fluid.

However the Coriolis flow sensor was rarely used because it required heavy installation and was available only in a small 6in. size. The installed sensor requires a bypass setup. Its small size limits the flow rate by inducing a significant pressure drop that leads to a hydrostatic head before the bypass. This hydrostatic head reduces the flow rate.

The introduction of larger Coriolis sensors in recent years has raised the limit of the maximum flow rate. When combined with an optimized bypass design, these large sensors can be used at very high flow rates for all drilling operations as long as drilling fluid return is directed into the flow line.

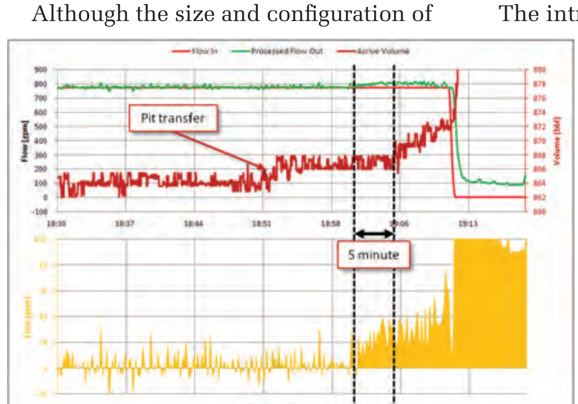


Fig. 2: Comparison pit volume vs. differential flow out.

Measurement methods

Accurate measurement of return flow is required to obtain well flow, an important factor for monitoring.

Standard measurement methods currently being employed on rigs are mostly achieved using a flow paddle and the active volume. Measurements based on the flow paddle can be easily obtained, but paddle reliability is low due to its mechanical principle and the noisy signal, especially on floating rigs where heave is a significant factor. Moreover, comparing the signal with pump flow rate also is not possible. The accuracy of the measurement from the flow paddle is debatable. The flow paddle provides fluid height measurement, but requires an assumption of the fluid velocity in any attempt to infer a flow rate. Unfortunately, the fluid flow profile can change significantly with fluid properties like density and rheology.

The advanced measurement process in this paper includes many factors that can influence the measurement of actual flow including pump rate, pipe movement, mud compressibility effect, flow line flow back and heave effect.

Differential flow out, which is the difference between actual flow out and theoretical flow out, allows for accurate and quick calculation of the actual volume of the influx or loss without being affected by pit transfers that happen often during drilling.

Early gain detection is the first advantage of using flow measurement at the flow line. Detecting influx as early as possible is crucial to reducing volume and minimizing the risk of an uncontrolled event, or spending time controlling the well.

Case study

Figures 1, 2 and 3 demonstrate real-time data from a kick event on a sixth generation drillship in 2500m of water drilling a 12¼-inch section. The curves plotted on the charts have been drawn and displayed in real time during a drilling operation in which a kick occurred.

The kick occurred at 7 p.m., the decision to stop the pumps was made at 7:10 p.m., and finally the well was shut in at 7:20 p.m., recording a shut-in casing pressure of 450psi. Some maintenance was performed on the Coriolis sensor during the well control operation, which explains the flow measured by the sensor after the well has been shut in.

Figure 1 compares the measurements of the flow paddle with the differential flow out based on the Coriolis flow sensor. The plot highlights the fact that, if the rig had been equipped with only the flow paddle, it would have been impossible to detect the influx that occurred at 7 p.m. Even when the pumps are stopped, the signal from the flow paddle is not clear enough to determine influx. However, in examining differential flow out, the wellbore obviously began flowing at 7 p.m.

Figure 2 represents the active volume monitoring. This method of gain/loss detection is accurate, but, as shown on the plot, the increase in the pit volume is observed five minutes after the gain was observed on the differential flow out. Considering that the well was flowing at about 35gpm, a five minute delay represented more than four barrels, a significant amount when a gain is considered, especially if the influx is gas. The delay was explained by the fact that the pits were far from the bell nipple, after the gumbo box and the shakers, when the flow sensor was installed farther upstream.

Figure 3 highlights the effect of pipe movement. Once the gain was detected, the decision to stop drilling had been made. When the basic differential flow is considered (flow out–flow in), the decrease of flow out can be seen.

Performing only this calculation to visualize gain or loss flow can lead to the erroneous conclusion that influx has stopped and that the drilling operation can restart without risk. But the decrease of flow out is due to the steel volume of the drill string that was removed from the well while pulling out of the hole.

The differential flow out is compensating the steel volume, which demonstrates that the kick is not only occuring, but the kick is actually increasing due to the swabbing effect. The trend of differential flow out is slightly different and highlights an increase of the well flow magnitude.

The other advantage of the processed differential flow out is the compensation of flow back. It is important to consider mud volume in the flow line to accurately evaluate the influx volume and in order to determine the procedure for well control. The active volume presents one disadvantage: Once the well has been shut-in, the measured volume needs to be corrected, including the mud volume in the flow line. This can be achieved by substracting the value of the active volume at the previous connection if it has been long enough to be stable.

This volume also needs to be adjusted by considering the different transfer that could have been performed during drilling. If the trip tank is used to perform the flow check, it should be included. Because differential flow out is not influenced by any transfer and is calibrated to compensate for this flow-back effect, the calculation of the gain volume is done accurately in real time, as shown in Figure 4. This enables decisions to be made more quickly.

Packoff complications

Besides the influx, the packoff also can lead to undesirable consequences, including damage to the formation. Packoff occurs when a plug is formed downhole, primarily at the stabilizer level. This leads to an increase of the pressure on bottom as drilling mud compresses. If the packoff is not released

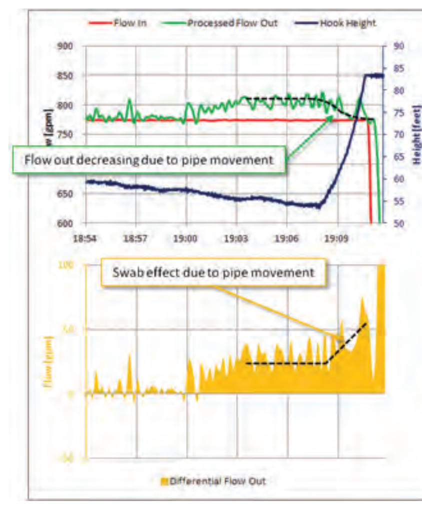


Fig. 3: Pipe movement compensation and swab effect.

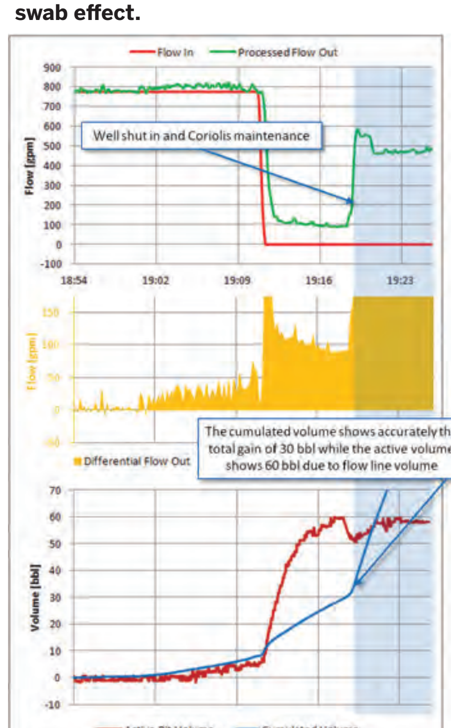
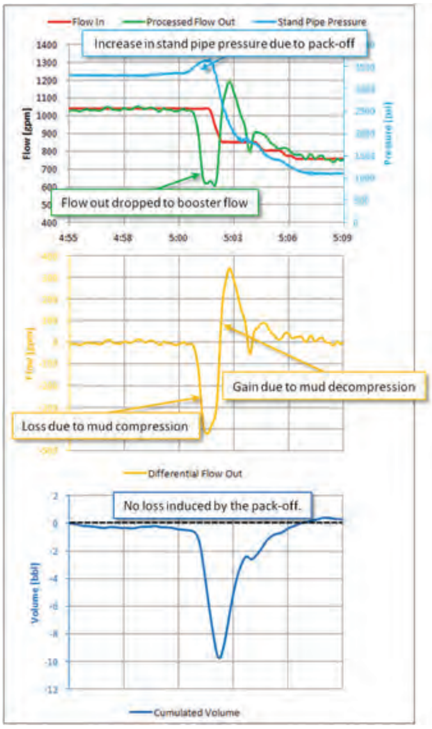
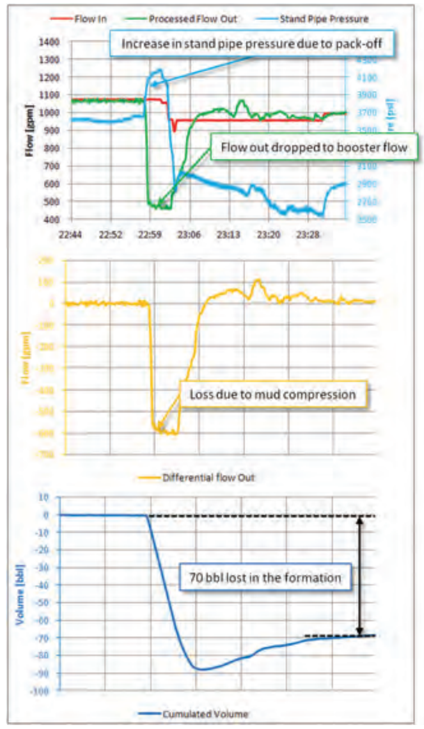


Fig. 4: Accurate real-time gain volume calculation.



Packoff without formation damage.



Packoff with formation damage.

quickly enough, the pressure can reach the fracture pressure of the formation and lead to an injection of drilling fluid by fracturing. When the drilling rig is not equipped with a flowmeter solution, stand pipe pressure (SPP) and downhole torque can help detect packoff.

The packoff event is detected when an increase of torque and SPP is observed while the pump rate remains constant. The differential flow out process introduces the idea of visualizing the compression of the mud and fluid injected in the formation during the event.

Figure 5 presents a packoff event where no damage has been done to the formation. The packoff is building up at 5:01 a.m., as shown by the SPP increase. At that time, the flow out dropped to the booster flow (600gpm). This meant that there was no additional flow from downhole due to packoff. The difference between the flow out and the flow in was the compression of the mud in the drillstring and the annulus up to the packoff.

Once the packoff had been detected, the downhole flow rate was reduced following the established procedure in order to release the plug. As observed on the flow out, after decreasing the downhole flow rate, a gain was noticeable from mud that was compressed when the packoff occurred.

Calculating the cumulative differential flow out allowed for the investigation of whether mud had been lost in the formation. As shown in Figure 5, the cumulative differential volume out was reduced when the mud was compressed to the packoff and increased to 10gal once it had been released.

This 10gal is due to the accuracy of the differential flow out, which was not perfect and the error was cumulated. But this error was negligible when considering that the cumulation was done over 15min. In contrast to the previous case, Figure 6 illustrates a packoff that induced lost fluid.

As noticed during the previous event, when the packoff was building up, the SPP increase could be seen as the flow out decreases. The difference in comparison with the previous case appears once the packoff was released. The flow out returned to normal very slowly and did not show the compressed mud releasing, as was the case previously.

This is explained by the fact that the downhole pressure increased when the packoff occurred and had reached the value that induced the fracture of the formation leading to a fluid loss. In this case, the conclusion can be drawn that the formation had been damaged due to the packoff event.

Conclusion

The accurate flow measurement combined with the processed differential flow out method was effective in detecting unplanned events during drilling such as gain, loss and packoff. Beyond the detection, this system enables accurate, real-time calculation of gained or lost mud volumes, which impacts the time required for effective decision making.

Because of the accuracy and reliability of this method, drilling procedures have been adapted that reduce the number of flow checks required at each connection. After the various successful event detections, the decision was made not to perform any flow checks without prior detection by the processed differential flow out, which allows a saving of 10-15 min. at each connection. **OE**

This article was prepared based on SPE 158374, presented at the 2012 SPETT Energy Conference and Exhibition held in Port of Spain, Trinidad, June 11-13, 2012.

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Well control for pre-salt production efficiency

Baker Hughes has been developing completion technology and well control with Petrobras in deepwater ever since its first intelligent completion system contract in the early 2000s. Claudio Paschoa found out more.

Baker Hughes' well stimulation vessel *Blue Shark* in Rio de Janeiro. Photo by Jean Mathiel.

Baker Hughes entered the Brazilian market in 1973, when Hughes Tool Company acquired its representative bit manufacturing facility in Salvador, the capital of the state of Bahia.

Since the very start, the company established itself as a major drill bit supplier in the Brazilian oil industry, entering into other sectors, including well control and completion in around 1978. Today, Baker Hughes is one of Petrobras' preferred partners in pre-salt development.

In early 2000s, Baker Oil Tools was awarded Petrobras' first-ever intelligent completion system contract, for the deepwater Marlin field, and Baker Hughes has been developing completion technology and well control with Petrobras in deepwater ever since.

Mauricio Figueiredo is Baker Hughes' vice president of business development at its regional headquarters in Rio de Janeiro. Figueiredo has been with Baker Hughes for all of 35 years, starting as a trainee in 1978, at about the same time that Baker Hughes launched its Brazilian company, and worked his way up to the position of vice president for Brazil, where he managed Baker Hughes' business, 2008-2013. In his current position, as vice president, business development–a role he assumed in October 2013–he oversees all Baker Hughes' business with Petrobras on a global scale.

"With the decrease in Petrobras' drilling operations, as the national operator increased focus on development of pre-salt fields and reduced exploratory activity, business for us in Brazil began decreasing in 2013. This was also caused by the decreased activity of private local companies and international oil companies (impacted by lack of bid rounds for five consecutive years). We believe this is only temporary though and business should pick up again by 2016," Figueiredo says.

Baker Hughes believes that the industry is experiencing a migration from traditional hydraulic IWS to systems with electric valves and components for a higher level of functionality. Photo from Baker Hughes.

Intelligent well system

Decreasing costs and reducing risks through a partnership with Petrobras in tackling drilling challenges led Baker Hughes to sign a cooperation agreement with the national operator in 2009, for well construction, reservoir analysis, and artificial lifting research and development, based at Baker Hughes' Rio de Janeiro technology center. Petrobras invested US$16.4 million and Baker Hughes injected US$29 million in the project.

The collaboration is focused exclusively on developing technology to solve Petrobras' challenges. "We started with a major investment with our drilling and evaluation business, and during the last seven years, Baker Hughes has had more

FASTrak from Baker Hughes. Photo from Baker Hughes.

than 50% of the directional drilling market with Petrobras," Figueiredo says. "In addition, we've invested a lot in subsea completions, establishing an important leadership position for our artificial lift business in deepwater environments. We have around 60% of that market share. This represents a huge growth from seven or eight years ago, and it has a lot to do with having the right strategy in place and pursuing the most promising opportunities in the market, not only with Petrobras, but with other companies, as well. It also has to do with understanding our customer needs and delivering above their expectations."

"Baker Hughes and Petrobras have a long and successful history of joint technology development for addressing pre-salt challenges, and this has led to important breakthroughs in pre-salt development," Figueiredo says. Since 2005 Baker Hughes has invested around $300 million in Brazil (infrastructure, technology tools and personnel qualification), much of which was earmarked for pre-salt fields development. At the Marlin field in 2003, Baker Oil Tool's InCharge Intelligent Well System proved to be ideal by being user-friendly and by its all-electronic design, which incorporated a one-penetration approach and a power-on-communications architecture that required little to no retrofit of existing subsea trees. This helped in terms of decreasing customer OPEX. "The system now has been greatly developed, with new tools and techniques implemented, which has greatly increased the overall scope of the Intelligent Well System and enhanced its capabilities, in order to deal with the specific challenges posed by ultra-deepwater pre-salt wells, which are spudded into geologically complex reservoirs," Figueiredo says.

Although there is no well control technology development being done at Baker Hughes' technology center in Rio at the moment, the center has been instrumental in creating, developing and implementing dependable high performance solutions to maximize production and recovery since its inauguration. The oil and gas industry has generally defined intelligent wells as wells equipped with downhole remote flow control devices used to open, close, or regulate flow from and to multiple zones without the need for well intervention.

"Intelligent wells completion systems are usually complemented by downhole permanent monitoring systems, which provide valuable information used in the decision making process for the control of production or injection. All these systems require multiple control lines and cables to link the downhole tools to the associated surface equipment, which serves as the interface between the operator and the system," Figueiredo says.

In subsea systems, the wellhead and wet X-mas trees are installed on the seabed, providing a means of controlling the wells through a series of valves, piping, chokes and other related equipment. Deepwater subsea trees are operated by remote-control systems, through hydraulic actuators. The well control systems on the surface are linked to the trees by means of dedicated lines in an umbilical or by sophisticated electro-hydraulic multiplex systems mounted on the trees, controlled through a subsea electronic module. Figueiredo explains that, "The electro-hydraulic multiplex systems are becoming more popular because of their quicker response time, increased reliability, and lower umbilical costs. These subsea control systems not only need to control functions on the trees, but also need to be able to interface with and control downhole equipment, such as safety valves, downhole chemical injection valves, permanent monitoring instrumentation, and intelligent well valves."

Penetrations through the tubing hanger provide a means of communication between the subsea control system and the downhole equipment. Subsea control systems normally have two hydraulic circuits for controlling downhole functions: one high pressure (HP) normally dedicated for the safety valve and one low pressure (LP) normally used for the intelligent flow control valves.

"Baker Hughes' completion fluids for the pre-salt are well developed and do not constitute a major challenge. We have drilled over 80% of pre-salt wells in the Santos Basin," Figueiredo says. These presalt optimized completion fluids are designed to ensure a smooth transition between the reservoir drilling and the completion phases. There are clear brine fluids, filtration units, viscosifiers, filtration control agents, scavengers, and surfactants. Each serves a special purpose in providing the best possible wellbore scenario for intelligent well completion operations.

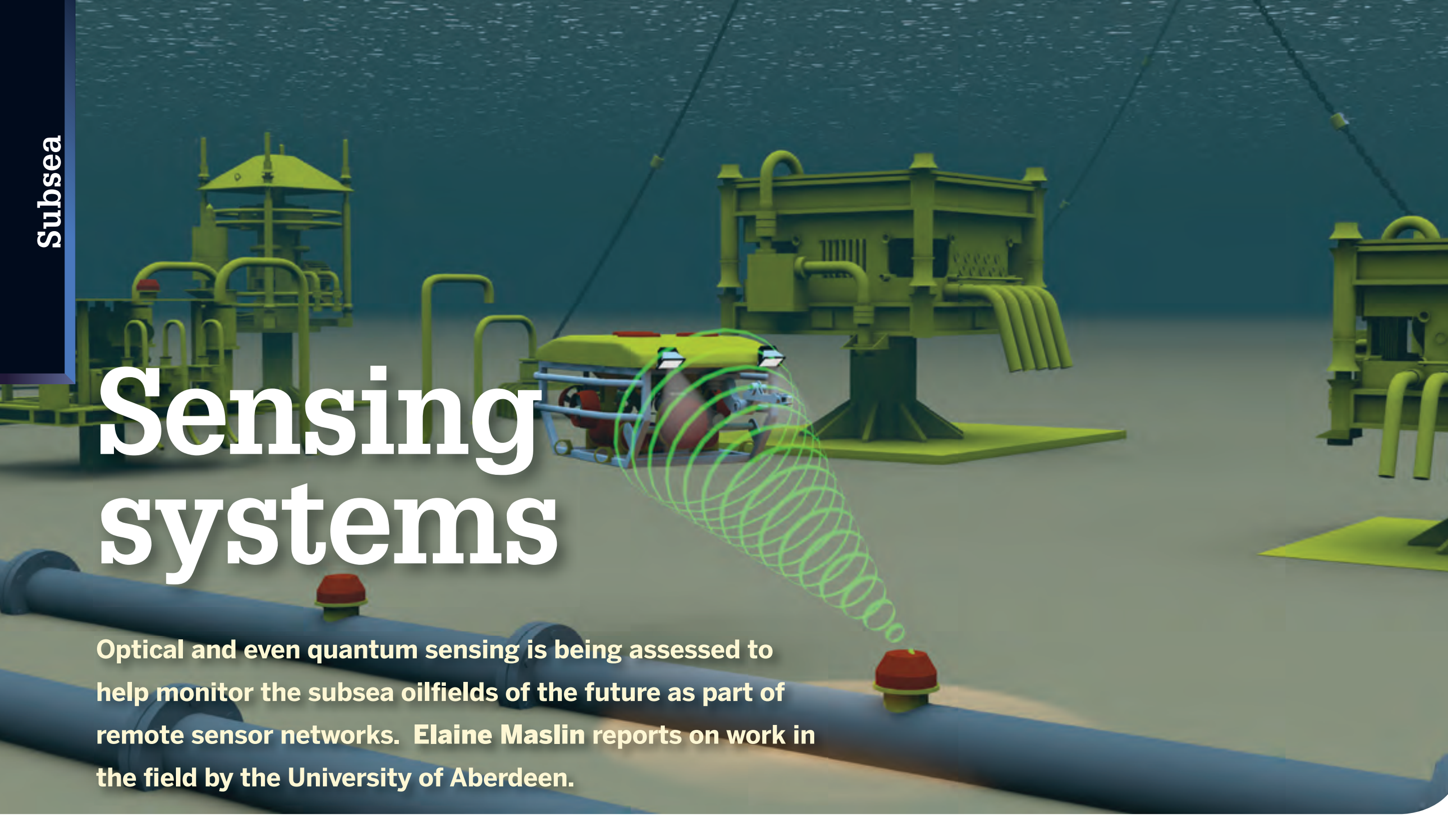
Well monitoring instrumentation measures pressures, temperatures, flow rates, water cut, and density in the wellbore with both electronic and fiber optic gauges and are key components in intelligent completion technologies. This instrumentation includes zonally isolated, hydraulically adjustable valves and chokes, which allow adjustments to product inflow from any zone, without well intervention. Water and gas can also remotely control the flow to individual zones. The SENTRYNET chemical automation tools allow control of the chemical regimen at remote oil and gas production facilities, such as pre-salt areas in Brazil. Another essential part of intelligent well systems, feed-through packers, offer a way to pass downhole tool control lines through the packers while controlling fluid flow and maintaining production zone isolation.

