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Global Deepwater Review

Brazil Offshore

Offshore Engineer • May 2014

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ON THE COVER

Floating production. The spherical image taken from an R2S capture by Return To Scene shows an FPSO operating in the UKCS. On this occasion, the operator utilized R2S imagery to prepare for maintenance work - streamlining the planning process and reducing demand on valuable POB. Photo from Return To Scene, www.R2Senergy.com

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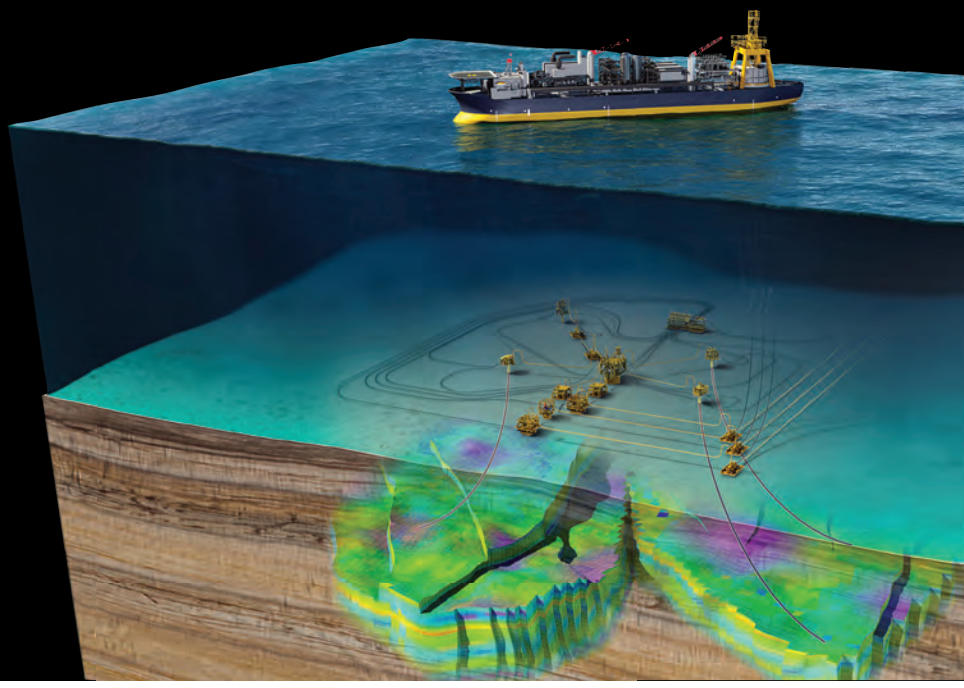

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Departments & Columns

"What's the biggest barrier to the complete subsea processing factory?"

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People

Noble succession

Noble Energy Inc. will appoint David L. Stover CEO, effective October 2014, succeeding current Chairman and CEO Charles D. Davidson (pictured), who retires this month.

Online Exclusive

HRT moves ahead at Polvo

Peter Howard Wertheim reports on Brazilian oil independent HRT's future plans for its offshore Polvo field development in the Campos Basin.

What's Trending

Big deals

OE provides news updates on the industry's largest projects, discoveries and permiting.

- **$16B Kaombo project approved**
- **GOM lease sale includes US-Mexico Transboundary areas**
- **Shell discovers DW gas off Sarawak**


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Voices

The briny deep. With seabed processing now a popular concept, OE asked:

What's the biggest barrier to the complete subsea processing factory?

Complete subsea processing could play a significant role in enhancing recovery from mature and marginal fields. However, although the track record of many of the individual technologies required to achieve it is growing, the full potential is not yet being realized. To move forward, the industry needs to be more proactive in working collaboratively to trial new equipment and technology.

Dr. Patrick O'Brien
CEO, ITF

Project management over the factory lifecycle of such "mega-projects" with focus on schedule and costs, for both capex & opex will be the big challenge. The availability of standard subsea modules is a key element towards the success of subsea factory, especially on the power distribution side. Standardized solutions will drive the non-recurring engineering down and will benefit both the capex. Reliability will also be a key factor for the opex, as well as standardization, which will keep intervention costs as low as possible.

Josselin Legeay
Product Manager, High Power Systems – DEUTSCH Offshore
TE Connectivity - Aerospace Defense & Marine

The complete subsea factory is closer than we think. In our view, all the enabling technology already exists and the real challenge is moving from a series of separate niche technologies to a complete subsea system. Projects like Åsgard subsea gas compression are proving the industry's capability of taking topside functionality subsea. The next step is to simplify the concept, making it available for smaller fields.

Svenn Ivar Fure,
SVP Subsea Strategy and Business Development, Aker Solutions

With the oil and gas industry extending its reach to deeper and harsher environments, the vision of a complete subsea factory is closer to reality than ever. However, in this tight financial landscape, operators will have to strike a balance between field economics and the risks associated with this innovative approach. The biggest challenge for the complete subsea factory lies in the successful financing of a relatively not field-proven solution over its traditional surface alternative.

John Ferentinos
Senior Analyst, Infield Systems

Subsea factory (SF), as any new concept, has its own challenges, mainly large power requirements for long distance, equipment reliability and intervention needs. Traditionally, power demand subsea has been confined to control systems. SF steps up the power demand from the kW to the mW range. There is ongoing research developing capable underwater power sources. For intervention, subsea process intervention vessels have to be developed. They would need to be available year-round with large enough capacity to lift modules and handle hydrocarbons. Once a candidate field is identified, the potential risks may be balanced out by the realized benefits.

Martha Viteri
Head of Section, Subsea and Well Systems, DNV GL - Houston

Much like the single leadership act to commit to put man on the moon, I believe the biggest barrier is for industry leadership, at the right time, to commit to deploy full subsea processing in the face of the perceived technical and economic risks. The right circumstances are coming, and in the interim, it becomes a matter of planning, risk management and allowing our talented engineers to overcome the technical barriers that exist today. Meanwhile, subsea processing solutions, which are both building blocks for full subsea processing and standalone solutions in their own right, are being developed, qualified and deployed. We will get to full subsea processing in a series of smaller steps rather than one "Big Bang" event.

Rob Perry
Global Subsea Processing Director
FMC Technologies

Achieving high availability via reliability and integrity management is key, as many systems utilize marinized topsides technology, for which the availability equation is typically maintainability. Further technology development is required in subsea equipment, such as electrical power systems, variable speed drives, and monitoring systems for very low oil in water concentration. Deeper water requires a further shift to more novel technology and increasing step-out distances, and flowrates demand larger pumps and compressors. Further standardization would improve industry acceptance, but each field demands bespoke engineering to optimize production.

Keith Moar
Technical Specialist - Subsea Production System, Atkins

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A Helping Hand

Brion Palmer

As a publisher, one of the most rewarding experiences is when a reader tells you how important and influential your magazine is to them. This type of feedback provides the sense of purpose everyone seeks from their professional endeavors. It provides the vital to answer to the question, "Is what I am doing truly important in the grand scheme of things?" Everyone aspires to make a difference.

All of us at AtComedia, parent company to and publisher of *Offshore Engineer*, are excited to take this pursuit of making a difference to the next level and we invite you to join us.

For the entire month of May, AtComedia will donate one dollar to Oilfield Helping Hands for every person that creates a personal profile on OilOnline, our new professional development and networking website for the oil and gas community. Your individual profile will empower you to network, access professional development content, receive breaking news, and explore new professional opportunities. Now, as an added value, you will be making a difference in the lives of a family less fortunate.

"The mission of Oilfield Helping Hands is to help oilfield families in crisis through no fault of their own," said Gary Brooks, president. "The monies generated through our events, corporate memberships, foundation funds and employee choice programs help with operating the organization and allows our selection committee to assist families who are in a crisis."

Established in 2003, Oilfield Helping Hands has recently added three new chapters in Louisiana, Oklahoma, and Colorado. "This vision is supported by corporate member sponsors, event sponsors, and volunteers," Brooks said. "Working together, as the oil and gas industry, we have assisted over 200 families with $2.4 million."

Additionally, AtComedia will donate 25% of all OilOnline advertising revenue sold for the month of May. This is a chance for companies' advertising dollars to work on two fronts – for their business and for Oilfield Helping Hands. AtComedia will recognize all companies supporting this program with their advertising dollars with a special ad thanking the supporting companies.

There is no ceiling on what AtComedia will donate to Oilfield Helping Hands during this promotion and we challenge the industry to force us write a very large check.

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Colloquy

Nina Rach

PECOM celebrates 20 years

The Petroleum Exhibition & Conference of Mexico (PECOM) recently celebrated its 20th year. The location in Villahermosa, Tabasco's state capitol, is fundamental to the continuing success of the conference and convenient for many PEMEX personnel. Villahermosa is the center of a wealth of petroleum activity, exemplified by nearby Ciudad Pemex and its gas processing complex, the Centla project area and Port of Frontera on the Grijalva River, and offshore support activities at Ciudad del Carmen on the Bay of Campeche.

At a US Department of Commerce-sponsored lunch briefing the day before the expo opened, Jose Luis Chavez, Planning and Evaluation Manager, gave a presentation about the PEMEX Southern Region: "Exploration and Production Projects and Opportunities, 2014-2018."

He explained that the South Region produces a diversity of hydrocarbons, with oil ranging from 20°-60° API gravity, comprised of heavy Maya (3%), Istmo (64%), and Olmeca (33%) crudes.

The South Region also hosts 52 separation facilities, and 1395 operating wells. Oil drilling began in 1953, and gas drilling in 1958.

Today, the region produces 482,000b/d of oil and 1592 MMcf/d of natural gas.

In 2014, PEMEX will drill 47 Mesozoic wells in the region. PEMEX is decreasing use of pneumatic pumps and will install electro-centrifugal pumps in more than 40 wells this year. It employs coiled tubing, foam, vapor, nitrogen, and gas injection in secondary recovery operations, and will test air injection in the Mesozoic later this year.

Opening

Gustavo Hernandez, the new General Director of PEMEX Exploration & Production (PEP), opened the conference with a keynote address. He said PEMEX will be proposing a major new reorganization in the following weeks that would be more harmonious and allow the company to face competition.

"The figures give context" to the importance of oil & gas in Mexico, he said. Mexican oil production, at 2.877MMb/d is 7th highest in the world, and 1P oil reserves are 13th. Although many fields are declining, Hernandez said he wants to keep PEMEX crude oil production at ~2.504MMb/d.

The company's main oil production comes from the Bay of Campeche: primarily the Ku-Maloob-Zaap (KMZ) fields, followed by the Cantarell complex (in production for 35 years as of June 23).

Hernandez said PEMEX natural gas production, at 4.262MMcf/d, is 17th in the world, and 1P gas reserves are 33rd. The two major sources are the Burgos basin in northern Mexico and the offshore Cantarell fields.

He said the PEP South Region is important because of extensive infrastructure that enables low development costs (US$6.84/bbl to produce in 2013, lowest among IOCs and NOCs), and also because of Mesozoic discoveries in Tabasco.

PEMEX wants to optimize flow and uses pressure injection to increase recovery from wells. Of 120MMbo produced from 14 fields, he said 10% of the production results from injection.

To develop heavier, higher viscosity oil, Hernandez said the company is investigating the use of nanomaterials as catalysts, and microwave heating to reduce viscosity and improve flow.

Air injection (10MMcf/d at 4500psi) into Well 142 at the Cardenas field will be the first in the world, scheduled for October.

"We've also been working hard to avoid/ reduce venting gas," and 98.4% of gas produced in 2013 was captured, rather than flared.

In terms of investment, Hernandez said: "The oil & gas industry needs a big effort to start moving." PEMEX acquires new seismic data every year, but needs specialists to process and interpret. "Our diversified portfolio allows us to diversify risks" in conventional and unconventional, deepwater, and shale projects.

In 2013, the company drilled 672 development wells and 40 exploratory wells, but still needs execution capacity, including drilling equipment. "The activity is not enough yet," he said, "but it is exactly what this legislation seeks to accomplish. Together [with outside companies] we will be able to explore the national territory."

PEMEX exploration strategy is focused on extraction, he said, with more than 55,000 workers to implement the work. Of the company's top 21 exploration projects, only eight are land-based, so there is cleary a major emphasis on offshore.

Hernandez reiterated that all work is based on the three pillars of PEMEX: Safety, Environmental Protection, and Sustainability. OE

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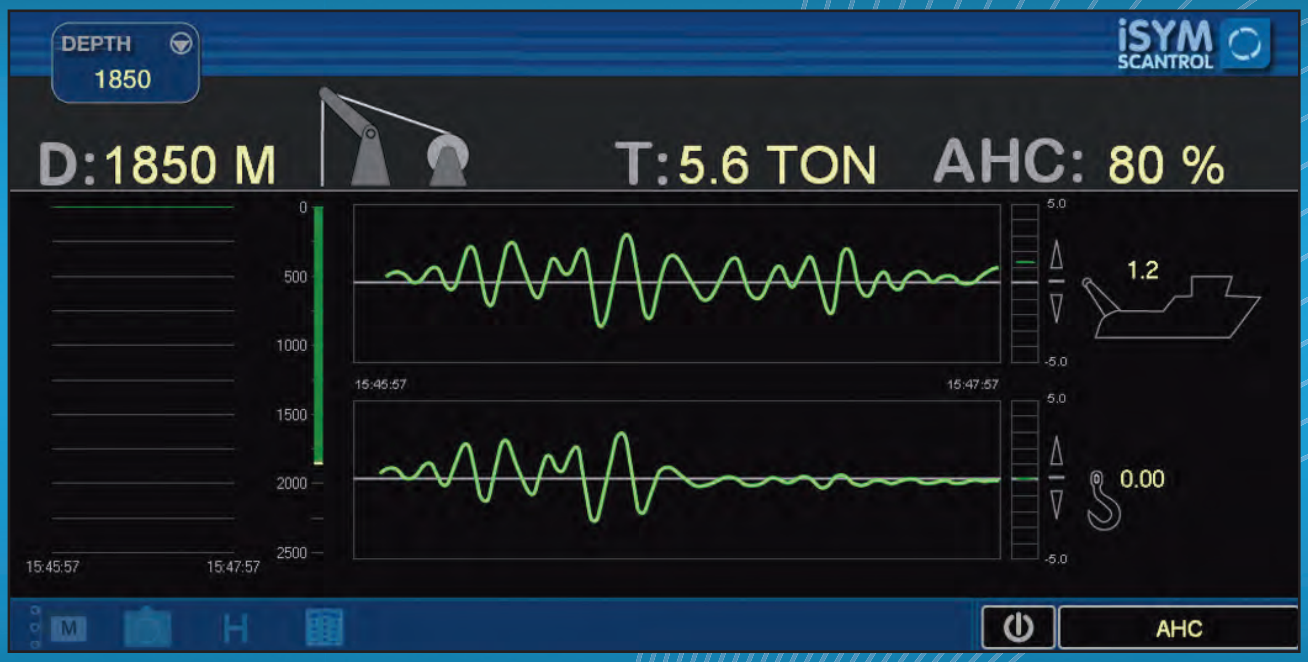

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ThoughtStream

Brian Teutsch, Baker Hughes

Ensuring risk mitigation with a drilling fluid design

With one question, the tone of the room changed from light banter to serious contemplation.

"What is the most important thing to you in a drilling fluid," I asked 74 mud engineers at a Gulf of Mexico engineering meeting held in Louisiana.

Everyone openly acknowledged that if we don't have an environmentally compliant system, we have nothing but liability.

The next question was about priority number two for a drilling fluid. The answer was a modest demand that the system and its components perform well and consistently.

The role of the drilling fluid as a major player in operational safety is ever more prominent. As a well barrier element, the drilling fluid must remain stable and capable of sustaining its density uniformly, even in adverse conditions. Likewise, it must work in conjunction with the cement.

Sourcing and production of quality materials, and quality management systems themselves also bear universal consideration. As the drilling fluid design relies on more complex, synthesized chemistries, the tolerance for manufacturing variance is reduced. For a drilling fluid system that is to be deployed globally, incorporating the aspects of a global supply chain is required in system design.

The last priority was somewhat more complicated, but could be summarized as a need for improved hydraulics. No matter what system is in play, equivalent circulating density (ECD) and hole cleaning are continual constraints. These two basic hydraulic aspects have major effects on the drilling operation, such as expensive mud losses, inability to properly place cement in the annulus, and nonproductive time. The hydraulics also have wide reaching effects into areas of rig selection, well and casing design, field development strategies, etc.

One category of fluids that tackles these hydraulic challenges is constant rheology. These systems seek to avoid thickness associated with cold temperatures (and resulting high ECD), while sustaining an adequate viscosity at higher temperatures for removing and suspending cuttings.

Standards are essential in benchmarking performance and measuring improvement, yet for a category of fluids as important as this, there has been surprisingly awkward silence when asked how to characterize the defining attribute of such a system. Now, a method of defining the system's rheological response to temperature has been posed to the industry, clearing the way for objective targets for improvement in future system design and development.

Though all intentions are to minimize time on the critical path, nowhere more than offshore areas recognize that the most efficiency comes from steady progress and risk aversion.

Lastly, water depths vary, as do temperatures on the surface and downhole, but narrow pore pressure/fracture gradient (PP/FG) windows appear in practically every region. With continued exploration into deeper waters and continued development into depleted fields and increasingly horizontal trajectories, PP/FG windows continue to contract. The importance of hydraulics is essential and ever-increasing.

The industry is also constrained by drilling fluids limitations. In terms of hydraulic performance alone, lack of definition has blurred objective performance assessments. With a methodical definition established, performance improvement can be measured and applied in critical applications. This does not just enable one well; it enables access to one basin, then another. New energy reserves are now within reach.

In some areas of the world, increased efficiency is associated with instantaneous rates of penetration and how fast casing can be jammed in the hole. Though all intentions are to minimize time on the critical path, nowhere more than offshore areas recognize that the most efficiency comes from steady progress and risk aversion. Every area is high risk, with distinctions only by matters of degree.

In order to ensure that risk is managed as effectively as possible, the drilling fluid has to consider these risks as fundamental in the design. The outcome of this design will be unveiled in coming weeks. This drilling fluid system shows promise of ensuring access to future energy reserves, and ensuring efficiency through improved risk management during drilling and cementing operations.

To learn more about system described in this article, visit Baker Hughes (booth #3731) at the Offshore Technology Conference (OTC) in Houston this May. **OE**

Brian Teutsch *serves as product line director for drilling and completion fluids at Baker Hughes Inc. He joined BHI in 2001 as a field engineer and has progressed through various engineering, business, and management positions. Teutsch graduated from Southern Arkansas University.*


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Allseas

Global Briefs

A GOM block sale

The Bureau of Ocean Energy Management (BOEM) received 380 bids on 19 Mar 2014, for 326 blocks in the central Gulf of Mexico, totaling more than US$850 million. Gulf of Mexico Lease Sale 231 attracted operators to bid on almost 40 million acres, the most popular being the deepwater and ultra-deepwater regions.

Freeport-McMoRan Oil & Gas was top bidder, with 16 bids totaling $321.44 million. The company's highest bid went on Atwater Valley Block 198, which received the most bids of all blocks offered. Supermajors Chevron and Shell placed the single highest bids for acreage in the region.

B Pil a success

Partners in the Pil exploration well 6406/12-3 S have carried out "a highly successful production test" on the well, on the Norwegian Sea's Halten Terrace. The well flowed at 6710bo/d of 37° API oil, exceeding expectations.

Preliminary estimates by operator VNG Norge (VNG) put the size of the Pil discovery at 50-170MMboe.

C Statoil farm-in

Agência Nacional do Petróleo, Gás Natural e Biocombustíveis cleared Statoil to enter the São Bernardo discovery in Espírito Santo, the Norwegian company announced. On 27 Dec 2012, Statoil farmed in to the BM-ES-22A concession, which holds the São Bernardo discovery, through the purchase of Brazilian mining firm Vale SA's 25% participating interest for a cash payment of US$40 million. Petrobras, as operator, holds the remaining 75% interest.

D New well at Sapinhoá

A third well is now producing in the Sapinhoá field, Petrobras announced.

Well 7-SPH-04-SPS, which lays in 2120m of water on Block BM-S-9 of the Santos basin presalt region, has an estimated production potential of 26,000bo/d, the Brazilian company said. Sapinhoá's first producing well, 1-SPS-55, was brought online in December 2013, with a potential production rate of 25,000b/d.

E Eni progresses

Eni CEO Paolo Scaroni outlined the Italian company's exploration progress and activities within the country to the President of the Republic of Mozambique Armando Guebuza. Eni announced that the "possibility of enlarging the shareholder base of Area 4 was favorably received by the President, as this would further strengthen the project." Next steps for 2014 include the drilling of two additional wells, after achieving a perfect success rate in the completion of 11 wells.

F Lukoil completes

Lukoil Overseas completed drilling on its first offshore exploration well, Capitaine East-1X, at block CI-101 in the Republic of Côte d'Ivoire. The well penetrated through 140m of sandstone from a Turonian formation. Lukoil said a survey confirmed the presence of hydrocarbons, indicating the oil potential of the area. The well's target depth exceeds 5200m; the water depth at the well location exceeds 2000m. Drilling was conducted using the *Eirik Raude,* a fifth generation self-propelled semisubmersible drilling rig.

G Kaombo approved

Total and its partners will move ahead with the 650MM bbl deepwater Kaombo project offshore Angola after cutting US$4 billion from the project's capex costs. Kaombo will develop six of 12 discoveries made in Block 32, covering 800sq km, through 59 subsea wells, connected to two floating production vessels. Capex costs to reach full capacity on the 230,000 bbl/d potential development were reduced by $4 billion to $16 billion. Start-up is expected in 2017.

H Woodside MOU fails

Australia's Woodside and the offshore Israel Leviathan project joint venture partners missed a target date to agree a deal which would see Woodside take a 25% stake in the two petroleum licenses containing the Leviathan field—349/Rachel and 350/Amit.

Woodside and its partners agreed in principle under a non-binding memorandum of understanding (MOU), with a target date to execute a fully-termed agreement by 27 March 2014. The deal would see Woodside become operator of any LNG development of the field, with Noble Energy remaining the upstream operator.

I Further Kashagan delays

The Kashagan oilfield development in Kazakhstan may be delayed to restart if testing

next month reveals that cracks remain in the offshore portion of its pipeline. The company said it cannot give a restart date for the development until it determines what repairs are required.

The US$50 billion pipeline began production in September 2013, but was halted weeks later after gas leaks were detected in the pipeline's network.

J Peluang produces

Australia-based Santos Ltd. announced that natural gas production has commenced ahead of schedule from the Peluang gas project offshore East Java in Indonesia. Sanctioned in February 2013, Peluang is a tie-back to the existing facilities at the Maleo gas field and is located in the Madura offshore production sharing contract. The project is expected to have gross peak production of 25MMcf/d.

K Roc Oil farm-in

Roc Oil Ltd. farmed in to a production sharing contract in three fields about 50m off Malaysia. The D35, D21 and J4 fields are 100% owned and operated by Malaysia's Petronas Carigali, with Roc Oil holding 50% participating interest. Roc Oil farmed in US$25 million plus a carry with the 50% interest of $80 million for the project spread over Phases 1 and 2. Petronas Carigali will continue as operator of the PSC, retaining responsibility for operations and maintenance of the facilities.

L FLNG hull launched

Petronas launched the hull of its first floating LNG facility, *PFLNG SATU*, at the Daewoo Shipbuilding & Marine Engineering shipyard in Okpo, South Korea. The facility, targeted for completion 4Q 2015, will be the world's first floating LNG facility in operation. The launch took place 5 April.

M FAR evaluates Aussie blocks

Melbourne's FAR Ltd. has identified multiple prospects with total resources of 447MMboe (unrisked best estimate basis) in its exploration permit areas off the in the Dampier basin in Western Australia, WA-457-P and WA-458-P.

Vintage 2D and 3D seismic data and existing well data were used to calculate the resource estimates. Water depths are 25 to 110m. FAR is planning to acquire a new 3D seismic survey over both permit areas in mid-2014

N Roc Oil exits BMG

Roc Oil has farmed out its entire interest in the Basker-Manta-Gummy (BMG) fields in the Bass Strait. The Australia-based firm sold its 50% interest and operatorship to Cooper Energy Ltd. for a US$924,959 cash payment, followed by a A$5 million contingent consideration, subject to first hydrocarbons from a commercial development. The transaction, effective 1 Jan 2014, includes the transfer of all remaining ROC BMG liabilities to Cooper, resulting in a reversal of ROC's full abandonment obligation, netting the company US$32 million.

Cooper now holds a 65% total interest in the field, 15% acquired form Beach Energy Ltd., which retains a 35% interest in the field.

O New Zealand block offering

New Zealand's Minister of Energy and Resources Simon Bridges announced the country's third block offering. Up for grabs is a total of 405,000sq km, including both on and offshore acreage. Offshore release areas include the Reinga-Northland Basin; the New Caledonia Basin; the Taranaki Basin; the Pegasus-East Coast Basin, and the Canterbury and Great South basins.

The invitation for bids for block offer 2014 closes on 25 Sep 2014. Permits will be granted between December 2014 and March 2015. ■

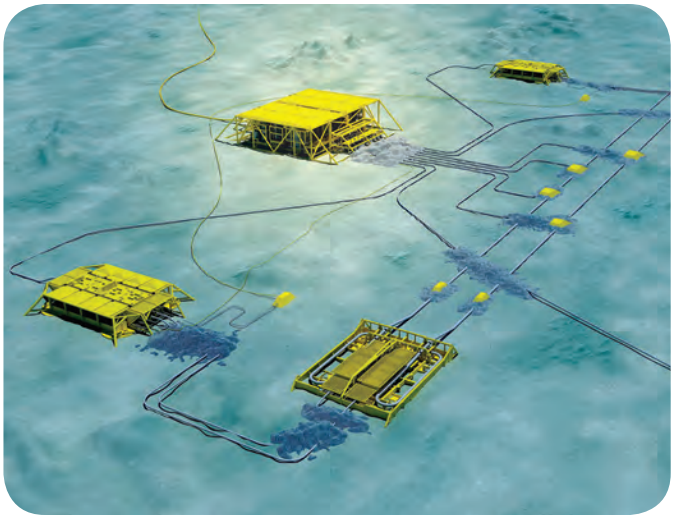
Ormen Lange compression dropped

Shell and its partners on the Ormen Lange license have postponed plans for what could have been one of the first subsea compression projects.

Ormen Lange, Norway's second largest field and producing via subsea wells since October 2007, in the Norwegian Sea, about 140km west of Kristiansund, was being assessed for subsea compression.

Norway's Aker Solutions carried out a pilot project 2004-2011, and system testing 2011-2013, based on one, 12.5MW compression station, at a 120km step-out distance. Shell was also considering using tension leg platform to house topsides compression facilities.

Early April, Shell said it was halting ongoing concept select work. Ormen Lange management committee chairman Odin Estensen, said:



Ormen Lange Field. Photo from Statoil ASA.

"The decision [to stop concept select] is based on an updated economic assessment Incorporating new cost information for the current concepts and updated analysis of the reservoir. The current concepts do not provide an economic return, based on the required capital investment and expected production volumes. The updated reservoir analysis also shows that offshore compression timing is not critical to the ultimate recovery of the field."

"The oil and gas industry has a cost challenge," Estensen said added. "This, in combination with the maturity and complexity of the concepts and the production volume uncertainty, makes the project no longer economically feasible."

The decision to halt concept select was supported by all the Ormen Lange partners, except state oil firm Petoro, said Shell.

Ormen Lange was discovered in 1997, in blocks 6305/4, 5, 7 and 8, in 800-1100m water depths. The field was developed with four subsea templates with a total 24 wells, tied back to an onshore facility in Nyhamna. The field has an estimated life span of 30-40 years, with gas produced mostly sold to the UK.

The Ormen Lange Partnership comprises: Shell (operator 17.81%), Petoro (36.49%), Statoil (25.35%), DONG Energy (14.2%), ExxonMobil (6.34%).

—Elaine Maslin

Contract Briefs

Shah Deniz 2 deals awarded

The BP-led consortium operating the Shah Deniz field development in Azerbaijan has awarded US$750 million in jackets, subsea fabrication and supply contracts for Stage 2 of the $28 billion project.

BP announced that BOS Shelf LLC and Star Gulf FZCO will supply 2300 subsea structures weighing a total of 30,000tonnes. The companies are a part of a consortium led by Italy's Saipem, which will construct two eight-legged single batter jackets, weighing 13,400 and 12,300 tonnes for the development. Each of the jackets will stand 110m high. The subsea fabrication scope of the contract includes eight subsea isolation valve structures, 10 flowline termination assemblies, 80 walking anchors, 100 subsea tie-in piping spools, 100 pipeline crossing supports, 1000 concrete mattresses and 1000tonnes of current transfer zone foundations.

Shell, CNPC agree

Representatives from China National Petroleum Corp. and Shell met in Beijing on 8 April 2014 to sign global cooperation agreements.

CNPC Chairman Zhou Jiping met with Shell CEO Ben van Beurden, where they signed agreements covering unconventional resources, deepwater, LNG, and upstream and downstream businesses. The companies are long-time partners, most recently pairing up alongside CNOOC, Petrobras and Total to form a consortium that will develop the giant Libra presalt oil discovery located in the Santos Basin, offshore Brazil.

Subsea 7 wins BC-10 work

Subsea 7 won a lump sum contract worth about US$110 million from Shell for the installation of jumpers, umbilicals and associated subsea structures for the BC-10 Phase 3 project in the Campos basin, offshore Brazil.

Project management and engineering will be performed from Subsea 7's offices in Rio de Janeio and will start in Q1 2014, with the offshore campaign starting Q3 2015, using the construction/flexlay vessel *Skandi Neptune*. The project has a total duration of about two years.

CB&I wins Wheatstone job

CB&I announced it has been awarded a contract by Bechtel valued at about US$625 million to provide structural, mechanical and piping construction work for all outside battery limits modules and associated units for the Chevron-operated Wheatstone Project at Ashburton North in Western Australia.

Shell agreed to sell its stakes in the Chevron-led Wheatstone-Iago joint venture and the Wheatstone LNG project off Western Australia in January 2014.

EMAS grabs Gunflint work

Noble Energy and EMAS have signed a letter of agreement for installation work on Noble's Gunflint project in the US Gulf of Mexico. EMAS' subsea services division, EMAS AMC, will install pipelines, umbilicals and ancillary equipment for the Gunflint, located in the Mississippi Canyon Block 948 at a water depth of 2000m. The pipelines will be installed with EMAS AMC's flagship vessel, *Lewek Constellation*, while the EMAS Marine Base in Ingleside, Texas, will be used to perform the pipe stalking and fabrication of various subsea structures. Project preparation activities have commenced and offshore works will be carried out during 2015. ■

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FPS expenditures on the rise

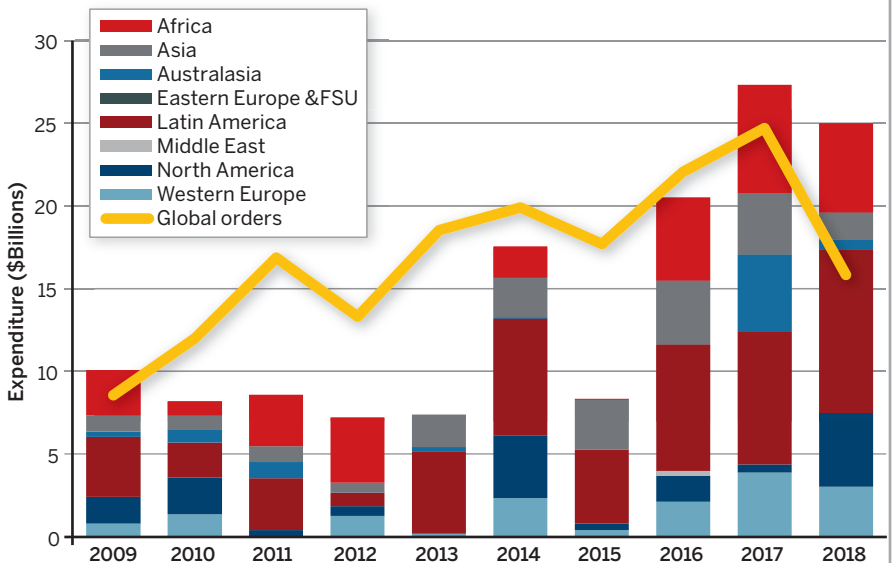
Douglas-Westwood's Damilola Odufuwa examines the FPS market, and forecasts an increase in spending during the 2014-2018 period.

Douglas–Westwood forecasts that during the 2014–2018 period, US$99 billion will be spent on floating production systems (FPS) – an increase of 138% over the preceding five–year period. A total of 139 floating production units are forecast to be installed – a 72% increase.

This growth is driven by multiple factors, such as a larger proportion of newbuilds and conversions compared to redeployments, a greater degree of local content resulting in increased costs, and general offshore industry cost inflation.

The slight dip in global orders in 2018 is due to restricted visibility of future projects.

Global FPS installation capex by region 2009-2018



Source: Douglas-Westwood

Market forecast

Foating production, storage and offloading vessels (FPSO) are to remain the most common floating production system (FPS) concept. FPSOs represent by far the largest segment of the market in terms of numbers (111 installations) and account for 80% of the forecast capital expenditure (capex). Floating production semisubmersibles (FPSS) account for the second largest segment of capex (9%) with tension leg platforms (TLP) third (8%). Although the smallest segment, Spars have a forecast capex of $2.9 billion (3% of the total forecast capex).

The forecast period highlights the increase in TLP installations and capex compared to the previous five-years. Thirteen TLPs with a total capex of $7.6 bilion are expected to be installed, while only one unit was installed during 2009–2013.

Latin America accounts for 29% of the 139 installations forecast and 38% of the projected capex, with the majority of these installations being FPSOs. The disparity between the two figures is due to Latin America having higher than average capital costs compared to other regions due to Brazil's higher proportion of expensive deepwater projects.

Africa is the second largest region, with a forecast capex of $18.9 billion (19%). Like Latin America, a large proportion of the African installations will take place in deepwater.

Although Asia has more installations (28) forecast than Africa (27), it is due to account for only $14.7 billion, a smaller proportion of global capex (nearly 15%). This is due to the majority being located in relatively shallow water and benign environments, requiring more straightforward FPS designs, sourced from converted vessels which are usually cheaper than newbuilds. However, the number of deepwater projects in this region is likely to increase over the forecast period as shallow water basins reach maturity and as a result, an increasing proportion of newbuilds are planned, a consequence of the complexity of deepwater developments.

Although a predominantly shallow water region where fixed platforms are utilized, Western Europe is expected to see a respectable number (21) of FPS installations over the next five years. Some of these projects revolve around the rejuvenation of mature producing areas.

Key demand drivers

Three main factors are driving the sustained FPS sector growth:

- Move to deepwater;
- Development of complimentary production technologies;
- Marginal field development and early production systems.

As shallow water opportunities become increasingly scarce, the development of deepwater reserves will accelerate rapidly. For a field in deepwater, an FPS is the development method of choice, since fixed platforms are often ruled out on technical and/or economic grounds.

As a result, floating production expenditure in deepwater is expected to total $68 billion over the 2014-2018 period, equating to 69% of the value of the global FPS market. The deepwater market distribution for the next five years shows the continued dominance of Latin America and Africa, with Latin America expected to increase its share of forecast capex from 46% to 50%.

The subsea sector has developed at a remarkable pace in recent years, enabling the economic development of fields in deeper waters further offshore. Furthermore, subsea processing technology is maturing and is now enabling production to FPSOs from challenging reservoirs, including heavy oil.

Considerable versatility enables FPSs to be used for a variety

of different applications besides conventional life-of-field production. These include extended well testing (EWT), early production systems (EPSs) and rejuvenation projects.

FPSOs are also an attractive solution for marginal field developments, particularly where an existing unit can be renovated, modified and redeployed at a significantly lower cost than a newbuild.

Supply-side considerations

Three main factors will affect the supply of units in the FPS sector:

- Financing;
- Local content;
- Leasing.

Financing remains a challenge for leasing contractors and smaller E&P companies as a result of the debt crisis in Europe. At the same time, local content requirements are pushing up prices and extending lead times, particularly in Brazil.

For the oil company field operator, FPS ownership becomes the more cost-effective option where production extends over a long period. Alternatively, the decision to lease an FPS can be seen as a trade-off between the lower up-front capex and the increased opex as a result of the leasing charges. However, leasing also brings advantages in terms of the cost of field abandonment (abex).

The top three leasing contractors are SBM Offshore, BW Offshore and MODEC, which collectively account for 37% of the leased fleet. The FPSO leasing sector has seen slight improvements with 86% utilization at present. However, the sector continues to be affected by severe project delays and cost over-runs, with contractors still reporting write-downs on new projects.

Conclusions

The FPS sector recovery following the 2008/2009 downturn continues steadily. A total of 54 units were ordered in 2011-2013, compared to 23 units ordered during the downturn.

Marginal fields, deepwater, and remote fields will continue to be areas of focus for the E&P industry. Energy demand is growing as a function of population and economic growth. The upstream E&P business is increasingly reliant on offshore reserves to achieve incremental production as most of the easy-to-access reserves onshore have already been exploited.

Floating production systems are a key enabler for offshore production in deep waters and for economically marginal fields.

We are finally seeing some recovery in the FPS sector. Up until now there has been little growth in the annual value of installed units over the last four years; 2014 is, however, expected to show a significant increase. Analysis of the order book shows 56 units in-build at present – a slight increase compared to Douglas-Westwood's last edition of the report (51).

The immediate near-term outlook is uncertain. There is potential for a "soft" 2014 in terms of units ordered as some E&P companies are forced to focus on returns and cut spending. To date, announcements from Hess, Shell, BG, and BP suggest this will be the case for some independent oil companies. However, we note that national oil companies and many independents will most likely have more robust spending plans for 2014.

FPS projects have grown in complexity and cost. Billion-dollar FPSs are increasingly common. Deeper waters, challenging reservoirs (e.g. very high or low pressure, sour

hydrocarbons, high water content) all drive complexity and cost increases.

The FPS supply chain is causing concern amongst investors and E&P companies. The challenges in delivering large and complex production systems on time and on budget are such that cost over-runs have become the norm and delays in both project sanctioning and project execution are more common than delivery on time. Once again the industry is looking at ways of approaching FPSO projects differently, perhaps through a standardised approach to FPSO engineering.

Local content requirements are causing delays in project execution and cost overruns. The ambition of creating value and employment locally will need to be balanced with the need to have an efficient, competitive and competent supply chain. These ambitions may continue to prove to be mutually exclusive. Political risk often compounds the challenges of local content requirements, with issues such as unstable fiscal regimes, changes of government and regional conflict present in a number of upstream environments worldwide.

There is also upside potential, if the supply chain can deliver and if the operators are willing to move ahead. We are tracking more than 200 FPS deployment opportunities and have taken what we believe to be a realistic appraisal of these projects to arrive at our forecast of 139 installations.

Ultimately, FPSs are likely to remain the only option for deepwater oil developments for the foreseeable future and an attractive proposition for marginal and remote fields. Given the increasing reliance upon reserves in these areas, we have confidence in the long-term proposition of the FPS sector, despite the current risks and disruption that are evident. **OE**

Established in 1990, **Douglas-Westwood** *is a leading provider of market research and consulting services within the engineering, OEM and field services sectors of the energy industry.*

Damilola Odufuwa *joined DW as a researcher and primarily works on bespoke consultancy/ advisory projects, including due diligence analysis and research publications, and is the lead author of The World Floating Production Market Forecast 2014-2018. Damilola graduated from the University of Kent with a degree in Financial Economics and a master's degree in International Finance and Economic Development.*

The ***World Floating Production Market Forecast 2014-2018****, now in its 12th edition, has been tracking and analyzing the industry for over a decade.*

FURTHER **READING**

www.douglas-westwood.com/shop/shop-infopage.php?longref=1287

More about Douglas-Westwood's capabilities in the FPS sector

Douglas-Westwood is widely recognized for its analysis of spends and trends in the FPS market and has completed many high profile FPS-related projects. These include bespoke research and consultancy for exploration & production companies, charterers, integrated engineering contractors, shipyards, equipment manufacturers and the financial sector.

Surveying the Atlantic

The US Bureau of Ocean Energy Management (BOEM) has proposed permitting surveys off the Atlantic coast, but will the public and industry support it? Anthresia McWashington takes a look.

The Bureau of Ocean Energy Management (BOEM) announced it is producing a Programmatic Environmental Impact Statement (PEIS) to evaluate the potential environmental effects of multiple geological and geophysical (G&G) activities on the Atlantic outer continental shelf (OCS).

The proposed action is to permit G&G activities in support of oil and gas exploration and development, renewable energy, and marine minerals extraction in the Mid- and South Atlantic planning areas off the US from 2012-2020.

With the oil and gas industry expressing interest in expanding into Atlantic waters, several G&G companies—including CGG Veritas, SeaBird Exploration and WesternGeco—have submitted requests for seismic airgun surveys in the Atlantic.

However, Dolphin Geophysical Chairman Tim Wells says that the likelihood of shooting off the Atlantic coast is pretty slim.

"I don't know that we'll actually be able to shoot off the Atlantic," Wells said in Houston to OE in late March. "I know they (BOEM) said they're going to license it. I just imagine a room this size filled with paper to be able to operate. We are preparing for it yes, we're getting our permit. I'm just not holding my breath."

Newer technology and instrumentation surpass the quality of data in surveys acquired during the 1970s and 1980s, BOEM said. The PEIS refers to collection of new data, which could provide information about the location and extent of oil and gas reserves, seafloor conditions for oil and gas or renewable energy installations, and marine minerals deposits off the US Atlantic coast.

Alternative actions

BOEM's proposed PEIS presents three alternatives:

- **A.** Authorizing G&G activities with additional time-area closure, geographic separation of simultaneous seismic airgun surveys, and use of passive acoustic monitoring.
- **B.** The preferred alternative is the same as Alternative A; however, Alternative B would:
  - Expand the time-area closure for North Atlantic Right Whales.
  - Add a time area closure off Brevard County, Florida to protect nesting sea turtles.
  - Consider a 40km separation between concurrent seismic airgun surveys.
  - Require passive acoustic monitoring (PAM) in seismic airgun surveys.
  - Require use of PAM or similar equipment in some high-resolution geophysical (HRG) surveys.
- **C.** No action.

G&G data

The need for the proposed action is to use the information obtained by G&G surveys to make informed business decisions regarding oil and gas reserves, engineering decisions regarding the construction of renewable energy projects, and informed estimates regarding the composition and volume of marine mineral resources.

According to BOEM, G&G activities for all three program areas (oil and gas, renewable energy, and marine minerals)

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YOUR NEEDS MAKE OUR DIFFERENCE

Quick stats

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

New discoveries announced

Depth range	2011	2012	2013	2014
Shallow (<500m)	105	75	67	7
Deep (500-1500m)	25	24	18	3
Ultradeep (>1500m)	19	37	31	–
Total	**149**	**136**	**116**	**10**
Start of 2014 date comparison	151 -2	135 1	98 18	– 10

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

Reserves in the Golden Triangle

by water depth 2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	16	738.25	1,060.00
Deep	16	2,615.00	2,515.00
Ultradeep	45	13,239.75	18,090.00
United States			
Shallow	24	1,608.11	2,104.57
Deep	24	1,608.11	2,104.57
Ultradeep	33	4,825.50	4,690.00
West Africa			
Shallow	170	4,604.02	22,577.83
Deep	51	5,956.50	7,240.00
Ultradeep	16	1,785.00	3,160.00
Total	**393**	**35,481.53**	**62,172.40**
(last month)	(393	(35,481.53)	(61,779.40)

Greenfield reserves

2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	1,323	54,073.30	842,190.49
(last month)	(1,340)	(54,309.42)	(842,988.86)
Deep	174	13,762.48	102,319.77
(last month)	(177)	(13,837.48)	(108,639.77)
Ultradeep	114	20,400.75	60,207.00
(last month)	(116)	(20,424.75)	(62,207.00)
Total	**1,611**	**88,236.53**	**1,004,717.26**

Pipelines

(operational and 2014 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,782	(42,127)
Planned/ possible	24,237	(24,573)
	66,019	(66,700)
8-16in.		
Operational/ installed	78,422	(78,734)
Planned/ possible	49,545	(48,876
	127,967	(127,610)
>16in.		
Operational/ installed	89,859	(90,075)
Planned/ possible	46,246	(45,771
	136,105	(135,846)

Production systems worldwide

(operational and 2014 onwards)

Floaters		(last month)
Operational	271	(276)
Under development	44	(45)
Planned/possible	331	(332)
	646	(653)
Fixed platforms		
Operational	9,509	(9,569)
Under development	106	(99)
Planned/possible	1,382	(1,378)
	10,997	(11,046)
Subsea wells		
Operational	4,501	(4,503)
Under development	402	(408)
Planned/possible	6,367	(6,316)
	11,270	(11,227)

Global offshore reserves (mmboe) onstream by water depth

	2012	2013	2014	2015	2016	2017	2018
Shallow	6,015.41	23,595.12	48,776.97	38,704.23	34,484.94	49,265.43	31,991.23
(last month)	(5,912.91)	(23,595.12)	(48,782.97)	(39,438.17)	(34,661.72)	(50,403.46)	(30,313.42)
Deep	2,821.40	471.51	4,628.59	7,249.37	3,547.37	6,649.19	9,718.46
(last month)	(2,821.40)	(471.51)	(4,628.59)	(7,249.37)	(3,579.42)	(6,742.69)	(10,782.26)
Ultradeep	737.15	2,937.44	2,826.43	2,173.17	5,255.06	14,060.03	6,701.05
(last month)	(737.15)	(2,937.44)	(2,826.43)	(2,173.17)	(5,255.06)	(14,436.64)	(6,701.05)
Total	**9,573.96**	**27,004.07**	**56,231.99**	**48,126.77**	**43,287.37**	**69,974.65**	**48,410.74**

8 April 2014

Map of Mid- and South Atlantic planning areas.
Image from BOEM.

include high-resolution geophysical surveys (HRG) to detect geohazards, archaeological resources, and certain types of benthic communities. Techniques also include bottom sampling and analysis to assess seafloor suitability for supporting structures such as platforms, pipelines, cables and wind turbines, or to evaluate the quantity and quality of sand for beach nourishment and coastal restoration projects.

Reaction to the proposal

After negative public response, BOEM took a harder look at airgun surveys. "We're doing the permitting now," Wells said. "What's happening now are the environmental impact statements. There was a 30-day period and we (IAGC) put in some

objections because they (BOEM) put in a few new things about marine mammals that were deleterious to our work."

Some concerns were focused on active acoustic sound sources from airguns and electromechanical sources; vessel and equipment noise; vessel traffic; aircraft traffic and noise; vessel exclusion zones; trash and debris; seafloor disturbance; drilling discharges; and accidental fuel spills.

Andy Radford, a senior policy advisor with American Petroleum Institute (API); Sarah Tsoflias, a former vice president for Marine Environment with the International Association of Geophysical Contractors (IAGC); and Luke Johnson, former policy director with the National Ocean Industries Association (NOIA) advise that additional methods be included within the PEIS, in order to emphasize the risks affecting different species in the Atlantic region.

"We strongly encourage that both the range of alternatives analyzed and their evaluation reflect the nature and extent of the known causes of injury and mortality faced by various protected species," the respresentatives said.

"In addition, we oppose several of the mitigation measures proposed as part of Alternative A. We believe that Alternative B is unwarranted for a number of reasons including the finding in the DPEIS that doubling the size of the closure area does not provide additional protection for Right whales or marine life generally."

In February 2014, BOEM published a final environmental review of G&G activities off the Atlantic coast, specifying mitigation efforts, which include requirements to avoid vessel strikes, special closure areas to protect the main migratory route for the endangered North Atlantic Right Whale, geographic separation of simultaneous seismic airgun surveys, and passive acoustic monitoring (PAM) to supplement visual observers and improve detection of marine mammals prior to and during seismic airgun surveys.

"Analysis of this scale is a significant undertaking that has involved extensive public input and coordination among several federal agencies and state governments," said BOEM Director Tommy P. Beaudreau. "The Department and BOEM have been steadfast in our commitment to balancing the need for understanding offshore energy resources with the protection of the human and marine environment using the best available science as the basis of this environmental review."

The Final PEIS was available for public comment until 7 April 2014. After reviewing the comments, the BOEM will issue of a Record of Decision (ROD), which will state the decision of the agency; identify the alternatives considered, including the environmentally preferable alternative; identify and discuss the factors involved in the decision; and will state whether all practical means to avoid or minimize environmental harm have been adopted. OE

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	98	92	6	93%
Jackup	413	361	52	87%
Semisub	192	171	21	89%
Tenders	32	22	10	68%
Total	**735**	**646**	**89**	**87%**

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	22	21	1	95%
Jackup	94	82	12	87%
Semisub	30	28	2	93%
Tenders	N/A	N/A	N/A	N/A
Total	**146**	**131**	**15**	**89%**

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	15	13	2	86%
Jackup	115	101	14	87%
Semisub	36	31	5	86%
Tenders	23	15	8	65%
Total	**189**	**160**	**29**	**84%**

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	28	27	1	96%
Jackup	9	6	3	66%
Semisub	42	41	1	97%
Tenders	2	2	0	100%
Total	**81**	**76**	**5**	**93%**

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	47	42	5	89%
Semisub	46	44	2	95%
Tenders	N/A	N/A	N/A	N/A
Total	**94**	**87**	**7**	**92%**

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	101	85	16	84%
Semisub	3	3	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	**105**	**89**	**16**	**84%**

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	30	28	2	93%
Jackup	24	22	2	91%
Semisub	19	15	4	78%
Tenders	7	5	2	71%
Total	**80**	**70**	**10**	**87%**

Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	23	23	0	100%
Semisub	16	9	7	56%
Tenders	N/A	N/A	N/A	N/A
Total	**40**	**33**	**7**	**82%**

Source: InfieldRigs

9 April 2014

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

Strength in numbers

E&P companies will continue to invest in deepwater exploration and development, despite shale-based rumors to the contrary. New developments spread across offshore Africa, Asia Pacific, Europe, and North and South America. Jeannie Stell reviews the highlights of current top offshore projects in water depths exceeding 1500ft.

The rumor: Unconventional onshore shale production is a threat to global deepwater exploration capital spending.

The fact: Not exactly, according to energy advisory firm Douglas-Westwood.

Despite industry rumors (based on investment banks and government agencies forecasts) that oil markets will be flooded with shale oil, thus leading to a reduction of deepwater activity, the evidence suggests differently, reports Douglas-Westwood. "If the oil supply increases, then any overhang will be quickly absorbed. That's what the record shows."

While the US was first to develop the technology to unlock shale resources, non-US countries are quick to adapt the technology in their own relevant basins. Hence, the global threat. But consider this: In the US, oil demand reached 20MMb/d in January, up a whopping 1MMb/d, or 5.3%, compared to the same period last year. Although the US

The *Centennial J* tanker will be converted by MODEC for Tullow's TEN field.
Photo from Tullow Oil Plc/Joseph Lynch

shale plays "posted a blow-out year," rising by 1.3MMb/d as a three-month average by November 2013, and Canada added another 0.7MMb/d for a total North American production growth of "an astounding 1.9MMb/d," Brent oil prices increased to US$111/bbl, reports Douglas-Westwood.

As a plethora of non-US countries begin developing unconventional resources or plan to do so, the North American shale play development versus oil demand statistics serve as logical indicators of global onshore-versus-offshore strategies for energy companies.

So despite the rumors, at least $99 billion will be spent on floating production systems (FPS) 2014-2018, a 138% increase compared to the previous five years, according to the research firm. Of that, approximately $68 billion, or two-thirds of total spending, will target deepwater FPS deployments.

The FPS sector recovery is steady, evidenced by some 54 units that were ordered 2011-2013, compared to 23 units ordered throughout 2008-2009. And 2014 is expected to show a significant increase in the value of units deployed.

Meanwhile, utilization of FPSOs owned by leasing contractors has also improved, up 3% to 88%, reports Douglas-Westwood. Clearly, the relatively new onshore shale plays are no threat to deepwater exploration and development.

Africa

Offshore Nigeria, Total continues to develop the Egina oil field. Total Upstream Nigeria (with a 24% interest) is developing the field in partnership with CNOOC (45%), Sapetro (15%) and Petrobras (16%). Egina lies in block oil mining lease (OML) 130 and covers an area of around 500sq mi in 5741ft of water.

Although the partners initially planned to develop the field with a subsea tieback to the Akpo FPSO, new discoveries in the region led to an independent-infrastructure development of Egina.

The field's infrastructure will include an FPSO and an oil-offloading terminal, subsea production systems, comprising injection flowlines, risers, flexible jumpers, umbilicals, and subsea manifolds, and gas export pipelines.

In June 2013, Total and its partners awarded a $3 billion engineering, procurement, fabrication, installation, and pre-commissioning contract to Saipem, and a $1.2 billion engineering, procurement, construction, and commissioning contract for Egina's subsea production systems to FMC Technologies. In January 2014, FMC Technologies subcontracted Aveon Offshore to provide fabrication services for the subsea structures at the field.

Egina is expected to go onstream by the end of 2014 or early 2015. Production from the Egina-5 well is estimated to reach 12,000b/d. The oil field is estimated to reach a peak production rate of 150,000b/d, and a future FPSO will increase production capacity by 200,000 b/d. Egina is Total's third deepwater development off Nigeria, with total field production expected by the end of 2017.

Offshore Angola, BP operates block 31 and holds a 26.27% interest, with partners Sonangol E.P. (25%), Sonangol P&P (20%), Statoil Angola (~13.33%), Marathon International Petroleum Angola Block 31 (10%), and SSI 31 (5%).

The PSVM development in block 31's northeastern sector comprises the Plutao, Saturno, Venus, and Marte fields, all in water depths of about 6560ft. The four fields are expected to produce 150,000b/d, and production from the first three wells of the Plutao field started in January 2013. For now, the wells are producing about 70,000b/d. The Saturno and Venus field were expected to enter production in 2013, with production at Marte field to follow in 2014.

The PSVM project utilized a converted

2014 Selected Current Deepwater Developments

Country	Development	Production System	Status	Onstream	Water (ft)	Operator
Africa						
Nigeria	Agbami	FPSO	Producing	2014	4800	Chevron
Nigeria	Aje	FPSO	Under development	2014	3000	YFP
Nigeria	Bonga SW	FPSO	Design	2016	4000	Shell
Angola	CLOV	FPSO	Under development	2014	4600	Total
Nigeria	Egina	FPSO	Under development	2015	5700	Total
Ghana	Jubilee 1A	FPSO	Producing	2010	3600	Tullow
Nigeria	Kaombo	FPSO	Under development	2017	5200	Total
Congo	Moho Nord	TLP-FPU	Under development	2016	3600	Total
Angola	PSVM	FPSO	Producing	2013	6500	BP
Ghana	TEN	FPSO	Producing	2015	6500	Tullow

tanker with 1.6MMbbl storage capacity. Full project development will see about 48 wells drilled, including gas and water injection, and infill wells, which will be connected to 15 manifolds and associated subsea equipment. About 550ft of flowlines and 300ft of control umbilicals are involved.

ODEC was awarded a frame agreement to supply the PSVM project's FPSO and, in turn, subcontracted Jurong Shipyard to convert the very large crude carrier (VLCC) tanker, *Ex-Bourgogne*, to *FPSO PSVM.*

The pre-front end engineering and design (FEED) studies for the project were carried out by JP Kenny. A $1 billion contract was awarded to Heerema Marine Contractors to lay 160ft of pipe-in-pipe production flowlines, 130ft of service flowlines, 55ft of vertical risers, 77 ancillary structures and nine piles driven at a water depth of 6660ft. Pipeline Technique provided its HALO welding technology, and the design for the umbilical riser flowline was provided by INTECSEA.

Technip supplied 200ft of rigid flowlines, 40 flexible jumpers and 34 umbilicals covering a total length of 140ft through a contract valued at $615 million, while Aker Solutions will supply 150ft of steel tube umbilicals for the project. Halliburton is providing well assembling equipment for the project under a contract valued at more than $600 million. VWS Westgarth, a subsidiary of Veolia Water Solutions & Technologies, will supply a single-lift module seawater sulfate-reduction system.

Offshore Ghana, Tullow Oil continues to develop its TEN project. Tullow is the operator of the Deepwater Tano license and holds a 49.95% interest. Partners include Kosmos Energy (18%), Anadarko Petroleum (18%), Sabre (4.05%) and the Ghana National Petroleum Corp. (10%).

At press time, Total announced it made a final investment decision on the $16 billion Kaombo project, in up to 200m water depth, offshore Angola. Two FPSOs, to be converted tankers, are planned. Major contracts awarded to Aker Solutions, Saipmen, Technip and Heerema Marine Contractors. (See page 20.)

The TEN development project includes the collective developments of Tweneboa, Enyenra (formerly Owo), and Ntomme. The three oil and gas fields are found in water depths ranging from 320ft-6561ft, and the development is located 15mi from the Tullow-operated Jubilee field. It is the first deepwater field to be developed in offshore Ghana. First production is expected mid-2016. A peak production rate of 100,000b/d is expected by 2018, with ultimate recovery of about 216MMbbl.

Tullow will jointly develop the three fields using a single FPSO facility. A total of 33 wells are planned, including 15 oil production, 15 water injection, one gas production and two gas injection wells, with another 16 planned depending on production levels.

Three FPSO contractors, including Modec, are participating in the FEED for the vessel, which will have a processing capacity of 105,000b/d, and will be spread-moored with an oil offloading buoy. INTECSEA will conduct the FEED for the subsea infrastructure.

Offshore Congo, Total continues development of its Moho-Bilondo oil field—the first ultra-deepwater offshore field of the Republic of the Congo. The field was found in water depths ranging between 1970ft and 2950ft. Total, via its Congolese subsidiary Total E&P Congo, holds a working interest of 53.5% and is the operator. Chevron and SNPC have working interests of 31.5% and 15%, respectively, in the field. The Moho-Bilondo includes the Bilondo, Mobim, Moho Nord Marine-1 and 2, and Moho Nord Marine-3 reservoirs.

The Eirik Raude semisubmersible rig operating on the Jubilee Field offshore Ghana. Photo from Tullow Oil Plc.

The Moho-Bilondo's first project phase targeted the Mobim and Bilondo reservoirs that were brought onstream with plateau production of 90,000b/d. Construction on the second phase, which includes development of northern part of the license, began in 2013 after FEED studies were completed. The project will require an investment of $8 billion and is expected onstream in 2016.

The Moho-Bilondo floating production unit was designed by Doris Engineering and built by Hyundai Heavy Industries (HHI) under a $400 million engineering, procurement, construction, and installation contract. Aker Solutions has been commissioned to deliver the subsea

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An aerial view of ships at the Laggan-Tormore development.
Photo: Total E&P UK.

production system.

Asia Pacific

Offshore Indonesia is home to the Abadi gas field in the Masela block in the Arafura Sea. The field lies in 984-3281ft water depth. Inpex Masela, a subsidiary of Japan's Inpex, operates the field with a 60% interest after transferring 30% to Shell Upstream Overseas Services in exchange for its expertise in floating LNG (FLNG) technology. PT EMP Energi Indonesia owns the remaining 10%. First production is expected in 2018 with an initial output of 2.5MTPA of LNG and 8000b/d of condensate. The field is estimated to contain 10Tcf of gas.

Wood Group's Indonesia subsidiary will conduct FEED for subsea production facilities, including detailed engineering for subsea, umbilical, riser and flowline works. Phased development plans include the subsea production system and FLNG.

About 18 directional production wells will be drilled from five subsea drilling centers, and initial development will be carried out in the northern portion of the field where most of the reserves are concentrated. In January 2013, Inpex awarded the FEED contract for the FLNG to JGC and PT Saipem Indonesia Group. The EPC contracts are expected to be awarded 2014-2018. According to recent reports, Abadi partners will invest more than $19 billion in the development.

Middle East

Noble Energy continues to develop its Leviathan gas field in the eastern Mediterranean Sea. Leviathan is in 5396ft water depth in the Levantine Basin, offshore Israel. In February, Woodside and the Leviathan joint-venture participants, Noble Energy Mediterranean Ltd, Delek Drilling LP, Avner Oil Exploration LP, and Ratio Oil Exploration LP agreed to convert a previous agreement for an interest in Leviathan into a non-binding memorandum of understanding (MoU). The MoU is a framework for the acquisition of a 25% participating interest in each of the 349/Rachel and 350/Amit petroleum licenses. Woodside would operate any LNG development of the field, while Noble Energy will remain the upstream operator. As of press time, Woodside announced that the project partners have not executed the definitive agreements by the target date of 27 March 2014. Discussions are ongoing between the Leviathan partners and the Israeli Government.

According to US Geological Survey estimates, the Levantine Basin holds about 1.7 billion bbl of oil and 122Tcf of gas. The partners' plans for the domestic gas phase for Leviathan are well advanced, while FEED studies for the second phase will begin in late 2014. A possible final investment decision trigger point should be reached in late 2015. If approved, production is expected to commence in 2017.

