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October 2015

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World Trends and Technology for Offshore Oil and Gas Operations

Lower Tertiary update

Drilling and production focus

North Sea review

Offshore

Celebrating 60 Years of Trends, Tools, and Technology

International Edition
Volume 75, Number 10
October 2015

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International Edition
Volume 75, Number 10
October 2015

COVER: Experts foresee seismic and drilling operations continuing in the Gulf of Mexico's Lower Tertiary play, despite the down market. Although the Lower Tertiary presents some challenges, its plentiful resources and solid, existing infrastructure make the high operational costs worth the risk for operators and contractors. An example of seismic activity continuing in the area is WesternGeco's *Amazon Warrior*, the world's first purpose-designed and built seismic vessel specifically designed for seismic acquisition, shown on the cover at day break in the Gulf of Mexico. The vessel was christened as the first in WesternGeco's Amazon-class in November 2013. Read what experts have to say about current and future activity in the Lower Tertiary on page 38. (Photo courtesy WesternGeco)

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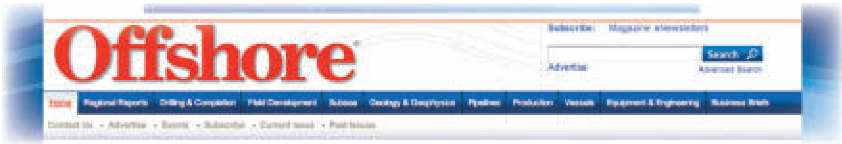

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http://www.offshore-mag.com/learning-center/learn-more.html

New on-demand webcast

➤ Assessing Mexico's new offshore oil and gas opportunities

When Mexico's historic energy reform legislation became law on Dec. 21, 2013, it opened the country to foreign investment in its oil and gas sector for the first time in 75 years. The newly formed Mexican National Hydrocarbons Commission has published the bidding and contract terms for the first three phases of the Round 1 bidding process, which includes shallow-water, shallow-water production, and onshore areas. The Commission is also expected to announce the deepwater areas to be awarded, as well as bidding and contract terms. Mayer Brown lawyers Dallas Parker and Gabriel Salinas discuss the bidding process in Mexico.

http://www.offshore-mag.com/webcasts/offshore/2015/09/assessing-mexicos-new-offshore-oil-and-gas-exploration-opportunities.html

New on-demand webcast

➤ Anadarko's decommissioning of the first-ever cell spar in the Gulf of Mexico

The Red Hawk spar made history throughout its design life, commissioned and decommissioned as the first of its kind. Heralded as the first cell spar ever built, it remains the lone cell spar ever fabricated just slightly 10 years after its inception. Decommissioned in September 2014, it then earned distinction of being the deepest floating production unit to be retired in the Gulf of Mexico.

Ryan Kavanagh, a facilities engineer and project manager working in Anadarko Petroleum Corp.'s Deepwater Facilities group, discusses the decommissioning of the first-ever cell spar in the GoM.

http://www.offshore-mag.com/webcasts/offshore/2015/08/anadarkos-decommissioning-of-the-first-ever-cell-spar-in-the-gulf-of-mexico.html

New video

➤ Anadarko – Lucius Success

The Lucius field in the ultra-deepwater Gulf of Mexico entered production in January 2015. Lucius was developed with six subsea wells tied back to a truss spar floating production unit (FPU), a cylindrical-shaped vertical platform connected to the shore via dedicated oil and gas pipelines. In this video, operator Anadarko Petroleum Corp. describes Lucius' journey from discovery to first production.

http://www.offshore-mag.com/index.html

David Paganie • Houston

Making the case for an all-subsea development

Statoil and its partners are moving the industry one step closer to an all-subsea field development solution. Last month, following a lengthy qualification and testing period, the industry's first subsea gas compression facility became operational in the Norwegian Sea. It also marks a milestone in Statoil's quest to qualify and prove all of the elements of a full-scale "Subsea Factory."

The new "dry" subsea compression system is designed to boost recovery from the Midgard reservoir on Åsgard from 67 to 87%, and from 59 to 84% from the Mikkel reservoir, for an additional 306 MMboe of total output. The solution involves the connection of two 11.5-MW centrifugal compressors equipped to handle 21 MMcm/d to existing subsea templates and piping the produced hydrocarbons 40 km from the *Asgard B* semisubmersible production platform. Qualification of the technology began in 2005 and involved about 50 components/systems.

Meanwhile, a separate, stand-alone project on the Gullfaks field will employ the industry's first subsea "wet" gas compression system. It is designed to increase recovery from the Gullfaks South Brent reservoir by 22 MMboe. The solution, involving two 5-MW wet gas compressors with capacity to handle 10 MMcm/d, is connected to existing subsea templates. The hydrocarbons will be transported via pipeline some 15 km from the *Gullfaks C* semisubmersible production platform. Qualification of helico-axial multiphase compressor technology for the project has been ongoing since 2008.

In general, a well with subsea compression can produce at lower wellhead pressures, thereby accelerating production and/or increasing recovery. The difference relative to topside compression is an improvement in wellhead pressure depending on water depth, by locating the compressor closer to the wells. The subsea approach is also thought to be more energy efficient than the traditional topside solution.

Business case

The business case for an all-subsea development is heavily influenced by the production phase of a reservoir, explains DNV GL in a recent position paper: "All Subsea – Creating Value from Subsea Processing."

The firm finds that, for brownfield projects, the various subsea systems may be used alone or in combination with other technologies. In contrast, an all-subsea solution for a greenfield project has more limited applicability. Meanwhile, FLNG technology is emerging as the preferred development concept for greenfield gas developments as an alternative to a subsea tieback directly to shore. **For more on the FLNG market and topsides weight considerations, see page 58 for a report by Nick White with Granherne.**

The DNV GL paper suggests that the Åsgard and Gullfaks projects, together, illustrate that the strongest candidates for brownfield subsea compression are likely projects in mature areas such as Northwest Europe. The infrastructure in the area is sufficient for pipeline transport, onshore processing is developed, and power is available from a stable grid onshore. **For more on the market in Northwest Europe, see page 32 for a report by Markus Nævestad and Jo Husebye with Rystad Energy.**

The business case for wet subsea compression on Åsgard was strengthened by the lack of available space on the field's platform topsides, which would have required a new compression platform in the absence of an alternative.

For fields that are larger or have long step-out distances, such as Gullfaks, and thus require greater pressure boost, dry gas compression emerges as a feasible solution for the business case. The configuration also allows for the tie-in of future satellite wells.

The successful installation and start-up of subsea compression in the Norwegain Sea illustrates the industry's ongoing commitment to advancing susbsea technology. However, the length of the qualification process raises an interesting question: Is it possible to advance the pace of technology development without compromising quality and integrity? More research and development is needed in the areas of condition monitoring, power transmission and distribution, and storage, to enhance the case for an all-subsea development.

David Paganie

To respond to articles in Offshore, or to offer articles for publication, contact the editor by email (davidp@pennwell.com).

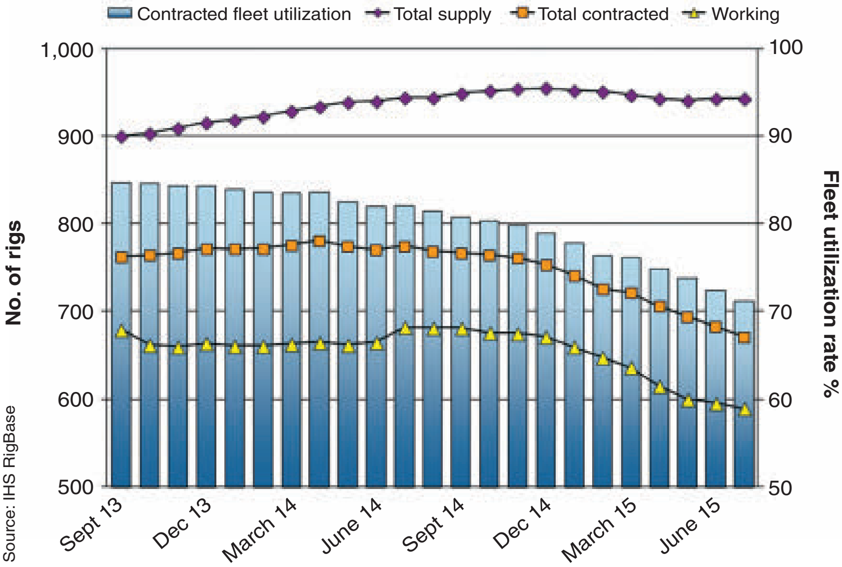
Worldwide day rates

Year/Month	Minimum	Average	Maximum
Drillship			
2014 Sept	$151,000	$497,377	$735,000
2014 Oct	$151,000	$502,593	$735,000
2014 Nov	$151,000	$508,019	$735,000
2014 Dec	$151,000	$506,320	$735,000
2015 Jan	$151,000	$502,063	$735,000
2015 Feb	$151,000	$507,978	$735,000
2015 Mar	$151,000	$507,013	$735,000
2015 Apr	$97,000	$504,913	$735,000
2015 May	$97,000	$503,880	$708,000
2015 June	$97,000	$509,929	$670,000
2015 July	$97,000	$509,459	$670,000
2015 Aug	$97,000	$500,953	$670,000
Jackup			
2014 Sept	$43,300	$141,099	$389,000
2014 Oct	$43,300	$142,736	$389,000
2014 Nov	$43,300	$143,299	$389,000
2014 Dec	$43,300	$144,383	$389,000
2015 Jan	$51,405	$142,947	$389,000
2015 Feb	$51,405	$143,636	$389,000
2015 Mar	$51,405	$144,267	$389,000
2015 Apr	$38,000	$142,561	$389,000
2015 May	$51,405	$142,717	$389,000
2015 June	$51,405	$142,498	$414,000
2015 July	$53,000	$138,886	$414,000
2015 Aug	$35,000	$138,896	$414,000
Semi			
2014 Sept	$145,000	$386,874	$641,000
2014 Oct	$145,000	$388,652	$641,000
2014 Nov	$145,000	$391,135	$641,000
2014 Dec	$145,000	$389,285	$641,000
2015 Jan	$145,000	$396,411	$641,000
2015 Feb	$145,000	$397,120	$641,000
2015 Mar	$145,000	$403,260	$641,000
2015 Apr	$145,000	$401,542	$641,000
2015 May	$115,000	$401,439	$605,000
2015 June	$115,000	$403,049	$605,000
2015 July	$115,000	$400,393	$624,000
2015 Aug	$115,000	$400,940	$624,000