"Corrosion is always high and can be a very costly problem in the pre-salt wells. For this reason Petrobras has been gravitating to special steel materials, more resistant to the corrosion from salt formations. This special steel, in conjunction with corrosion inhibitor, is designed to work in a variety of brines and water-based fluids, along with keeping CO2-caused corrosion in check, limiting its destructiveness. So corrosion is a challenge that has been in most cases addressed and can now be effectively controlled," Figueiredo says. Over the years, Figueiredo adds, the Petrobras and Baker Hughes partnership in the pre-salt development has led to a 40% increase in pre-salt drilling operations efficiency and it was Baker Hughes that did the completion of the first pre-salt well with an intelligent well system installed to monitor and control a deep, dual-zone, gas-injector well at the Lula field (former Tupi field), in the Santos Basin, leading to its use in other Brazilian pre-salt plays.

Mauricio Figueiredo, vice president-business development, in his office in Rio de Janeiro. Photo by Claudio Paschoa.

"Petrobras' requirements for the future, include: a better understanding of reservoir heterogeneity in the complex microbial carbonate environments; faster, safer drilling and high quality wells in very challenging ultra-deepwater environments; intelligent production systems and overall completions technology that uses materials and equipment customized for the characteristics of the developments; Improved reservoir hydrocarbon stimulation techniques and well integrity dependability in unstable thick salt layers," Figueiredo says.

Baker Hughes also has the majority of the well stimulation vessel market in Brazil and has three stimulation vessels under an exclusive contract to Petrobras, the *Blue Shark*, the *Blue Angel* and the *Blue Marlin*, all based in Niteroi. Pressure-pumping operations perform between 1200 and 1300 jobs a year, including cementing, stimulation, coiled tubing services, wellbore cleanup, casing running, completion tools, filtration fluids and chemical services. OE



Sensing systems

Optical and even quantum sensing is being assessed to help monitor the subsea oilfields of the future as part of remote sensor networks. Elaine Maslin reports on work in the field by the University of Aberdeen.

The amount and complexity of subsea production equipment is growing. In 2013, about 20% of UK offshore production, or 280,000boe/d was from subsea developments, a figure set to rise to about 400,000boe/d by 2016. Subsea separation is growing in use and subsea gas compression is nearing its first commercial use.

As these developments come online, in ever deeper, or harsher waters, where local, manned structures may not be possible, or are too costly, the need for remote monitoring, especially leak detection, is also increasing.

While operators and contractors work out how to make variable speed drives work in 3000m water depth, others have been focusing on future monitoring systems, including the University of Aberdeen.

The university is researching the different types of sensor systems required for remote subsea developments, under its work as part of the Scottish Sensor Systems Centre (S3C), a collaboration between eight Scottish universities, running 2009-March 2014.

Richard Neilson, Director of Research and Commercialization for the College of Physical Sciences, at the university, says future subsea sensor system networks will need to operate remotely, providing high-quality data, including operational data (flows, pressures, and temperatures), condition data (corrosion and actuator condition) and environmental monitoring data. Sensor systems will need to provide early leak detection, with automated leak warnings, as well as hydrocarbon flow monitoring and pipeline integrity monitoring. "Environmental leakage, without having to introduce tracers into the flow, is going to be one of the biggest areas," Neilson says. "The other holy grail is pipeline inspection," Neilson adds. "If you could fly an AUV along the length of the pipe to detect wall thickness, corrosion pitting, hydrate formation or waxing, instead of putting a pipeline inspection gauge through the pipeline, with the potential to have it jam and interrupt production, which would be ideal."

The S3C program assessed various sensor types, including spectroscopy, for leak detection, and has developed a new technique, quantum sensing, for pipeline inspection. It also looked at what is needed to support subsea sensor networks, such as wireless sensor and communication networks and subsea power.

Sensing systems

Molecular sensing, using optics, is one way to examine well fluids and to detect well fluids released to the environment without using tracers by detecting molecular species, i.e. hydrocarbons and other compounds, such as nitrogen, carbon, and sulfur dioxide.

"Using laser diodes you can see what is reflected back and what is being adsorbed," Neilson says. "At a molecular level, you can look at not-visible light to either measure absorption or reflection and use the information to quantify the presence of hydrocarbons."

Subsea monitoring using radio frequency. Image from WFS.

Options using optics were researched by Johannes Kiefer, an honorary professor and former senior lecturer at University of Aberdeen's School of Engineering. They include infrared and near-infrared spectroscopy, Raman and fluorescence spectroscopy, and UV/LED absorption and fluorescence (see panel).

- Infrared (IR) spectroscopy - an absorption technique using molecule specific absorption in the mid-infrared spectrum, where the vibrational frequencies of molecules can interact with radiation, e.g. each hydrocarbon species exhibits a fingerprint IR spectrum, so the IR spectrum of a mixture can be used to quantitatively analyze the chemical composition. Moreover, IR spectroscopy is sensitive to the chemical environment of a species, allowing the investigation of effects like emulsion stabilization, for example in oil/water systems.
- Near-infrared (NIR) spectroscopy - an absorption technique using molecule specific absorption in the near-infrared spectrum, where the overtone and combination vibrations in molecules can interact with radiation. NIR is typically less species-specific than IR, but may be cheaper and easier to implement, Kiefer says.
- Raman spectroscopy – a technique complementary to IR. Some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molecules (e.g. hydrogen) are not IR active but they are Raman active. As in IR, the interaction of radiation with the fundamental vibrational frequencies of molecules are used. However, in Raman it is not an absorption but a scattering process (typically of incident laser light).
- Fluorescence spectroscopy - selected target molecules (typically aromatic compounds or tracer dyes) are excited by visible or ultraviolet radiation (e.g. from a laser) and subsequently emit fluorescence. Fluorescence offers detection limits in the order of ppm and below, Kiefer says.
- UV/LED absorption and fluorescence - similar to IR, the absorption of radiation in the visible and UV spectrum, where selected molecules can be electronically excited, can be used. Like fluorescence, the technique can be highly sensitive and allow traces of specific molecules to be detected and quantified.

While each of the above offer benefits, the most beneficial sensor network would use a combination of technologies, Neilson says.

"Each technique has its specific pros and cons, for example, regarding the types of molecules that can be detected, the sensitivity/limit of detection that can be achieved, the possibility for multispecies measurements," Kiefer says. "Hence, it is beneficial to combine several methods in a sensor network in order to obtain a complete picture, e.g. of the chemical composition and the thermodynamic state. Which techniques should be selected and how they can be integrated depends on the required specifications of the sensor system."

Quantum sensing

Another technique being developed by Aberdeen under the S3C program, is quantum-based interferometry led by Charles Wang from the university's physics department. A recent breakthrough in quantum physics has enabled the use of ultra-cold atom interferometers—sensitive instruments able to measure acceleration, rotation, gravity, and magnetism. They have, to date, been used in space to look at gravity waves.

This technology has the potential to be used to measure pipeline integrity from outside the pipeline, Neilson says. A laboratory-based demonstrator quantum sensor is being built at the university to test some of the theories for its use.

"Their (quantum-based interferometry sensors) capabilities make them an ideal tool in the next generation of gravimeters, enabling gravity anomaly detection to be carried out for subsea sensing and inspection using autonomous underwater vehicles (AUVs), remotely operated vehicles (ROVs), including pipeline condition monitoring using magnetic fields," Wang says. "Quantum technology is expected to improve measurement sensitivity by at least three orders of magnitude over existing methods, with less power and size."

Challenges

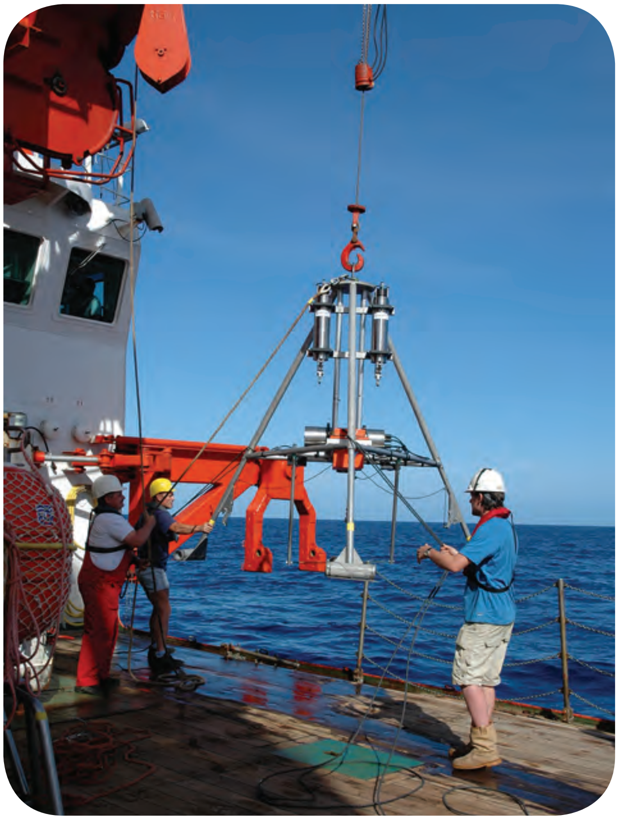
To create a smart subsea sensor system, you would need to create a network of sensors around key installations, to "sniff" for small hydrocarbon releases, and detect them before any major release, as well as monitoring flow assurance and asset integrity, using wireless communications and underwater wireless sensor networks, Neilson says.

"Wired systems offer access to power supply, shielded cabling, and high data rates, but typically have a single point failure, and high installation and maintenance cost," Neilson says. "Wireless networks would have lower installation cost, and would not require the use of deepwater wired connectors. However, underwater wireless sensor networks could suffer from interference, data rates are slower, and power is limited," Neilson says.

The ideal system would be low cost, with low power consumption, offering secure data transfer, re-configurability, and robustness in the underwater environment, Neilson says. Such a system would also need to have adaptive routing, to avoid single point failures, reduce power consumption (by signals finding the shortest route), and secure connections. Systems of this type would enable AUV communication, and back up, or remove the need for, existing copper of fiber optic communication channels.

Available wireless networks for subsea are optical, electromagnetic, and acoustic. Each have their own capabilities and limitations, for example, acoustics have low attenuation and long range but a low bit rate. Electromagetic (commonly called radio frequency) communication subsea has high bit rate but short range. Optics has high attenuation, but very high data rates, at up to 10-150Mbps in up to 100m water.

Just as using a combination of sensors, depending on the application, is most effective, using a combination of wireless networks is also the most likely solution.



A deep water environment/biological landers, used by the University of Aberdeen. Photo from University of Aberdeen.

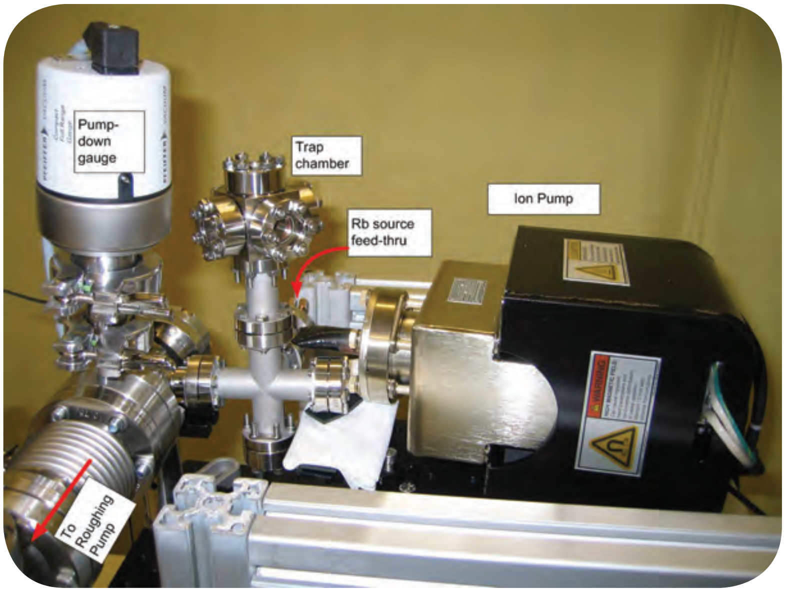
Challenges: power

For such a system to operate, it would be best to be part of an all-electric system, which would provide more diagnostic data for the electric actuators and well-understood faults, and direct control of power, rather than electro-hydraulic, Neilson says.

But, increasing subsea power requirements, for subsea boosting or compression, could mean AC power is not desirable in terms of losses, and that high voltage DC (HVDC) power will be needed, due to better transmission efficiency. However, to date HVDC is mostly used point to point. EU and Engineering and Physical Sciences Research Council funding is supporting research, led by Prof Jovcic, on some of the issues around HVDC, including HVDC circuit breaker technology to protect HVDC networks and HVDC DC-DC conversion to allow direct voltage step-up and down, Neilson says.

Autonomy

To be autonomous, subsea systems would need to be able to make decisions and report. But, autonomous systems, which are able to make decisions and then act on them, could raise problems around employee and public perception, as well as trust in the system and choice of decision making scheme—using ruled bases, Bayesian reasoning, Fuzzy logic or a neural network, Neilson says. Making sure the knowledge base/domain for decision making is complete, is also critical.



The University of Aberdeen's Quantum sensor. Photo from University of Aberdeen.

Neilson, however, points out that such systems already exist in others sectors from simple, e.g. anti-lock braking systems (ABS), through engine management systems, and automatic parking in the automotive sector, to commercial autopilot systems and the likes of the Typhoon Eurofighter flight control system in aviation.

Finally, how an autonomous subsea field sensor network then reports is a further challenge, but one which is being addressed. "There are a number of data mining companies that take data and look for trends. But there are also further developments. Data2Text (a University of Aberdeen spin-out recently acquired by Arria) is able to take the data, analyze it and put the result into a readable document," Neilson says. Such a system would be able to, in plain English reporting, identify alerts which need an expert's attention and potentially allow an engineer to immediately formulate an action plan to correct the cause of alerts. **OE**

*Oil & Gas UK interpretation of Wood Mackenzie data.

Neilson presented the S3C's work at the Institute of Mechanical Engineer's Subsea Engineering conference, in Aberdeen, in May.

A new university collaboration project is partially taking over from the S3C this year, the Centre for Sensors and Imaging Systems (CENSIS), based in Glasgow. The University of Aberdeen is involved in this, as well as the newly formed Oil & Gas Innovation Centre (OGiC), established to accelerate the development of innovative technology, systems and processes.

Cranking up the power on connectors

Critical electrical component testing on the SpecTRON 45.
Images from Siemens.

Siemens is putting a 45Kv wet mate connector designed for up to 3000m water through its paces. Elaine Maslin went to learn more at the firm's plant in Ulverston, Cumbria, England.

In picturesque Cumbria, northwest England, a series of torture chambers have been created to put the next generation of subsea connectors through the worst conceivable conditions they might need to survive and operate at high voltage in.

Testing varies from putting up to 200Kv through the latest subsea connectors to exposing them to sudden temperature drops—or increases.

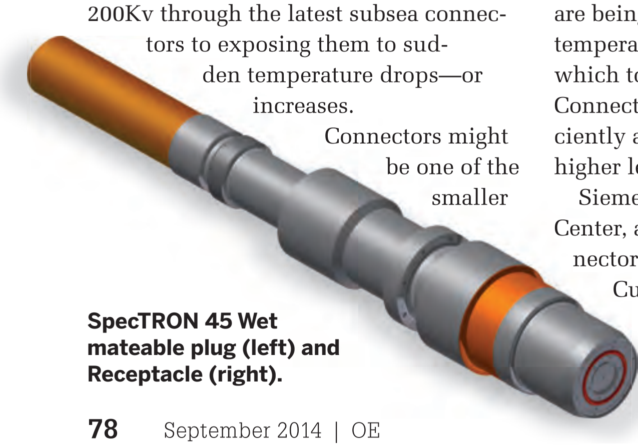
Connectors might be one of the smaller components both in the subsea factory of the future or in enabling technologies such as subsea power grids, but, along with harnesses, they are also a crucial component, responsible for delivering reliable, high voltage power to multiple consumers on the seafloor.

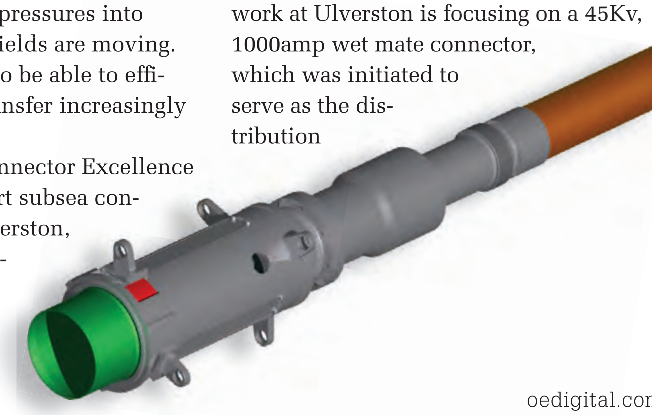
The number of consumers, and the power they require, is increasing. Subsea boosting and separation technologies are increasing in use, as is subsea metering. Subsea gas compression is coming closer to commercial reality, more and more electrical submersible pumps are being used, and more complex wells are requiring instrumentation.

The challenges today's connectors face are being able to operate at the depths, temperatures, and the pressures into which today's subsea fields are moving. Connectors also need to be able to efficiently and reliably transfer increasingly higher levels of power.