Offshore Azerbaijan, the Shah Deniz oil field lies in the South Caspian Sea in up to 1968ft water depth. in the south-eastern section. BP, with a share of 25.5% in the project, is the operator. The other PSA partners are Statoil (25.5%), Socar, Lukoil, Total, and Nico (10% each) and

2014 Selected Current Deepwater Developments

Country	Development	Production System	Status	Onstream	Water (ft)	Operator
Asia Pacific						
Indonesia	Abadi	FLNG	Design	2018	3300	Inpex Masela
Australia	Gorgon	Subsea	Under development	2015	4300	Chevron
Malaysia	Gumusut-Kakap	FPS	Producing	2012	4000	Shell
China	Liwan	Subsea	Producing	2014	4290	Husky
China	Liwan 3-1	Subsea	Producing	2014	4200	Husky
Malaysia	Malikai	TLP	Under development	2015	1800	Shell
Malaysia	Siakap North - Petai	Subsea	Producing	2014	4400	Murphy
Middle East						
Israel	Leviathan	FPSO	Design	2016	5400	Noble Energy
Israel	Tamar	Subsea	Producing	2013	5500	Noble Energy

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The Lucius facility in deepwater Gulf of Mexico, on which Heidelberg's spar design will be based. Photo from Anadarko.

Tpao (9%).

Stage two of Shah Deniz will triple the field's production by drilling 30 subsea wells and constructing two offshore production platforms. Engineering studies on the full-field development are being carried out and first gas from stage two is expected in 2016.

Europe

Offshore UK, Total E&P UK (with 80% operating interest) and Dong E&P (20%) are nearing the final production on their US$5.5 billion (£3.3 billion) Laggan and Tormore gas and condensate project, located northwest of the Shetland Islands in about 1968ft of water. The field will be developed as a long subsea tie-back to the new Shetland gas plant, which is being built at Sullom Voe. The plant will include eight subsea wells and one subsea production system each for Laggan and Tormore, and two six-slot production manifold templates. The total field reserves are expected to exceed 1Tcf of gas and condensates. Total says production capacity is 90,000boe/d, with peak production listed at 500MMscf/d of gas and condensate. Ode and its majority owner Doris Engineering won the contract for basic engineering of the field development, including the subsea infrastructure, gas treatment plant, and the export pipeline. FMC Technologies will supply the field subsea production systems. First production is expected by late 2014.

Offshore the Shetland Islands, operator Chevron (40% interest) is reassessing its 3700ft deep Rosebank oil and gas field. Its partners are OMV (60% interest), OMV (20%) and Dong Exploration & Production (10%). A drilling program was expected in 2015, followed by first production in 2017; however, Chevron announced last year that the JV's focus is on making the right decisions, not on schedules and timelines.

Offshore Norway, Statoil is developing its 4265ft-water depth Aasta Hansteen gas field in blocks 6706/12 and 6707/10 in the Norwegian sector of the North Sea in production license 218. ExxonMobil (15%) and ConocoPhillips (10%) hold interests in the reservoir.

The field is estimated to contain up to 60Bcm of gas and 5.6MMbbl condensate. It will be developed with a spar platform (OE: March 2014) featuring a processing facility, a single vertical cylinder, two subsea templates with four wells on each, and a satellite template with one well, as well as condensate and gas storage facilities.

Aker Solutions and Technip won the FEED contract, which includes design, planning, procurement, construction, and transportation of a spar hull and the mooring systems. Work also includes the design of the steel catenary risers. First gas production is expected by late 2014.

North America

Royal Dutch Shell is working on its Cardamom oil and gas field in block 427 of the Garden Banks in the Gulf of Mexico (GOM). The field, in 2720ft water depth, is under development with a $2.5 billion price tag. This was the first project to be approved since the lifting of the moratorium on deep drilling in GOM following the Macondo spill in 2010.

Cardamom will eventually produce 50,000b/d at peak production. The development plan includes subsea tiebacks to the Auger tension leg platform sited about 9200ft west of Cardamom. The new subsea system will include five well

2014 Selected Current Deepwater Developments

Country	Development	Production System	Status	Onstream	Water (ft)	Operator
Europe						
Shetlands	Laggan-Tormore	Subsea	Under development	2014	1900	Total
Norway	Aasta Hansteen	Spar	Under development	2017	4300	Statoil
UK	Rosebank	FPSO	Design	2017	3700	Chevron

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expandable manifolds, a dual flowline, and eight well umbilicals. A contract for the subsea and topside systems was awarded to FMC Technologies, which will supply five 15,000psi subsea production trees, control equipment, and manifold and tie-in equipment. DUCO, a subsidiary of Technip, won the contract to construct the umbilicals. First oil is expected in late 2017.

Also in the GOM, Anadarko and its partners continue to develop the

2014 Selected Current Deepwater Developments

Country	Development	Production System	Status	Onstream	Water (ft)	Operator
North America						
US	Big Foot	ETLP	Under development	2014	5300	Chevron
US	Delta House	FPS	Under development	2015	4500	LLOG
US	Heidelberg	Spar	Under development	2016	5300	Anadarko
US	Jack-St Malo	Semisubmersible	Under development	2014	7000	Chevron
US	Julia	Platform	Under development	2016	6500	ExxonMobil
US	Lucius	Spar	Under development	2014	7100	Anadarko
US	Mad Dog	Subsea	Under development	2018	5100	BP
US	Mars B	TLP	Producing	2014	3000	Shell
US	Pony	FPU	Design	2015	3500	Hess
US	Tubular Bells	Spar	Under development	2014	4300	Hess
South America						
Brazil	Lapa (Carioca)	FPSO	Under development	2016	7000	Petrobras
Brazil	Iara	FPSO	Under development	2017	7300	Petrobras
Brazil	Lula Northeast	FPSO	Producing	2013	7100	Petrobras
Brazil	Papa Terra	FPSO	Producing	2013	3900	Petrobras
Brazil	Roncador	FPSO	Producing	2007	6000	Petrobras

Heidelberg field offshore Louisiana in 5310ft water depth. The field includes Green Canyon blocks 859, 860, 903, 904, and 948. Heidelberg is estimated to contain about 200MMbo. The Heidelberg development was sanctioned in 2Q 2013, with production expected in 2016. A truss spar will be used as the drilling and production platform.

Technip was contracted for the engineering, construction, and transport, and the detailed hull design and fabrication will be conducted in Pori, Finland. Technip subcontracted First Subsea to supply the subsea mooring connectors for the Heidelberg truss spar platform. FMC Technologies received the contract to supply subsea equipment, including five enhanced horizontal subsea trees, tree-mounted controls, and two manifolds. Subsea 7 holds the contract for engineering, fabrication, and installation of risers, pipelines, and flowlines. The offshore work is expected to start year-end 2014 and will utilize the *Seven Borealis* pipelay vessel.

The Chevron-operated Jack-St Malo deepwater project (51%) is also underway. Its partners include Petrobras (25%), Statoil (21.5%), ExxonMobil (1.25%), and ENI (1.25%). The Jack field lies in Walker Ridge blocks 758 and 759 in 7000ft water depth. The St Malo field lies in Walker Ridge Block 678 in 2100ft water depth.

Cameron was awarded a $230 million contract to supply subsea equipment, engineering, and project management services, and will provide 12 subsea trees with 15,000psi along with manifolds and related connection systems. Wood Group company Mustang conducted the FEED and will produce a detailed design for the topsides. Saipem will transport and install the crude oil export pipeline, and Wood Group will commission the facility. McDermott International will fabricate and install subsea equipment, including umbilicals, jumpers, and control systems, and KBR will provide detailed design services. Production start-up is expected in late 2014.

Elsewhere, ExxonMobil (50%), along with partner Statoil (50%) and future operator Chevron, are moving forward with the Julia oil field in the GOM. The first phase of the field's development began in May 2013, with a capital spend of $4 billion. Julia's first production is expected in 2016 with an initial production capacity of 34,000b/d. FMC Technologies will provide six subsea trees, a manifold, and associated tie-in equipment.

South America

Petrobras is developing its Iara oil field in the Santos Basin off Rio de Janeiro. The light oil field near the Lula field sits in 2230ft of water.

Aker Solutions will supply 40 subsea trees for the Iara and associated Sapinhoá field. The project will include 40 vertical subsea trees, subsea control systems, and 17 complete tool sets to be installed by late 2014. Engevix Engenharia won the EPC contract worth $3.5 billion for eight hulls for FPSOs to be used in blocks BM-S-11 and BM-S-9 of the field. A total of six vessels will be allocated to block BM-S-11, including the Lula, Iracema, and Iara discoveries, and the rest will be dedicated to block BM-S-9, which includes the Sapinhoá and Lapa discoveries. The subsea production from Iara is expected by 2017.

Going forward, global offshore E&P companies continue to see deepwater developments, and their associated high production rates, as viable economic opportunities for the foreseeable future. OE

Driving deepwater growth

Infield Systems analyst Catarina Podevyn reviews some of the projects forecasted to drive growth, and expenditures, in the deepwater sector around the globe over the next five years.

As Infield Systems prepares for the annual release of its Deep and Ultra-deepwater Market Report to 2018, we look to global development of the deepwater sector and the emerging trends over the forthcoming five years. Looking back over the previous five-year period, offshore investment directed towards deepwater development has increased from 22% of the global total capital expenditure (capex) in 2009 to 48% today; a trend that is expected to continue towards 2018, when over half of offshore capital expenditure is anticipated to be directed towards projects at water depths of 500m and greater.

The extraordinary growth in deepwater development has been driven by projects located at depths of 1500m and greater, with the ultra-deepwater sector expected to comprise 28% of total offshore capex across the 2014-2018 timeframe; which equates to 57% of total deepwater capex spend during the period. While the ultra-deepwater market will continue to be driven by developments offshore Brazil and the Gulf of Mexico (GOM), Infield Systems expects a further 20 countries to require capital expenditure on ultra-deepwater developments during the 2014-2018 timeframe. Such developments include the continued development of the Dhirubhai fields, in addition to the Krishna Godavari development offshore India; Leviathan and Tamar offshore Israel, and a number of ultra-deepwater field developments within the Rovuma Basin offshore Mozambique. Indeed, going forward, Infield Systems expects a significant growth in ultra-deepwater activities outside the central "deepwater triangle," with IOCs and leading Independents taking their deep and ultra-deepwater experience from areas such as the GOM and West Africa to emerging development zones and frontier waters where significant deepwater production potential is to be found.

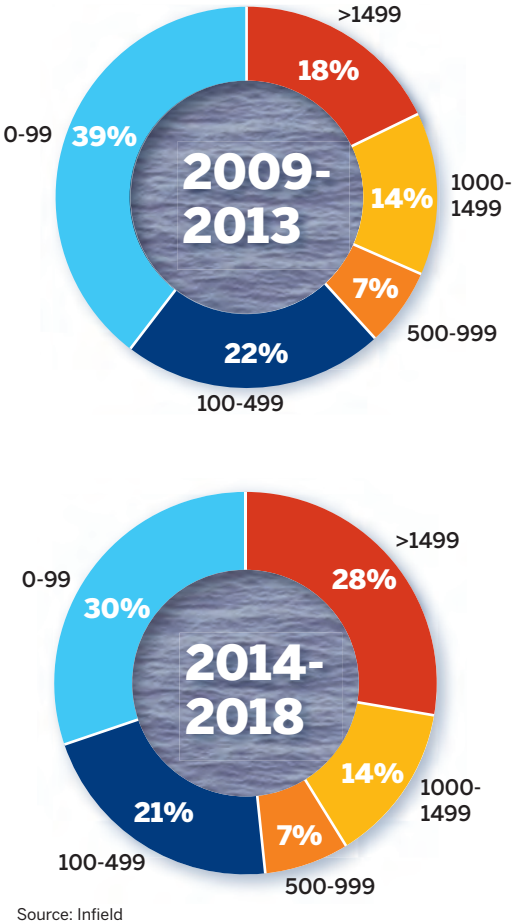
The forthcoming period is expected to see a consolidation among the major deepwater investors, with capex from the top 10 global deepwater operators expected to almost double going forwards to 2018, compared to the previous 2009-2013 timeframe.

Petrobras is anticipated to remain the key investor within the market, holding a forecast 33% share of the deepwater sector and a 49% share of the ultra-deepwater market over the timeframe. Key projects for the NOC are expected to include the multi-phase Franco developments, Lula Central and Alto, and Iracema Sul.

Despite accounting for a significantly smaller proportion of total deepwater spend compared to Petrobras, French IOC Total is anticipated to remain a strong player within the market, with West Africa continuing to be the main destination for the operator's investments, and where the Egina development is expected to demand the highest capital expenditure for the operator.

Chevron is expected to be the third largest investor in deepwater development globally over the period, with the largest proportion of the US-based IOC's spend expected to be directed towards Gulf of Mexico projects, driven by the Keathley Canyon-Buckskin and Moccasin developments, in addition to the Walker Ridge-Jack & St Malo hub. On a global level, Chevron's deepwater activity is expected to remain diverse, with significant spend expected on projects offshore Indonesia, Australia

Global capital expenditure (%) by water depth (m)



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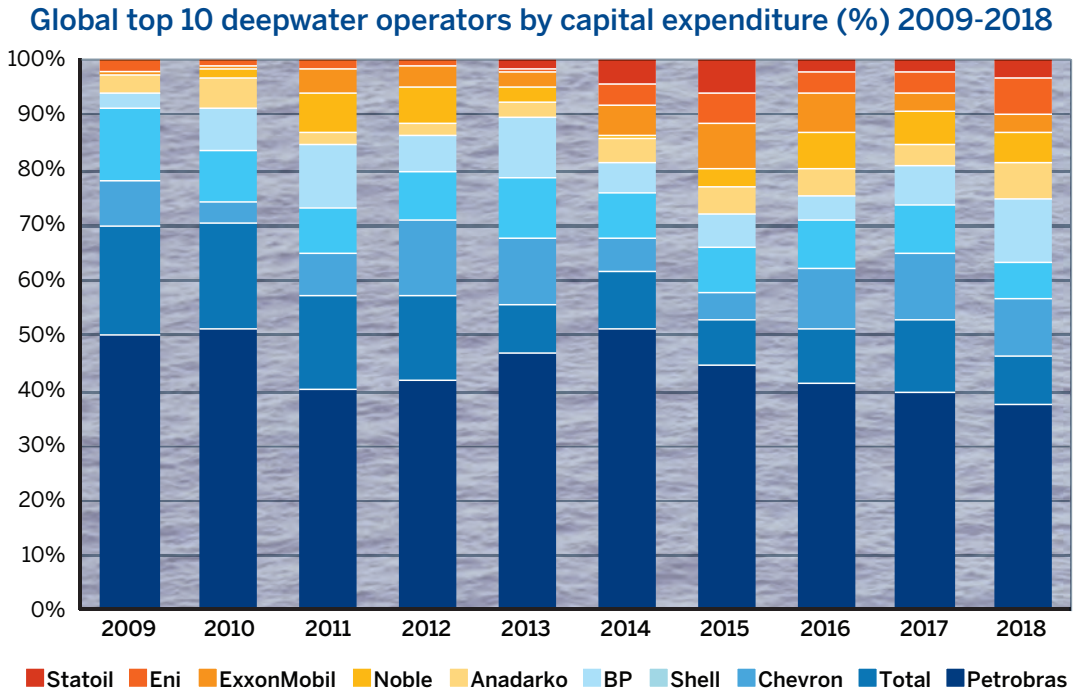

and Angola during the period to 2018.

Latin America

On a regional level, Latin America is expected to remain the leading deepwater region, driven by Petrobras' highly ambitious presalt development plans. The forecast period is also expected to witness an increasing number of foreign and independent operators entering the market offshore Brazil. The largest spend is expected to be attributable to IOC Shell, with capex expected on six deepwater field developments, whilst Queiroz Galvao, a Brazilian Independent, is also expected to direct significant capex towards deepwater developments, in particular upon the 1554m ultra-deepwater Atlanta field (BS-4).

Infield Systems also anticipates increased levels of spend across other parts of the region; with five deepwater fields expected to enter production offshore Mexico from 2016 onwards. Here, capex demand is expected to be driven by the Lakach and Labay developments at water depths ranging up to 1700m.

Gulf of Mexico

Deepwater development within North America's GOM is expected to gain in strength over the forthcoming five-year period, led by Shell and Anadarko, while Chevron, BP, and ExxonMobil are also expected to maintain a strong presence within the region. Production from the area is expected to increase substantially, with key developments driving production gains expected to include the ExxonMobil-operated Hadrian North and Shell's Stones and Appomattox field developments. While the future of GOM production appears positive, significant challenges remain. The GOM is a notoriously capital intensive area of development due to challenging environmental factors. With the increased regulation of activities within the area following Macondo, operators have been forced to carefully examine development plans in order to ensure economic viability.

Africa

Looking towards the African region, development offshore West Africa, in particular Angola, is expected to lead deepwater reserve additions entering the market over the forthcoming five years. Indeed, Angola is forecast to account for 70% of the region's deepwater reserves entering the market over the 2014-2018 period.

The majority of West African reserves lie within depths of between 1000-1499m, with key fields expected to come onstream including Egina, the Maersk-operated Chissonga, and Tullow's TEN development offshore Ghana. While West African developments are expected to lead the deepwater market within the region in overall terms, Anadarko's Prosperidade prospect offshore Mozambique, at a water depth of 1463m, is expected to yield the largest reserves entering production during the period, with Infield Systems currently expecting 2.1 billion boe to enter production before the close of 2018 or early in 2019.

While the deepwater triangle is expected to continue to account for the largest share of overall deepwater capital expenditure over the forthcoming five years, eight of the top 10 most capital intensive deepwater projects globally over the 2014-2018 timeframe are expected to take place outside these traditional strongholds of deepwater development. Such developments are expected to include the ultra-deepwater section of Gazprom's South Stream pipeline, running from Dzhubga, Russia, across the Black Sea to Bulgaria, while Statoil's Aasta Hansteen and Polarled developments are also expected to demand significant capital expenditure during the forthcoming four years. Indeed, Aasta Hansteen is currently the deepest development on the Norwegian Continental Shelf at 1274m, while the Polarled line will become Norway's deepest offshore gas pipeline at 1265m once installation is complete, currently expected before the close of 2015 (see page 72 for more on the Polarled pipeline project).

Australia

Other key deepwater developments expected to take place outside of the

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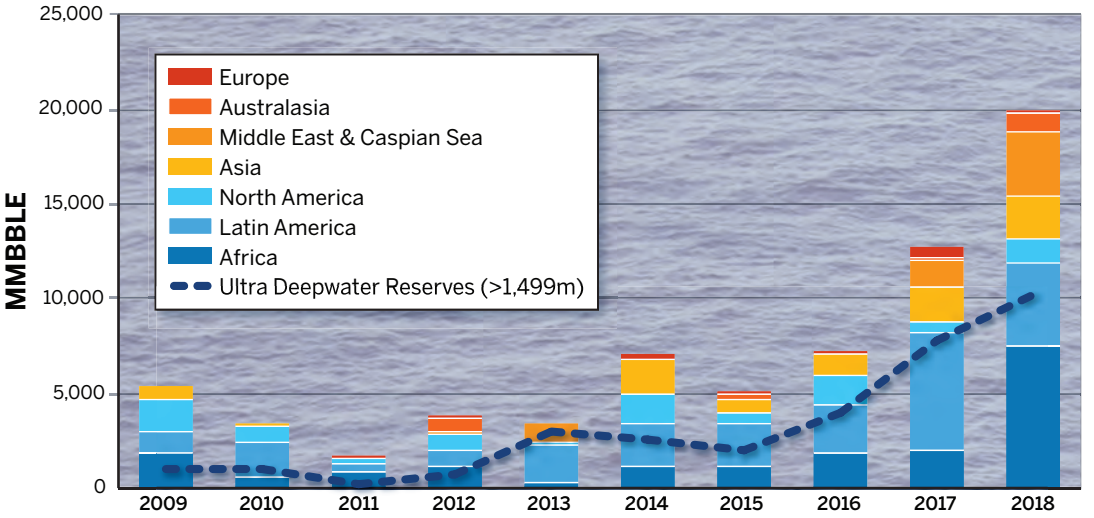
Global deepwater reserve additions (MMBBLE) 2009-2018 by region vs ultra deepwater reserve additions



deepwater triangle over the forthcoming five years are anticipated to include the Scarborough FLNG FPSO offshore Western Australia, which saw government approval in late 2013. At a forecast water depth of 500m, Scarborough is anticipated to see a final investment decision (FID) by 2015. Once installed, the platform is expected to be larger than that of Shell's *Prelude* facility, which is currently under construction in South Korea. Over the forthcoming five years, Infield Systems expects further deepwater projects offshore Australasia to include the Hess-operated Equus project and Woodside's *Laverda* FPSO development at water depths ranging up to 850m.

Asia

Looking towards the diverse Asian region, traditionally viewed as a shallow water area of development, Infield Systems expects an increasing movement into more remote waters in order to exploit deepwater reserves. Currently the region's deepwater assets are predominantly centred offshore Southeast Asia; in particular offshore Malaysia and India. The Petronas FLNG 2 development on the Rotan field, offshore Malaysia at a water depth of 1140m, is expected to be the most capital intensive project taking place in the region over the 2014-2018 timeframe, whilst in global terms PFLNG2 is anticipated to be the fifth most capital intensive project over the period. The project's FID took place in January 2014, with the EPIC contract award issued to JGC Corporation and Samsung Heavy Industries, whilst Infield Systems expects installation to take place before the close of 2018. Infield Systems also expects a number of countries to become new entrants within Asia's deepwater sector, with deepwater fields expected to enter production offshore Philippines, China, Brunei, and Sri Lanka.

Europe

Offshore Europe deepwater expenditure is expected to increase by over 400% during the 2014-2018 timeframe compared to the previous five years, and will be predominantly driven by projects offshore Norway, most notably the aforementioned Aasta Hansteen, in addition to significant development offshore UK, Italy, and on the South Stream project within the Black Sea.

New areas of deepwater development are also expected to demand significant expenditure during the period, with key prospects including the Aphrodite field offshore Cyprus, in addition to possible developments offshore Crimea, Albania ,and the southern Adriatic towards the end of the 2018 timeframe. While the Statoil Polarled and Gazprom-led South Stream pipeline projects are expected to lead deepwater development spend within the European region, Infield Systems also expects significant investment from the likes of Chevron on the Rosebank development. The Galsi Spa consortium is expected to direct significant expenditure towards its giant pipeline development stretching from Algeria to Sardinia and onto Italy, with investment expected in each year of the forecast period.

Middle East

Infield Systems expects capital expenditure directed towards the Middle East and Caspian Sea markets to comprise 3% of total global deepwater spend over the 2014-2018 timeframe. This disguises the significant deepwater development expected here, with a number of key global deepwater projects within the region. Noble Energy is expected to lead this investment with its activities within the Levant Basin anticipated to require 54% of the operator's total offshore capex during the 2014-2018 timeframe. Here, the deepwater projects of Tamar (Phases 1 & 2), Leviathan, and the smaller satellite prospects of Mari-B, Dolphin, and Dalit are expected to require 59% of the Middle East and Caspian Sea regions' deepwater spend over the forthcoming five years, while BP's Shah Deniz (Phase 2) within the Azeri sector of the Caspian Sea is also forecast to require significant expenditure during the period as it pushes out its subsea reach into deeper waters.

Conclusion

The next five years are expected to be a pivotal time for the deep and ultra deepwater sector. No longer a marginal area of development, E&P within water depths of 500m and greater is beginning to form the largest share of offshore spend. With a plethora of new prospects outside of the traditional areas of deepwater development, Infield Systems expects this market sector to become not just a regional phenomenon contained within the deepwater triangle, but a key driving force behind offshore development globally to the end of the decade and beyond. OE

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Subsea

The growing deepwater market is driving pipeline and umbilical manufacturing expansion on Newcastle's Walker Riverside in the UK. Elaine Maslin paid a visit.

Deepwater drives manufacturing expansion

Large-bore center tube, or a center bundle, is fed on polymer rollers into the building, then into the center of the VHAM, via a pit beneath the machine. Photo by Elaine Maslin.

Umbilical and flexible pipe manufacture has become an established and visible presence on the banks of the River Tyne in Newcastle, Northeast England.

Now, growth in deepwater developments is driving demand for steel tube umbilicals and for deepwater flexible pipe, leading to an increase in capacity at this hub (See page 54: Wellstream expands capacity).

Umbilicals form the links between

A large-bore center tube umbilical cross section. Photo from DUCO.

subsea production systems and remote control, power, communications, and chemical supply services. They can be static or dynamic (when through the water column) and based on thermoplastic or steel tube design.

According to global engineering group Technip, around 70% of global subsea developments now require steel tube umbilicals, as the subsea sector moves into deeper waters.

To meet demand, DUCO, part of Technip Umbilical Systems, has built a new automated vertical helix assembly machine (VHAM), housed in a dedicated building, to manufacture steel tube umbilicals.

The facility, due to be officially opened this month (May), is flanked by two new storage carousels, new quayside, and reel transporters, all controlled via a wireless network.

DUCO – created through a joint venture between Dunlop and Coflexip – has been manufacturing at Walker Riverside in Newcastle since 1990, the company was reaching capacity for steel tube umbilicals manufacture on its existing horizontal helix assembly machine, says Ian Probyn, research and development business development manager, Technip Umbilical Systems.

"Over the years we have extended the helix machine as requirements have increased. But a few years ago, we could see we would need greater capacity, to meet market needs," he says.

"We went back to the drawing board and designed the dream machine." The result is a 50m-high, 10 level, VHAM tower, fabricated by Brazil's BRASTEC Technologies. By moving to vertical assembly, following a design used for DUCO's Houston facility, the firm is able to incorporate a greater number of larger component product bobbins, increasing capacity, and maximizing space and production line efficiency.

Vertical manufacturing

To create an umbilical system using the VHAM, a large-bore center tube, or a center bundle ("first pass bundle"), is fed on polymer rollers into the building, then into the center of the VHAM, via a pit beneath the machine.

The chain-driven revolving VHAM deck, houses and pays out the umbilical components on counter rotating, individually tension-controlled bobbins. High capacity bobbins carry steel tube, for hydraulic and chemical fluid, and fiber optic and electrical cables, and smaller bobbins contain product such as "filler," typically polyethylene (PE) or polyvinyl chloride (PVC), but also cross-linked PE (XLPE), for use in higher temperature applications, used as packing between functional components, to keep product in place and to maintain the umbilical's overall circular shape.

Operational, the VHAM's linear

To date, the longest steel tube umbilical manufactured by DUCO was a 126km-long system for Shell's Mensa project, 140mi. southeast of New Orleans in Mississippi Canyon Blocks 686, 687, 730 and 731. The Newcastle facility also created what it believes is the world's largest subsea umbilical, in terms of outer diameter, at 325mm, and weight, at 205kg/m, for BP's Skarv development in the Norwegian North Sea.

Product feeds up into the machine. Photo from DUCO.

The VHAM deck houses and pays out umbilical components from bobbins. Photo by Elaine Maslin.

The north carousel. Photo from DUCO.

speed at its widest point is as fast as an Olympic runner—although in reality the speed is not likely to need to be this high.

The VHAM has a SCADA-based system, to ensure control and traceability of the process parameters and product quality, on product ranging from complex stiff umbilicals, to light fragile designs, with tension and pay-out speed pre-set and monitored.

Due to the amount of instrumentation and control this required, DUCO opted for a wireless network.

As the umbilical bundle moves up the tower, pulled by two automated and slip and grip pressure monitored caterpillar tensioners, it passes through a welding bay, where steel tube sections are welded or electrical cable spliced, and for digitally processed X-ray inspection. Preforming rollers then put the helical shape into the umbilical tubes, before the multiple components are wound together and then wrapped in fiber-reinforced tape.

Finally, a measurement head, including a six-head laser, measures the outer diameter (OD) and the umbilical then runs out on rollers, via a set of points, to either the south or north swan necks, sending the product down and out to either the north or south of the site.

Large bore center tubes (typically 2-4in.) will arrive in straight lengths to be welded together on site, before being reeled to enter the VHAM.

The VHAM building also contains an extrusion line, able to coat metal tubes with millimeter-thick sheath (PE, XLPE or nylon) on half inch bore tubes or outer sheaths on umbilicals over and beyond the current record of 325mm OD for BP Skarv.

Carousels

DUCO's investment included two new, automated, chain-driven, large diameter basket storage carousels, north and south of the VHAM, both controlled by a wireless network, interconnected to the VHAM. In theory, umbilical lengths created on the VHAM could be unlimited, Probyn says. Carousel size, for

Quayside upgrade

To make way for the VHAM and to upgrade the quayside foundations, DUCO's research and development facility and laboratory, which had been on the site, was moved to a new building nearby.

The facility is the group's global research and development center, performing testing and qualification as well as product research, design, and development.

Recent work has seen the center researching and fully qualifying replacing copper power cables with light weight, high strength aluminum conductors.

Part of the work on the quayside site also included upgrading a 250-tonne Hammerhead crane, built in 1930, to 325-tonne.

Shepherd Offshore's Hammerhead crane, with DUCO's new VHAM building in the background. Photo by Ken O'Heed.

The crane, owned and operated by quayside owner Shepherd Offshore, was built for the former Naval Yard at Walker, where it worked on vessels including battleship King George V and the aircraft carriers *Ark Royal* and *Illustrious*.

It is a revolving cantilever jib type crane, with a maximum 325-tonnes capacity at 25.25m radius, ranging to 100-tonnes at 55.75m radius.

The quayside is deep water, and could accommodate Technip's largest vessel, *Deep Energy*. ■

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spooling the product on to, is the only limit.

The two new carousels increase DUCO's storage capacity, allowing storage of up to four separate umbilical systems in each, including their termination pieces, and have been built with capability to be easily upgraded if needed.

The larger basket size also means steel tube does not have to be wound on under tension, minimizing any plastic strain on the umbilical. An automated accumulator is also used to accommodate slack or tension, in the event of a power failure or emergency shutdown, to avoid strain on the product, while it is being loaded into the carousel using caterpillar tensioners.

The carousel loading equipment is based on designs already installed at DUCO's recently upgraded Angoflex plant, West Africa.

From storage, umbilicals are then either spooled direct on to vessels, via a quayside roller path, or on to reels, which are then lifted on to vessels.

DUCO has a contract backlog of more than one year for the VHAM, including the Egina and Moho Nord projects, for Total, to be installed offshore West Africa.

Thermoplastics

DUCO's facility at Walker also produces thermoplastic and power cable umbilicals on its existing Helix and S-Z lines, named due to the helical alternating process used to create the bundles, which creates S-Z shapes.

The site also has existing vertical spool and basket carousels. It also has an armoring machine, with more than 100 bobbins, for thermoplastic umbilicals requiring armoring for tensile strength and steel tube umbilicals made on the new VHAM where the client requires additional mechanical protection or weight. OE

Technology takes deep water challenge

By Meg Chesshyre

Technip Umbilical Systems has undertaken a design study of future technology requirements needed in deepwater projects. The results were presented by Ian Probyn, R&D business development manager, at a Subsea UK conference in London late last year (2013).

The umbilical design study looked at future umbilical requirements in deeper water 3000m+, harsher environmental conditions, with greater fatigue and subsea power requirements. The outcome was to identify technology gaps which have led to a number of R&D programs with the aim of developing and qualifying solutions ready for product deployment, with some projects now being more advanced than others.

The first technology that Probyn addressed was strength members and evolving joints. He also looked into the development of aluminum power cables, deepwater thermoplastic umbilicals, smart umbilicals, a quick-connect stab plate and a tape to increase friction.

High strength members provide additional tensile strength to achieve greater water depth and enable dynamic performance to be optimized. Another innovation is the evolving joint. "We've innovated what we call an evolving joint," Probyn explained. "This enables us to optimize the strength near the hang-off, the topside, where we see the highest fatigue loading. As the umbilical drops to the seabed we can transition from these high strength members to lighter, more cost effective polymer structures." This technology was first deployed on a project in the Gulf of Mexico in 2012, and very successfully qualified.

Technip Umbilical Systems has also developed a lightweight, high corrosion resistant aluminum conductor, which has undergone an extensive risked based technology qualification program, including corrosion, fatigue, electrical, splicing and terminators. The high strength aluminum power cable can operate in water depths below 3000m, having superior reliability at any water depth, greater fatigue capability and reduced electrical stress.

Deepwater challenges for thermoplastic hose include higher working pressure and higher collapse resistance. These are particular challenges for Arctic service in terms of greater temperature range, both hotter and colder. "We're working in increasing the water depth capability for that product in terms of some of the materials we use," Probyn said.

Smart sensing umbilicals are now being developed with fiber optic temperature and strain monitoring, and dynamic positioning sensing. This makes it possible to record actual response to service conditions, to carry out hotspot monitoring during extreme storm events, and have a feedback loop for operations optimization. There is a lot of synergy with technology that has been developed in the flexible pipe market.

The MQC (Multi-Quick Connect) stab plate has been developed in conjunction with Technip ROV experts. It is a light weight and compact connector for flying lead and jumper umbilicals. It has a more than 15 degree out of alignment mating capability and can easily be manipulated by ROV subsea. The product has recently completed all of its qualification testing, including hyperbaric mating and demating, misalignment mating, and impact and vibration loadings. It is now ready for the market.

The friction increasing tape is called Compressi-Grip. This is still blue sky technology, said Probyn, but Technip has had a patent accepted and so can now start to talk about it. He explained that the weakest friction interface in the umbilical is between the outer bundle of the components and the inner surface of the polymer sheath. The bundle could slip through the sheath when it is squeezed in what is known as the 'caterpillar' position during installation possibly causing damage.

The Compressi-Grip artificially increases the friction interface while the umbilical is in the squeezed 'caterpillar' mode. Once the umbilical comes out of the caterpillar the friction interface drops off again. Increasing the friction the friction increases the water depth for umbilical deployment. Doubling the friction effectively doubles the water depth. "We've proven the concept, and over the next year or so we'll prove the component and do a full qualification program as well," Probyn concluded. He added that investing in manufacturing capabilities was also a tool in meeting future technological requirements. ■

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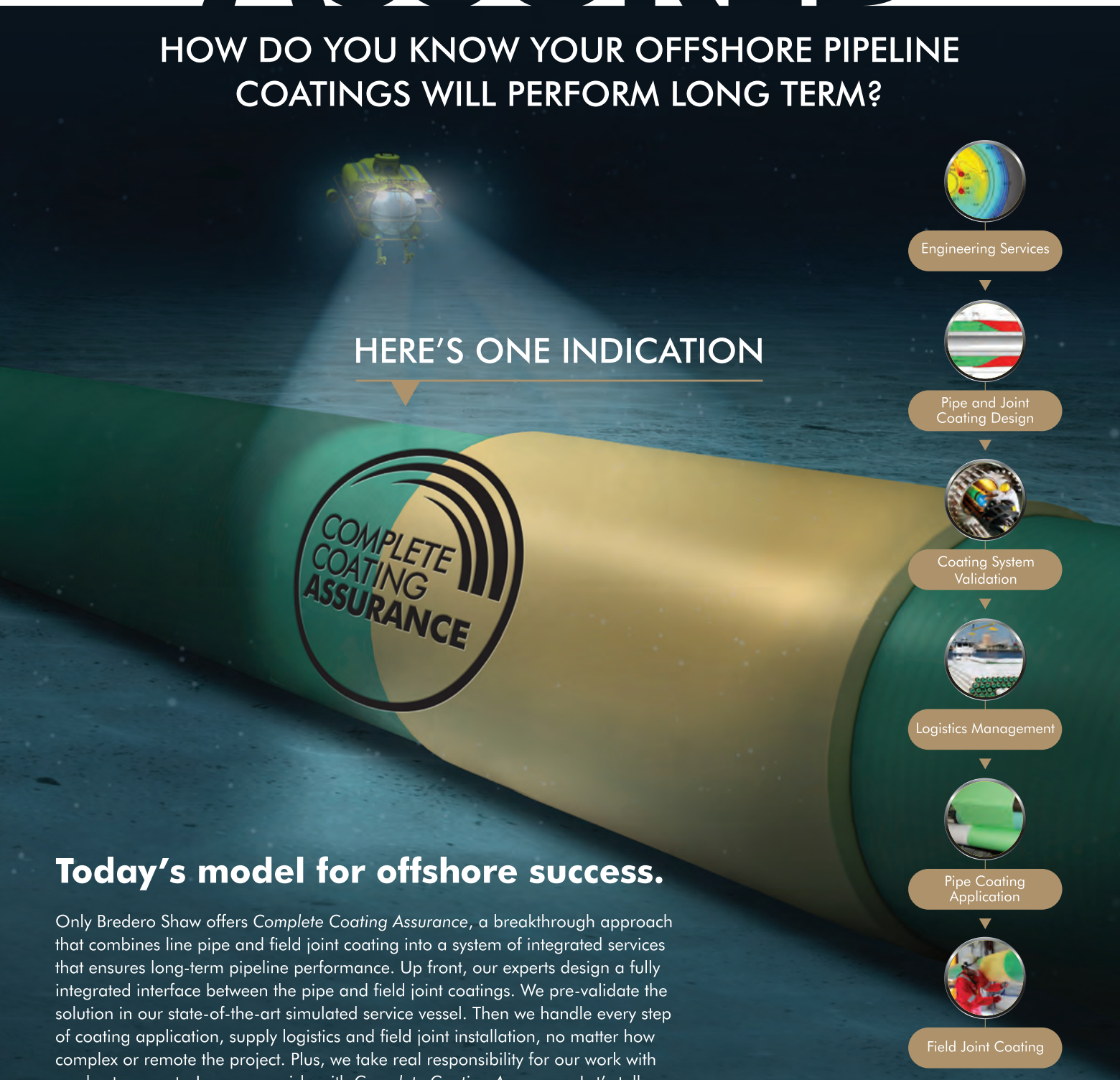

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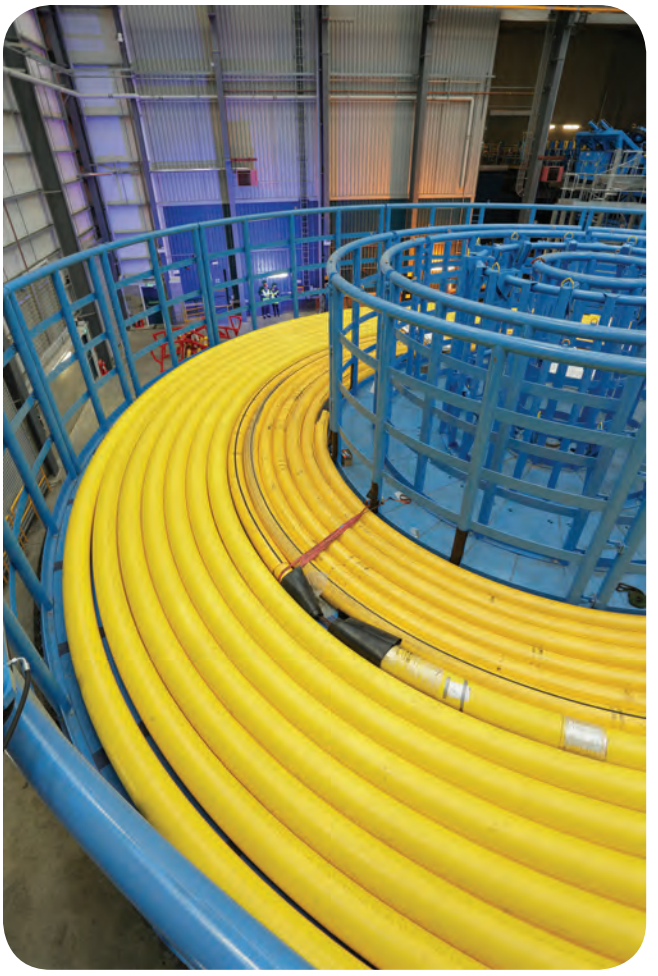
Flexible investment

Flowlines and getting bigger and longer. Wellstream, part of GE Oil & Gas, has increased capacity at its Newcastle facility.



One of GE's two new storage and manufacturing carousels at its Newcastle facility. Photo from GE.

Walker Riverside's expansion has extended to unbonded flexible pipe manufacturing.

Wellstream, part of GE Oil & Gas, officially opened two new storage and manufacturing carousels at its unbonded flexible pipe manufacturing facility at Walker Riverside at the beginning of April.

The two new carousels, which increase capacity at the site, have been built to meet the increasing demands for deepwater and high-pressure pipelines.

"With FLNG coming, and production coming from deeper and deeper waters, pipes are getting heavier and bigger in diameter and the conditions they are going into harsher," says Bruce Heppenstall, general manager, Wellstream. Higher pressure requirements are also increasing, he says. Flexible pipe produced at Wellstream currently extends to a 10,000psi design load.

"The industry wants more and more in higher and higher pressures, and it is a trend we are investing in on our research and development programs in Newcastle," Heppenstall says. "There is a lot of proprietary technology and manufacturing technique to make and wrap around a reel what are effectively flexible pressure vessels."

The site already had two, 1000-tonne storage and manufacturing carousels. These are used for storage and during the manufacturing process, by rotating to wind on the pipe at the same speed it passes through the production line, as each component layer is added. Wellstream also has one 1000-tonne storage carousel.

The two new carousels are 26m diameter, 3000-tonne manufacturing and storage carousels.

Wellstream has also invested in two new 35ft reels to supply the larger diameter pipes, and increased lengths, and it has taken a lease on a new building, in Newcastle, for its research and development, and testing activity. R&D is currently focused on high-pressure, and the types of polymers used. "Also, as pipes get larger in diameter, they get heavier, so we are looking at using composites to make pipes lighter," says Heppenstall.

GE's Newcastle facility was opened in 1997, on the former Vickers Armstrong naval shipyard, which closed in the 1980s.

Since 1997, the site has been making unbonded flexible pipes for the oil and gas subsea industry. The site, which produces pipe from 2in.-16in. internal diameter, has the capacity to make about 300km of up to 8in. normalized kilometer pipe a year. These are mostly used as flowlines on the seabed, or as risers up through the water column to platforms or floating production facilities.

The Newcastle facility exports about 80-90% of what produces around the world, except to Brazil, where Wellstream has a dedicated facility working for this region.

The facility produces pipe, starting with flat steel strips, which form a carcass to prevent the pipe from being crushed, then adding extruded polymer barriers, to stop fluids or gases escaping, and then a flexlok layer, which at up to 12mm thick prevents high pressure fluids (up to 10,000psi) from causing the pipe to burst.

Flexible tension layers, using armor wire, is applied to hold on end pieces, which can be under considerable tension hanging off a vessel or production facility, and also further polymer layers, to protect the wires from seawater. Insulation can also be added where required and the number of layers of each component depends on each specific application and requirements. During the production process, pipe is wound on to each carousel in turn, as each layer is added.

Pipes are tested to 1.5x their design pressure. Flange end fittings are also fitted, so the pipe can be connected to the platform, production vessel, wellhead, or each other.

The firm can get up to 1km of pipe (or 180-tonne) on a reel. Reels are then transferred to vessels for transport to installation locations. OE

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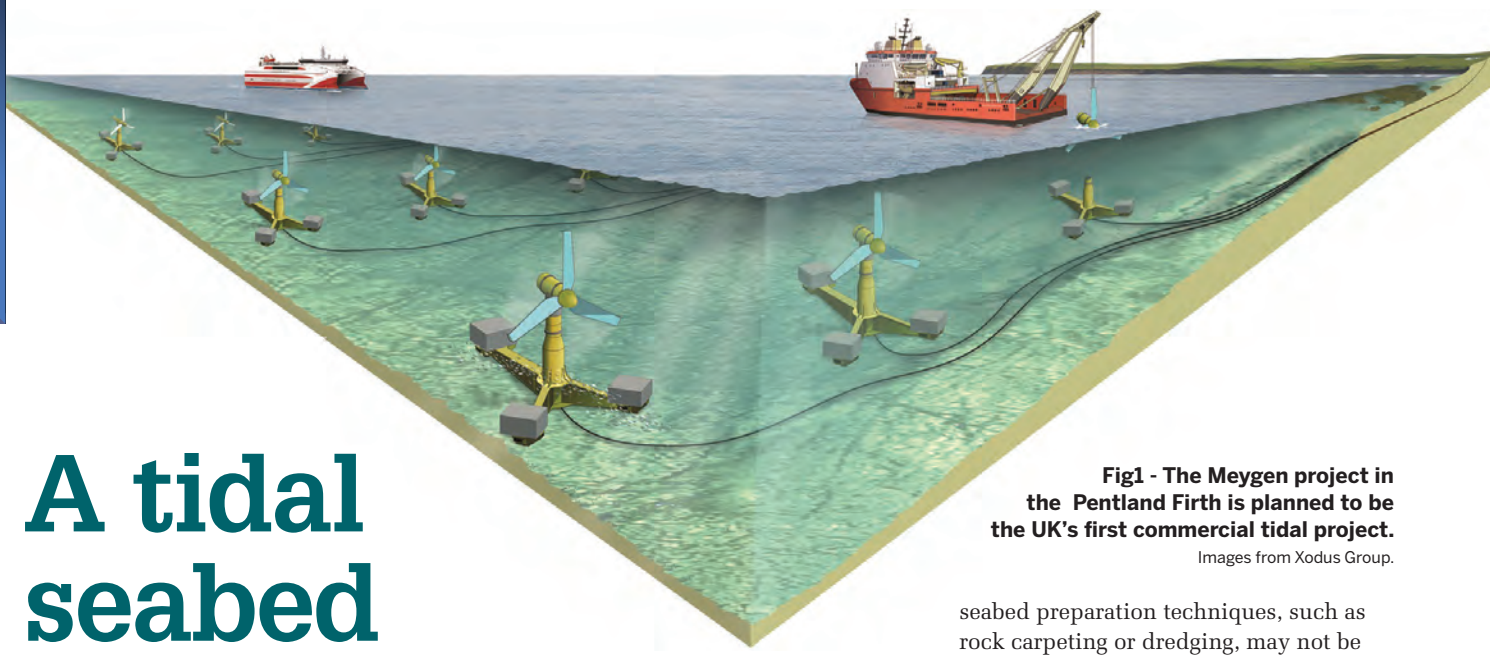


Fig1 - The Meygen project in the Pentland Firth is planned to be the UK's first commercial tidal project.
Images from Xodus Group.

A tidal seabed challenge

Extreme environmental conditions and complex geotechnical challenges make tidal energy projects a huge undertaking. Andrew Small and Greg Cook explain how some of these challenges can be assessed and mitigated.

Though still very much in its infancy, tidal energy is gaining momentum. In 2006, the first test rig turbine was installed and generated electricity to the UK grid, using OpenHydro Technology's prototype. Seven years on, the Meygen project in the Pentland Firth is planned to be the UK's first commercial tidal project, initially comprising six turbines with a total installed power of 9MW, with planned further expansion to 86MW.

Unlike offshore wind, which has seen huge investment from major energy companies, smaller developers and intelligence investors have been the key players in this new and more uncertain market. Despite limited capital, a number of tidal energy converter (TEC) devices have now been installed at several locations around the UK.

The high tidal energy environment required to drive tidal devices presents a combination of design and installation challenges, particularly geotechnical uncertainties, where novel solutions are required.

Challenging Environment

The bedrock geology of the UK coastline is complex and varies significantly. From Precambrian- marine sedimentary rocks, including sandstones, limestones, and shales in the West of Scotland, and slates and schists around the Welsh coastline, a variety of basement materials need to be considered for foundation design. In addition, a thin veneer of unconsolidated coarse sediments often blankets the bedrock.

Tidal turbine site investigation can be extremely difficult and challenging and geotechnical design and installation elements pose a major risk to the project, unless properly considered and effectively managed. Jagged, hard substrates often present challenging seabed profiles (Fig.1) to design around and typical seabed preparation techniques, such as rock carpeting or dredging, may not be practical or feasible.

Fig2 - Wave cut platform in Old Red Sandstone on the shore of the Pentland Firth.

Data Acquisition

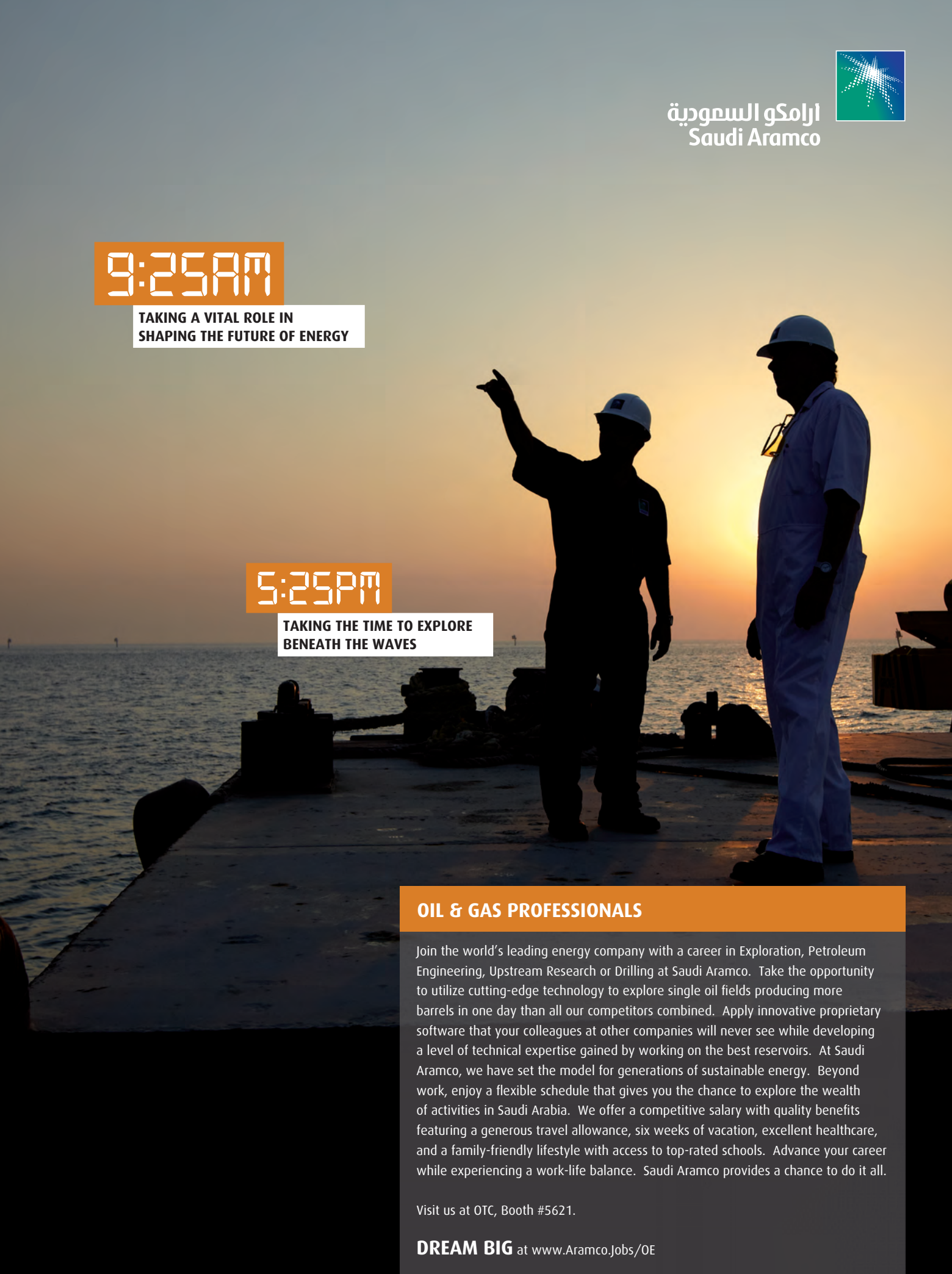
In order to design efficiently, a comprehensive site investigation program should be developed, beginning with a detailed desktop study, shore site walkover, and geophysical and visual camera survey. This is followed by more complex and costly geotechnical surveys, potentially comprising onshore, nearshore, and offshore drilling.

A detailed geophysical survey using surface and subsurface techniques, such as multi-beam echo sounder, side-scan sonar, and sub-bottom profilers, provides data that are essential to understand the topography of the development area. The profiles are used to select and optimize the location of the TECs and the lay routes of inter-array and export cables. The aim of the survey is to identify hazards and determine where potential mitigation measures may be needed.

Geotechnical data may be required to 20-30m below the seabed for detailed foundation design, to determine foundation capacity, soil-structure interaction, and install ability.

While offshore geotechnical drilling can seem expensive, the data can be supplemented by data from onshore drilling, and additionallaboratory tests could provide a better understanding of the variation in bedrock propertiesand their geotechnical characteristics, at a fraction of the cost of marine investigation.

Additionally, material-specific research on soil-material interface friction may also promote efficient



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foundation designs. Acquiring appropriate data to coincide with project milestones will culminate in a comprehensive understanding of the geological features and geotechnical conditions relevant to design.

Design considerations

Initial design evaluations typically use geotechnical parameters derived from qualitative descriptions of shore geology and from camera surveys, often resulting in very conservative foundation designs with safely factors calculated to accommodate the uncertainty in site conditions and seabed materials. As a result, base structures may grow significantly in size and cost. While this may be acceptable for front-end engineering design considerations, it may lead to issues with certification during detailed design, where optimizations are actively investigated.

The design of each tidal turbine varies significantly between manufacturers and a wide variety of foundation systems have been installed, including drilled and grouted monopiles, pin piles, and gravity-based solutions.

The foundation solution is typically governed by seabed conditions andthe tidal energy converter design, which may limit potential foundation solutions. Selecting the appropriate TEC for the seabed and tidal conditions is a key to success.

Tidal power and TEC development

Together with smaller demonstrator sites, the European Marine Energy Centre (EMEC) test site off the coast of the Orkney Islands, northern Scotland, has provided a catalyst for innovation into wave and tidal energy research. EMEC is near the treacherous Pentland Firth, with high-velocity marine currents and challenging geomorphology. Reports suggest that the Pentland Firth area alone could theoretically generate around 1.9GW tidal power.

One e of the demonstration sites in the UK includes Marine Current Turbines' (MCT) SeaGen device, installed in Northern Ireland's Strangford Lough in 2008, which used a novel foundation installation approach. A quadrapod-design base was temporarily ballasted for stability. A temporary work deck was installed on top of the turbine structure, above water level. In a similar manner to the OpenHydro device, this allows the turbine assembly to be raised above the sea surface to realize reduced maintenance costs.

In mid-2011, Germany's Voith installed the foundations for its prototype HyTide 1MW device at the EMEC test site.

Fig3 – Typical Horizontal Axis Tidal Turbine (HATT)

Unlike SeaGen and OpenHydro devices, which protrude above the sea surface, the Voith device is completely submerged.

Possibly the most conventional TEC designs are those featuring large gravity-based or piled tripod foundation configurations, similar to those sometimes used at German windfarm sites. A prototypical horizontal axis tidal turbine with a gravity-based foundation solution is shown in Fig. 3.

Cable protection

In shallow seas (<200m water depth), pipelines and cables laid across the seabed are protected by being placed into a trench or by being covered with crushed graded rock, or using cable casings. These systems protect the pipeline or cable from fishing gear, dropped objects, anchoring, and also ensures on-bottom stability from hydrodynamic forces. The amount of protection is used will likely be selected based on protection philosophy, the requirements of other sea users, and the level of risk the developer is willing to accept.

Decommissioning

Decommissioning is a key design consideration for new offshore developments and should be considered early in the design phase to minimize future environmental impact, offshore activities, and associated costs.

As tidal turbine installation is typically remote, it is presumed that decommissioning will take place remotely. In 2011, the UK Department of Energy and Climate Change (DECC) published guidance notes on decommissioning renewable energy installations, including the removal of foundation elements and cable deburial.

Assessing the recovery loads from a structure placed on the seabed for a typical 20-year design life requires careful determination of the additional loads arising from marine growth, seabed suction, and potentially cementation. It is also necessary to consider the capacity of existing lifting points intended for re-use. At present, there are few recorded cases of recovery of large gravity-based subsea structures after long periods of use. However, it is likely that as North Sea decommissioning activity increases, these will be better understood.

Harnessing tidal power

Extreme environmental conditions and complex geotechnical challenges make tidal energy projects a huge undertaking. The ambition for tidal to become a viable and reliable source of renewable energy for the future continues to require significant financial and intellectual input. However, the challenges are being overcome and solutions found. It is important that seabed conditions and materials are adequately investigated prior to deployment to minimize project risk.

While the design of tidal devices does vary, each has the same fundamental issues to resolve, from concept to project sanction, through asset integrity to end of life.

***Andy Small** is a senior geotechnical engineer for Xodus Group based in Aberdeen Before taking his current position in 2013, he worked for offshore EPIC Contractors and specialist offshore geotechnical consultancies. He holds a MEng in Civil Engineering Design and Management from the University of Dundee, UK.*

***Greg Cook** is a Consultant Engineer contracted to Xodus Group in Aberdeen. He holds an MSc in Engineering Geology from the University of Canterbury, New Zealand, and worked in onshore civil consultancy prior to coming to the UK. For the past 10 years his work has been focussed on marine geotechnics within the oil and gas and renewables sectors.*

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“ Nature was my inspiration when I designed the first UT 704 vessel ”

A long time ago, when I was young, I would go fishing and study marine wildlife. I observed that fish like mackerel have an optimal shape. They are wide amidships and slim fore and aft, and they move very fast in the water. It’s a form that has influenced me as a ship designer and especially when we designed the original UT 704. You can still see the same high-speed hull profile in modern UT vessels that focus on efficiency and low fuel consumption. Now we’re developing new designs and technologies to help the offshore industry move into deeper water and colder environments. There are always interesting new challenges to meet, so I believe UT has a great future.

SIgmund Borgundvåg - Founder of UT Design

SIgmund spoke to us at his home in Ulsteinvik. Far from being retired, he still goes to work every day. Explore the passion and commitment behind 40 years of UT design. You can find Sigmund’s story and many more at www.rolls-royce.com/UTstories

UT. The ship that launched a thousand stories.

Systematic sampling

Benthic's Alan Foley, discusses the company's seabed drilling and sampling system, the Portable Remotely Operated Drill (PROD).

PROD on a rare sunny day west of Shetlands.
Photo from Benthic.

Since 2001, Benthic has operated a seabed drilling and sampling system to assure the integrity of the seabed for a variety of applications including mooring, piling and pipeling route survey. This seabed system or PROD, an acronym for Portable Remotely Operated Drill, has grown from its roots as a geological hard-ground coring system into a full-range geotechnical site investigation tool able to operate in water depths of 3000m.

Typical projects handled by the system have been in deepwater areas of Norway, Angola and East Africa, where the seabed applications shine compared with vessel-mounted rigs. Other deployments have included in the Caspian, Timor Sea, Solomon Islands, Korea, all coasts of Australia and Patagonia. While not completely insulated from the effects of bad weather, seabed operations can continue in poor weather, with control and power being fed to the PROD seabed unit via an armored umbilical, when vessel-based drills run for shelter.

Operating in water depths down to 3000m, PROD can be deployed from DP anchor handlers, or PSVs. The system offers many commercial and technical advantages, especially in deepwater, where the fixed location on the seabed provides precise control over the drilling parameters without the effects of vessel motions, and allows multiple tools to be deployed in the same borehole, without the need to travel back to the surface for each tool change.

Starting with a standard suite of soil borings, comprising of coring and cone penetrometer data, the offerings of the seabed system have expanded to include ball penetrometer, seismic probe, pore pressure standpipes and in-situ hydrocarbon sensors. These tools have proven useful in establishing parameters for geohazard analysis and, in conjunction with geophysical data, provide a basis for pre-lay site clearance and baseline measurement of critical geotechnical parameters.

With increasing emphasis on well safety since 2010, Benthic has expanded the pore pressure measurement capabilities of the cone penetrometer (CPT) system to integrate the results of laboratory testing of core samples. The resulting reports can provide critical analyses of near-seabed conditions for mitigating risk in jackup rig siting, well tophole design, slope stability, seismic hazard analysis in seismic zones and the measurement pressure in shallow formations for shallow water flow potential. These conditions all present risks, not only to pipelines and structures, but also to exploration wells through the setting of conductor penetration parameters. In deepwater settings these analyses can save days of lost NPT with a rig on location and negate the need for moving seabed locations.

Increasingly as deepwater wells move into areas with stiff seabeds and unknown drilling conditions the capabilities of PROD's in-situ measurement techniques come to the fore. The seismic probe has the capability to provide direct measurement of transmission seismic velocity values, including Vp

and previously unavailable Vs values. This has resulted in meaningful measurement of Poisson's Ratio and other rock properties within the range of the PROD probes. As analysis techniques are refined the measurement of velocities, pore and fracture pressures below the maximum penetration level of the drillstring will remove uncertainty in difficult drilling conditions. In the future Vertical Seismic Profiling will extend the depth of analysis and surface wave techniques have the potential to expand the lateral coverage using the seabed seismic probe.

In Arctic areas comes a challenge of permafrost and gas hydrates therefore measurement of temperatures with cone penetrometers is a key. As the reach of these remote sensing systems allows more integration of geotechnical results with geophysical, data the reach of geophysical data to enable engineering-quality assessment is increasing. This removes the need for drilling open hole to ever increasing depths and allowing riser or dual gradient mud systems more accurate pressure control. In preparation, Benthic is already building a new generation of launch and recovery systems to cope with increasing depths and weather conditions, and will build the next generation PROD4 with an extended the water depth capability of 3500m. These systems will work in conjunction with AUV and other seabed acquired data to allow earlier and more comprehensive site assessments.

Benthic is investing heavily in the next generation of engineers "We have a graduate training program in Benthic taking on six graduates across several disciplines," commented CEO Stephen Pywell. In 2014 Benthic will take on a further six, both geo-sciences professionals and engineering professionals.