Source: Rigzone.com

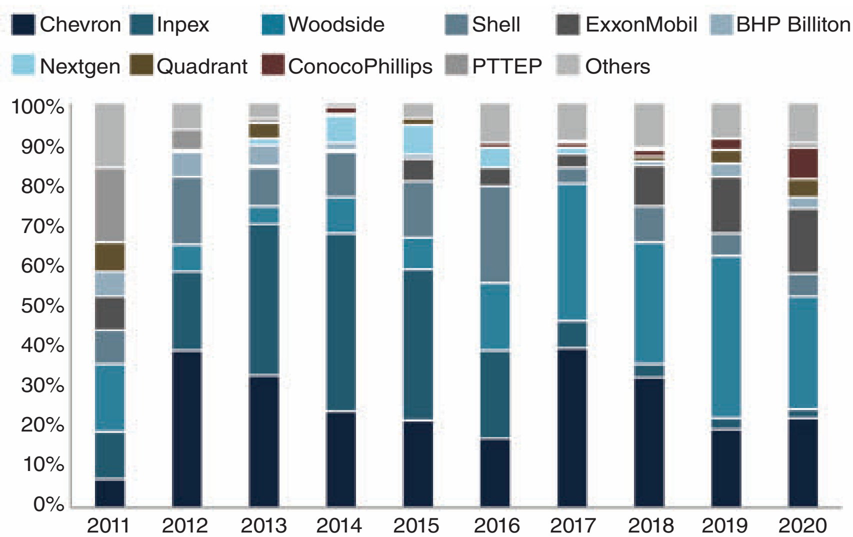
Worldwide offshore rig count & utilization rate

September 2013 – August 2015



Source: IHS RigBase

Australian offshore capex (%) by operator 2011-2020



Source: Infield Systems Market Modeling & Forecasting Database

This month Infield Systems takes a brief look at the Australian offshore market up to 2020. Australia is anticipated to continue to attract offshore investment despite the current slump in global oil prices, with Infield Systems' market projection expecting Australian offshore capex to hit a low point in 2017. Despite this fall, there could be a 152% increase in offshore fields coming onstream between 2016 and 2020 in comparison to the historic period (2011-2015), with Woodside, ExxonMobil, and Chevron expected to see the largest number of fields enter production. The North West Shelf is expected to see the largest concentration of activity, with the Carnarvon, Browse and Bonaparte basins being key areas of offshore development.

Australia has large natural gas resources; this, coupled with its proximity to the Asian gas markets has seen the country become an increasingly important player in the export of LNG. There are currently three onshore LNG projects under construction which will source feedstock gas from offshore sources: Chevron's Gorgon and Wheatstone LNG projects and INPEX's Ichthys LNG project. Other onshore LNG projects are also under construction but these will source gas from onshore sources.

Australia is expected to see increasing interest in FLNG technology in the future to unlock some of its remote offshore resources. Indeed, the country will see one of the world's first FLNG projects enter production over the next few years, Shell's Prelude FLNG project in the remote Browse basin. Once deployed the Prelude FLNG FPSO will be the world's largest offshore production facility capable of producing around 3.6 mtpa of LNG. Other operators are also considering the possibilities of using FLNG FPSOs in the country, such as Woodside, which is currently looking to develop its Browse resources using FLNG technology.

–George Griffiths, Senior Energy Researcher, Infield Systems

Mexico

PEMEX has awarded Wood Group a three-year scoping study, worth up to $28 million, for various fields in the Gulf of Mexico. Wood Group Mustang will perform concept and basic engineering of topsides, subsea, and floating facilities for the deepwater Exploratus Piklis, Kunah, Trion and Lakach fields and the heavy-oil Ayatsil, Tekel, and Utsil fields.

Talos Energy's shallow-water blocks offshore Mexico. (Map courtesy Premier Oil)

Two of the offshore blocks awarded under Mexico's first licensing round this summer were in the shallow-water Sureste basin. Talos Energy operates blocks 2 and 7, both containing Tertiary clastic plays, according to partner Premier Oil. The partners will acquire and reprocess 3D seismic with a view to firming up drilling locations by the end of 2016.

South America

Ecopetrol plans to establish a subsidiary company focused on exploration offshore Colombia. It will then seek approval from the country's National Hydrocarbon Agency to assign its contractual rights to the E&P contracts for offshore blocks in which it is a partner.

•••

Petrobras has produced first oil through the FPSO *Cidade de Itaguai* on the Iracema Norte area of the Lula field in the presalt Santos basin, 240 km (149 mi) offshore Rio de Janeiro in 2,240 m (7,349 ft) of water. The company's subsidiary Tupi BV has chartered the vessel from MODEC under a 20-year lease and operation contract. It is designed to process 150,000 b/d of oil and 280 MMcf/d of gas.

West Africa

Kosmos Energy plans delineation drilling on its deepwater Tortue gas discovery (since renamed Ahmeyim) offshore Mauritania. The discovery well earlier this year was one of the largest offshore finds anywhere this year, the company claimed, encountering hydrocarbons in Cenomanian and Albian intervals. Kosmos was also preparing to spud the Marsouin-1 exploratory well in block C-8 in the central Mauritanian offshore sector.

•••

The drillship *Ocean Rig Athena* was due to start drilling back-to-back appraisal wells this month on the 2014 deepwater SNE oil discovery offshore Senegal. The vessel is under contract to ConocoPhillips, a partner in the consortium led by Cairn Energy. Depending on the results, the partners plan a third well on the previously unexplored Bellatrix prospect, which is thought to overlie the northern end of SNE.

•••

Nigerian independent Oriental Energy Resources has agreed to take charge of operations for the shallow-water Ebok field offshore Nigeria after partner and operator Afren declared insolvency. Oriental will take on all duties as technical advisor and will renegotiate all existing contracts for the development with the various suppliers. Oriental also planned to continue implementation of the development plan for the offshore Okwok field via the same handover process.

•••

Sonangol has agreed to acquire Cobalt International Energy's 40% operating interest in blocks 21/09 and 20/11 offshore Angola for $1.75 billion, subject to approvals. Until the transfer goes through, both parties will work to secure a final investment decision for the Cameia development in block 21/09 by year-end, with a view to deliver first oil in 2018.

Eastern Europe

Representatives from Gazprom, E.ON, Shell, OMV, and BASF/Wintershall have signed an agreement to construct two new gas lines for the Nord Stream II project in the Baltic Sea. These will supply 55 bcm/yr of Russian gas to markets in Europe via a reception point in Germany, doubling the current throughput of the existing Nord Stream pipelines. Gazprom will have a 51% share in the joint project company responsible for the program.

Mediterranean Sea

Rockhopper has received approval for the environmental impact assessment for its Ombrina Mare field development in the Adriatic Sea. Subsequent authorization from Italy's Ministry of Economic Development should complete the formal award of the surrounding production concession.

•••

Circle Oil has secured a renewal of the exploration permit for its Mahdia block offshore Tunisia until Jan. 19, 2018. The concession includes the 2014 El Mediouni (EMD-1) discovery well, which encountered oil in Ketatna (Oligo-Miocene) carbonates, although mud losses prevented logging. Circle, which has identified numerous other similar prospects, has committed to drill one exploration and one appraisal well and to acquire 3D seismic.

•••

Eni claims to have proven a potential gas super-giant in the deepwater Shorouk block offshore Egypt. The Zohr 1X NFW well, drilled in 1,450 m (4,757 ft) of water, may have unlocked 30 tcf of lean gas covering an area of around 100 sq km (39 sq mi). The well encountered hydrocarbons in Miocene carbonates. Eni plans follow-up drilling, including a well targeting the structure's deeper Cretaceous potential.

•••

Israel's government has approved a drafted outline relating to development of various offshore gas fields. According to Delek Group, these include the Leviathan, Karish, and Tanin fields and a project to increase gas extraction from the deepwater Tamar field.

Middle East

McDermott has scooped its largest single award ever in the region in the form of a lump-sum contract from Saudi Aramco for brownfield work on various fields offshore Saudi Arabia. The duration is until 2Q 2018. McDermott plans to assign much of the engineering and fabrication scope to its facilities in Al Khobar and Dammam, supported by its teams in Dubai and Chennai. McDermott vessels will handle all offshore installations.

•••

ZADCO has extended Amec Foster Wheeler's project management consultancy contract for the UZ750 project, originally awarded in mid-2008. This involves a redevelopment of the offshore Upper Zakum oil field, 84 km (52 mi) northwest of Abu Dhabi, which is intended to sustain production at 1 MMb/d until at least 2050. Production is via four artificial islands with associated drilling and production facilities. All work under the extension must be completed by December 2017.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East Africa

ION Geophysical has a contract from the Puntland Petroleum Minerals Agency (PPMA) to acquire 8,000 km (4,971 mi) of 2D seismic over the entire Somalia Puntland offshore margin. Results from the program, designed to improve understanding of the sedimentary basin in this unexplored region, will assist a future license round initiative. PPMA has divided the Puntland offshore territory into 25 exploration blocks spanning a total area of 180,000 sq km (69,498 sq mi).

• • •

Aminex has secured a deferral of its obligation to drill two exploration wells in the Nyuni area offshore Tanzania from the Ministry of Energy and Mines. It also has approval to convert shallow-water 2D seismic commitments to acquisition of 3D data on the potentially more prospective deepwater portion of the license, and has started re-tendering for a contractor to perform the program.

Eastern Russia

Two Rosneft/Statoil joint ventures – Magadanmorneftegaz and Lisyanskmorneftegaz – have secured a rig for two exploration wells next year in the Sea of Okhotsk. The China Oilfield Services Ltd.-owned semisubmersible *Nanhai-9* will drill in the Magadan-1 and Lisyansky areas, respectively 100 km (62 mi) and 90 km (56 mi) offshore, south of the Arctic Circle, in water depths below 150 m (492 ft).