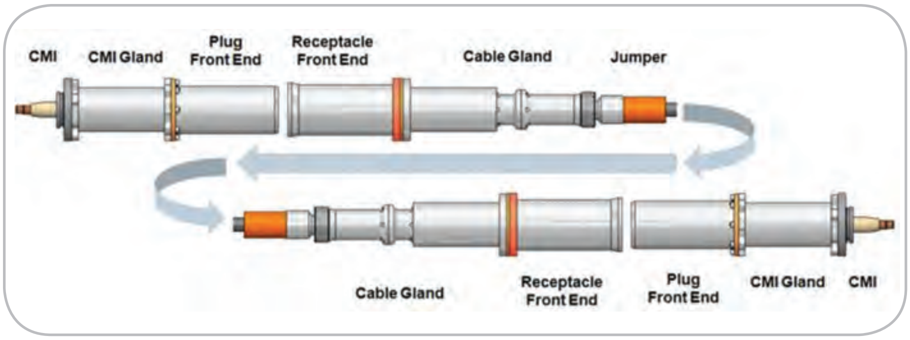
Siemens' Subsea Connector Excellence Center, a state-of-the-art subsea connector facility in Ulverston, Cumbria, is creating and then "torturing" the latest connectors for such environments. Siemens' goal is to create a subsea power grid (SPG)—a complete power supply and distribution system for large-scale subsea processing or for what Statoil calls the "subsea factory," (OE: April 2014), complete with subsea mateable connectors. Siemens is currently in the final stages of the five-year SPG program which will be completed next year, at which time Siemens will be ready for a full-scale subsea pilot project. The system, and all its components, is being qualified to work in 3000m water depth, at up to 200km step out distance.

In 2012, former Tronic, a leading subsea connector specialist in the industry, was acquired. Since then, development work at Ulverston is focusing on a 45Kv, 1000amp wet mate connector, which was initiated to serve as the distribution

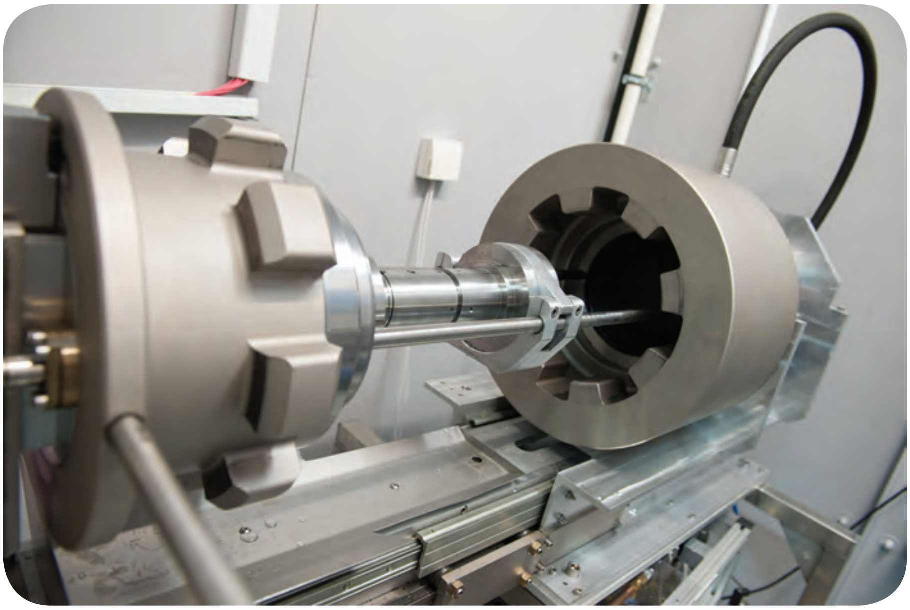




SpecTRON 45 Wet mateable plug (left) and Receptacle (right).



Typical phase configuration.



A pressure test vessel at the Ulverston facility.

connector for the SPG and it will be the highest voltage connector worked on. The highest power rated wet mate connector commercially available, and being used, at the moment, is a 10Kv connector, at 400amp, says Phil Ashley, head of Siemens Subsea Connectors. "We do have a 60kV dry mate connector developed, but it has never been used in anger."

The core mechanical design, invented by the founder of Tronic, bought by Siemens in 2012, is a cone-shaped connection spring, with dual barriers, which enables subsea wet-mate connections in a controlled environment.

"We are taking a step up to produce the world's highest rated subsea matable connector," says Mike Marklove, director of technology and innovation at Siemens Subsea. "It means a step-change in materials, the connector has to become bigger, to be able to take the forces that comes with those ratings. It also represents challenges within sealing—we need new inventions in sealing to overcome some of the issues we have in sealing this up."

The 45Kv connector will be rated to 3000m water depth, for use in the SPG and the connector qualification program is expected to run for 1.5 years.

Qualification is being done according to (Statoil Spec) TR2313—Subsea Electrical High Voltage Connector Assemblies. It will be tested at 200Kv during qualification.

Siemens Subsea's Tronic connectors are designed to be modular, which means parts are standardized and can be ordered to create a component which meets its application needs. This includes a common module interface (CMI), and common module glands, with the addition of wet mate receptacles or plugs, with gender choice.

The longest modular configuration for a single phase 45kv connector will be about 1.5m, comprising a CMI, plug front end, receptacle front end, CMI gland, cable gland, and jumper.

"We are aiming to have the connector available by 2015 and finish long-term qualification testing by 2017," Ashley says.

The connector work is being done at Siemens' Subsea Connector Excellence Center at Ulverston. Testing, including materials and corrosion testing, high voltage and environmental testing, shock and vibration testing, high pressure testing, and gas testing is carried out and can take up to two years to qualify a connector.

An environmental chamber is used to put materials through temperature gradients, as well as humidity. Temperature tests can range between -40°C and +90°C. Pressure testing can be carried out up to 30,000psi at Ulverston, including circulated sand and silt and circulated in the pressure chambers, for connection tests.

For critical component testing, HV trials at 104Kv are run for four hours, partial discharge-free up to 90Kv, with no breakdown at 200Kv, and components are X-rayed for faults.

For qualification, about 150 connection cycles are tested. On Siemens Subsea's Tronic DigiTRON, 1000 cycles were performed, without the product failing. A typical connector is likely to see no more than 50 connection cycles, Marklove says.

In comparison, for a standard factory acceptance test, a 10,000Kv rated harness—an electrical jumper/flying lead—would be put through a 15,000Kv test. Measurements test for current leakage, to make sure there is minimal discharge, to assess the insulation material performance.

The boundaries at which these components need to perform will continue to be pushed out, and Marklove says more new technology will need to be developed.

"For longer step-out distances you need to compensate for the effects of transmitting over a long cable. There are various options being considered," he says. "DC is an alternative, but it does introduce new issues around power electronics, which are not powerful enough, yet. DC also represents different challenges to AC, with how it effects materials. We are working on DC testing a product at high voltage, getting us technology-ready for if and when DC gets considered seriously."

Materials technology has already come a long way, but it has further to go, he says. "We use a wide variety of materials, thermoplastics for insulation, oils and fluids, elastomers, exotic alloys. Over the years, every single material has improved to increase performance."

Giving an example, Marklove says 254 SMO stainless steel was quite commonly used. "We have now evolved to a much higher grade super duplex stainless steel. This has been by a need

Based in Ulverston, Cumbria, in England, former Tronic is one of the core pieces of the subsea power grid puzzle for Siemens. It was founded in 1979, by John Alcock, who saw an opportunity to create a reliable topside to remote vehicle connection.

Mike Marklove says the main innovation came in 1987, when the company invented the first controlled environment connector, enabling wet mate subsea connections, followed by a miniaturized version in 1991, which helped to open the market to Tronic. In 1992-5 the first power and instrumentation connectors were produced, followed by DigiTRON, in 2000, Ethernet and high voltage connectors in 2-11, and DigiTRON+ in 2012.

DigiTRON was a re-engineered miniature CE connector focused on modularity. DigiTRON+ was the firm's first low voltage connector for 4000m water depth.

Tronic was bought by Expro in 1998 and then by Siemens in 2012. A new connector research and development facility opened in 2010, today known as the Siemens Subsea Connector Excellence Center. ■

for reliability. Also, in the 17 years I have worked in the industry, there has been a progressive tightening of the materials science and performance requirements. There was quite a wide range of stainless steels approved for use in the 1980s, now it has tightened and there are only a few. Even then, we need specific grades, manufactured using specific processes, and certified in a particular way, if they do not have cathodic protection and are to be subsea qualified. And that's been industry driven."

Siemens also develops materials directly with suppliers, if, for example, they see a material aging more than they would like. The next step in technology will be higher temperatures, he suggests.

"Some wells being drilled are now above 200°C and that puts high demand on electrical insulation. It cannot be metallic, so we are having to use insulating materials such as plastics, rubbers and oils. We are developing new grades of all of those to operate at 180-200°C, just to meet requirements for wells being explored now."

But, under Siemens' Corporate Technology division, Siemens Subsea is also looking at glass to metal sealing technologies, to help meet some of the higher temperature applications.

"The problem with plastic is that, at some point, it melts, and you can have creep, and you cannot afford for that to happen," Marklove says. "We either need new plastics, which can cope with those conditions, and there are developments to do that. But, ultimately, there will be a ceiling at which plastics will no longer suffice. Then you could move to something like glass. But unlike plastic, it is inherently brittle, so you need to understand the limitations and strengths."

Siemens Subsea is also looking at using fiber optics, driven by the longer step-outs for development projects. Tronic had developed an Ethernet connector to increase band width, the next natural step is to offer high performance fiber optic connectors, Marklove says. Traditionally, fiber optic cables are connected using fusion splicing. But, in the underwater environment, this is not possible. So Siemens Subsea is developing a way to connect the two terminations, "in a repeatable and reliable way," he says. The challenge is like "connecting two hairs in perfect alignment," he says. "We are about 18 months away. Achieving it will enable the customer to think seriously about using fiber optics for communications lines," using a product that is light and compact. OE

RoboSub: International AUV competition

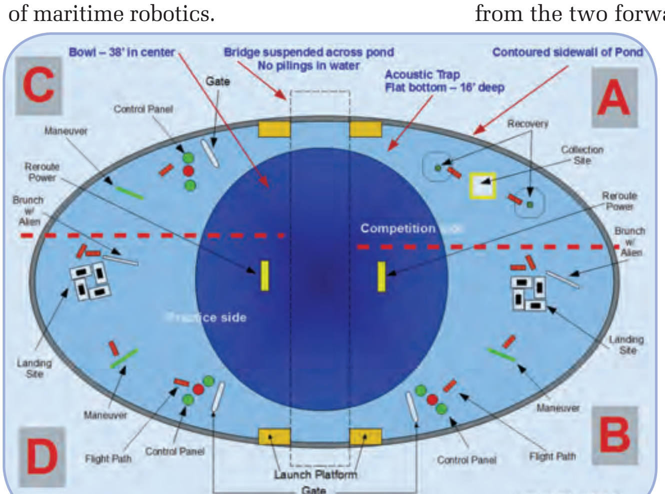

Anechoic pool during competition.

by Nina Rach

Thirty-eight student-led teams from 12 countries competed at the 17th annual RoboSub competition, 28 July-3 August, held at the US Navy's SSC Pacific TRANSDEC Anechoic pool, Point Loma, California. The event is co-sponsored by the Association for Unmanned Vehicle Systems International (AUVSI) Foundation and the US Office of Naval Research (ONR).

The goal of the competition is to advance the development of autonomous underwater vehicles (AUVs) by challenging a new generation of engineers to perform realistic missions in an underwater environment.

RoboSub fosters ties between young engineers and organizations developing AUV technologies. The sponsors say the event has been tremendously successful in recruiting students into the high-tech field of maritime robotics.



Layout of pool.

CUAUV

The Cornell University Autonomous Underwater Vehicle (CUAUV) team designs and builds AUVs for competition and research. The undergraduate team's primary annual objective is the international RoboSub competition, and CUAUV has placed in the top ten every year and has won the overall competition six times, including 2013, with their vehicle *Ragnarök*, and this year, with AUV *Gemini*. Rising senior Melissa Hamada contributed photos from this year's competition.

The CUAUV team has four subteams, each responsible for a specific vehicle system to promote individual accountability, and three faculty advisors: Alan Zehnder, Graeme Bailey, and Bruce Land.

Adlink provided an "Express-HL" computer-on-module (COM) to power the autonomous sub using a stripped-down version of Debian "Wheezy" Linux.

CUAUV Mechatronics Team Leader Moonyoung (Mark) Lee studies electrical and computer engineering, and told OE: "RoboSub always offers a vast variety of challenges. Aside from the rigorous obstacle course itself, the competition demands adaptability from both the teams and the AUVs. For example, our vehicle navigation algorithm is heavily dependent on the vision data it receives from the two forward machine vision cameras. Because our vehicle was mainly tested in an indoor pool, which provides constant lighting with minimal ripples, the outdoor TRANSDEC facility proves to be a difficult due to San Diego's varying sunlight and strong breeze that causes ripples on the surface of the pool.


Gemini AUV, built by Cornell University team. Photo from CUAUV's Melissa Hamada.

"Despite our success in the past two years, this year's competition was by no means a smooth sail. We had our fair share of obstacles to overcome when many points of the vehicle started failing after we arrived in San Diego. Our computer failed to reboot due to hard disk corruption, our custom motor controller board blew FETs, and our enclosure constantly flooded. Such challenges required us to come up with new design solution on the fly. For example, since we couldn't keep the water from leaking into our valve enclosure, we actively filled the enclosure with mineral oil to prevent further leaking and decoupling of electrical components. It's the exhilarating moments when we resolve and overcome real challenges with building an AUV as a team that attract us to participate in RoboSub every year."

To help inspire young engineers and scientists, CUAUV is also engaged in local outreach. In March, they co-hosted a Boy Scout Robotics Workshop on campus, and 17 scouts built and tested their own SeaPerch submarines.

CUAUV team member Corey Chang told OE, "I want to give a huge thank you to our sponsors, alumni, advisors, friends and family. They've always been our biggest supporters and one of the main reasons why we can do this year after year."

RoboSub schedule

Teams were required to submit a video introducing the team and their approach to the event; the video is scored and used online and on-site during the webcast on the final competition day. They are also required to write and submit a journal paper describing the design of their

Results

1st Place—Cornell University
2nd Place—University of Florida
3rd Place—ETS (École Technologie Supérieure)
4th Place—Far Eastern Federal University
5th Place—National Univ. of Singapore

Judges Awards

Best New Entry — California Institute of Technology
Best Branding — McGill University
International Collaboration — Team Bangalore Robotics
Mayor's Cup for Outreach — ETS

OE congratulates all the competitors!

vehicle and the rationale behind their design choices.

Orientation and check-in took place on 28 June, followed by three practice days. Static judging began on 31 July, during which judges evaluated each vehicle for technical merit, safety, and craftsmanship. Teams exhibited posters describing their vehicles during this static display period. The semi-final competition was on 1-2 August, followed by live streaming of the final competition on 3 August.

Technical specs

For the RoboSub competition, an AUV must fit within a 6ft x 3ft x 3ft box (1.83m x 0.91m x 0.91m), and weigh less than 125lb (56.7kg); ideally less than 84lb (38kg). For AUVs between 84lb-125lb, a point penalty was assessed. For AUVs less than 84lb, bonus points were added. Extra bonus points were given to AUVs weighing less than 48.5lb (<22kg).

All vehicles must be battery powered and all batteries must be sealed to reduce the hazard from acid or caustic electrolytes. The open circuit voltage of any battery (or battery system) in a vehicle may not exceed 60 VDC.

The competition uses Teledyne Benthos ALP-365 pingers that can be set at 25-40 kHz in 0.5kHz increments.

Mission

The goal of the mission is for an AUV to demonstrate its autonomy by completing an underwater TRANSDEC 17 moon mission. The vehicle must be able to stop and interact with the control panel (dock/interact with buoys), complete a maneuvering task (pass over/around an obstacle), reroute power (manipulate pegs on a board), choose a landing site (drop markers), invite aliens to brunch (fire torpedoes through a cutout), and collect samples from the moon (find a pinger, grab an object and move/release the object). Each team has 20 minutes of competition time, including 5 min. preparation out of the water and 15 min. performance in the water.

During the competition, the vehicle must operate autonomously, with no control, guidance, or communication from a person or any off-board computer. The vehicle and any parts connected to the vehicle must submerge and remain submerged. No item may break the surface or be left floating while the vehicle is underway.

Direction

The Technical Director, responsible for rules, procedures, and specifications, is Dr. David Novick, from Sandia National Labs, Albuquerque, New Mexico.

Executive Director Daryl Davidson, responsible for coordination, said the teams have "got to be able to raise money; they've got to get logistics in place to get here, to ship their vehicles here. Then once they get here, they've got to operate and make sure they've got their support network…to be able to say that if something breaks or goes wrong– which it always does– 'we can fix that.'"

Susan Nelson, Executive Director of SeaPerch, the US Navy's signature K-12 Outreach program, now managed by the AUVSI Foundation, told U-T San Diego TV poolside during the competition, that China graduates 1 million engineers/year and India graduates half a million. "Here in the US, we graduate less than 70,000 engineers/year. In 10 years' time, that will not be enough engineers to fill the pipeline." OE

2014 RoboSub team entrants

- **Ain Shams University (ASU Racing Team):** Cairo, Egypt
- **Amador Valley High School:** Pleasanton, CA
- **California Institute of Technology:** Pasadena, CA
- **California State Polytechnic University:** Pomona, CA
- **Carl Hayden High School (Falcon Robotics):** Phoenix, Arizona
- **Cornell University:** Ithaca, New York
- **Daytona Beach Homeschoolers (S.S. Minnow):** Palm Coast, FL
- **Delhi Technological University:** Delhi, India
- **Embry-Riddle Aeronautical University:** Daytona Beach, FL
- **Far Eastern Federal University:** Vladivostok, Russian Federation
- **Harbin Engineering University:** Harbin, China
- **Indian Institute of Technology Bombay:** Mumbai, India
- **Indian Institute of Technology Madras:** Chennai, India
- **Istanbul Technical University (AUVTECH):** Istanbul, Turkey
- **Kasetsart University:** Bangkok, Thailand
- **Kyushu Institute of Technology:** Fukuoka, Japan
- **Mälardalen University:** Västerås, Sweden
- **McGill University (McGill Robotics):** Montreal, Canada
- **Montana State University:** Bozeman, Montana
- **National University of Singapore (Team Bumblebee):** Singapore
- **Nautilus:** Temecula, CA
- **Prairie View A&M University:** Prairie View, TX
- **Reykjavik University:** Reykjavik, Iceland
- **RoboEgypt Electronic Research Institute:** Alexandria, Egypt
- **RoboSub Club of the Palouse:**
  - Washington State Univ., Pullman, WA
  - University of Idaho, Moscow, Idaho
- **San Diego City College:** San Diego, CA
- **San Diego Robotics 101:** San Diego, CA
- **San Diego State Univ. Mechatronics Club:** San Diego, CA
- **Southern Polytechnic State University Autonomous Underwater Vehicle Team:** Marietta, Georgia
- **St. George's School:** Vancouver, Canada
- **Team BangaloreRobotics:** Bangalore, India
- **Team SONIA - École de Technologie Supérieure (ETS):** Montreal, Canada
- **University of Alberta (ARVP):** Edmonton, Canada
- **University of Arizona (AUVUA):** Tucson, Arizona
- **University of Colorado Boulder:** Boulder, Colorado
- **University of Florida:** Gainesville, Florida
- **University of Maryland:** College Park, MD
- **University of Southern CA:** Los Angeles, CA
- **University of Toronto:** Toronto, Canada

Innovating field joint insulation

Dow Chemical discusses the development of non-mercury-catalyzed field joint insulation material for subsea pipelines

By Amber Stephenson, Dave Parker, Mike Huspek, Kamesh Vyakaranam, and Mark Whelan.

For decades, offshore applicators of field joint insulation materials relied on the high performance characteristics of formulations containing mercury (Hg) catalysts. Among the more critical performance characteristics of these Hg-catalyzed field joint materials were outstanding adhesion to different substrates, outstanding hydrothermal aging, robust processability, fast-build of compressive strength, and other mechanical properties.

Pipe sections are connected by field joints in a multi-step process where the slowest step determines productivity—so minimizing cycle time for application of the field joint coatings is critical. Legacy Hg-catalyzed field joint coatings typically exhibited rapid compressive strength buildup, which optimized cycle times to enable high productivity in assembling pipelines.

When the use of mercury catalysts was phased out several years ago, the industry responded with a variety of field joint formulations manufactured using non-Hg catalysts. While these first-generation, non-Hg field joint formulations worked well enough, none of them quite matched the performance of legacy Hg products. The most elusive property was rapid development of compressive strength and other mechanical properties after application, [such as tensile and tear strength]—which can potentially slow the onsite assembly of pipelines significantly.