Lights, camera, action in a port at night. Photo from Benthic.

Following the production of the new units the original PROD1 will relocate to Houston as part of a new development and training centre, with courses running internally and externally to introduce seabed drilling to the GoM and industry-wide.

Recently extensive activity in deep-water mineral mining in the Pacific since 2009 has pointed to a wider scope for seabed sampling. Benthic sees a growing opportunity in other environments, where the PROD equipment can offer some distinct advantages over more conventional equipment in some of the most challenging environments around the world.

With an emphasis on working in challenging environments and using a readily adaptable system on a range of vessels seabed systems can fit schedules and budgets where permanently deployed rigs are absent. OE

Jackups on the rise

A number of rig providers are increasing their fleet with newbuilds over the next three years. Audrey Leon provides a roundup of the latest designs hitting the market.

Many rig operators are making efforts to not only renew but increase their drilling rig options. Jackups are the hottest commodity with a slew of newbuilds heading up the global market in the next few years. Transocean chalks it up to demand.

"We anticipate demand for these rigs as the renewal of the industry's jackup fleet continues," the company said in its 2013 Annual Report. "This sector has been developed to a significantly greater degree than the deepwater market sector because the shallower water depths have made it much more affordable and accessible than the deeper water market sectors."

InfieldRigs shows that as of 14 April 2014, there are 413 jackups around the globe, 361 with contracts for a total utilization rate of 87%.

Transocean is not alone in opting to build more jackups. Seadrill, Ensco Plc, Noble Drilling and Maersk Drilling will also bring multiple new jackups into their fleet over the next three years.

"The jackup market has traditionally been a shorter term market; however we expect longer term contracts to be executed going forward," said Fredrik Halvorsen, Chief Executive Officer of Seadrill Management Ltd, in 2013. "In addition to increased terms, we expect to see rising dayrates as attrition accelerates amongst an aging global fleet."

Maersk Drilling's recent 2013 Annual Report says that the market for ultra-harsh environment jackups remains strong with full utilization of its capacity throughout 2013. "Most jackups are tied up in long term contracts reducing the near term availability of jackup rigs in the market where the first rig is available in the 4Q 2014," according to the Maersk report.

InfieldRigs data, as of 1 April 2014, lists high-spec jackups as having an average dayrate of $231,400. By comparison, drillships bring in an average of $365,100/d. Semisubmersible rigs on average bring in $394,100/d.

Maersk Drilling

Maersk Drilling has an extensive program of newbuilds to come over the next two years that includes four new jackups and four new drillships. The company has ordered four ultra-harsh environment GustoMSC CJ70 designed jackups, built for a maximum water depth of 492ft, and a maximum drill depth of 40,000ft. Three XL Enhanced jackups are currently under construction at the Keppel FELS shipyard in Singapore. A fourth jackup is under construction at the Daewoo Shipbuilding and Marine Engineering's (DSME) Okpo Shipyard in South Korea. Delivery is expected to occur from 2014-2016.

Three newbuild jackups based on the XL Enhanced design will hit the market in 2014, 2015, and 2016. Photo from Maersk Drilling.

The XL Enhanced jackups are designed for year-round operation in the North Sea, with the capacity to operate in water depths of 492ft, and a maximum drill depth of 40,000ft. The design also features dual pipe-handling, which allows for offline stand building of drill pipe, casing or bottom hole assembly while one string is working at well center, and a remotely-operated pipe handling system, which allows all standard operations such as stand building and tripping to be conducted without personnel on the drill floor.

The first XL Enhanced jackup, due for delivery in 2014, will serve Total E&P Norge's Martin Linge field (formerly Hild), in a four-year contract valued at $550 million. The XL Enhanced 2, due for delivery 4Q 2014, will be used for drilling on Det norske Oljeselskap ASA's Ivar Aasen (formerly Draupne), in the Norwegian North Sea. The contract is for five years and is worth $700 million. Maersk's XL Enhanced 3, due for delivery in 2Q 2015, will serve Statoil's Gina Krog (formerly Dagny) development off Norway in a four-year, $630 million contract. The XL Enhanced 4 jackup, to be delivered from DSME in mid-2016, has been signed by BP Norway for five-years in a contract valued at $812 million. Options to extend up to a total duration of 10 years. The XL Enhanced 4's work will include plug and abandonment assignments on the Valhall field in the Norwegian North Sea.

Ensco

Ensco plc currently plans to add five jackups to its fleet. Ensco announced in April that it ordered two jackups, the Ensco 140 and 141–based on the LeTourneau Super 116E design–to be built at the Lamprell shipyard in UAE, due mid-2016. Three more jackups are under construction at the Keppel FELS yard in Singapore. The Ensco 122 and the Ensco 123 are in the Ensco 120 series–based on the Keppel FELS Ultra-Enhanced Super "A" Class design. The 120 series includes a patented high-capacity cantilever envelope and a 2.5 million-pound quad derrick for drilling in harsh environments up to 400ft water depth, capable of drilling down to 40,000ft. The series features automated

hands-free offline pipe handling systems, ultra-high capacity jacking and fixation systems, and 145-person quarters.

The Ensco 122 and Ensco 123 are scheduled for delivery in 4Q 2014, and 2Q 2016, respectively. A third jackup, the Ensco 110 is a Keppel FELS B Class Bigfoot design capable of operating at 400ft water depth, and drilling down to 30,000ft. The Ensco 110 will have a nominal variable deck load of 7500kips and a cantilever load of 2500kips. It also has a 1.5 million-pound derrick, TDS-8 top drive and 15k BOP. Ensco says it customized the rig to add dual drilling fluid capability and to upgrade the living quarters to 6 one-person and 67 two-person rooms. Delivery is due 1Q 2015.

Noble Drilling

Noble Drilling has six rigs, four jackups and two drillships, under construction and due for delivery between 2014 and 2016.

Two jackups, the Noble Tom Prosser, and the Noble Cam Hartley, are under construction at Jurong Shipyard in Singapore, and due for completion in 2014. The Noble Sam Turner was delivered this year and is preparing to work offshore Denmark. All three are Friede & Goldman JU3000N-designed jackups. All are ABS +A1 classed, self-elevating drilling units. The three jackups are built for water depths of 400ft, can drill to depths of 35,000ft, have a variable deck load of 14,300kips, and quarters for 150 people. The Noble Tom Prosser and Noble Sam Hartley are both in-transit and undergoing acceptance testing, with delivery expected 4Q 2014.

Another jackup under construction at the Jurong yard is the Category J Noble CJ-70–based on the GustoMSC CJ70. The unit is due 1Q 2016 and will undergo acceptance testing in the UK, according to Noble's latest fleet status report. It can operate in up to 492ft water depth, and drill to 32,000ft. It has a variable deck load of 17,600kips, with quarters for 150. Noble's CJ-70 will work Statoil's Mariner field in the UK North Sea, approximately 150mi. east of the Shetland Islands.

Transocean

Transocean announced 14 additional newbuild projects for the next three years, including nine high-specification ultra-deepwater drillships and five premium jackups scheduled to join the fleet between 2014 and 2018. In 2013 three newbuild jackups–Transocean Andaman, Transocean Ao Thai and Transocean Siam Driller–were placed into service with Chevron in Thailand.

Transocean signed shipyard contracts valued at approximately $1.2 billion to construct five Super B 400 Bigfoot Class jackup rigs with options for five additional jackups. The first five, unnamed, are scheduled for completion in 1Q 2016 and continuing into 3Q 2017. All of the jackups have an operational capacity if 400ft water depth and can drill down to 35,000ft.

Seadrill

Seadrill's newbuild campaign includes nine jackups, eight drillships, and three semisubmersibles. Seadrill is currently building nine harsh environment jackups at the Dalian yard in China. All will have the Friede & Goldman JU2000E design, which features a modular hull design, enhanced leg design, extended reach cantilever (75ft aft of transom with maximum combined drilling load of 2600kips on centerline at 75ft extension) and 15k BOP. The JU2000E is also capable of operating in up to 400ft of water and drilling down to 30,000ft, and has capacity for 140 people. Delivery will take place between 1Q 2014 and 3Q 2016. OE

The *Maersk Inspirer*, the jackup on which the XL Enhanced design is based.
Photo from Maersk Drilling.

Bit by bit

Sarah Parker Musarra reviews the 2014 International Association of Drilling Contractors/ Society of Petroleum Engineers Drilling Conference and Exhibition.

The doors leading to the exhibit halls, where more than 1355 exhibitors were present. Image from SPE.

More than 1000 attendees braved unseasonable (for Texas) icy conditions that made driving in most North Texas cities nearly impossible, including host city of Fort Worth, to attend this year's International Association of Drilling Contractors/Society of Petroleum Engineers Drilling Conference and Exhibition (IADC/SPE 2014).

Rolv Rommetveit, managing director of eDrilling Solutions, accepted SPE's Drilling Engineering Award Winner for 2014, which recognizes "outstanding achievement or contributions to the advancement of petroleum engineering in the area of drilling engineering technology." Rommetveit was nominated by his colleagues and selected by committee for the award, which celebrated its 30th year.

Technical session highlights

Paper IADC/SPE 167937, entitled "Alternative Drilling Fluid Weighting Agents: A Comprehensive Study on Ilmenite and Hematite" was the first paper of the first technical session, "Fluids and Hydraulics." Presenters Ahmadi Tehrani presented the paper he co-authored with Angelika Cliffe, Michael Hodder, Steven Young, John Lee, James Stark, and Suzanne Seale of Schlumberger's M-I SWACO. In his presentation, he discussed whether the more abrasive, higher-density minerals ilmenite and hematite could be successors or alternatives to barite, the "standard weighting agent in the drilling fluid industry," noting in the paper that this study was a more "comprehensive laboratory study" than what had been done in the past.

According to Tehrani's presentation, increased consumption in China and India in API-grade barite, along with low production, has led to a price increase of more than 100% since 2009.

Several tests were conducted on hematite and ilmenite, including magnetic property testing and abrasion testing. In addition to the standard API 131/ ISO 10416 Section 7 Tehrani said that abrasion testing with the Taber abrader found that "abrasion can be reduced significantly by lowering particle size," however, both minerals are more abrasive than barite. The paper concluded that "the results of tests conducted by two different methods suggest that only the size grade $D_{95} = 25_{\mu m}$ displays abrasivity similar to API barite."

In addition, one of the other pressing points in the question if either of these two minerals could be heir-apparents to barite was their magnetic susceptibilities. Tehrani pointed out that para-magnetism affects downhole tools, including directional drilling tools and magnetic resonance tools. Both ilmenite and hematite have much, much higher magnetic susceptibility than API-grade barite – up to 100 and 1000 times, respectively, higher. Tehrani and his co-authors wrote in the paper, that to their knowledge, "the upper limit of acceptable para-magnetism has not been determined for downhole tools."

Baker Hughes' FASTrak LWD and wireline fluid sampling service was recently successfully deployed in a deepwater GOM case study. Image from Baker Hughes.

The authors concluded that hematite and ilmenite could only be considered as a replacement for barite "if they are milled to a fine [particle size distribution] PSD (e.g. $D_{95} = 25_{\mu m}$), noting that "[compatibility] with downhole tools remains an open question that needs to be assessed under real conditions."

In Tuesday's Session 2, "Drilling Dynamics," Ryan Gee presented paper IADC/SPE 168034, entitled "Drilling with induced vibrations improves ROP [rate of penetration] and mitigates stick/slip in vertical and directional wells," which

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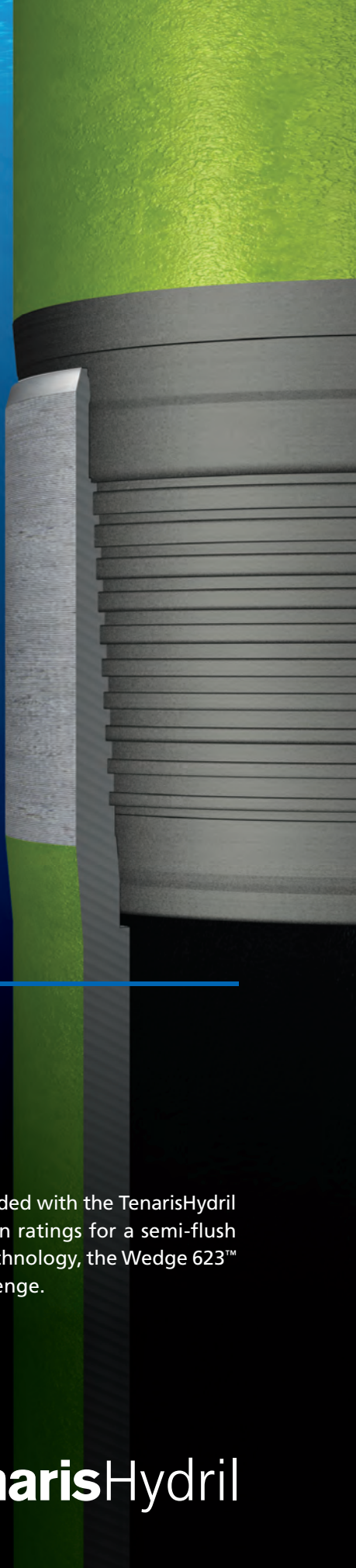

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he co-authored with J.R. Clausen, A.E. Schen, I. Forster, J. Prill, all of whom were from National Oilwell Varco.

The authors published that they found "a low-frequency, benign axial vibration can increase the ROP in all well types."

"No lateral excitations – this was purely axial," Gee clarified in his presentation, noting that lateral excitations and stick/slip can actually improve performance and maintain directional control.

Using an the axial excitation tool, which creates excitation over a frequency range, was simulated at the hard rock drilling facility at Sandia National Laboratories, axial excitation between 5-20Hz was tested at two speeds: 60rpm and 135rpm.

"We saw ROP gains from 20-50%," Gee said, with lower frequencies showing increased ROP improvement than higher frequencies. In the paper, the authors noted this trend could be "[owed] to the decreasing amplitude of excitation at higher frequencies."

Multiple tests were performed in the field at testing was also performed in the field at a test well in Catoosa Test Facility in Owasso, Oklahoma.

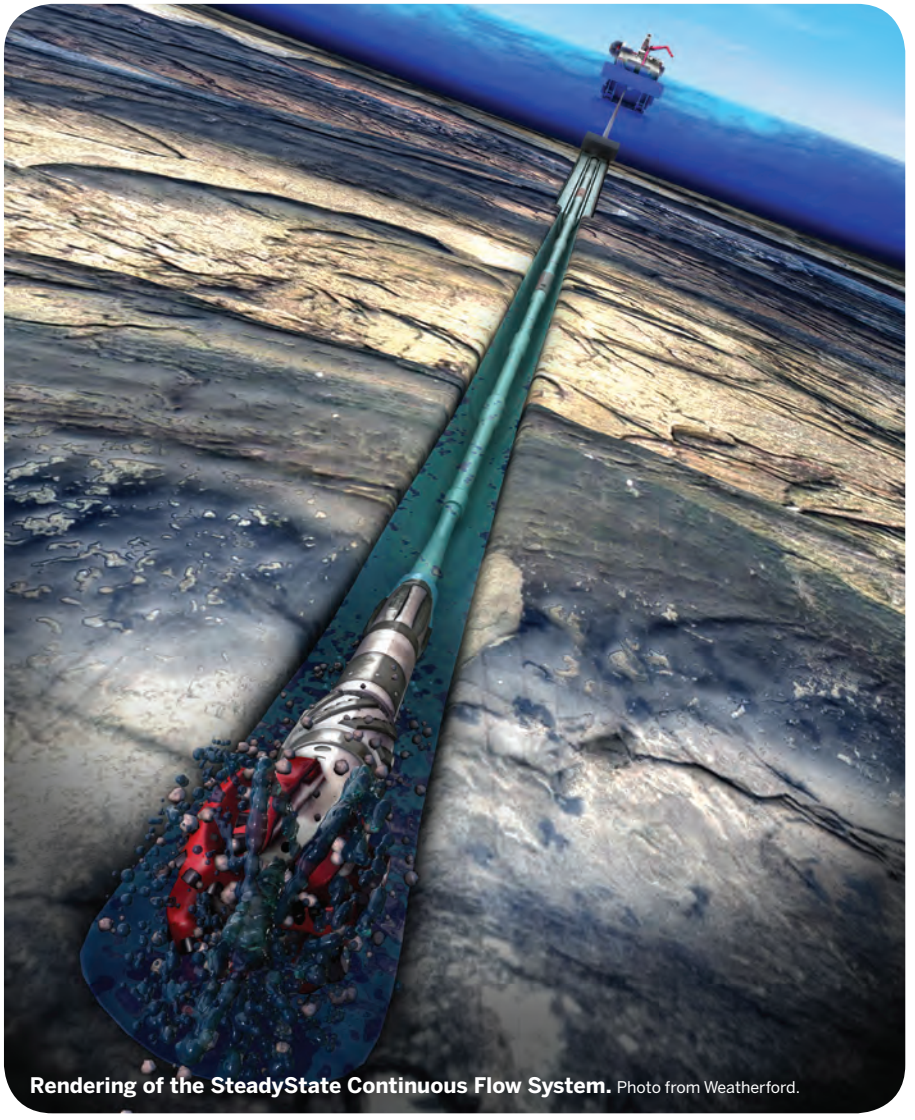
Gee said in his presentation that it was notable that "the same bit drilled all three field tests," with only minor wear displayed on the edges of the PDC, and no damage whatsoever to the PDC cutting structure. In the paper, the authors wrote that "it was highly unexpected given the amount of load placed on the bit during peak WOB (weight on bit) fluctuations."

In conclusion, Gee said, the authors saw "ROP improvements, significant reduction in stick/slip and improved RSS (rotary steerable system) control." They also saw "increased WOB without generating stick/slip by adding fluctuation and changing the DOC (depth of cut)."

On Wednesday, Schlumberger's Hrishikesh Majumdar presented paper IADC/SPE 167916, "Solving deepwater GOM pore pressure puzzle: multiple activation reamer eliminates trip prior to running coring bottomhole assembly," which he co-authored with Xianjie Yi and Kevin Corbin of Chevron North America E&P, and Jefferson Davis, Patrick Davis, Mahavir Nagaraj, Oguz Yalcin of Schlumberger.

Majumdar discussed how the "nature of the pore pressure profile on deepwater Gulf of Mexico (GOM) dictates the need for hole enlargement while drilling (HEWD)" and examined the case study behind one operator who decided to use a "ream-on-demand (RoD) system in the 12 ¼-in. section and eliminate multiple trips to change out BHAs (bottomhole assemblies)."

The paper concluded that the RoD tool "was successfully deployed to overcome the potential additional time and complexity of navigating through the pore pressure issues on this development well." The RoD eliminated a BHA trip from more than 25000ft measured depth, which in turn, incurred that additional savings by eliminating the need to pump down devices.



Rendering of the SteadyState Continuous Flow System. Photo from Weatherford.

Spotlights from the exhibit floor

More than 1300 exhibitors from domestic and international companies and organizations were present to showcase their respective companies' premier drilling products.

FASTrak Among other products, Baker Hughes highlighted its FASTrak logging while drilling (LWD) fluid-analysis sampling and testing services, which provides formation pressure testing, fluid analysis and caption, and the retrieval of downhole reservoir samples. The service company said the product, which will become commercial 2Q 2014, can quickly provide fluid's physical properties to reduce rig time and operative costs.

Ana Carolina Hinkle, product champion – LWD Formation Testing and Sampling Services, was on hand in Baker Hughes' booth to explain that one "important application is the ability of taking samples on extended reach and horizontal wells."

FASTrak was recently chosen by a GOM operator in a deepwater development well for testing and sampling. In the case study circulated at the conference, FASTrak obtained three samples with less than 5% contamination.

"In terms of benefits, FASTrak, unlike its competitors has been able to capture ultra-high purity samples with very low oil-based mud contamination," Francisco Galvan-Sanchez, product manager- Fluid Characterization & Testing for Baker Hughes, said. He added that "FASTrak can capture the highest amount of fluid volume in the industry, we also have the ability to transmit the most fluid properties in real time for fluid analysis."

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Collecting up to 16 single-phase samples in a single run, FASTrak's sensors continuously monitor refractive index and measure density, viscosity, and sound speed, among other variables, in real time.

Weatherford experts were available to discuss several of the company's drilling-related products and services.

Alex Goodwin, Weatherford's global business development manager, discussed the company's RipTide Rathole Killer, which was introduced commercially August 2013.

"It really is one of the hottest drilling applications in deepwater Gulf of Mexico," Goodwin said, explaining that two of the four major operators in the deepwater GOM used the product and achieved US$3 million savings in rig time and rig savings for both operators.

The RipTide Rathole Killer, modified from the original RipTide Reamer, is placed below the measurement-while-drilling/logging-while-drilling (MWD/LWD) tools in the BHA, closer to the drill bit.

"Previously, this application was not attainable. Our reamer isn't mechanically-activated, it's radio frequency identification (RFID)-activated, so we are able to activate the reamer even if there is a restriction above it in the BHA," he said.

Justin Cunningham, Global Product Line Manager for Continuous Flow System (CFS), explained the technology behind Weatherford's new SteadyState CFS, a product of its Secure Drilling services line.

Unlike conventional drilling methods, SteadyState CFS allows drilling fluid to circulate continuously during connections.

"This is particularly important in the managed pressure drilling realm because, as well programs become more challenging, greater control of downhole pressure is required," Cunningham explained. "A large percentage of drilling hazards related to wellbore pressure occur when mud pumps are cycled off and on during connections, causing fluctuations in equivalent circulation density and downhole pressure spikes. CFS' ability to continuously circulate drilling fluid remedies these fluctuations, especially in narrow drilling margins."

Weatherford says that the use of this technology reduces non-productive time, and "enables fewer and deeper casing strings when pore-pressure and fracture-gradient windows are narrow."

CFS is planned to enter field trials 3Q 2014.

While a plethora of exhibitors touted products, Italy's **Drillmec** had something else up its sleeve: The drilling equipment and oilfield product provider is nearing completion of a newbuild offshore modular platform drilling rig for client Compañía Perforadora México (PEMSA) to be deployed in the Petróleos Mexicanos (Pemex)-operated heavy oilfield Ayatsil.

Discovered in 2008, and located off Campeche Sound near Cantarell, Ayatsil is Pemex's largest-ever discovery. Sitting in a water depth range of 125-143ft, Ayatsil is estimated by Mexico's Energy Ministry to contain reserves of up to 553MMbo.

"As a 3000hp offshore modular drilling rig, it's the first of its kind in this size," the rig's Project Manager John Folsom explained. "It is roughly 120 lifts, in total, and each modular has different equipment in it: from mud pumps, to generators, to quarters.

"It's a first for Pemex, it's a first for Drillmec, it's the first [of its size] for the Gulf of Mexico," he said.

As a self-erecting rig, it can be installed on a fixed platform with Drillmec-supplied cranes, opening the market up

for other countries to pursue offshore play.

"For this client and also worldwide, the original API platform drilling rigs were bigger rigs, and you would have to have a derrick barge to install it onto the platform," Folsom said. "With Mexico, with Brazil, with a lot of different countries, derrick barges are not readily available. They need a big rig, but they need it to be modular so they can load and unload it without a derrick barge.

"Derrick barges are very expensive to operate, and you have to get scheduled in, because there is not that many in the world. So Pemex and countries like Peru are looking to modular rigs so that they can actually complete in the market place."

Folsom said that while Drillmec received the contract in December 2012, it had already been working on the project for about six months prior to that. Drillmec plans to ship the rig in June with installation on the platform to follow in August.

"Most prototypes of this size take nearly two years to complete, and we are looking at 18 months to two years [for completion]," he said.

This particular rig can be installed in water depths of around 185-300ft, depending on the platform, which in this case is being built by McDermott International.

Rendering of Drillmec's 3000hp offshore modular drilling rig, which the Italian company says is the first of its kind. Image from Drillmec.

The system itself consists of two main modules: the drilling equipment structure (DES) and the drilling support module (DSM), which is equipped with one 75-ton crane and one 50-ton crane.

Drillmec said that the DES has the capacity to move above 15 wells arranged in a 3x5 matrix. The rig is capable of drilling wells up to 25,000ft. The rig can accommodate 100 people, with a helipad on top of the housing area that meets International Civil Aviation Organization standards. OE

Traq-ing underwater

Cable-laying challenges on offshore wind farms has led to a new tracked trenching vehicle being designed, which may also have benefits in oil and gas sector. Chris Jones explains.

Hi-Traq's self-levelling system allows vertical trenching on sloping terrain.
Photos from IHC EB.

Unlike the calm subsea environments in deepwater locations, the waters around offshore wind farms are susceptible to strong currents and wave action.

These conditions lead to changes in the underwater landscape, creating up to 20m high sand waves and ripples on the seabed. Potentially uneven seabeds range from loose sands through to extremely hard clays, which require different trenching tooling for cable burial operations.

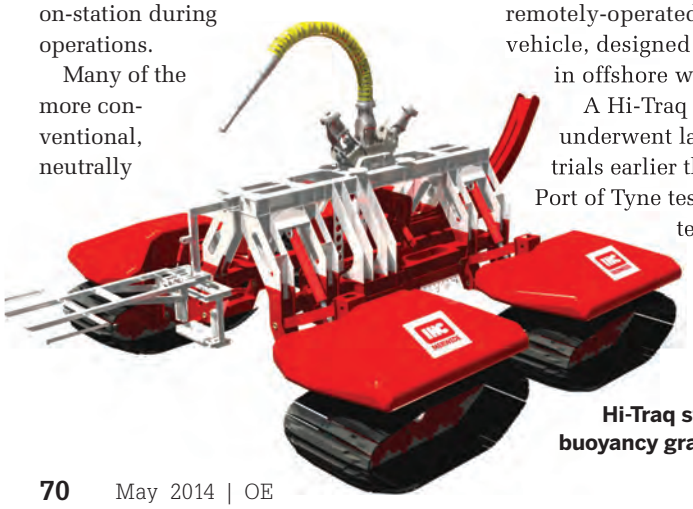
High wave loadings and strong currents can create up to 6knot combined water velocities, requiring a minimum submerged vehicle weight, in order to keep a vehicle on-station during operations.

Many of the more conventional, neutrally buoyant, free swimming ROV's have difficulty coping with these demanding environments and can lose position; endangering the cable being buried.

IHC Engineering Business saw an opportunity to create a new solution to make traversing these rough terrains easier by using a tracked vehicle. The Hi-Traq subsea crawler is designed to stay on station in challenging conditions, increasing available operational windows and safety.

With support from the European Regional Development Fund, Hi-Traq has been developed by northeast England-based IHC Engineering Business, part of Netherlands-based IHC Merwede, over two years. It is a remotely-operated, tracked, trenching vehicle, designed for power cable burial in offshore wind farms.

A Hi-Traq demonstration vehicle underwent land-based proving trials earlier this year at IHC EB's Port of Tyne testing facility. The testing encompassed a range of activities, from 20° incline traverse trenching to 10m-radius trenching with skid, wagon, and crab steering tests.



Hi-Traq streamlined chassis with buoyancy grabs and tooling cylinder.

Hi-Traq has a four-track undercarriage system with a bogey arrangement. The design means the vehicle has low ground-bearing pressures, because it evenly distributes the weight of the vehicle, enabling maneuvers over variable terrain to be managed, while providing high traction, compared to two-track alternatives.

The vehicle has an automatic self-levelling system, allowing it to traverse 20° sand wave and ripple slopes and maintain a constantly level chassis to ensure stable and vertical trench depth.

Independent track steering reduces the traction loss associated with skid steering, preventing the trencher from getting "bogged down, and enabling a 10m radius corner trenching capability. This means cables can be trenched up to the wind turbine foundations, avoiding the need to deploy additional support vessels, which are usually required for external protection measures, such as matressing or rock-dumping.

The undercarriage system has two trenching modes; jet sword cutting, for softer soil conditions, and mechanical cutting, using cutter chains, for trenching through harder seabeds.

The system was primarily designed for cable burial on offshore wind farms.

trenching

For this purpose, two chassis configurations were designed, a 25-tonne (in air) unit, with jet swords only, and a second, weighing 50-tonne, with both jetting and mechanical cutting options.

IHC Merwede also sees the potential for Hi-Traq to be used in offshore oil and gas, so a third design weighing 65-tonne in air was created. The larger system has been designed to handle larger product diameters, such as oil and gas flowlines and flexible pipelines, of up to 400mm in outer diameter. This vehicle's functionality compares with a previous IHC Merwede trenching vehicle i-Trencher but the Hi-Traq system is 30 tonnes lighter.

EB designed and built the i-Trencher system, including a 1.25MW trenching vehicle, its launch and recovery system, and heave compensation system for trenching and backfilling up to 2m deep in hard soil and deep waters.

Hi-Traq has an operator control system with surveillance and locating technology, which enables operations to be viewed remotely using a universal fiber optic multiplexer system. A launch and recovery spread has been designed to be suitable for deployment in high sea states, with a snubber system designed to manage dynamic loads caused by wave action. The offshore renewables-focused Hi-Traq vehicles can be deployed using a lift umbilical.

IHC Merwede is planning to extend Hi-Traq's tooling range to address the inspection, repair, and maintenance, segments, as well as decommissioning. Hi-Traq could also carry other subsea tooling, such as an eductor dredging system, coupled to a long-reach excavation linkage, to carry out subsea dredging. OE

Chris Jones *is responsible for product development of subsea excavation and trenching equipment at IHC Engineering Business. He primarily works with product focused research and design whilst developing close contact with the market place to define product development requirements. He was previously at Caterpillar Building Construction Products, aiding in the development of market hydraulic excavators. He studied at the University of Central Lancashire.*

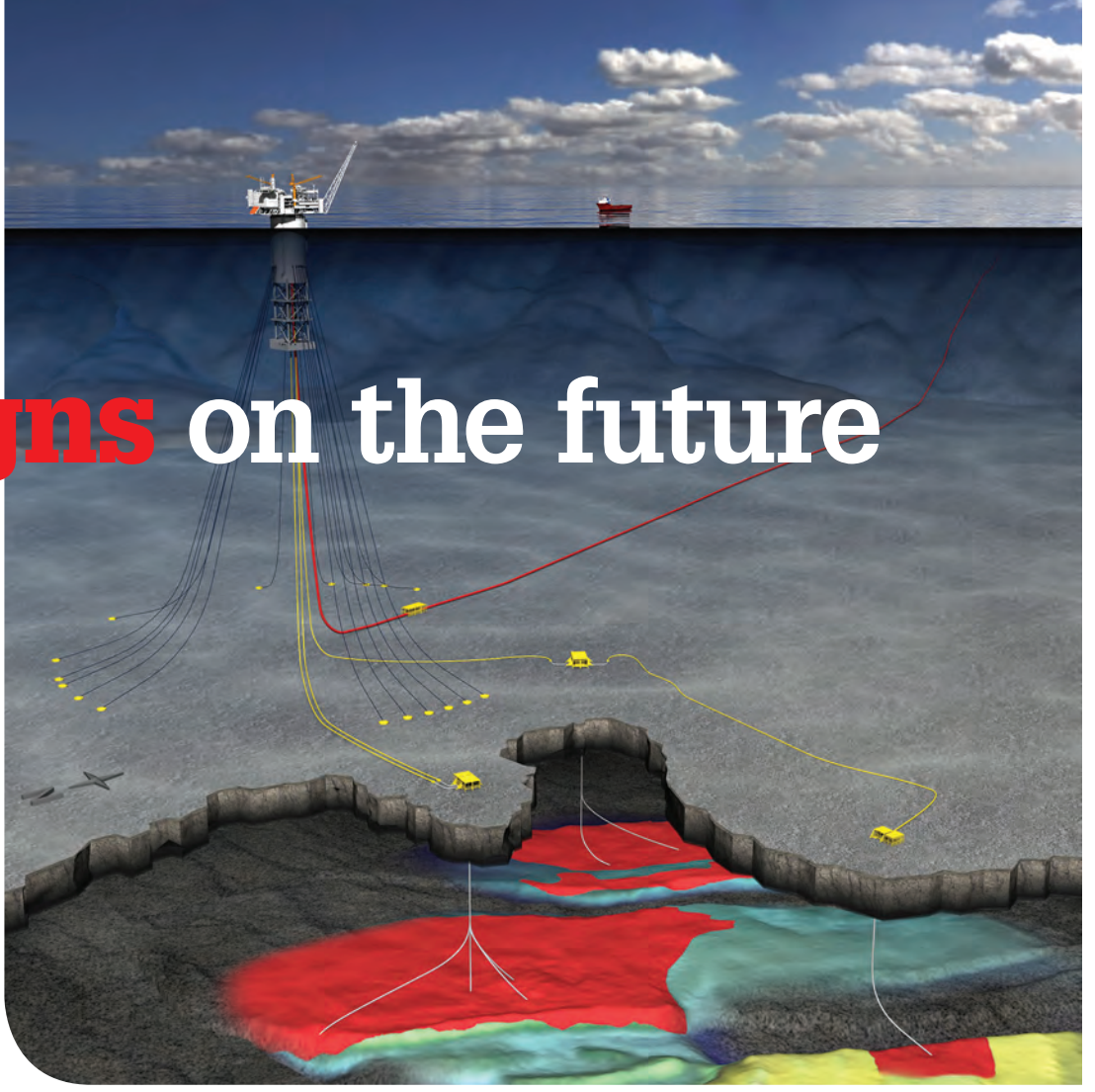
IHC Engineering Business is part of IHC Merwede, which supplies vessels, equipment and services to the dredging, mining, offshore and marine markets.

The Hi-Traq demonstration vehicle during land-based trials.

Track pivoting on the Hi-Traq demonstrator vehicle.

Hi-Traq's steering capabilities improves the minimum trenching radius.

Designs on the future



First oil from the Gina Krog development is expected 2017. Photo from Statoil.

Copenhagen's Ramboll Group pocketed two intricate Statoil pipeline contracts and announced a new office in Houston. Sarah Parker Musarra discussed the company's latest developments with Project Manager Jan Bohl Andersen.

Two major Statoil projects are scheduled to come online in 2017. Engineering, design, and management consultancy group Ramboll are behind subsea pipeline design for both of them. The Copenhagen-based company is responsible for the design and engineering of the Polarled subsea pipeline, connecting the Aasta Hansteen platform with the Nyhamna terminal, and the pipelines of the Gina Krog field development. The Polarled pipeline will be finalized 4Q 2016.

The large Polarled pipeline will cross the Polar Circle, and will be laid in record water depth for its 36in. size, with an inner diameter of 34in., exporting gas from the Aasta Hansteen development in the Norwegian Sea to the Nyhamna gas plant. With the capacity for future developments to be tied in, it stands to make a major impact on Norwegian Sea production.

"The Norwegian Sea is an exciting area on the Norwegian continental shelf. Polarled underpins this. Establishing new infrastructure increases the opportunities for the discoveries already made, and at the same time paves the way for further exploration and the development of future discoveries," said Rune Bjørnson, Statoil's senior vice president of Natural Gas, in 2013.

The Norwegian giant labeled Gina Krog as "among [its] major new developments." While it might seem unbelievable that its pipeline design and install phases could be considered as challenging as the complicated, record-breaking Polarled pipeline, Ramboll's Gina Krog Project Manager Jan Bohl Andersen insists that it is so.

It will be engineered with great care," Andersen said, chuckling at the overwhelming nature of his understatement.

Gina Krog

Originally known as Dagny field, the now-NOK26 billion (US$4.3 billion) Gina Krog project was originally considered a minor gas development after the discovery of its 15/5-1 well in 1974.

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Stavanger in the Norwegian North Sea, Gina Krog lays in 120m of water, 30km away from the Sleipner field. Gina Krog spans Blocks 15/5 and 15/6 within production licenses (PL) 303, PL 048, PL 029 and PL 029B.

Operator Statoil said that since discovery, the field was brought up for development consideration a number of times. Concepts were tabled each time until 2007, when oil and gas was proven in the neighboring development of Gina Krog Øst (originally Dagny East).

A 100m-long oil column was proven throughout the entire Gina Krog/ Gina Krog Øst structure through appraisal well drilling in 2008 and 2011. Project partner Total said the field, "contributes to the renaissance of hydrocarbon production in the Norwegian North Sea." Statoil estimated reserves of 225MMboe, giving 600,000bo/d and 9 million cu. m/d gas.

Ramboll received the Gina Krog pipeline contract and five subproject contracts in March 2013, just months after being awarded January 2013's Polarled contract. Gina Krog's export pipelines design is currently in follow-on phase, and seabed preparation activities offshore are imminent. Pipeline installation is scheduled in 2015. Marine work, including tie-ins, will take place in 2016.

First oil is scheduled for 2017, but Andersen said the first true test comes well before then.

"The pipeline installation is actually the first part, before the Gina Krog jacket itself come in," he said.

Heerema is constructing Gina Krog's 142m-tall jacket. It is the biggest the company has ever produced, and is scheduled to sail in April 2015.

Design

Gina Krog will be tied to Sleipner, allowing the two developments to enjoy a mutually beneficial relationship.

"The Gina Krog field development is of one of several fields being developed in the vicinity of the Sleipner hub. This will assist in substituting some of the oil and gas from mature fields with declining production," Andersen said. Through its tie-back to Sleipner, a concrete gravity platform from the 1990s, Statoil plans for Gina Krog to use the older development's existing infrastructure.

However, accessing and processing such reserves usually requires many hours of dedicated, creative engineering work. Gina Krog is no exception.

Andersen explained that Gina Krog's platform, supplied by DSME and engineered by Aker Solutions, will produce oil and gas. Gas will be exported to the Sleipner A platform through a 27km, 20in. export pipeline. A couple of hundred meters from Sleipner, a riser base splits the 20in. pipeline in two 10in. riser extension sections. The two 10in. risers will be pulled-in through existing J-tubes through to topside. Oil will be exported from Gina Krog through a 10in. insulated pipeline, terminating at a permanently-moored FSO tanker. A flexible riser connects the pipeline to the FSO.

"Gina Krog requires gas for gas injection in wells [to maintain reservoir pressure]. This gas will be tapped through a hot tap connection to existing gas pipeline Zeepipe IIA. Zeepipe IIA is owned by Gassco and is part of the Gassled pipeline infrastructure exporting gas to Europe," Andersen said.

Beyond the delicate riser pull-in, Andersen has identified hot-tapping as another massively complicated operation.

Andersen said that the highly-competent Statoil, which has had a 10-year working relationship with Ramboll, is a very collaborative client, calling it a very open process.

Polarled

Crossing the Polar Circle, the 36in.-diameter Polarled pipeline runs 482km in water depths reaching nearly 1300m. It will be constructed to transport gas volumes for planned and future developments, including Aasta Hansteen, the world's tallest spar platform. The pipeline installation will be in 2015.

At least three Ramboll offices collaborated on the massive project: Denmark, Norway, and India, where much of the drafting work took place.

The wall thickness is between 29-37mm – "very heavy indeed to start with," he said. Due to the 1300m water

The Polarled pipeline, running from Aasta Hansteen to the Nyhamna terminal.
Image from Statoil.

Third-party testing of BOP software

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

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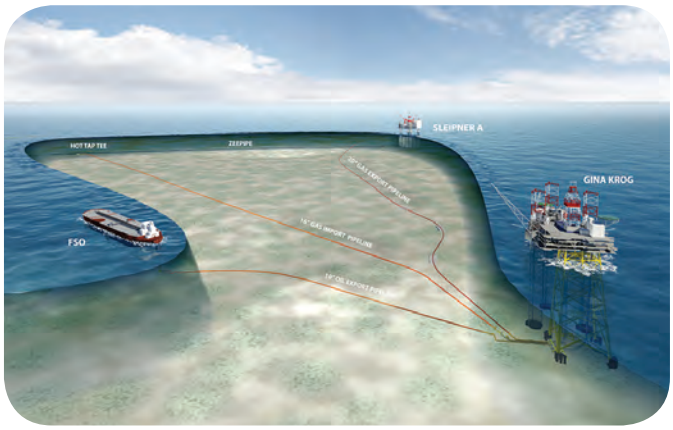
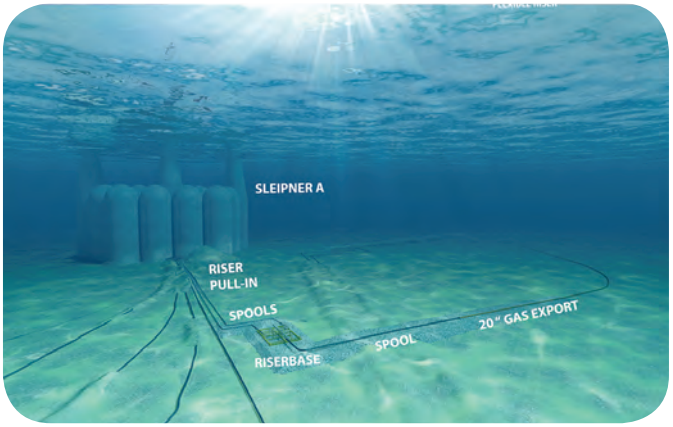




Rendering of the US$4.3 billion Gina Krog development. Ramboll is engineering the pipelines. Images from Ramboll.

depth, which will amount to around 130bar of external pressure, the pipe will have buckle arrestors, i.e. reinforced wall thickness sections, with wall thickness of 73.9mm every kilometer or so. The design pressure of the pipeline is 233barG.

Another issue the project will need to contend with is that it runs parallel to other pipelines as it nears the shoreline. Part of the pipeline's route also runs in the ship traffic lane.

"Due to the harsh environment of the Norwegian Sea, all water depths will be an issue. The more shallow the water … the more wave action on seabed," Andersen said. The parts of Polarled resting in water depth less than 700m will be concrete-coated to ensure stability and protection against trawling.

Another issue is the sea floor itself.

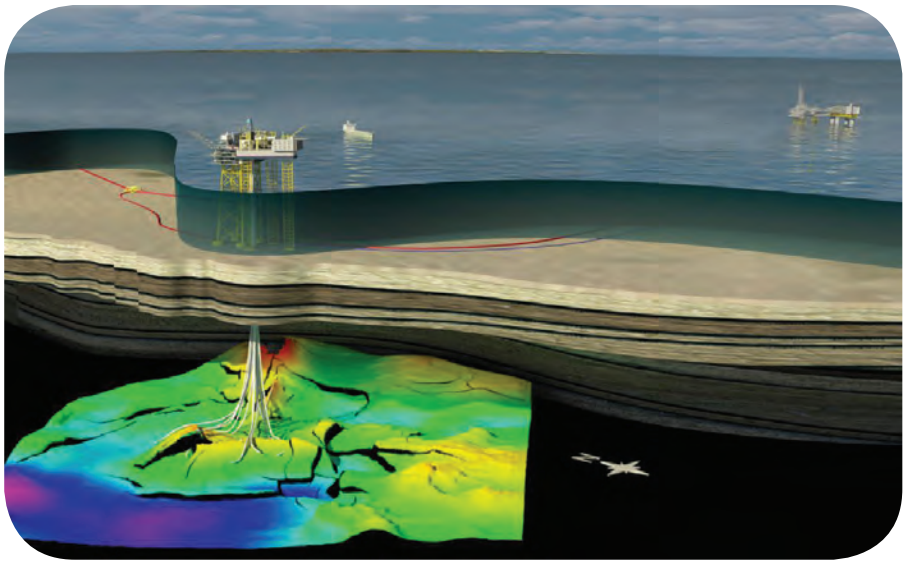
"We have severe challenges in terms of uneven and soft clay seabed. Because of this seabed, there is a lot of seabed prep work for rectifying pipeline free spans, and that is mobilizing just now," Andersen said. "Due to the uneven seabed, Polarled will shave off around 40 peaks and fill in 200,000cu. m of crushed rock to secure a safe pipeline foundation. After pipelay, a further 270,000cu. m of rock is the current estimate to rectify the free spans and secure the pipeline."

First gas for the Aasta Hansteen development is also expected in 2017.

"The Polarled pipeline is the backbone for future field developments offshore central Norway and shall feed gas to the Nyhamna terminal for many years to come," Andersen explained. "This will assist in continuing high amounts of gas exported to Europe."

Houston office opening

Already present in 22 countries, Ramboll



Rendering of the Gina Krog development. Image from Statoil.

Group expanded its global footprint last year by partnering its Ramboll Oil & Gas business unit with the 20-year-old, Houston-based Excel Engineering.

"Becoming part of a 10,000 people strong organization such as the Ramboll Group is exciting and obviously provides us with a much larger pool of resources to draw on. When Ramboll approached us and we saw the shared values and technical match of our companies, it was an easy decision to join the Scandinavian-founded company," Mostafa Jamal, Excel Engineering Inc. president and CEO, said at the time of the announcement.

Both companies are highly-recognized in their respective areas. Ramboll Group said it is Europe's fourth-largest consultancy group. The Houston Business Journal recognized Excel Engineering as one of Houston's top 25 local energy engineering firms.

"Excel Engineering has operated in other markets and deeper water than we have so far. They have also cooperated with a host of contractors and possess immense knowledge about structural engineering in the Gulf of Mexico and a great many [other] locations around the world," John Sørensen, managing director, Ramboll Oil & Gas, said.

John Sørensen and Mostafa Jamal, president and CEO, Excel Engineering, signed the agreement in Houston 1 Oct 2013. Excel Engineering's existing office space, located at 3200 Wilcrest Drive, will continue to serve as its office location.

Ramboll looks to add its traditional engineering services plus some of its other specialties, environmental studies and strategic and commercial consultancy to Excel Engineering's existing client base.

"Houston has been dubbed the oil and gas capital of the world, and if we as a company want to play with the big boys and land the big projects, we need to be active here," Sørensen concluded. OE

New solutions for grouted connections

Grouted connections have been a challenge to the offshore wind industry. The sector is now looking for class society guidance so that the latest applications for grouted connections are reflected in the latest design standards.

By **Claus F. Christensen**, DNV GL – Energy

Wind energy is a fast developing industry, which means independent certification bodies like DNV GL have to ensure that widely used standards for the design of offshore wind turbine support structures like DNV-OS-J101 or GL-IV-2 are based on the most recent technical knowledge, methodology, experience and test results.

The most well-known offshore wind turbine support structures are monopile, gravity based, jacket, and tripod structures. Monopiles are the most widely used design and grouted connections are used to connect the transition piece to the monopile. Grouted connections have been successfully used in the offshore oil and gas industry on drilling and production platform jackets for the last 40 years.

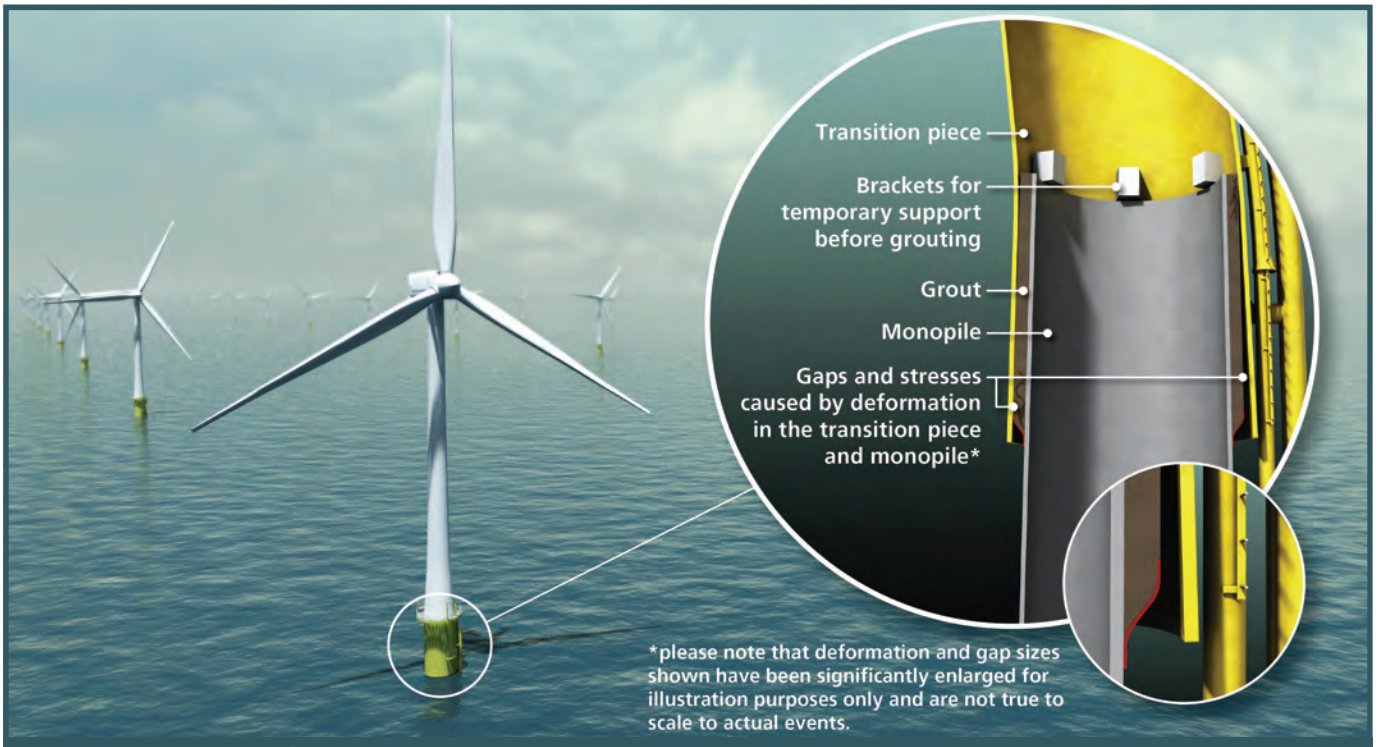
However, the major difference for a monopile offshore wind turbine structure is that, while the grouted connection in jackets is mainly intended for small diameter piles, with large axial forces, the wind turbine monopile grouted connection is large diameter and predominantly subjected to bending.

An unintended force transfer through the temporary supports as a result of settlement in some grouted connections has led to concern about fatigue cracking in the structures which would lead to repair needs. During a thorough review of the DNV-OS-J101 standard in 2009, we discovered that some scale effects were not properly accounted for in this standard or in other standards for similar types of connections.

Joint Industry Project

A Joint Industry Project (JIP) has been initiated by DNV GL in order to look further into the issue, with the aim of solving an industry-wide challenge. Conical grouted connections have been developed and tested as an alternative design. In addition, the industry partners have been looking at grouted connections with shear keys.

The joint industry project has con-



Grouted connections

A grouted connection connects the transition piece to the monopile. A transition piece is placed on top of the monopile, resting on temporary supports. During installation, the transition piece is then jacked up before grouting. After curing, the jacks are removed, leaving a gap of a few centimetres between the tempworary supports and the monopile. Settlement down to the temporary supports may result in a different force flow in the structures.

cluded that a cylindrical-shaped grouted connection design, without shear keys or additional support arrangements for axial load, or grouted conical connection with shear keys, are possible design solutions for large diameter grouted connections.

The industry partners also came up with new design solutions. In addition, solutions for existing installations, including support arrangements, were presented.

Shear keys

Shear keys are circumferential weld beads on the outside of the monopile and the inside the transition piece, in the grouted section. The shear keys' purpose is to increase the sliding resistance between the grout and steel so that no settlement occurs.

Existing design standards for such connections were based on limited test data on small diameter connections for alternating dynamic loading. Therefore, before this solution could be recommended, a design practice for shear keys had to be developed and properly incorporated in a revised design standard.

Physical testing

The collaboration between DNV GL and owners, operators, grout producers, university, certifying body, and designers, has involved carrying out physical testing in DNV GL's laboratory, in addition to structural analyses, field monitoring, and sharing experience.

The laboratory testing is intended to obtain more reliable data for design and guidance on the use of shear keys in monopile solutions. After the testing, a design methodology was developed to account for the dynamic bending moment and the vertical force in connections with shear keys.

The results have been compared with laboratory test data from simulated capacity of large diameter connections. It was found that the design procedure provides design data that are in good agreement with the measured laboratory data.

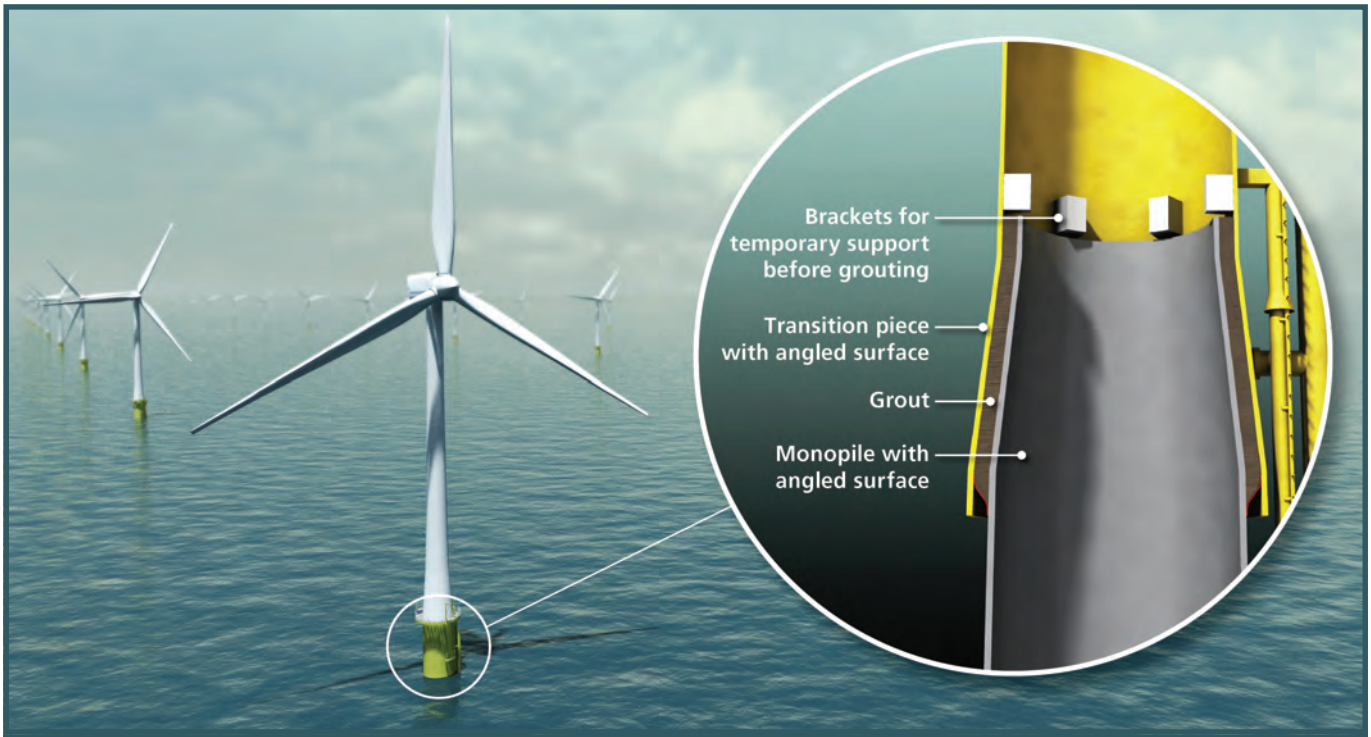
Looking for guidance

The revised DNV GL design standard DNV-OS-J101 was launched for an external hearing, which was due to be held in February 2014. This was due to include results of the JIP.

In December 2013, DNV GL published a technical note for the certification of grouted connections, which is a supplement to the latest version of the offshore guideline GL-IV-2. This technical note is based on the research project Grouted Joints for Offshore Wind Turbine Structures (GROW), started in 2007, and funded by the Germany Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU). It reflects latest research results and supports the industry in avoiding past failure. Guidance on design calculation and structural details as well as requirements for manufacturing, quality control, installation, and monitoring is given.

Both DNV GL offshore standards (DNV-OS-J101 or GL-IV-2) now reflect latest industry solutions and state-of the art recommended practices. OE

Dr. Claus Fridtjof Christensen **is** *regional manager for Europe and North America, Renewables Certification, at DNV GL – Energy. He has worked for the company for 13 years and has a background in oil and gas, within the field of structural reliability and safety analysis for structures subjected to various types of load. Christensen also has experience in risk management and technical risk assessment, especially related to ship collision risk analysis on offshore platforms, transformer platforms, and offshore wind farms.*

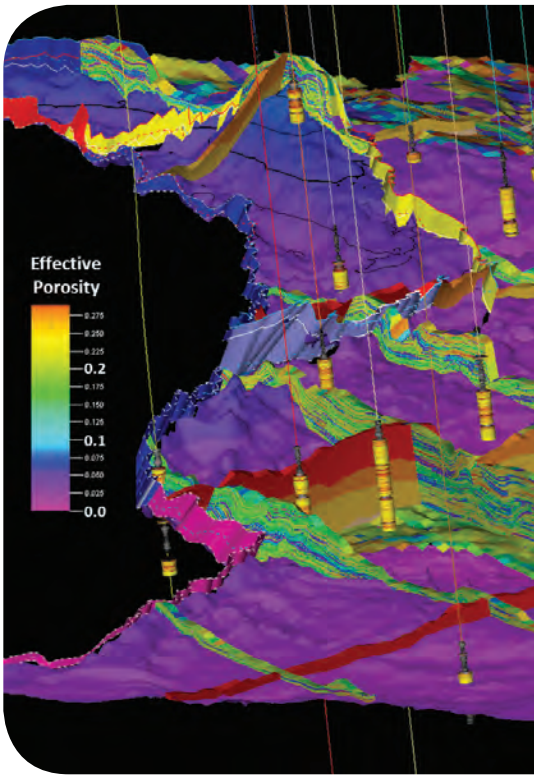


Conical shaped connection

The monopile and transition piece are fabricated with a small cone angle in the grouted section. If the bonds between the steel and grout are broken, some slight settlement of the transition piece will occur. This will introduce compressive contact stresses between the steel and grout which, together with some friction, will provide sufficient resistance against further settlement.

Images: ©DNV/Max & Co

Data gathering and large-scale reservoir modeling will be key to unlocking Anadarko's big gas development off Mozambique. Bruce Nichols spoke with Anadarko and engineers at Halliburton's Landmark to discover more.



Computerizing offshore Mozambique

When Anadarko made three big natural gas discoveries in quick succession offshore Mozambique in 2010, the company was already using computer modeling to de-risk the undertaking.

"We start from day one," says P.K. Pande, Anadarko's Director of Reservoir Technology and Characterization. "We look at our early models, and we use them as input into making judgments about the overall project economics and viability."

Now that nine successful wells have been drilled in the field named Prosperidade, the model built using Nexus software from Halliburton's Landmark unit is in its third development cycle. And it has grown more detailed. There are 13 million "active cells" in it, and it has been "upscaled" to 2.5 million "active cells" for faster processing without losing the detail needed to plan development, Pande says.

When Prosperidade begins production in 2018, performance monitoring will help refine the model and maximize output over the life of the field.

Prosperidade is not the only field Anadarko has discovered off Mozambique. In all, it has drilled more than 20 wells and has identified separate natural gas deposits in multi-layered fields named Golfinho/Atum, Orca and Tubarao, which are in different stages of modeling. Prosperidade is the furthest along, Pande says.

"The Prosperidade area has been defined by Anadarko, its the partners and the government as a focus of the initial development," Pande says.

Reservoir modeling and its adjunct, reservoir monitoring, are not new. They've been a part of the industry for 60 years. Anadarko has used it on old projects as well as new ones. A notable example is Anadarko's Hugoton field, a low-pressure gas field straddling the Kansas-Oklahoma border that has been producing for nearly 100 years, enhanced by ever more sophisticated modeling.

Increased computing power and more sophisticated software capability have made modeling tools more useful.

"One of the things that has really changed, especially in the last 10 years, is our ability to visualize in 3-D. Instead of just getting quantitative results, we have easier ways to actually visualize the results and get meaning," Pande says.

Shell: Future oilfield models will dwarf today's

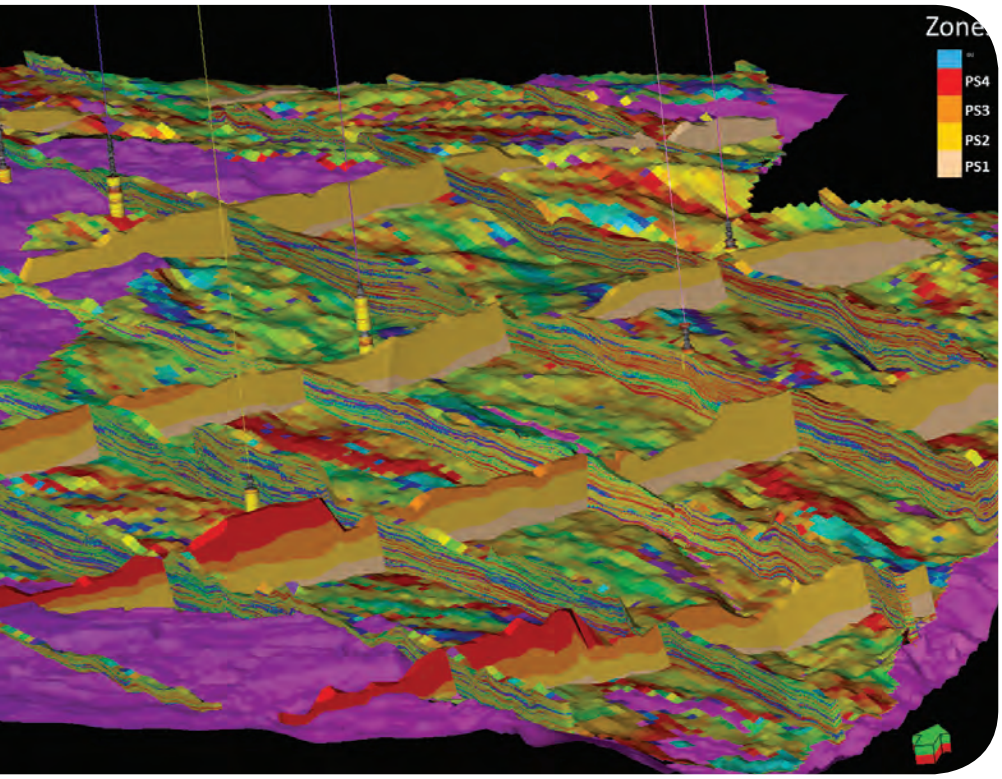
Enhanced computer-based evaluation and visualization is at the heart of a big Shell push to improve oil and gas exploration and production. Some of the reservoir modeling technology development is proprietary within Shell. Some of it is bought off the shelf and customized for Shell in cooperation with the provider.