Gazprom Geologarzvedka has approval to acquire 3D seismic in the Sea of Okhotsk offshore Sakhalin Island. The agreed program for this ecologically sensitive area, which followed detailed consultations, stipulates continuous environmental monitoring for all stages of operations. The company operates three license blocks offshore Sakhalin that include the Yuzhno-Kirinskoye field, recently added to the US government's list of sanctions in response to Russia's activity in Ukraine, according to Reuters. Export or transfers of oil will now require a license from the US Department of Commerce which is unlikely to be approved, Reuters reported.

Australasia

Esso Australia has completed a five-well program on the Turrum gas/oil field in the Bass Strait off southeast Australia. The AUD $335-million ($232-million) project involved drilling four new gas wells and one oil producer.

• • •

New Zealand's consultation process with local authorities and tribal communities on new oil and gas exploration permits is due to close at the end of this month. The government aims to issue tenders for offshore and onshore oil and as acreage by March 2016. According to Energy and Resources Minister Simon Bridges, "Successive block offers have shown that operators are looking for long-term opportunities in a mix of mature and frontier acreage."

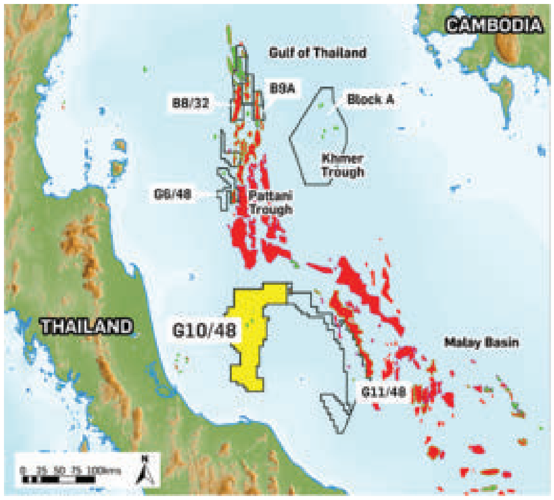
Asia/Pacific

Tap Oil and partner Smart E&P International have signed a production-sharing contract for block M-7 in the Moattama basin offshore Myanmar. They will conduct an 18-month environmental/social impact study campaign over the shallow-water concession before deciding whether to proceed to a three-year exploration phase.

• • •

Singapore-based KrisEnergy has started up its first offshore project as operator at the Wassana oil field in the Gulf of Thailand. Main facilities are the MOPU *Ingenium*, a mooring buoy, and the FSO *Rubicon Vantage*. The jackup *Key Gibraltar* is drilling the wells. KrisEnergy plans up to 14 producers and one water disposal well, with peak oil production of around 10,000 b/d. Wassana is

The Wassana oil field is in the G10/48 concession offshore Thailand. (Map courtesy KrisEnergy)



in the G10/48 contract area in shallow water in the Southern Pattani basin.

Ophir Energy has contracted the jack-up *Vantage Emerald Driller* to start its first exploration campaign in the G4/50 block since acquiring former operator Salamander Energy. The block surrounds the B8/38 license containing the producing Bualuang oil field. The rig was due to drill the Soy Siam and Parichat prospects with combined prospective resources of more than 50 MMbbl.

• • •

Oil and gas production is building through the newly onstream H5 wellhead platform on the southern part of the Te Guiac Trang field in the Cuu Long basin, 100 km (62 mi) from Vung Tau in southern Vietnam. This is the third platform to be brought into service on the field since it was discovered in 2005.

Talisman Energy has contracted Wood Group branches in Kuala Lumpur and Houston to perform front-end engineering and design studies for the 67-MMboe Ca Rong Do field offshore Vietnam. The combined scope covers the subsea system, including flowlines and umbilicals, and the dry tree riser systems for the field's tension leg wellhead platform.

Rosneft has commissioned Japan Drilling Co.'s *Hakuryu-5* rig to drill two exploration wells next year on blocks 06.1 and 05-3/11 in the Nam Con Son basin.

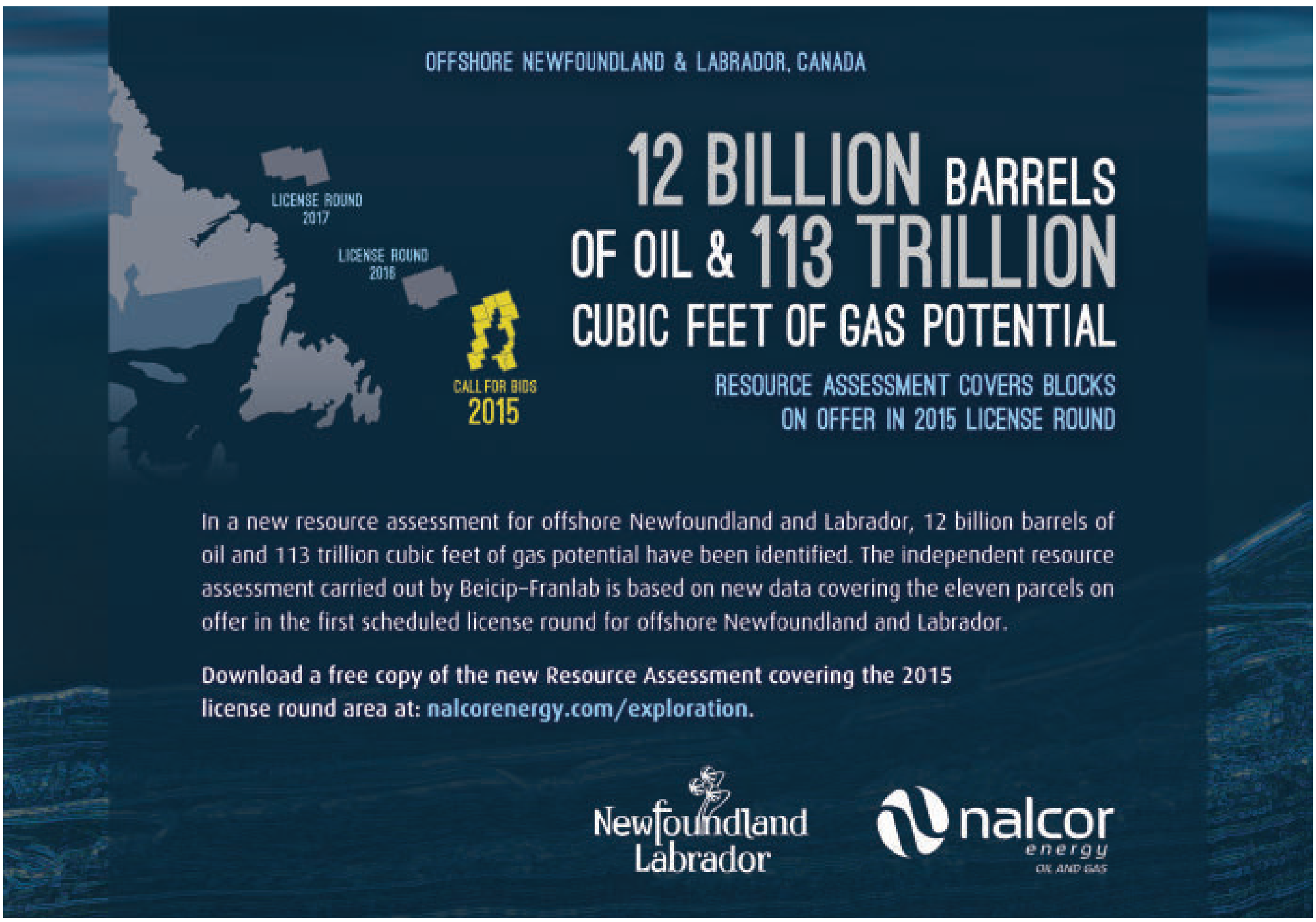
• • •

Fluor and CNOOC subsidiary Offshore Oil Engineering Co. have agreed to form a joint venture, COOEC Fluor Heavy Industries Co. This will operate the 2-million sq m (21.6-million sq ft) Zhuhai fabrication yard in China's Guangdong province, which will be able to accommodate modules weighing more than 50,000 tons.

CNOOC has signed production-sharing contracts with ROC Oil for blocks 16/07 and 03/33 in the South China Sea. Both are in the Pearl River Mouth basin, in water depths ranging from 65-145 m (213-476 ft). ROC will operate during the exploration period, covering all related expenditures.

• • •

INPEX has submitted a revised development plan for the Abadi gas field in the Masela block in the Arafura Sea offshore Indonesia. This calls for use of an FLNG vessel with a capacity to process 7.5 MM tons/yr, three times the volume of the originally envisaged scheme. The increase follows positive results from appraisal drilling on the field during 2013-14.

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Jeremy Beckman • London

OGA outlines steps to safeguard UK's future

Britain's new Oil & Gas Authority (OGA) has issued its second report on the way forward for the UK continental shelf, following its Call to Action earlier this year. *Six months on* highlights how OGA has been working with the sector's main producers to improve production efficiency and management of late-life offshore facilities. Another new initiative is an enhanced oil recovery (EOR) strategy, designed to deliver an extra 250 MMboe from the shelf over the next decade, focusing on polymer and low-salinity water technologies.

Revitalizing exploration is also a priority, with recent exploration drilling in UK waters failing to deliver the returns achieved in previous decades (although Chrysaor's recent wildcat on the Mustard structure west of Shetland has reportedly discovered oil). OGA forecasts a total of 16 exploration and appraisal wells across the sector this year, higher than last year's total, but almost half the 31 drilled during 2010.

The association's analysis of failed wells drilled in the Moray Firth and UK central North Sea between 2003 and 2013 identified room for improvement in technical work to avoid drilling poor-quality prospects in the future. OGA plans to implement a pre- and post-drill evaluation quality assurance process with operators and ensure that lessons learned from analysis of the dry holes is shared. In addition, it plans to work with operators to high-grade their prospect inventories and stimulate more drilling, particularly in frontier regions.