Critical customer requirements

Dow Oil, Gas & Mining set out to develop a second-generation, non-mercury catalyzed field joint coating, that matched or exceeded the performance of our own legacy formulation—HYPERLAST FJ589 Polyurethane. The first step was to formally survey customers across the offshore value chain, including applicators, lay contractors, and offshore owners/operators. This gave us four primary performance targets for a second generation, non-mercury catalyzed field joint coating:

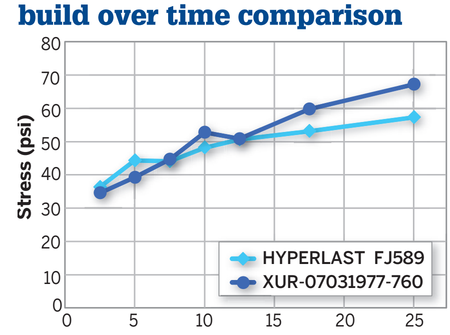
- Easy processing – applicators asked us to widen the mixing tolerances if possible, up from the standard ±1% by weight, to make the formulation more forgiving than all previous field joint coatings.
- Faster build of compressive strength – all parties wanted a faster build of mechanical properties contributing to more efficient onsite pipeline assembly.
- Strong adhesion to various substrates – primarily the fusion-bonded epoxy (FBE) anti-corrosion coatings and the glass syntactic polyurethane (GSPU) "parent" coatings on the pipe sections.
- Mechanical and aging performance equivalent to legacy Hg-catalyzed systems – subsea flow assurance coatings must withstand thousands of hours of service.

Laboratory screening and testing

Dow's research and development team initiated an experimental program to deliver against these customer requirements. Starting in April of 2012, a series of different catalysts, chain extenders, polyols, and isocyanates were screened at laboratory scale in Freeport, Texas, using a multi-variable design of experiments to find formulations that matched or exceeded the cure profile, property build and final performance characteristics of the legacy Hg-catalyzed field joint coating.

Formulations were first screened to ensure that the cured elastomer provided the requisite thermal and mechanical properties. Cup calorimetry was then used to optimize catalyst type and loading, to provide the desired cure time and

Figure 1: Compressive strength build over time comparison



profile. Formulations showing a satisfactory cure profile and final mechanical properties were then screened for property development using reactive rheometry and transient compression testing.

The screening process narrowed our candidates down to five formulations that showed the most promise. These formulations underwent further lab-scale testing measure the rate of development of rheological and mechanical properties. The three most promising formulations were selected for evaluation at the pilot scale, where a plural component polyurethane machine was used to injection mold and bond X760E to a two inch thick coating of Dow HYPERLAST DW512/300E GSPU on a two inch diameter pipe.

Pilot-scale testing

Pilot-scale testing was carried out at Dow's application center in Birch Vale, UK. Full-sized, industry standard equipment was used to produce, mix and apply the test materials, as would happen in the field. These larger samples were then subjected to the same series of tests performed in the laboratory, including adhesion, cure profile, compressive strength, hardness, and thermal conductivity. Based on this testing, XUR-07031977-760 was selected as the best performing of the three development formulations.

Phase one mission accomplished

Just one year after laboratory testing started, machine-scale testing and lab-scale aging studies confirmed that XUR-07031977-760 is a two-component, non-mercury, catalyzed field joint insulation material that matches or exceeds the important properties of the legacy Hg-catalyzed product. Most importantly, XUR-07031977-760 cures rapidly after the field-joint mold is filled, and it builds compressive strength quickly – comparable to the legacy Hg-catalyzed material (Figure 1).

Final thermal and mechanical properties of XUR-07031977-760 also closely match the Hg-catalyzed legacy material, as shown in Figure 2.

When compared to HYPERLAST FJ589, XUR-07031977-760 shows excellent mechanical integrity during hydrothermal aging, shown in Figures 3 and 4. XUR-07031977-760 and HYPERLAST FJ589 were aged in simulated seawater at 85°C, dried, and tested at 23°C. XUR-07031977-760 demonstrated excellent adhesion to both GSPU parent coatings and FBE substrates. Furthermore, machine-scale testing confirmed that the two-component XUR-760 field joint insulation material is mouldable onto anti-corrosion FBE coatings at temperatures up to 120°C. Finally, processing ratios were doubled from ±1% by weight to ±2% using compact, mobile, standard industry equipment.

Ready for customer evaluation

Based on our machine-scale test results, XUR-07031977-760, now named HYPERLAST FJ 760E, was invited to participate in pre-qualification testing on a major project in the Gulf of Mexico. **OE**

Figure 2: Thermal property comparison

Property	Measure	XUR-07031977-760	HYPERLAST™ FJ589
Hardness	Shore A	86 – 94	86 – 92
Tensile strength	MPa	≥10	12
Elongation at break	%	≥100	220
Nicked crescent tear strength	N/mm	≥30	45
Density	Kg/m3	1050 – 1165	1100 – 1150
Taber Abrasion	mg loss	≤250	≤250
Thermal conductivity	W/m·K	≤0.195	≤0.195
Specific heat capacity	J / g·K	1.4 – 1.7	~1.5 – ~1.9

NOTE: During customer Interviews, applicators requested minimal values on technical charts rather than typical values. Values shown for HYPERLAST FJ589 are typical or average values. Values shown for XUR-07031977-760 are minimum specifications.

Figure 3: Tensile strength comparison after 4,000 hours

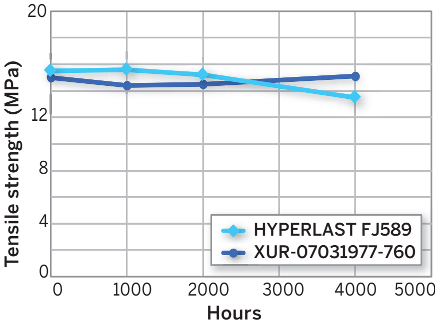
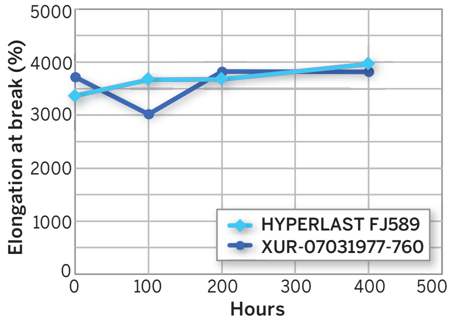


Figure 4: Elongation at break comparison at 4000hrs



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***Dave Parker** is the offshore coatings specialist at Dow Oil, Gas & Mining.*

***Mike Huspek** is a global account manager at Dow Oil, Gas & Mining.*

***Kamesh Vyakaranam**, is a polyurethane associate scientist at The Dow Chemical Company. For the past six years, he has been working in epoxy and polyurethanes product research. His current focus is on oil and gas flow assurance research.*

***Mark Whelan** is a technologist leader at Dow Oil, Gas & Mining.*

How to break a pipeline

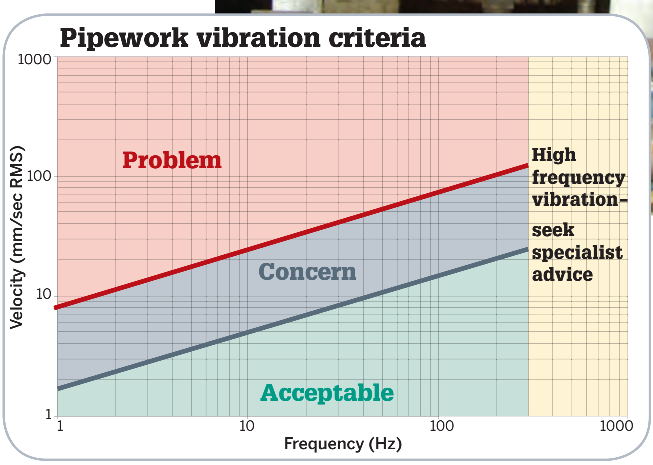
An alternative view of pipework vibration management by Neil Parkinson, technical director at AV Technology.

Complex offshore pipework.
Images from AV Technology

Some incidents are guaranteed to make headlines, never more so than at control of major accident hazards regulations and offshore installations safety case regulations sites, which have the ability to turn even the smallest incidents into disasters.

The UK Health & Safety Executive (HSE) reports that more than 20% of offshore hydrocarbon leaks are caused by piping vibration and fatigue.

In 2012, 431 serious incidents were reported, of which nearly 30% involved hydrocarbon release. More than 50 were classed as major, and 33 in total were attributed to pipework failure. Vibration-induced fatigue clearly represents a serious risk category, but how exactly were these pipelines broken?



Energy institute chart T7-2.

If asked to break a paperclip, most people would probably bend it back and forth, or perhaps rub it against another surface until it wore through. One might pull it until it snaps, or use tools to cut it through. Although pipework is far larger and more complex, individual molecules of steel behave the same way in a pipeline as they do in a paperclip – meaning that pipelines can fail as easily as a paperclip can be broken. Bending a paperclip back and forth has the same effect as low-cycle fatigue in pipework, leading to vibration fatigue over time. Rubbing a paperclip to wear it down through friction is equivalent to fretting in pipework. Static overloads and pressure surges in pipelines are similar to pulling a paperclip until it snaps, while both can be subjected to mechanical damage.

Back-and-forth vibration of pipework is one of the most common causes of failure. Mechanical excitation, flow-induced pulsation, changes in surge or momentum, acoustic-induced vibration, or cavitation and flashing are all common vibration-induced failure mechanisms. But how much vibration is significant?

The Energy Institute (EI) publication "Guidelines for the Avoidance of Vibration Induced Fatigue Failure in Process Pipework"* contains an assessment chart to determine whether pipes are likely to suffer fatigue, based on frequency and velocity of movement – and the levels for concern might be surprising.

In fact, problematic vibration may not even be visible to the human eye as even at dangerous levels, prolonged movements of only 0.5mm can produce fatigue failure. For EI assessments, pipework movement must be measured in units of velocity at different frequencies. At 25Hz (1500rpm) for example, pipework vibrating at 8mm/s would place it in the "concern" range, while anything above 40mm/s is a definite problem.

The EI guidelines cover proactive and reactive assessments, and aim to ensure compliance with statutory duty as well as improving safety and reliability, reducing liability from leakage, and minimising plant downtime. Proactive assessments can be used to routinely evaluate all existing pipework on site to ensure that best practice has been adopted and to identify possible areas of concern, as well as assessing the feasibility of planned extensions to pipework. Reactive assessments follow, to further investigate known vibration issues or troubleshoot actual

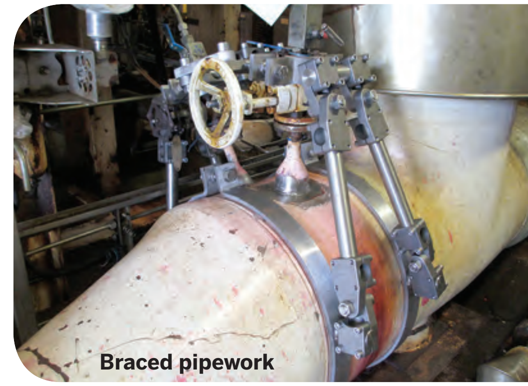
failures within both mainline pipework and small bore connections (SBC).

Although vibration amplitudes are barely visible and velocities are relatively low, the cumulative effect over time can be significant – especially as problems can go unnoticed until a dangerous failure suddenly occurs. However, as vibration is well understood, fatigue failures are easily preventable with a range of retrofit solutions available for a host of applications.

As the solution to vibration depends on the excitation mechanism, thorough inspection must be undertaken before determining the corrective action. There are six key phases to achieving pipework vibration assessments in line with requirements of the EI guidelines:

- Qualitative assessment
- Visual assessment
- Basic vibration monitoring
- Specialist measurement techniques
- Specialist predictive techniques
- Corrective actions

The qualitative assessment phase involves calculating the likelihood of a vibration-induced fatigue issue, taking into account fluid energy, flow velocities



Braced pipework

and cyclic operation as well as the construction quality of infrastructure. This may include assessment of process machinery and types of valves as well as supporting structures. It also assesses the chance of flashing or cavitation, and includes a calculation process for scoring likely excitation factors – which are combined with conditional and operational factors to predict the likelihood of failure for each pipe branch.

Visual inspection is a quick and effective method of identifying potential areas for concern and flagging up areas for improvement relating to pipe infrastructure. This may include installing more effective pipe supports or replacing worn or damaged supports, proper bracing of SBCs, avoiding fretting and poor geometry, and allowing for thermal expansion of tubing.

In the basic piping vibration measurement phase, specialist engineers will first use a single axis accelerometer connected to a portable data collector to take initial vibration levels, ranging from 1Hz up to 300Hz. These measurements are presented as vibration amplitude versus frequency and enable the vibration to be classified as acceptable, concern or problem, based on EI guidelines.

If, following the basic measurement phase, vibration is found to be at concern or problem level, or for pipework with a higher frequency vibration of more than 300Hz, the next phase is based on specialist measurement techniques. A variety of more in-depth tests are deployed depending on circumstances, including: dynamic strain measurement and fatigue analysis; experimental modal analysis; operating deflection shape analysis; and dynamic pressure (pulsation) measurement. Engineers also have a choice of specialist predictive techniques, applying sophisticated modeling tools and multi-channel instrumentation systems to assess in more detail the dynamics of specific pipelines throughout their lifecycles. Specialist predictive techniques include finite element analysis, computational fluid dynamics, and pulsation


Visco-elastic damper

and surge analysis.

The final stage of any pipework assessment is to recommend corrective actions to reduce vibration levels and the likelihood of future vibration-induced fatigue failures. Although one solution to pipework fatigue is to remove the excitation mechanism altogether, this may be quite intrusive, requiring modification of the process conditions or the pipework geometry. As this disrupts production and may involve temporary shut-down, generally a non-intrusive retrofit solution is preferred as a means of providing increased resistance to vibration.

Some corrective actions can be very straightforward. For example, it is very common for pipelines to rest on supports without any additional protection against fretting damage, in which case a secondary "doubler" plate can be installed for additional support and strength without modifying any processes. However, unsuccessful or incomplete attempts at supporting pipework can result in no reduction of vibration or even an exacerbation of the problem. SBCs are frequently braced to the deck or nearby structures, for example, but to adequately counteract vibration they should in fact be braced back to the parent pipe. Bracing solutions can also be fitted in the wrong place, supporting the pipe itself rather than the main mass such as a valve, while poorly maintained bracing can loosen and return the pipework to its original level of excitation.

Another common mistake is to brace the pipework in only one plane, where vibration can cause movement in several directions. The most effective bracing system will be able to accommodate any geometric alignment of SBC, with a stiff truss design to resist movement on any plane. Similarly, for mainline pipes, visco-elastic dampers are effective in all degrees of freedom as they provide dynamic damping movement in all directions and over a wide frequency range. Another option for mainline pipework is a dynamic vibration absorber, which when tuned to the same frequency and direction as the problem vibration, will resonate to the same level out-of-phase in order to cancel it out. This is especially useful if there is no steelwork nearby on which to attach a visco-elastic damper.

Although pipework vibration can be difficult to visually detect, knowledge of EI Guidelines and safe limits as well as an understanding of the six assessment phases and the most effective corrective actions can prevent the kind of vibration-induced pipework fatigue which can break a pipeline and hit the headlines. **OE**

* 2nd edition 2008, current edition. ISBN 978 0 85293 453 1.

***Neil Parkinson** is a chartered engineer with more than 30 years' experience in vibration management and structural asset integrity. He has held the position of technical director for AV Technology since 1993. He holds a BSc in engineering science from the University of Warwick and was elected a fellow of the Institute of mechanical engineering in 2011.*

Lebanon languishes

As its bid licensing round is delayed again, will Lebanon's offshore industry ever take off? Sarah Parker Musarra analyzes the current situation and explores the history of the troubled country.

In April, Lebanon once again delayed its offshore licensing round to August for the fourth – and supposedly final – time. Beyond the normal political posturing that can often complicate frontier country's initial offshore bid rounds, Lebanon's list of issues to overcome was long and exceedingly complicated: political gridlock preventing necessary decrees from being signed; maritime border disputes with one neighbor, Israel; violence caused by the wars of another neighbor, Syria.

Najib Mikati's government resigned during April 2013, and Lebanese politics were at a standstill for the better part of the next year. The country was unable to build a government for 10 months. The new government had only been in place for a few months at the time the fourth delay was announced, and the necessary decrees could not be finalized during the stalemate. Lebanon's Energy and Water Minister Arthur Nazarian told Reuters on 7 April 2014 that the decrees in question, the tender protocol and the model exploration and production agreement (EPA), would be pushed through without further delay.

"Today [7 April 2014], I signed a memo that probably after four months' time we will be able to receive bids and close the bid round, which I think is a reasonable time according to what I'm informed by the people concerned," he told Reuters in an interview.

Despite these promises and the Lebanese government's best-laid plans, delays continued. On 8 August, Nazarian extended the deadline to submit bids a fifth time, this time with a somewhat blurred deadline – a period not to exceed six months after the adoption of the two decrees.

Pre-qualified right-holding operators

The Lebanese Petroleum Administration evaluated and selected 12 right-holders operators and 34 right-holders non-operators from the 52 companies that submitted pre-qualification applications. The administration said the companies participating represented 25 countries. The 12 right-holders operators, selected from 16, are:

Anadarko Petroleum
Chevron
Eni
ExxonMobil
Inpex
Maersk
Petrobras
Petronas
Repsol
Shell
Statoil
Total

Resources at stake

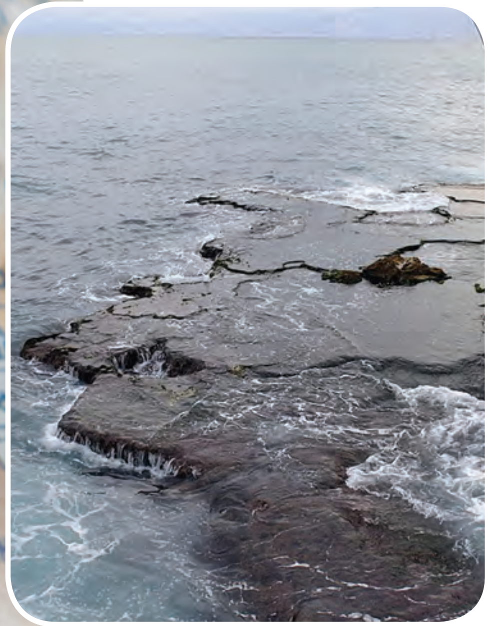
Bidding was originally opened on 2 May 2013 for 10 exploration blocks ranging from about 1400-2300sq km. Analyst GlobalData says that such a range is in keeping with frontier countries as they try to attract companies. Lebanon's Ministry of Energy and Water selected 12 right-holders operators and 34 right-holders non-operators were selected as pre-qualified in April 2013.

According to regulating body Lebanon Petroleum Administration, its evaluation methodology on the right-holdiers operators was based on four areas of criteria: legal, financial, technical, and HSEQ. Within these parameters, the companies must:

- Be joint stock companies "conducting petroleum activities"
- Have assets totaling US$10 billion
- Operate a least one petroleum development in more than 500m of water
- Have HSEQ policy statements and have established and implemented HSEQ management services

The Administration says that there must be three rights-holders at all times, and that explorations activities must be completed within a five-year period, divided into periods of three years and two years. This exploration phase can be extended up to 10 years with the approval of the Council of Ministers. Should a find become commercial, the rights-holders must pay the State royalties equivalent to 4% of the gas produced, and a percentage varying between 5% and 12% of the oil produced. A percentage, to be determined by bidding, of the oil and gas would also be allocated to the right-holders to reimburse their costs. The Administration explains that remaining oil and gas "is split between the State and the right-holders in proportions determined by bidding under a formula pursuant to which the State's share increases after the right-holders have recovered their investment."