"While we aggressively invest in proprietary processing and visualization technology in the seismic area, we invest more selectively in proprietary reservoir modeling technology because the market anticipates many of our needs, and we communicate with market providers," says Detlef Hohl, Shell's manager of computation and modeling.

An example of Shell's taking advantage of products available on the market is its software license and joint development agreement, announced last September, to use the Baker Hughes JewelSuite (trademark) platform as the basis for high-quality modeling of complex reservoirs.

In a joint announcement, Shell and Baker Hughes said the new platform would complement Shell's existing applications, including GeoSigns, Shell's proprietary software used to visualize and interpret seismic data.

The basis of reservoir modeling is mathematical, but the step change of recent years has been the capacity to create 3D models that can be visualized and interactively manipulated



A 3-D view of an earth model filled with the effective porosity and stratigraphic zones displayed on the base structural horizon. Image: Anadarko.

"Visualization used to be a lot more 2-D. You'd have to have layers and layers of maps. Geoscientists, the way their thinking process goes, it's very much a 3-D type of process, so 3-D visualization actually helps us quite a lot in our interpretive work."

Still, even after being converted into pictures, all models are essentially mathematical estimates of subsurface reality. The types of data that go into making the eye-popping 3-D visuals in use today – seismic, well logs, core sample analyses, fluid samples, flow tests – are essentially the same as when the visuals were 2-D layers of maps or, before that, mere charts and graphs.

As models grow more sophisticated and the data going into them more precise, oil companies' reliance on the technology has increased as they move into more costly, more difficult areas in search of oil and gas.

"The big thing about reservoir modeling is it helps operators make a decision," says Garrett Leahy, North American Sales Manager, Emerson Roxar. "It's a commercial problem. The question is, 'Are there enough barrels of oil down there to make it worth drilling?"

Despite advances in recent years, everyone who touts modeling emphasizes its limitations.

"One thing we need to make clear. A model is a model. The fact that we can visualize it in 3-D does not mean that's exactly what the subsurface looks like. It's our best representation at that point in time given the information we have," says Joe Lynch, director of reservoir management for Halliburton's Landmark Graphics unit.

It is ironic. Oil companies are seeking as much certainty as possible to underpin investment decisions. But they want modeling software to spell out the range of uncertainty in whatever picture a model is presenting.

"One of the really powerful things about having this technology is that we can look at uncertainty," Pande says. "We're in a business where when we get an exploration project, there's a range of outcomes, and we need to understand what that range is.

"We never look at a model and say this is what it is. We say there's a range of possibilities. And if we don't meet our economic threshold, even on the higher end of the range, it gives us some really unique insight into whether we should chase this or whether we should drop it and move to another opportunity," Pande says.

Modellers use a phrase borrowed from gambling as well as mathematical and statistical terms to describe the process.

"When assessing uncertainty, Monte Carlo simulations are performed," says Tomi Owodunni, a senior reservoir engineer at Schlumberger. Monte Carlo sims involve inserting different values for key data to see how it affects the model.

"For example, if the response of interest is cumulative oil production, then you would display the distribution of oil results from all combinations of your input data. Using the CDF (cumulative distribution function) curve, you can select three cases representing, say, a P10, P50 and P90. These cases are then used to investigate different development plans."

allowing geologists, geophysicists and petroleum engineers to exercise their judgment in new ways.

"It's not a luxury," Hohl said. "The interpreter has to be able to see these things in three dimensions. He has to be able to dive into it. The visual user interface is extremely important for interpretation."

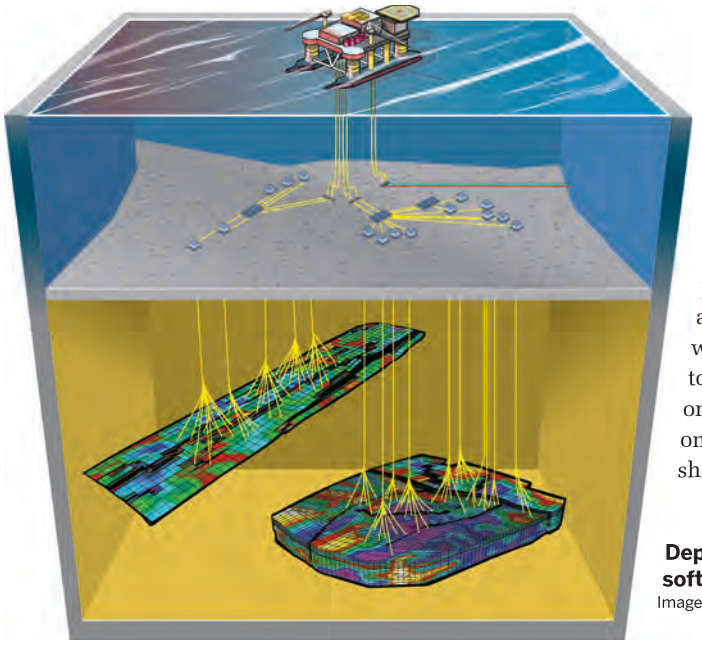
Shell is working on other step changes as sensors and data-gathering equipment improve, computer power grows and visualization technology surges. A key focus is uncertainty analysis, says John Karanikas, Shell's chief scientist for reservoir engineering.

"We've made a significant effort to include more and more of the breadth of the subsurface uncertainty in our calculations," Karanikas says, noting executives need to know quantitatively the magnitude and impact of this reservoir uncertainty in order to make sound economic decisions.

"Another way our models are changing is the inclusion of more advanced chemistry and physics," Karanikas says.

And "big data" – the term used for increasingly massive data-gathering and storage capability in all areas of life and of business – is coming to the oilfields. In time, the piles of data already gathered in oil exploration and development will seem small.

"We expect in the future to get avalanches of data, factors of 10 or more, and that in turn will drive larger models," Karanikas says. ▪



Depiction of Nexus software.
Image: Halliburton.

Pande says more important than powerful computers and sophisticated software is good commercial judgment – the ability to decide wisely whether to spend money on a project, based on what a model is showing about key production drivers.

"Just having more complexity that both hardware and software allow does not necessarily mean you're going to get a better product," he says.

Pande notes that there are a lot of good reservoir modeling software products, that all the major service companies and some niche operators offer good tools.

Aside from Halliburton-Landmark Nexus and Decision-Making System, there are Schlumberger's Eclipse and Intersect; Baker Hughes' JewelSuite; Emerson's Roxar RMS, and CMG's IMEX, GEM and STARS, to name a few.

"We could have done equally as good a job on any other products because it's more about how you apply this. It's

How Halliburton built Nexus

Creating software that can model an oil or gas reservoir involves writing lines of code that can perform billions of calculations per second. The software runs simultaneously on clusters of computers linked by high-speed interconnections.

But it still can take a couple of days to finish a model. And when you're done, you still can't be sure what the subsurface looks like, even after you drill and produce it. After all, you can't actually see it.

Welcome to the world of using computers to model oil fields and monitor their performance as they age.

"What we are doing is solving a complex set of four-dimensional partial differential equations with what is known as a finite difference approximation," says Steve Crockett, product manager for Nexus®, reservoir simulation software which is developed and marketed by Halliburton's Landmark unit. "I've worked with models that solve 50 million-plus equations simultaneously."

Despite its uncertainty and complexity, adoption of modeling for exploration, development and production management has accelerated as oil companies take on more and more challenging projects, and the cost of being wrong about a prospect has skyrocketed.

"We don't know what a reservoir is going to deliver. So if a reservoir doesn't deliver what is expected, then an oil company has a problem. One way to address that problem is to get a better understanding of what the reservoir is going to deliver beforehand, and understand the uncertainty because we cannot predict perfectly," says Joe Lynch, Landmark's director of reservoir management.

Modeling is especially important offshore, where the potential to over-produce, though rarer, can be almost as embarrassing as under-delivering. It can mean that because the reservoir was misunderstood, the platform, pipelines and other production equipment have been built too small, and output can't reach its full potential, Lynch says.

"The production guys are pleased about it, but typically, if that happens, then the operator is leaving money on the table because they are surface-facility-constrained. They could actually be producing more oil and getting a better rate of return," he says.

Uncertainty analysis, in fact, is a growing focus in modeling oilfield reservoirs.

"What we want to try and do is deliver this envelope of possible outcomes, and then it's up to the decision-makers to decide how they want to go and size the project. Think about capacity for, let's say, water-handling up front. To build that into the platform, that's expensive. But it's nowhere near as expensive as having to retrofit later on when you get a surprise," Lynch says.

Uncertainty is enormous at the exploration and appraisal stage. "In those early stages, you're in an extremely speculative mode in your modeling. You're at the point of trying to decide do we sink hundreds of millions or more into developing this field. And so you have to have the widest range of possible realities," Crockett says.

Uncertainty diminishes – but never completely disappears – through the life of the field.

"When we have a model, it is a model. It is not reality. But then against that model we'll have hypotheses. Then we will drill appraisal wells to test hypotheses. Based on the results, we'll have a whole bunch more information and that model can be refined," Lynch says.

Information gathering continues and the model evolves as field development matures.

"What you find is, as soon as you have the first six months or year of production for even one well, you can start to eliminate some of the possibilities from your models," Crockett says.

And done right, tweaking of a reservoir model is a never-ending process.

Lynch foresees a trend toward tighter linkage between modeling a field and monitoring it after production begins. Monitoring data can be used to update the field model and improve forecasting of the future life of the field. Part of the reason monitoring feedback into the model is feasible is advancements in data-gathering and field-management equipment.

"We're getting data back on a much more frequent basis, plus we're getting better ability to control the production system, Lynch says. "I think we're starting to get something like an evergreen reservoir model. Instead of every few years going back to scratch and building a new model. I think models are now having to be kept fairly up to date. I can see more use of simulation in that role in the future." •

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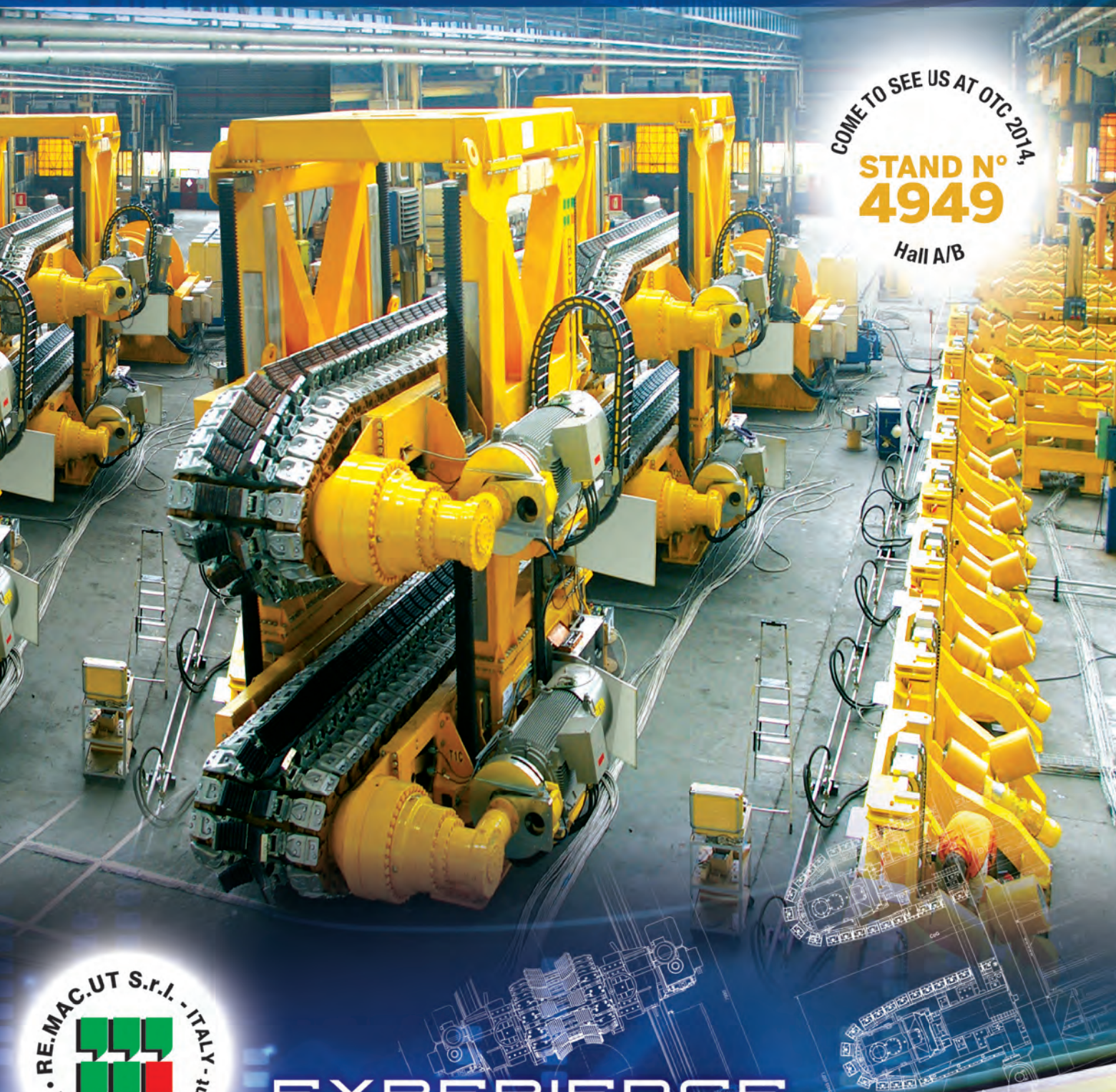

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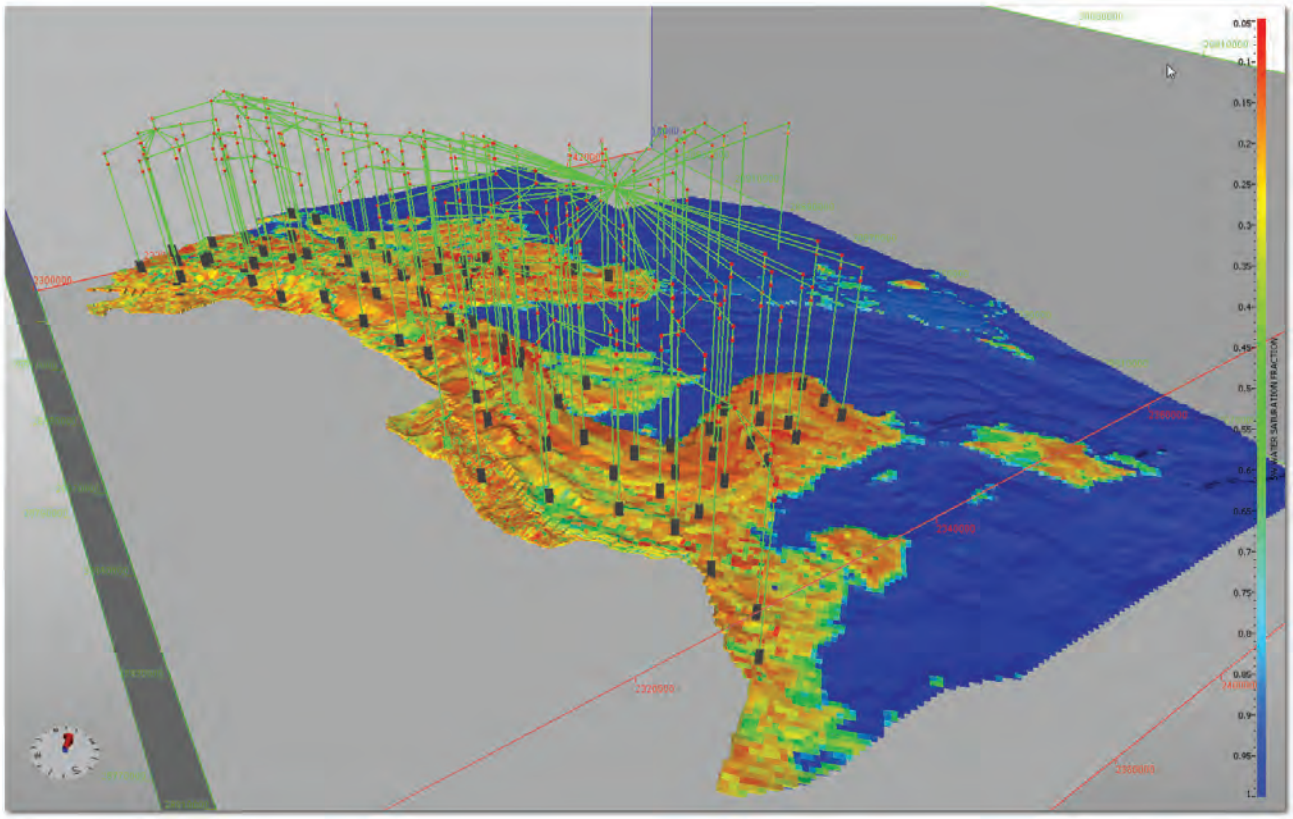

Subsurface and well planning reservoir simulation model for Prosperidade field offshore of Mozambique. Image: Anadarko.

an art," Pande says. "It depends on the operator's experience and judgement."

The art work begins early. Anadarko's Mozambique exploration program started with a geologic model of the Rovuma Basin based on knowledge of similar basins and how they matched up with Rovuma. Seismic surveys helped identify potential subsurface accumulations of hydrocarbons.

Then, in February 2010, the first wildcat well came in big. Windjammer, about 30mi. east of Palma, found 555ft of net natural gas pay layered over more than 1200ft of Oligocene and Paleocene sands after reaching 16,930ft total depth in water 4800ft deep.

Next, also in 2010, came the Barquentine discovery 2mi. to the southwest of Windjammer (308ft of net pay in Oligocene and Paleocene sands) and the Lagosta find (550ft of net pay in Oligocene and Eocene sands) 14mi. to the southeast.

At that point, as exploration continued, the appraisal phase began in earnest to gather more data to feed the computers and build the models of Prosperidade.

"In 2012, we conducted the single most extensive deepwater testing program in Mozambique that was comprised of well tests and interference tests," Pande says.

Anadarko ran at least 10 flow tests of three to seven days in duration, with each test producing up to 120MMscf/d, events which resulted in spectacular video posted on You Tube by Anadarko.

Flow testing a well without producing significant pressure drop is encouraging because it indicates a sizable reservoir. Flow testing in conjunction with pressure monitoring at other wells can start to define the actual geographic dimensions of the reservoir.

"We needed to really establish how continuous this reservoir was and we establish continuities through interference tests," Pande says, describing a process in which flowing one well and watching the pressure impact on another well some distance away indicates whether they are connected.

How quickly that pressure response shows up provides additional information about how well the fluids in the reservoir will flow.

These pressure measurements are incredibly sensitive. In the case of Prosperidade, the analysis took into account the effect on reservoir pressure of Mozambique's tides, which can be 12ft or more.

"You actually have more water on top of the sea floor from tides, and we can actually see this in the pressure data," Pande says. "The differences are small, but they're very discernible. And this is such a huge reservoir, such a large asset, we had to figure out how to account for that."

Estimates of recoverable gas at Prosperidade grew rapidly as drilling of exploration and appraisal wells and modeling continued. The estimate was 6Tcf in August 2011. It climbed to 10Tcf in October. In November 2012, after the Camarao discovery 5mi. south of Windjammer found 380ft of net pay and two new sand layers, the estimate soared to 15-30+ Tcf.

Information from drilling and testing was so good and the model, by this time, so promising, that Anadarko was able to attract a new investor into the project.

India's OVL paid US$2.64 billion for a 10% stake in 2013, reducing Anadarko's share to 26.5%. The original partners in the project were Mitsui, BPRL, Videocon Mozambique, PTT E&P and ENH, Mozambique's national oil company.

The results also led Anadarko and Italian giant Eni, which operates Mozambique exploration Area 4 adjacent to Anadarko's Area 1, to agree in late 2012 to partner in building an LNG plant. Prosperidade straddles Area 1 and Area 4

Delivery of the first LNG cargo is targeted for 2018. OE

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Sensing a marinized solution

OptaSense is collaborating with Shell to develop a fully-marinized DAS system. OptaSense's David Hill explains.

As the oil and gas industry enters ever more challenging and previously inaccessible plays, the financial risks can be greater. Therefore, the need to understand better the issues being faced becomes more acute.

Optimal reservoir monitoring has traditionally been a key issue, and providing a clear and accurate picture of activity is regarded as a significant enabler in achieving that.

A range of techniques have been used in the past, but, with advances in technology, the deployment of distributed fiber-optic sensing has become an increasingly prevalent, more accurate, and cost effective alternative.

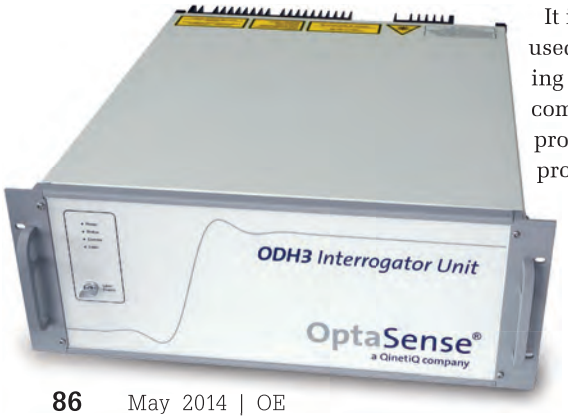
Distributed temperature sensing (DTS) using fiber-optic cable has been around for several years, but the development of distributed acoustic sensing (DAS) is a relatively recent phenomenon and, through its versatility, it has the potential to radically improve our understanding of a broad range of issues, including reservoirs, fields, geology, and asset integrity.

Working on the principle "if you can measure it you can manage it," OptaSense, a subsidiary of QinetiQ Group, has developed a DAS system able to provide decision-ready real-time data through the conversion of any standard optical fiber into a distributed acoustic (or seismic) sensor.

Acoustic or seismic signals that strike the fiber cause minute strains. These are measured using laser interrogation, turning the fiber into a distributed acoustic/seismic sensor. An interrogator unit (IU) fires a laser beam into the cable and measures backscatter returns from naturally occurring imperfections inherent in the optical fiber. The minute strains cause subtle modulations of the backscatter, that are then measured by the IU, thus sensing the acoustic/seismic signal.

It is five years since DAS was first used downhole and it is now delivering significant benefits in a range of completion, production, and evaluation projects, including hydraulic fracture profiling, permanent wellbore flow monitoring and seismic monitoring.

OptaSense is now developing the first fully marinized and qualified DAS system, in a joint program with Shell. The system, which will be deployed in up to 10,000ft water depth, will allow highly accurate acoustic data acquisition for the first time offshore and will provide data for a wide range of subsea and deepwater applications, including pipeline surveillance and leak detection, geo-positioning, in-well monitoring, subsea assembly condition monitoring, and permanent reservoir monitoring.



An OptaSense interrogator unit.

An OptaSense instrumented well with a viborseis unit conducting OptaSense DAS-VSP. Photos from OptaSense.

The device will include functional and technical parameters, configurable in software, avoiding different hardware for settings or functions.

The marinization process will require the re-engineering of the interrogator unit, to reduce its size to fit into a highly robust pressure canister. The modified opto-electronics will be tested, to ensure they meet the rigorous and stringent temperature, vibration, shock, and electrical certifications required of subsea equipment, particularly during transportation and deployment.

In the subsea in-well monitoring application, the interrogator unit will be positioned near to the wellhead, with a processing unit, and processed data will be relayed back to shore or appropriate installation, via a further fiber-optic link in a control line.

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The enabling technology to get a fiber into an offshore well has been developed and deployed. This enables fiber to pass through the wet tree and through the packer, via a downhole wet-mate fiber-optic connector, into the producing zone. Once permanently deployed on the production tubing, the fiber can be used with a DAS system to continuously profile the flow along the well, measuring the inflow contribution at each producing stage.

In-well equipment, such as electrical submersible pumps, inflow control valves, and gas lift valves can be constantly monitored to optimize performance and access their condition for predicative maintenance purposes. Also the downhole fiber can be used to acquire the shot records for a vertical seismic profile (VSP). Because it is permanently in-situ, repeat VSPs can be performed easily enabling time-lapse imaging of the reservoir around the well. In EOR applications 4D VSP using DAS can be a powerful tool in understanding the effect of injection and other forms of stimulation on the reservoir.

OptaSense has been able to use its parent firm's facilities for qualification testing. It is anticipated that the marinized unit will be ready for demonstration by the end of 2014.

Further potential uses of the DAS technology subsea are currently being explored but appear wide-ranging, such as monitoring the condition of subsea equipment, by wrapping the sensors around the pressure vessel they are contained in.

Onshore, fiber-optic DAS technology is being used in hydraulic fracturing operations to measure the full length of the production lateral, without having sensors inside the cased well. Clamped or strapped to the production casing and cemented in place, a fiber-optic cable can provide real-time DAS and DTS from completions through abandonment, without well intervention.

The uses of DTS, although complimentary, are limited. While DTS has been used for over a decade, borehole temperature is only part of the story when it comes to monitoring a hydraulic fracturing operation. With a DAS system, it is now possible to listen to the well at each perforation location and hear how the fluid and proppants rush through the orifices, and how the rock fractures just outside the well and beyond into the formation.

Combining DAS data with real-time pump data from the pumping trucks, it is possible to estimate how much fluid and proppant is being pumped into each perforation cluster. With the full-well continuous monitoring DAS enables, all activities during the hydraulic fracturing operation can be monitored for effectiveness including:

- wireline tool tracking;
- bridge plug setting; perforating;
- ball drop, ball seating, sleeve sliding and isolation from previous stage; and
- casing leaks and restrictions that can halt or hinder operations, and accurately report their depth.

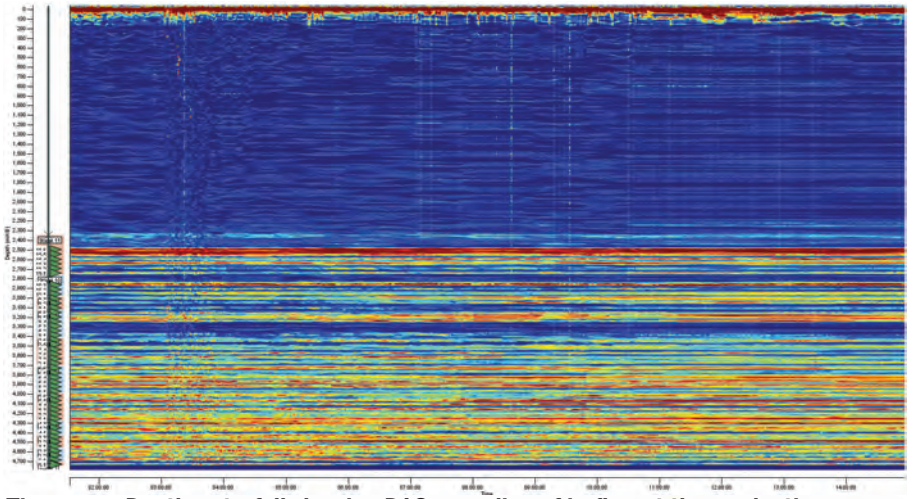
The system can also be used to visualize flow dynamics, providing an alternative to conventional permanent production logging tool (PLT) readings, with the DAS fiber installed on casing or tubing. Through a permanently installed fiber, measurements can be taken on a continuous basis or at regular intervals without the need for costly well intervention and deferred production, using the company's drive-by acquisition service. It is also able to provide full well bore seismic imaging.

Earlier this year, OptaSense was contracted by Petroleum Development Oman (PDO) to provide the industry's first multi-well 4D DAS vertical seismic profiling system, to monitor and map the performance of up to 12 steam-injected oil wells in a brownfield development at South Oman salt basin.

Seismic signals have been recorded from fiber-optic cables attached to each well's production tubing, permanently installed and linked to a surface data-gathering center. The final processed data set will be integrated into PDO's reservoir models and assist in the determination of fluid substitution through production and contribute towards the positioning of infill wells.

Weighed against using geophones in this type of application, the DAS technology provides benefits, including lower-cost on-demand acquisition through permanent cable installation; deployment in wells inaccessible to geophones, with no well intervention required; synergies with existing systems and retrofitting capabilities; coverage over the entire length of a well and simultaneous data acquisition of multiple contiguous wells.

The development of distributed acoustic sensing through deploying fiber-optic cable represents a technological development in the monitoring arena, allowing operators to see what is happening across the wellbore in real-time. The system has multiple uses and, as it prepares for its deployment offshore, a new range of opportunities. OE



Time verse Depth waterfall showing DAS recording of in-flow at the production zone of a horizontal well.

Fiber optic cable.

David Hill *is a QinetiQ Senior Fellow and the Chief Technology Officer at OptaSense, a UK-based QinetiQ company, which he jointly founded. He has over 29 years research and development experience in acoustic sensing, with over half that time spent developing fibre-optic based sensors for the military, as well as oil and gas and other civil applications. He has a BSc(Hons) in Imaging Sciences from the University of Westminster, London, and a PhD in Physics, specializing in fiber-optic sensing, from the University of Kent, UK.*

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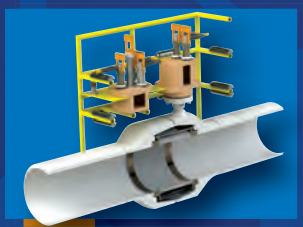

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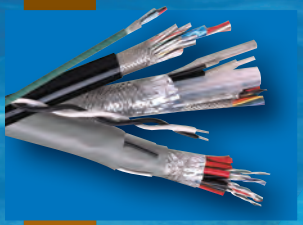

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The new frontier

Stephen Whitfield takes a look at some of the major development projects now utilizing subsea separation and processing technology to increase field life.

Several companies are looking at subsea processing and separation as they try to maximize production out of difficult projects. Recently, developments have sprouted in new and aging fields the world over, from the Gulf of Mexico to the Norwegian coast to West Africa. Here is a look at some of those developments from three top companies.

Aker Solutions

Within the next 12 months, Norway-based Aker Solutions expects to have the world's first subsea gas compression system up and running in the Åsgard field of the coast of its home country (OE: August 2013).

The Åsgard field is located on the Haltenbank in the Norwegian Sea, about 125mi off the Norwegian coast and 31mi south of Statoil's Heidrun field. Petoro owns a majority stake in the field, with a 35.69% share, but Statoil is the operator of the field. Statoil has a 34.57% share, Eni Norge has a 14.82% share, Total E&P Norge owns 7.68%, and ExxonMobil owns 7.24%.

According to Statoil, by the end of this year pressure in both of Åsgard's subsea satellites (Midgard and Mikkel) "will become too low to sustain their ability to produce to the B platform," leaving the company in a lurch. Until recently, the typical solution for a problem like this was to install gas compressors on an existing surface platform, or build an entirely new manned compression platform.

Statoil has chosen a different approach: installing the compressors on the seabed, near the wellheads. It's cheaper and it doesn't require as much additional manpower as a new platform. The only problem was that it hadn't been done before.

That is where Aker Solutions came into the picture. In 2010, the company was awarded a contract to develop a subsea compression system for the Åsgard field, with a target date of 2015 to have everything up and running. So far, thing appear to be running on schedule: Aker Solutions finished the steel frame for the facility in June 2013, and it was installed on the seabed within two weeks of its delivery.

So how will it work? The contract Aker Solutions received to develop the compression system for Åsgard called for a gas cooler and a liquid separator in addition to the compressor. According to Statoil, the electricity used to power the compressor will come from the Åsgard A oil production ship. A motor in the

Aker Solutions delivers the steel frame for the world's first gas compression facility at the Statoil-run Åsgard field off the coast of Norway. Photo from Aker Solutions.

compressor that consists of a number of vanes around a shaft will convert this energy to mechanical energy. Gas will enter the system at a low pressure and, after a gradual compression process, will exit at a higher pressure sufficient enough to move through the pipeline to the receiving platform.

Construction on the Åsgard unit should be completed soon. The three compressor trains are scheduled to be delivered this year, and startup of the full station is scheduled for 2015. Statoil expects to recover 280MMboe after the system's installation.

Åsgard is not the only subsea compression system in the works for Aker Solutions–the company also has one planned for Ormen Lange field, and the second-largest gas field off the Norwegian coast. Like Åsgard, the Ormen Lange unit is designed to run entirely on electric power: a subsea power cable connected to a transformer would transmit about 58MW of power to the compressor, with the power being contributed through a circuit breaker module. The circuit breaker would be surrounded by an enclosure filled with nitrogen at atmospheric pressure.

Ormen Lange is operated by Norske Shell, and the compression system is designed to run at 2950ft. According to Aker Solutions, it should be operational by 2020. However, in April, Shell and its partners postponed plans for the subsea compression project, halting ongoing concept select work, citing costs and reservoir data.

FMC Technologies

For much of the past decade, FMC Technologies has been heavily involved in the boosting systems at Shell's BC-10, a complex off the Brazilian coast. When the system came online, it was the first full-field development comprised around subsea oil and gas separation.

The project, also known as Parque das Conchas, consists of three small and mid-sized fields – Abalone, Ostra, and Argonauta – that range in depth from 4900-6560ft. Its heavy oil reserves and low reservoir pressures presented a significant challenge in terms of maximizing the field's production.

BC-10 utilizes caisson boosting systems, as opposed to installing electrical submersible pumping systems at each wellhead. Each caisson was installed vertically into the seafloor, at an approximate depth of 330ft. Separation comes from the gas-liquid cylindrical cyclonic process, as the raw wellstream swirls thanks to a tangential inlet to the top of each caisson. Gas comes into a riser through the caisson's center, while oil goes down the side of the caisson.

For the first phase of construction, FMC Technologies provided ten of its then recently-created Enhanced Vertical Deepwater Tree systems, each of which had a bore size of 5.2in. and a 10,000psi rating.

BC-10 has been developed in phases. Phase I came online in July 2009. It focused on the lighter oil reserves found in Abalone and Ostra. Separation was only used in reserves with a gas-to-oil ratio above 40%, but all of the targeted reserves were boosted to relieve approximately 2,000psi of back pressure.

The second phase, which was completed last year, involved the delivery of 11 subsea trees and four subsea gas-liquid separation units, along with their related controls. In September 2013, FMC Technologies announced its contract for the third phase of development, which includes seven more subsea trees, two manifolds, tie-in connection systems, and subsea distribution hardware.

BC-10 was just one of several projects in which FMC Technologies delivered some significant advancement in subsea separation technology. The Total Pazflor project, located in Block 17 off the coast of Angola, marked the first use of subsea separation technology in West Africa. But its influence may be in its sheer size: its three separation units (SSUs) weigh nearly 1200-tons, operated at 333psi, and can process 110,000b/d. With the SSUs in place, a gas-tolerant pump can push oil and water to the surface.

Pazflor drew first oil on 24 August 2011. Two years later, in March 2013, FMC Technologies delivered a subsea separation system to Marlim, a large mature field operated by Petrobras in the Campos Basin offshore of Brazil. It is the

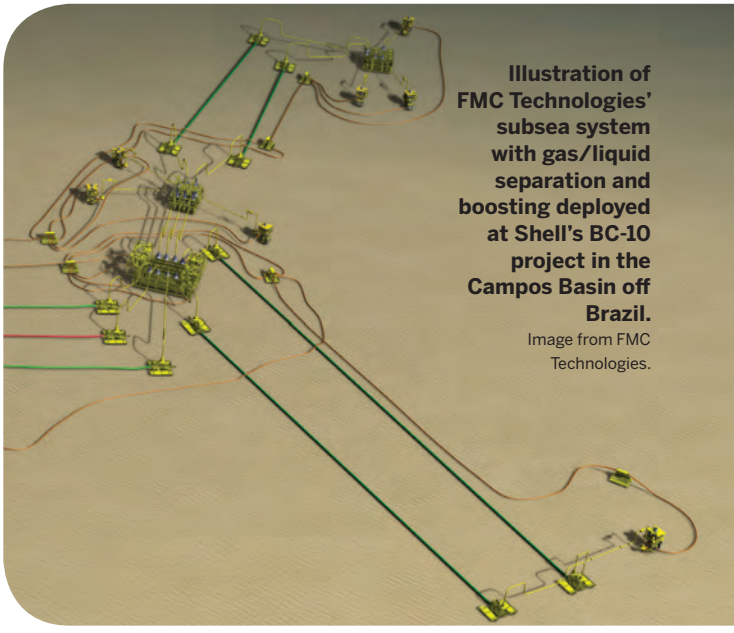

Illustration of FMC Technologies' subsea system with gas/liquid separation and boosting deployed at Shell's BC-10 project in the Campos Basin off Brazil. Image from FMC Technologies.

first such system to boost production of a mature field that also includes the reinjection of previously-removed water.

OneSubsea

OneSubsea has several projects currently underway in the area of full wellstream subsea boosting that are expected to begin production either later this year or early next year.

Notable among these projects is Draugen field, located in block 6407/9 in the Haltenbanken area, approximately 87mi north of Kristiansund, Norway (OE: June 2013). The field was discovered in 1984 and production began in 1993. It currently consists of 13 production wells – seven of them subsea.

The Garn West Reservoir ties back to the Draugen platform through a 2.05mi pipeline. Gas exports are transported through the Åsgard Transport pipeline to Kårstø. Norske Shell is the operator of the field, owning a 26.20% stake. Petoro owns a plurality stake at 47.88%, with BP Norge and Chevron making up the rest.

As with any aging field, production at Draugen had dropped off precipitously heading into its second decade of operation. In 2009, the field's average crude oil production was 63,000boe/d, 14% less than the previous year and 56.25% less than its average production from five years earlier.

OneSubsea will develop four new production wells in the field. These wells are located at a depth of 879ft, and all of them will be routed to a new pump located between the platform and the reservoir. This pump is a helicon-axial pump with two units.

The subsea boosting pump at Draugen is scheduled for a June installation, and the new wells are expected to be operational 3Q 2014.

Also scheduled to wrap up this year is Jack-St. Malo, a new project that combines two fields located in the lower tertiary trend of the Gulf of Mexico. The Jack field is in Walker Ridge blocks 758 and 759. Chevron holds a 50% interest in the field, which has a water depth of 7201ft. Maersk has a 25% stake in Jack, as does Statoil.

St. Malo is not nearly as deep–only 2100ft. It is also operated by Chevron, which owns 51%. Petrobras (25%), Statoil (21.50%), ExxonMobil (1.25%), and ENI (1.25%) are the other partners. Both fields are located about 300mi off the coast and are expected to last between 30-40 years.

Unlike Draugen, the Jack-St. Malo project is not a case of revitalizing an older field but maximizing potential production in an untapped field. OneSubsea is contracted to build a 12-well system, along with a centrifugal pump and related control systems. It plans to boost production on the seabed as a way increase recovery rates on a field that has yet to draw first oil.

The pump is a single-phase pump operating on 3Mw shaft power, with a 13,000 psi pressure rating and a 4000psi boost, which makes it capable of processing up to 60,000b/d.

This is not OneSubsea's first foray into Jack-St. Malo. In 2009, it delivered a subsea tree system that incorporated multiphase flowmeters and sampling of its Multiple Application Reinjection System (MARS), its first such system to do so. MARS is a universal interface that, according to a company manual, enables "the connection of production optimization systems to be installed easily in the field, either on or off the subsea tree." OE

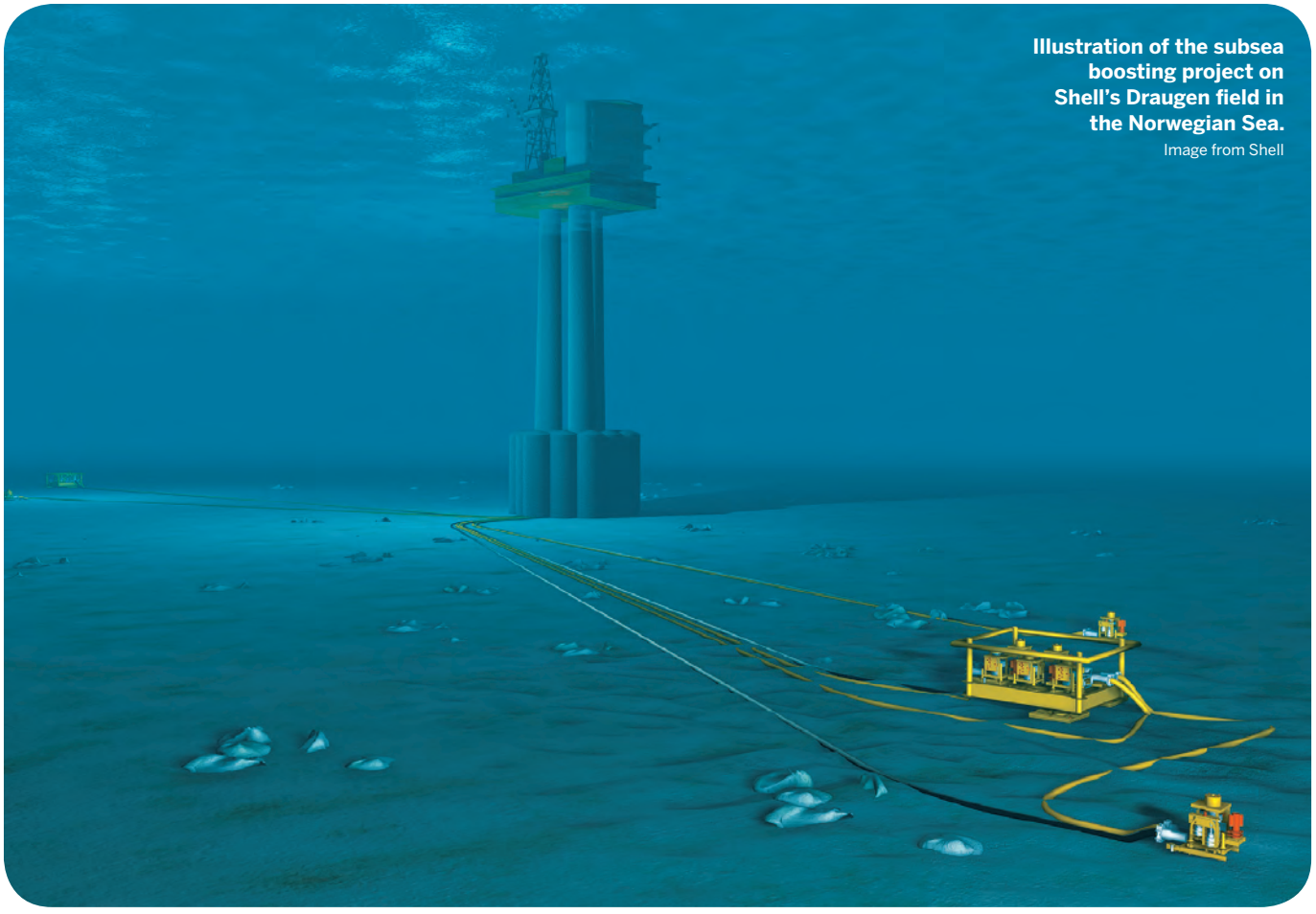

Illustration of the subsea boosting project on Shell's Draugen field in the Norwegian Sea.
Image from Shell

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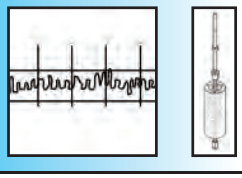
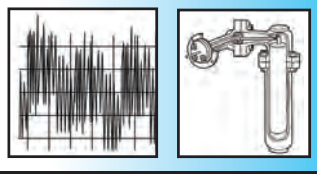
• Range spring's 1.25" range of motion and turbulence- and vibration-dampening effect deliver outputs 4x more stable than torque tubes 	• Torque tube travels only 0.63" into controller and is negatively impacted by turbulence and vibration 
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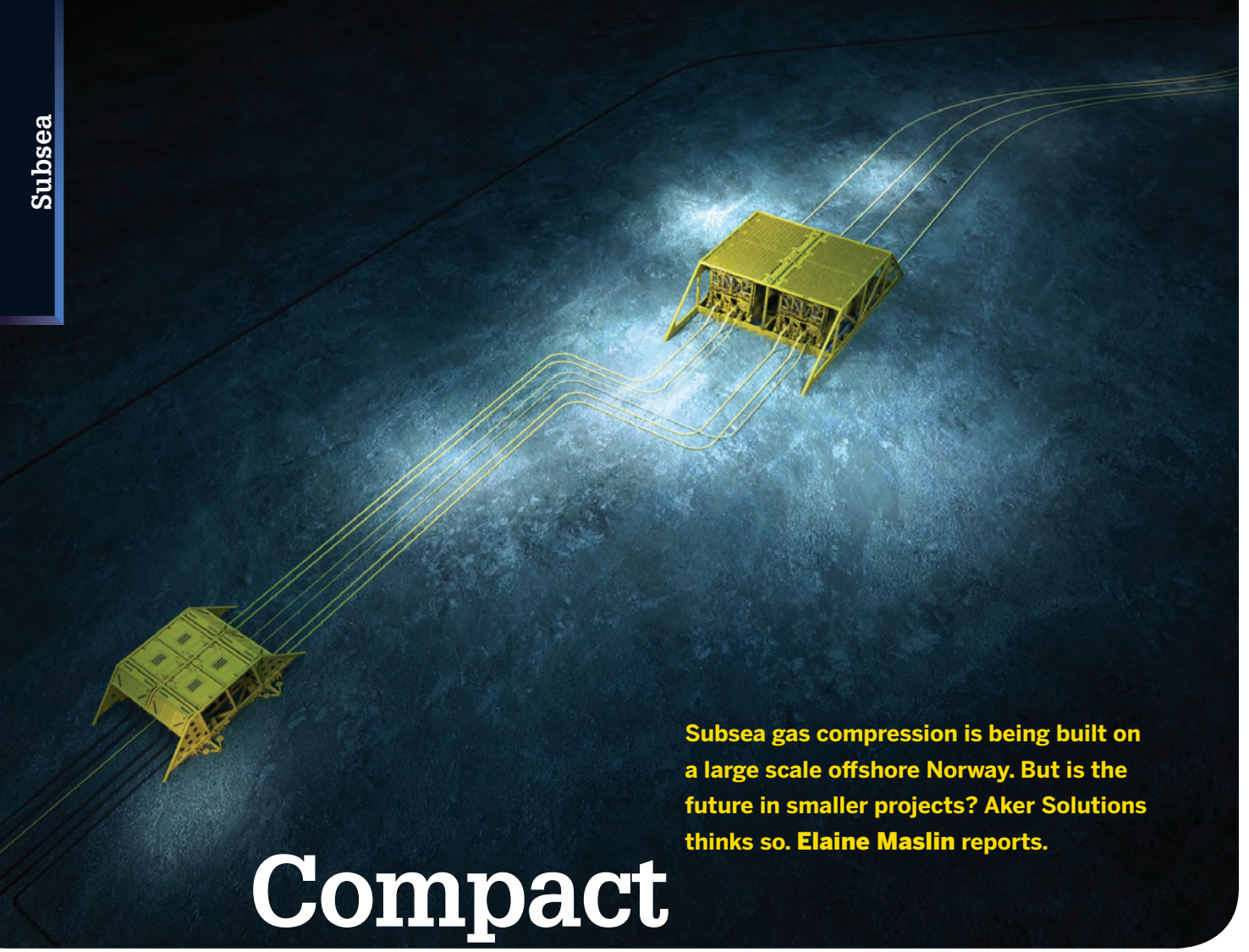

Subsea gas compression is being built on a large scale offshore Norway. But is the future in smaller projects? Aker Solutions thinks so. Elaine Maslin reports.

Compact compression

An artist's illustration of the Åsgard subsea compression facilities.
Images from Aker Solutions.

The active cooler module

Subsea gas compression technology has been making the headlines. Statoil's giant Åsgard project offshore Norway is getting closer to first production, in 2015, and the Norwegian major's second subsea gas compression project, at Gullfaks, is also underway.

Gas compression is used to boost the reservoir flow on gas fields as reservoir pressure depletes. Subsea gas compression is beneficial because it is closer to the well, giving additional recovery due to a lower pressure drop in the pipeline, compared to topsides compression.

Rystad Energy, a Norwegian oil and gas consultancy, has predicted subsea gas compression technology will take an increasing role in the growing subsea processing market, which the firm says could be worth US$8 billion by 2020, from about $500 million today.

But will it be the mega projects that make the majority of that market? Bjørn Søgård, business development leader, wells subsea and risers, at DNV GL, suggests that, while focus is on the mega projects, the potential could be unleashed in making smaller units and through industrialization—making them more affordable.

Marco Gabelloni, senior engineer, subsea power and process, at Aker Solutions

Aker Solutions, which has been leading the Åsgard project, is now doing just that. Marco Gabelloni, senior engineer, subsea power and process, at Aker Solutions, presented the firm's compact subsea compression concept at Subsea Expo in Aberdeen.

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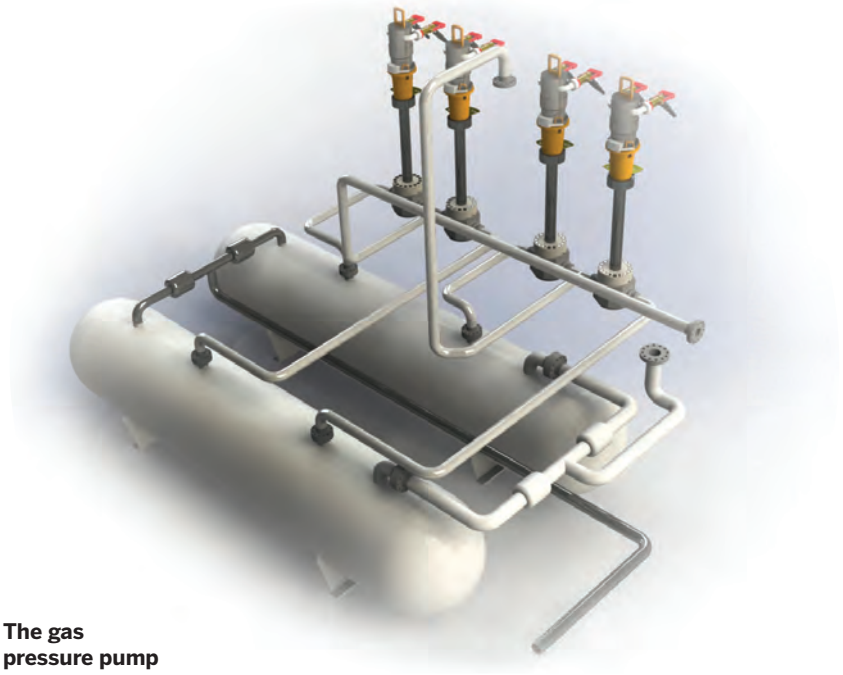


The gas pressure pump

The Rotoconverter

The aim, he says, is to offer a solution with a smaller footprint and higher flexibility, so that it can provide compression throughout the life of field, adapting to changes in the well stream and or reservoir.

"To do that we are developing a compact subsea gas compression solution," Gabelloni says. "Based on our qualified subsea compression system design, our target is to introduce new technologies, in order to develop a compact option targeting medium to small size gas and gas condensate fields. We are especially looking also at long step-out distances and deep water."

Aker Solutions started this development project nearly two years ago and is now in the concept selection and feasibility study phase. Proof-of-concept tests are now on-going, and they will be followed by the identification of related technology qualification programs.

The concept so far comprises three modules, to allow for flexibility, as field requirements change. These will be cooling, compression and power modules. The wellstream will enter via an inlet, pass through an active cooling system, then a compact scrubber, suitable for deep water and to minimize size, before going through gas compression.

Liquid removed by the scrubber will be boosted using a gas pressure pump, utilizing two vessels, which are emptied in turn utilizing gas coming from the compressor. Power supply will be via a subsea transformer and Aker Solutions' RotoConverter, which is a frequency step up device to enable long distance AC power transmission at low-frequency.

A scaled-down Rotoconverter prototype.

Three core elements being developed for the project are the active cooler, the gas pressure pump, and the RotoConverter.

Subsea cooler

Today's subsea coolers are designed based on what is known about a field during the design phase, Gabelloni says. "They are passive coolers, mostly with a big footprint, and the temperature control is designed in the initial phase of the project.

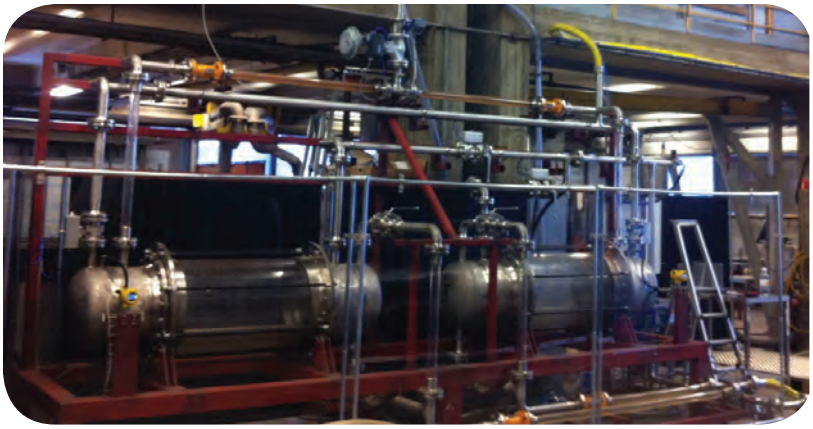
"On an active cooling system, we use forced convection cooling, with a small subsea pump to push the seawater through the cooler. The design is similar to Åsgard, but with additional walls around the cooler and some baffles inside, to increase the heat exchange. The main benefit is the increase in the heat transfer coefficient, so we can reduce the weight and the size of the module," he explained. Aker Solutions is currently in the concept selection phase on the cooler.

Gas pressure pump

"The challenge with current systems is that the subsea pumps needed for the liquid part of the well stream require the use of barrier fluid, with related tubing, and, in the case of a long step-out, a subsea variable speed drive. Also, in some cases, when we have a small liquid content in the wellstream, we need to re-circulate most of the flow to allow the pump to operate.

"To overcome these issues, we are developing a gas pressure pump. It uses pneumatic transport by leveraging the gas coming out of the gas compressor outlet. We use two vessels, and a set of axial valves, which control the gas from the compressor. The two vessels are emptied alternately. The benefits are that we do not need barrier fluids or any dedicated power supply."

The company has completed concept selection and is moving into a proof-of-concept test phase, including sand



The gas pressure pump during proof of concept testing. Photos from Aker Solutions.

testing, to make sure there is no issue with sand accumulation.

RotoConverter

To address the issue with transmission of AC power over long distances Aker Solutions has been developing a step-up device which is called the RotoConverter. Gabelloni says, "typical loads in subsea gas compression require quite high frequency to match the compressor rotating speed— up to more than 10,000rpm. But transmitting power over long distances with high frequency is limited due to charging currents. Therefore we need low frequency transmission, then locally, close to the compressor, we can have a frequency step-up device."

The RotoConverter consists of a motor and generator coupled together with a different number of poles. "In this way we can increase the frequency to match the requirements of the compressor," Gabelloni says.

"This is a proven concept and has been used in the industry for a number of years. Our program is to further develop this for subsea use. We are planning to have an enclosure that will be oil-filled with a pressure compensator, which will allow the system to be installed in deep water. With this device, we can remove the need for subsea VSDs, enable more power to be transmitted at longer distances and enable better cable performance."

Aker Solutions is moving to the proof-of-concept test phase, with plans to test a small scale 50kW unit.

Simplification

"When targeting small gas fields, the need for a compact and simplified system is quite clear," Gabelloni says. "We are using fewer and smaller components with a long track record topside. That helps to maximize the production and provide a reliable solution. The system is reduced in size and weight, we do not need the VSD subsea, we don't need the barrier fluid and related auxiliaries for the pump, and the cable cost can be reduced by using the RotoConverter unit.

"The modular design with three small units means they will be easy to install, retrieve and change as necessary during field life, as part of a building block strategy. We strongly believe these technologies unlock new possibilities for smaller gas accumulations and fields that currently cannot be exploited with existing technologies." OE

Proficient processing

TE Connectivity's Josselin Legeay examines the approaches and components of subsea processing necessary to keep brownfield developments operating successfully.

While offshore drilling activity continues to migrate into deeper waters, oil and gas producers are also looking to extend the life of existing brownfield sites. As these sites mature, the challenges of maintaining a profitable flow of hydrocarbons crease is leading producers to use innovative methods to ensure unobstructed flows. A variety of approaches allow subsea processing to keep brownfields operating efficiently and profitably. Subsea systems must be modular to allow practical deployment; wet-mate connectors are important enablers in allowing modules to be connected,

In brownfields, as pressure drops, the water cut increases. As the flow rate decreases, the hydrocarbons are cooled faster by the low seabed temperatures. This can lead to the formation of hydrates on the pipe walls or the mixed water cut freezing. Either can restrict flow and potentially clog the pipe entirely. Hydrate formation is combated by adding inhibitors such as mono ethylene glycol (MEG) in the pipes, heating the pipes to maintain sufficiently high temperatures, and maintaining a sufficient flow pressure. A large quantity of MEG inhibitors are required, which must then be removed topside and recycled for re-injection.

Pipeline heating can be achieved by direct electrical heating (DEH) or pipe-in-pipe heating (PiP). In DEH, a cable laid alongside the pipeline heats the pipe by either conduction or electromagnetic coupling. PiP uses two concentric pipes. The inner pipe carries the hydrocarbons; the annulus (between pipes) contains the heating cable and fiber-based temperature monitor sensors. To maximize the thermal insulation, the annulus is either held at vacuum or filled with an insulating material.

The third way to achieve flow assurance is to separate the different phases and types of flow—gas, oil, water, or solids (sand). Typically, this involves subsea boosting, either through gas compression or subsea pumping. Subsea boosting increases the flow rate of the oil or gas to the surface by reducing the back pressure on the well, and therefore increases the recovery factor of the reservoir. For oil, pumping can be used, while natural gases are boosted by compression. Another technique, which can be used in combination with pumping, is to separate the water and oil/gas, injecting the water back into the reservoir to limit pressure drops in the well. This saves energy (the potential energy of getting the water to the topside facility and down again into the well), and it saves a significant amount of space and weight on the heavily-crowded topside facilities. Fig. 1 shows examples of types of subsea processing.

Modularity is key to deploying subsea processing

Moving processing equipment from the platform or shorelines to the seabed creates challenges in its design and deployment. A limiting factor is the weight of such equipment, especially in deep waters. Weight and size issues require that the equipment is designed in a modular fashion, with modules connected together on the sea floor. For example, transformers, circuit breakers, variable-frequency drives, and the final consumers (pump or compressor) all need to be interconnected. Modularity also presents advantages in retrieving, repairing, or upgrading equipment because it is more economical to replace a module than the entire system.

Where several trains of pumps or compressors are in parallel, modularity allows selective shutdown and retrieval of a module, while the other trains continue to boost hydrocarbon production, increasing the overall availability factor of the subsea station. This also eases maintenance by allowing smaller intervention vessels, which are more readily available than high-payload deployment vessels and less costly to operate.

For pipeline heating, wet-mate connectors allow the pipeline to be deployed with its heating elements. The umbilical cable is separately deployed and used to power the system. The

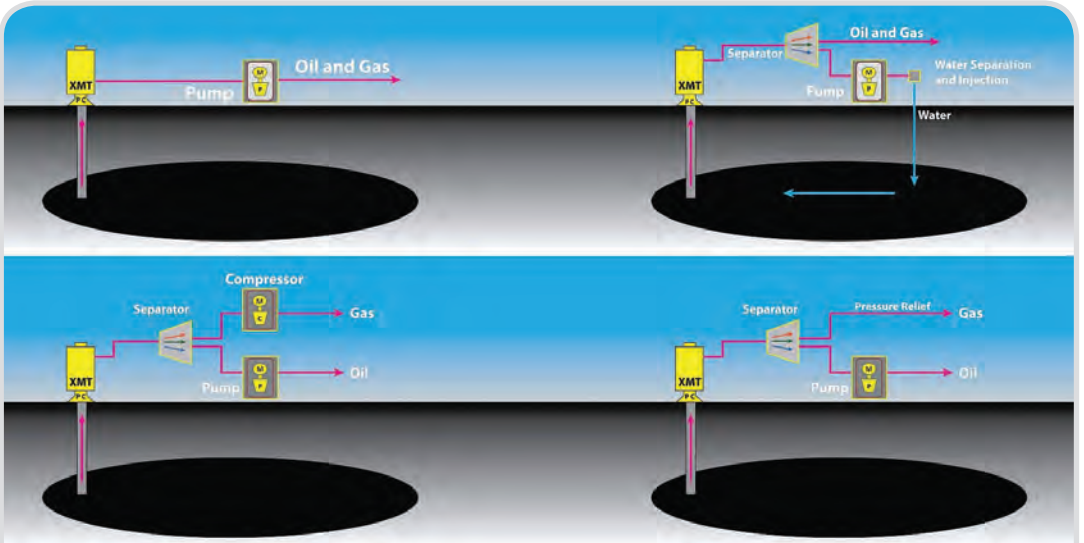


Fig. 1. Subsea processing helps maintain flow rates and keep brownfield wells operating efficiently.
Image from TE Connectivity.