In July, Western Geco started work on a UK government-funded seismic acquisition survey over the Rockall Trough area in the Outer Hebrides off northwest Scotland. Only 12 exploratory wells have been drilled here since 1980, including the 2000 Benbecula discovery, but most of the existing seismic data was shot pre-1998. Another area to be surveyed is the Mid-North Sea High, where advances in broadband acquisition technologies and processing techniques will be applied to improve deeper imaging of the Palaeozoic interval.

Heerema Fabrication Group is building all three jackets for the Culzean platform complex. (Image courtesy Heerema Fabrication Group)

Culzean, Maria get the green light

OGA has approved the $4.5-billion development plan for the high-pressure/high-temperature (HP/HT) Culzean gas/condensate field in the UK central North Sea. Operator Maersk Oil and partners JX Nippon and Britoil plan a three-platform complex in 90 m (295 ft) of water, delivering plateau production of 60-90,000 boe/d. Start-up is scheduled for 2019.

Prior to sanction Maersk had already placed some of the major construction contracts. Post-sanction awards include the $1-billion EPC order to Sembcorp Marine subsidiary SMOE for the topsides for the three platforms; construction of the jackets for two of the platforms to Heerema Fabrication Group; and the $150-million SURF contract to Subsea 7 which includes installation of a 52-km (32-mi), 22-in. gas export pipeline to be connected to the UK's Central Area Transmission System. Maersk said the project was able to go forward in the current climate thanks to the government's new HP/HT Cluster Area allowance.

Wintershall secured the Norwegian government's approval to proceed with its $1.9-billion development of the Maria field in 300 m (984 ft) of water in the Norwegian Sea via two subsea templates tied back to three existing production platforms. Maria's wellstream will head to the Kristin platform for processing, with the Heidrun platform supplying water for injection into the Maria reservoir, and Åsgard B providing gas lift via the Tyrihans D field subsea template. Odfjell Drilling's dual-derrick semisubmersible *Deepsea Stavanger* will drill at least six development wells, starting in April 2017, while Expro will supply a workover riser system, including surface test tree and subsea landing string systems.

Forward planning under way for Johan Sverdrup

Statoil has commissioned Kvaerner Verdal to construct the 22,500-metric ton (24,802-ton) jacket for the drilling platform for the Phase 1 Johan Sverdrup development in the central Norwegian North Sea. The operator and its partners are also closing on concept selection for Phase 2, said Statoil's Senior Vice President Oivind Reinertsen during a briefing last month at Offshore Europe in Aberdeen.

Norway's government sanctioned a revised plan for Phase 1 in August that calls for installation of a bridge-linked four-platform complex connected to three subsea water injection templates in 110 m (361 ft) of water, and producing up to 380,000 boe/d. Johan Sverdrup's oil is under-saturated with small volumes of associated gas, Reinertsen said, and much of the gas that is produced will be needed for gas lift purposes (Statoil plans to implement water-alternating-gas technology to increase oil recovery). What remains will be piped to Kårstø: oil and gas pipelines will both be installed during 2017-18.

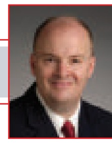
Phase 2 will tie in more outlying areas of the field to the super-complex either via subsea facilities or jackups drilling on small satellite platforms with eight to 10 well slots, Reinersten said. To take into account the government's stipulation that all new field developments on this part of the Utsira High must be powered from shore, Phase 2 must also come onstream no later than 2022. One of the considerations for the partners is whether to locate the cable importing power on Johan Sverdrup's riser platform (which would serve as the local offshore power hub). Future phases of the project, which could lift the field's production to 650,000 boe/d, remain on the drawing board, he added, but would probably cost in the range of $6-12 billion.

UK decomm on the rise

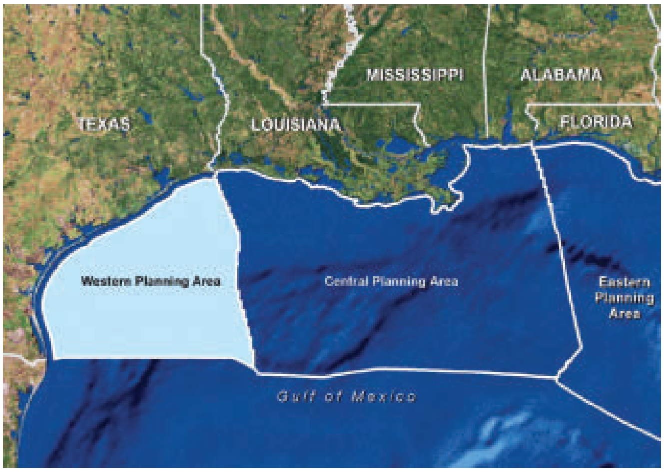
Spending on decommissioning on the UKCS could overtake field development outlay in 2019, according to analyst Wood Mackenzie. The current prolonged period of lower oil prices, and the likelihood of a modest recovery only in the short to medium term, has forced UK operators to re-evaluate their field life extension plans.

Over the next five years around 140 UK offshore fields could cease production, even if the oil price recovers to $85/bbl, Wood Mackenzie claims. Around 50 fields could shut down earlier if the recovery is restricted to $70/bbl, it adds.

To date, 30 UK offshore fields have been abandoned, and the experience of what is involved has pushed estimates for future decommissioning projects above predictions from a decade earlier. Another factor driving up costs are stricter P&A rules for well abandonment.



Bruce Beaubouef • Houston



The BOEM is proposing to offer approximately 22 million acres for oil and gas leasing in the Western Planning Area Lease Sale 248, proposed for 2016. (Courtesy BOEM)

BOEM outlines next GoM lease sales

The US Bureau of Ocean Energy Management (BOEM) says it will offer 40 million acres offshore Louisiana, Mississippi, and Alabama for oil and gas exploration and development in sales that will include all available unleased areas in the Central and Eastern Gulf of Mexico Planning Areas.

Proposed Gulf of Mexico Central Planning Area (CPA) Lease Sale 241 and Eastern Planning Area (EPA) Lease Sale 226, scheduled to take place in New Orleans in March 2016, will be the ninth and tenth offshore sales under the Administration's Outer Continental Shelf Oil and Gas Leasing Program for 2012-2017 (Five-Year Program).

Proposed CPA Sale 241 will include approximately 7,919 blocks, covering 42.1 million acres, located from three to 230 nautical miles offshore, in water depths ranging from nine to more than 11,000 ft (three to 3,400 m).

Proposed EPA Sale 226 will offer approximately 175 blocks, covering 595,475 acres. The blocks are at least 125 statute miles offshore in water depths ranging from 2,657 ft to 10,213 ft (810 m to 3,113 m). The area is bordered by the Central Planning Area boundary on the West and the Military Mission Line (86º 41'W) on the East. It is south of eastern Alabama and western Florida; the nearest point of land is 125 miles (201 km) northwest in Louisiana.

The BOEM says it has published the final supplemental environmental impact statement prepared for these sales.

In addition, BOEM has published a draft supplemental environmental impact statement for its proposed Gulf of Mexico Western Planning Area Lease Sale 248.

The BOEM is proposing to offer approximately 22 million acres for oil and gas leasing in the WPA, with the exception of whole and partial blocks within the boundary of the Flower Garden Banks National Marine Sanctuary. The sale is proposed to be held in 2016.

Public meetings were scheduled in Houston and New Orleans in September, but interested parties may also comment by email no later than Oct. 19, 2015, at wpa248@boem.gov.

The Public Review page on the BOEM website is also available at http://www.boem.gov/nepaprocess/ for details on how to submit comments and to download or view the Draft Supplemental EIS.

Shell taps OneSubsea for Stones

Shell Offshore Inc. has awarded OneSubsea a contract to supply subsea processing systems for the Stones project in the Gulf of Mexico.

The award comes after a technology qualification program and will deliver the industry's first 15,000-psi subsea pump system, to be installed in the Gulf of Mexico at approximately 9,500 ft (2,900 m). The system will be tied back to the Stones FPSO.

The subsea processing systems scope includes a dual pump station with two 3-MW single-phase pumps and two subsea control modules, a topsides power and control module, a barrier-fluid hydraulic power unit with associated spares, as well as installation and maintenance tools.

Manufacturing and testing will take place at OneSubsea's facility in Horsøy, Norway, for delivery in early 2018.

Shell awards Appomattox contracts

Shell Offshore Inc. has awarded a number of contracts related to its Appomattox project, which will be developed in the Mississippi Canyon area in approximately 7,200 ft (2,195 m) of water.

Oceaneering International Inc. says it has secured a contract from Shell to supply umbilicals for the project. The order is for electro-hydraulic steel tube control umbilicals, totaling approximately 60 km (37 mi) in length. Product manufacturing is planned to be performed at the company's umbilical facility in Panama City, Florida, beginning in 4Q 2015 and completed in 3Q 2017.

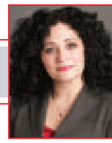
Danos reports that it has received a contract from Shell to fabricate three boarding valve skid assemblies for Appomattox. Danos says that the project will engage five of its divisions – coatings, fabrication, instrumentation and electrical, project management, and procurement. The company says that this work is underway, and is expected to take about 12 months to complete.

The boarding valve skids will be fabricated at the company's fabrication facility in Amelia, Louisiana, and shipped to Ingleside, Texas, for integration on the facility topsides. Following integration, the equipment will be installed on a floating production platform about 80 mi (129 km) offshore Louisiana.

COSCO Shipping Co. has signed a contract with Shell for the transportation of the Appomattox semisubmersible platform hull from South Korea to Ingleside, Texas via the heavy transport vessel *Guang Hua Kou*. (Courtesy COSCOL)

COSCO Shipping Co. Ltd. (COSCOL) says it has signed a contract with Shell for the transportation of the Appomattox semisubmersible platform hull from South Korea to Ingleside, Texas.

Shell's 41,165 metric ton (45,376 ton) hull will be transported on COSCOL's newbuild 98,000 deadweight ton vessel *Guang Hua Kou*. The heavy transport vessel is currently under construction at the COMEC shipyard in Guangzhou, China, and expected to be delivered in late 2016.