The US Geological Survey (USGS) estimated in 2012 that Lebanon's average total undiscovered, technically-recoverable resources to be 320MMboe, and less than 1Tcf of gas. However, on 30 October 2013 the Ministry of Energy and Water Resources triumphantly announced that recent seismic performed vaulted its estimated offshore reserves up to 95.9Tcf of gas and 865MMbo with a probability



The Lebanese capital of Beirut, left, and Sidon (or Saïda), right. Block seven is offshore the two cities, with Sidon on the boundary of blocks seven and 10. Images from the Lebanon Ministry of Tourism.

of 50% – and that was only for about 45% of its waters. It was a remarkable departure from the USGS' more modest estimates. However, that news was tempered months later in April 2014 by an admission from then-Energy and Water Minister Gebran Bassil to Reuters that despite the fact that no companies had formally withdrawn, the delays in the bid round had made some "hesitant," and that there were "questions being raised." Reuters outed Eni and Statoil in particular to be rethinking their interest in the country.

Michael Wachtel is a partner in Clyde & Co.'s Corporate Energy Group and is the head of its upstream oil and gas practice. Having worked in the Middle East for a number of years over a 20-year career in oil and gas, the region is now one of his regions of specialization. He acknowledges the rumors without comment, but admits that the two majors could be up to some posturing of their own.

"Companies may in fact indicate a loss of interest when they are just playing a game. Even if there were rumors out there, they may have put them out themselves to gain interest. I've been in the oil business for many years, and what you see is not always what you get," Wachtel says.

Political divides

Even after Lebanon put a government into place, Will Scargill, upstream fiscal analyst for GlobalData, describes its issues behind cabinet doors as "deep political cleavages."

Lebanon is directly and extremely impacted by Syria's war. Lebanon has two main political parties, or blocks, the March 8 Alliance and the March 14 Alliance. These blocks are characterized by their pro-Syrian regime and anti-Syrian regime stances, respectively, as well as by sectarian affiliations, Scargill explains.

"The spillover of the Syrian conflict has hardened these divisions," he says. "This led to the repeated delay of the offshore licensing round, as a government was required to approve two crucial decrees, delineating the blocks and approving the tender protocol and model [EPA].

"Although a coalition government including both political blocks was formed in February and won a vote of confidence in March, the decrees have still not been signed. This has meant further postponements."

Gustavo Bianchotti, GlobalData's senior upstream analyst for Europe, Middle East, and Africa, agrees that "the main problem is political."

The great pro- or anti-Syrian regime issue dividing the country is reflected in the group of six that constitutes the Lebanese Petroleum Administration. There are six members in the group, each representing one of Lebanon's ethnic groups to form a consensus.

"Ethnically, there are six groups. Politically, there are two. Each want to control the oil and gas resources because studies show there will be a huge profit. Whoever controls the resources will have more political hold," Bianchotti says.

However, Wachtel, says the system is not functioning as planned.

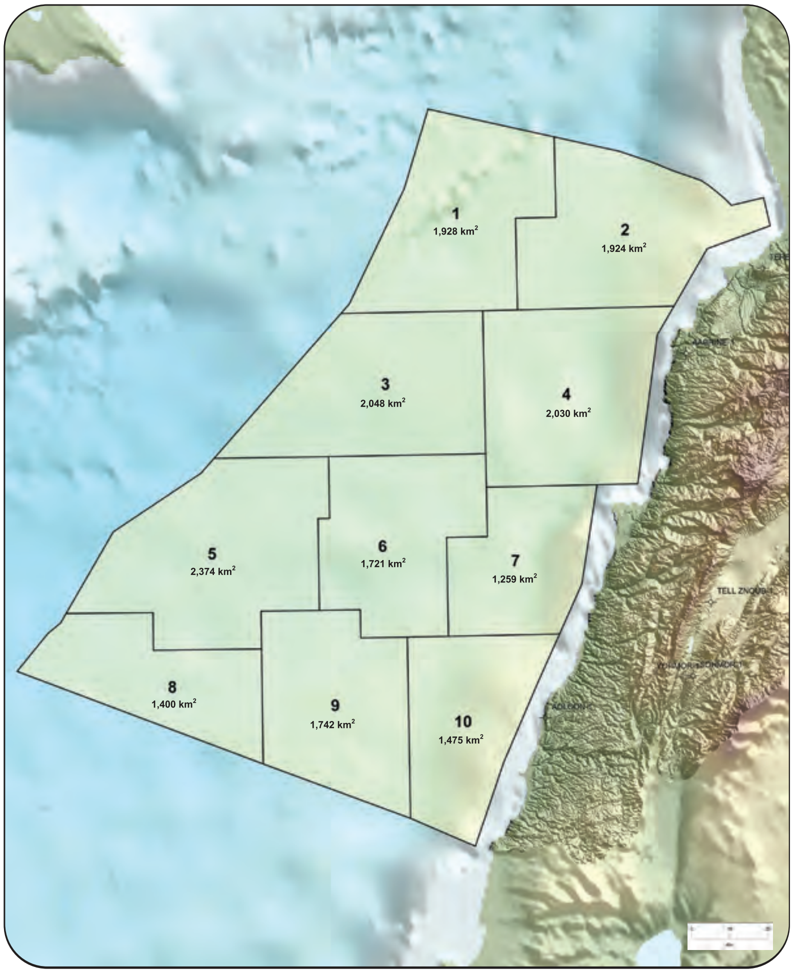
"They can't get any sort of consensus, and in fact, they are not even meeting on regular basis. There's just complete paralysis in the political machinery at the moment. They haven't even had a president, and they really haven't had any sort of executive government until earlier this year," he says."Their problems are bigger than just this. You can imagine that anything they want to get done is probably ground to a halt."

Wachtel characterizes the current political situation as "power vacuums" keeping the decrees from being signed. "When you fold into the mix possible corruption in the oil and gas section, and the maritime border dispute with Israel, there's not a recipe for rapid resolution for problems they're having," he says.

This delay could change the scope of what the participating companies will receive. "The latest postponement states that the licensing round will now close up to six months after the two decrees are approved," Scargill says. "This longer delay is needed, as even once the decrees pass, participating companies will require time to re-evaluate the opportunity. The process of amending the decrees could mean that they are faced with a significantly different proposition to that which was originally on the table in terms of the contract terms and available blocks."

Beyond that, the group cannot form a consensus on a bidding strategy. Originally, the government planned to offer roughly half of the 10 offshore blocks for bidding. Some members of the new government feel differently, Scargill says, while others still argue that rolling the blocks out in stages will encourage more competitive bidding and higher revenues.

Oil and gas companies are becoming more educated in how to operate in frontier countries; however, Lebanon does not offer a level playing field. "IOCs are used to operation in politically unstable countries, but the political challenge in Lebanon is not like other countries such as Nigeria or Iraq, where a united government is facing a strong opposition or other political organizations. In Lebanon, the government itself is not united, and it has been always a tough task to reach political consensus to form a government, particularly the Energy Ministry, which will be in the midst of political conflicts," GlobalData noted in its whitepaper, Political and Exploratory Risk Balance Anticipation for Lebanon's Initial Bidding Round.



Block	Block Km^2	Status
1	1,928	Open
2	1,924	Open
3	2,048	Open
4	2,030	Open
5	2,374	Open
6	1,721	Open
7	1,259	Open
8	1,400	Open
9	1,742	Open
10	1,475	Open

Map of the Lebanese offshore blocks. Image from the Lebanese Petroleum Administration.

Border disputes

The current maritime border dispute between Israel and Lebanon is not unprecedented. The Leviathan natural gas field, discovered in 2010 off the coast of Israel in the Mediterranean Sea, is estimated by operator Noble Energy to contain 19Tcf of natural gas. Lebanon and Israel initially squabbled over whether the giant field encroached on Lebanon's waters, escalating to a point where Israeli Minister of National Infrastructure Uzi Landau told Bloomberg on 24 June 2010 that the country "[would] not hesitate to use our force and strength to protect not only the rule of law but the international maritime law."

In August 2010, Lebanon submitted a proposal to the United Nations stating that, while Leviathan did not extend into Lebanon's waters, other fields did. The US backed Lebanon's proposal.

Lebanon is offering 10 offshore blocks with a total area of approximately 17,900sq km. Of these 10, two blocks are in a disputed zone with Israel. "Approximately 5,300sq mi (13,727sq km, 75% of the total acreage) is covered with 3D seismic acquisition, with all blocks being covered with over 70% 3D seismic acquisition except for blocks two and eight. It is likely that the lack of seismic coverage in block eight is intentional as its absence avoids any potential problems of Exclusive Economic Zone (EEZ) border disputes with Israel over an area of 330sq mi (855sq km)," GlobalData notes.

Dr. Amit Mor is a former assistant to the Israeli Minister of Energy and Infrastructure currently serving as the chief executive officer of Israel's Eco Energy. He was also chief economist in the Economic Planning Authority of Israel's Ministry of Economic Planning. "The disputed area is very small, absolutely, [in relation] to other conflicts, such as the conflicts over much of the eastern Mediterranean … or other conflicts in the world," he said. "It is for the benefit of the parties, especially of the Lebanese, that the dispute will be resolved to enable oil and gas exploration. I also hope that the Lebanese will discover oil and gas for the benefit of their people."

While Nazarian insisted to Reuters in his 7 April interview that companies are interested in the blocks, calling it "only a minor area," Wachtel says that it is yet another hurdle for the government to contend with. "Maritime border disputes effectively render those parts of the blocks in the disputed areas unsaleable. Some very brave investors may pick up the blocks in the hope that the disputes may get resolved or joint development zones will be agreed. Obviously the value of blocks becomes greatly reduced," he says.

However, Wachtel insists that despite all the issues the Lebanese government must deal with to get the round underway, hope is not lost.

"These are long-term projects. A delay of one or two years–while it might be frustrating for investors–is not the end of the world for the country or the investors. It is important to keep a perspective," he says. "These reserves will still be there, and it's perfectly possible that the price of gas increases.

"Eventually, the economic drivers will be enough, I think, to keep the politicians together," he said. OE

Setting sights on Tunisia

Audrey Leon takes a look at recent exploration and production activities occurring offshore Tunisia.

Top: The Ashtart platform offshore Tunisia. Bottom: The Maamoura platform operated by Eni Tunisia. Photos from ETAP.

The US Energy Information Administration (EIA) lists Tunisia as a 'relatively small hydrocarbon producer.' Oil production in the country declined to 67,000b/d in 2012, from its peak of 120,000b/d in the 1980s. EIA says Tunisia's proved natural gas reserves are 2.3Tcf.

Tunisia is currently listed an oil importer due to its limited refining capacity, not because of its reserves. The North African country has only a single oil refinery. Plans for a second are in the works, according to EIA.

Despite Tunisia's decreasing production, foreign explorers are still attracted to the country and are sizing up new prospects off the North African coastline and into the southern Mediterranean.

In January 2014, Norway's DNO International farmed into the Sfax offshore exploration permit and the Ras El Besh concession off Tunisia, which left DNO as operator with 87.5% interest. The Sfax and Ras El Besh permit areas are in the Gulf of Gabes, covering 3296sq km, in shallow waters.

DNO says the work program for the two permit areas includes a large 3D seismic acquisition campaign to confirm prospects identified on 2D seismic. The company plans to drill the Jawhara-3 exploration well to test additional upside potential, about 4km north of the Jawhara-1 discovery well that flowed 1500bo/d. The program is expected to begin 3Q 2014.

The Norwegian company also holds 30% participating interest in the Hammamet offshore permit. DNO says geologic and geophysical studies are ongoing to define the best prospect to be drilled in early 2015. The permit was operated by Canada's Chinook Energy until it sold all of its Tunisian assets to Indonesia's PT Medco Energi in August 2014 for US$13.7 million.

The acquisition is MedcoEnergi's re-entrance into Tunisia's oil and gas industry and gives the company working interest in eight fields in four exploration areas. While five fields are onshore, three are offshore. MedcoEnergi will serve as operator for three areas — Cosmos, Hammamet and Yasmin — in the Pelagian basin off the northeast coast of Tunisia. MedcoEnergi says the Cosmos and Yasmin developments are scheduled for completion in 2018.

The Cosmos concession, according to L'Entreprise Tunisienne d'Activités Pétrolières (ETAP), Tunisia's state-owned oil and gas company (20% interest), contains recoverable resources of 9.45MMbo at Cosmos South blocks A and B. ETAP says that Cosmos, which is in the Gulf of Hammamet in 120m of water, will be developed with a central platform connected back to an FPSO. Development plans could include both gas lift and water injection to maintain pressure.

In August, Australia's ADX Energy Ltd. won a two-year extension of the exploration period for its Kerkouane permit offshore Tunisia, extending the exploration period until 21 February 2016.

ADX operates the Kerkouane permit with 100% interest. The area contains both the Dougga gas condensate field and the Lambouka gas discovery. Kerkouane and ADX's Pantelleria license off Italy are in the Terravecchia Foredeep in front of the Tunisian Atlas thrust front, a geological subprovince of the extensive Italian foredeep and foreland area.

The Dougga gas field sits in 328m of water, about 45km east of Cap Bon in the Gulf of Hammamet, and 22km south-southeast of the Lambouka discovery. ADX estimates that Dougga has an assessed mean resource of 74MMboe (196Bcf and 42MMbbls). The field was originally discovered by Shell in 1981.

The Lambouka discovery is located 70km northeast of Cap Bon in the Sicily Channel. Drilling began on the Lambouka-1 well in July 2010. ADX conducted comprehensive logging while drilling analysis and susequent wireline logging runs. However, the company says further well tests were not possible due to instability of the borehole. Based on the well results and the 3D seismic interpretation, ADX estimates the mean recoverable gas resource at 309Bcf.

Prior to drilling its next well in the Kerkouane permit area, ADX is seeking to divest part of its interest.

Another company investing in Tunisia's offshore is Ireland's Circle Oil plc, which spudded the El Mediouni-1 (EMD-1) well in the Mahdia permit in June. Circle Oil used the *PetroSaudi Discoverer* drillship for the campaign. The company plans to test the potential of the El Mediouni prospect, including the primary Birsa Sands target and the

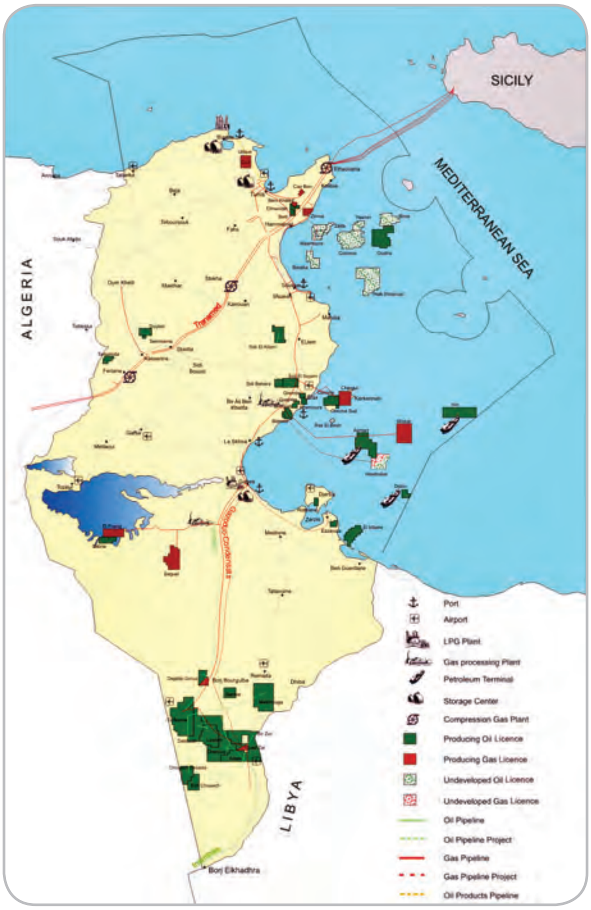


Image from ETAP.

secondary fractured carbonates of the Ketatna formation.

Awarded in 2009, the Mahdia permit covers a 3780sq km area near the Nabeul permit to the north and Lampedusa Island to the east. It is adjacent to commercial oilfields such as Tazerka, Birsa, Oudna, Halk El Menzel and Isis. Both 2D and 3D seismic surveys have been conducted on the permit area in 2009 and 2013, respectively. Circle Oil says that there are several classic tilted fault block structures that could provide traps for both sand or carbonate reservoirs, one of which is a target for the EMD-1 well.

As of 31 July, Circle Oil had drilled the EMD-1 well to 753m measured depth. The company ran 20-in. casing and successfully cemented the well. However, after it ran the blowout preventer and riser, mechanical problems resulted in damage to the permanent guide base that was irreparable.

A replacement guide base has been installed, and drilling is expected to continue on to the well's primary and secondary targets at 1260m and 1460m depth.

Circle Oil also holds 23% working interest in the Ras Marmour permit in southeast Tunisia, which includes both onshore and offshore prospects covering Djerba Island and a portion of the Gulf of Gabes. Its partner in the permit is Tunisia's Exxoil Ltd. (77% WI). The permit is near the offshore El Biban oil and gas field that was discovered by Marathon Oil in 1982 (Marathon later sold all its Tunisian interests in 1996). Circle Oil says the main reservoir in the El Biban field is composed of fractured limestones from the Bireno formation of Middle to Early Turonian age.

Cooper Energy is another explorer offshore Tunisia, holding interest in the Bargou, Hammamet and Nabeul permits with 30%, 35%, and 85% interest, respectively.

The old guard

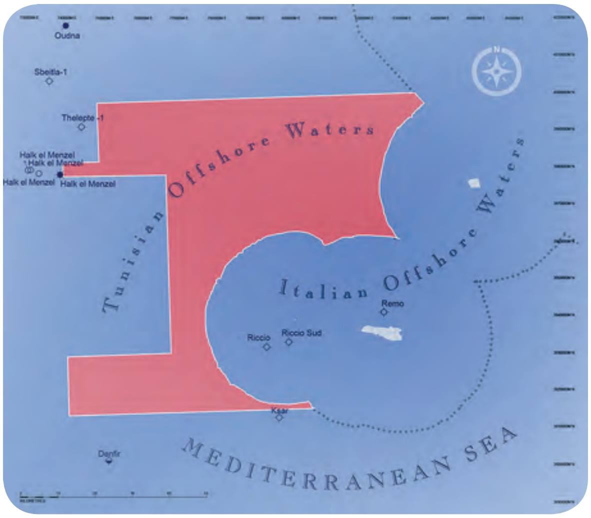
One of Tunisia's oldest offshore developments is the Ashtart field, discovered in 1971 and developed by the Elf-Aquitaine Oil Co. Ashtart is located in the Gulf of Gabes, 80km southeast of the port city of Sfax.

Currently, Serept (Society of Research and Exploitation of Petroleum in Tunisia) – a joint venture between 50:50 partners ETAP and Austria's OMV – operates the field development.

The Ashtart field is the second-largest field in Tunisia, and celebrated its 40th year in production this May. According to Serept, Ashtart has a single, 70m-thick, porous limestone reservoir, El Gueria, that is heavily faulted. The downhole temperature is 140ºC and the pressure ranges between 200-250bar. Serept says most wells have a depth of approximately 3000m. ETAP lists recoverable reserves at 12.5MMbbl.

The project underwent revitalization efforts from 2009 to 2013 to increase recovery using artificial gas lift, as well as increasing power generation capacity to meet ESP pump needs, and also modernizing management and control systems.

Eni, through its Tunisian subsidiary Eni Tunisia BV, operates the Maamoura field with 49% interest along with partner ETAP (51%). The Maamoura field, which began production in 2009, is located 19km off the Gulf of Hammamet in 50km of water. ETAP lists the field's recoverable resources at 6.4MMcu m of oil and 985MMcu m of gas.



This map depicts the Mahdia permit area near the Tunisia-Italy maritime border. Image from Circle Oil.

Good neighbors

Tunisia is no stranger to border disputes, like most countries in the Mediterranean and elsewhere. However, the country has enjoyed stable relations with its European neighbor Italy, with which it shares the aforementioned Sicily Channel. Tunisia and Italy signed the Italy–Tunisia Delimitation Agreement 43 years ago on 20 August 1971, and it was later ratified in 1978.