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umbilical and heating cables can then be connected on the seabed via ROV. This makes a more efficient and cost-effective approach. Without the ability to make wet-mate connections, the two cable ends need to be "fished up" to the surface–requiring an extra length of cable–so that splicing can be performed topside. This operation takes a long time, is costly, and depends on adequate weather conditions. Poor weather can disrupt deployment schedules.

Fig. 2: Wet-mate power connectors.

Wet-mate connectors enable modularity

A wet-mate connector is a device that allows connection of electrical conductors. Connectors are designed for a certain current and voltage, frequency, and water depth. Their materials are corrosion resistant and designed to withstand the harsh conditions of subsea environments for their design life, typically up to 25 - 30 years.

For modularity to be achieved, power distribution must rely on wet-mate high-voltage connectors that can be mated or unmated in an unprotected underwater environment. Fig. 2 shows a typical wet-mate connector pair. Offshore applications distinguish between dry-mate and wet-mate connectors. Dry-mate connectors are mated topside in dry circumstances and then submerged to their rated depth. They cannot be interconnected on the sea floor. A subsea processing system will involve both dry-mate connectors within a module and wet-mate connectors for intermodule connectivity.

Application of subsea wet-mate connectors is similar to other connector applications—they are used to directly connect two modules or to connect a cable to a module.

A special type of connector is the penetrator, an example of which is shown in Fig. 3. The penetrator is a feed-through connector used to separate chambers from each other or separate a chamber from the outside world. It is basically a bushing designed to accommodate pressure differentials. The inside of a sealed piece of equipment, for example, may be at a significantly different pressure than the surrounding seabed. When possible, subsea modules are pressure balanced—i.e., fluid filled—with the fluid being adjusted at the same sea pressure as outside the module. This allows for thinner walls, reduced weight, and higher reliability as seals are not required to withstand differential pressures. Some modules, such as those containing electronics or other devices such as circuit breakers, cannot withstand pressure higher than atmospheric. Therefore, a penetrator is used to prevent the seawater from leaking into them. On other devices, such as pumps and compressors, which are potentially exposed to the reservoir shut-in pressures, pressure ratings can get up to 15kpsi/1034bars.

Penetrators are rated for withstanding pressures—such as 5kpsi, 10kpsi and 15kpsi—which are linked to the reservoir pressure. Required withstanding

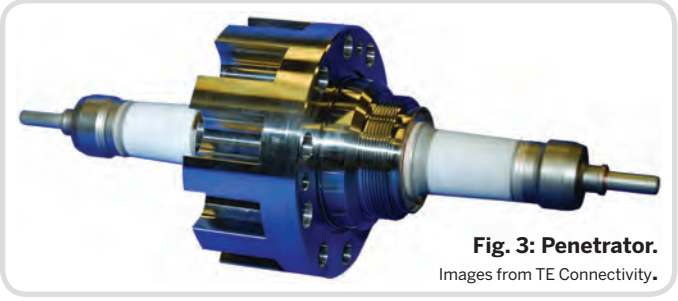


Fig. 3: Penetrator.
Images from TE Connectivity.

pressures are related to the fact that the boosting unit is in contact with the hydrocarbons. In case of a shutdown, the whole reservoir pressure may apply to the penetrator.

The penetrator serves an environmentally-important function: an electrical failure would mean a loss of production, but a mechanical failure would release hydrocarbons into the environment.

On other modules not linked to the oil flow, the penetrators are the barrier ensuring the electrical integrity of the module, preventing the modules from being flooded with water.

Wet-mate connectors, then, are key elements allowing cost-effective and technically feasible deployment, while penetrators are essential to preserve the integrity of the complete electrical power supply and to prevent hydrocarbon release into the environment.

Specifying wet-mate connectors

A high-voltage wet-mate connector is usually specified by the following criteria:

- **Voltage/Current Rating**: Voltage and current handling capabilities are the basic metrics in choosing any power connector. Since power in subsea systems is usually three-phase, a connector is specified through three values, such as 18/30 (36) kV. The first number, 18kV, is the phase-to-ground rating. The second, 30kV, is the phase-to-phase rating. The final, 36kV, is the maximum system voltage.
- Some operational philosophies require the connectors to still operate when there is a ground fault on one of the three phases. In that case, the connector needs to withstand the second value (30kV in this example) and is selected accordingly.
- **Frequency**: Depending on the connectors and the application, the frequency can be low (50 or 60Hz) for transmission. Higher frequencies—up to 200Hz—are found downstream of a variable-speed drive. For some long, step-out applications, low-frequency AC transmission or DC can come into play.
- **Water Depth/Pressure**: Connectors must withstand not only the pressures of deepwater applications, but also other harsh conditions. Today, subsea processing must withstand depths of up to 3000m, and, in the next decade, will need to withstand even deeper depths.
- **Temperature Rating**: Seabed temperatures are usually rather low and very stable, but the connectors and penetrators need to withstand storage temperatures that may be in direct sunlight in places like the hot climate of the Gulf of Mexico, or the cold climate of the Norwegian Continental Shelf. Penetrators must also be able to withstand the high temperatures generated by the modules (up to 90°C) or the hydrocarbons, which may be up to 200°C.
- **A Typical Interconnection System:** Fig. 4 shows a typical power-cabling system. An umbilical cable is terminated to a subsea umbilical termination assembly (SUTA), which is roughly equivalent to a wall socket in a home. From the

Fig. 4: Power-cabling system diagram. Image from TE Connectivity.

SUTA, electrical flying leads (EFLs) bring power to the pump or other modules. To continue the home analogy, EFLs are like extension cords. A secondary jumper harness ensures connection from the EFL to the penetrator that serves as a transition at the pressurized motor enclosure.

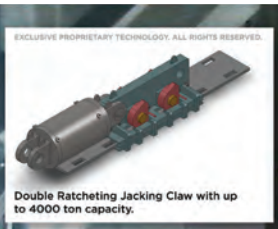
Signal and optical connectors

Wet-mate connectors also provide a means of communications between the control room and the subsea equipment. They enable information retrieval from the sensors located in the well and related subsea equipment to assess the integrity of the well and related equipment, optimizing reservoir production. Available for both copper and fiber-optic cables, signal-level connectors serve telemetry and control needs.

Conclusion

Wet-mate connectors are suitable for harsh marine environments. They are a key element of subsea equipment used in the subsea factory processing for oil and gas extraction. They are more complex than standard electrical connectors because of the need to provide a sealed interface that can be maintained at subsea water pressures. Products such as TE's DEUTSCH line of subsea wet-mate connectors and penetrators are the result of years of offshore experience, both topside and undersea. Our product development advantage includes a close working relationship with designers and users of deepwater equipment to best match the connector to application needs, providing for subsea power distribution and processing in a safe, reliable and economical manner. OE

Josselin Legeay *is Product Manager for High Power Systems within TE Connectivity, Global Aerospace, Defense & Marine. Josselin has more than 10 years' experience with subsea electrical connecters. His areas of expertise include high voltage connectors, connection systems and subsea distribution/collection systems.*



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Subsea separation gains momentum

Greg App dives deep into the advantages of subsea separation units (SSUs), which have been deployed on fields such as Total's Pazflor development.

Nearly five years have passed since FMC Technologies introduced the world's first large-scale subsea separation system. The Pazflor subsea gas-liquid separation system promised the ability to produce from subsea fields hindered by factors such as heavy oil, low productivity indices, and low gas-oil ratios. Historically, fields with these characteristics are not well-suited for subsea production. Thus, this new implementation of subsea separation technology had the potential to change subsea development and processing outlooks throughout the industry.

Working under contract for Total E&P Angola since September of 2011, this next-generation subsea separation equipment seems to have met these high expectations. Positioned about 93mi. off Angola, FMC's subsea separation units (SSU) have enabled the 238sq mi. Pazflor project to produce oil and gas from 25 subsea wells drilled in four separate reservoirs at water depthsto 4000ft.

The 2009 Offshore Technology Conference (OTC) paper "Comparison of Subsea Separation Systems" discusses the primary advantages of SSUs by highlighting their ability to lift oil and water to the surface by utilizing gas-tolerant hybrid pumps, a method found to be far more efficient than more traditional gas lift and multiphase pumping systems. Such technology is also cost effective. The omission of gas-lift systems and slug catchers results in extremely reduced compression size and more compact first-stage separators. Additionally, and perhaps most importantly, subsea separation greatly reduces the overall length of the drilling trajectory (Fantoft, Gruehagen, Shaw, and Vu).

The introduction of this technology on a large scale has been successful, with Total calling the Pazflor SSUs provided by FMC Technologies a "bold innovation" and an "audacious solution." According to Rob Perry, Director of Global Subsea Processing at FMC Technologies, "the success of subsea separation on Pazflor will endorse the fact that subsea separation is a reliable solution with technology that can be counted upon for significant levels of investment and associated revenue by the operators."

Thus, as a single case study, the Pazflor project is a testament to the effectiveness of subsea separation technology in overcoming seabed production challenges. However, this is merely the first time SSUs were utilized on such a large scale.

Top: The Pazflor gas-liquid separation system is the first of its kind to be utilized on such an immense scale.
Above: FMC's subsea separation units (SSUs) have enabled the 238sq mi. Pazflor project to produce oil and gas from 25 subsea wells drilled in four separate reservoirs at water depths to 4000ft. Photos from FMC Technologies.

According to the authors of a 2012 OTC paper, "Compact Separation Technologies and Their Applicability for Subsea Field Development in Deep Water," subsea separation is attracting interest because of its ability to increase production, enhance recovery and improve field economics on a commercial scale (Akdim, Hannisdal, and Grave). The concept of this technology is not new; subsea separation and

pumping systems have been in various developmental stages since the late 1960s. In a 1969 OTC paper "Production Processing Prototype for Submerged Operational Test," the authors explain that the world's first prototype seafloor separation module was tested in 1969 offshore Abu Dhabi, and was successfully used for three years before being decommissioned. Another separation system was successfully tested in the Gulf of Mexico between 1972 and 1973 (Burris, Hill, and Lowd).

***The Espirito Santo* FPSO is a key component of Shell's Parque das Conchas(BC-10) project.** Photo from Shell.

However, despite these successful early prototypes, a lack of clear understanding regarding the cost and benefits of this technology has prevented the industry from deploying it on any sort of significantly large scale until very recently. "The first subsea separation systems were conducted on an experimental level," states Rune Mode Ramburg, Chief Engineer of Subsea Technology & Operations at Statoil ASA. "For the first few decades, there was not an immediate incentive to pursue this technology on such a large scale. However, as the need to drill in deeper waters became more apparent, so did the economic and logistical advantages of subsea separation."

The industry's interest in the potential advantages and opportunities provided by subsea processing and SSUs did not truly gain momentum until the implementation of the Norsk Hydro Troll C pilot in 2002. Based on ABB Offshore Technology's Subsea Separation and Injection System, this pilot was able to remove and dispose of the water produced by Troll subsea well templates before piping the gas and oil as a mixed stream to the Troll "C" platform for continued processing. Three years after the successful installation and operation of the Troll subsea separation pilot, a study conducted by Douglas-Westwood Energy Research Group indicated that industry enthusiasm towards this technology was on the rise. Although actual industry participation in the development of subsea processing was still relatively insignificant, the Douglas-Westwood report revealed that 90% of operators expected to utilize this technology within 10 years.

These predictions began to materialize with the successful start-up of the world's first full-field subsea separation system on the Statoil-operated Tordis field in 2007. Because of subsea processing advantages, operators in the Tordis field were able to increase recovery by 35MMbbl while extending the expected field life by almost 20 years.

Soon to follow was Shell's Parque das Conchas project (BC-10) off Brazil, which has the distinction of hosting the world's first subsea system with gas-liquid separation and boosting. This system was developed with 13 subsea

wells, six subsea separators and a floating production storage-offloading system (FPSO). This project area includes five fields with an estimated 400MMbbl of heavy crude oil.

In 2011, the technological and economical advantages of subsea separation technology enabled Shell to make history with the Perdido project. Located in the Gulf of Mexico, the Perdido project has set multiple offshore industry world records, including recognition as the world's deepest oil development and deepest drilling and production platform. Additionally, it is predicted to produce from the deepest subsea well on earth.

The Perdido project has set multiple world records, largely due to the use of subsea separation technology. Photo from Shell.

The Future

Kimball says that current technological developments will eventually lead to full subsea processing. "The technology developments in the area of subsea separation are related to ultra-deep separation solutions in addition to further treatment and separation steps that are required after the primary separation," Kimball says. "FMC Technologies is already qualifying these methods, often through joint industry programs, which are undertaken in collaboration with operators that will deploy the technology."

According to Ramburg, the technology to successfully implement a full-scale subsea processing system already exists, and its successful implementation is just beyond the horizon. "From Statoil's point of view, the technology is definitely doable," he says. "It is really just a question of economic incentive and necessity.

"Realistically, I believe that we will have installed a fully operational subsea processing system by 2020," he says. "However, in the meantime, we are going to see multiple technological developments regarding subsea separation systems. These include secondary separation on the seafloor, improved efficiency of current separation systems and a larger utilization of subsea compression technology."

Recent trends seem to indicate that industry confidence regarding the effectiveness of subsea separation technology is gaining considerable momentum. As the cost benefit analysis of SSUs becomes clearer with the increased participation of major operators, one can expect the remainder of the industry to follow suit in utilizing this technology to increase deepwater production. OE

Abaqus FEA helps INTECSEA deliver durable pipe solutions for deepwater oil producers. Kip Hanson reports.

It's all in the pipeline: Transporting sour hydrocarbons more reliably

It's not that the world is running out of oil. The problem is getting to what remains of it, at a price that consumers can swallow. A September 2013 oil market report from the International Energy Agency (IEA) said that global demand for oil and liquid fuels will rise to 93MMb/d in 2014, an annual increase of more than 2%. This comes at a time when most experts agree the days of "easy" oil are over. Petroleum companies are now forced to drill in areas deeper and more remote than ever before.

In the case of deepwater production, this means very high and unpredictable pressures coupled with severe temperature gradients both inside the pipe and out. Worse, the wellstream fluids coming from these depths are increasingly sour, a corrosive witch's brew containing high levels of hydrogen sulfide, CO_2, and volatile organic compounds that make short work of regular carbon steel pipe. The oil industry has responded with calls for better pipeline material.

Clad pipe has been used in high-strain environments for decades. By metallurgically bonding a thin layer of corrosion resistant alloy (CRA), typically 316L or Alloy 625, to the inside of C-Mn structural steel pipe, a robust combination of strength and corrosion resistance is formed.

However, clad pipe suffers from long lead times and high cost. Sherif El-Gebaly, lead pipeline engineer at INTECSEA, a global company within the WorleyParsons Group, says that clad pipe can cost 10 times that of regular C-Mn Steel. "An alternative is CRA mechanically lined pipe using a weld overlay at the ends," he says. "This is both easier and quicker to manufacture, presenting cost savings of 30% over clad pipe."

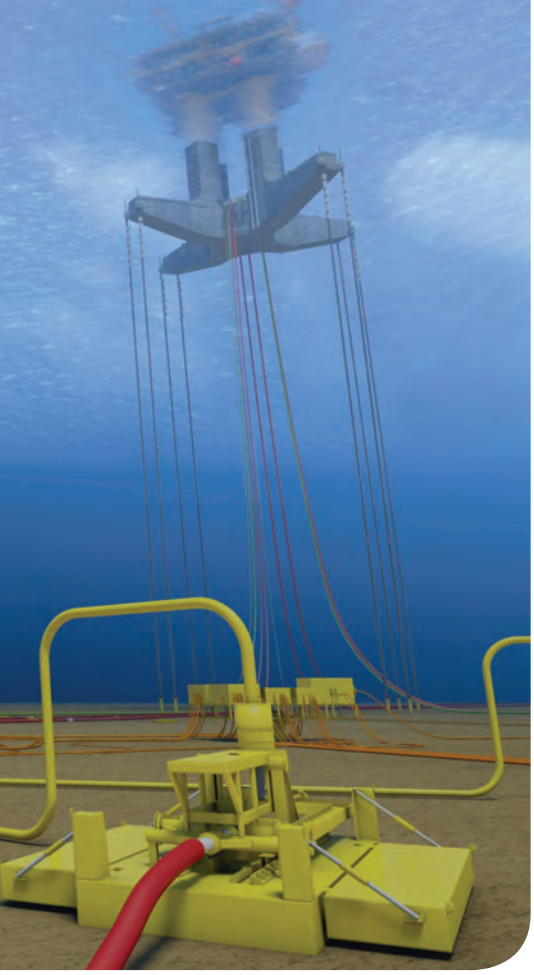
However, concerns over the weld overlay to liner interface joint have prevented wide use of CRA mechanically lined pipes due to the technology readiness level (TRL) not meeting operator requirements. INTECSEA has been working to resolve and increase the confidence in CRA mechanically lined pipe for use in harsh environments.

Making the weld stronger than the pipe

Pipe sections are manufactured in lengths of about 12m, called pipe joints. These joints are then girth welded together end-to-end to create a pipeline. For mechanically-lined pipe, each CRA joint is slid inside a carbon steel joint and plastically expanded in the radial direction to ensure a tight fit between the carbon steel and the liner. The fitted CRA joint is shorter in length, leaving a distance of about 50-150mm at each end; this gap is filled with a weld overlay of a CRA material, bonding the CRA layer to the carbon steel pipe and enabling the joint-to-joint girth weld to be performed.

"Girth welds are critical," said INTECSEA global technology director Philip Cooper. "Some of these installation vessels are running a million dollars a day. The weld joints are inspected prior to lowering the pipe into the sea, and if repairs have to be made at this point, it can seriously impact production rates."

Regardless of how much pipe gets laid in a day, environmental and safety considerations mandate zero tolerance



Typical offshore deepwater field development. Image from INTECSEA.

for failure once the pipeline is in the water. This is because deepsea flowlines are subject to tremendous stress as they transport a mix of oil, water, gas and sand from the wellhead to the offshore storage facility (FSO) or onshore processing terminal. This fluid alternately heats and cools the pipeline, causing expansion, bending and potential buckling. High-velocity slugs of liquid and gas within the pipe create vibration, leading to fatigue. Even the weight of the pipe itself as it crosses the uneven terrain of the seafloor is a cause for concern.

"The movement of the pipeline under production conditions is similar to your garden hose when you turn on the tap," Cooper said. "You'll get wiggling and sideways motion due to the pressure. This is why fatigue performance and strain capacity in this environment is so important."

The oil industry demands thorough testing of any component used in deepsea oil production, and CRA-lined pipe is no exception. Because of its two-layer design, some experts were concerned over the possibility of ripples forming in the liner material under bending stress which presents a risk of premature failure (Image 1). Equally important was ensuring the integrity of the girth welds used for the weld overlay-style pipe.

But since sticking your head inside a 12in. diameter pipe one mile under the ocean is clearly not an option, INTECSEA design engineers have been employing realistic simulation with Abaqus finite element analysis (FEA) software from SIMULIA, the Dassault Systèmes 3DEXPERIENCE application.

Visualizing deepsea conditions with Abaqus

FEA lets the team query the geometry and behavior of computer models of their pipe designs, simulating every condition from production to performance thousands of feet below the ocean surface. "We've been using Abaqus for the past decade or so," Cooper said. "Over the last few years it's really become our preferred tool for pipeline design. On top of that, many of our customers show a preference for Abaqus. It's more or less a standard in this industry."

El-Gebaly's team had a number of factors to consider when setting up their Abaqus FEA models to predict lined pipe and weld behavior. "One challenge was a potential problem with under-matching," he said.

"Imagine that you have two 12m long pieces of pipe and you're welding them together (Image 2). The weld is basically just a ring, one that is stronger than the pipe on either side. Normally when you bend the whole system, you don't have to worry about this small ring, you're concerned more with the pipe materials.

"But if at some point the yield strength of that ring becomes less than that of the pipe on either side—for example, under certain high-temperature operating conditions, or where the consumable selected for welding exhibits a lower yield strength at certain temperature than the base material—the joint will actually become more flexible than the pipe and then all the strain flows into it. FEA helped us investigate such cases."

There were other scenarios to check within the assembled pipeline itself. Aside from the garden-hose example described by Cooper, El-Gebaly was concerned with the development of ripple-type deformations induced in the liner layer during spooling and subsequent installation. "You have to understand the behavior of liner under bending moment,

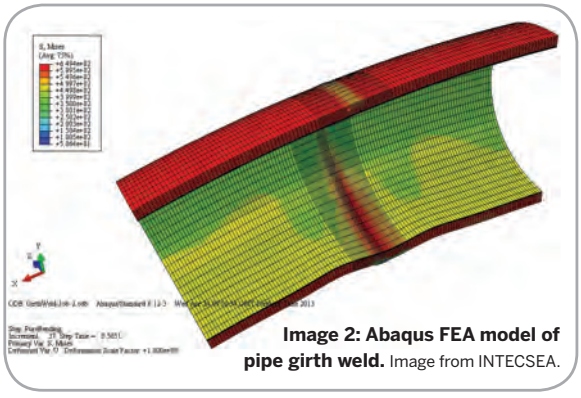


Image 2: Abaqus FEA model of pipe girth weld. Image from INTECSEA.

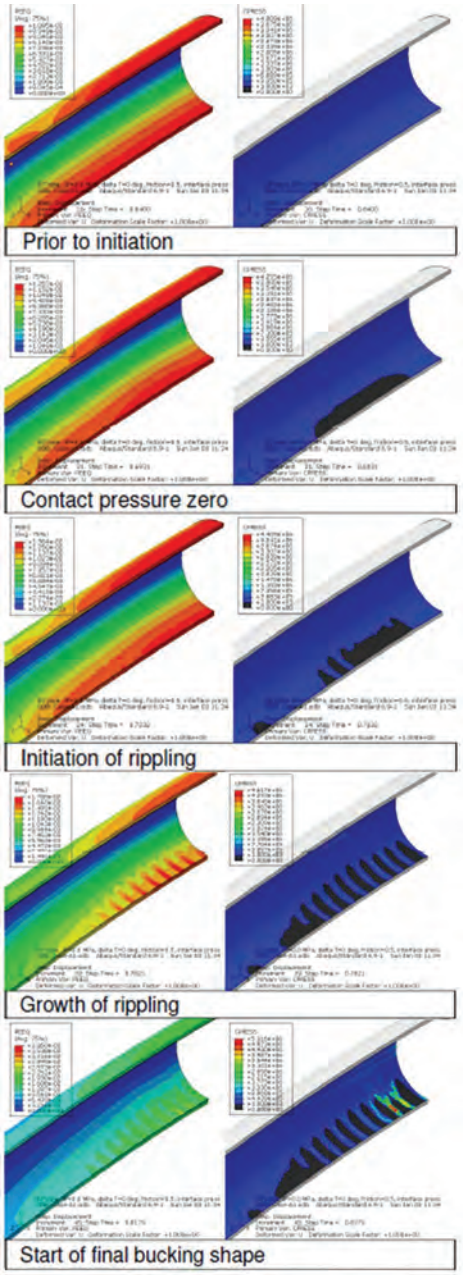


Image 1: FEA analysis of pipe response to stress. The diagram at the top shows the pipe at rest. As bending force is gradually applied, ripples begin to grow in the CRA liner. At the bottom, the pipe is beginning to buckle. Image from INTECSEA

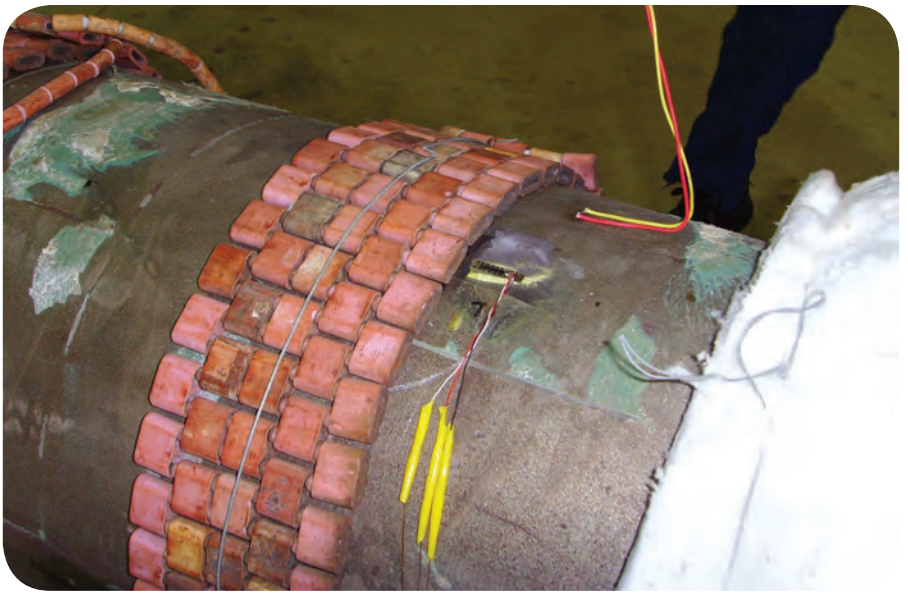


Image 3: Temperature is an important component in pipe performance and simulation models replicating such performance require accurate data capture. Here, a pipe is wrapped in a heating blanket as it is brought up to 130°C, replicating the effect of high temperature well fluids.

Image 4: CRA-lined pipe wrapped in insulating material. This test demonstrates a pressurized and heated pipe placed under a 1.5% strain load.

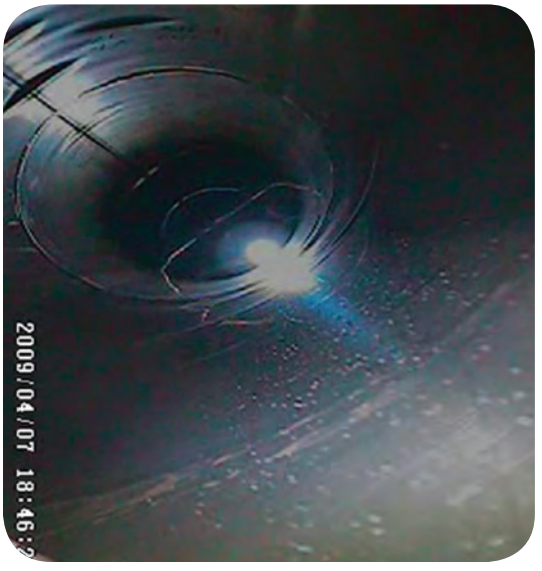


Image 5: A bird's eye view—looking inside a heated pipe that has been reverse loaded with a severe bending strain. Several ripples can be seen in the upper left hand corner of the photo.
Images from Paul Montague.

the wrinkling onset conditions, as well as the fatigue performance of the girth weld during the installation and design life," El-Gebaly said.

A day in the life of lined pipe

Much of the data needed to accurately capture such behavior with FEA models comes from extensive land-based testing. Sections of CRA-lined pipe are put through numerous physical tests, monitored by strain gages used to measure axial and radial force, and piezoelectric and Bourdon gages to monitor pressure. Hydraulic rams, heating coils, and various other devices are then applied to sections of pipe to simulate the severe conditions at the bottom of the sea

Using test data, combined with industry-standard material properties for X65 pipe lined with 316L CRA, INTECSEA created Abaqus FEA models of their pipe and carried out parallel virtual tests. Multiple simulation runs were performed using both pressurized pipe models replicating production conditions, and unpressurized ones that reproduce the conditions expected during transport and installation.

Reducing both development costs and long-term risk

Results to date have been promising. Ultrasonic tests show close correlation between FEA and real-world behavior, demonstrating that INTECSEA's pipe and weld designs are performing well. Better yet, internal rippling of the CRA liner has been demonstrated to be minimal for certain design conditions, even when subjected to high buckling forces and temperatures of 130°C. (Image 5)

According to El-Gebaly, once the models have been fully validated, using Abaqus will certainly help INTECSEA reduce real-world testing costs. But there's more to it than higher front-end savings: FEA helps to assess design risks and possible failures. "For pipelines, it only takes one joint to fail for a release-of-contents event to occur, so it is crucial to assess every failure mechanism," he said. OE

Kip Hanson *is a freelance writer and manufacturing consultant in Tucson, Arizona. With more than 30 years' experience in manufacturing and business management, he has written on a wide range of topics, including machining and fabrication, consumer products, oil and gas, CAD/CAM/FEA and ERP systems. Prior to his current position, Kip worked as the IT director for a global manufacturing company, and also spent a number of years business consulting with a mid-range ERP software and services provider.*

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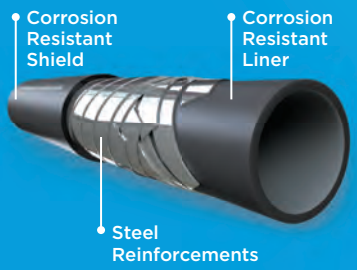

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FLEXSTEEL

Alpha Mahatvaraj of GMC Inc. discusses how their new mechanically connected risers could offer a potential solution for ultra-deepwater projects.

Making connections

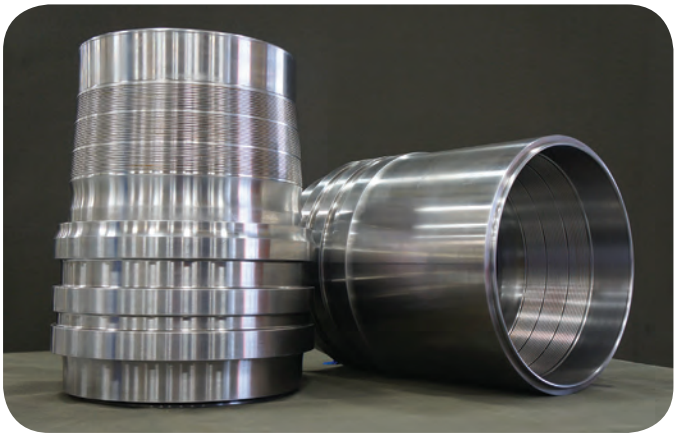
The contribution of ultra-deepwater developments to world oil production is expected to accelerate in the coming years provided that the escalating capital expenditures (capex) of these projects can be contained. A major component of the ultra-deepwater project capex is the SURF cost, particularly risers and flowlines. The current riser solutions for deepwater fields including flexibles and steel reeled or J-lay welded risers have either limitations on service requirements or have significant cost impact.

GMC Ltd. developed a mechanical connector product line for risers and flowlines called intelligently connected pipe (ICP) to meet the emerging needs of the deepwater SURF market. The connection of risers and flowlines with pre-manufactured tubular eliminates the need for offshore welding and high-cost installation and lay vessels. The SURF installation market will be opened up to allow many potential new subsea contractors to bid for projects.

Current limitations

Flexibles manufacturers have yet to find a qualified solution for presalt risers, primarily due to the high CO_2 content that attacks the carbon steel tensile layer. Additionally, deepwater and associated high pressures (internal and external) are at the limit or beyond the current capability of flexible pipe. Flexible risers currently do not offer a life of field solution and given that these wells can produce for over 20 years, the flexible route is a very costly option for the operator. Corrosion resistant alloy (CRA) clad steel pipe addresses these problems, however at greatly increased installation cost.

J-lay welded and reeled SCRs have their own inherent problems in that installation is very costly with the extremely high day rate of the specialized installation vessels.



GMC's mechanical connectors. Photo from GMC Inc.

Timing is a key issue

Recent presalt projects have been delayed by riser and subsea installation assets, a rare scenario as normally the FPSO was the critical path. Component time is therefore a critical issue and one of the big potential drivers for using connectors, which can be delivered much faster than flexible pipe or reeled steel spools. The ICP can be installed using a 120m DP MSV with a modular J-lay tower using a connector pipeline installation procedure (C-Lay) developed by GMC. Smaller installation vessels such as these are readily available unlike the conventional welded J-lay options. The large specialized installation vessels have a single line critical path and this has proved a problem for major operators with delays on other projects having cascade effects on installation schedules.

The ICP solution enables the operator to more quickly and cost effectively produce and manage well production. It allows local assets to be used in SURF rather than waiting for the large international contractors to plan the mobilization of assets from distant shores. Traditional welded lazy wave steel catenary riser (LWSCR), freestanding hybrid riser (FSHR), and flexible

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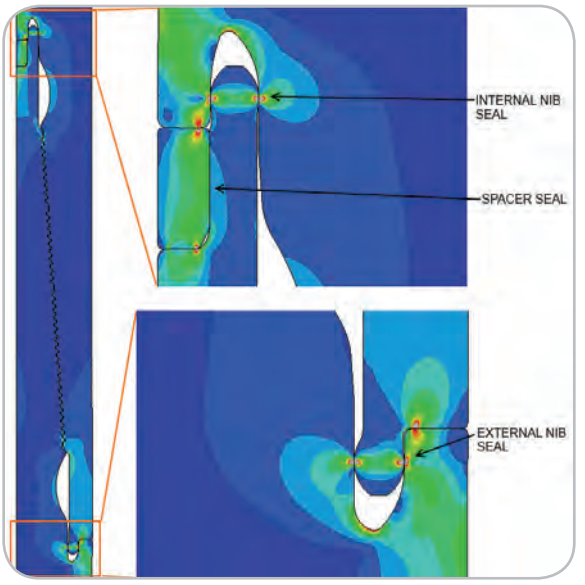
riser technologies are time consuming to manufacture as well as to install. Other opportunities for ICP exist in pipe-in-pipe, work-over risers, flow-lines and subsea jewelry applications to name just a few.

A key feature of ICP is the fabrication process, where the pipe joining happens off the critical path in a controlled onshore environment. This assures a high degree of consistency in the joining process and produces joints with high fatigue resistance. The coating and CRA cladding of the joints for offshore installation can also be customized per project requirements. The ICP solution also enables operators to include more local content in the manufacture and installation of the risers and flowlines.



Redundant seals. Photo from GMC Inc.

Mechanical connector

GMC's mechanical connector is the enabling technology behind ICP. The connector is an axially made-up pin and box type connector designed to meet the requirements of ISO 13628–petroleum and natural gas industries, design and operation of subsea production systems–and API 2RD–dynamic risers for floating production systems, API Standard 2RD, Second Edition, September 2013– and is fully qualified to the testing requirements per ISO 21329.

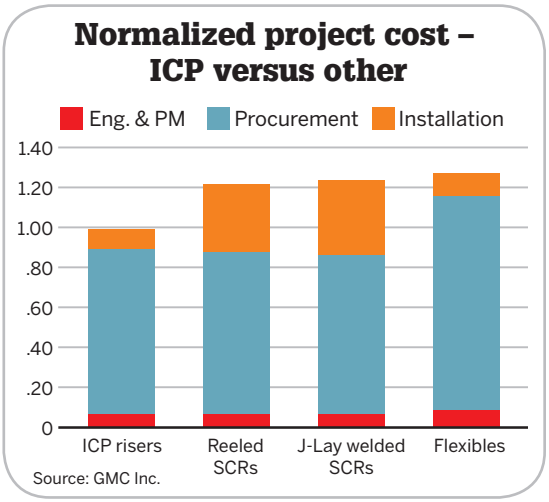
The connector has a redundant sealing mechanism with three separate seals. The figure (left) shows the three sealing locations and the metal to metal contact areas that comprise the connector sealing mechanism. It is also corrosive service compatible and fatigue resistant. The connectors are reusable, and the installed pipe can be recovered in reverse sequence, and can be cleaned, surveyed, and stored for reuse.

Pipe joining

Assembly of the ICP pipe joints including the pipe to connector joints and the pipe-to-pipe joints is accomplished in a controlled manufacturing facility onshore, off the critical path of the installation project. Options for the joining process include friction joining which results in pipe joints that are 100% parent metal and exhibit fatigue and strength properties comparable to the parent pipe. This friction joining process can be fully automated to maximize efficiency and maintain the high quality of joints. GMC is currently conducting friction joining trials to qualify the process for high strength, high fatigue and corrosive service requirements.

Even for conventionally welded pipe

joints, the ability to complete all welds in a controlled environment, including the ability to perform post-weld heat treatment and internal clean-up machining results in joints with superior strength and fatigue properties than can be accomplished by offshore welding. This removes the pipe joining process away from the critical path during offshore installation.



Improved economics

GMC analyzed a 12-riser field development installed at 2200m water depth and considered the riser scope only. When compared relative to reeled SCRs, J-lay welded SCRs and flexibles, the economic advantage was in excess of 25% of total costs for installation, riser procurement and engineering.

Installation is assumed to be completed by a local 120-130m MPV with a modular J-lay tower on board.

While this comparison alone provides compelling economic support for the ICP riser solution there is an additional consideration of a qualitative nature that should be taken into account when assessing the economics of ICP. This consideration is related to the risk profile of these large installation contracts and the schedule uncertainty associated with them. Installation contractors who have access to a very limited number of the highly specialized vessels required for either reeled SCR installation or welded J-lay are forced to price their projects based on a comparatively long block of time (so called "block booking") in order to ensure that the vessel will be available when the project is ready for installation of the risers and flowlines. This results in project costs that can easily be double the cost calculated by simply multiplying day rates by the time required to install the risers. An ICP vessel however has a much lower day rate and can be easily assigned to other well intervention, IRM, or light construction tasks when not utilized for the riser installation. This allows project costs to be much closer to the actual duration, with weather being the one remaining risk for which to account. OE

Alpha Mahatvaraj *is offshore products manager at GMC Inc., a subsidiary of GMC Ltd. He has over 15 years of experience in mechanical design and product development. Recent projects include development of mechanical connectors for dynamic applications, design and delivery management of riser system components and TLP tendon connectors. GMC Ltd. is a deepwater product, engineering, and project management company that develops and produces enabling technologies.*

Surveying Brazil's

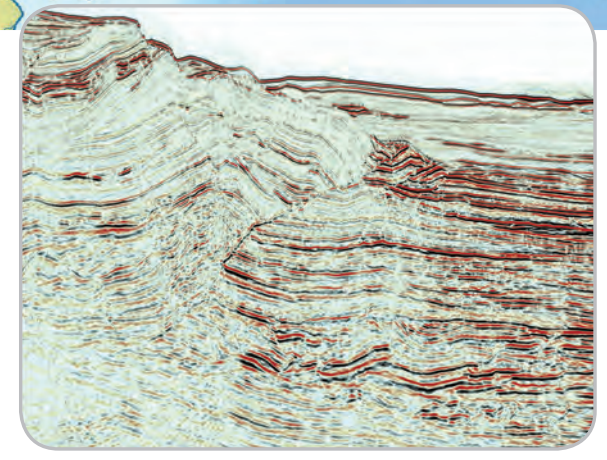
CGG's *Oceanic Endeavour* vessel. Photo from CGG

Brazilian correspondent Claudio Paschoa, visited CGG's Rio Technology Center, and spoke with Luiz Braga, CGG Vice President and Latin American Geomarket Director, about the basin's formation and results of seismic surveys in the equatorial margin.

Brazil has made headlines due to its large deepwater presalt discoveries off the country's southeast coast. Plays like Lula and Libra have helped attract investors and service providers. After Brazil's 11th bidding round, which offered areas along the north and northeast coasts, new exploration frontiers opened, and the most exciting is along Brazil's north coast, known as the equatorial margin (EM).

Tectonic origins

The South Atlantic rift system developed during the mid-Mesozoic breakup of Africa and South America, which began around 140 million years ago. These continental masses were part of the Gondwana super-continent during the Paleozoic. Rifting started in the south, and propagated toward the north. Lithospheric stretching and rifting in northeastern Brazil progressed to sea floor spreading, which probably began in late Aptian to early Albian times and took place along transform fractures in the equatorial rift zone. The South Atlantic rift system created two very different margins around Brazil: the north



Above: Map showing location of CGG's legacy multi-client 3D seismic surveys offshore Brazil as well as four CGG multi-client 3D surveys currently in progress.

Left: Conventional seismic from the Barreirinhas basin.
Images from CGG Data Library.

equatorial margin

and the east Brazilian margins. The North Brazilian Equatorial margin evolved in response to strike-slip motion between Brazil and Africa, resulting in complex shear-dominated basins.

Seismic surveys

"CGG has the largest set of seismic imaging suites in Latin America, with processing power unmatched in the region and expansion plans may well place the Rio imaging center as the third largest in the world," Braga said.

OE: What are the main geological features of the equatorial margin basins?

Braga: The Brazilian EM basins formed as a series of transtensional and transpressional rift basins in the Late Cretaceous as a consequence of the oblique continental rifting that occurred between South America and West Africa. Five major basins are defined from west to east: the Fóz do Amazonas, Pará-Maranhão, Barreirinhas, Ceará, and Potiguar basins.

The westernmost basin (Fóz do Amazonas) has seen very high sedimentation rates brought by the Amazon River throughout the Cenozoic period until now, and this has led to the formation of a thick deltaic sequence. Further to the east, in the Ceará and Potiguar, we observe the presence of volcanic features such as large sea mounts and igneous intrusions. Due to the steep slope of the equatorial margin and with the presence of a "soap-like" layer provided by Upper Cretaceous-Lower Tertiary shales, all these basins have been affected by large gravity slides through the Tertiary.

The Pará-Maranhão and Barreirinhas basins are further east of the Amazon delta, so they are much less affected by the Amazon River sediment load. However, the margin is steeper and the Upper Cretaceous-Lower Tertiary soap shales are still present in these basins, which means that mega-slide complexes have formed around a narrower band following the main slope break of the equatorial margin. We see a very quick transition from extensional to compressional faulting.

Further to the east, the extensional regime dominates throughout the Ceará and Potiguar basins, which are characterized by tilted fault blocks and listric faulting. Perhaps an explanation is the presence of several sea mounts and igneous features downdip, which scatter the compressional front and interrupt the thinner Tertiary sedimentary sequence.

OE: What are the main geological similarities between the Brazilian equatorial margin basins and those of West Africa?

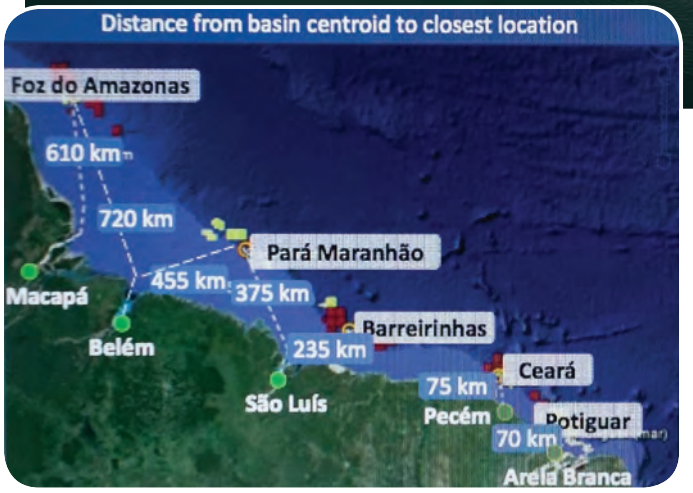
Braga: Before South America and West Africa rifted apart, approximately 140 million years ago, they formed one single supercontinent, Gondwana, with the Pará-Maranhão and Barreirinhas basins located adjacent to Ivory Coast and Ghana. As rifting started, in Aptian times, shallow water lakes formed around the rift axis and saw the deposition of the evaporitic Codo hydrocarbon source rock, which is found on both sides of the Atlantic nowadays. Then, as the rift opened up a narrow band of open seaway, shallow marine conditions prevailed and both sides of the Central Atlantic experienced deposition of deltaic and shallow marine sands. These have been identified and exploited as reservoirs throughout the West African transform margin and similar reservoir systems have also produced hydrocarbons on the Brazilian margin.

From Upper Cretaceous times, as the South American and African plates kept drifting apart, deep open marine conditions dominated. A number of similar marine source rock intervals were deposited on either side of the equatorial Atlantic margins, as well as deepwater turbiditic sands. It is within these sands that a number of recent discoveries have been made, on the African and South American margins (Jubilee, Mercury, Venus, Zaedyus, etc.).

OE: What seismic survey technologies and techniques were used in the EM?

Braga: Broadband seismic acquisition, using CGG's benchmark BroadSeis solution for highest-resolution imaging at the reservoir level; pre-stack depth migration for accurate imaging of the reservoir; and

Right: Kita Brasil and Luiz Braga Ph.D at CGG's Technology Center, Rio de Janeiro. Below: View of one of the seismic imaging suites at the CGG Technology Center, Rio de Janeiro.
Photos by Claudio Paschoa.



Above: Natal Port in the State of Rio Grande do Norte, one of the gateways to the equatorial margin. Photo from CGG.

Left: Distances from available ports to basins at the Brazilian equatorial margin. Image from Brasco.

expertise from our Rio subsurface imaging center, resulting in high-quality data and local content.

OE: What visualization technologies were used by CGG and what are the advantages of these visualization technologies?

Braga: CGG carried out interpretation of its regional multi-client seismic data to build understanding of the regional petroleum geology including 10,000sq km of 3D seismic. Attention was paid to the gravity-driven structures, trying to understand how their characteristics change from one basin to another and how this may affect hydrocarbon prospectivity in the Upper Cretaceous and Tertiary intervals.

New 3D surveys are being acquired throughout the Fóz do Amazonas, Barreirinhas and Ceará basins targeting these deepwater plays. These surveys cover an area of approximately 32,000sq km, using CGG's BroadSeis broadband seismic technology to increase the resolution of the main reservoir intervals.

OE: What are the differences in characteristics between shallow and deepwater plays at the Brazilian EM?

Braga: The deepwater plays consist mainly of deep marine sand turbidites stratigraphically trapped on the main continental slope, with the predominant source rocks being Cenomanian-Turonian-aged black shales.

The shallow water plays are found within older strata from the pre-rift and syn-rift sequences. The reservoir consists of predominantly fluvio-deltaic deposits of Neocomian to Albian age, structurally trapped within tilted fault blocks, the main hydrocarbon source rock being the Late Aptian-aged, shallow lacustrine Codo shales. This shallow water play has been successfully explored for many years on the Brazilian shelf, whereas the deepwater turbidite plays are fairly recent, and follow the success of the African equivalent margin.

The Upper Cretaceous section is also affected by major gravitational collapses and mega-slides due to significant sediment supplies and the steepness of the continental slope. This means that the sedimentary section in the shallow water areas is mostly affected by extensional faulting whereas it is dominated by compressional structures and thrusting in the deepwater regions. Thus, gravitational faulting may have a significant impact on the Upper Cretaceous plays (i.e. seal breach by faulting on the downside or additional structural traps on the upside).

OE: What can you tell us about future seismic survey plans for the equatorial margin?

Braga: With over 50 years of experience and continuous operations in Brazil, CGG has built up a unique 3D data library in the equatorial margin basins. We will continue to follow the exploration program in the area, and extend the library when and where possible with sufficient industry funding.

OE: What are the main challenges you faced in terms of local infrastructure during the seismic survey campaign?

Braga: It's two-fold: Complicated logistics to ensure non-stop continuous operations offshore; and it's a difficult environment with strong sea currents

OE: What are the main characteristics and advantages of using a seismic survey vessel such as the MV *Oceanic Endeavour*?

Braga: The vessel is the best in term of propulsion, redundancy and equipment (including Sercel Sentinel RD streamers) allowing us to safely deploy a spread of 12 seismic cables, 8000m long, in a difficult environment. The vessel also has an excellent HSE record. The choice of the vessel was critical for conducting a safe operation with a heavy geophysical spread. There have been no problems so far, either with currents or with the strong tidal variations in the area.

OE: What can you tell us about the partnership between CCG and Spectrum?

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Braga: Spectrum had acquired in-depth knowledge of the Fóz do Amazonas area because of the intensive 2D program they acquired in 2011 and 2012. This knowledge complemented nicely CGG's expertise in 3D acquisition, 3D subsurface imaging, as well as the local-content capabilities of CGG's centers in Brazil. The partnership meant we were able to provide integrated solutions to our customers and secure the environmental permit very quickly.

Logistics and environmental issues

There is very limited infrastructure, such as ports and port equipment, refineries, equipment transportation, offshore aviation, environmental services and specialized labor along the EM. With most of Brazil's oil and gas production centered in the southeast, the government has focused on developing the offshore hydrocarbon potential of the north and northeast coasts in order to attain a more even distribution of oil production in the country while encouraging the development of other emerging regions.

Operators will need to invest in building up support centers and training centers in the area, as qualified local content in northern Brazil is hardly abundant. For operators engaged in exploration drilling, with no guarantee of successfully uncorking reservoirs, large infrastructure investments ashore can be a serious risk.

- From in Rio de Janeiro, distances to main suppliers are also sizeable. The distance from Macapá, capital of the state of Amapá, to Rio de Janeiro is 3600km; from Belém, capital of the state of Pará, it is 3150km; from São Luís, capital of the state of Maranhão, it is 2900km; and from Fortaleza, capital of the state of Ceará, it is 2600km. Distances from the exploration blocks to the shore at Fóz do Amazonas, Pará Maranhão and Barreirinhas basins are long; even at the presalt basins, distances are shorter than at the Fóz do Amazonas and Pará Maranhão basins.
- Macapá in Amapá to the Fóz do Amazonas basin – 610km
- Belém in Pará to the Fóz do Amazonas basin – 720km
- Belém in Pará to the Pará-Maranhão basin – 455km
- São Luiz in Maranhão to the Pará-Maranhão basin – 375km
- São Luiz in Maranhão to the Barreirinhas basin – 235km
- Rio de Janeiro to the Santos basin – 300km

Since much of the supply transportation may need to be by land, these long distances may cause delays in delivery of supplies and increase costs. "Some solutions to the long distances from the equatorial margin to the supply base in Rio, in terms of land logistics, may involve multiclient freight consolidation and optimization and the possibility of creating distribution centers in the region," said Renata Pereira, executive director of Brasco, a Brazilian offshore logistics company, and part of the Wilson Sons Group.

Companies involved in EM exploration will also face challenges in securing dedicated shore bases and vessel availability.

"There is the possibility of using shared supply bases (regional clusters), shared management and supply of vessels (vessel sharing/pool) and rig clubs," Pereira said.

Another logistics problem is related to the local mining industry, because a considerable amount of the available private port terminals belong to mining and steel companies (Anglo Ferrous,Vale do Rio Doce, and Alumar), especially in Macapá and São Luís.

Other logistics challenges involve developing an efficient local supplier chain and addressing the difficulties faced by offshore aviation, such as the need of aircraft charter for long-distance flights, with few options for takeoff and landing. It may be necessary to have some form of floating hotel and helicopter hub between the coast and the plays in order to transport rig workers, due to the long distances involved.

Oil spill response infrastructure will also need to be large and robust to be capable of dealing with the strong currents and large tide variations, as these remote seas and shores are home to the largest mangrove coast in the world and are also dotted by Coastal Conservation Areas, Marine National Parks, and major river mouths. Primary environmental studies will also need to be made along most of the northern coast, onshore and offshore. This will increase field development costs and may also delay exploratory drilling operations. In some instances Brazil's Environmental Agency (Ibama) may not grant environmental licenses to some exploration blocks acquired during the 11th bidding round after environmental studies are analyzed.

Also, according to Pereira, some of the potential logistics bases are located within the "Legal Amazon," which demands a compulsory maintenance of 80% of the native vegetation. This may lead to restrictions in backyard availability. As mentioned earlier, there will be the need to establish more complex and efficient emergency response infrastructure along the EM in order to

Pecém port in the state of Ceará is another gateway to the equatorial margin.
Photo from Porto de Pecém.

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Renata Pereira, Executive Director, Brasco (Wilson Sons Group). Photo by Claudio Paschoa.

protect the various sensitive ecosystems in the region. "Local markets lack certified waste destinations, and in general, local institutions have little experience working with the oil and gas industry."

Exploration challenges

Currents along the water column can be very challenging. It is not uncommon to encounter currents with speeds of up to 1 m/sec (1.94Kt). In some areas along the EM, the operator needs to place the rig dozens of kilometers against the current, before starting to lower a blowout preventer or other subsea equipment to land it at the planned location on the seabed.

There have already been a significant number of incidents where rigs have been pushed out of position by the powerful currents. On average, this occurs much more frequently at the EM than at any other oil basin off Brazil.

Petrobras even had to abandon a well due to mechanical problems caused by strong subsea currents at the EM in 2012 and recent Petrobras tenders have been specifying more powerful AHTSs and ROVs due to the force of the North coast currents.

Tide and wind dynamics have a stronger influence on sea conditions at the shallow continental shelf than in deep water, while deepwater locations are affected by strong surface and deepwater currents that can run hundreds of meters deep and potentially up to 100km wide.

These currents are capable of creating shifting vortices that can affect localized current direction and speed, causing cross-currents, which can be even stronger than the normal currents, significantly increasing the forces placed on risers, flowlines, and other subsea equipment.

During OTC Brasil 2013, Petrobras E&P Director, José Miranda Formigli Filho estimated that by 2020, presalt production will represent 50% of Petrobras' output, with the potential to reach 31 billion boe. By 2035, he said 39 million boe/d of new crude oil supply will be needed.

Currently, 30% of the company's exploration investments are directed to consolidation and appraisal of presalt and transfer of rights areas. The post-salt will stay with a 70% stake, including new discoveries taking place in Sergipe-Alagoas and Espírito Santo basins and the promising equatorial margin, a 36,897sq mi. (95,563sq km) area that includes 192 exploration sites, 59 evaluation plans, and a few significant discoveries.

Formigli explained that geological and geophysical (G&G) efforts led the company to find promising plays through integrated technologies such as well log modeling and simulation; calibration

of imaging; rock pore space characterization; rock physics modeling; rock and fluid interaction; sedimentological contextualization; 3D imaging and direct hydrocarbon indicators, and petrophysical properties. He also explained that Petrobras was able to test these technologies in West African countries such as in Benin, Angola, Gabon, Namibia and Nigeria.

Magda Chambriard, director of the ANP (National Petroleum Agency), echoed Formigli when commenting that the Brazilian equatorial margin acreage offered in Brazil's 11th bidding round bears similarities to oil-producing regions in Africa's equatorial margin.

She also commented on why the 11th round of bidding did not concentrate in southeast Brazil: 'The majority of the offer is situated in basins far from the presalt polygon. This has been done in order to decentralize the pattern of investment in Brazil, in which hydrocarbons investment is concentrated in the southeast."

North coast

G&G efforts, along with core sampling and exploratory drilling will be vital in pinpointing new reservoirs along Brazil's equatorial margin, which runs from the border of the state of Amapá with French Guiana, passing through the Amazon River basin all the way to the state of Rio Grande do Norte, where the coast turns downwards and where the northeast coast begins.

Petrobras has great expectations for the north coast, but faces serious environmental and infrastructure challenges to develop resources there.

Market share per basin in the equatorial margin

Basin	Petrobras	Other
Espirito Santo	70%	30%
Campos	69%	31%
Santos	68%	32%
Potiguar	88%	13%
Ceará	50%	50%
Pará-Maranhão	50%	50%
Barreitinhas	18%	82%
Fóz do Amazonas	13%	88%
Pernambuco	43%	57%
Total Brazil:	66%	34%

Only 50km from Brazil's border with French Guiana, the Zaedyus prospect, discovered in September 2011 and the first deepwater well uncorked in French Guiana at a water depth of 2048m, is forecast to hold 700MMboe in untapped reserves, highlighting the potential of equatorial margin.

"We are confident that other opportunities will be identified by the exploration professionals in the equatorial margin," Formigli said.

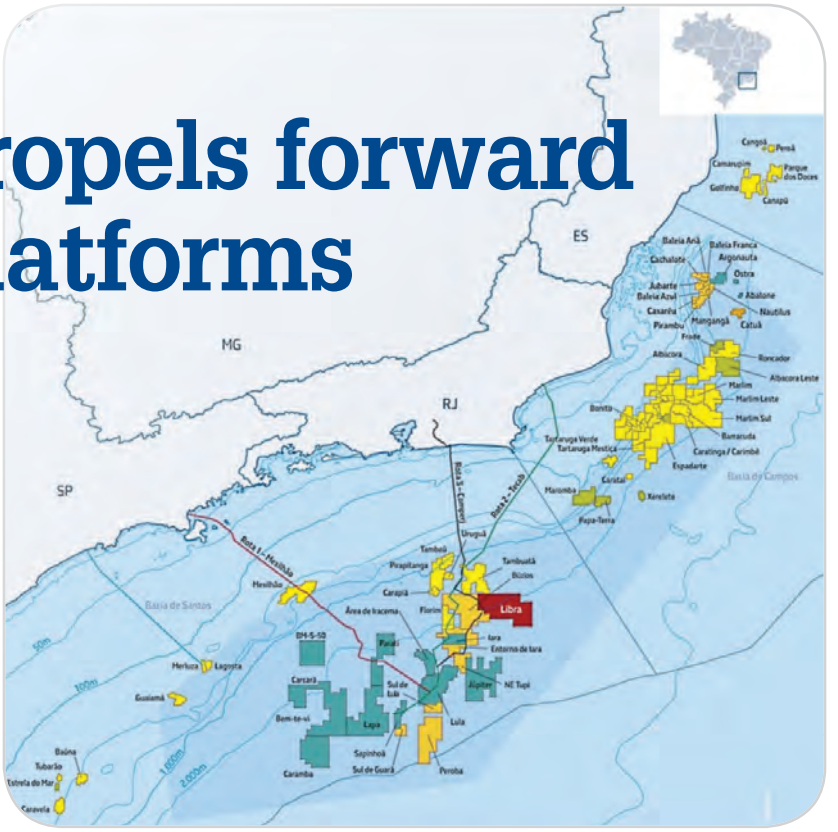
Petrobras recently reported that it has completed drilling a wildcat well in the deep waters of the Potiguar basin.

The results confirm the discovery of intermediate oil (24°API). The well, informally called Pitu, sits at water depth of 5679ft (1731m), and is 34mi. (55km) off the Rio Grande do Norte. The well reached a total depth of 17,562 ft (5353m) and intersected a hydrocarbon column of 616 ft (188m). A formation test was carried out, which confirmed satisfactory permeability and porosity in the reservoir.

There have also been indications of a significant discovery in deep water at Pará-Maranhão, but this has not been confirmed by Petrobras yet. OE

Petrobras propels forward with new platforms

Petrobras' demanding newbuild platform schedule proves that the Brazilian giant believes that presalt production shows no sign of slowing down. Peter Howard Wertheim delves into the details of Petrobras' plethora of platforms coming online between now and 2020.



Map of major field projects in Campos and Santos basins, Brazil.

Between 2013 and 2017, 25 platforms are scheduled to come onstream while 38 new units will start producing oil and gas in the period ranging from 2013 to 2020, said Petrobras director for Exploration and Production, José Formigli, who added that "very few companies in the world have such a demand for new units. That is because they do not have the portfolio we have," highlighting the 100% exploration success rate in the massive oil and gas reserves in the presalt.

Formigli says that Petrobras is working to reach by 2016 an output of 2.5MMb/d from the present 2 MMb/d. By 2017, the volume should rise to 2.75 million and, in 2020, to 4.2 million. Production in barrels of oil equivalent (oil and gas, boe) is expected to reach 3 MMboe in 2016, 3.4 MMboe in 2017, and 5.2 MMboe in 2020.

He adds that the presalt will play an increasing role in that growth in production. The 1 MMb/d mark at the presalt will be surpassed in 2017, when it will account for 42% of the country's production and reach 2.1 MMb/d in 2020. At present, output per day is of around 320,000 b/d in the presalt.

Petrobras achieved an amazing feat in 2013 when it completed construction of nine new offshore platforms. Of these nine, four are already onstream.

FPSO *Cidade São Paulo* is operating in the Sapinhoá pilot project, in Santos basin's presalt, with processing capacity of 120,000bo/d and 5MMcu. m/d natural gas. The project is on schedule and is one of the largest in Santos basin. Production at the Sapinhoa field in Block BM-S-9 began in January 2013.

FPSO *Cidade Itajaí* is operating at the Baúna site, also in the Santos basin, with 80,000bo/d and 2 MMcu.m/d of gas processing capacity.

FPSO *Cidade Paraty*, operating at the Pilot project Lula NE, Santos basin, processing 120,000bo/d and 5 MMcu.m/d of natural gas.

FPSO *P-63* is operating at Papa-Terra field, Campos basin, with processing capacity of 140,000bo/d and 1 MMcu. m/d gas. Wells will be connected to *P-63* using flexible subsea pipes with electric heating.

The ***P-55*** semisubmersible at Roncador III, Campos basin, has a processing capacity of 180,000bo/d and 6 MMcu.m/d of gas. At present, the company is installing the seventh of eight tendons for the *P-55* platform, built at the Brasfels Shipyard in Angra dos Reis (Rio de Janeiro).

After this stage is completed, McDermott will install the topsides and conclude with anchoring the unit. The project has the support of a DP3 ship for the installation, plus two jumbo heavy-lift ships, and will use 9000m of tendons, eight anchoring stakes, eight flotation modules, and 130 pipe and pipeline connectors.