Sarah Parker Musarra • Houston

DNV GL discusses new JIPs

Following an August report issued by the US Bureau of Safety and Environmental Enforcement (BSEE) entitled the "Quality Control-Failure Incident Team (QC-FIT) Evaluation of Connector and Bolt Failures," DNV GL Oil & Gas is now working with the US regulator on a joint industry program (JIP) addressing subsea bolt integrity. Prior to kick-off, *Offshore* spoke with DNV GL Oil & Gas' Eric Allen, business development leader—deepwater technology, to get more details on the project.

The report references a Dec. 18, 2012 incident where the lower marine riser package (LMRP) of an ultra-deepwater drillship working in the Gulf of Mexico separated from the BOP. As a result, 432 bbl of synthetic-based drilling fluids were spilled.

The operator reported to the BSEE that "the incident was the result of the failure of H4 connector bolts on the LMRP." Analysis conducted after the incident prompted the bolt manufacturer to send replacement bolts to its customers around the globe for all known H4 bolts – more than 10,000 bolts overall.

The report concluded that the bolt failure was primarily caused by hydrogen-induced stress corrosion cracking due to hydrogen embrittlement, which led to the fracturing of the installed bolts. It was also found that a subcontractor employed to work on the BOP was relying on an outdated American Society for Testing and Materials bolting standard, and that the H4 connector bolts did not receive post electroplating treatment. At the time, the operator only audited first-tier suppliers, a practice which complied with safety standards of the time, the report said. A third-tier supplier performed the electroplating coating of the bolts, so the bolt manufacturer was unable to detect the issue.

Allen has been developing this JIP, which aims to enhance reliability and integrity for subsea bolts, over the past year. Although subsea bolt failure was not common, he explained, it was not rare, and as an engineer, he felt it needed to be addressed.

Although subsea bolting failure due to the issues described in the QC-FIT have been widely documented, other failure modes and mechanisms have also been experienced. Allen said that the JIP is unique because it hopes to address all aspects of the subsea bolting lifecycle, starting from design.

The JIP is also placing a priority on providing BSEE with an industry code review and survey to identify state-of-the-art requirements for bolts, and identify parts for clarification and improvement. BSEE can then define how standards or regulations should be changed to best address these issues accordingly.

The QC-FIT report also noted that "existing standards do not adequately address bolting/connector performance in subsea marine application." One key issue with these different standards is consistency, and the JIP is looking to evaluate industry standards to make its own determinations and recommendations to BSEE.

In addition to there being several different existing standards specifying materials for subsea high-strength fasteners applications, Allen explained that these standards are not necessarily focused on subsea applications. In this context, "this JIP is about code harmonization, and trying to create the proper methodology" he said. In order to develop a comprehensive standard that addresses specification for the subsea fasteners, Allen said that it is important to quantify the effect of mechanical properties and other critical parameters, in accordance with the subsea bolt application and operating environment.

The JIP aims to begin its work in 4Q 2015, and will launch into the industry code review and gap study. It also plans to examine past failures, performing root cause analysis on these incidents.

Allen discussed this development with *Offshore* days after DNV GL released news of other JIPs it was forming. The advisor/classifier is also launching a JIP to investigate affordable composite components for the subsea sector.

The DNV GL affordable composites for the oil and gas industry JIP aims to reduce the cost of qualifying composite components for subsea use by replacing large-scale tests with certification by simulation. Statoil, Petrobras, Petronas, Nexans, Airborne, and the Norwegian University of Science and Technology (NTNU) in Trondheim are participating in the project, which is partly funded by the Research Council of Norway.

The project, which DNV GL says could potentially deliver a 40 to 50% cost saving for certification and qualification of subsea composite components, will seek to validate new advanced material models by experimentation, with the main focus on predicting chemical aging.

"On a general basis, we would say that during these cost-challenging times it is also a great time for collaboration," Bjørn Søgård, Segment Director Subsea and Floaters in DNV GL Oil & Gas, explained to *Offshore* when asked about its recent JIPs. "We urge the industry to join forces on innovation and smart standardization to lower costs and enable rapid and efficient technology implementation. Our JIPs have shown that collaboration actually works and we are now seeing the powerful results they can make. The proof comes now when they are put into real projects."

The Åsgard subsea compressor, shown here prior to installation in December 2014, is now the first plant to operate on the seafloor, rather than onshore or on a platform. (Courtesy Harald Pettersen, Statoil)

Subsea compression online at Åsgard

Statoil says the world's first subsea gas compression plant has begun operating at the Åsgard production complex in the Norwegian Sea. Located in about 300 m (984 ft) of water, the plant should add around 306 MMboe to total output over the field's life, the operator added.

Work started on the program in 2005, and the plan for development an operation was approved in 2012. Overall, project costs totaled just above $2.3 billion.

The Midgard and Mikkel gas reservoirs, both connected to the Åsgard complex, were originally developed using subsea installations. The two gas compressors now installed on the seabed are both close to the wellheads. Prior to gas compression, gas and liquids are separated out, and after pressure boosting are recombined and sent through a pipeline 40 km (25 mi) to the Åsgard B platform.

Statoil estimates that subsea compression should boost recovery from the Midgard reservoir from 67% to 87%, while recovery from the Mikkel reservoir should increase from 59% to 84%. Both reservoirs' productive lives should therefore be extended through 2032.

Statoil says that over the course of the project, more than 40 new technologies have been developed and deployed following testing and verification.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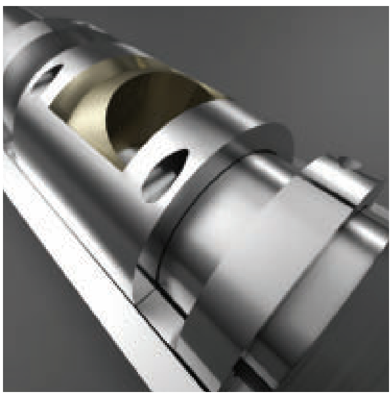
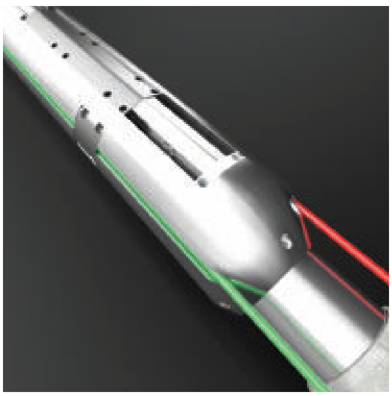
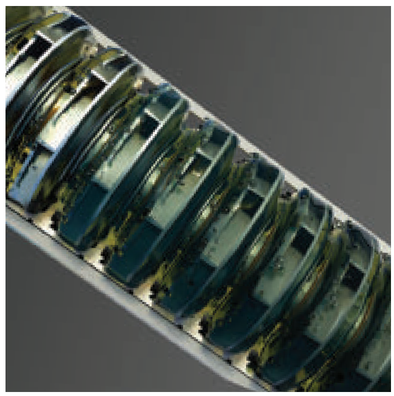
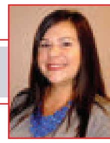








Robin Dupre • Houston

ZPMC and OTL form joint venture

ZPMC Offshore Services Group, a subsidiary of Shanghai Zhenhua Heavy Industries (ZPMC) and OffshoreTech LLC (OTL) have formed a strategic joint venture, ZPMC-OTL Marine Contractor Ltd. The new JV is slated to pursue top-tier offshore T&I projects and decommissioning projects, while providing access to unique niche vessels and engineering for execution of a broad range of complex offshore projects.

Leveraging the complementary capabilities and experience of both companies, the alliance will open up further opportunities by combining ZPMC's fleet of 23 transportation vessels, five shear leg cranes (1,600-5,000 MT), 18 tugs, 22 barges, three jackup barges, and ultimately the *Zhen Hua 30*, the largest single floating crane in the world with a lifting capacity of 12,000 MT, with OTL's expertise in offshore transportation and installation engineering design and proficiency.

The *Zhen Hua* 30 heavy-lift vessel can accommodate 380 persons and is suited to meet deepwater development demands. (Photo courtesy ZOMC)

"The *Zhen Hua 30* with the supporting fleet of assets combined with specialist engineering knowledge will allow ZOMC to execute projects 100% in-house, and we provide the complete service by combining transportation with the installation," said Ryan Rush, vice president Sales and Marketing for ZOMC. "This significantly reduces interface risk and ultimately reduces project costs which is critical in today's market."

PGS to take third Ramform vessel offline

PGS says it will cold-stack its seismic acquisition vessel *Ramform Viking* after it completes a multi-client project offshore east Newfoundland in late October. The vessel was originally due for a yard stay and classing in 1Q 2016, which will be deferred. *Ramform Viking*'s in-sea equipment will now be deployed on vessels in operation. This should cut PGS' capex related to maintenance in 2016 by around $50 million.

Earlier the company announced it would cold-stack the *Ramform Explorer* and *Ramform Challenger* after the end of this year's North Europe acquisition season.

Cold-stacking the three vessels should reduce its quarterly cash costs by $25-30 million from 1Q 2016.

Damen workboat headed to Middle East

Damen Shipyards has delivered a Damen Fast Crew Supplier 2610 workboat to Atlantic Maritime Group.

The *AOS Swift* will be the first Damen Twin Axe vessel in the Middle East. It will be used for passenger transfer and delivery of materials and equipment to unmanned offshore platforms in the Strait of Hormuz. The vessel is going to be chartered to a Norwegian oil and gas company for its platform operations offshore Oman.

Damen Fast Crew Supplier 2610 named *AOS Swift*. (Photo courtesy Damen)

The vessel was shipped from Damen Shipyards Gorinchem to Damen Shipyards Sharjah for further outfitting. A gas detection system has been installed and extra air-conditioning units were needed for the Middle East climate zone. This FCS workboat is also equipped with an additional hydraulically-operated 2,200 kg (2.45 ton) crane with a reach of 8.6 m (28 ft) and has deck space for two 20-ft (6-m) containers. The vessel is also equipped with a GPS Plot self-managed man overboard system and a Jason cradle for emergency personnel recovery.

Fugro Americas unveils newbuild survey vessel

Fugro's geophysical survey vessel, the *Fugro Americas*, was showcased to clients at the Martin Midstream Dock in Galveston, Texas. Fugro gave guided tours of the newbuild vessel, with geophysical, geoscience, survey, and HSE professionals on hand to demonstrate its state-of-the-art equipment and features, along with the working parts of a geophysical survey.