The treaty states that the boundary terminates just short of an equidistant line between Malta and the Italian Pelagie Islands. It further created a 13nm semi-enclave around the Italian island of Pantelleria. Another semi-exclave was created comprising overlapping 13nm arcs around the Italian islands of Linosa and Lampedusa that also intersect a 12nm zone around Lampione. The boundary's westernmost point forms a maritime tripoint with Algeria. OE

Making an entrance

Alan Thorpe examines the latest pipelaying vessels debuting on the market.

Two new pipelayers for Ceona

The hull of London-based Ceona Shipping's *Ceona Amazon* has now arrived in Bremerhaven, where it will be completed by Lloyd Werft (Bremerhaven) before sailing to Huisman's Rotterdam facility for the installation of pipelaying equipment. The hull was built at the Gdansk Crist Shipyard in Gdynia, Poland.

With a design based on a drillship, the *Ceona Amazon* meets all the demands of a special purpose vessel with DP2 dynamic positioning capability. It will also be suitable for operation in remote and challenging regions, and can lay flexible as well as rigid pipes and supply lines.

The completed ship will be 199.4m (654ft) long and 32.2m (105.6ft) wide. It will draw 8.0m (26.25ft), be of 33,000grt and offer not only cabin accommodation for 200 crew and specialist personnel, but also considerable storage space below-deck for pipes and connecting components. This will guarantee the shipping company a wide area of operation for the ship, which will lay rigid and flexible piping in depths down to 3048m (10,000ft).

Pipelay will take place via moon pool and *Ceona Amazon* will have a DP2 satellite system installed to ensure exact positioning and navigation. The newbuild will boast a helipad on the bow, be fitted with seven thrusters at bow and stern and also have an operational ROV that will be able to supervise work taking place at great depths. Supplying pipes for gas and oil directly out of the hold, the *Ceona Amazon* will be a specialized floating factory capable of operation, for the main, independent of land support.

Two 400-ton capacity heavy cranes to port and a 30t knuckle boom crane located amidships on the 4600sq m (49,514sq ft) deck behind the superstructures help transport pipes into a special bending and laying system after they have been joined by robotic welding machines.

The pipelaying systems, which comprise a 275t vertical-lay system, will be installed after the vessel arrives at Huismen's Schiedam facility in Rotterdam, prior entering service for Ceona.

Earlier this year Ceona took delivery of the 9000grt X-Bow diesel-electric propelled pipe-layer *Polar Onyx*. **Take an in-depth look at the *Polar Onyx* on page 102.**

The *Ceona Amazon* leaving Cryst Shipyard in Poland. Photo from Ulstein.

Work on the quayside at Huisman's Schiedam facility. Photo from Alan Thorpe.

Huisman – supply of lay systems

Rotterdam's Huisman, the worldwide specialist in lifting, drilling and subsea solutions, has recently delivered five pipelay systems out on the quayside of their production facility in Schiedam. This 66m high production hall offers the largest indoor lifting capacity in Europe (1200tonnes), allowing for the simultaneous indoor assembly, including testing and commissioning, of several products and systems. This allows for fast installation, commissioning and testing onboard.

Pipelay systems recently delivered by Huisman, Schiedam include an 800t Multi-lay System (MLS) for Ezra's *Lewek Constellation*, a 275t vertical-lay system for Ceona's *Polar Onyx*, a 150t vertical-lay System for (VARD) Ocean Installer's *Normand Vision* and a portable 150t vertical-lay system for Technip. An additional 550t tiltable-lay system (TLS) for Subsea 7 has already been installed onboard the *Seven Waves*, which underwent the installation at Huisman's quayside and departed for sea trials in February 2014. The 150t Ocean Installer VLS and the 150t Technip VLS were transported to other yards for installation– respectively Sovik in Norway and Le Trait in France. The 275t VLS for Ceona's *Polar Onyx* and the 800t MLS for Ezra's *Lewek Constellation* were both installed when the ships arrived in Rotterdam.

Royal IHC busy with pipelayers

During the past 12 months, Holland's Royal IHC's offshore division – formerly IHC Merwede – has been successful in securing orders worth over €1 billion for the design, engineering and construction of seven pipelaying vessels. The agreements have been signed with Subsea 7 (four vessels) and Seabras Sapura (three vessels), the partnership between SapuraKencana and Seadrill.

The orders secured with Subsea 7 include two vessels already delivered – *Seven Waves*, during March this year, and *Seven Seas*. With an overall length of 146m (479ft), a beam of 30m (98.4ft) and a Class-2 dynamic positioning system, these vessels will be equipped for transporting and installing flexible flowlines and umbilicals in water depths of up to 3048m (10,000ft). Subsea 7 is delivering the pipelaying spreads for the three new vessels. The first in the series, *Sapura Diamante*, was delivered during late June this year.

Royal IHC then signed contracts with SapuraCrest for the design, engineering and construction of two new 550t pipelaying vessels and a third vessel, a 300t version, to be delivered to Brazil's OSX Construção Naval S.A. All three ships will install flexible pipelines in Brazilian waters, pursuant to Petrobras' contracts for the charter and operation of pipelaying support vessels, which were awarded to SapuraCrest.

These first two vessels are the first fully integrated offshore vessels completely designed, engineered and built by Royal IHC with a pipelay spread supplied by

Principal particulars

	550t pipe-laying vessels	300t pipe-laying vessel
Length overall	146.00 m	133.81 m
Breadth	29.94 m	24.00 m
DP Class	2	2
Main crane capacity	250 t	100 t
Pipe tension capacity, dynamic load	550 t	300 t

The *Seven Waves* from Royal IHC. Photo from Lloyd Werft.

The *Polar Onyx*. Photo from Royal IHC.

IHC Engineering Business. In addition, IHC Drives & Automation will deliver the integrated automation system, the full electrical installation and the complete electrical machinery package. Other IHC Merwede businesses, such as IHC Piping, are also delivering equipment.

The third vessel – with a top tension capacity of 300t – will also be designed and engineered by Royal IHC. The vessel will be – in accordance with Petrobras specs – built in Brazil, at the OSX yard in Açu, Rio de Janeiro. The pipelay spread will also be supplied by IHC Engineering Business.

The first ships in the two series were delivered earlier this year.

Two new pipelay vessels for McDermott

McDermott International has two pipelayers on order, both due for delivery this year. The first is the *Lay Vessel 108*, due for delivery this summer by Metalships and Docks S.A.U. shipyard in Vigo, Spain. It is a sistership to the LV105, which was delivered two years ago from the same yard.

LV108 is designed for advanced deepwater operations with a high-capacity tower for rigid and flexible pipelay and state-of-the-art marine construction equipment that will enable installation of a variety of products to 3048m (10,000ft) deep, including rigid-reeled pipelines, subsea components and hardware, and deepwater moorings for floating facilities as well as flexible products – cables and umbilicals.

The principal characteristics of the vessel, such as payload, tension capacity and product size, will mirror those of the *LV105* – built by the same yard in 2012, but McDermott anticipates enhanced functionality of the *LV108* equipment design compared to the *LV105*. Delivery is anticipated to be around 3Q 2014 for outfitting of the custom-designed lay system, built by a specialist fabricator in Europe.

The vertical reel will have a nominal payload of 2500t plus, subject to vessel loading conditions, and a lay tower operational between 90 º and 40 º. The nominal tension capacity is expected to be 400t, and the range of pipe the vessel can install is between 101.6mm-406.4mm (4-16in) diameter. This 130m (427ft), DP vessel will be equipped with a 400t heave compensated crane, will have a transit speed of 15 knots and will operate across a range of water depths up to more than 3048m (10,000ft).

The second vessel is a new high-spec, highly capable DP combination S-Lay vessel with a 2000t crane, to be named *Derrick Lay Vessel 2000*. The vessel is being constructed at Singapore's Keppel Singmarine, part of Keppel Offshore & Marine, and is due for delivery during 2014.

Developed by Keppel's ship design arm, Marine Technology Development (MTD), *DLV2000* is equipped to support advanced deepwater pipelay operations that will allow pipelines to be installed at depths of up to 3048m (10,000ft). An economical vessel transit speed is expected to be 12knots with a top speed of 14knots. On completion, the vessel will be able to accommodate up to 400 personnel. **OE**

The *Lay Vessel 108* at Metalships in Spain. Photo from Metalships.

A look at Ceona's *Polar Onyx* PLSV

Claudio Paschoa takes a look at Ceona's vertical pipelay vessel, *Polar Oynx*, now serving Petrobras offshore Brazil.

With Petrobras' decision to speed up pipe lay capacity needed for pre-salt and other deepwater plays to become operational, today Brazil boasts the largest number of pipelay vessels in the world and there are more to be built.

***Polar Onyx* PLSV.** Photo from Ceona Offshore.

One of the modern deepwater PLSVs to operate in Brazil is the *Polar Onyx*, with its peculiar Ulstein X-bow design. The vessel was formally christened at the Ulstein yard in Ulsteinvik, Norway on 28 February 2014. From there it sailed to Huisman's yard in Schiedam, The Netherlands, for final outfitting.

The *Polar Onyx* is currently on a five-year charter with Ceona for pipelay work at Petrobras' Espirito Santo basin in southeast Brazil, with options for up to five more years. The PLSV is based on ULSTEIN's SX121 design, for operations in the deepwater SURF/construction/IRM markets, with high capacity for flexible pipe loads.

The vessel owner, GC Rieber, was founded in 1879 and is known for its expertise in harsh environment offshore operations and for the design, development, and maritime operation of seismic vessels. Ceona, on the other hand, is a young company, founded in early 2012, targeting the growing global deepwater SURF and subsea construction market. Ceona has a small but growing fleet of multi-functional pipelay and construction vessels, including an interesting, new field development vessel, the *Ceona Amazon*.

Ceona considers its financial stability to be one of its four pillars, along with their assets, their strategic partnerships, and the execution experience found within their team. With solid financial backing from major shareholder, Goldman Sachs Capital Partners, Ceona looks to have the financial strength to support its ambitious strategy. Ceona belongs to Goldman Sach's portfolio of rapidly growing companies in oil and gas and renewable energy, like Expro, Cobalt and Dong Energy. With such backing, Ceona managed to complete, in April 2014, a US$290 million secured debt facility to finance two newbuild projects, the *Ceona Amazon* and the *Polar Onyx* VLS, along with performance bonds to further support the company's growth initiatives. In 2012, Ceona acquired Project Development International (PDi), which has offered offshore field development and engineering solutions to the oil & gas industry since 2003.

Ceona's *Polar Onyx* offshore Brazil.
Photo from Ceona Offshore

OHH

Tee Off Gala

Sunday, September 21
6:00 PM – 11:00 PM

Red Oak Ballroom – City Centre
Houston, TX

The Oilfield Helping Hands Texas golf tournament has been a premiere event in Houston for almost a decade. This year we are excited to expand the event to include our inaugural Tee Off Gala. Enjoy dinner, dancing and a live auction in anticipation of our 9th annual golf tournament the next morning.

OHH raises money for those working in the oil and gas industry who have fallen on hard times. In the last 10 years, we have raised and donated more than $2.5 million. Thanks to golfers and bidders like you, we are able to make a difference and change the lives of those in need.

So put on your boots and blazers and get ready for a night of fun. Visit the OHH website at **oilfieldhelpinghands.org** and sign up for the gala, become a sponsor or volunteer. You do not have to play in the tournament to attend the gala.

***Polar Onyx* in the Storfjord in Norway.**
Photo from Norsk Skipsfarts Forum.

The vessel

The *Polar Onyx* is a high-capacity flexible pipelay and construction vessel designed for operations in harsh conditions and deep waters. With a length of 426ft (130m) and a 82ft (25m) beam, it is built to the highest standard for dynamic positioning, DP3 (Operation +), and equipped with a 250t AHC offshore crane. It is fitted with a 275mt vertical-lay system above a moonpool, which is capable of installing flexible pipe and umbilicals of 2in. to 25in. OD in water to 10,000ft (3000m) deep. The vessel is designed to operate in the SURF/construction/IRM market, with capacity for 2000t of flexible pipe on its deck-mounted carousel. The ship can accommodate 130 crewmembers and is built according to the latest international environmental standards (CLEAN design with Green Passport).

The vessel was classed by DNV, and meets the highest standards for station keeping, redundancy and dynamic positioning (DP3). Moreover, operability in DP2 operational mode is maximized due to GC Rieber's *Operation+* feature, which allows the vessel to continue and retain system integrity with uninterrupted operations even after a substantial single system failure — a vital trait in reducing downtime and increasing operational safety. "We are extremely pleased with the maiden contract of the *Polar Onyx*, working as a subsea construction vessel for Petrobras through our strategic partnership with Odebrecht Oil & Gas. She has already worked in more than 1700m water and is answering well to our client's demanding requirements. Our collaboration with OOG is also very satisfactory," said Ceona's CEO Steve Preston.

Propulsion system

The *Polar Onyx* is powered by a diesel electric plant, comprising of six identical 3673hp generator sets. It has 22,037hp of installed power generation capacity and 20,482hp of thrust power, and boasts DP3 (Operation +), DNV dynpos AUTRO, Kongsberg DP3 (Operation +). Abiding to their forward thinking philosophy, environmental responsibility was a key consideration in the construction of the *Polar Onyx*, which was designed for minimal environmental impact during operations. This includes efficient use of fuel and energy due to the inverted bow design of its hull. The *Polar Onyx* has already proved to possess excellent seakeeping characteristics and benefits from the increased safety and power efficiencies afforded by its Ulstein X-bow design. The inverted bow notoriously suffers less speed loss in rough seas, thereby improving fuel efficiency and transit speeds. All major pumps, motors and fans are driven by variable speed drives, to match demand. All propulsion motors are also driven by variable speed drives to reduce idling power consumption.

Deepwater flexible pipelay and subsea construction capabilities

This PLSV is a real workhorse and its multipurpose nature is a key factor of the design. The *Polar Onyx* has already undertaken deepwater construction work for Petrobras at the Roncador field and Ceona says it is well-regarded by Petrobras. A high-capacity flexible pipelay and construction vessel, the *Polar Onyx* is equipped with a 250t AHC offshore crane, rated to 3000m. It can be used to install pipe and umbilicals to depths of 10,000ft (3000m) with the 275mt vertical lay system built by Huisman. The two moonpools offer extra versatility for construction jobs in rough weather, with one of the ROVs being launched through a moon-pool. **OE**

Vessel specifications

- Length overall: 426ft (130m)
- Beam: 82ft (25m)
- Draught max: 25ft (7.6m)
- Max transit speed: 15 knots
- Deadweight at 7.6 m draught: 9000t
- Deck storage capacity: 5800t
- Deck area of 18,300sq ft up to 10t/sq ft
- Heavy-lift capacity: 37,549hp installed-multi-reel drive system able to handle 400t flexible reels
- Carousel: One 2000t flexible pipe range: 2in.-25in. OD
- Main crane: 250t active heave compensated (AHC)
- Depth rating pipelay and heavy lifting: 10,000ft (3000m)
- Long endurance: ~ 80 days (weather and tide dependent)
- Accommodation for up to 130 people
- In service as of April 2014
- Ulstein X-bow
- Diesel electric propulsion
- 6 main diesel generators: ea. 2,700 ekW
- 3 main azimuth thrusters: ea. 3,000 kW
- 1 retractable azimuth thruster: ea. 2,000 kW
- 2 tunnel thrusters forward: ea. 2,200 kW
- Helicopter deck: dva/21, 12.8t
- 2 ROVs capable of 3000m working depth
- Two moon pools: 8.0 x 8.0m and 4.9 x 4.9m
- Special Purpose Ship (SPS)
- Classification: DNV 1A1, SF, EO, DYNPOS-AUTRO,
- CLEAN design, NAUT-OSV(A), COMF-V(3), COMF-C(3),
- DK(+), HELIDK-SH, crane, SPS, VIBR, BIS
- Flag: NIS

Cranes and lay system

- 250t AHC, 3000m rated crane. Winch below deck.
- Main hook: 250t @ 15m radius/ DAF 1.4 (max r36m)
- Aux hook: 20t @ all radii (max r40m)
- 2nd knuckle boom crane: 12t @ 15m/ 8t @ 21m
- Vertical lay syst. (VLS) top tension: 275t
- Flex pipe range: 50-630mm OD
- A&R capacity: 300t (96mm diameter, 3000m wire)
- Tensioners: 4 track 275t retractable
- Reel drive system 400t (with track system for multi reels)
- Under-deck carousel ready

Deck load capacities

- As ocean construction vessel (OCV): 5800t
- As cable/pipelay vessel: 2500t (above and below deck)

A new concept in efficient pipelay

MacKinnon Marine's Alex Jackson discusses the merits of the company's new spiral pre-lay system, which seeks to bring pipe construction closer to the lay site and eliminate the need for a spool base.

As the requirement to lay pipelines in an ever-increasing range of distant locations continues, there is a corresponding increase in pressure to improve the utilization of pipelay vessels.

The current preferred system of pipe construction at an onshore spool base, requiring long transits of a reel lay vessel to collect the pipe, is extremely expensive and inefficient in terms of utilization of the vessel, a huge capital asset with massive running costs.

Spiral pre-lay process

It can be seen that, since the reel lay speed is much faster than the pipe construction, and the time lost in transit has been greatly reduced, there is a need to accelerate pipe construction to avoid the reel lay vessel waiting or making multiple transits with short pipe stalks, thus negating the efficiency benefits offered.

Pipe construction can be carried out by a very simple barge or by a purpose built vessel. The barge is relatively low-cost and the increased output which is required can be achieved by using a number of vessels for construction. The purpose built vessel, however, is a much higher investment and its own efficiency must be maximized by enabling it to produce a number of pipe stalks simultaneously. For instance, the deck arrangements can be optimized to create an efficient and versatile pipeline factory with multiple firing lines which extend the whole length of the vessel offering multiple weld and field joint coating stations, giving efficient cycle time.

When not contracted for spiral pre-lay the purpose built vessel or the barges can operate as a conventional S-lay facility giving high overall utilization.

Multi-pipe S-lay vessel

Pipe is stored on and below deck and manipulated by dedicated pipe-handling equipment to give an efficient lay rate. Pipes of differing diameters and stalk lengths can be laid in parallel and additional pipe received from barges via deck cranes. The inshore sheltered conditions suit pipe replenishment and continuous 24 hour operations, unaffected by

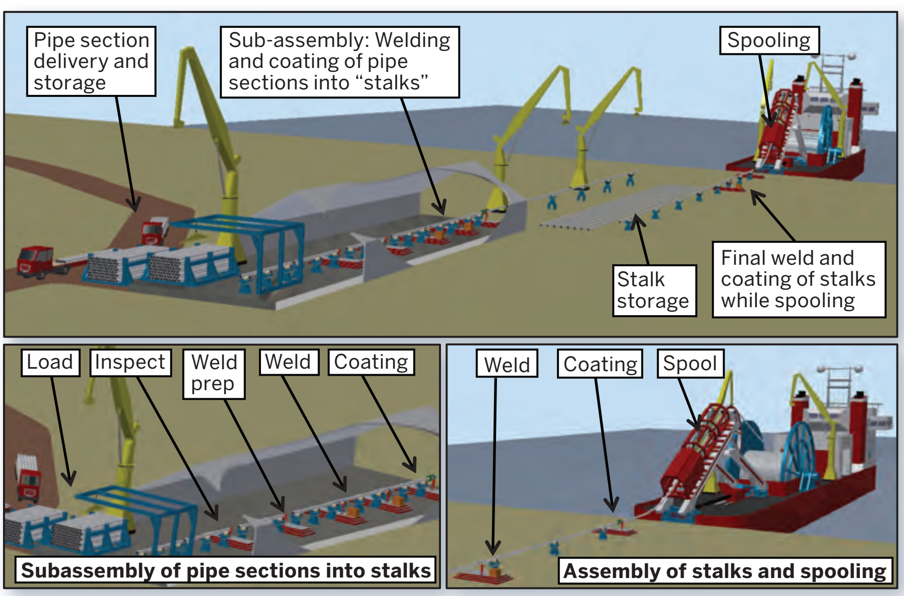


Fig.1: Schematic of spooling base and reel vessel spooling (loading).
Illustrations from MacKinnon Marine.