FPSO P-58, completed in 2013, is scheduled to come onstream 1Q 2014 at North Parque das Baleias, Campos basin. The unit's processing capacity is of 180,000bo/d and 6 MMcu.m/d of gas. The *P-58* is located about 85 km off the Espírito Santo state coast, in 1400m of water. It will be connected to 15 production wells, of which eight are pre-salt and seven are post-salt, and with 9 injection wells in the Baleia Franca, Cachalote, Jubarte, Baleia Azul, and Baleia Anã fields. This will require about 250km of flexible pipe and two underwater manifolds (to transfer the oil from the wells to the platform). The oil will be pumped into tankers, and natural gas sent by pipeline to the Cacimbas Gas Treatment Unit, in Linhares, Espírito Santo.

FPSO *P-62* was completed in 2013 and has a processing capacity of 180,000bo/d and 6 MMcu.m/d of gas. The unit is now at Roncador IV field, Campos basin and is forecasted to come onstream in 2Q 2014.

P-61 operation is expected to start in 2Q 2014 in the Papa-Terra field. It was moved to Campos Basin last December, after the unit's construction conclusion, featuring 140,000bo/d and gas compression plus 1 MMcu.m/d processing capacity. *P-61* is anchored in 1200m of water

and is able to inject 340,000bbl of water. The platform *P-61* is also the first tension leg wellhead platform (TLWP) to be connected to 13 production wells to operate in Brazil. These wells will be drilled and completed from the unit. The hull was built and integrated at the BrasFels Shipyard in Angra dos Reis, Rio de Janeiro state. The topsides were built in Singapore. In Brazil, the work generated nearly 2450 direct jobs, 7350 indirect jobs, and achieved 67% local content.

The *SS-88* type TAD (tender-assisted drilling) is a semisubmersible platform chartered by Petrobras, together with the American company BassDrill, to provide drilling and well completion services, also in the Papa-Terra field. The *SS-88* TAD will work together with the *P-61* production platform. The *SS-88* platform was built at Dalian Shipbuilding Industry Co. (DSIC) in China, and Superior Derrick Services (SDS) in the US. The *SS-88* TAD will be anchored alongside the *P-61* platform and has a modularized drilling package that will be set up on the deck of the *P-61* platform. The *SS-88* TAD will supply energy, provide accommodation, store drilling fluid and support systems to enable wells to be drilled from the *P-61* platform. It is expected to come onstream during Q2 this year.

In the Papa-Terra field, *P-61* and the TAD will work together with the FPSO *P-63*, which began oil production last November 11. *P-61* will be connected to dry completion wells, with control valves located on the platform instead of the seabed. All 18 wells will be fitted with submersible centrifugal pumps. Output from *P-61* will be transferred by multiphase flow to FPSO *P-63*. The oil will be offloaded using shuttle tankers and excess gas will be reinjected into a nearby reservoir. The project is a joint venture between Petrobras (62.5%) and Chevron (37.5%).

Petrobras strategic projects of the 2013-2017 Business and Management Plan also forecasts to place onstream the following platforms during 2014.

FPSO *Cidade Ilhabela* at Sapinhoá Norte in Santos basin presalt, forecast for 3Q 2014 with processing capacity of 150,000bo/d and gas compression at 6MMcu. m/d gas.

Well 1-SP-55 was the first to be connected to FPSO *Cidade de São Paulo* and will flow at a restricted rate of 15,000bo/d while gas processing and reinjection equipment is commissioned. Then, the well will be flowed at a production rate of 25,000bo/d. Ten additional wells will be utilized by the FPSO consisting of five production wells alongside five injection wells. Peak field production is expected to occur in the second half of 2014 with the addition of a second FPSO, the *Cidade de Ilhabela*. Both vessels will provide a combined production capability of 270,000bo/d and 388 MMcf/d of gas.

FPSO *Cidade Mangaratiba* at Iracema Sul field, forecasted to come onstream by the 4Q 2014 with processing capacity of 150,000bo/d and 8MM cu.m/d of gas.

Brazil oil/gas industry: equipment and materials required for 2012-2017

	Unit	2012	2013	2014	2015	2016	2017	Total
Pumps	un	899	1.737	942	381	96	331	4.386
Compressors	un	174	54	51	23	40	45	387
Cranes	un	23	25	24	8	7	6	93
Structure Steel (Ships Hull)	t	205.100	45.600	31.750	29.600	70.900	70.900	453.850
Structure Steel (Plataforms Hull)	t	140.000	364.000	224.000	112.000	140.000	112.000	1.092.000
Structure Steel (Rigs Hull)	t	0	120.000	120.000	120.000	120.000	80.000	560.000
Flares	un	11	12	8	6	4	5	46
Power Generators (13,8 kV)	un	32	189	14	20	27	17	299
Power Generators (0,48 kV)	un	158	0	0	0	0	0	158
Tanks	un	253	180	68	55	39	89	684
Processing Towers	un	101	119	53	0	5	17	295
Reactors	un	114	71	0	0	4	0	189
Wet Christmas Trees	un	141	117	132	114	200	244	948
Offshore Wellheads	Un	83	67	99	123	164	198	734
Dry Christmas Trees	Un	544	576	501	296	316	155	2.388
Onshore Wellheads	un	550	580	503	296	333	181	2.443
Manifolds	un	10	24	17	21	35	26	133
Umbilicals	km	551	817	717	648	1.192	1.901	5.826
Tubing (Onshore)	t	28.681	28.681	28.681	28.681	28.681	28.681	172.084
Tubing (Offshore)	t	13.947	13.947	13.947	13.947	13.947	13.947	83.682
Flexible pipes	km	769	1.409	1.493	812	1.637	2.416	8.536
Risers	km	223	294	412	456	606	995	2.986
Turbines (Gas)	un	41	38	18	12	16	26	151
Turbines (Steam)	un	28	91	67	0	0	17	203
Special alloys for tubing and casings	t	2.470	3.293	5.927	6.256	11.525	11.854	41.325
Turbo generators	un	32	37	12	8	12	37	138
Polyester mooring cables	km	182	249	319	113	170	114	1.147
Fiberglass pipelines	km	425	128	353	353	353	353	1.966
Electrical cables for CSP	km	9.362	8.487	10.073	10.363	0	0	38.485
Steam generators	un	0	0	0	0	0	0	0
HCC reactors	un	0	5	0	0	4	0	9
Special alloy boilers, reactors, towers, and pressure valves	un	64	79	67	0	4	5	219
Heat exchangers	un	7	61	63	65	0	0	196
Reformer furnaces	un	3	6	0	0	0	0	9

(**) This list does not exhaust all the equipment and materials required for 2011-2016 period.

Source: Brazil Business Link – Rio de Janeiro

The chart was presented by Pedro Vassalo Maia da Costa, Director of Brazil Business Link - Rio de Janeiro, Brazil, in a study titled How to do business in Brazil. www.bblink.com.br

Typical subsea tree used offshore Brazil.
Photo from FMC Technologies Brazil.

Peter Wertheim discusses subsea technology with Nelson Leite, president of FMC Technologies Brazil.

FMC Technologies boosting Brazil's subsea installations

Subsea processing and boosting are fundamental for developing challenging fields. Benefits increase with water depths, flow rates and step-out. New technologies maximize profit and reduce operational risks.

FMC began in operating in Brazil in 1956. Nelson Leite, president of FMC Technologies Brazil speaks about subsea technologies, how FMC do Brasil is promoting advanced oil recovery and gives his opinion on what Brazil could do to be more attractive to international oil companies. He affirms that "Brazil must create the commercial support system that ensures Brazilian opportunities are appetizing, not just palatable for these international players."

"Subsea systems were born in Brazil," he says. "There was a great deal of technology developed here in the 1970s and FMC Technologies seeks to demonstrate that this legacy of excellence continues. With the opportunities offshore, there are significant openings for mounting a greater deal of equipment on the seabed, which should make operations more efficient and cost effective."

OE: How important is technology facilitating advanced oil recovery to FMC Technologies' ambitions?

Leite: There are greenfield and brownfield sites and the latter are far more difficult to produce oil from, frequently involving filtering a great deal of water from the oil reserves. The future of the fields depends on producing more oil in fields containing an ever-larger store of water. It is one reason why producing cost-efficient separation technology, parting water from oil, is so important. FMC Technologies is developing such technology together with Petrobras. Along with

boosting extraction of oil, a number of technologies are central to subsea works. Pumping and subsea construction techniques are very important to advanced oil recovery, They should be seen as key areas for investment in this respect.

OE: Would you agree with the statement that local industries do not compete with international businesses in terms of quality?

Leite: I do not agree. It is frequently difficult to find a good supplier, not just in Brazil. I would also point out that Brazil now excels in several industries, such as in the automotive and aeronautical industries. Bringing skills and talents like those developed in these enterprises to the oil and gas industry is a notable, but not insurmountable, challenge for developing Brazil's industrial capacities. There are many small suppliers in Brazil, and their contribution to the diversity and availability of parts is to be welcomed in this market. One further positive development, however, would be if they were prepared to deliver in high scale, as well as more complete unit final products. This would reduce the number of operations required to receive a desired final unit, ready for integration into a production chain. Having more advanced production and financing schemes for goods would be a great boon for Brazilian industry.

OE: Please cite which subsea technologies, FMC Technologies in Brazil is promoting for advanced oil recovery.

Leite: FMC Technologies has developed solutions to increase oil recovery such as subsea separation, subsea boosting and subsea intervention tools that allow well access without the need of a rig.
In Brazil, FMC Technologies developed and delivered to Petrobras many subsea boosting modules for ESP (either vertical and horizontal configuration) and the oil/water separation and water injection for the Marlin field. For Shell, at Parque das Conchas, a subsea artificial lift manifold was developed with retrievable processing modules, capable of performing the gas liquid separation and boosting which enhances the ESP efficiency. We believe the positive results achieved with such technologies provide field-proven alternative solutions to be considered by the operators to improve production either in green or brown fields.

Nelson Leite

OE: FMC Technologies has a contract with Petrobras to develop specific technologies. Please give some examples of some specific technologies and their purposes?

Leite: FMC Tecnologies do Brasil has a memorandum of understanding (MOU) with Petrobras that defines and shares common vision of future technologies need. Basically, that agreement was intended to develop or to expand subsea processing technologies to allow field development solutions to increase oil recovery and, in the future, consider production from subsea to shallow or to the shore.
The most significant technology example is the Marlim SSAO. The heavy oil water subsea separation system (SSAO) for the Petrobras Marlim field was the first full-scale prototype tested in the Technology Center (located in the Rio de Janeiro's Federal University (UFRJ), which was later installed in the field during 2012.

The main purpose of this prototype project was to develop a subsea technology solution to reduce the amount of produced water that reaches the topside processing facility, by doing this, oil production is increased and the topside process plant efficiency is enhanced.

The subsea system combines multiple separation technologies to deal with gas, heavy oil, water and sand. Basically, after the gas is separated, the water is also separated from the heavy oil by using the pipe separation design and then cyclone separation modules, further cleaning the water before having it pumped and injected back in the reservoir. The separated oil, gas and sand are recombined to flow to the surface facility. The subsea test confirmed performance expected from the design and qualification program which further support the trend to apply such solution in a near future.

OE: Regarding new operators, what Brazil could do to be more attractive for international oil companies?

Leite: Brazil has very large potential areas for oil and gas production and Petrobras has been playing an important role demonstrating that, but there are also many challenges. Different from Petrobras, with more than 50 year experience in Brazil, the new players will have the challenge to build its own local staff, infrastructure, logistics, supply chain and meet the local content. Taking such premises scenario, Brazil should be more attractive by creating local conditions to reduce risk and provide long term opportunities. This a complex issue as there are many opportunities improvement areas under the government decisions and in the industry, such as keep or improve frequency the concessions bid rounds, tax regimes, supply chain and logistics just to mention some.

OE: FMC Technologies signed a $1.5 billion contract with Petrobras. What is the status of the work?

Leite: In 2012, FMC Technologies do Brasil inked with Petrobras a US$1.5 billion contract to supply up to 130 subsea trees to be installed in the pre-salt fields. The scope of supply also consider subsea multiplex control module for each tree and installations tools. Along with that contract, we received the first call-off for 78 trees, then, in 2013, we received the final call-off for 49 trees, achieving a total of 127 trees. The project has been designed at our technology center and it is currently under manufacturing in our plant, both located in Rio de Janeiro. We expect delivery to start this year.

The company made significant investments in operations in Brazil to enable large scale manufacturing and development of new technologies. In the last three years, the technology center was built, plus plant capacity and subsea services expanded. OE

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Simulation solutions

Audrey Leon spoke with Kongsberg Maritime about their range of simulator training services in Rio de Janiero.

Kongsberg Maritime is no stranger to simulator training services. The company has worked for years to provide operators and service providers with the knowledge to run complicated technologies effectively.

Maersk is a long-time customer and even uses Kongsberg's dynamic positioning (DP) simulator in its own training facilities, including its brand new training services center in Barra da Tijuca, Rio de Janeiro, which opened last June (OE: May 2013).

It is easy to get the full effect of what it is like to be onboard an offshore vessel once you have stepped inside a simulator room. The computerized waves on screen contain just enough bobbing and weaving motions to make one sick to their stomach, if you have not yet developed your sea legs. The life-like sounds piped over the speakers include humming machinery, and blaring helicopter blades, which allows students to not only adjust to the offshore environment but to encourage thinking under pressure. Of course, it's not every day when one gets to hear the eerie crunch of metal on metal as you slowly collide with another vessel. That last one is definitely not recommended, but it is good practice when millions of dollars of steel and technology are not at stake.

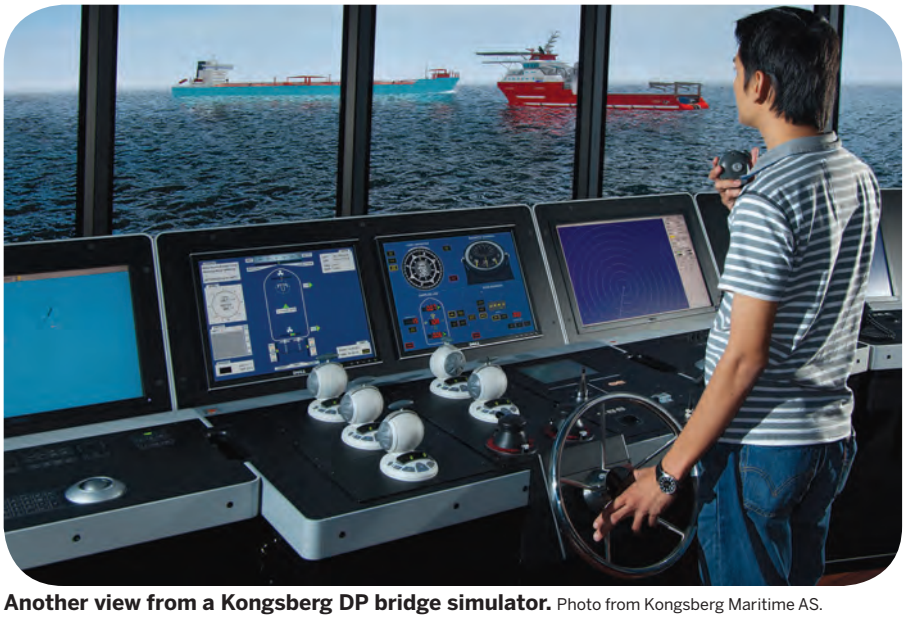
Brazil is an important market for most companies, and this is no exception for Kongsberg Maritime.

"It's important because offshore is growing there," says Clayton Burry, Vice President for Sales-Americas, at Kongsberg Maritime. "We're seeing a lot of companies go set up there. Maersk just opened a training center there. We have a lot of customers looking for training solutions, and we're trying to grow what we're doing in Rio."

A bridge simulator in action. Photo from Kongsberg Maritme AS.

The Norwegian-headquartered company first established its training center in Macae, but opted to move the center to Rio last year. "The market wanted to not travel to Macae," Burry says. "That's (Macae) where all the vessels are coming in, but we're providing training now in Rio."

Cinthya Lopes, Area Sales Manager for Simulation and Training at Kongsberg Maritime in Rio, agreed that the move



Another view from a Kongsberg DP bridge simulator. Photo from Kongsberg Maritime AS.

was inspired by customer demand.

"The logistics, once we had the training here in Rio, were better than Macae," she says. "About 70% of the students live here in Rio or very close to Rio. Those who don't, come through the airport and then they would have to go to Macae, which is about three hours driving. It was definitely a request from customers (to move)."

Lopes says Kongsberg students are not just made up of locals. Students come from all over South America including Colombia, Venezuela and Peru. For DP instruction, Kongsberg offers two course levels: basic and advanced. Training includes both theoretical and practical exercises. Kongsberg says students work with scenarios based on real operations under various simulated conditions, including failure modes. On average, there are 6-10 students for the basic and 4-6 for the advanced, Lopes says. Students receive DP certification, which is required by the Nautical Institute. Lopes says training is certified by DNV, which allows those with the certification who have applied for a license, to work in Brazil and abroad.

The newest version of Kongsberg's K-Sim DP Manoeuvring simulator, which just received certification from DNV in December, is configured with a dual redundant DP system and a 240º or wider visual scene. It includes a fully integrated power management system and is delivered with standard DP reference systems such as Artemis, Hydroacoustic Position Reference system (HPR), DPS and DARPS.

Lopes, a graduate of the merchant marines, she worked for the Brazilian Navy before coming to Kongsberg Maritime as a DP instructor. She taught for six years before switching over to sales. "It was a very good challenge," she says. "Working as a teacher allowed me to learn how to deal with different types of people, which helps with sales."

Kongsberg Maritime refurbished an older builder in Rio, and opened its doors to students in May 2013. Lopes says the Rio facility boasts six classrooms with desk top simulators, including one Class B DP simulator and one Class A simulator (navigation bridge). Lopes says the company plans to purchase another Class A simulator, which it hopes to install in 2H 2014. She says Kongsberg's Rio facility will be the only one to have a second Class A simulator.

In addition to DP training, Kongsberg offers training in electronic navigation charts as well as courses on automation and hydroacoustic systems. Lopes says the company is currently working on a new program for shuttle tanker training, which it is currently working on with Brazilian captains. "This would be a very new type of training here in Brazil," she says. "This is not requirement, but a request from customers. Currently the shuttle tanker trainers, the seafarers, need to be sent to Norway and Denmark for training. This would be something very new for Brazil.

"Not only are the logistics, but the shuttle tanker operations different from the North Sea," she says. "We have different types of operations in Brazilian waters. They want to focus on developing shuttle tanker training based on operations are conducted here in Brazilian waters. We hope in 1H 2015, we will be delivering the training."

Not the only game in town

One of the major problems with working in Brazil is finding enough qualified personnel. Lopes says Kongsberg's experience in Rio has been better.

"They're not difficult to find, but not that easy," Lopes says of qualified personnel. "All of our instructors have at least some experience onboard, and all come from maritime background.

"When people work offshore, they are used to a different lifestyle, different salaries. There are many parameters that are different from working onboard and working onshore," she says. "It's not very easy (to find people), but now that we are (located) in Rio, it has been a little bit easier."

While Lopes says Kongsberg training center does not lack students, it has ramped up its recruiting efforts.

"Our efforts are more now than before because we have competitors now in Rio," she says. "They were not here before. Five years ago, there were only two to three centers with DP training, now there are more training centers."

Including Maersk's Barra da Tijuca center, and Kongsberg's Rio outpost, the Nautical Institute in London lists other approved DP training centers including Centro de Simulação Aquaviária in Rio, L3 Communications DP & Control Systems in Barra, and The Dynamic Positioning Centre in Rio, which also uses simulators by Kongsberg and Converteam. OE

A Kongsberg DP bridge simulator at the Houston training facility. Photo by Audrey Leon/OE.

Integrating Ilhabela

Brazilian correspondant Claudio Paschoa shares his insights after visiting SBM Offshore & Synergy's Brasa yard in Niteroi to tour Petrobra's latest FPSO *Cidade de Ilhabela*.

The first time I visited the Brasa shipyard, a joint venture between SBM Offshore and Synergy, in early 2013, construction had just begun on the topside modules for the *Cidade de Ilhabela*. The scope of work looked large even back then, and yet as I drove by on the Rio-Niteroi bridge a few times a month, I could clearly see the modules taking shape. In January 2014, when the converted VLCC hull arrived at the shipyard, and with most of the modules nearing completion, I knew it was time to pay another visit to the sprawling shipyard.

Upon the arrival of the FPSO hull to Brazil, Phillipe Levy, Country Director for SBM Offshore, commented, "The arrival of FPSO *Cidade de Ilhabela* to Brazil represents a newsworthy double milestone for SBM Offshore. Firstly, the success of SBM's global project management of the hull conversion at the CXG shipyard in China. Secondly as joint venture partners with Synergy in Brasa shipyard, we are very proud to welcome her to the quayside for the final integration of 10 of her 18 modules, which were built here at Brasa in Niteroi, Rio."

Developed in 2011, through a 50/50 partnership with Brazil's Synergy group, the Brasa yard has risen from land in Niteroi that stood empty almost two years ago. "We aim to be seen as a yard that delivers on time. It's the mark of SBM and we want to build on this reputation," Levy said.

The Brasa shipyard project entailed the development of new fabrication yard facilities dedicated to complex FPSOs for the Brazilian deepwater market. The plan was for the 65,000sq m shipyard to have the capacity to assemble topside modules and integrate them with FPSO hulls. The added challenge was to build the yard while preserving the fragile ecological surroundings. The yard is situated on the Conceição Island next to the Port of Niteroi and within the environmentally sensitive Guanabara Bay. The location of the yard, which is near the entrance to the Port of Niteroi, is a heavily polluted area, dotted with ships ready for scrapping and abandoned fishing vessels. The shoreline is mostly made up of small shipyards, the port, warehouses and a fish market. SBM Offshore along with the Brasa shipyard have periodically led campaigns to remove trash from the water and coastal areas adjacent to their yard.

"Brasa shipyard was created by Synergy and SBM in order to simplify topside module integration for FPSOs, the unit currently being integrated at the yard, FPSO *Cidade de Ilhabela*, will be leased to Petrobras for production at a presalt field in the Santos Basin, Levy said. "A holding company named SNV

The FPSO *Cidade de Ilhabela* at quayside Brasa yard in Niteroi. Photo: Stephanie Chauvin/Brasa yard.

A panorama of topside modules construction underway at the Brasa shipyard. Photo: Claudio Paschoa.

was created, with its assets being the shipyard and the Pelicano 1 crane barge, with equal shares belonging to Synergy and SBM Offshore."

With the Brasa yard, SNV managed to resolve three major bottlenecks at the same location. "These bottlenecks are: the shipyard construction site, heavy lift crane barge, and integration quayside," Levy said. "Therefore allowing us to streamline production, while at the same time eliminating problems to secure suppliers and of attracting qualified workforce, by being located within a major city," Levy said. The fact that SBM Offshore's Brasa shipyard can boast almost 100% local content, in terms of workforce, by having the yard in country and by creating thousands of jobs, guaranteed SBM Offshore being well regarded by local and federal government and a preferred partner to Petrobras. This showcases SBM's successful strategy in building a private yard in Brazil, which, allayed to its established reputation in FPSO construction and operation, gives the company a significant advantage when competing for contracts in Brazil.

The conversion project of a VLCC to a FPSO capable of producing 150,000 bo/d and with a storage capacity of 1.6MMbbl was done in China. The work included a special mooring system add-on, inport/outport platform and main deck renewal, reinforced tank, refitted accommodation and engine room reconditioning, along with hull blasting and coatings, which were effected at the CXG yard, also known as Guangzhou Dockyards. The vessel sailed 10,625nm (19,678 km) from China and arrived in Brazilian waters in December 2013.

"The relationship with the yard is developing well and CXG is now expanding their capabilities in the piping and the E&I scope of work. SBM is very happy with the conversion of the *Ilhabela* vessel," says John Schubert, SBM Offshore Operations Director, who is based in Schiedam and is responsible for the overall project management of the Schiedam FPSO projects. "CXG is now continuing with a similar scope of work on our *Cidade de Maricá* & *Cidade de Saquarema* projects," Schubert said.

Logistics for the project was daunting with equipment suppliers from all over the world. Blue Water Shipping, provided logistics for FPSO *Cidade de Ilhabela* materials and equipment to China and Brazil. The project involved Blue Water Shipping's offices worldwide. In the past 18 months, the company handled over 1200 shipments for the project. The majority was from Europe to the yard in China, but also many shipments from the Far East and Europe to Brazil.

In terms of engineering, this project required the complete hull renewal, including the structural reinforcement to receive more than 23,000 tons of topsides, the spread mooring system, including 4x6 polyester mooring lines and specially designed chain stoppers and finally, the complete process facilities on deck, including power generation of over 110MW, oil and gas treatment, CO2 and H2S removal, water treatment

The Brasa yard with topside modules ready to be integrated to the FPSO *Cidade de Ilhabela*. Photo: Brasa Shipyard.

and injections modules, along with all the redundant safety systems required for such a vessel. Once the module integration is completed the vessel will be installed on the Sapinhoá presalt field, spread moored at a water depth of 2140m.

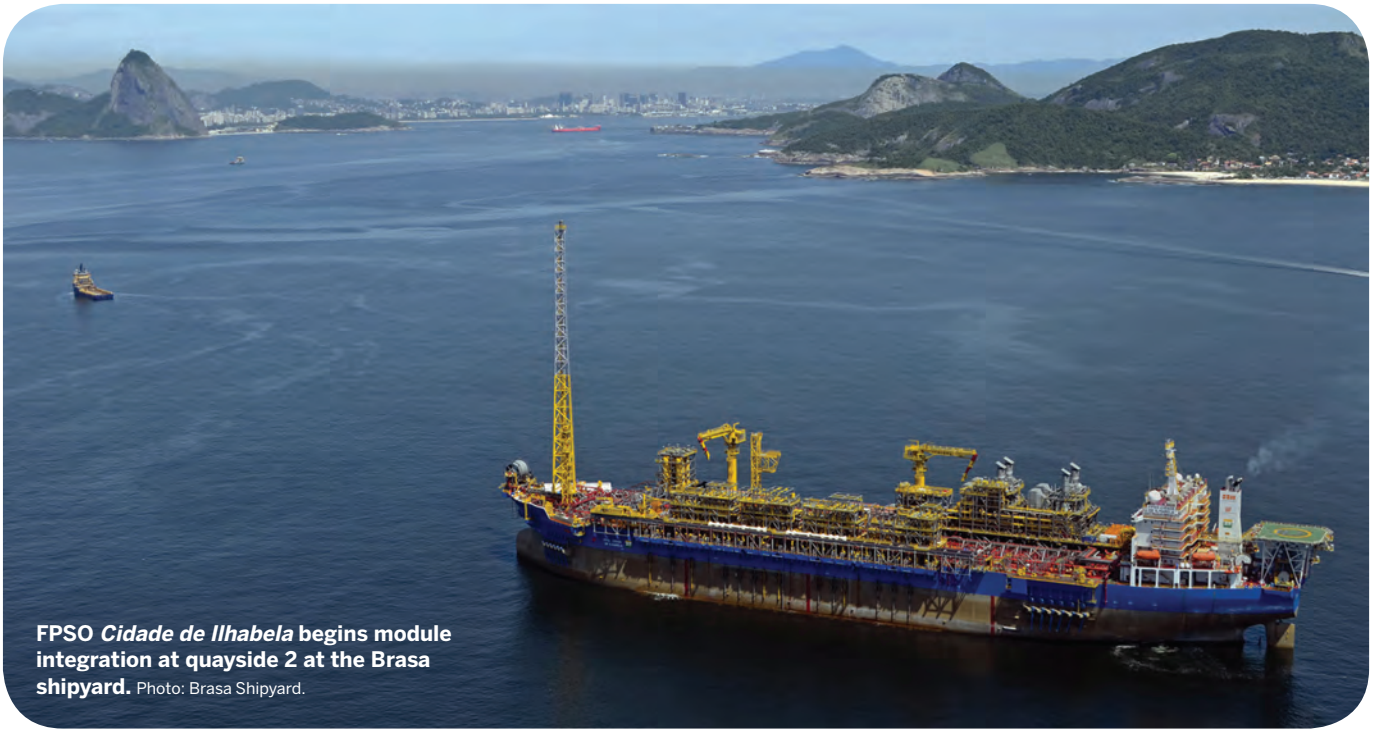
"A spread mooring system was chosen for this FPSO because of its size and the extreme water depth. With this system, a group of mooring lines is distributed over the bow and stern of the vessel to anchors on the seafloor. The vessel is positioned in a fixed heading, which is determined by the sea and weather conditions. The symmetrical arrangement of anchors helps to keep the ship on its fixed heading location. The spread mooring system does not allow the vessel to weathervane (Rotate in the horizontal plane due to wind, waves or current)," said SBM Offshore Project Manager Martijn Kleijn, who accompanied the author on a visit to the FPSO.

The FPSO *Cidade de Ilhabela* will be linked to around 20 wells, with an estimated production of 150,000 bo/d and capability to compress 6MMcu. m/d of gas. The vessel is designed to last 25 years and the newbuild accommodation block is designed for a crew of 120 persons to live in comfort. The oil produced at Sapinhoá is high quality and medium density, graded at 27° API, along with associated CO2 and traces of H2S. The consortium that owns the Sapinhoá field, in BM-S-9 block, is operated by Petrobras (45%), in partnership with BG E&P Brasil (30%) and Repsol Sinopec Brasil (25%).

The FPSO will be owned and operated by a joint venture owned by SBM Offshore with other partners including Queiroz Galvão Óleo e Gás S.A. (QGOG). Once in operation FPSO *Cidade de Ilhabela* will be SBM Offshore's largest FPSO. It is the company's second vessel in the Generation 3 model, engineered to the specifications of the presalt plays offshore Brazil. The first is FPSO *Cidade de Paraty,* which achieved first oil in June 2013. The next pair of FPSOs *Cidade de Maricá* and *Cidade de Saquarema* also for offshore Brazil, will be copies of *Cidade de Ilhabela* and their modules will also be fabricated at the Brasa shipyard.

First lifting of topside module onto FPSO *Cidade de Ilhabela* by Pelicano-1 crane. Photo: Stephanie Chauvin/Brasa shipyard.

Phillipe Levy, Country Manager in Brazil, explains SBM Offshore's strategy of building and integrating modules in Brazil. Photo: Claudio Paschoa.



FPSO *Cidade de Ilhabela* begins module integration at quayside 2 at the Brasa shipyard. Photo: Brasa Shipyard.

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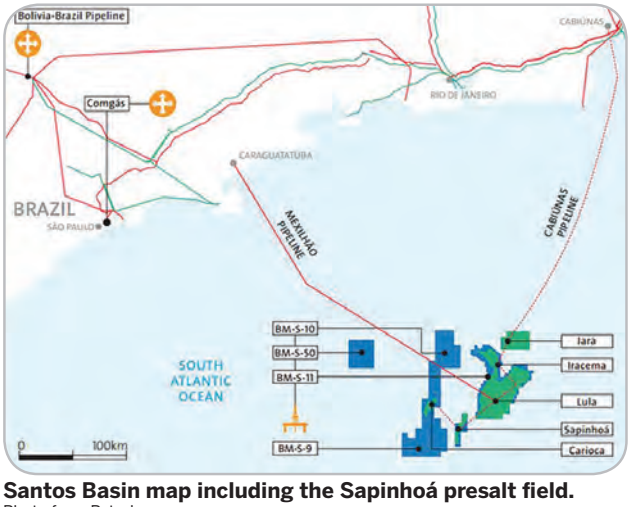
FPSO *Cidade de Ilhabela* begins module integration at quayside 2 at the Brasa shipyard.
Photo from Brasa Shipyard.

Topside Module Integration

Cidade de Ilhabela is the first FPSO to be integrated at Brasa's quay number two. Three additional modules were constructed and delivered by EBSE, a Rio de Janeiro yard that SBM works closely with as part of its development of solid local content solutions. Therefore, a total of 13 modules were built in Brazil for FPSO *Cidade de Ilhabela*.

Chief Technology Director at SBM Offshore, Mike Wyllie says, "The 23,000 tons of topsides to be carried on *Ilhabella* is by far the largest we've ever designed and constructed and it is approaching the limits of what is practical on a converted tanker. We've run out of space to spread the topsides anymore, so now we can only build upwards. On some modules we are now up to four operating levels. We're happy to keep pushing the limits of what you can do with tanker conversions because that's what we do best and it's where our core technology lies."



Santos Basin map including the Sapinhoá presalt field.
Photo from Petrobras.

The Brasa shipyard was a significant factor in helping secure the *Cidade de Ilhabela* contract and the subsequent double vessel, *Cidade de Maricá* and *Cidade de Saquarema* contract. "Petrobras gave us the awards because we have more capacity for local content," said Levy, who sits on the Board of the Joint Venture in addition to his role as Brazil Country Director for SBM Offshore.

The Brazilian scope for the conversion of the vessels is managed in close cooperation with the Rio office of SBM Offshore and a dedicated site team is in place at Brasa yard made up of combined resources from SBM's Schiedam and Rio offices. Project completion for *Cidade de Ilhabela* is scheduled for 2Q 2014.

"The arrival of FPSO *Cidade de Ilhabela* to Brazil represents a newsworthy double milestone for SBM Offshore. Firstly the success of SBM's global project management of her conversion at the CXG yard in China. Secondly as joint venture partners with Synergy in Brasa shipyard, we are very proud to welcome her to the quayside for the final integration of ten of her 18 modules, which were built here at Brasa in Niteroi, Rio," Levy said.

When asked about the safety systems aboard the new FPSO, Phillipe Levy was very direct, "Well, any FPSO is potentially explosive, so we take safety systems very seriously and we've also installed redundant systems to back them up. It would be too complicated and time consuming to talk about all these systems, but I believe it suffices to say that there has never been any major accident in any of our FPSOs and we intend to keep it that way."

When visiting the FPSO, it was easy to get lost between the maze of pipes and valves, but it was also easy to see how the module connections are well organized and how safety is considered paramount even during construction. The modules, built at the main yard, across the bay from the fitting out quay, are picked up by the Pelicano 1 crane barge from the main yard, lifted to the appropriate height and then the crane barge crosses the little bay to where the FPSO is moored and delicately lowers the module onto its selected position on deck. This sounds straightforward enough, it is however, an extremely complex operation that actually begins before sunrise, with the movement of the module to the correct loading area, an operation which is done by massive rollers, this is followed by a safety check and the connection of the huge lifting chains from the crane to the module, and more safety checks before

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FPSO *Cidade de Ilhabela*'s topside modules await integration. Photo by Claudio Paschoa.

the module is raised. The whole operation to transport a module to the FPSO deck takes nearly a whole day and was being done every Tuesday and Thursday, weather permitting.

The Pelicano 1 crane barge, following a 21-month extensive upgrade and refurbishment program, was awarded an ABS Class certificate and has officially become the highest capacity crane barge in all of Latin American. It is a joint venture between SBM Offshore and Synergy who formed the company BSL Serviços, a Brazilian shipping company which specializes in heavy lifting. The major upgrades to the Pelicano 1 included the installation of state-of-the-art instruments providing it with enhanced loading capabilities for integrating modules onto FPSOs. To complete the final stages, the crane underwent overload tests (110% of the maximum capacity) to certify the crane's safety and capacity. The tests were overseen by the crew and project team (engineers and heavy lift specialists) as well as representatives from Petrobras. ABS acted as Marine Warranty Surveyor and awarded certification of the crane barge liftinghooks for over-load with 2255MT.

The particular technical specifications of the Pelicano 1 (shallow draft, long outreach and massive lifting capacity) are a powerful combination, which SBM will employ to create value for complex projects all along the Brazilian coast. Referring to the integration of module TS-062 onto FPSO *Cidade de Ilhabela*, which took place in February 2014, Gustavo Adolfo, General Manager for Leased Production Units at Petrobras said: "This event is an important step ahead and please accept our congratulations to the team involved." All modules have now been integrated to the FPSO, with the integration actually ahead of schedule, in part due to the fact that there was very little rain and almost no storms during the summer in Rio de Janeiro.

SBM has not given a date for the final delivery of the FPSO to Petrobras, and the technicians and engineers are now checking and testing all the module systems and other integrated systems along with mandatory IMO ship safety tests and ABS certification. In Brazil, SBM Offshore is currently involved in 10 major FPSO projects, boasting an uptime performance record across their Brazilian fleet with an uptime of over 99%. OE

Subsea systems

Although not directly related to the topside module integration, it is interesting to understand how some of the modules will be connected to the production and injection wells at the Sapinhoá field. Technip was awarded by Petrobras an ultra-deepwater contract for the supply of flexible pipes for the Sapinhoá Norte field, at a water depth of up to 2500m. The contracts cover the supply of flexible pipes for oil production, gas lift, and gas injection. It also includes related equipment for the presalt, to be installed on FPSO *Cidade de Ilhabela*. The equipment is designed to operate in severe conditions of H2S and CO2 as well as to withstand high internal pressures. The full contract foresees the supply of 12.5km of flexible pipes and 4.9km of dynamic jumpers systems to be installed in risers of FPSOs in the Lula Nordeste and Sapinhoa presalt fields. The gas injection top risers are designed for high internal pressure, using the Teta profile developed by Technip's R&D team in its Flexi France plant in Le Trait, France. The gas injection top riser, together with the majority of the scope above, will be manufactured in Flexibras Açu, located on the north coast of the state of Rio de Janeiro. The remaining scope will be manufactured in Flexibras Vitória. Technip's operating center in Rio de Janeiro will perform the engineering and project management.

FPSO *Cidade de Ilhabela* details:

- Total Length - 344.9m,
- Beam - 58m,
- Height - 30.3m;
- Gross Tonnage – 160,842
- DWT - 265,243
- Storage Capacity - 1.6MMbbls
- Water depth - 2140m
- Field - Sapinhoá
- Lease Period - 20 years
- Uptime record - N/A
- Number of risers - 55 (up to 16 spare risers)
- Date first oil – 2H 2014
- Max. throughput - 150,000 bo/d
- Gas injection - 210 MMscfd
- Gas export - 140 MMscfd
- Water injection - 180,000 b/d

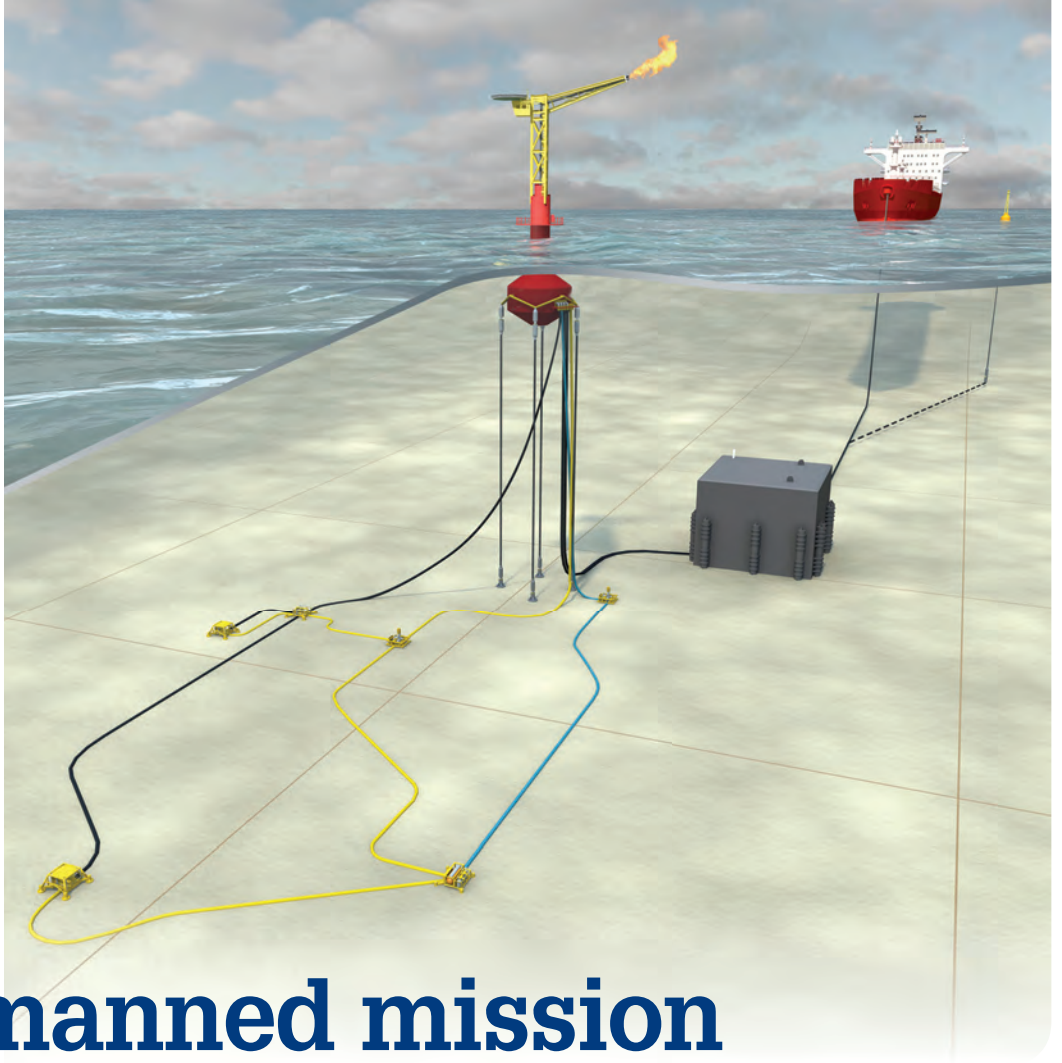
Four FPSOs in four years for Petrobras:

- 2013 *Cidade de Paraty*
- 2014 *Cidade de Ilhabela*
- 2015 *Cidade de Maricá*
- 2016 *Cidade de Saquarema*

Main highlights of *Pelicano 1* upgrade program:

- 200MT+ of steel plates re newed in the vessel's hull
- Special Survey completed hilst indry-dock
- ABS Class certificate valid for next five years
- Replacement of all wire ropes, including luffing tackle, lifting hooks and mooring winches
- Certification and overhauling of all sheaves and replacement of all bearings in the mechanical components of the lifting apparatus
- Installation of two azimuthing thrusters of c. 2500BHP (ea)
- Replacement of all four diesel generators
- Replacement of out-dated electrical cables and switch boards
- Installation of state-of-the-art instruments to aid in the operation of the crane barge
- In addition to quicker operations, greater manoeuvrability and flexibility, the installation of azimuthing thrusters has improved the crane making it safer and less polluting. ▪

Unmanned buoy technology is increasingly looking like an attractive option for marginal field developers in the North Sea and further afield. Elaine Maslin looks at why and some of the options on the market.



An unmanned mission to the North Sea

ABT Oil & Gas' production buoy concept. Image from ABT Oil & Gas.

A 20-year-old concept is receiving increasing attention in the North Sea as operators look for options to develop marginal fields.

The concept is for unmanned production buoys, which could cost-effectively support production from small or marginal fields.

About 60% of newly discovered fields have less than 20MMboe recoverable reserves, according to Guernsey-based investment firm Shore Capital.

Citing IHS data, independent, Manchester-based explorer Enegi, which is a joint venture partner in unmanned production buoy technology firm ABT Oil & Gas, says there are 88 fields in the North Sea containing less than 15MMboe, which it believes no conventional offshore unit can currently develop economically. In addition, it says there are a total 116 fields with < 30MMboe.

Many are proven discoveries that have remained undeveloped because capital and operating costs are thought to be too high to justify commercialization. As a result, the licenses in which they sit have been relinquished. Some projects, although fundamentally economic, are stranded due to a lack of nearby infrastructure.

When infrastructure is nearby, projects can also struggle to agree tariffs associated with using third party infrastructure, for oil and gas processing, storage and utility provision. In the North Sea, failure by multiple partners to negotiate satisfactory terms for tie-backs to existing infrastructure has notoriously held back a number of projects.

Unmanned production buoys could also provide an early production solution and or end of field life redevelopment concept.

To date, most buoy technology has been limited to control buoys, housing control technology for subsea wells, with remote communications, as well as power, flare, monitoring, metocean data, or offloading buoys.

Only half a dozen control or flare buoys have been installed to date, between 1993 and 2000, according to Intecsea. Two of these were conversions, from a CALM buoy and a metocean data buoy.

Last year, production buoy technology started to make the move to the mainstream. Major engineering firms AMEC and Wood Group PSN joined the market, by agreeing partnerships with technology development companies Unmanned Production Buoy (UPB) and ABT Oil & Gas, respectively. China Offshore Oil Engineering Company (COOEC) also signed an agreement with UPB for manufacturing.

Here we take a look at the technologies being developed.

Ocean Resource

Under a former name, Ocean Resource, based in Monmouthshire, UK, patented its first remotely controlled buoy concept in 1979.

Based on experience on the early Condeep platforms, in the 1970s and 1980s, and in civil engineering, the firm has engineered three buoys for offshore production: a three-tether flare buoy for

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Zafiro, off Equatorial Guinea; a control buoy for Mossgas' current E-M development off South Africa, in partnership with Mentor Subsea, a division of Dubai-based McDermott subsidiary J Ray McDermott; and the East Spar control buoy offshore Australia.

Ocean Resource also designed a 5MW power buoy for CNR International's Lyell field, in the North Sea, to provide power generation for up to 16 downhole electrical submersible pumps. The project stalled during final construction. In addition, the firm has designed and seen installed 10 other monitoring buoys over the last 20 years.

Dr. Lewis Lack, commercial director for Ocean Resource, says buoy technology is proven and there is growing demand, be it for control and power buoys, which can be used for local power or control, where space on a facility is limited or to power stranded fields where they can be tied back but do not have local control.

"They are a proven entity," Lack says. "This is why we are seeing now an upturn in offshore activity. There is strong interest in the buoys, not so much in the North Sea, but in many other regions. One area with a lot of interest right now is Perth, Australia, and the areas driven out of Australia, southeast Asia and to some extent West Africa. Buoys are one of the lowest cost structures you can put in to water to do a job, including in deeper waters."

In total, the firm has five different buoy concepts: SeaCommander, SeaPower, and SeaSentinel, for oil and gas well control, electrical submersible pump power and control, and offshore monitoring, the SeaProducer, for production, and the SeaSequestor, for CO_2 injection.

Ocean Resource's production buoy concept under construction. Photo from Ocean Resource.

SeaProducer

Ocean Resource has an agreement with ABTechnology to license SeaProducer technology for oil production systems.

The SeaProducer is the firm's production buoy concept, aimed at fields able to produce 1-20,000b/d. Its design differs from previous Ocean Resource designs in that, for installation, the buoy would be towed to the location upright, instead of horizontally, to protect production equipment. This means the design is wider than previous designs, and also with fewer decks, better facilitating integration of production equipment.

The system is designed to last 25 years, and comprises a semisubmersible buoy, taut-moored with tethers, to a gravity base, with a subsea riser connecting the production facilities to subsea wells.

An example of a configuration, the firm says the floating buoyant structure, could be 57m-high, weighing 650-tonne (dry), with a 20m hull diameter, moored to a self-installing, 4000-tonne, concrete gravity base. The production facilities, which could be stored across three or more decks, will house first and second stage separation facilities, heat generation and process control systems.

"The production process used will depend on the clients' preferences and also the produced fluid, plus availability and reliability requirements, Lack says. "As well as temperature, vacuum separation has been considered."

Up to 4.1MW of power could be generated through six 820kW on board diesel generators, using one generator as a standby, to power, via a subsea riser and seabed umbilicals, up to eight electrical submersible pumps (ESPs), or other functions requiring power. Associated gas could also be used to provide power, as well as heat for separation. ESP control will be through eight onboard variable speed units, with a ninth installed as backup.

The number of wells produced will depend on the tie-in system used, and will be driven, in most cases, by the selection of subsea system, Lack says.

The unit would include a 3m diameter access shaft for maintenance. The buoy could support a helideck. Produced liquids would be stored in subsea storage tank, positioned up to 500m away, or exported to a host facility. The storage tank size will depend on production rate and offtake frequency. Typically, Ocean Resource says it will be a 200,000 bbl concrete storage tank, weighing 13,000-tonne, using an oil water interface

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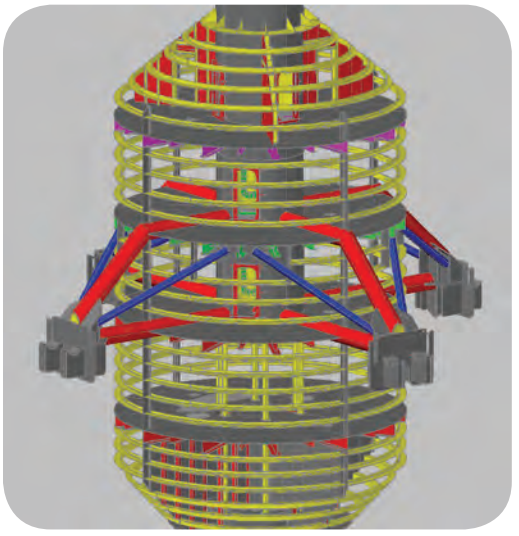
Ocean Resource's production buoy concept under construction.



Ocean Resource's production buoy concept schematic. Images from Ocean Resource.

designed to avoid high hydrostatic loading, instead using the hydrostatic pressure differential to minimize additional energy requirements to pump out the oil. Control and monitoring could be from a remote host platform or a land-based station through UHF, VHF and satellite communications.

Ocean Resource has also been investigating use of a buoy for carbon sequestration for enhanced oil recovery.

SeaSequestor would be able to store 45,000-tonne of liquid CO_2 in a subsea tank and then pump it into the seabed to support EOR. The buoy would provide power for the pumps and conditions the CO_2 so it is ready for the subsea well and condition the CO_2 to meet subsea well operating parameters.

ABT Oil & Gas

ABTechnology is part of a joint venture (JV) called ABT Oil & Gas, with Manchester-based exploration firm Enegi Oil.

The ABT JV has partnerships with Wood Group PSN for engineering on its unmanned production buoy design, which it has said would typically cost US$140 million to construct and install, and oil and gas consultancy RMRI.

The JV also has an agreement with GMC to look at unmanned self-installing buoyant platform designs for use in the North Sea (*OE: December 2013*), agreed in 2013. The company also has an agreement with Ocean Resource, which could see it use the firm's SeaProducer technology.

The company's most advanced project is the Antrim Energy-operated 9MMbbl Fyne oil field, in blocks 21/28a in the central North Sea.

Early April, ABT Oil & Gas submitted an environmental statement, for Fyne, which revealed the firm is planning to use a GMC self-installing tower design on the field. Following approval for the three-well development (two producers and one water injection well) from the UK Department of Energy and Climate Change (DECC), it will in late summer submit a field development plan, earning Enegi and ABT 50% interest in the field, as part of an agreement made with Antrim last year. First production is anticipated prior to 25 Nov 2016, a date agreed with agreed with DECC.

Late last year, ABT agreed a farm in deal with Providence Resources and its partners on the Helvick and Dunmore oil discoveries, in the North Celtic Sea basin, offshore Ireland.

The terms were for ABT to carry out an assessment of the commerciality of using its buoy technology on the fields, and to then to provide a field development plan for the scheme.

ABT's buoy

ABT's own unmanned production buoy technology is aimed at fields containing 3-30MMboe recoverable, in 60-600m water depth, with a capacity for up to 20,000b/d total fluids and 20,000b/d water injection, with any suitable number of production and injection wells tied in via subsea manifolds.

The production buoy, which is over 60m-high and up to 30m-wide, consists of a semi-submerged hull and topsides structure, with a 4500-tonne dry weight, which is taut-moored to the seabed.

Production will be based on a conventional thermal stabilization approach, says the firm. Control and process equipment, will typically consist of a two stage separation system, to remove water and gas, located on decks within the buoy, which has an access tower for maintenance. Internal power systems will be field-specific, ABT says, and will be fuelled by associated gas, with excess gas flared.

The production buoy will be linked by flow lines and flexible risers to the subsea production wells. An autonomous shutdown control system is housed inside the buoy and remote intervention is possible using radio, microwave or satellite communications, ABT says.

Crude oil is transferred and stored in a 100,000-300,000 bbl seabed storage system, made from steel, which is secured by piles driven into seabed, and from where the oil will be offloaded to a shuttle tanker.

In a recent statement, the JV partners said: "In order to maximize the opportunities to develop marginal fields, Enegi and ABT are reviewing the structure of its JV, ABT Oil and Gas, and expect to make an announcement on this in due course."

The firm added: "We are in discussions with a number of players about utilizing both our buoyant technologies on their assets. We also announced that we have farmed into the Helvick oil field and Dunmore discovery last November and work has started on evaluating the feasibility of implementing buoyant solutions to develop both."

The firm is also planning to apply for further licenses in the 28th licensing round.

Unmanned Production Buoy

Founded eight years ago, Aberdeenshire-based Unmanned Production Buoy (UPB) says it has a £756 million European field development program using unmanned buoy technology.

The plan involves three units, to

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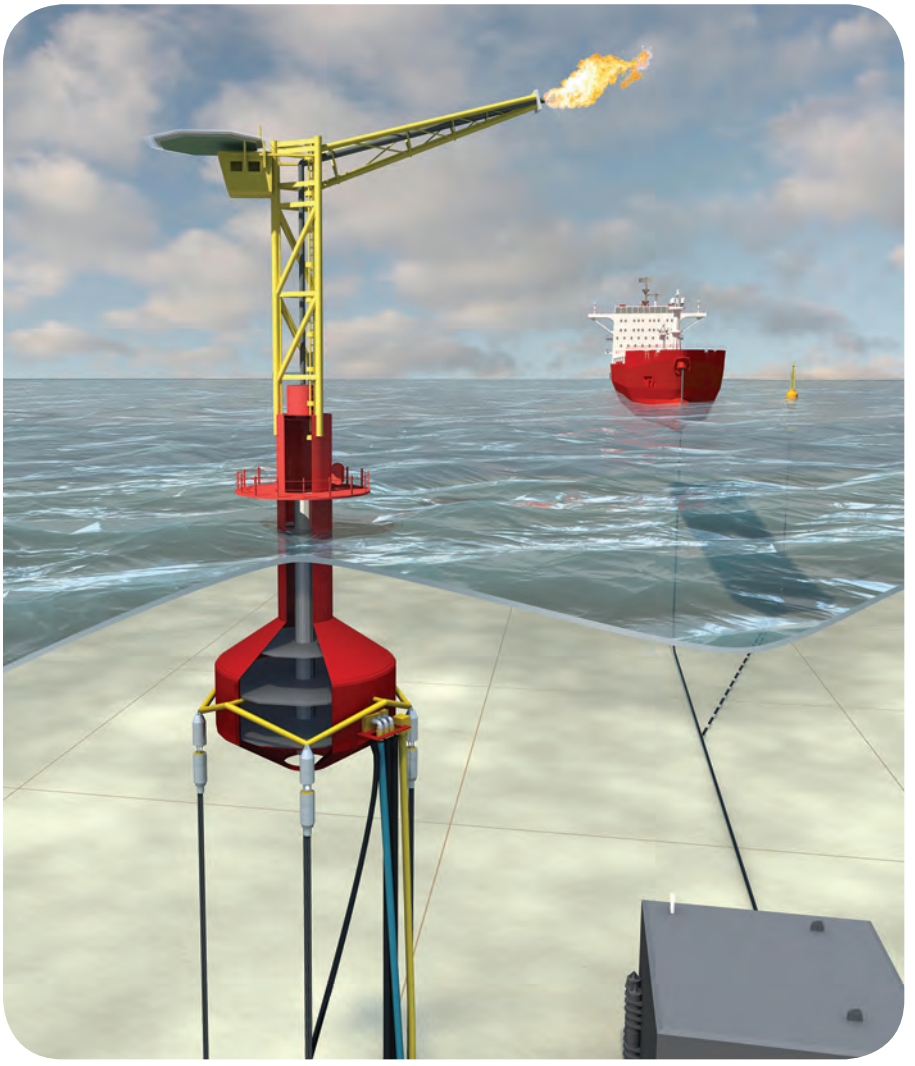

ABT Oil & Gas' production buoy concept.
Image from ABT Oil & Gas.

Unmanned Production Buoy's Richard Selwa, with a model of the firm's concept.

develop six oil fields across the UK (UPB-1), Ireland (UPB-2), and Denmark (UPB-3).

UPB's foci are producing fields which are reaching the end of their economic using a floating production vessel (FPSO), or small deposits (3-25MMbbl) that are uneconomic using manned methods (FPSO or platform).

UBP has announced a 10-year hull and shell-manufacturing deal with China Offshore Oil Engineering Co. (COOEC) and says it is close to agreeing a UK assembly site for fit-out and detailed fabrication. The first commercial units are planned to be on stream in late 2016-2017.

UPB has a memorandum of understanding with AMEC for support on engineering, procurement, construction management, and asset support services.

The first fields UPB plans to develop are Angus, with a single well, and Fife, both in the UK North Sea, and awarded to UPB in the 27th offshore licensing round, in which the company was also awarded licenses containing the Fergus and Flora fields.

Angus and Fife former producers, decommissioned by Armerada Hess, after becoming uneconomic.

An independent testing and verification program is about to start, Selwa says, as well as site survey work, for an environmental impact assessment, required for a field development plan to be approved.

The UPB system

The firm, led by founder and chairman Richard Selwa, says its reusable design is based on mass-manufacturing principles, using standardized components, based on learnings from tank farms in Canada, and the principles of onshore "nodding donkeys".

UPB's design comprises three main parts, a 1800-tonne dry-weight semi-submerged buoy, a 500-tonne subsea, steel, sealed tank system, and a combined, service riser bundle. The riser bundle will connect to up to three subsea production wells and two water injection wells, via infield flowlines, and be expected to produce 600-15,000 bo/d over a 20-year life span.

Selwa says the maximum 28m-diameter buoy and 200,000 bbl-capacity gravity-based storage tanks, both fabricated from steel, are standard designs. Depending on depth, the buoy will either be moored with a spread mooring system (60-90m) or tension leg configuration (90m+), with a standard offloading system.

The production system will be a standardized, temperature-stabilized, "nodding donkey," system, typically deploying electric submersible pumps. The electric submersible pumps will be powered using 10MW onboard generated electricity, created using flue gas for power and heating. It will also carry its own diesel supply, where there is not enough produced gas, on which it could operate for up to four months.

Process equipment, controlled via satellite, will be in an enclosed environment, so access for maintenance will be via a walk-to-work system, using a supply vessel. As a result, system availability, Selwa says, will be 60-70%, with process up time at 90%, due to not being able to get access in bad weather.

The units will be self-installing, by floating out the unit, using 2-3 tugs, and then ballasting at sea.

Selwa says while the North Sea will be the first basin to use the system, Asian countries are showing great interest in its potential, for smaller fields they would like developed quickly, or larger fields they would like production to start on early, to bring in revenues. OE

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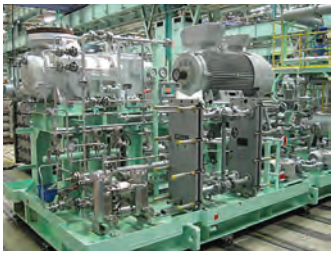

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MV *Connor Bordelon* is the host vessel for Baker Hughes new StimFORCE stimulation system in the Gulf of Mexico. Nina Rach went to Houma, Louisiana, to see the modular installation.

StimFORCE prowls the Gulf

Behind the sleek bow and spacious superstructure of MV Connor Bordelon are the StimFORCE system modules. Photo by Nina Rach.

Baker Hughes recently constructed a new stimulation vessel dedicated to the Gulf of Mexico market, the *StimFORCE GoM*. It's the newest addition to the company's fleet of vessels, facilitating well stimulation, production enhancement, acidizing, and sand control operations.

System

The Baker Hughes *StimFORCE* modular stimulation system includes a flexible pumping package, with skid-based equipment, customizable to any convenient vessel of opportunity. The system can be shipped and assembled on a platform supply vessel (PSV), barge, or offshore rig, mounted on a grid framework and secured to the vessel.

The *StimFORCE* system is DNV 2.7-1 certified and CE marked. The equipment design meets ISO dimensional standards.

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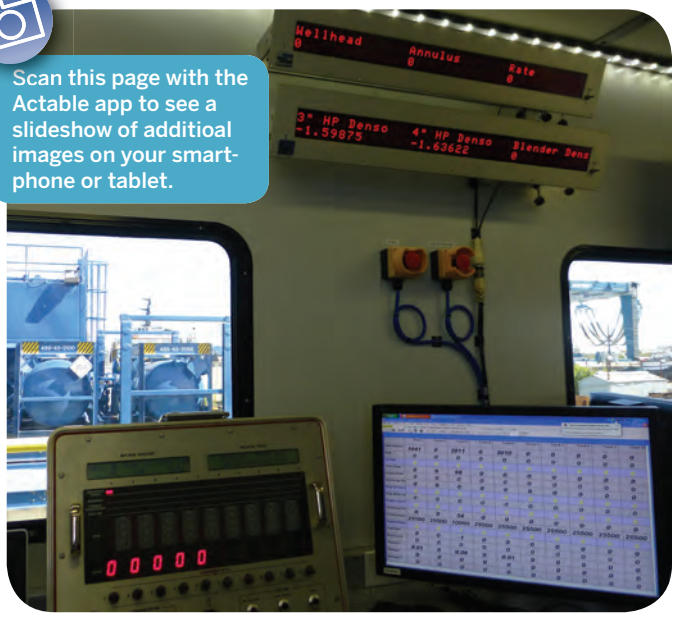


Control room monitoring screens with pressures and rates at wellhead, annulus, and umbilicals. Photo by Nina Rach.