The *Fugro Americas* departed the shipyard in Louisiana on April 13, and was immediately mobilized to the Caribbean for a geochemical coring campaign. Measuring 193 ft (59 m) in length, the multi-purpose vessel is well suited for high-resolution geophysical surveys and seafloor mapping and is permanently mobilized for rapid deployment to locations throughout North and South America. Fugro also owns and operates three Hugin AUV systems, two depth rated to 9,843 ft (3,000 m) and one to 14,764 ft (4,500 m), all of which are portable and able to be mobilized onto the *Fugro Americas* or other vessels of opportunity.

Fifth Sapura-series pipelay vessel nears completion

Royal IHC has launched the pipelay vessel *Sapura Rubi* at its shipyard near Rotterdam.

This is the fifth vessel with a 550-ton top tension capacity that IHC is supplying to Sapura Navegação Marítima, a joint venture between SapuraKencana and Seadrill.

Like sister vessels, *Sapura Diamante*, *Sapura Topázio*, *Sapura Ônix* and *Sapura Jade*, *Sapura Rubi* will be used to develop oil fields in waters up to 2,500 m (8,202 ft) deep for Petrobras.

The new vessel will be equipped with a pipelay spread designed and built by IHC, and two below deck storage carousels, respectively with capacities of 2,500 tons and 1,500 tons of product.

A vertical (tiltable) flex-lay system will be permanently installed – the tower orientation is said to allow for maximum deck space.

An IHC-designed control system integrates each aspect of the pipelay spread to ensure required levels of performance, safety and reliability, the company added.

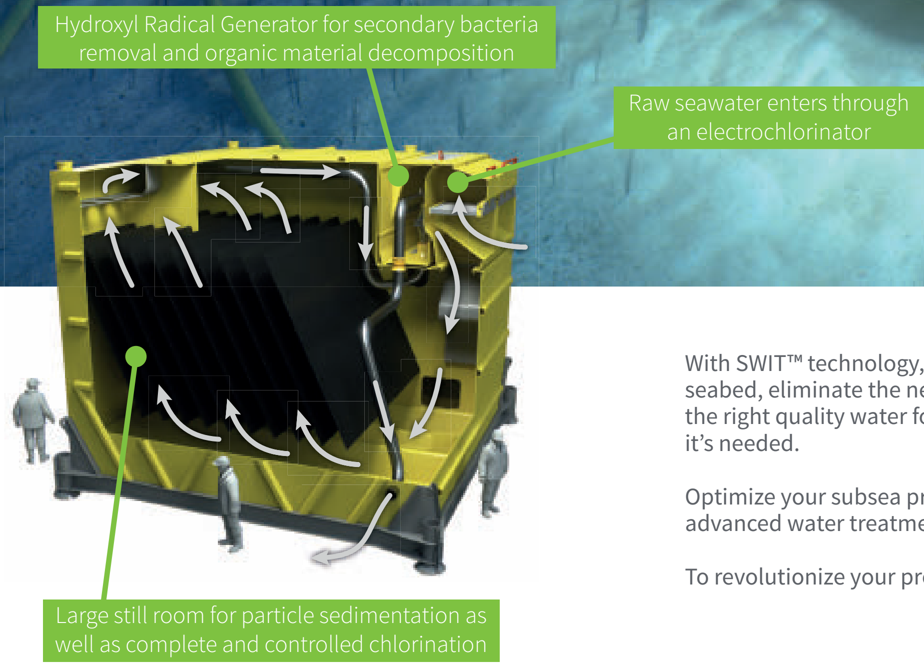
Ultra Deep orders another newbuild DSCV

Ultra Deep Group has contracted China Merchants Heavy Industry to build an Ultra Deep Installer multi-purpose diving support construction vessel.

The vessel, which is based on the proprietary Red Class 6027 MT design DSCV, will be a DP-3, 142-m (466-ft) diving support construction vessel, with planned delivery in 1Q 2018.

This new Ultra-Deep DSCV will be equipped with Flash Tekk's 24-man twin bell saturation dive system.

Other vessel design features are a 400 VLT in the reinforced moon pool area and equipped with twin 24-man SPHL. The vessel also has 2 x 250 hp work class ROVs with 3,000-m (9,842-ft) working depth installed in ROV hangers inside the vessel.



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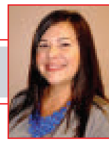


Robin Dupre • Houston

MPD increasingly embraced for offshore drilling

More than 40% of drilling problems occur during offshore operations, significantly increasing non-productive drilling time and therefore cost. As oil operators move toward more complex drilling environments, they find themselves exposed to high risk. Against this backdrop and the continued need to maintain energy security, oil operators are increasingly adopting advanced technologies such as managed pressure drilling (MPD) that offer safety benefits. Recent analysis from Frost & Sullivan, titled "Managed Pressure Drilling," finds that the MPD service market earned revenues of $11.4 billion in 2014 and estimates this to reach $18.5 billion in 2020 at a compound annual growth rate of 8.4%. Frost & Sullivan Energy & Environment Industry Analyst Mahesh Radhakrishnan said: "Geographically, North America will be the highest revenue contributor due to huge capex advancement in MPD technology. West Africa will be another important market for MPD as drilling costs are high and large investments in offshore drilling have been made in the region," he said. "Along with these markets, Asia/Pacific and Europe are expected to witness high end-user interest in MPD technology owing to rising energy demand and redevelopment of mature oilfield wells."

Although MPD reduces non-productive drilling time significantly, the high capex generally deters operators from moving away from conventional drilling. The lack of industry experts and the strong expertise needed to execute MPD projects have also discouraged adoption.

"The breadth of knowledge and skill required for the successful use of MPD is typically too wide. Oil and gas companies must collaborate with the right kind of suppliers to make this technology cost-effective," noted Radhakrishnan. "Suppliers will also have to create awareness among operators on the benefits of MPD, demonstrate the life-cycle cost of installing the technology, and educate end users on offshore drilling hazards and safety issues to fight market challenges."

Schlumberger, Cameron join forces

Schlumberger and Cameron have agreed to merge in a stock and cash transaction valuing Cameron at $14.8 billion. Given the lower oil price environment, Schlumberger CEO Paal Kibsgaard highlighted the combined company's ability to deliver "innovative technology and greater integration" to meet customers' demand for increased efficiency, while Cameron CEO Jack Moore added that the transaction "builds on our successful partnership with SLB."

Cameron shareholders will receive 0.716 Schlumberger shares and $14.44 in cash for each share of Cameron, valuing the company at $66.36 per share. Cameron shareholders will own about 10% of Schlumberger upon closing and Schlumberger expects the deal to be accretive in the first year, despite an increase in the share count, driven by cost synergies that can be immediately realized. Schlumberger targets $300 million in pre-tax synergies in the first year and $600 million in synergies in the second year, primarily related to reducing operating costs, streamlining supply chains, and improving manufacturing processes. Evercore ISI estimates that the combined company will generate sales of $47 billion in 2016 and $50 billion in 2017.

Gazprom Neft has brought its second well into production at the Prirazlomnoye field, with output totaling 1,800 metric tons/d (1,984 tons/d). (Photo courtesy Gazprom)

Second well brought into production at Gazprom Neft Prirazlomnoye field

Gazprom Neft brought its second well into production at the Prirazlomnoye field, with output totaling 1,800 metric tons/d (1,984 tons/d).

The launch of this facility plans to see production increase more than double over 2014 production levels at Prirazlomnoye, which stood at 300,000 metric tons (330,693 tons). The depth of the new well extends to more than 4,500 m (14,763 ft), with drilling undertaken by Russia's Gazprom Burenie LLC.

Altogether, the project envisages 36 wells being brought into production, including 19 production wells, 16 re-injection wells, and one absorption well. The first production well at the field was launched in December 2013.

Gazprom says the Prirazlomnaya platform is equipped with a system to prevent the discharge of any production or drilling waste into the sea. All wells to be drilled at Prirazlomnaya will be located within the platform, the base of which then acts as a buffer between the well and the open sea. In addition, the company explained that all of the wells are specially equipped to prevent the possibility of any uncontrolled emission of oil or gas and can, if necessary, be hermetically sealed within 10 seconds.

Schlumberger, IBM to provide integrated services

Schlumberger and IBM have teamed up to provide integrated services to upstream oil and gas customers that will improve the business impact of production operations projects.

The offering combines Schlumberger's production optimization services, upstream expertise, and industry-leading Avocet production operations software platform with IBM's enterprise asset management and enterprise services to deliver an end-to-end service for optimizing integrated production operations. Through the service, customers should expect improved productivity, efficiency, and cost management across operational areas including production optimization, flow assurance, logistics, scheduling, HSE, human resources, equipment monitoring and maintenance.

Uwem Ukpong, president, Software Integrated Solutions, Schlumberger, said: "Our customers have high expectations of the business impact of integrated production operations projects and in the current financial climate the demand for return on investment is stronger than ever. The alliance with IBM will drive production excellence beyond engineering to all workflows across the production operations business lifecycle."

John Brantley, IBM general manager for the Chemicals and Petroleum Industries, said: "Traditional ways of doing business are being challenged and business process re-engineering has become an absolute requirement. Schlumberger and IBM are coming together with a joint engagement model to deliver our clients a clear path to achieving operational excellence, through integrated enterprise and domain-specific business processes with collaborative, real-time intelligence for improved decision making in the oil and gas industry."

This new service unifies the decision environment to provide the support critical for productivity and efficiency gains in today's oilfield operations. The combination of production optimization workflows with enterprise business processes enables multidisciplinary solution teams to implement customized business offerings spanning asset to enterprise levels.

Drilling resumes at Guendalina offshore Italy

Eni has begun drilling a side track at the Guendalina gas field in the Adriatic Sea offshore eastern Italy.

Operations should last around 80 days, according to Rockhopper Exploration, and are designed to optimize production from the field.