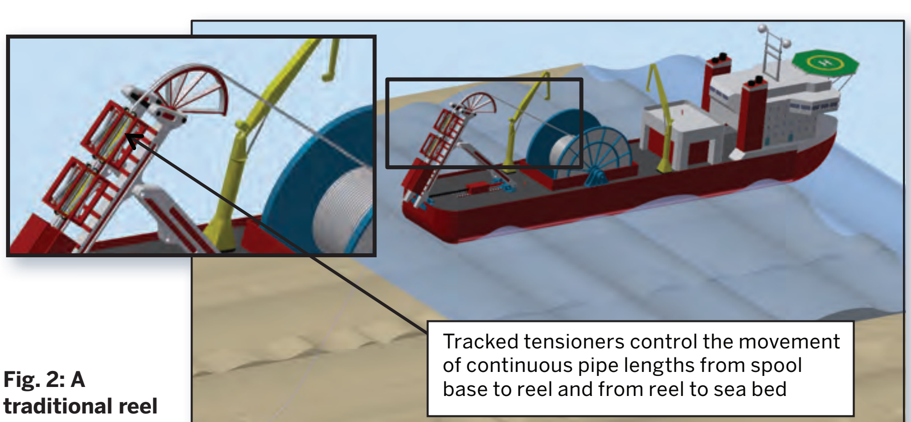


Fig. 2: A traditional reel lay vessel.

Comparison of the two processes

Factor	Conventional reel lay	Novel spiral pre-lay
Total project duration	45 days	14 days
Utilization of specialist vessel	40 days	8 days (construction) 12 days (reel lay)
Transit distance traveled	9000km	450km

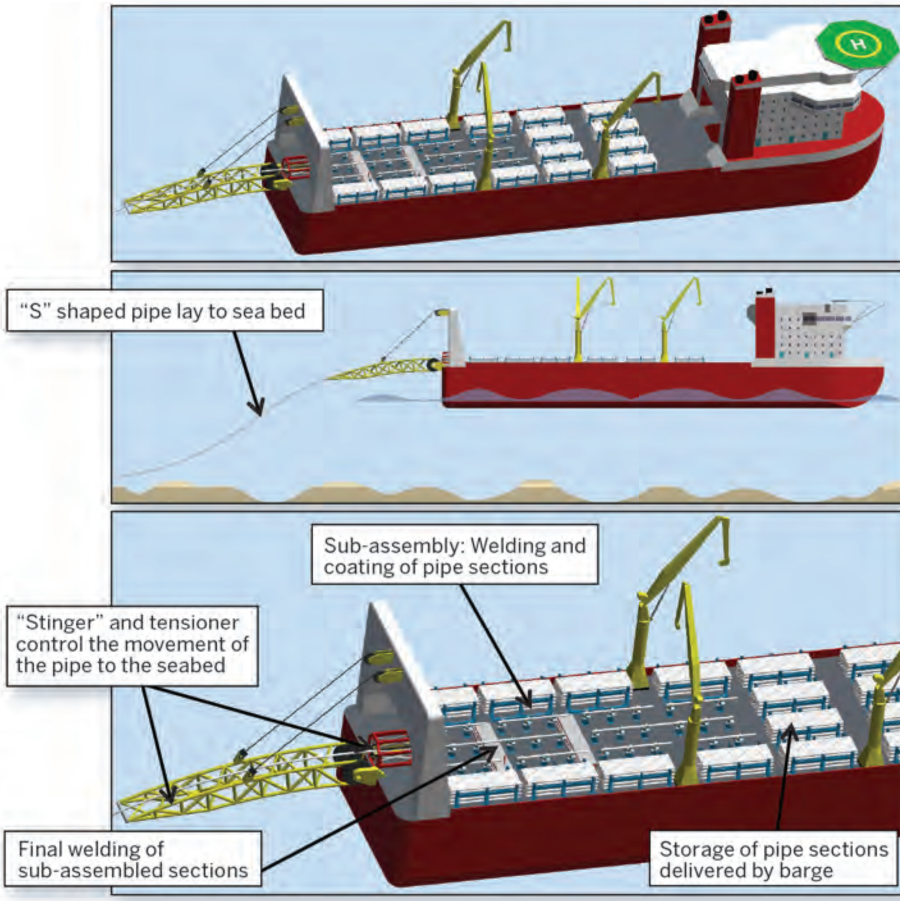


Fig. 3: Pipe construction on vessel and S-lay.

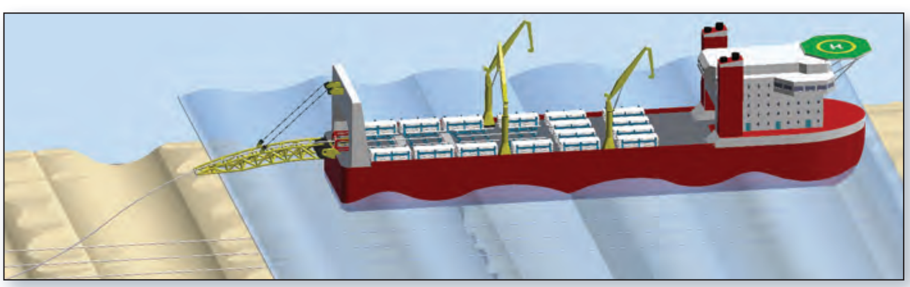


Fig. 4: Pre-lay of a spiral pipe by a conventional construction vessel.

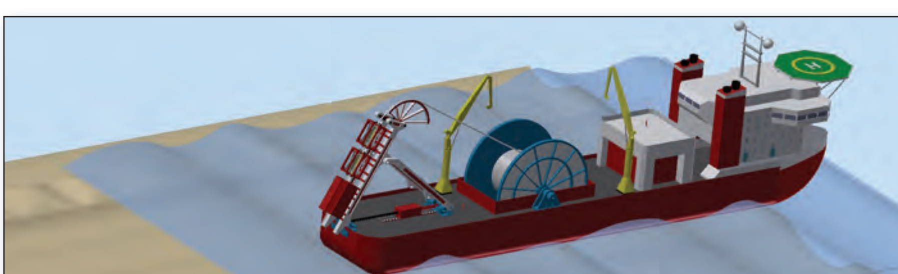


Fig. 5: Recovery of the pre-laid pipe by a conventional reel lay vessel.

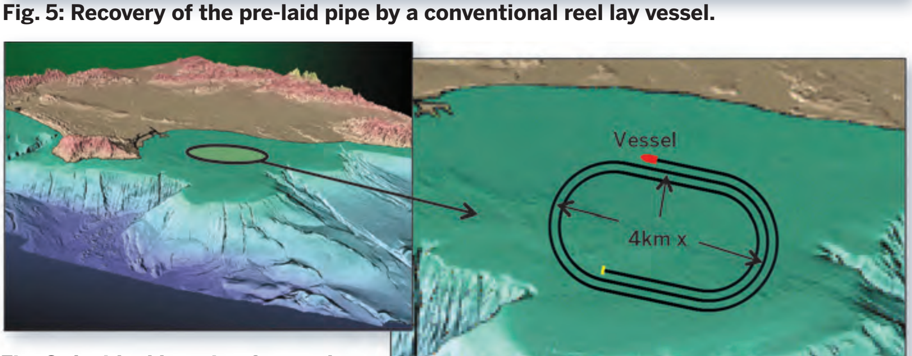


Fig. 6: An ideal location for pre-lay.

weather or vessel motions.

In the formation shown above, the vessel is laying five pipes simultaneously. These pipes may be the same or of different sizes or types.

If the lay site is very close and transits consequently short, it may be necessary to construct more than five pipe stalks to keep pace with the reel lay vessel. In this case, the construction vessel can use more than one deck and a further quantity pipe stalks can be installed.

Other benefits offered by spiral pre-lay

If desired, the constructed stalk can be pressurized while on the seabed before spooling. This aids resistance to ovalization under bending and in the case of internal liners, assures the integrity. Pressurization on the seabed offers many process and safety benefits over the current methods.

- The construction vessel can produce pipes of different sizes and types, as required for the project. Unlike a spool base where stalks are available in a fixed order, the vessel can then select which stalk to spool next to suit field development requirements.

Summary of key benefits

- Eliminates geographical restrictions of the spool base entirely – The spool base is where you need it.
- Minimizes transit distances for reel lay vessel – Major cost reduction and time saving.
- Avoids large capital investment cost of land clearing and pier construction.
- No need to tolerate limited stalk lengths of typically 1-2km.
- No need to carefully schedule order of pipeline manufacture

The spiral pre-lay process and concepts for the required new technologies are currently being developed by MacKinnon Marine and are protected by patent application. **OE**

***Alex Jackson** is MacKinnon Marine's R&D Manager. He is a chartered engineer with a BSc in engineering from Nottingham University. He previously worked an Automotive O.E.E., in manufacturing process development and new product introduction, before starting work in pipe lay improvement and testing eight years ago.*

Security offshore: Reigning in complexity

Vigilance remains key when it comes to offshore cyber security. Gregory Hale explains.

Computer networks on offshore oil rigs and platforms have ended up incapacitated in the past by malicious software directly downloaded over satellite networks or via workers' infected laptops and USB drives.

Today's offshore platforms consist of interconnected systems, running, monitoring, and recording thousands of calibrations each minute. These systems can be sitting ducks for an attack.

"Offshore oil and gas platforms today have an increasing complex set of interconnected networks," says Graham Speake, vice president and chief product architect at Atlanta, Georgia-based NexDefense, Inc. "These range from the critical and essential control and safety networks owned and operated by the end user, third party networks for monitoring these networks and rotating equipment, and also open access networks to ensure that rig personnel can effectively communicate with friends and family onshore. Coupled with these networks, more and more subsea devices are being deployed that connect into the control networks. A lot of this technology has been added on to these platforms to extend the life and improve the yield. The networks are therefore extremely complex and often deployed with reduced security as the location of the platforms has always been seen as great perimeter defense."

Technology sophistication continues to increase so users can get the most out of wells, but there are other issues, says Eric Byres, CTO and vice president of Engineering at Tofino Security Products, a Belden company, based in British Columbia, Canada.

"Not only are the systems getting more connected, but there are more and more applications for the communications links to drilling and production units – for example, voice-over IP, corporate business networking, Internet access, real-time monitoring, maintenance support services, regulatory reporting and 'crew infotainment services,' to name a few," Byres says. "All of these need to be secure both on their own and from each other, yet typically they all run over the same satellite or fiber backbone from the beach.

"Plus there are more parties (consultants, service providers, regulators, etc.) with legitimate needs for accessing data from the platform. Each of these parties add a level of complexity and a potential new vulnerable path that needs to be

Interconnected systems can be risky.
Photo: OE Staff.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considered. For the bad guys, it is all about finding the weakest link. For the platform owner/operator, it is all about making sure there is no weakest link in all the partners and suppliers connectivity systems. And when trouble does happen, having a way to quickly quarantine off the infected components or systems without impacting the whole platform," Byres says.

"Platforms are having greater and greater bandwidth allocation, often through dedicated fiber cables," Speake said. "The cyber security issues that need to be addressed when deploying these networks has been lagging behind, often due to a lack of skilled engineers in the industrial cyber security field and partly due to a conscious decision to reduce security and complexity to ensure greater uptime.

"Typically, oil and gas platforms have limited cyber security professionals on their staff, and the pressures to keep the platform up and the workers happy (through Internet connections) often mean that security will take a lesser priority. Security updates such as anti-virus signatures files and updates to the operating systems (typically Microsoft-based) and vendor software are usually a low priority and often may only be upgraded once a year (or even less). Running old, out of date software coupled with more interconnected networks, often indirectly connected to the Internet, is exposing these systems to more and more risks which is likely to result in off shore platforms experiencing security issues and potential unexpected outages."

Dollars can add up

One highly likely effect of a malware infection offshore is unplanned downtime. As it is in any industry, downtime means money, and offshore the millions add up fairly quickly.

"Even something that could be considered 'minor' in business IT could have significant cost impact offshore. A dropped packet could skew visibility and impact automated systems to where production slips from its optimal state," says Eric Knapp, director of cyber security solutions and technology at Honeywell Process Solutions. "Worst case, of course, there is a loss of visibility or a broader impact that halts production altogether. Regardless, to address any issue is more expensive when it's miles offshore on a controlled facility."

As communications systems advance, companies reap the benefits of real-time analysis and quicker decision making

Separating entertainment from ICS

Crews working offshore do not work all the time, so they need some form of entertainment during their off hours. The Internet is a savior in that entertainment is only a few clicks away. The problem is the Internet introduces a new element of potential compromise.

Crew welfare connectivity is crucial in attracting workers from younger generations to work offshore. Very few people younger than 30 can go a whole day without streaming video as flash players now dominate.

"I have personally talked with employees of a major multinational petroleum company and found that workers were allowed to bring their own (personal) computers on the rigs and connect to a 'public' network for use during free time," said Joel Langill, ICS cyber security consultant.

"This came as quite a surprise, considering that this company is also one of the leaders regarding cyber security within their production and manufacturing assets. It was evident that in this case, a risk assessment and associated failure modes and effects analysis (FMEA) was not thoroughly performed taking into account the risks of the 'insider' as the threat source," Langill said. "They believe that the traditional security controls used to segment and isolate the 'public' and 'production' networks were sufficient. Sufficient by whose standards?

"Today's threats are becoming more advanced and are designed to circumvent many standard security controls – such as firewalls and host-based mechanisms like anti-virus software," Langill said. "Once any malware has bridged on to the production side, the consequences can be great. Many ICS installations in this environment have little technology deployed to monitor the characteristics of the network. The malware could then target the embedded devices that exist to perform critical production tasks and any associated loss-of-view or loss-of-control would result in downtime.

"The problem has the potential to rapidly escalate with the deployment of technologies like WiMAX that effectively among others, but they can also suffer from the weaknesses. The real challenge is how to prevent unwanted malicious software from affecting the critical systems offshore.

"When computing systems are new they are ideally secure and we can supplement that security with anti-virus, whitelisting, among others," Knapp says. "But over time vulnerabilities are discovered, and patched. It's hard enough deploying patches in a production ICS. When your system is offshore it is compounded. You need to have regular visits or a reliable and secure network connection to the platform. And then you need to apply the patches.

"That's one reason why application whitelisting is well suited for these environments: It only needs to be updated when a system update or new application is installed, which keeps the system better protected for longer periods of time than traditional AV," Knapp says.

Taking control

That all means offshore platform operators need to start working to identify weaknesses and take a proactive stand against possible infections.

"One challenge is not making your process control system so convoluted or littering it with such complicated tools, taps, appliances and so on that the cure becomes almost as bad as the disease. Many engineers are now staring glaze-eyed at new technology that just a couple of years ago was totally outside the scope of their knowledge and responsibility," says Dan Schaffer, business development manager, networking and security at Phoenix Contact, in Pennsylvania.

As always with security, vigilance remains a key thought. "The biggest thing is visibility; staying on top of what's happening and quickly assessing the risk of any cyber incident or indication thereof, so that corrective action can be taken quickly," Knapp said. **OE**

***Gregory Hale** is the Editor and Founder of Industrial Safety and Security Source (ISSSource.com) and is the contributing Automation Editor at Offshore Engineer.*

creates a mesh network interconnecting multiple rigs from various operating companies. This will not only provide a vector for those on a particular platform to breach the segmentation, but could also provide multiple, external vectors that could facilitate a remote attack from another rig that may have a different set of security policies and associated latent vulnerabilities."

Breaking the network into zones can help alleviate the issue. "Separating such a high-risk (but needed) system from the mission critical systems running the platform is a good example of how important a zone style design is," said Eric Byres, CTO and vice president of Engineering at Tofino Security Products. "And once you have such an architecture in place, then it is critical that operators manage all the traffic flows and monitor these flows continuously. Good security wherever it is deployed isn't just about blocking the bad guys, but also watching what is going on in the communications systems. In a mission critical operation like a platform, this is doubly important." ■

Solutions

Seatronics, Digital Edge Subsea partner in video inspection

Seatronics, an Acteon company, signed a contract with Ulverston, England-based Digital Edge Subsea for the company's complete range of digital video inspection systems. Seatronics will be equipped with Digital Edge Subsea systems for each of its global bases and they will be available for both rental and sales. Seatronics, in partnership with Digital Edge Subsea, will offer training locally at six locations.The company's EdgeDVR range allows both HD (high definition) and SD (standard definition) video recording, with full multichannel overlay built-in. Event hot keys allow data to be input quickly and simply into the automatically generated dive, photo, video and anomaly excel logs. Video can also be constantly recorded, utilizing a built-in black box feature.

Each system is remotely accessible via the internet, allowing Digital Edge Subsea to provide technical support and assistance rapidly and simply.

Seatronics has offices in Aberdeen, Abu Dhabi, Germany, Houston, Macae, New Iberia (Louisiana), Norway, Perth, Peterhead, and Singapore.

www.seatronics-group.com

Equalizer develops alignment tool

Equalizer International has introduced its Wind Turbine Tower Alignment Tool, used to resolve bolt hole misalignment on flanges inside wind turbine tower sections during assembly or installation.

The tool was developed from concept to delivery in less than 10 weeks, at the request of Siemens Wind Power, via Equalizer's Danish distributor Hytor.

www.equalizerinternational.com

AST achieves ATEX certification

Pressure sensor and transmitter manufacturer American Sensor Technologies' (AST) pressure transducers have achieved ATEX certification. In coordination with CSA and SIRA, AST gained ATEX certification for Class I Zone 0 Exia IIB and IIC, T4 rated areas. AST's ATEX certified pressure transducers are available for submersible and non-submersible applications including oil field SCADA systems, compressors, hydraulic systems, water management and more.

www.astsensors.com

Crowcon introduces new gas detectors

Gas detection firm Crowcon released its latest IRmax capability extension, enabling the detection of 29 hydrocarbon gases or vapors. The infrared (IR) gas detector can now be calibrated for more obscure gases or vapors including toluene, cyclohexane, isopropyl alcohol, methyl ethyl ketone (MEK) and para-xylene, along with methane, ethanol, and LPG.

IRmax is an ultra-compact IR gas detector which delivers rapid hydrocarbon gas detection with very low power consumption. It has dual-wavelength IR sensor technology in a 316 stainless steel package and can operate in temperatures ranging from -40°C to +75°C. IRmax has IEC61508 SIL 2 Sira, ATEX, IECEx, Inmetro, gas, and dust zone certifications.
www.crowcon.com

WFS launches updated Seatooth

WFS has launched its latest Seatooth, the new edition of its subsea wireless video camera. Seatooth is an upgraded version of WFS' previous Viewtooth product. The subsea wireless video camera is enhanced with the latest Seatooth S300 technology and exceeds the underwater wireless video streaming capabilities so far known in the subsea industry. Seatooth Video removes the need for a second monitoring ROV, while providing a second perspective on construction and IRM activities or complex tasks and helps ensure operations are completed without ROV umbilical snags.

Seatooth Video allows for remote monitoring of subsea equipment and inspections.

The camera is capable of wireless video streaming at a range of up to 4.5m, at 4000m water depth, in H.264 CIF (352x288), providing up to 10 frames/sec. The control module integrates with an ROV Ethernet port and the output files are .asf format. The wireless video system also integrates with other standard subsea cameras, and an optional primary battery may last to up 10 years in standby mode.
www.wfs-tech.com/

Flowrox releases new pipeline monitoring system

Flowrox released the new Flowrox Deposition Watch, designed to enhance pipeline monitoring and related flow-process equipment affected by paraffin wax and asphaltene deposition.

The Flowrox Deposition Watch is a predictive device that enable operators to address deposition issues before they reach critical levels that can cause downtime or damage. It shows deposition thickness, deposition profile, growth rates over time, composition, and free flow volume - all of which help engineers identify and understand areas where pipes are prone to these damaging deposits. It can be integrated into existing systems to avoid unnecessary production stops caused by cleaning.

The Deposition Watch utilizes electrical capacitance tomography to create real-time images of the pipe interior and uses electrical capacitance tomography to detect differences in permittivity (resistance) of substances found in the piping system. The instrument uses a patented algorithm that creates a 3D image of the process fluid in the piping. It generates trend data and shows free volume inside the pipe and the growth rate of deposition over time.
www.flowrox.com

Activity

Mexican energy reform signed into law

Mexico's President, Enrique Pena Nieto.
Image from Pemex.