StimFORCE GoM

It's equipped with five 15,000psi (103.4MPa) triplex pumps, and two flexible steel umbilical lines that can provide pumping rates up to 70 bbl/min (0.22 cu m/s). There is 100% redundancy on critical systems.

There is ample storage for large volumes of acid or chemical solvents, and the additional capacity lowers costs and reduces nonproductive time.

"The *StimFORCE* vessel's pumping capacity of 8800 HHP, combined with the large, flexible deck configuration allows for multiple well acid or chemical treatments in a single trip, without the need to return to the dock and resupply," said Kevin Wetherington, BHI vice president, Gulf of Mexico Geomarket. "The vessel's fluid system, quality control laboratory and remote data acquisition services ensure critical pumping information is available."

Baker Hughes JobMaster software package is integrated into the system, and simplifies all operation phases. The software acquires, processes, records, and displays pumping data in real-time, allows remote control and monitoring, with secure global wireless data transmission.

Host vessel

Baker Hughes' new stimulation service modules were installed on the newbuild MV *Connor Bordelon*, operated by Lockport, Louisiana-based Bordelon Marine LLC.

The *Connor Bordelon* is the first of three Stingray class 260 offshore support vessels (OSVs) with DP2 dynamic positioning, built at Bordelon Marine Shipbuilders yard in Houma. It was completed in September 2013 and named 'Ship of the Year' by the American Ship

Left – Deck view of control cabin (white), storage, pumps, and equipment. Photo from Baker Hughes.
Above – Coflexip hose reels and laydown reel near vessel's stern. Photo by Nina Rach.

Review 2014. The vessel has a soaring superstructure that spans the full width of the deck. The extra-wide span allows for an ample bridge, spacious accommodations for 50 people, as well as increased deck space for equipment. The bow is noticeably sleek and thinner than other OSVs, and has a soft, curved chine (underwater profile). Owner Wes Bordelon describes it as a "chine wave sweep" that functions to more efficiently lift the ship with the waves.

Most importantly, the vessel sports a 185ft x 44ft cargo deck, protected by 5ft-high bulwarks (cargo rail); ample space for all the StimFORCE modules.

The reduced vessel draft (15ft) supports shallow-water operations.

The *StimFORCE* modular stimulation system was loaded and installed on the *Connor Bordelon* in just over a week, and the vessel started sea trials out of Houma in November 2013.

Bordelon Marine's second Stingray vessel, MV *Sheila Bordelon* is nearing completion and it will be delivered toward the end of this year. The third Stingray vessel, MV *Brandon Bordelon* is in shipyard with an expected delivery date in Spring 2015. OE

Stimulating the Gulf of Mexico

Kevin Wetherington, Baker Hughes' Vice President for the Gulf of Mexico Geomarket, talked with Nina Rach about the Gulf of Mexico and the company's new *StimFORCE* well stimulation vessel.

OE: Tell us about your work in the region.

Wetherington: It's a very exciting market, one of the fastest growing in the industry. There's been increased activity and investment in deepwater, especially the ultra-deepwater frontier market, with wells in water 4000ft or deeper, and 30,000ft TD.

In 2013, Baker Hughes was involved with a high-pressure well in the Green Canyon area that set a new depth record for the Gulf of Mexico: 36,552ft TD. Baker Hughes MWD/LWD equipment was used at pressures exceeding 30,000 psi.

More generally, it's been a long-term move into the frontier market. The desired completion systems for these wells don't exist yet. In 2012, the Baker Hughes Lower Tertiary Integrated Project Team (IPT) was formed to develop new integrated completion and production

The Center for Technology Innovation in Houston. Photo from Baker Hughes.

systems. The IPT includes 100 of the brightest engineers and industry experts, assembled to develop innovative, high-performance, cost-effective, commercially feasible solutions for ultra-deepwater.

OE: It sounds very collaborative. Where is the IPT work being done?

Wetherington: The Center for Technology Innovation (CTI) in northwest Houston, which has test cells rated to 40,000 psi and 700°F. The capability is beyond the parameters that customers are asking for, which range up to 30,000 psi and 400°F.

At these depths, the high temperatures and high pressures take a toll on seals, hydraulics, electrical components. We're trying to enhance technology across the whole front.

Reliability is important; we have some requests for 10-year life and intervention-capable systems. Baker Hughes builds and tests ESPs [electric submersible pumps] in Claremore, Oklahoma for subsea and deepwater well boosting.

Product reliability and system reliability become more important with the high cost of well intervention in the deepwater market.

OE: How do you improve on operational execution and reliability?

Wetherington: For the Baker Hughes staff, we use competency assurance programs, with training and certified assessors to test competency and proficiency. It gives our employees the training and tools necessary to be able to meet and exceed current and upcoming operating requirements and government regulations.

Based on our Competence Management Program, Baker Hughes proactively sought, and was the first service company to receive, IADC Competence Assurance Accreditation to meet BSEE regulations. That was in January 2012, and now our program is global, after starting in the Gulf of Mexico, and now moving into our land markets.

The Baker Hughes operating system, BHOS, includes operational documentation, and was created to streamline our systems from the 7-9 systems we used to have, down to one. The Baker Hughes Quality organization oversees BHOS, and is rewsponsible for auditing and testing to standards.

We continuously update standards in the Gulf of Mexico, as part of our continuous process improvement program.

OE: What about your new facilities on the Gulf coast?

Wetherington: Baker Hughes has invested heavily in infrastructure. We opened a new Gulf of Mexico laboratory in Broussard, Louisiana, in April 2013, where we test cementing products, fluids, and chemicals: the Baker Hughes Center for Offshore Cementing, Fluids, and Chemicals. The lab is open 24 hr/d and is close to our operating centers. We also perform pre-job testing, as needed.

Our deepwater chemical testing is done at the new Chemicals Lab, in our Center for Technology Innovation facility in Houston. We have also made investments in various operational bases and in our facilities at Port Fourchon, to enhance our capacity and capabilities.

OE: Speaking of stimulation , what about the new Baker Hughes vessel?

Wetherington: The *StimFORCE* is now the newest stimulation vessel in the Gulf, with pumping capacity of 8800 HHP. It carries a modular, plug &

play package with a large, flexible deck configuration.

The *StimFORCE* finished final testing in Fourchon last fall, and now Baker Hughes has three well stimulation vessels in the GoM market, including the *Blue Dolphin* and the *Blue Tarpon.*

Before Macondo, there were nine stimulation vessels in the GoM. Afterward, when work slowed considerably, there were only five vessels, and with the arrival of the *StimFORCE* in 2013, there are now six.

OE: What are the stimulation needs in the Gulf?

Wetherington: The stimulation needs continue to advance, as made evident by the largest single hydraulic fracturing job on a deepwater well in the GoM, where 2.7 million lb of proppant was pumped into a single well.

OE: Can the Gulf of Mexico market support the new vessel?

Wetherington: The number of deepwater rigs entering the GoM has increased significantly since 3Q 2010, when there were fewer than ten. There were more than 40 deepwater rigs in 2013, and by the end of 2014, there may be 50 deepwater rigs in the Gulf.

OE: What's happening now in the GoM?

Wetheringon: The regulatory environment continues to evolve in this market, which increases the cost of operating, so we believe fewer service companies will have the appetite to participate, especially on the deepwater projects. Integrated systems are also becoming more important. The risk for deepwater and ultra-deepwater wells is so high that we're having more discussions with customers on integrated drilling systems, which include drill bits, drilling fluids, formation evaluation, and directional drilling. This integrated approach is also becoming more prevalent with completions and production systems.

OE: What about safety initiatives?

Wetheringon: Safety is priority one for Baker Hughes, so we ensure that our offshore workers have all the essential training, including Safe Gulf training and water survival training, and carry transportation worker identification credentials (TWIC cards).

Baker Hughes is also part of the Center for Offshore Safety (COS), a group of operators and service companies that came together after the 2010 oil spill to improve safety in the Gulf of Mexico. We focus on both personal safety and process safety, particularly when it comes to maintaining well control. BHI is committed to this effort and I personally represent Baker Hughes on the COS Governing Board. We work closely with Chevron, Shell, BP, ExxonMobil, and Anadarko, among others. OE

Kevin Wetherington *is the Baker Hughes Vice President for the Gulf of Mexico Geomarket, where he leads the Operations, Engineering, and Sales teams responsible for supporting the oil and gas operators in the offshore deepwater, shelf, inland, and land business segments. He began his career 22 years ago, as an offshore wireline field engineer in the Gulf of Mexico, and has since held numerous managerial roles in both operations and sales, both within single product lines as well as across multiple product lines.*

Round and round

A new study by RPSEA, Doris-Inc., and Sevan Marine investigates whether circular-hull FPSOs can provide a low-cost production solution for remote ultra-deepwater Gulf of Mexico operations. Audrey Leon spoke with the project leads to find out more.

US-based research nonprofit RPSEA (Research Partnership to Secure Energy for America) selected Doris-Inc. to conduct a feasibility study on circular-hull FPSOs for application in ultra-deepwater Gulf of Mexico.

This region poses many technical and economic challenges, including extreme water depth, complex Paleogene reservoirs with high pressure and temperatures, not to mention the distance from shore and existing pipeline infrastructure. The GOM also is prone to hurricanes in the summer months with high wind and high seas.

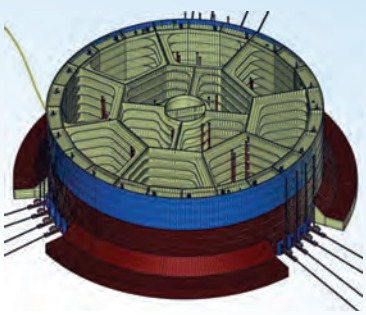
RPSEA's members discussed what other options could serve the ultra-deepwater GOM at a lower cost than giant spars and TLPs. FPSOs, mostly due to regulations and the Jones Act (1920, 46 U.S.C.A. § 688), have not been favored. However, for one operator, Brazil's Petrobras, it's the only preferred production option.

Currently, Petrobras operates the GOM's first FPSO at its Cascade/Chinook fields, approximately 250km south of Louisiana. In 2012, the *BW Pioneer* FPSO, which serves the fields, was forced to shut-in during Hurricane Isaac, a category one storm that made landfall along the coast of Louisiana on 28 August 2012, a mere six months after production first came online at the Cascade field in February 2012.

The *BW Pioneer* boasts a production capacity of 80,000bo/d and 500,000 cu. m/d of gas, and storage capacity of 500,000 bbl. It also utilizes a disconnectable riser system. In the event of a severe hurricane, the turret riser buoy can be disconnected and submerged to a depth of 46m; the buoy remains at that depth, anchored, until the storm passes and the crew can recover it back to the host vessel.

Nine hours before the storm made landfall, the buoy recorded wave heights of about 5.9m, according to a US Geological Service report entitled, "Hurricane Isaac: Observations and Analysis of Coastal Change." The FPSO was able to stay moored while shut down with its riser turret remaining in vessel, since the hurricane's winds were below the vessel's mooring capacity.

The RPSEA study aims to investigate storage options for the Central GOM. While the *BW Pioneer* ship-shaped FPSO can store 500,000 bbl, RPSEA aimed to



A moonpool was added to specs for a Sevan-designed circular FPSO to accommodates steel catenary risers. Images from Sevan Marine.

Sevan Marine's Sevan 300-designed circular FPSO, which serves Petrobras' Piranema field off Brazil.
Left: Sevan Marine's Piranema circular FPSO during offloading operations.
Photo from Sevan Marine.

study a design concept that could safely hold 1MMbbl while remaining on anchor during hurricane conditions.

Originally, RPSEA members looked at several other offshore storage options in ultra-deepwater GOM, while also looking at subsea completions concepts, says Bill Head, Project Manager, RPSEA. The members opted to investigate options for a 2MMbbl floating storage facility, which included semisubmersibles, MODUs and circular FPSOs.

Head says RPSEA wanted to start the project by assessing circulars and comparing them to ships, spars, and large semisubmersibles. Houston-based Doris-Inc., a subsidary of France's Doris Engineering, was selected as a subcontractor for the project. During the project, Doris collaborated with different stakeholders, including government and industry. Success, Head says, depends in large from support at RPSEA and the RPSEA project working group that consists of volunteer subject matter experts from six major operators: Statoil, ConocoPhillips, Chevron, Petrobras, Total and Marathon.

"Operators desire a safe, low-cost system, that feature a high level of concept maturity in order to reduce the time-to-market especially when innovative design is involved," says Jelena Vidic-Perunovic, principle investigator on the project, Doris-Inc. "An FPSO concept offering local oil storage, offloaded by use of DP shuttle tankers has been selected as the main focus in our study."

Before the study settled on circular FPSOs, Head says that the project partners didn't believe spars, could give the desired storage capabilities. "Theoretically you could build huge spars," he says. "They cost a lot more than circular. If you build a spar that size, you're investing a significant amount of money, more than you need to. A circular is portable; it is shallow draft, and you have more options where you can take it and where you can build it."

After some consideration, Head says the project partners doubted that US regulators would allow storage of 2MMbo during a hurricane, and the study parameters were downsized to 1MMbbl. "We had to get to a point where regulators wouldn't worry about what was in the container," Head says.

Vidic-Perunovic says for the study, the full life cycle of the system needed to be considered. Thus, an important element, she says, is design flexibility.

"We are applying it in terms of topside production facility flexibility with regard to uncertainties in reservoir and fluid characteristics, and the possibility for an expanded production rate of the topside facility," she says. "That way, doing a conceptual study based on a hypothetical field, Doris' team can offer a design with a wide range of application in the Gulf, which gains importance if production is expanded, in case a platform should be moved to a new location, or change in market conditions."

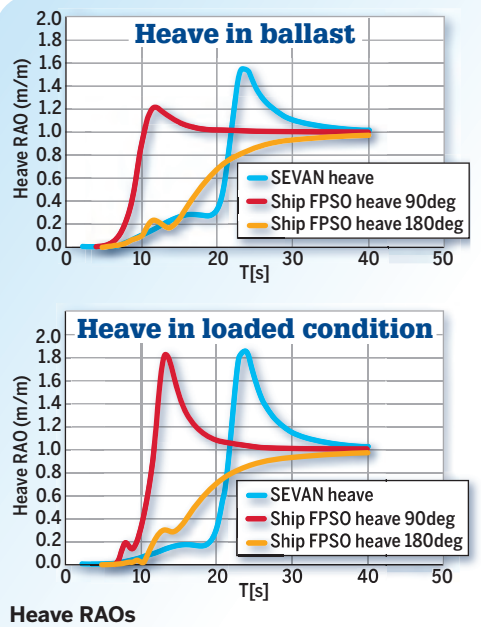
Vidic-Perunovic says the hull and riser play a dominant role in the production concept selection and may result in total cost reduction. Norway's Sevan Marine was brought into the project as it has several circular FPSOs in operation, two in the North Sea, one serving Petrobras' Piranema field off Brazil, and one (under construction at HHI in South Korea) that will eventually serve Eni Norge's Goliat field.

Vidic-Perunovic says out of many circular designs considered, Sevan's hull was selected because it featured the highest technology readiness levels.

"The technological readiness level of other Sevan's units in operation is the highest, seven according to API," she says. "They have experience with harsh environment in the North Sea, although not hurricanes. The North Sea is quite a severe environment, and the experience counts a lot."

Sevan Marine's participation included providing knowledge gained from wave tank experiments on their circular-hull FPSOs. Doris, in turn, incorporated hull hydrodynamic data for the FPSO design with steel catenary risers (SCRs), which would serve a hypothetical field in ultra-deepwater Lower Tertiary play with HPHT reservoirs and central GOM metocean conditions.

Design parameters also included a 2500m water depth, 60,000b/d initial topside production capacity, 1MMbbl storage capacity, 20-year service life,



Heave RAOs

The BW Pioneer at the Keppel Shipyard in Singapore before it became the first FPSO to serve the US Gulf of Mexico Photo from Keppel Corp.

20,000psig reservoir pressure, 13,000psig wellhead shut-in tubing pressure, and 240°F reservoir temperature.

Sevan's circular FPSOs traditionally use flexible risers in the North Sea, but SCR was selected for this study because it was the simplest and most economic riser configuration for the GOM, Vidic-Perunovic says. "SCRs are suitable for HPHT fluid conditions, which we encounter in the Lower Tertiary GOM reservoirs," she says.

The hull was designed with a central moonpool with a diameter of 30m for hanging SCRs. The hull measured 93m in diameter with a bilge box of 124m in diameter, and main deck that is 103m in diameter. The draft, ballast/loaded came in at 22m/31m.

For the study, the FPSO's hull needed to be optimized to accommodate the SCRs. The size of the bilge box was increased to temper the vertical motions, Vidic-Perunovic says. Another big difference was the introduction of a moonpool in the hull's center.

In a paper to be presented at OTC in May entitled, "Steel Catenary Riser Design for Cylindrical FPSO Application in Ultra-Deep GOM," Vidic-Perunovic and her co-authors, which includes Head, states that due to the riser hang-off location being close to the hull's center, the effect of hull angular motions on riser response is minimized.

For the excitation wave periods of interest, heave motion response amplitude operators (RAO) are smaller than that of the conventional ship-shaped FPSO, in either head- or beam-sea condition. This will result in an improved riser wave fatigue response. RAOs were calculated by Sevan Marine using the WAMIT/WADAM 3D diffraction/radiation panel method, according to the OTC paper.

"Results indicate that both strength and wave fatigue design criteria are satisfied," Vidic-Perunovic says. "In addition, the minimum effective tension in the riser touch down region remains positive in extreme 100-year hurricane condition. The study demonstrates that cylindrical FPSO in combination with a SCR is a technically feasible solution for developing ultra-deepwater GOM fields."

Because of this study, Head believes when hurricanes are involved circular trumps ship-shaped FPSOs. "There are no angles so wind and waves go around it," he says. "We have good wave tank data that shows that.

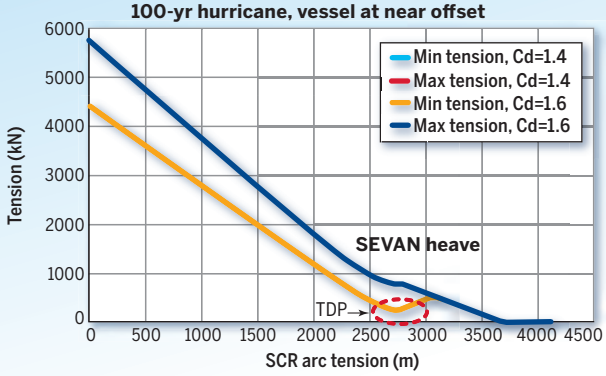
"In terms of storms and hurricanes, circular design has significant advantages over very large tankers," he says. "They have a much higher survivability than ships and MODUs, similar to spars.

"The intent of a circular FPSO is to stay on during a storm. You would have longer production, you could shut-in during the most intense part, and then come back online."

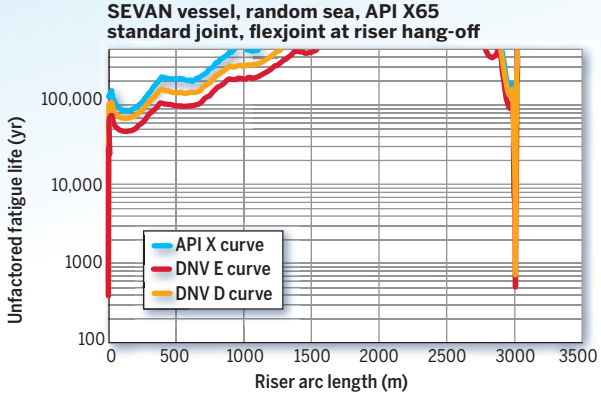
The Future

The project is ready to enter phase two study, but due to issues with the latest US Congressional budget changes to the 2005 Energy Policy Act where RPSEA receives most, but not all, of its funding, the fate of phase two is unknown.

"If DOE efforts to secure OMB approvals to release funds allocated by Congress before 9 January 2014 result in no forthcoming energy funding, we will try to pursue outside resources," Head says. Currently, Sevan Marine is cost-sharing in the project. Vidic-Perunovic is optimistic. "I hope for the best because phase two would validate the applicability of this very interesting novel production concept in ultra-deep Gulf." OE



Minimum and maximum tensions along riser arc length, 100-year hurricane (Load Case No. 4). Sensitivities on C_d.



Fatigue life along riser arc length. Source: Doris-Inc.

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OE REVIEW

AUTOMATION & SECURITY

INSIDE

Gregory Hale

Moving forward from automation awareness

Awareness is a very big word circulating around the industry these days. Awareness about automation. Things like Big Data. More awareness about safety. And a new-found enlightenment about security.

With all the changes, and fears, this awareness brings, it would be easy to just slip back into the old ways of doing things. But that just is not an option anymore.

When looking at automation, it is inevitable the technology will come on and take a firm grasp. Companies need to jump on the bandwagon or else they will end up left behind.

With a stronger push from automation and the benefits it brings, that will push more companies to figure out their security needs because attack vectors will change. When it comes to safety, suffice it to say, with more automation and a need for security, safety professionals need to ratchet it up a few more notches.

The China National Offshore Oil Corp. (CNOOC), one of China's three major national oil companies, knows all about the advantages automation can offer.

As the largest offshore oil and natural gas producer in China, CNOOC works with foreign countries for the exploitation of offshore oil and natural gas resources in China's territorial seas.

As a part of its plan to move forward and capture the essence of what an oil and gas producer does, CNOOC adopted a progressive strategy of employing new automation technologies as the best way to ensure offshore projects are brought into production as quickly as possible with lower operational and maintenance costs as well as reduced man power levels.

This strategy, for CNOOC, should reduce the time required for engineering design, construction, and equipment commissioning. In addition, these automation systems should optimize production assets through real-time monitoring and management of intelligent field devices in order to ensure stable operation of production installations.

Those moves to optimize assets and increase automation should lead to reducing production downtimes and breakdowns and increasing uptime.

To do that requires more data points which leads to an increase in information. As operators, engineers and executives end up deluged with the rush of data coming at them, parsing and understanding all that information into chunks of vital, usable facts and figures becomes so much more important. That is where understand Big Data comes into play.

Operators on the platform or in a central control room on shore can analyze these huge amounts of data and use it as an early warning system when problems threaten or highlight a way to safely increase production. That knowledge garnered from all that data, in turn, will be able to keep facilities running more reliably and productively.

With new systems and data running from the platform to the head office and back, the communications stream has to remain constant and viable. However, as we have learned in this era of control systems having the potential for bad guys to take them over, the level of awareness of cyber security continues to rise.

Security is an enabler for the business and more folks are becoming aware of that.

"I think there is building level of concern and awareness where we have started building a practice around helping people think through where to start and how to broadly attack the problem and we are making progress in that regard," said Mike Caliel, president and chief executive of Invensys' Software and Industrial Automation businesses during a meeting at the ARC Forum in Orlando, Florida, in February.

"I think beyond the cyber dimensions of the problem and system dimensions are the issues around physical assets as well. I think there is a building awareness of people looking at the problem and it is such a complex problem that people just don't know where to start."

That understanding will lead to a having a solid security plan in place to ensure the benefits of an open architecture and communication.

Technology in the automation environment has come a long way in the past decade. It has gotten to the point where communication and real time decision making can occur safely and securely from the sensor to the boardroom.

But the time to become aware is over, now the industry needs to start moving toward a stronger automation environment. OE REVIEW

***Gregory Hale** is editor and founder of Industrial Safety and Security Source (ISSSource.com) and is the contributing Automation Technology Editor at* Offshore Engineer.

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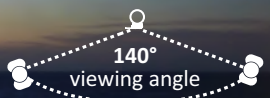

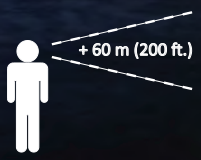

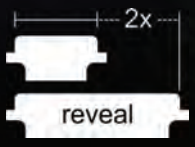

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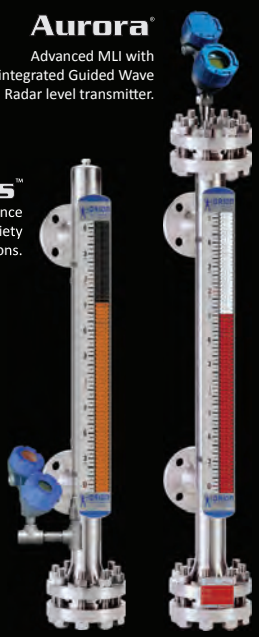

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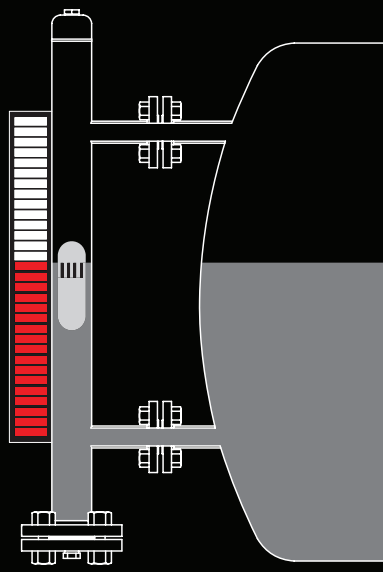

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Big Data Buzz Grows Louder

Knowing performance levels boosts asset lifecycle, profitability

By Carol Huff

Just spin it the right way, and digital technology - working with standardized infrastructure, sprinkled with new age seismic sensors, analytics and algorithms - produces Big Data which transforms workflows, improves collaboration and enhances production and profit.

"Automation in mixing and pumping is out there," said Jason Dykstra, Ph.D., senior technical advisor and manager of Halliburton's research group, the Automation Center of Excellence. "But the full automation of the process is still to happen."

Acceptance of new automation and new systems has taken so long because it's difficult, requires a large investment and there's a fear it will take jobs. But there are now more doors open to these ideas and changes upstream. In the end, however, upstream still lags behind in automation compared to downstream which has pioneered the use of advanced automation techniques since the 1980s, Dykstra said.

A term used loosely in the industry for years, automation is significant now because of its relation to Big Data. Today, automation can capture data, put everything in proper context; get the information to the right people and enable real-time decision making. This allows systems to do what humans can't. By accepting the shift to more supervisory roles, crews can now spend more time overseeing operations and making real-time, profit-making decisions based on data that has been automatically pre-analyzed.

The complexity of systems is why the automation model is still evolving. After all, an offshore platform is not the place to experiment with a new system. But once people accept the fact automated systems work better, they are more open to adopting it. With the manpower gap of capability growing in all levels of operations, companies will have to make the investment, Dykstra said.

NOW'S THE TIME

"The easy days are over. It's a technology race," said Arjen Dorland, the man charged with reinvigorating Royal Dutch Shell, the world's second largest company, with a 100 percent increase in computing power. His work uses the latest seismic sensors linked to new interpretative software, visualization applications to

Strategies to ID Potential Disasters

Experience with process safety management has shown seven strategies that can help in the identification of early indicators and root out the latent errors behind them. The seven strategies are:

1 – Controlling head high pressure
2 – Learn from deviation
3 – Uncovering root causes
4 – Demand accountability
5 – Consider worse case scenarios
6 – Evaluate projects at every stage
7 – Reward responsibility

make new information available to a wider internal audience – all to reduce the cost of drilling thousands of wells with increased speed and efficiency. Preparing for the onslaught of Big Data, Dorland was named in 2011 to lead Shell's new effort, called Technical and Competitive Information Technology.

As Shell Chief Executive Peter Voser told *The Wall St. Journal*, information technology (IT) innovation is critical for the company to become the most competitive and innovative energy company in the world. While declining to comment specifically on the amount of its investment in IT, Shell's capital spending rose to $38 billion in 2013 from $32 billion in 2012 up 23 percent from $24.6 billion the previous year, according to the company.

"Transforming Big Data to enable better decisions requires significant work," said Charles Peters, senior executive vice president at Emerson. "Big Data opens a sea of opportunities." Organizations must simply work through the challenges to ensure numerous inputs are useful inputs. "The potential looms large for those organizations that commit – to better business processes, to destroying organizational silos, to smarter products and to solutions that allow our customers to prosper."

Exploration and Production is data-driven, that's not new. However, what drives the data is. New technology is now available to process high volumes of data, which is unprecedented in scale and scope, in streams rather than fixed datasets, accumulating in large volumes at high velocity. The potential is enticing: More oil from existing wells, a hedge against price volatility, a buffer to risk, enhanced use of diminishing talent, remote operation, and, the holy grail, the fully automated rig and higher profitability.

Advanced technology is the spine of 21st century energy development. Just take a look at Chevron's internal IT traffic which exceeds 1.5 terabytes a day. In one case a large seismic data processing center "will gather the power of 20,000 personal computers to crunch a single seismic data set," said Jay R. Pryor, vice president, business development, Chevron Corp., in a speech to the World National Oil Companies Congress.

"The oil and gas industry is recognizing that there could be untapped value in data that has been previously unexamined or inaccessible," said the global research and consulting firm IDC Energy Insights, adding the industry is starting to think about whether there is value in analyzing data across disciplines. For example, could seismic data, typically the province of exploration, be used to enhance oil production?

IDC expects the Big Data technology and services market to grow from $3.2 billion in 2010 to $16.9 billion in 2015, predicts Jill Feblowitz, vice president at IDC Energy Insights.

Big Data is generally defined as volume, velocity, variety and value, which Invensys Operations Management calls the "four rights" – the right information to the right people at the right time with the right context.

Because of the torrent of data, people are still spending about 70 percent of their time preparing data, the same as 20 years ago. What they need is better context, Invensys executives explain. This is essential.

Simply stated, the context needed for the data is the business objective of the rig: Increase quality or quantity of production, or to reduce cost of operation, costs of drilling or energy use, while improving safety and environmental standards. With the context for the business objective of the operation, the operator through all the automation tools can quickly arrive at the strategy to achieve the objective. Don't gather data for the sake of gathering data, use it to turn a business strategy into profit, Invensys executives urge.

The key to understanding the business objective is the overlay of policies and procedures, involving contractors and operators. Difficulty in ensuring the lack of compliance to policies and procedures is inherent in the business model which doesn't allow companies working on the same rig to cooperate.

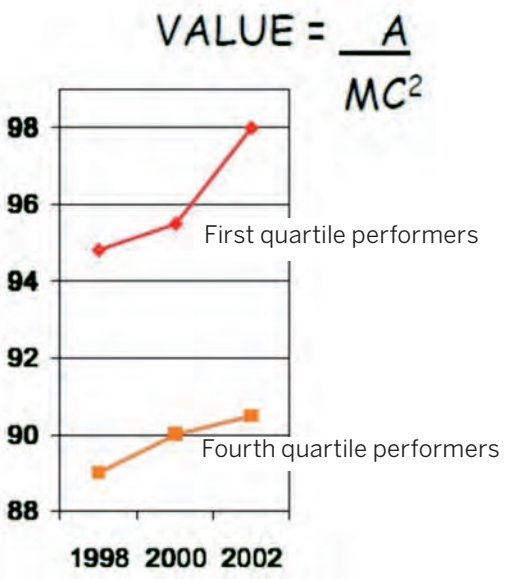
> Big data is generally defined as volume, velocity, variety and value . . . the right information, to the right people, at the right time, with the right context.

"We can't change the culture, but we can change behaviors; we can ensure that policies and procedures are responded to. This is why people are investing in process improvement," said Victor Lough, Invensys Operations Management product manager.

While Big Data is revered as the silver bullet, it also looks like a short cut, "let's remember policy and procedure, then apply technology. With Big Data you need software but you must remember that you also need the boundaries from policies and procedures," Lough said.

As the industry faces an unprecedented drain of expertise from retirements, experience and knowledge can be leveraged effectively with a process safety management system. Also, as the visibility of the costs of decisions increases with the system, decisions get faster action, saving time and money, as well as

PSM framework



Mechanical availability

The process safety management framework engages operations management, policies and procedures to achieve reliability. Maintenance must be tightly integrated with operations and business processes to reduce costs and maximize productivity and quality. As shown here, asset reliability impacts safety and maintenance costs more than any other factor and that reliability is a multi-disciplinary responsibility that is highly operational – not just an element of a "fix it" maintenance strategy. Source: Invensys.

maximizing talent.

NEW FRONTIER OR WILD WEST

Senate Committee chairman Jeff Bingaman stated at the first Deepwater Horizon oil spill hearing in 2010, "At the heart of this disaster are three interrelated systems: A technological system of materials and equipment, a human system of persons who operated the technological system, and a regulatory system. These interrelated systems failed in a way that many have said was virtually impossible. We will likely discover that there was a cascade of failures: Technical, human and regulatory."

In fact, more than 40 percent of all safety/reliability related incidents are caused by human factors, reported the Norwegian Continental Shelf Petroleum Safety Authority in 2011. "Many of these failures could have been avoided if the management and field based operations were situationally aware and able to take preventative action using well defined operating procedures," Lough noted in a paper (SPE 146289, Mobile Workforce Integration with Process Safety Management Framework Enables Sustained Improvement) presented at the SPE Offshore Europe Oil and Gas Conference in Aberdeen, UK.

The days of "near misses," that is, when luck overrides disaster, should be long gone with the deployment of Big Data solutions allowing real time visibility through to the control center of the operation.

To further reduce risk and its associated costs, there needs to be a collaboration of technology for condition monitoring and human factors, specifically:

- Tracking small failures: Weaning reliance on paper charts
- Resisting the urge to oversimplify: Considering complications from sub-contracting non-core functions
- Ensuring sensitivity to operations: Eliminating the information gap between front line and management
- Requiring resilience: Resolving exceptions with readily available information
- Accessing expertise: Engaging needed knowledge regardless of location

With the development of an automated enterprise control system a company can generate the consistent data needed for an operation with less risk and downtime, while using technology to analyze interoperable layers of data.

"In the past, such a safety system was seen as a cost, not a profit; however, safety is reliability and reliability is profit," Lough said.

SETTING THE PACE

"Chevron set out to reinvent and automate operations using existing, emerging and yet-to-de-developed technologies and workflow enhancements," said Mike Hauser, program manager of Chevron's Upstream Workflow Transform (UWT) effort in Chevron's on-line publication "Next." Under a broad business priority known as the digital oil field, the new program is the result of a decade of investment in infrastructure and instrumentation, mostly in Chevron's North America operations. Now the company wants to extend the

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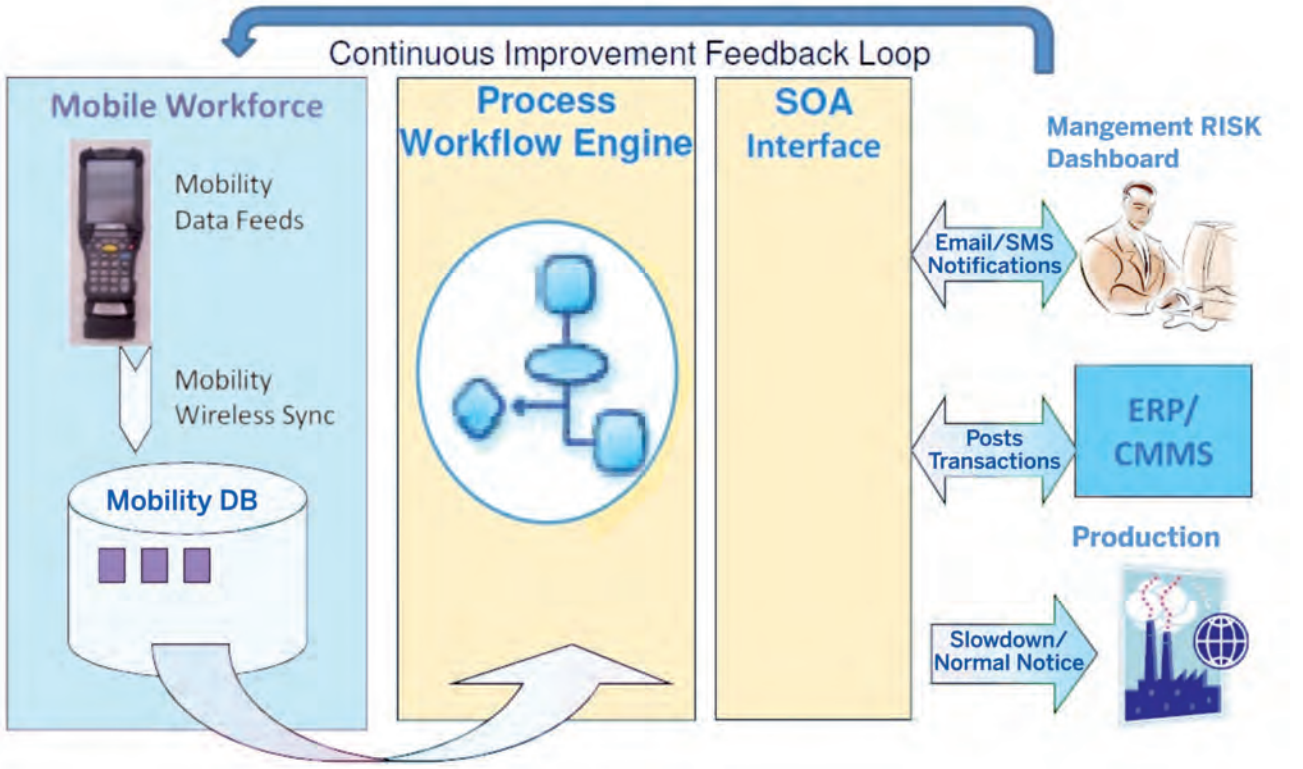


The process safety management framework requires an Enterprise Control System with a continuous improvement feedback loop. This ensures consistent execution of standard operating procedures, a move toward foresighted maintenance and traceable interdepartmental information tracking to drive the workflow through the reliability lifecycle. The aim: less risk and downtime; with less room for error; producing less need for costly expert oversight.

Source: Invensys

proven solutions and safety gains from its U.S. oil and gas fields to its operations on six continents.

Industry results show up to 25 percent in operating cost savings, up to 8 percent higher production rates, 2 to 4 percent lower project costs, and as much as 6 percent improved resource recovery within the first year of deployment of a "digital oil field," according to global information company IHS CERA, which is tracking projects at a dozen companies.

"Chevron has been a leading light, one of the early industry drivers, and they've worked methodically and thoughtfully to become one of the top three companies working on the digital oil field," said Judson Jacobs, IHS CERA research director.

"We used technology to change what we do, rather than optimize what we have always done," said Jim Williams, one of the key managers of Chevron's foray into the digital oil field.

Each day at Chevron's big Sanha Field off the coast of southern Africa, operators inject millions of cubic feet of natural gas, an essential task at a complex facility that produces millions of barrels of ultra-light oil per year. When a compressor showed subtle signs of overloading, the first person to notice was 6,000 miles away in Chevron's Machinery Support Center (MSC) in a Houston office tower.

Now this and other Chevron upstream operations have solid backup to detect any similar situations with the teams and technologies at the global MSC. The MSC actually evolved from an earlier surveillance center designed to monitor compressors in the Gulf of Mexico and California.

"We've seen a revolution in sensors to measure what's happening down in the wells and in production equipment and have seen major advances in process instrumentation. And we've connected hardware and data to field performance models, continually analyzing information and making optimum decisions to maximize output," Hauser said.

INTEGRATED TECHNOLOGY

It's about automation, but also integration – linking once separate functions, such as maintenance and drilling, and managing them within value chains. This requires streaming all relevant data into asset-decision environments, which fuse humans, data and technologies in a collaborative setting, said Chevron i-field specialist Darrell Carriger. "Centralized surveillance allows management of exception, which enables a more efficient use of the workforce than manually checking every well and facility." For example, a malfunction that might reduce output by 200 barrels in a week is caught and fixed in a day.

Before the support centers were conceived, Chevron's Gulf of Mexico operations created an Offshore Logistics Decision Support Center to streamline the constant coordination of vessels, supplies, equipment and people moving between shore bases and hundreds of structures. Within a year of opening, the center was logging cost savings from smarter vessel usage and fleet management, and safety gains as well, Hauser said.

It is no surprise the Gulf of Mexico presents major challenges for data managers and IT professionals. The difficult job of tracking and then correcting data issues, such as missing wells and wellbores, was creating a growing resource

Making the case for Big Data

Automation involving Big Data on the rig is inevitable, but right now the question is how can you make the business case for an implementation? Remember, Big Data is not about getting more information; it is about getting the right information and then putting it in the proper context to make quality, real-time decisions.

IDC Insights listed what companies could do to achieve greater benefits from Big Data and analytics, still in its nascent stages in the offshore environment:

- Build cases to address the challenges and connect those cases to business value
- Understand the competitive implications of operating without all the information at your disposal
- Conduct a gap analysis to determine what new technology and staff investments are required
- Formulate a Big Data strategy that includes decision processes and available resources
- Recognize the requirements for a shared environment that supports the total workflow of a work group
- Consider a shared services model with other oil and gas companies to reduce costs

resource allocation problem for Chevron. It was also becoming harder to keep information in sync with the steady stream of new well data entering the master database from various vendors and government agencies, Schlumberger explained in a case study.

Chevron ended up having to manage huge amounts of well data stored in approximately 100 project databases, ranging in size from 200 to 17,000 wells. Working to actively find errors, correct them and keep project data in sync with the most current well data, Schlumberger engineered several advanced software packages to achieve full data quality management automation. This enabled Chevron to:

- Define their own "pass"rules, based on four standard measurement categories: completeness, consistency, validity and uniqueness
- Rely on the software to automatically find errors, correct them according to predefined rules and update projects with high quality well data
- Quickly view all failures in various formats (maps, reports, graphs, etc.)
- Run assessment and correction jobs on a regular basis
- Easily verify location-specific data online (zoom in on an exact area and compare master data against project data)
- Remotely monitor interpreters' activity (modifying, adding or deleting data)
- Perform fewer manual tasks (i.e., when reviewing "failed" data at the back end of the automated correction process

Chevron now has higher quality data in master and project data stores, which allows personnel to focus

on exceptions or other situations that need expert attention. Standardization and the high level of accuracy from the upgrades has improved Chevron's Gulf operation.

As a result, UWT is building an enterprise version of the Gulf of Mexico's logistics solution for deployment across all major Chevron upstream operations.

Recognizing the value of designing and building its major new projects as digital oil fields, the company is investing at least $1 billion in each of 40 energy developments. Within 10 years, 50 percent of company production is expected to come from today's big projects. "We've set a course to fully harvest the potential of the digital oil field" Hauser said.

HYPE, HOPE OR HAPPENING?

So why are the applications of Big Data and analytics in E&P still "in the experimental stage," as claimed by IDC and other industry observers.

In IDC's 2012 Vertical IT and Communications Survey of oil and gas companies based in the United States, 70 percent of the 144 respondents were not aware of the terms Big Data and analytics. The most highly ranked (at 22.5 percent) barrier to adoption of Big Data and analytics was the lack of business support and/or business units not understanding the benefits of Big Data.

The market is still uncertain about the costs and requirements of Big Data and analytics. There have not been enough cases for the industry to weigh the business benefits of Big Data and analytics against the level of investment required to achieve greater reliability and speed, IDC concluded.

Deloitte Consulting in a report entitled, "*The Insight economy, Big Data matters – except when it doesn't,*" cautions, "the goal is more insight, not more information."

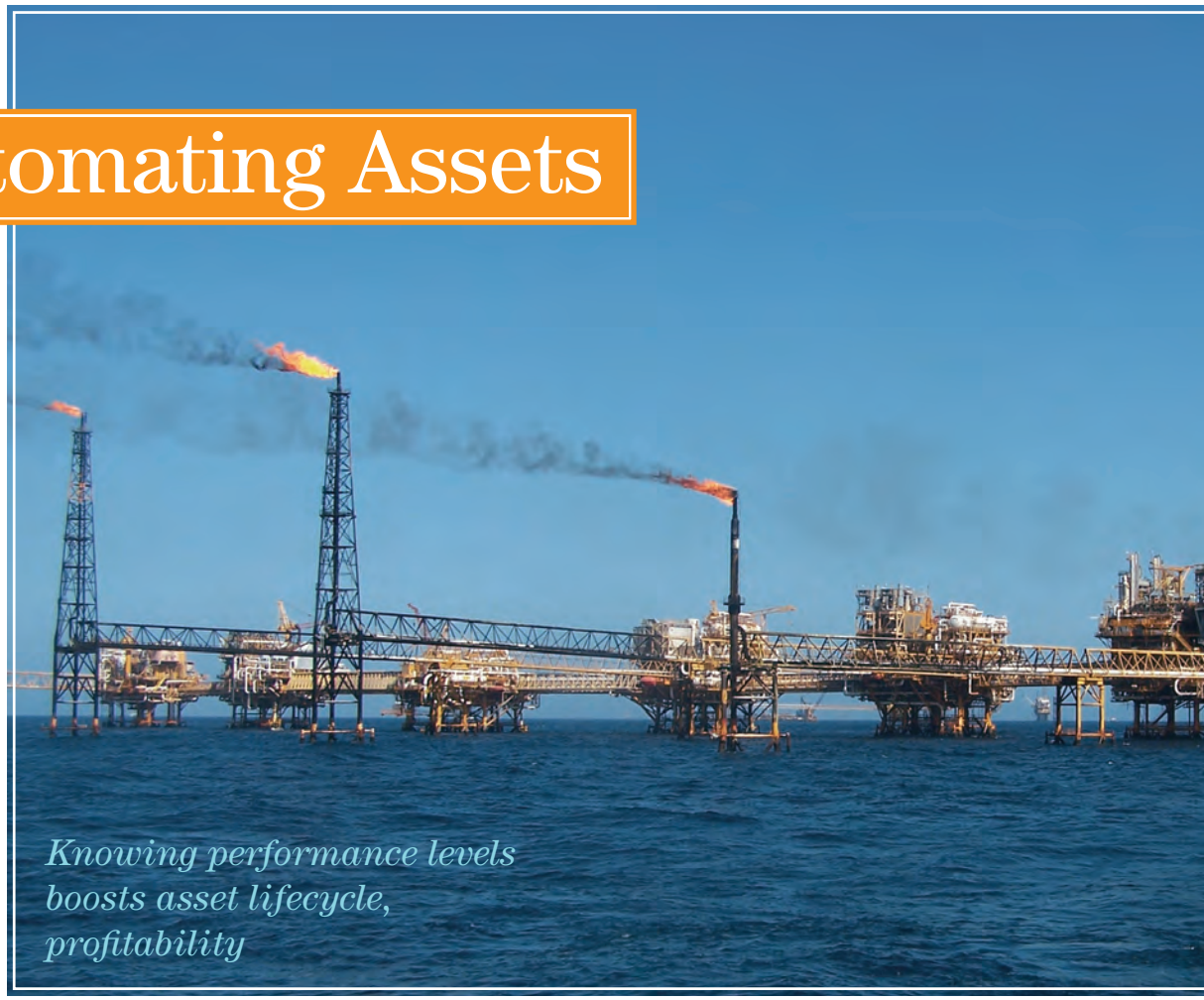
Deloitte suggested "crunchy questions" to chew on:
1 – What are the five most critical business decisions your organization made last year?
2 – How many of them should have had better information?
3 – Who within your organization is making sure you have better information next year?

Deloitte advised: "Whether you're looking for quants who understand business or up-and-coming leaders who 'get' analytics, there are simply not enough data scientists to go around. Fortunately, you already have some of the talent you need in-house. Identify them. Understand them. Take care of them. And make sure they have opportunities to learn, grow, and be fulfilled.

"Getting Big Data right means aligning information capital, human capital, and organizational capital to build a culture of disciplined decision-making. Analyzing data. Concerting data into actionable insights. Generating foresight and creating incentives for people to make effective decisions no matter where wGetting Big Data will also transform workflows, improve collaboration and enhance production and profit. OE REVIEW

Carol Huff is a freelance writer based in Durham, NC.

Automating Assets



Knowing performance levels boosts asset lifecycle, profitability

By Ellen Fussell Policastro

Statoil's Valemon oil field is located 160km west of the Norwegian coast and is one of the international energy company's largest development projects. The site contains recoverable reserves of 26 billion cu. m of gas and five million cu. m of condensate, which equates to over 1% of Norway's gas reserves.

The company will begin work this year to deploy an integrated control and safety system to enable remote operation of the Valemon platform, running the entire operation from the existing Kvitebjørn platform. "With this type of remote monitoring and visualization," users can more effectively monitor and support equipment "to minimize downtime without deploying resources to the platform," said Bart Winters, product director for Honeywell Asset Management Solutions in Phoenix, Arizona.

This system integrates an automation platform and software applications to enable a distributed control system to integrate disparate data across facilities and feed it all into a unified automation system. A distributed systems architecture integrates processes for multiple units, control rooms, or geographically distributed locations and adjusts to changing user and application demands for information.

This case is just one of many trends making waves in the offshore oil industry. Others include creative uses of radio frequency identification (RFID) on the platform and below the surface, virtual visualization software, and cloud storage of critical information to more effectively manage assets offshore.

The key to maintaining and managing an asset is to look at it from a lifecycle standpoint – from its design and operation to retirement.

"Understanding the health of the asset is critical to maintaining and extending asset life," Winters said. "With high-dollar equipment especially, that means accessing data and turning that data into actionable information."

A damaged compressor, for instance, could mean a US$2 million project to overhaul. "It means taking the compressor out of service, shipping it to shore, overhauling, and then returning it to the platform. With compressor monitoring, we can use advanced algorithms to detect abnormal conditions; then engineering and maintenance can investigate and determine the proper intervention or response."

And it's not only equipment that needs precision planning to keep operations afloat. Everything to do with the offshore process becomes an astronomical expense when it all has to be mobilized. Working on

STORY FAST FACTS

- *RFID gets rugged for offshore use*
- *Virtual visualization enables better remote monitoring*
- *Cloud stores data; transfers knowledge from onshore*

Oil and gas companies are using cloud-based solutions to remotely monitor production and machine health at disparate locations to maximize uptime and increase output. Source: Rockwell Automation

a facility with limited capacity means personnel on board is tightly constrained; bed space, lifeboat support, helicopter scheduling, food and fuel – all have to be strictly managed and managed safely in a volatile and corrosive environment.

RUGGED RFID TRACKS MOBILE ASSETS

Because offshore assets move around and live in hostile environments, tracking those assets can be a challenge. If you want to track an asset through its useful life, you have to be able to identify it. That's where RFID comes in.

Operator rounds are becoming more automated with RFID's use in field inspections. Operators use mobile handheld devices with RFID tags to properly identify assets when they're performing visual inspections for process equipment, Winters said. "Field operators are key to enabling operator-driven reliability, where operations [personnel] take more ownership of the basic care of the equipment," he said.

With handheld computers, field operators can scan the RFID tag, check the oil level as well as a leaky field or visible vibration. "They use these handhelds to record and collect data to demonstrate compliance and ensure they've collected the right information on the right asset," Winters said.

The problem with RFID is that it was originally adapted for non-hostile environments, said Mark Riddell, president of The Marrell Group, a management consulting firm for oil and gas businesses, based in The Woodlands, Texas. So, conventional RFID had to be adapted for surface applications, such as equipment around the rig, and downhole assets, such as riser pipes running from the rig to the ocean floor. Since anything going downhole is subject to high pressures and temperatures, RFID has to survive drilling fluids and other corrosive environments. Even with surface RFID tags, the goal is to make them survivable for the life of the asset.

"A lot of these things look the same—a piece of pipe, a pump, or an engine. They all have original serial numbers stamped on them," Riddell said. "But those become worn off and painted over. If you're looking at 10 pumps, all manufactured by the same company, you can't tell which one is which. And you have to know because each asset has its own maintenance schedule and date it went into service," Riddell said.

And since this equipment moves around so much—going to shore for repairs or to be replaced—you need a mechanism to tag them permanently.

RFID isn't just an ID number anymore. Downhole RFID uses a combination of an RFID chip and a reading device. "If that reading device is installed downhole, even permanently in a well completion, you could pump RFID chips down the well with instructions on them, and it tells the downhole equipment to do something—close a valve, open a sleeve, or take a measurement," Riddell said.

RFID is useful in underreaming, where operators activate and deactivate traditional underreamers (reamers operating below the casing of a borehole to enlarge it for the pipe) "by dropping a steel ball down to the tool via the drillstring," said Tommy Laird, global technical and competency manager for performance drilling tools at Weatherford International in Houston. Laird and co-authors, Luis A. Gonzalez (Marathon Oil) and Eddie Valverde (Weatherford International), explain more about this drilling technique in a 2012 paper, "Improving underreaming reliability with RFID technology."

RFID creates "an option to improve the performance of the underreamer by allowing multiple activations or deactivations without restricting the drillstring ID. The operator may elect to underream only specific sections of the well, where swelling formations cause stuck drillstrings, or perform full circulation in deactivated mode to clean out sections of the wellbore," Laird said.

RFID is also seeing use with GPS. An RFID chip by itself doesn't transmit its location. But active RFID actually transmits information.

The GPS communicates the coordinates of its physical location.

"With active RFID, you could have a single reading device centrally located on a drilling rig and have it communicating with all the assets on the surface

continuously. So you have a real-time snapshot of what's out there," Riddell said.

ALL EYES ON DECK

When all hands cannot physically be on the rig, virtual visualization software is helping keep all eyes on deck at least. "If I'm sitting in a control room on shore, I can virtually go to the Gulf of Mexico with virtual visualization and get a snapshot in time with high-definition clarity," said Glyn Thorman, senior consultant for ABB in Houston.

"I can see the problem associated with that piece of equipment and look at other details in the planning processes. This contrasts with having to get on a helicopter or even having a video conference and relying on someone to take a picture." The technology works like Google maps or Google street view, but in high definition with the zoom on.

"Think of it as driving down the road; you're at the driveway, and there's a note on the door," Thorman said. With this visualization feature, "you can zoom in and read that note. The definition and pixel strength is so high, if you're sitting in Houston wanting to do structural repairs on the platform, you can zoom in on a data plate on a pump and read it. And there are multiple camera locations where spherical images were taken. The quality is so high, you'll swear you're actually on the platform." Not only can virtual visualization help with repairs, it makes work safer and easier; it can reduce personnel on board and see into areas where planners might have to get a permit to go physically.

"The data on an asset could be several pages of information, and even on the rig you can have hundreds of assets," Riddell said. "If you're just looking at textual information and data or just searching a database, that becomes consuming and frustrating for users. Visualization offers instant access to complex domains."

> "Operators, engineers, managers and executives all have access dashboards in the cloud, creating a system of checks and balances to ensure they will not overlook a critical detail."
>
> *Adam Howard, Business Manager, Oil & Gas Solutions, EMEA, Rockwell Automation, Aberdeen, U.K*

The system can also help users who aren't familiar with a rig. "We create a database so they can search it and know by location what's there and tie it all back to their existing data," said Walt Reed, senior project consultant with ABB in Houston. "Because equipment changes, we have to do reshoots in certain areas. So we have to keep the database current with users' day-to-day documentation and standard operating procedures, say, for startup and shutdown. You can link these images to procedures and you don't have to go back out to the rig."

The interesting part about visualization is "it integrates cognitive science with computer science and business," Riddell said. "We haven't spent enough time understanding the cognitive aspects of people's jobs and their need to understand

the big picture of domains and to share that big picture. We use visualization as a communications tool. So instead of text, we give people a diagram as a way of communicating. It's faster, and it saves time and money for users. If you look at user preferences, it's been shown over and over; people would much rather look at a picture and let that guide them as opposed to wading into a database or research box."

SEA DATA IN THE CLOUD

Not only are assets on board becoming more virtually maintained, the information about those assets can be stored virtually – on the cloud. Operators who have to deal with complex extraction methods and technologies running facilities on the ocean floor are sometimes overwhelmed by all the different alarms from intelligent devices for safety, fire and gas, instrumentation, intelligent motor control, and condition-based monitoring.

"When we started in the oil and gas business, communications were remote and infrequent; we had to think of bandwidth. Now we can see information on any operator screen and diagnose any faults we're allowed to," said Adam Howard, Business Manager, Oil & Gas Solutions, EMEA, at Rockwell Automation, Aberdeen, UK.

The cloud has helped make immediately available information to support the maintenance and ongoing management of offshore assets. "The cloud is just a means of storing and accessing information to a mutually remote location," Howard said. "We can upload information from the control room and safety systems to a virtual storage space so we can access that information in real time."

One big challenge with the cloud is this: "If we can get access to that information, so can others," Howard said. "And what we find now is a significant increase in

Among the many automation devices that use the cloud for asset management, operators can access real-time information remotely from offshore operating sites. Photo from Rockwell Automation.

the amount of IT compliance to the point that it becomes as important as the safety or control system itself."

The remote monitoring system allows access to assets in a secure environment using IT-approved, outbound communication rather than transferring it bi-directionally through a firewall. "This helps prevent computer viruses, worms or other digital threats tied to inbound data transfer," Howard said.

The key to using the cloud successfully is to make sure the information stored is handled appropriately "because you have large volumes of information; if you don't manage it properly, it could get out of control," Howard said. "Is this the right revision? Where is the master document?" That's where version control comes in.

Using an automated change management functionality will help prevent unauthorized changes and assure everyone they're working from the same version of the truth. Independent archiving of the newest version saves the entire stream of changes, resulting in improved clarity and accuracy in version selection and helping companies return to production faster.

Another big advantage of the cloud, particularly in northern Europe, is its ability to help transfer information from seasoned operators working onshore to less experienced offshore workers.

Managing operations through the cloud allows centrally located staff with years of experience to interpret the asset-management data, make it usable for operators, and analyze patterns and trends that may help optimize production. "When it comes to alarms, engineers can also assess any critical states and notify operators in the field if necessary," Howard said.

"Operators, engineers, managers and executives all have access dashboards in the cloud, creating a system of checks and balances to ensure they will not overlook a critical detail," he said. "If the operator misses an important alarm, the engineer with access to the same information can flag it. Production intelligence can pass through multiple sets of eyes, meaning one person's oversight does not impact the entire operation."

PEOPLE ARE ASSETS, TOO

Because so many of these oil and gas pioneers are retiring from offshore duties and working more onshore, it's important for them to have a way to share their knowledge with offshore workers starting out. "Some companies are losing 40-50% of their employees to retirement within a four-year span," Riddell said. Allowing these remotely located subject-matter experts to drive real-time decisions automates work flows and takes advantage of the ubiquitous environment of the cloud, which in turn drives down costs and lets experts focus on crucial tasks.

"It's been documented, and we know there are only a few key guys who know how to solve the difficult challenges in our industry," Howard said. Using this seasoned expertise with cloud technology lets you "get the best out of the people who have that experience and apply it most effectively. By working together, they can solve problems in real time or receive a data dump from a control or safety system. Photos of this equipment can be stored on the cloud, and they can assess situations from there."

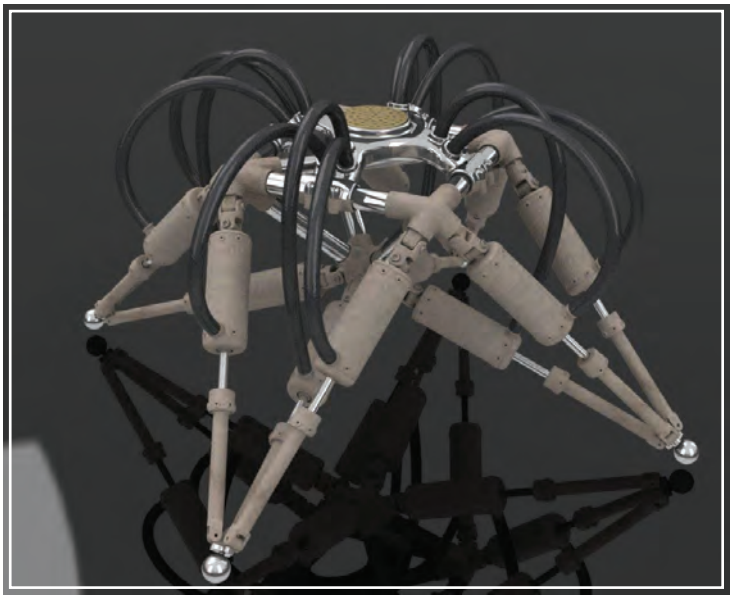
Riddell's group focuses on communication and factors that impact performance in oil and gas – knowledge, skills, and experience. They use a software-based solution that runs on SharePoint to capture knowledge from experts within the company and those who have already retired. It employs visualization for people to communicate information about a specific domain. "It can be a department, project, or workgroup," Riddell said. It's organized into a community of practice (COP), a group of people who have common work objectives. So you'd pull together people who have knowledge they can share that would be useful to each other," Riddell said. "This can really work well in offshore communities or anywhere knowledge recovery and retention are issues."

Today, leading operating companies want to locate their engineering staff in regional hubs to help share their knowledge offshore. This way, they can translate asset-management data into less unplanned maintenance, optimized production, and reduced down time. So instead of trying to decipher dozens of alarms, operations can focus on answering those most critical to the operator. And centrally located subject-matter experts can use live data with cloud-computing technology to make life easier for operators and engineers. **OE**REVIEW

Ellen Fussell Policastro *is a freelance writer based out of Raleigh, NC.*

Automation's Growth Curve

RoboPlatform coming to waters near you, sooner than you think



▲ ***Walloid is a prototype robot that is capable to climb in the oil and gas offshore environment. Although it's still an ongoing project of Akbar Moghaddam and his team, they are testing it and it is showing promise. The current design satisfies critical requirements of a climbing robot such as stability, flexibility, homogenous force distribution, minimum power consumption that prevents motors overheating.***

By Bob Felton

When a feature published in 2008 speculated that "offshore platforms could soon be run by robots alone, with human beings staying on land," a commenter in an online discussion group at gCaptain.com dismissed the idea: "I think our ET's and mechanics will have a job for quite some time."