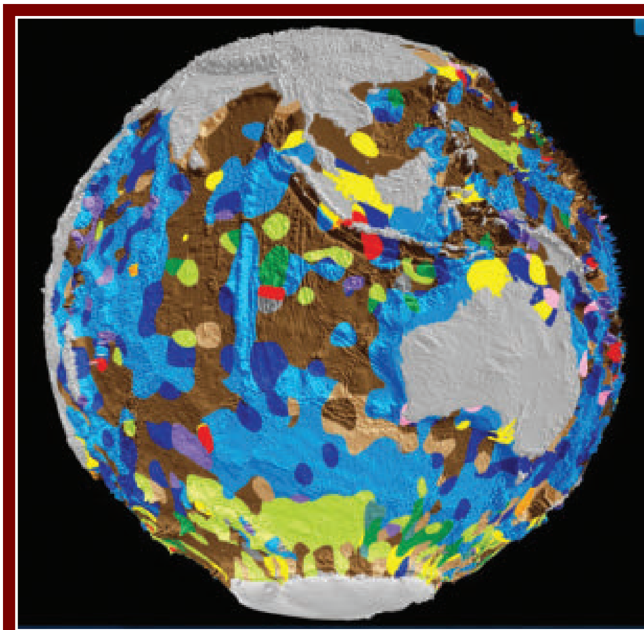
Asia/Pacific

PT Bahari Lines, in partnership with Nordic Geo Services Ltd., have won contracts to conduct two 2D offshore seismic data acquisition and processing programs offshore Indonesia.

The first program is for Total Indonesia and consists of 3,000 line km (1,864 mi). The second is for PSG, a local government company, covering 1,600 line km (994 mi).

The partners will use the *Nordic Bahari* with support from the newbuild *Nordic Barakuda* and *Nordic Emma*. The first project is off West Papua and the second is off West Sumatra.

The PT Bahari and Nordic Geo Services partnership will conduct a pair of seismic data acquisition surveys offshore Indonesia using the *Nordic Bahari*. (Courtesy Nordic Geo Services)



The University of Sydney has created a digital map of seafloor geology. The map indicates the distribution of the composition of the ocean seabed, say the researchers. Dietmar Muller, geophysicist at the university's School of Geosciences, says that the map uses 13 colors including yellow for sand, red for volcanic rock, and pink for shells and corals. It "brings out the enormous ecological and geological complexity of the sea floor that before we had no idea about." More than 15,000 sea floor samples were generated to make the new map.

Also in the Asia/Pacific, Electromagnetic Geoservices ASA has received a letter of award for a $4.2-million contract from an unidentified oil company for 3D EM data acquisition over an operated area in Malaysia.

The two parties have entered into a two-year contract, of which this LOA constitutes the commitment for the first and initial phase. The parties have also designed a survey for an optional second phase in 2016.

The survey will be done using the vessel *BOA Thalassa*.

Polarcus Ltd. has a letter of award from Shell Myanmar Energy for a 3D marine seismic project offshore Myanmar. The project is currently expected to start in 4Q 2015.

Africa

Spectrum ASA entered into a multi-client master cooperation agreement with the federal government of Somalia.

The agreement allows Spectrum to acquire approximately 28,000 km (17,398 mi) of long-offset 2D seismic data offshore south Somalia. The new acquisition has been specifically designed to complement 20,000 km (12,427 mi) of existing seismic data acquired in 2014. Spectrum has also been granted the marketing rights for this data.

Middle East

BGP is doing an interesting project for Kuwait Oil Co. The 3D survey covers areas ranging from Kuwait city to Kuwait Bay and includes both shallow and deepwater areas.

Offshore Abu Dhabi, CGG, and the Seabed Solutions/Fugro joint venture have completed acquisition of a 3D seismic survey at the Hail and Shuweihat oil and gas fields. The work in the environmentally sensitive area covered 1,200 sq km (463 sq mi), starting with 600 sq km (232 sq mi) that included the shallow water Merawah natural reserve. The remainder of the survey covered offshore and onshore portions of Shuweihat field.

Following that, ADNOC awarded CGG a contract covering 1,500 sq km (579 sq mi) of shallow water over the Ghasha-Butini field. The work also will be supported by Seabed Geosolutions.

Sea of Okhotsk

The public hearings in Nogliki settlement have resulted in approval for Gazprom Geologorazvedka to conduct 3D seismic work in the Sea of Okhotsk. The company explained "soft-start" acoustics, zero discharge of wastes, and continuous environmental monitoring.

Gazprom Geologorazvedka is a subsidiary of Gazprom.

The company operates in three license blocks offshore the Sakhalin Island: the Kirinsky prospect, including the Yuzhno-Kirinskoye field, as well as the Vostochno-Odoptinsky and Ayashsky blocks.

Gulf of Mexico

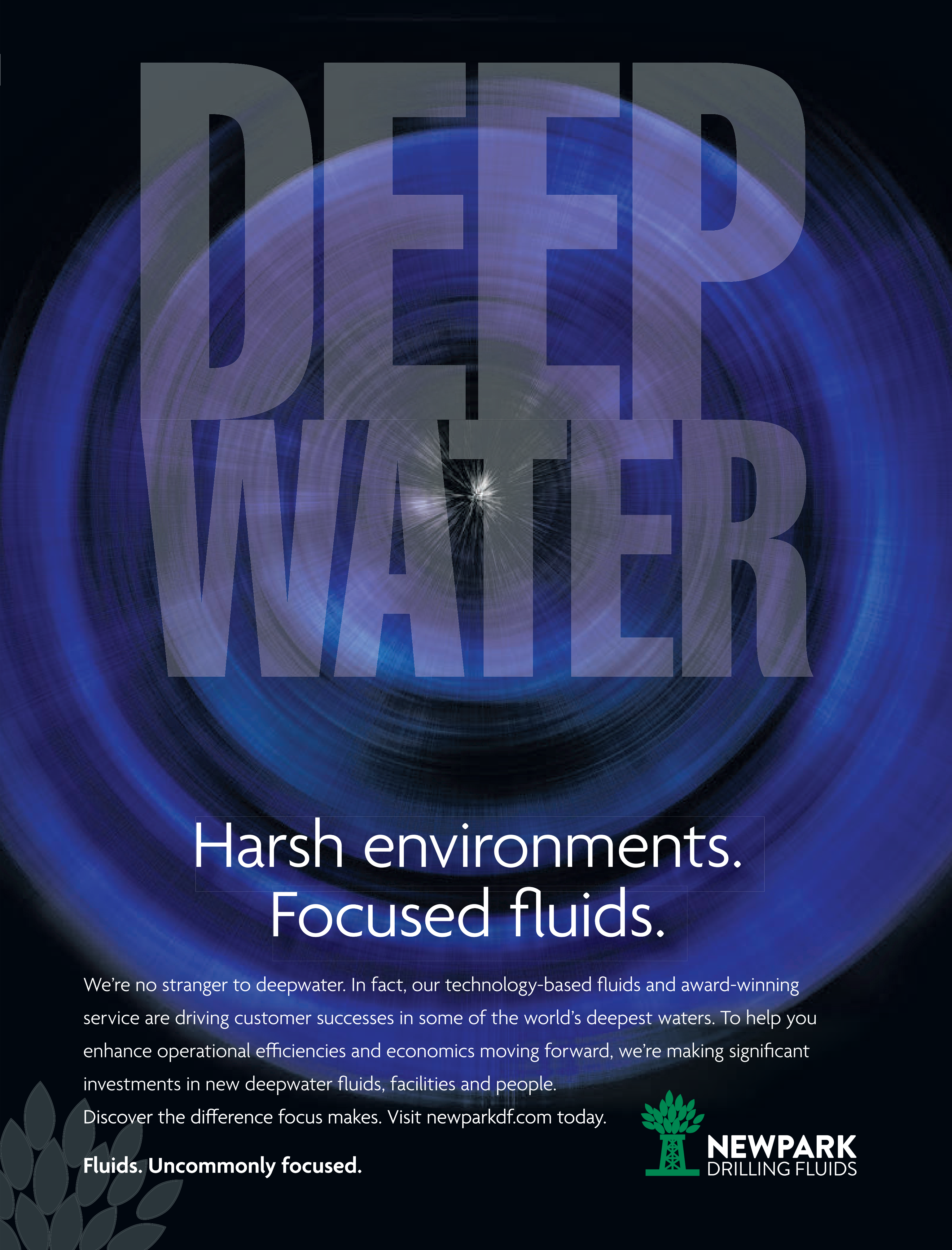
Mexico's Comisión Nacional de Hidrocarburos has authorized TGS to acquire multi-beam coring and geochemical analyses over 600,00 sq km (231,661 sq mi) of Mexican waters.

This project will cover the entire deepwater area of the Mexico's deepwater, including the Perdido Fold Belt and Campeche Bay. This project will be conducted in conjunction with the 186,000 km (115,575 mi) TGS Gigante seismic survey.

The multi-beam data will be acquired by Fugro using vessels equipped with the latest generation of multi-beam sonar equipment. Multi-beam bathymetry and backscatter data will help identify possible oil and gas seeps for sediment sampling.

More than 1,000 navigated piston cores are expected to be collected by TDI Brooks International and detailed geochemical analysis will be performed.

The survey is supported by industry funding.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Regulations cause offshore companies to examine independent contractor status

Daniel D. Pipitone
Munsch Hardt Kopf & Harr

The utilization of independent contractors in the offshore industry is, and has been, more than common place. Those serving as independent contractors prefer the status with the freedom and opportunities it permits. The companies utilizing independent contractors benefit as well, with many basing their operations on a business model relying upon them. Although the case discussed here refers to an onshore oilfield, the issue of contract labor is very relevant to the offshore oil and gas market.

Unfortunately, the acceptability of independent contractor utilization depends on the philosophies and pre-dispositions of the federal government administration in public office at the time. During the course of the past six and one-half years, the Obama administration has implemented stricter regulations affecting companies utilizing independent contractors. Current Secretary of the US Department of Labor (DoL) Tomas Perez is publicly on record stating that the misclassification of employees as independent contractors is pervasive and, more significantly, that such misclassification is "used intentionally by employers to…avoid various laws designed to create protections in the workplace." The DoL, in turn, has vigorously pursued investigations and prosecutions against various companies and their individual owners in an effort to re-classify as many independent contractors as employees as possible.