Mexican President Enrique Peña Nieto signed the long-awaited secondary legislation of the country's recent energy reform into law, opening the country to private investment.

Days later, Mexico's Ministry of Energy (SENER) granted state-owned Pemex almost all of the acreage detailed in its Round Zero wish list, including rights to all requested domestic proven and probable reserves (2P).

SENER granted the state-owned company 83% of Mexico's 2P reserves, which represents the whole of what it requested on 21 March.

Pemex was assigned 21% of the country's prospective resources, versus the 31% requested. It requested and received all of its producing areas, totaling 120 entitlements. Mexico's National Hydrocarbons Commission will conduct its first-ever bid round in 2015.

Helix, OneSubsea and Schlumberger form alliance

OneSubsea – the Cameron and Schlumberger-owned company – Helix Energy Solutions Group, and Schlumberger announced that they have entered into a letter of intent to develop technologies and deliver services to optimize the cost and efficiency of subsea well intervention systems.

Subsea well intervention provider Helix has the largest fleet size of well intervention vessels. Subsea well control company OneSubsea has experience in the manufacture and supply of subsea well intervention equipment and services. Schlumberger is a supplier of technology and services to the oilfield, including conveyance systems and in-well technologies for subsea applications.

Upon agreement on the final terms, the three companies will provide a fully-integrated offering, combining marine support with well access and control technologies. The alliance will focus on several objectives, including the expansion of applications enabled by subsea well-access technology, and specific solutions for deep and ultra-deepwater basins and higher well pressure environments. ■

Sandvik and Tenaris sign agreement

Sweden's Sandvik and Luxembourg-headquartered Tenaris have signed a new five-year strategic alliance agreement on the exclusive joint supply of corrosion resistant alloy OCTG materials and technology to the oil and gas industry.

The two companies have already been working together for more than a decade. The alliance will bring together Sandvik's corrosion resistant alloy tubes and TenarisHydril premium connections with Dopeless technology.

Sandvik said this will bring many benefits including a complete offer for the market, particularly in the most challenging oil and gas exploration and production environments, such as high-pressure, high-temperature and deep water, where harsh conditions call for safe operational material solutions while reducing environmental impact.

Fosun to buy Roc Oil for US$441 million

Chinese industrial conglomerate Fosun International is buying Australia's Roc Oil Co. in an all-cash, A$474 million (US$441 million) transaction.

Sydney-based Roc Oil has assets from Australia to Malaysia, China, and the UK North Sea, produced 2.7MMboe in 2013, and earned a net profit of US$45.2 million. Roc says its Chinese and Australian assets provide over 90% of production and revenue, as well as almost 90% of 2P reserves (at 31 December 2013).

Bechtel and Gulf Island join forces

Gulf Island Fabrication has signed a cooperation agreement with Bechtel Oil, Gas, and Chemicals, Inc. to work together on offshore projects for the US Gulf of Mexico and abroad. Gulf Island Fabrication will offer its fabrication experience, infrastructure, and skilled labor, alongside Bechtel's engineering, project management, and direct-hire construction capabilities, to create an engineering, procurement, and construction provider to deliver fixed, floating, and subsea facilities to the market.

Gulf Island Fabrication, based in Houston, Texas, fabricates offshore drilling and production platforms, hull and/or deck sections of floating production platforms and other specialized structures used in the development and production of offshore oil and gas reserves.

Dassault Systèmes to acquire Quintiq

France's Dassault Systèmes announced the signing of a definitive share purchase agreement for Dassault Systèmes to acquire Quintiq, a Dutch supply chain planning software firm, for about US$335 million (€250 million) 23 July.

Completion of the deal is conditional. Quintiq will expand Dassault Systèmes' DELMIA brand, adding the new product line of operations planning and optimization to the existing ones of digital manufacturing and manufacturing operations management. Quintiq provides a new reach into industries such as metals, mining, oil & gas, rail, delivery and freight.

Spotlight

By Audrey Leon

From fjords to FPSOs

Stein Rasmussen, SBM Offshore's new managing director of the Houston execution center, says he had a natural affinity with water since he was a child growing up in Norway. It's fitting since he has spent his entire career working with floaters at companies such as Technip, Aker Solutions, and Keppel.

His career path was "a natural progression," Rasmussen says. His father was an engineer, and he followed in his footsteps. Rasmussen pursued a degree in marine technology and then set off to America to work on a master's degree in ocean engineering at Texas A&M University.

"The option for me was to go to Trondheim or to go abroad (to major in ocean engineering)," Rasmussen says. "I have always been a bit adventurous. If I was going to leave my home town, I might as well go far away to get more exposure and experience for something new." Once Rasmussen graduated, he went overseas to work for Keppel where he was able to see firsthand how FPSOs are developed from the ground-up.

"It was a very eye-opening experience," Rasmussen says. "It always helps when you're going to use, or buy a product, to understand how it was built.

"The biggest lesson, for me, was the aspect of constructability. Engineers will always engineer the best they can, but that may not always be the most cost-efficient or fit-for-purpose," he says. "In the yard sometimes when you see the final drawings, it's impossible to build it."

At Aker Solutions, Rasmussen worked primarily with semisubmersibles. It was here that he saw the significance of strategy. "It's important to set a clear path and have it endorsed within your company," he says. "We (SBM Offshore) are working very hard to be a bit more strategic in how we operate."

And Rasmussen believes strategy will help continue SBM Offshore's growth of the last few years. "One thing that has changed with SBM Offshore is that our products have grown in complexity, but also in capital value," he says. "We have to be very good at what we do, to be successful. A small mistake on a small project is very different from five years ago than a small mistake on a much bigger project today."

Several aspects attracted Rasmussen to SBM Offshore including the company's commitment to technology development, as well as its wide product offering including semisubmersibles, TLPs, and FPSOs, which he says allows SBM Offshore to span a broad spectrum of the market. However, SBM Offshore is a natural fit because it's a return to working with FPSOs. "I've always been fascinated with FPSOs," he says. "That's where I started my career and that was a good match for me."

Rasmussen does see a demand for FPSOs in the Gulf of Mexico. "As you go deeper and deeper, you go farther away from pipeline infrastructure, and an FPSO is a natural transition," he says. "Combining that with the challenge of the reservoir, you will need more power, more topside capacity, and then these other floater types become so big that the FPSO can be more attractive when compared with a semi."

Currently, SBM Offshore is designing and building the deepest disconnectable FPSO, Turritella, in the world for Shell's Stones project in the Walker Ridge area of the Gulf of Mexico. And Rasmussen says the company is focused on developing technology that will unlock potential in the Paleogene and Lower Tertiary plays. Having already won an award at this year's Offshore Technology Conference for the Very High Pressure Fluid Swivel.

"I've always been fascinated with FPSOs," he says. "That's where I started my career and that was a good match for me."

In addition to technology, Rasmussen says he's a big believer in developing the right company culture. And in his role at SBM, he says the company must focus not only on the "Safety" in Health, Safety, and the Environment, but also Health. "A healthy employee is a happy employee, is a more efficient employee," he says, noting that SBM provides employees with access to gym facilities and health screenings.

When reflecting on his career learnings, Rasmussen says in addition to have a focused leadership style, transparency is also important. "Open communication, and providing information is key," he says. "The more you leave people to speculate, the more confusion you create. I want people to be clear about what we're trying to achieve, and how we are going to do it." OE

Faces of the Industry

By Kelli Lauletta

This month's Faces of the Industry turns to the subsea sector. Over the course of Brian Skeels' illustrious career, he has notched a number of firsts: first producing guidelineless tree, ROV panel development on trees, and the first 10,000psi subsea tree in the Gulf of Mexico. Skeels' career has seen him playing the roles of deepwater pioneer, teacher, mentor, detective and aspiring "renaissance man." He was hooked by the sea at a very early age, and has an innate curiosity in figuring out how things work. Skeels never looked back as he dove into a subsea career.

OilOnline recently sat down with Brian Skeels, Director of Emerging Technologies at FMC Technologies, at his home with his rescue dog of ten years, Pops, close by his side. Skeels' face lit up as he talked about his entry into oil and gas, his career highs, and his take on what life has to offer and what he wants to offer back.

How did you get into oil and gas?

From an early age, I knew I had an affinity for science. In my adolescent years, my family got into boating with a second-hand cabin cruiser that my dad refurbished. I built my first Heathkit, a gas fume detector to make sure the engine hold was clear and safe before starting the engine. I was hooked with the sea. From there, I cox'ed for Cornell's rowing team to continue my stint with the water; while I settled in on mechanical engineering.

While in college, I started seeing commercials from Exxon launching their SPS template in the Gulf of Mexico and wondering how cool it would be to apply mechanical engineering to submarines and boats. This and a very depressed job market awaiting me after graduation persuaded me to get a master's degree. A fraternity brother's dad was a pharmacy professor at the University of Rhode Island (URI), and he persuaded me to take a road trip from upstate New York to Rhode Island to look around.

Driving into Narragansett, the Atlantic Ocean opened up before us at land's end. I was definitely hooked. The next 2.5 years were spent getting an ocean engineering degree at URI. Then along came Exxon. I started at EPR and within a week I was shipped off to New Orleans and started learning about the SPS (the very thing that I had seen on TV) to do the abandonment and removal of the SPS. I've been living in Houston ever since.

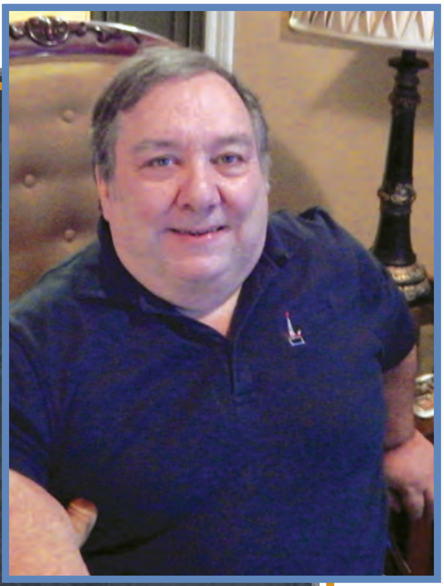
Were there any career turning points?

I have had a bunch of twists and turns along the way, both good and not so good. My biggest break was going offshore right off the bat. I was working with my hands, reading the newly minted text that the original SPS team was feverishly writing to preserve the technology they had wrought (led by Joe Burkhardt, Tom Childers, Bil Loth, Dan Tidwell, Pat Rickey, and Al Butler – to name but a few of the pioneers of subsea). They would sometime make surprise visits offshore to see how we neophytes were getting along trying to dismantle all the hardware they had put in.

As it turned out, I was exposed to many more of the pioneers that developed ROV and remote diving bell and "end effector" technology, advanced commercial diving (the SPS was in a whopping 170ft of water off Grand Isle), subsea pumping and level separator processing, through flowline (TFL), pipeline pull in and connection techniques. All of this was when subsea was still in its infancy (or toddler stage).

As luck would have it, an engineer at FMC Technologies was transferring to Brazil to be an in-house liaison with a licensee company that was building a reputation with Petrobras and the Houston office was looking for a replacement engineer. I know most folks tend to go from a supplier or contractor to an oil company along their career path, and I was headed in the other direction. It was a chance to get back to my comfort zone with hands-on problem solving, machine design, and offshore installation in a whole new offshore theater, Brazil, in the Campos Basin.

Right away, the licensee company, CBV, and their oil company benefactor, Petrobras took to me and my "crazy gringo" ideas to solve all kinds of issues. Petrobras was a "let's do it" kind of company. It turned out to be a great motivator to me, never wanting to let them down for any reason until the job was done and done right. My Brazilian connection pushed my career to the next level, giving me to opportunity to work on several "firsts" including the first producing guidelineless tree, ROV panel development on trees, the first



Brian Skeels *is director of emerging technologies at FMC Technologies, Inc. and adjunct professor-subsea engineering at the University of Houston. Brian has over 35 years of experience in subsea completion and pipeline design and installation, including five years with Exxon Production Research Co. working on its famous SPS and UMC subsea systems. As FMC Technologies' Emerging Technology Director, he serves as a technical subsea advisor and strategic planning specialist for frontier technologies and new business opportunities. His efforts delve into HPHT, riserless light well intervention, ROV and remote robotics technology and subsea spill containment programs.*

For 30 years, Brian has also partnered with the American Petroleum Institute in their upstream standards development and currently serves on API subcommittee 17 executive committee. He serves as task group chairman for 17G on subsea intervention systems, co-chair for 17D on subsea tree and wellhead equipment, and chair 17TR8 for HPHT equipment design. Brian is also an ASME Fellow and serves on various industry advisory boards. Brian earned his B.S. in mechnical engineering from Cornell Univeriisty and his M.S. in ocean engineering from the University of Rhode Island.

Brian is hitting another milestone this month when he turns 60. Happy birthday!

10,000 psi subsea tree in the Gulf of Mexico, the first guidelineless horizontal tree in the Gulf, the first internal tieback wellhead connection system from the first ever production spar, and the first 15,000psi subsea tree in the Gulf.

Tell us a secret about success?

Besides a strong work ethic, there are a few areas that the technically inclined "geeky nerds" need to work on: 1) Learn the art of public speaking; 2) Learn the art of technical writing, and be able to "tell a story;" 3) Learn the technology, even if you're not the one developing it; 4) Get involved with professional societies; 5) Get a mentor and stick with them, and 6) Later in your career become a mentor to the next generation.

Work/life integration–how do you make it work?

Family comes first, period. And family emergencies take precedent over everything else. It's easy in the oil patch to get caught up in fixing problems, putting out one fire after another, or meeting that latest deadline. But when its time, you need to take some equal time to decompress and get back to family.

What do you do for fun?

I like to travel and I'm a history buff. I really enjoy learning about other cultures and how history has shaped them. I enjoy the sights, sounds and aromas of new places. Also, I'm humbled that people from all over the world have invited me to their homes. I'm fascinated by their cultures and what we can learn from them.

What are top 2-3 subsea career trends you see into the next decade?

I liken the subsea industry to the aerospace industry. Right now, the subsea industry is emerging from the barnstorming days, to one of more maturity. The career trends will include: training to close the huge skills gap between the new hires and the retiring old guard – "great crew change," development of non-conventional materials and composites, advances in remote and autonomous control and sensor technology, data mining – ability to reduce mounds of raw data into actionable suggestions, perfecting the art of "marinization."

How would you brand yourself?

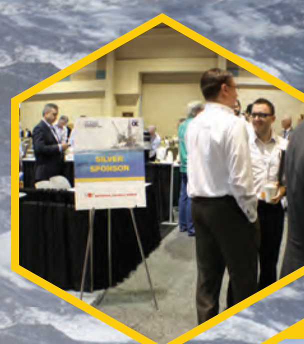
I'd like to brand myself as a renaissance man. I don't know if I consider myself a renaissance man now, but I strive to be. I know 2-3 others who are renaissance men with many talents. Being around them is like being around a multifaceted diamond. You don't know what light is going to play off to see ideas or concepts in a unique way. I hope to be that. I never want to stop learning about new things–I can't stop.

Skeels pointed out the importance of observing the world around you and not getting trapped in a "knowledge silo" in your career. Look outside your industry for the next great idea or solution. Skeels laughed as he explained how he had to figure out a compact locking device for a project and was really stumped until he noticed the spring loaded device in a toilet roll holder. The spring action mechanism was the perfect solution to his locking mechanism conundrum. Who knew? **OE**

Faces of the Industry will feature individuals who do extraordinary things for the industry and outside the industry. If you would like to nominate someone, please send an email to Kelli Lauletta.

Kelli Lauletta *is an HR consultant with 17 years experience. She also serves as an editor for OilOnline.com. If you have story ideas please email Kelli at klauletta@atcomedia.com.*

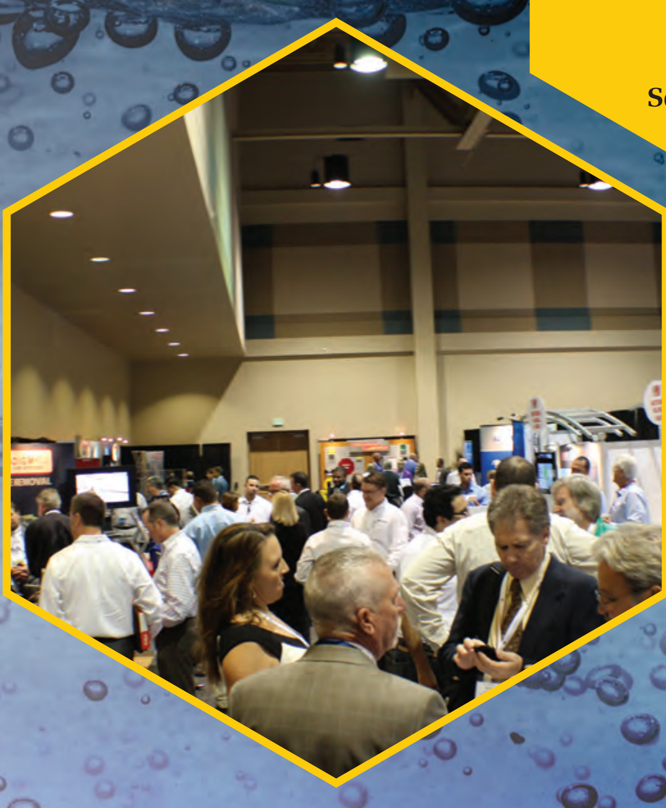
10th Annual Deepwater Intervention Forum at a Glance



DEEPWATER INTERVENTION FORUM

"Consider the "next-frontier" a few years ago, Deepwater is the present and the future of the Oil and Gas Industry. From West Africa to North Sea and from Brazil to Gulf of Mexico, the industry is looking at us. Deepwater is a reality and the Deepwater intervention Forum provides the place to meet, learn , discuss and…. get a flavor of the Gulf Coast."

J.J. Duenas
Senior Well Intervention Manager
BP-GOM-Wells



DEEPWATER INTERVENTION FORUM

DIF 2014 was the best attended yet and the growth of this forum since its inception has been tremendous. For Helix ESG it is the optimum platform for reaching out to clients, finding out about new technologies and advising the industry of our own progress and developments."

Colin Johnston
VP Commercial Engineering
Helix Energy Solutions

"I am very pleased to see my colleagues from different companies get together in a collaborative environment and share their experience and knowledge. The quality of presentations and audience is impressive. It is hard to believe that we had approximately 1,000 attendees in our 10th year anniversary conference. This means that the delegates are getting the value they expect by attending DIF."

David Brown
Program Manager
FTO Services

"With subjects varying from surface vessels, down hole tools, sub-sea intervention equipment and case studies from both operators and service providers the content was very informative on all aspects of well intervention work"

Tony Ryan
Principal Intervention Specialist
ConocoPhillips

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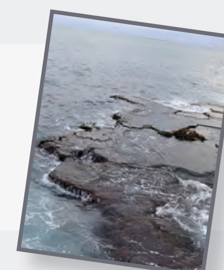
Numerology

US$91billion will be spent on floating production systems in 2013-2017, according to Douglas-Westwood. See page 26.

482MMboe

The estimated reserves of the primary leads on frontier exploration license 1/13 in the Porcupine basin off Ireland. See page 16. (GBCB)

12 right-holders operators have been pre-qualified for Lebanon's bid round. See page 90.



60%

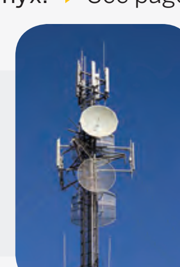
According to the UK Department of Energy & Climate Change, production efficiency on the UKCS fell from 81% in 2004 to 60% in 2012. See page 24.

50% Baker Hughes' new StayCool cutters run about 50% cooler than its standard counterparts. See page 48.

8mm/s of movement in a pipeline at 1500rpm would place in the "concern" range of Pipework Vibration Criteria as defined by the Energy Institute. See page 86.

2000tons of flexible pipe are on the deck-mounted carousel of the Polar Onyx. See page 102.

75% of 120 respondents in a Vodafone and Huawei-led survey use wireless technology for communications. See page 34.



1987 is when London-based Tronic, since acquired by Siemens, invented the first controlled environment connector. See page 78.