That was then; less than six years later, it's clear that top-to-bottom automation is indispensable to maintaining profitability while maximizing the yield of tired fields and assuring safety in increasingly challenging environments.

From drilling to production, automation is the wave upending everything in its way.

DRILLING

Everyone who has spent time standing next to a drill rig has a story about a surprise, about encountering something that was unexpected and tore-up a bit, causing lengthy delays, or bent a rod and caused the drill path to wander off course, or caused the drill-stem itself to abruptly drop out of sight. Drilling seems, inherently, to be an activity that needs an experienced operator with a deft and learned touch.

But the heuristics that seem almost intuitive to a skilled driller are now finding their way into software, and rapidly driving-up rates of penetration, or ROP. As detailed in a 2012 issue of *Oilfield Review*,

"Wired drillpipe makes it possible to gather annular pressure and temperature measurements along the drillstring, which allows operators to monitor the entire wellbore. Algorithms quickly condense these data and convert them into flags and control signals for the automation system. Other algorithms sort the data, recognize an event and bypass the driller to initiate proper corrective actions if necessary."

Further, relying upon the Sandia National Laboratories technology roadmap convention, an industry-wide initiative is now underway to "create a tool to guide the development of this technology through a cross industry collaborative program."

Sponsored by the Society of Petroleum Engineers (SPE), the International Association of Drilling Contractors (IADC), and the Association for Unmanned Vehicle Systems International, the preparation of the Drilling Systems Automation (DSA) Roadmap comprises 4-steps:

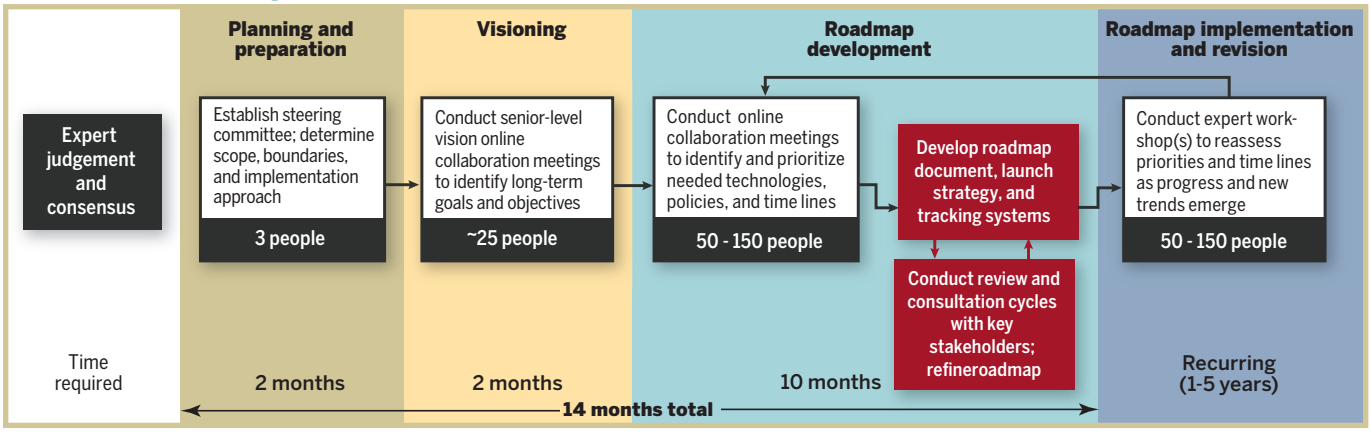
- Planning and preparation, or development of a goals statement for the roadmap process
- Visioning, or development of a goals statement for the technology itself
- Roadmap development, or a collaboratively-developed plan for the progress of the technology
- Implementation and revision, including monitoring

Now at Step 3, Roadmap participants will meet in Vienna, Austria, in June, and in Galveston, Texas, on 15 September 2014, for a series of workshops that will complement committee and subcommittee meetings.

Daniel Declute-Melancon, Halliburton, and a co-founder of the initiative, said, "The business side of the oil & gas industry is forcing efficient technology change, which requires the shift to automation as other industries have done. The DSA Roadmap efforts are to identify the gaps—hardware, sensors, software, standards, regulations, *etc.*— so that the industry can work through and create technology solutions that are missing." He added, "But as a volunteer effort, the timeframe is growing."

John de Wardt, another co-founder of the initiative, and the founder of the global management firm De Wardt & Company, shared his vision of drilling in the future: "Drilling systems automation is a technology

Steps for Drilling Automation



development that will significantly change the drilling business; it is not a question of how but when.

"Many people have spoken eloquently on the need for drilling to adopt automation; however, it remains a struggle through misunderstanding, negative reactions, and inadequate financial rewards. The case for automation in land and platform drilling, especially in the multiple well environments, is huge. The automation of a production platform has been inspired by the owner and end user. The delay in automating land and platform drilling lies in a number of barriers that include return on investment, reliability, ability to maintain higher technology equipment in the drilling environment, and the day rate business model adopted by the drilling industry. One major technical challenge is the fragmented organization of drilling equipment and operations which includes multiple companies providing their own proprietary equipment with their own proprietary measurement and control systems. Another is the inadequacy and lack of sensors in many of the drilling operations; while downhole sensors and controls have advanced, some surface systems remain 1930's to 1950's technology.

"The drilling industry will change; drilling rigs will become machines that correctly measure the state of their operations, automatically undertake some operations using algorithms, and provide frequent, timely, accurate, and relevant information to the drillers such that they are able to perform to the highest safety and performance standards possible. The transition has already occurred in industrial automation. Some challenges in the drilling industry are very similar to industrial automation and others require the ability to handle the uncertainty in drilling and, when needed, seamlessly hand back control to the driller. The only question is when and how this transformation to automated drilling will occur."

There is more to the drive for technological progress, however, than merely cost. As in many other heavy industries, there just doesn't seem to be so much skilled employment interest in drilling as there once was. According to the *Journal of Petroleum Technology*, "Adding to the interest [in automated drilling] is the limited supply of skilled drillers. The rapid expansion of drilling in certain U.S. shale plays has resulted in local shortages in directional drillers. And many of the best ones are reaching retirement age. In many other countries with large shale potential, people with directional drilling skills are a rarity."

For those who do seek offshore work, the safety improvements of automation are well known and readily acknowledged, even if there is a corresponding regional economic consequence. From an oral history of the offshore oil and gas industry prepared by Louisiana State University (LSU):

Joe Young, a retired geologist interviewed by Louisiana State University's Center for Energy Studies in connection with a history of that state's oil industry: "I think the biggest change that took place as far as drilling was concerned was the automation of the things that used to be done by hand. […] A lot of people would lose fingers. In fact, if you see a guy that worked in oil, it used to be if he worked in the oilfield any time at all, he had a couple of fingers missing where he would get it in the wrong place and have a stand of pipe on his finger, if he did not get it out of the way in time."

A related LSU study confirms safety improvements – and less interest in the oil and gas industry on the part of younger workers:

"Increased automation and safety programs have mitigated the physical dangers of offshore work, but stress-related health impacts remain high. Satisfaction from offshore work is less evident among younger workers than their predecessors."

Drilling automation is continuing its growth offshore and Sandia National Laboratories has an industry-wide initiative now underway to "create a tool to guide the development of this technology through a cross industry collaborative program."

PRODUCTION

Just as automation is taking over drilling work from advancing the drill bit to racking pipe, progress is also occurring in production. According to an inventory of oil and gas wells by the UK's Dept. of Energy & Climate Change (DECC), there are 140 unmanned and operational wells on the UK continental shelf (UKCS). Almost half of the wells were brought online in just the past 19-years, though development in the North Sea has been active for almost 50-years; the trend is clear and certain to continue.

Just last September, Premier Oil retained Emerson Process Management to automate a new platform in the Solan field, on the UKCS. Production will begin in late 2014.

The platform will be unmanned, and wholly managed

Prototype robot, Walloid.

from an operations center in Aberdeen Scotland, 100mi. away. According to Emerson:

"Designed for unmanned operations, the platform could serve as a model for future developments in marginal fields, where such operations can help increase profits as well as worker safety. The Solan field is expected to produce approximately 40MMbo, with an estimated initial production rate of 24,000 b/d by the end of 2014."

The Babbage platform, in the southern North Sea, was designed from the start to be unmanned. Brought online in 2011, it has an expected life of 20 years and exploits gas reserves long ignored because they could not be economically recovered by conventional means.

BEHIND THE SCENES

The support infrastructure that make drilling and production possible are undergoing change, too, with automation entering every phase of a platform's life, from construction to decommissioning.

First, the design and construction of platforms themselves are benefiting from automation. As detailed in a 2012 paper by industrial IT consultant Dr. Oskar Kwok Lum, the use of CAD/CAM drafting, analysis and design tools is automating the preparation of plans.

"Record high oil prices in recent years have contributed much to the investment in oil rigs and production platforms. In line with the number of new oil rigs and platforms being built, production technology in this industry has seen relatively higher levels of investment. Many shipyards new to oil rig building are leveraging on technology to ensure success in the high risk business of oil rig fabrication where penalties are measured in terms of day rates to lease the drilling rig."

Well construction is benefiting from automation, too. The Edison Welding Institute, for instance, has introduced automated laser inspection of riser pipe welds. According to a technical paper prepared by its engineering staff:

"For riser fabrication, the traditional methods of determining weld quality have been human visual inspection using a borescope-type camera or inspection using a shadow probe. Both methods are subjective and rely on operator decision. Inspection is necessary because a defective weld reduces the pipe's fatigue life. For offshore J-lay operation, common weld inspection techniques such as UT are currently used for immediate, post-weld inspection on the platform. In an effort to be conservative, traditional inspection techniques can sometimes provide false positives, incorrectly classifying an acceptable weld as one in need of immediate repair."

The laser inspection technique constructs a 3D image of a weld, analyzes it for conformance with preset tolerance ranges, and forwards the image to the operator when it senses an unacceptable discontinuity.

Similarly, field tests have established that mobile robots may serve reliably on offshore platforms to do routine inspection and testing. According to a 2008 paper prepared by engineers with the Fraunhofer Institute of Manufacturing Engineering and Automation, "The evaluation of the first autonomous service robot that has ever been operated in offshore environments has proven the applicability of mobile robots to offshore platforms. Different types of inspection tasks (visual and acoustic inspection, gas measuring) have been programmed and executed by the robot successfully without ever jeopardizing the safety of the platform or the platform personnel."

Simultaneously, a team led by Akbar Moghaddam, formerly at the University of Oslo and now with ABB, has developed a climbing robot for use on offshore platforms:

"Walloid is a promising prototype for oil and gas offshore environments. Although it's still an ongoing project and is being perfected through tests and academic reviews, but the development process of the project has made it a promising piece of work for further development and investment by the industry. Current design satisfies several critical requirements of a climbing robot such as stability, flexibility, homogenous force distribution, minimum power consumption that prevents motors overheating."

At the end of a platform's life, another robot may help to dismantle it. According to a 2013 report of a prototype's performance in the laboratory, in the *International Journal of Control and Automation*, "The 13 3/8in. casing was severed easily by the cutting robot in a short time. The cutting process was completed perfectly under the precision control and monitoring system."

BRAVE NEW WORLD

As the reliance of offshore work on automation steadily increases, the report of the Deepwater Horizon Study Group sounds a sobering note:

"Emergency situations caused by control system failures or design weaknesses are often trusted to be handled and mitigated by human intervention. However, this requires both fast and accurate alarms and warnings, as well as detailed operator knowledge of the system. This may in practice be unrealistic, especially considering that the control system behavior and alarms after a control system failure may be undocumented and inadequate for making the correct decisions. All human behavior is influenced by the context in which it occurs, and operators in high-tech systems are often at the mercy of the design of the automation system software. Many recent accidents blamed on operator error could more accurately be labeled as resulting from flawed system and interface design. Inadequacies in communication between humans and machines are becoming an increasingly important factor in accidents."

Almost certainly, then, given the stakes, the last step of the Sandia technology roadmap will have to be embedded industry-wide into the offshore culture: Constant systems evaluation and revision. OE REVIEW

Bob Felton *is an engineer and freelance writer based in Wake Forest, NC.*

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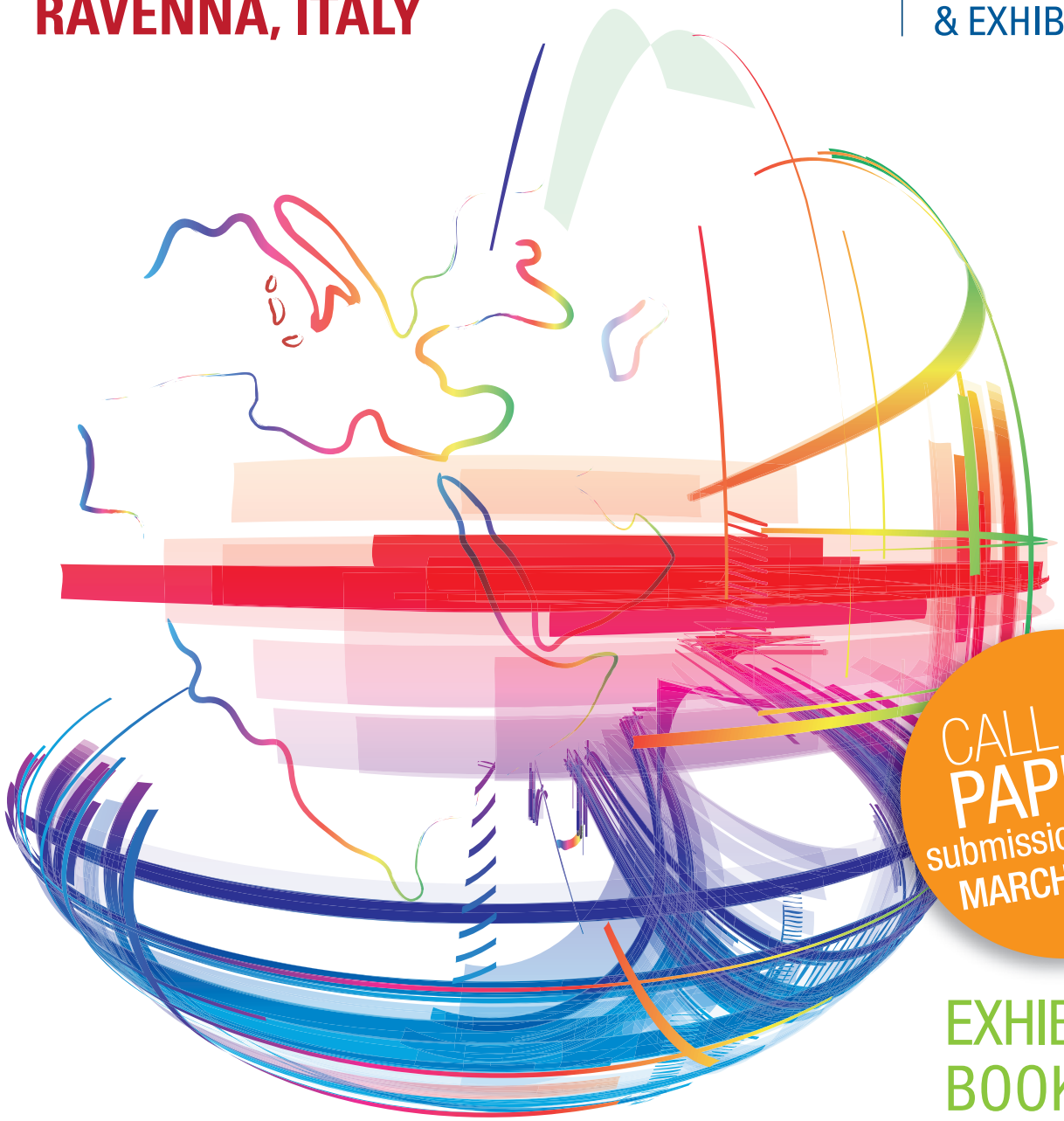

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Numerology

25% There is up to 25% in operating cost savings, up to 8% higher production rates, 2 to 4% lower project costs, and as much as 6% improved resource recovery within the first year of deployment of a digital oil field. See article page 158.

1% Statoil's Valemon oil field is 160 km west of the Norwegian coast and is one of the international energy company's largest development projects. The site contains recoverable reserves of 26 billion cu m of gas and 5 million cu m of condensate, which equates to over 1% of Norway's gas reserves. Statoil will begin work this year to deploy an integrated control and safety system to enable remote operation of the Valemon platform, running the entire operation from the existing Kvitebjørn platform. See article page 166.

20,000 Chevron's internal IT traffic exceeds 1.5 terabytes/day. A large seismic data processing center will gather the power of 20,000 personal computers to crunch a single seismic data set. See article page 158.

57% When it comes to reporting a cyber incident, 57% of organizations wouldn't voluntarily report attacks not required by disclosure laws. On top of that, 77% of the respondents said their companies suffered a cyber attack in the past two years, but only 35% shared attack and threat information with other organizations in their industry. 32% said they do not share such intelligence, and 27% did not say one way or the other, according to reports from Arbor Networks and The Economist Intelligence Unit.

$16.9B IDC expects the Big Data technology and services market to grow to $16.9 billion in 2015 from $3.2 billion in 2010. See article page 158.

96% of successful breaches could have been avoided if the victim had put in place simple or intermediate controls. In other words, security pays off over the long haul. In addition, 85% of cyber penetrations took five months to discover; the discovery in most cases made by a third party, according to the Verizon Data Breach Investigations Report.

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Activity

Viper Subsea enters JIP

Viper Subsea has signed a joint industry project (JIP) agreement with BP and Total to further develop its subsea line insulation monitoring (V-SLIM) technology, which identifies and locates cable and connector faults in remote subsea electrical distribution systems.

With the backing of the JIP, Viper Subsea is developing its V-SLIM technology to enable accurate electrical fault location. V-SLIM units can be positioned within the subsea distribution system, and together with a surface line insulation monitoring unit (V-LIM) that incorporates a topside modem, they build a network (V-NET) of electrical condition monitoring units that inter-communicate and transmit information back to the surface. Each V-SLIM can identify whether any electrical leakage is up or downstream of itself. In dialogue with one another, fault locations can be accurately located.

Viper Subsea will carry out research and development for the V-SLIM system, while the JIP partners will contribute funding and field testing of the technology. The establishment of the JIP has been facilitated by the Industry Technology Facilitator. Viper Subsea expects the new V-SLIM to be field-trialled in less than 18 months.

Technology developed by the JIP could be incorporated into greenfield developments or retrofitted into brownfields.

BP opens offshore training facility

BP and Fletcher Technical Community College announced the grand opening of the college's BP Integrated Production Technologies (IPT) building in Houma, Louisiana. The new home of Fletcher's IPT program, which the Louisiana Board of Regents recently designated a Deepwater Center for Workforce Excellence, features a 4000sq ft lab with US$500,000 in equipment. BP invested $4 million into the project and the state of Louisiana matched with $4 million.

Located near BP's Houma Operations Learning Center, the BP IPT Building will include space for essential offshore specialty training for mobile drilling systems, marine operations, production systems and safety training. The building also includes a math and science center for advanced coursework to prepare the next generation of engineers and classrooms for general studies courses to support Fletcher's student population.

Sierra Hamilton acquires GeoPro

Sierra Hamilton LLC acquired all the assets of GeoPro GmbH of Hamburg, Germany to create a new operating subsidiary, GeoPro Geophysics LLC.

GeoPro Geophysics' headquarters will be in Houston and its engineering and processing center will remain in Hamburg. GeoPro Geophysics will operate as a global seismic data acquisition, processing and interpretation company.

This acquisition is the latest by Sierra Hamilton, which formed at the end of 2013 through a merger of Hamilton Group and Sierra Engineering. Private equity firm Corinthian Capital Group owns Sierra Hamilton.

ITF, Tullow to tackle well integrity database

ITF is working with Tullow Oil to establish a global wells and completions reliability database and is urging more operators to join the project. The aim of the joint industry project (JIP) is to address efficiency and safety issues associated with well integrity through the creation and management of a global library of well data. This will provide users with accurate and reliable information about a broader range of well types than is currently available, allowing a wealth of knowledge to be shared across the industry.

The proposed database will be more comprehensive, consisting of a broad range of well types and the associated construction components such as tubulars, completion components, wellhead and Christmas tree components. It will allow wells to be constructed using factual reliability information, thereby allowing accurate assumptions to be made in relation to a number of conditions.

Discussions are already underway with data librarians, and to date, more than ten operating companies have shown interest in joining the project.

Schlumberger acquires RDR

Schlumberger acquired Rock Deformation Research (RDR), a UK-based company specialized in geological software development and structural geology consultancy for the oil and gas industry.

By integrating with the Petrel E&P software platform and Studio E&P knowledge environment, RDR's structural and fault analysis module provides users with tools to reduce risk and quantify uncertainty, while Studio Advisor enables Petrel platform users in process standardization and competency development. Core software product development and consulting services will continue to be in Leeds, UK, where most of the approximately 40 RDR employees are based.

It's wrench time

Production efficiency issues have been under the spotlight in the UK North Sea. Elaine Maslin heard the latest at NOF Energy's Newcastle conference.

Wrench time has been highlighted as one of the key areas the UK offshore oil and gas industry needs to address to improve production efficiency levels.

Average wrench time—the amount of time spent working on a mechanical project, either repairing or assembling from the ground up—is four hours in the UK North Sea, based on a 12-hour working day.

Best practice is six hours and, in some cases, it can reach nine hours, said Ronan Ferguson (senior business analyst, economics, Oil & Gas UK), outlining research by an industry working group at the NOF Energy conference in Newcastle, UK, in March.

The working group was set up under industry body Oil & Gas UK to address production efficiency issues on the UK Continental Shelf (UKCS) after production efficiency rates dropped from 80% to 60%, between 2004 and 2013. Other reasons for the low rates were turnarounds and unplanned outages, with most of the outages caused by unplanned compression plant failures.

Turning to the UK's production rates, some of the key reasons for the UKCS' recent dramatic fall in production—38% in three years—were political, economic, and environmental, Ferguson said.

In 2010, BP's Rhum condensate field was shut-in due to sanctions against Iran, a shareholder of the field. Rhum accounts for 2% of UKCS production and is expected to be back online later this year, after the recent easing of sanctions.

In 2011, severe weather saw two floating production units, Maersk Oil's *Gryphon* and CNR International's *Banff*, come off station, damaging subsea infrastructure and further reducing output.

In 2012, a supplementary charge, or tax, on UK North Sea producers damaged some field economics, and resulted in Centrica delaying the restart of production on its South Morecambe field, Ferguson said.

Also in 2012, the Buzzard field, which came on stream in 2007, and is the source of about 10% of UKCS production, went through its first major turnaround campaign.

Oil & Gas UK predicts production will start to increase again as all these issues pass and new fields—the result of recent record investment in the basin—come on stream, Ferguson said.

Recent start-ups include Breagh, Huntington, and Jasmine, which, together, are equivalent to a new Buzzard field, he said.

However, while the production decline is expected to slow, operational costs are still increasing, Ferguson added. A number of facilities operate at a unit cost over £30/bbl (nearly US$50/bbl), which has doubled in the past year. Average costs are at £17/bbl. One of the reasons for this is the aging infrastructure, with many platforms now more than 30 years old and operating beyond their design lives. "A key driver is fabric maintenance," Ferguson says. "This is hoovering [taking] up a lot of free capital, and reducing capital for other activities, such as exploration drilling."

Also speaking at the NOF event was former Energy Minister Charles Hendry. Addressing the broader energy landscape, he said, strategically, the UK should look at the fundamentals of energy security again, to underpin any drive towards a low-carbon future. This would include using indigenous energy resources, including tidal and wind energy, and nuclear energy, which has seen a renaissance in the UK. The UK should also look to develop carbon capture and storage technology, which it would be well-suited to deploy, and which it could then export, Hendry says.

As for the onshore shale potential, Hendry cautioned the UK first needed to quantify its potential reserves, not just resources, and then assess its potential for extraction, citing the excitement about Polish resources, which has since waned as firms struggled to find ways to exploit them. OE

Maersk Oil North Sea UK's *Gryphon Alpha* floating production, storage and offloading vessel, back on station after a storm in 2011 (OE: September 2013). Photo by Håkon Sunde.

Activity

Standardization – more than a buzzword?

An industry-backed project looking at how to increase recovery on the Norwegian Continental Shelf has led to a series of joint industry projects aimed at increasing standardization, to reduce costs and delays, and increase quality and safety. Elaine Maslin reports.

Standardization in the subsea sector has become a hot topic, especially in Norway.

A report by DNV GL looking at new subsea technology developments, commissioned by Norway's Petroleum Safety Authority and published in late March, says "'standardization' is a buzzword in the industry."

Standardization, what it means, how and where it could be implemented, and its limitations, dominated most debates at last year's Underwater Technology Conference (UTC) in Bergen (OE: August 2013).

At this year's UTC, the focus may be even sharper, and the reasoning is not surprising. More than 50% of Norway's part-state-owned company Statoil's production is from subsea wells. Overall, there are more than 800 subsea wells offshore Norway, out of 5000 globally, and the number is expected to increase.

According to a report by the Norwegian Oil & Gas Association (NOG), market survey data indicates a 50% increase in demand for subsea Christmas trees, to 186-264, for the Norwegian Continental Shelf (NCS) and Barents Sea for 2014-2017.

But, costs are also increasing. Lack of engineering resources, quality supervision, and manufacturing capacity is severe and set to get worse, the NOG report says. Part of the problem is differences in operator requirements, which have a "significant impact" on subsea equipment delivery times and costs.

"Diversity, change and preference engineering threatens the ability of the industry to systematically improve safety performance and asset integrity," the report says.

At the same time, developing industry standards is also time consuming and frequently lags behind the deployment of new technologies or the inclusion of lessons learned.

"Much of the future Norwegian Continental Shelf (NCS) oil and gas will come from marginal projects and tie-backs, where cost and delivery times are critical divers," according to the report. "It is clear… that 'business as usual' is no longer an option."

'Business as usual' is no longer an option

DNV GL's report, Subsea Facilities – Technology Developments, Incidents and Future trends, says "standardized building block design field developments" will be one of the two key themes for the subsea industry going forward, the other being "the advanced subsea system, where new and novel technology will be developed."

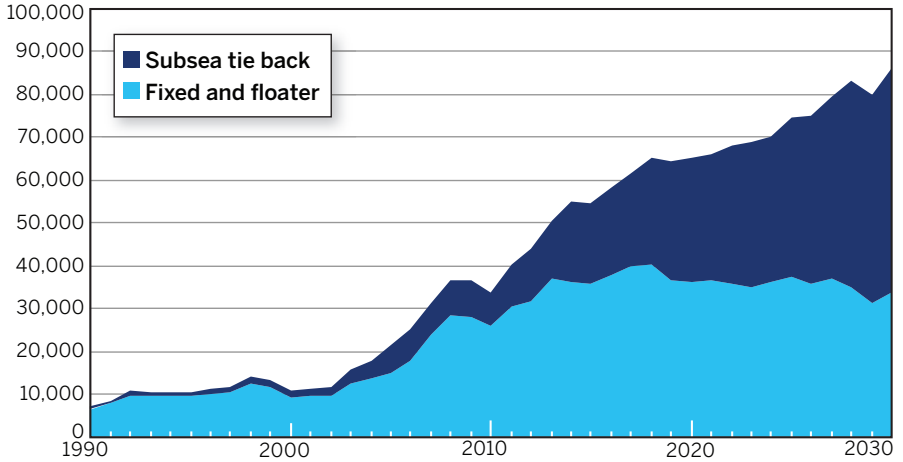
But, the report stresses that standardization applies not just to materials, specifications or interfaces, but also how projects are delivered or handed over to the client.

"The overall aim with standardization is to remove work that does not contribute to either quality or functionality," it says. "One example today is the lack of a common standard for supply of materials. The effect of this is that the supply chain is hesitant to order materials [at their] own risk and cost prior to having a contract with a customer in place. Typically, this adds 7-12 months of lead time for forgings."

Roald Sirevaag, the UTC 2014 program committee chairman, and VP Subsea Technology and Diving, Statoil, says: "I definitely need to do something. But you need an overriding vision of what you want to achieve, and that vision has been non-existent."

Sirevaag's vision, which he aims to share at UTC, is an analogy with car manufacturing, in which manufacturers have different models for different segments of the market, but still manage to

Total NCS E&P expenditures by facility type, MUSD



Norwegian Continental Shelf exploration and production spending, by type of facility, subsea and surface. Source: Rystad Energy UCube.

compete and innovate.

"Making an analogy with the car industry—which costumer would require his own material properties in the engine block, her own design on the petrol-tanking interface and narrate the script of the owner's manual? What is so different between the subsea industry and other industries? Are we really that unique?

"If we as operators could manage to agree on the number of models we need, then each of the vendors could have these models and then compete between themselves on delivery, not using their energy engineering things for different operators every time. When you industrialize, and have a large series of production, you can reduce costs, improve delivery times and quality. The challenge is the change itself, the change in the way we think and in establishes practices.

Roald Sirevaag, this year's UTC 2014 program committee chairman, and VP Subsea Technology and Diving, Statoil. Photo from UTC/Statoil.

"A subsea system consist of three main interfaces," Sirevaag says. "The interface with the reservoir, the interface with the marine environment—the seabed and marine conditions—and an interface with the facility to which it produces. These are diverse and have different characteristics. To modularize and configure a subsea system that is sufficiently generic to meet all these different characteristics is a challenge—but doable.

"What is also important is collaboration internally in oil companies, between reservoir people, subsea people, well people, everyone along the path of the hydrocarbon, and not having silos. We need to look at this holistically and we need to find common ground. We need a sufficient incentive to change, and that we have now in the cost level."

Joint industry projects and initiatives

Some positive moves have been made. Sirevaag says there have already been successful initiatives focusing on standardization, such as the Subsea Electrical Power Standardization joint industry project (JIP) that has issued the SEPS SP-1001 Power connectors, penetrators and jumper assemblies with rated voltage from 3kV to 30kV as a joint IEC/IEEE standard.

Ongoing projects include the Umbilical Termination Size Reductions project, and ongoing JIP's for forgings and documentation.

Other examples include Statoil's fast-track projects—subsea tie-in projects in which standardized solutions are used to reduce the time from discovery to production from five to about two years. Reducing costs by 30% is also an ambition for fast-track projects. An example is Skuld—considered Statoil's most complex fast-track project, and the largest of the development fields in the company's fast-track portfolio, the report says.

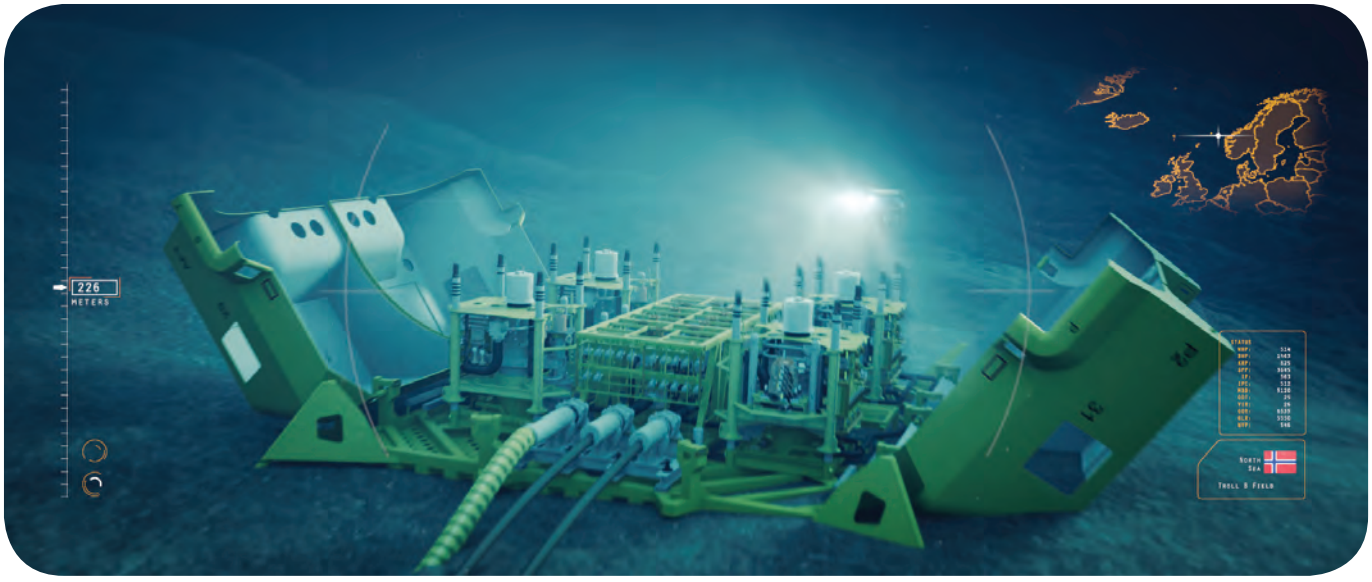
Since 2011-12, Statoil has also been leading work, with its main suppliers, on the creation of a standard subsea catalogue. This challenges past practice to specify and select equipment for each new project, according to requirements. This is a method which places a heavy engineering load on contractors, involves limited manufacturing volumes, and, in the event of project scope or timing changes, provides limited flexibility, the NOG report says.

Statoil's initiative includes developing standard components that can be used for the majority of Norwegian Continental Shelf applications (template structures, umbilicals, etc.) and designing configurable components that can be configured for different applications in the final phase of assembly (tree blocks, manifolds, subsea control units, etc.), the report adds.

Delivery is via "subsea catalogues," developed with each supplier and based on formal frame agreements, with engineers encouraged to work within agreed scopes and general design specifications. Petrobras has taken a similar approach, the report says, encouraging operators to develop standard specifications and interfaces through JIPs, typically using a third-party engineering house.

The initiative was included in a list of five main challenges to the industry, listed in the NOG' report, in addition to 21 detailed recommendations. These were assembled by a working group, backed by Norway's Subsea Installation Network, consisting of operators, equipment suppliers, and DNV, on opportunities for standardization in the subsea sector.

Overarching the recommendations is a



A vision of the subsea future. Photo from Xvision/UTC.

Activity

call for cooperation across industry. The five main challenges to industry:

1. Using standard catalogues with configurable components for multiple applications.

Here, the NOG says there has already been some success, with standard interfaces in guide post spacing, ROV tooling, H4 wellhead and tree connectors, flying lead connectors, pod receiver plates, and subsea instrumentation and interface standardization protocols. But, it says there is more to do, including agreeing interfaces for subsea processing, particularly around power supply, and also for brownfield engineering.

2. A universal, open water, workover system design that can be used with ease across tree suppliers and on different floating drilling rigs.

In the past, dedicated workover systems have been procured for each new project, resulting in an extensive inventory of systems for different tree and well types. In 2011, Statoil owned 19 workover systems, including lower riser packages (LRP) or landing strings, says the report. Older systems may no longer meet the latest standard, ISO 13628-7, require recertification every five years, take up storage space, and attract disproportionate maintenance costs, as well as needing unique interfaces to the drilling rig or vessel, increasing installation time and costs.

Statoil has already decided to procure a new generation of workover/LRP system and create mechanical adapters so the new system can be used on different trees. It is also developing control system interfaces at the tree, so the new LRP can be used with different tree control systems.

The report recommends creating an industry standard workover and tooling system to interface with the majority of global subsea well stock and rigs, to minimize well and rig specific modifications, enable better equipment sharing, utilization, and safety. Further, it suggests opportunity should be given to an organization wishing to build, rent, maintain, and operate such a system.

3. Best practices for subsea brownfields and industry standards.

The NOG report hopes to address aging subsea wells, with outdated equipment, obsolete control interfaces, and an unknown remaining life, by suggesting a set of standard protocols to facilitate and simplify re-engineering of existing subsea infrastructure.

The report cites issues faced on Shell's Draugen field life extension project. A key challenge was the range of equipment configurations and vendor systems in place, "because each phase of the field development was primarily driven by cost and reliability perspectives," says the report, limiting field-wide compatibility. It says Shell is now considering using "adaptive technologies," which could be added as an "over-ride" to avoid full replacement of original equipment.

The experience, and workgroup discussion, pointed to a need to improve life extension processes, including improved management of obsolescence throughout the supply chain, industry standards for "adaptive technologies," and "future proofing" new facilities, by using standardized control interfaces, subsea and topsides, and subsea architecture designed to be able to accommodate future expansion.

4. Best practice to improve individual compliance with industry standards.

5. Greater use of industry fora to anticipate future requirements and to create joint industry programs for equipment specification.

Two JIPs have already been launched: a recommended practice for subsea forgings, led by DNV, and one on minimum requirements for documentation.

Additional JIPs may be required to take forward ideas on brownfield best practice and to further develop material specifications for high-alloy steel forgings and other components, the report says.

In addition, in April, a meeting was held with OGP to discuss the potential for creating an international Subsea Installations Network.

The NOG report followed a broader report by Norway's KonKraft in 2010, commissioned by Norway's oil and gas minister at the time. KonKraft's report had aimed to find measures to increase recovery from Norwegian oil and gas fields. It proposed six initiatives, one of which was greater standardization, to reduce costs in equipment, project processes, and documentation.

Since 2003, subsea standards in Norway have been facilitated and driven by Standards Norge (Norway). Standards Norway is the national member of the International Organization for Standardization (ISO) and the European Committee for Standardization (CEN). OE

This year's UTC has the theme Subsea — Facing new realities, which Sirevaag says is meant to give the industry the sense of urgency required to get change.

A sub-theme is market and technology complexity, inspiring industry collaboration, which he says is the "crucial enabler."

UTC aims to provide a collaborative forum for key subsea technology professionals and experts in Bergen, June 18-19. For more information go to www.utc.no

Scan this page with the Actable app to read more: Standardization – a hot topic at UTC 2013

Standardization dominated panel debate's at last year's UTC in Bergen. Photo from UTC.

Solutions

Single trip clean-out reduces job cost

Performing inflow tests on the liner lap prior to displacing the wellbore from mud to clear brine fluid is a common practice. Inflow tests are performed by running a retrievable packer above the liner top, displacing the workstring with a lighter density fluid, setting the retrievable packer, closing the Hydril around the workstring and bleeding the pressure down while monitoring for any pressure increases. Upon completion, the retrievable packer is pulled out of the well and displacement operations begin.

A significant drawback to this approach is that it requires an extra trip to perform the inflow test which increases project cost.

To eliminate this extra trip, Wellbore Specialties has designed a single trip cleanout system. This system incorporates the new, LTIT1, liner top test tool in the same trip with the cleanout tools (scrapers, brushes, magnets etc.). The inflow test is performed using the LTIT1 with cleanout tools in the well. Once the test is complete displacement operations can commence.

The Wellbore Specialties patent pending LTIT1 has an integral dress mill that is used to polish off the polished bore receptacle (PBR) prior to performing the test. The LTIT1's unique sealing element and backup ring design allows maximum flow around the OD of the element. The LTIT1 has been successfully tested to 10,000psi differential pressure.

petrustech.com

Mesh-free fire protection

Jotun's Jotachar JF750 is the industry's first mesh-free solution for hydrocarbon and jet fires. Jortachar JF750 incorporates an advanced fiber matrix that eliminates the need for traditional mesh reinforcement, thus enabling operators to reduce installation time, cut material costs and reduce risks associated with traditional mesh installation. Systems that utilize mesh require a larger installation crew and more frequent inspections to ensure the complex mesh overlap is in compliance with product certification requirements. Additionally, Jotachar JF750 is applied continuously, eliminating the need for complicated repairs or upgrades.

www.jotun.com

Emerson offers next-gen fork meter

Emerson Process Management has released their next-generation Micro Motion Fork Density Meter. The fork density meter is designed to handle process applications such as pipeline interface detection, mineral slurry solids monitoring and corrosive acid concentration control. With the implementation of HART and RS485 Modbus digital I/O communications, the Micro Motion fork density meter can accept external signals from other field instrumentation such as temperature, pressure and volumetric flow devices. The new density meter also incorporates a new diagnostic capability called known density verification (KDV) that checks the meter for measurement alarm conditions, sensor integrity and the presence of coating, erosion or corrosion. This new technology expands the availability of diagnostics information in critical density measurement applications, reducing maintenance costs and cycle times.

www.emerson.com

ShipManager chosen for Harren & Partner fleet

German-based ship-owner Harren & Partner will implement the DNV GL business intelligence software systems ShipManager Analyzer and ShipManager QHSE for its entire fleet of 52 vessels. Both systems will enable Harren &

Solutions

Automated welding clamp

Serimax has recently introduced the Externax, a fully automated clamping and welding device specifically designed for tie-in welds. Externax is capable of welding on all types of pipeline applications for any grade of material, and is ideal to spoolbase both fixed and mobile projects. Externax saves time during fit-up, alignment, clamping, and welding operations to ensure productivity during spooling activities. As a result, it is able to reduce vessel mobilization time and increase spoolbase capacity management. Due to its fully automated and remote operated interface, Externax is capable of integrating technological innovations while mitigating operating risks.
www.serimax.com

Partner to extract data from operational systems and optimize management of its ships. The first trial implementation for the two software systems is expected to be running in April of 2014, with the entire fleet receiving installation by mid-year.
http://www.harren-partner.de

Honeywell launches intelligent ultrasonic flowmeter

Honeywell has introduced an ultrasonic flowmeter designed to help natural gas producers improve efficiency by accurately tracking the gas movement through pipelines. The USM GT400 ultrasonic flowmeter helps to reduce the effort needed to maintain pipeline metering by using a combination of multi-path measuring technology, field proven electronics and a user-friendly interface capable of achieving actual metering intelligence. The USM GT400 provides stability during flow perturbations due to its direct-path technology with six measuring paths on three levels. Regulator noise has marginal impact on the flowmeter's measurements thanks to Honeywell's proprietary, MID-approved detection algorithm.
www.honeywell.com

Ultrasonic gas leak detector

The Gassonic Observer-H ultrasonic gas leak detector is capable of distinguishing gas leaks by sensing airborne ultrasound emitted from leaking gas at high pressures.

This new technology is suitable for gas detection in open, well-ventilated areas where traditional detection methods may be unsuitable or dependent on ventilation. Since the gas leak detector responds to the source of a gas release rather than the dispersed gas, it is unaffected by changing wind directions, gas dilution, or the direction of the leak. The Gassonic Observer-H's wide coverage zone makes it possible to survey areas up to a 20m radius and detect leaks as small as 0.1 kg/sec.
www.gassonic.com

LED obstruction lighting system

Dialight has recently launched its Safesite Integrated LED obstruction lighting system for medium intensity installations. The complete system includes Dialight's Safesite L-864/L-865 dual red/white flash head, CID2 certified L-810 red side markers, CID1/CID2 integrated power supply/controller and CID2 long-life photocell. Dialight's integrated controller is mounted at the base of the structure for easy access and features a dual-certified CID1 and CID2 Groups B, C and D enclosure with real-time data reporting from the lighting system to the controller. Panel-mounted red and green LEDs indicate the system status at a glance, while the enclosed backlit display enables easy event and alarm diagnostics. The entire system is designed for integration with Dialight's Cloud Server monitoring system, a smart lighting solution that enables signal monitoring across multiple towers and multiple sites through a single web-based management console.
www.dialight.com

Subsea rubber

Metflex Ltd. has announced a new range of high performance rubbers designed specifically for subsea applications. Called the MetflexSubsea NRX, the natural rubber materials are available as

molded shapes for pipeline pigging connectors or protective shielding for HPHT pipelines and umbilical connection systems. The NRX rubbers offer temperature resistance in the range of -50°C to +80°C, 67-73 Shore hardness and compression of up to 14%. In large rubber blocks where greater stiffness is needed, Metflex is able to supply moldings containing multiple metal inserts.

www.metflex.com

Invensys releases new flowmeter

Invensys has introduced its new Foxboro 84 Series Male National Pipe Thread vortex flowmeter. This system is designed for flexibility and reliability in harsh process environments. It has no moving parts, and features a patented flexible tuning system that improves accuracy under operating conditions. It directly replace turbine, magnetic flow, and orifice meters with better performance and reliability provided by its DirectSense technology. The Foxboro 84 Series Male National Pipe Thread vortex flowmeter is an accurate liquid, gas, and steam measurement tool.

www.invensys.com

Guided wave radar integrity testing

Emerson Process Management launched an online Guided Wave Radar (GWR) transmitter and probe testing function. This system is designed for applications requiring periodical transmitters to ensure proper function of the level measurement device. The 5300 with verification reflector enables the operation of automated transmitter integrity tests without stopping

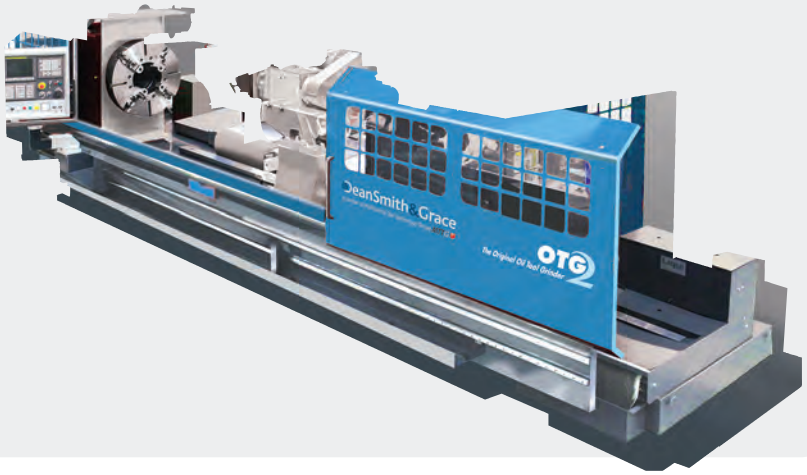
Solutions

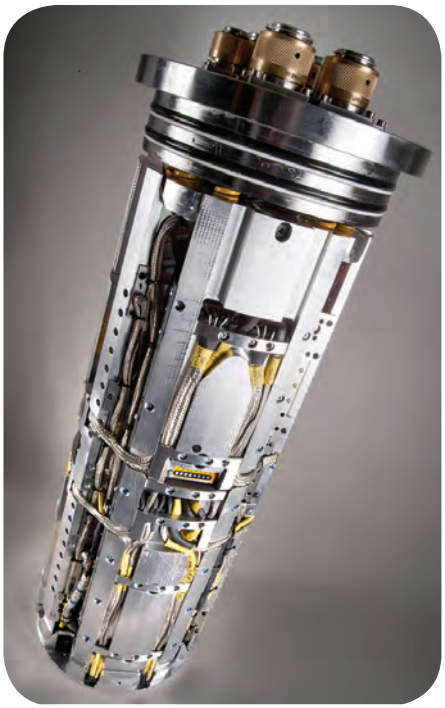
the process or manually raising the product level in the vessel. During commissioning, the location and amplitude characteristics of the reflector are stored in the transmitter. When the test procedure is later initiated, the stored reflector data is compared to current measurements in order to verify the integrity of the measurement

electronics and upper part of the probe.
www.emerson.com

Oil tool grinder

Dean, Smith & Grace have improved the original MTTG oil tool grinder by implementing a new Computer Numerical Control (CNC) system. Called the OTG2, this updated grinder is capable of grinding multiple types of stabilizers, drill pipes, drill heads, hydroclean bars, fishing tools, mills, reamers, and ancillary equipment. All machines in the OTG2 range are available in both electronic and CNC versions designed to meet each customer's specific requirements.
www.deansmithandgrace.co.uk/





Subsea electronics module

The Artemis 2G (A2G) subsea electronics module is a communications tool designed to detect additional signal capacities that enable cost-effective field upgrades by freeing operators from the constraints imposed by existing brownfield umbilicals. The A2G offers high-speed networks as a viable alternative to fiber optic infrastructures within the subsea production system. This system increases accessibility for remote usage through its webpage interface while providing advanced diagnostics to deliver adaptable communications.
www.proserv.com

SmartPlug isolation tool

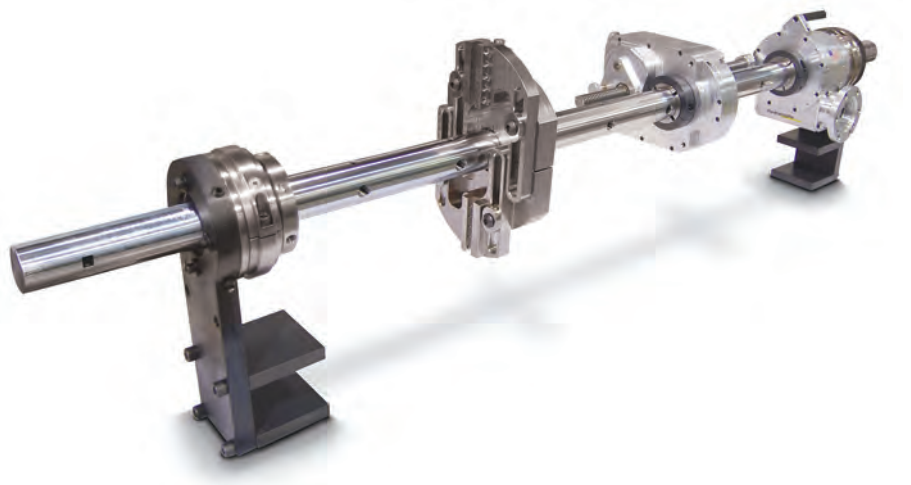
T.D. Williamson (TDW) recently completed a pipeline services program for an offshore operator to assist with efforts to relieve increasing contact stress between a gas export riser and platform jacket offshore East Malaysia. Due to changes in seabed conditions, the platform jacket moved, stressing the gas export riser attached to the platform jacket. To ensure that the bracing could be safely removed from the pipeline, TDW to isolated the affected section of the subsea line by inserting and setting its remotely-operated SmartPlug isolation tool in the line approximately 100m from the platform. Only a short section of the pipeline had to be depressurized and isolated while the bracing was removed.

www.tdwilliamson.com

RUD hoist ring

RUD Chains Ltd.'s WBPG 85-200 ton hoist ring is currently one of RUD's most popular offshore products. The WBPG is loadable from any side in the direction of the pivot, making it suitable for lifting and turning heavy loads. This system offers threaded holes for easy vertical assembly, and is extremely resistant to corrosion.

www.rud.com



Boring bar machining solution

Hydratight has introduced a 2250P boring bar capable of covering a diameter range of 2.5in. to 24in. and lengths of up to 12ft. The new 2250P boring bar features broached tooling holes every 6in., in conjunction with rapid transverse centering cones designed to realign the system. Radial adjustments can be made up to 0.25 in. by using the jacking bolts within the support assembly. The end supports have been designed with multiple mount options, with each support being fitted with a spherical bearing allowing up to 5 degrees of bar alignment. Each of the 2250P assemblies can be mounted at any point along the bar, allowing the system to be configured with almost any boring or facing application.

www.hydratight.com

Spotlight

By Elaine Maslin

PESGB reaches 50

As the PESGB reaches 50, 2014 President Oonagh Werngren takes stock of the North Sea oil & gas industry.

At the start of 2014, I was fortunate enough to take up the reins as president of the Petroleum Exploration Society of Great Britain (PESGB). I am only the second woman to take this role as the society celebrates its 50th year, but I am also humbled by the great contribution made by my predecessors in the role and the members of the society to advance the understanding of the basins which make up the UK Continental Shelf (UKCS).

What started with the signing of the Continental Shelf Act 1964 by the British Parliament on 15 May 1964, has transformed the North Sea into a very significant hydrocarbon province. Today, more than 450,000 people work in the UK on over 300 fields, and thousands more have been trained both on- and offshore in the basin, transferring their skills and technology overseas. However, 50 years into its development, the UKCS faces a number of challenges as global competition for funds, lackluster drilling results, rising costs, and falling production call for a material change.

Sir Ian Wood's recently published Wood Review (OE: April 2014) highlights the current exploration crisis and challenges that the industry faces. It is the wakeup call that policy makers and the industry need. It lays out clearly the challenges facing the basin and the way forward. It identifies the need for stimulation of exploration and a turnaround in production, as well as a more collaborative way of working in order to unlock the 42 billion bbl of hydrocarbons that remain.

It also calls for a new regulator and closer input from the UK Treasury on fiscal issues. This is the real tripartite approach we need to work together to unlock the maximum economic potential of the North Sea.

The 6000-strong PESGB membership mirrors this trend, with geoscientists and engineers learning their trades in great academic institutions and transferring their knowledge and skills to the corners of the globe. As home to the main geoscience talent in the UK, it also needs to pick up the challenge, especially around stimulating exploration.

The easy plays have already been found—we need to branch out, to identify missed pay and new play opportunities, to take on frontier basins like the Rockall Trough, to see beneath the basalt and utilize the latest innovation and technology to help us. The future is challenging, yes, but it's an opportunity to put that 50 years of learning, research, and knowledge to good use.

But is this enough? The much-heralded crew change is taking place and a new generation is coming through the system. The question is —are we doing enough to support them and to ensure we are selecting the visionaries amongst them?

The recent trends in the UK to take geology out of the school curriculum, reduce the number of universities training geology teachers, and the high costs of acquiring a degree and a masters mean that the selection process is potentially against us. Couple that with recent hiring trends of letting some computerized system determine whether candidates are suitable for a graduate program without even interviewing them leaves me cold.

The good news is that PESGB takes its role of education very seriously by sponsoring 28 MSc students. This activity is coupled with the new UK Research Council-sponsored Centre for Doctoral Training (CDT) oil and gas program, led by Heriot Watt University. The CDT will bring over 90 new Phd positions into universities in the UK over the next three years. This is a phenomenal boost. This is the future generation that will unlock the remaining reserves and create the much needed renaissance for the UK.

My plea to the industry is to nurture them and give them a career that will let them unlock their full potential. OE

Oonagh Werngren MBE joined industry body Oil and Gas UK as operations director in January 2013, and works primarily on the PILOT initiative to maximize economic recovery of the UKCS. Werngren is also President of the PESGB. She has worked at Tricentrol Oil Corporation, ARCO British, BP Exploration, and GDF Suez, on projects around the globe. She started as a field geologist, with an MSc in Stratigraphy from Birkbeck College, mapping landslides before progressing to well-site geologist, leading exploration and development teams and optimization projects.

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Spotlight

By Elaine Maslin

OAA winners shine

L-R Young Professional award winner Raymond Mckenzie, Brian Nixon, winner of the Significant Achievement award, and Inspiring Leader winner Steve Nicol.

More than 500 industry professionals came together for the sparkling 28th Offshore Achievement Awards ceremony in Aberdeen, 20 March.

The Society of Petroleum Engineers (SPE) Aberdeen Section organized and hosted the awards, known as "the industry Oscars" and supported by Offshore Engineer, for the third consecutive year.

Anthony Onukwu, chairman of SPE Aberdeen, said: "Since re-launching the OAAs three years ago, the awards have gone from strength to strength, attracting record-breaking audiences and increasing entries each year. SPE Aberdeen is proud to support innovation and recognize success across the UK energy industry."

The winners:

▪ Significant achievement

Brian Nixon As Decom North Sea's CEO, Nixon has helped grow the organization to more than 230 members and is due to retire this year. **Read more -** *OE*, February 2014 - http://ow.ly/vWjS7

▪ Posthumous significant achievement award

Steve Walton started at Wood Group in 1989, making him one of its longest-serving employees. He was a recognized expert in materials control in the core services team and served as a safety representative for more than 23 years, most recently on Step Change in Safety's leadership team. He passed away last year.

▪ Inspiring leader

Steve Nicol As Red Spider Technology's first employee, Steve Nicol's commitment and leadership led him to be appointed CEO. He helped secure the investment required for the company's growth, which led to its acquisition by Halliburton in 2012.

▪ Young professional

Ray Mackenzie – Nexen Twenty-six-year-old subsea controls engineer Ray MacKenzie impressed senior management with the trust he has gained and by showing commitment to company values, which he displayed while serving as Resident Engineer and Company Man on Nexen's Golden Eagle development project.

▪ Great small company

Coretrax Technology was formed in 2009 to develop tools and fluids for the wellbore clean-up and well abandonment markets. It has since increased its product offering and moved into markets in Europe, Africa, and the Middle East, with international sales now accounting for 70% of its business. Coretrax plans to open facilities in Saudi Arabia and Iraq this year.

▪ Great large company

Hydrasun provides integrated fluid transfer, power, and control solutions in more than 58 countries, with operational bases and facilities in UK, Holland, Caspian, Dubai, Brazil, and Angola, alongside sales offices and partnerships in the Gulf of Mexico, Trinidad, and Houston. Revenues are expected to grow to £130 million (US$2.15 million) this year.

▪ Emerging technology

Guardian Global Technologies' integrated Ballistics Delivery System is a new wireline perforating system, blending new technologies with traditional tools in a single unit. On the surface, it has a logging panel, a control panel, and a perforating panel. It can incorporate a multitude of systems downhole, including depth control devices and digitally-controlled detonator select fire switches. The system is entering the commercialization phase.

▪ The innovator

Tendeka's FloSure autonomous inflow control device helps operators overcome the challenges of early water and gas breakthrough. It preferentially chokes unwanted produced fluids, while promoting production of oil from an entire horizontal well. More than 1000 units are manufactured each month, and there have been 5000 successful applications since early 2013.

▪ Safety innovations

Stork's Extended Reach Breathing Apparatus System (ERBAS) improves safety on deep, confined space operations, such as work in platform legs and FPSO tanks. Multiple refill stations are deployed throughout the exit route. Rather than changing cylinders, ERBAS can be refilled in less than 60 seconds while still worn by the operative.

▪ Export achievement

EV designs and builds wellbore camera systems able to work 10,000m below surface in extreme environmental conditions, on electric line, slickline, coil tubing, or drill pipe. Covering 17 locations worldwide, EV does over 100 well interventions a month for more than 300 clients.

▪ Environmentalist

TWMA's TCC RotoMil and TCC RotoTruck handle and treat drill cuttings at source, reducing cost, environmental impact, and safety risks by using a process of thermal desorption, which separates drill cuttings and associated materials into oil, water, and solids for recycling and reuse.

▪ Working together

The Underwater Centre collaborated with Skills Development Scotland to help workers transfer land-based engineering, fabrication, and construction skills into the subsea sector. In 2012, eight Scots were trained as commercial divers. In 2013, the figure exceeded 60. OE

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1. What is your main job function?
(check one box only)

- ☐ 01 Executive & Senior Mgmt (CEO,CFO, COO,Chairman, President, Owner, VP, Director, Managing Dir., etc)
- ☐ 02 Engineering or Engineering Mgmt.
- ☐ 03 Operations Management
- ☐ 04 Geology, Geophysics, Exploration
- ☐ 05 Operations (All other operations personnel, Dept. Heads, Supv., Coord. and Mgrs.)
- ☐ 99 Other *(please specify)*_____

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

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

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

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

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

- ☐ 101 Exploration survey
- ☐ 102 Drilling
- ☐ 103 Sub-sea production, construction (including pipelines)
- ☐ 104 Topsides, jacket design, fabrication, hook-up and commissioning
- ☐ 105 Inspection, repair, maintenance
- ☐ 106 Production, process control instrumentation, power generation, etc.
- ☐ 107 Support services, supply boats, transport, support ships, etc
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S31OS1

Numerology

200 families have benefitted from Oilfield Helping Hands' assistance. See page 13.

US$231,400 The average contract day rate for a high-spec jackup. See page 60.

2950 ft Water depth for Ormen Lange's compression system. See page 90.

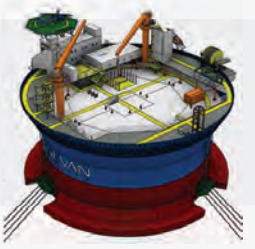
10,625nm Distance sailed by FPSO *Cidade de Ilhabela* from CXG yard in China to Brazil. See page 130.

365m The hull length of Petronas' first floating FLNG facility, PFLNG SATU. See page 20.

US$500 million How much the subsea processing market is worth according to Rystad Energy. See page 94.

233barG The design pressure of the Polarled pipeline. See page 72.

1MMbbl The proposed storage capacity for a circular-hull FPSO in the GOM. See page 150.



25,000 ft The drilling depth limit of Drillmec's 3000hp offshore modular rig. See page 64.

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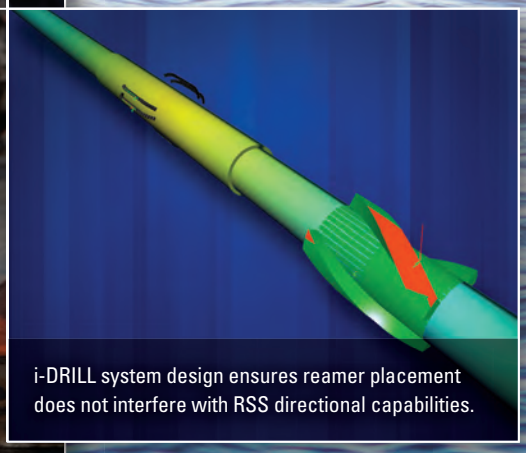
Rhino RHE

DUAL-REAMER RATHOLE ELIMINATION SYSTEM



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

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

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

Read the case study at
slb.com/RhinoRHE

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