The tactics employed by the DoL have not always been appropriate and, in large measure, have been employed relied upon the vast treasury and powers of the federal government. In many cases, companies have been forced into re-classification simply as a consequence of their inability to afford a defense. In some cases, the re-classification has later caused insolvency because an employee-based system is undesirable to many independent contractors, who then subsequently seek other opportunities and/or because the business model is no longer fiscally viable.

In July of this year, two events pertaining to the utilization of independent contractors occurred which are of rather substantial significance. Although not chronological, the DoL published its Administrator's Interpretation No. 2015-1, which further narrowed the circumstances under which it would interpret a proper independent contractor classification. Additionally, on July 2, 2015, the United States Fifth Circuit Court of Appeals entered an opinion in Gate Guard Services, LP; Bert Steindorf v. Thomas E. Perez, Secretary, Department of Labor; Cause No. 14-40585 in the United States Court of Appeals for the Fifth Circuit (also known as GGS). The opinion said that the DoL to have been in "bad faith" for investigating and prosecuting an energy service company which used independent contractors.

In the GGS case, the DoL relied upon one of its investigators who, prematurely and without sufficient facts and evidence, determined that GGS had misclassified its oil field gate attendants as independent contractors as opposed to employees. Both the direct and indirect impact of this interpretation resulted in imposition of a $6.2-million assessment to GGS to compensate the gate attendants for overtime. Notably, both the assessment and the requirement that these people be considered employees in the future would result in the insolvency of GGS and the ruination of its business model. Regrettably, the hierarchy within the DoL approved the investigation and threatened prosecution of GGS absent the latter's complete capitulation. Rather than await prosecution initiated by the DoL, GGS pursued a declaratory judgment in federal court seeking a determination to the effect that the DoL opinions were mistaken and its efforts misplaced.

The Federal District Court agreed with GGS and determined that the facts and previous case precedent dictated that GGS's gate attendants were properly classified as independent contractors. Moreover, the Federal District Court further found that the DoL was not "substantially justified" in prosecuting GGS in the first instance and that its counsel abused the judicial system with its unprofessional tactics, tactics concerning which GGS perceived as being adopted for the sole purpose of pushing the company to comply.

Thereafter, the DoL chose to appeal to the Fifth Circuit, the appellate court serving a level below the United States Supreme Court. Notably, the DoL did not appeal the classification of GGS's gate attendants as independent contractors, thereby agreeing to the finding and admitting its error concerning misclassification allegations. Instead, the DoL appealed only the Federal District Court's finding of not "substantially justified" and attempted to overturn the award of attorneys' fees to GGS. The Fifth Circuit found on July 2, 2015 that not only was the DoL not "substantially justified," but that it acted in bad faith both with respect to its investigation, as well as its prosecution of GGS. The award of attorneys' fees was intended to provide some compensation to GGS for its suffering through the investigation and litigation processes compelled by the DoL's overzealous actions.

The DoL does not appear to be inclined to moderate its clear direction to attempt to transform as many workers as possible from independent contractor status to employee status despite clear judicial interpretation. Courts generally have long utilized what is characterized as the "economic realities" test in order to determine independent contractor versus employee status. Factors such as supervision and control, relative investment, opportunity for profit or loss, skill and initiative, and permanency of the employment relationship are considered by courts.

Essentially, the DoL through its recent Administrator's Interpretation references the "economic realities" test, but subjects it to further limitation with the intention of reducing the instances when an independent contractor status would result. The obvious and intended purpose of the DoL in publishing its opinion and interpretation is to bolster its re-classification efforts by suggesting that its opinion interpretation is clear and consistent with case precedent.

The Administrator's Opinion is nothing more than an agency opinion. Its publication occurred without the formal rule-making process being invoked or note-and-comment period occurring. It is not binding law, nor is there any requirement that the courts adopt it in whole or in part. As the GGS Fifth Circuit Opinion more than suggests, the opinion of the DoL may be found to be misguided or, as regards to the Administrator's Opinion, overly expansive in support of a zealous effort to convert independent contractors to employees.

All companies engaged in the offshore industry, as well as other industries periodically or consistently utilizing independent contractors, should be aware of the DoL's pre-disposition to not only consider independent contractors as employees, but to actively pursue an agenda requiring re-classification. Knowledge of the "economic realities" test and its parameters is essential, as is the substance of the Administrator's Opinion. Only under these circumstances can a decision be responsibly made to resist the urgings of the DoL to re-classify. If such a decision is made, encouragement is most certainly available by way of the Fifth Circuit's Opinion regarding GGS.

The author

Dan Pipitone is a Shareholder in the Energy, Maritime and Environment Section of the Houston Office of Munsch Hardt Kopf & Harr. Pipitone has more than 30 years of maritime law experience during which time he has represented numerous vessel owners engaged in both 'blue water' and 'brown water' transportation, crew and supply boat services and dredging activities. He has additionally represented various offshore drilling contractors.


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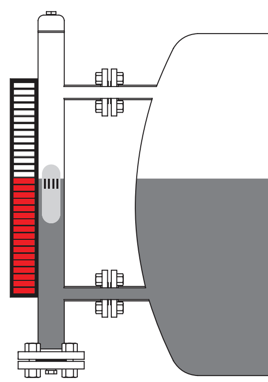


Norwegian E&P set to shrug off current downturn

Markus Nævestad
Jo Husebye
Rystad Energy

UK prospects more dependent on oil price upswing

Despite the steady decline in the oil price and its impact on new project activity, the downturn should be relatively short-lived. Rystad Energy's research points to upward pressure on oil prices towards 2017, with global oil demand growing by 1.1 MMb/d in the run-up to 2020. This should spur a new cycle of investment even in higher-cost offshore regions such as northwest Europe where many operators are under pressure to rein in exploration and new field development.

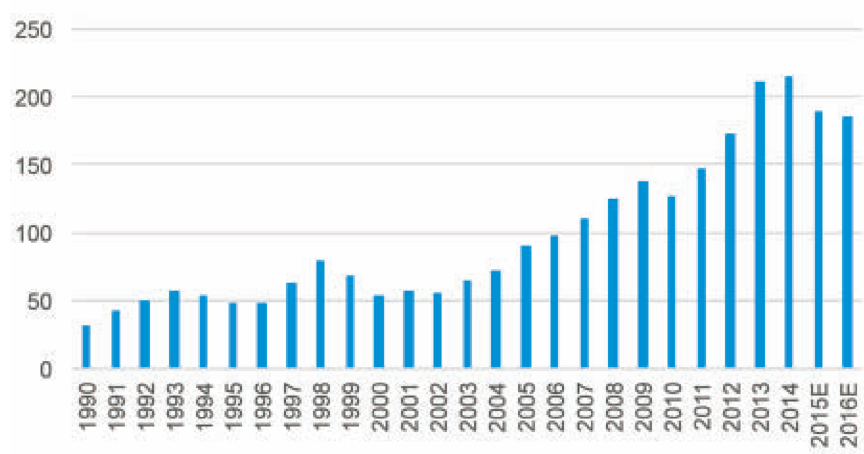
The Norwegian organization Statistics Norway recently published new estimates for investments on the Norwegian continental shelf (NCS), based on information collected from all the operators on behalf of the Norwegian Petroleum Directorate.

Overall investments flattened out in 2014 at NOK 214 billion ($25.5 billion), following an extraordinary growth period of 19% annually from 2010-2013, from NOK 127 billion to NOK 212 billion ($15.1-25.3 billion). However, estimates for spending on the NCS in 2015 and 2016 indicate a decline in two back-to-back years for the first time since 1999-2000.

When analyzing the details of the investment history and the forecast expenditure, several clear trends emerge:

Exploration. It is the rule rather than the exception to see either double-digit growth or decline in exploration activity year-on-year.

Total investments on the Norwegian continental shelf (NCS) year on year since 1990.



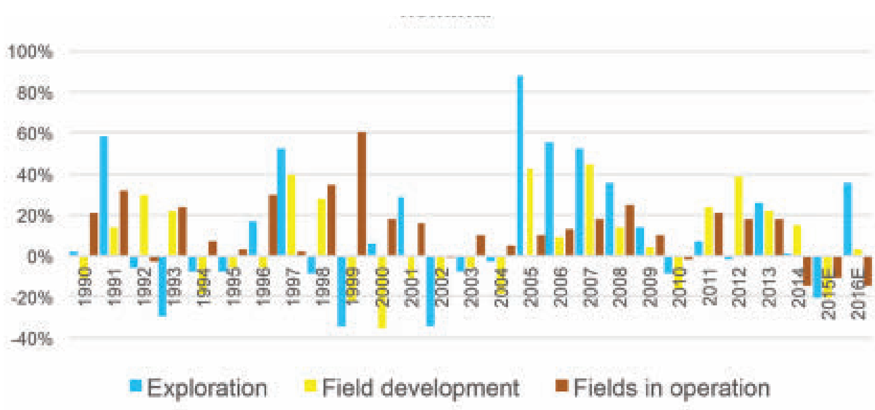
Source: Statistics Norway.

Following the Norwegian government's introduction of the Awards in Predefined Areas (APA) licensing procedure in 2003 and the "cash back" scheme in 2005, whereby the State reimburses the 78% tax base of costs related to exploration drilling, exploration activity grew steadily during the mid 2000s. This growth was also fueled by a rising oil price. But despite the recent oil price collapse, Statistics Norway now forecasts a 35% increase in Norwegian exploration activity compared to the most recent 2015 estimates. Rystad Energy believes this figure is too high and will most likely be lowered in future estimates, but the conclusion remains unchanged: exploration has and will be volatile – the observed trends are normal and not unique.

Field development. Following the oil price increase after the 2008 financial crisis, multiple PDOs (plan for development and operation) were submitted for standalone Norwegian field developments such as Knarr, Valemon, Ekofisk 2/4 Z and Eldfisk 2/7 S (2010), Edvard Grieg and Martin Linge (2011), and Aasta Hansteen, Ivar Aasen, and Gina Krog (2013). With such a large number of new projects going forward at the same time, the field development market soared from NOK 30 billion ($3.62 billion) in 2010 to NOK 73 billion ($8.8 billion) in 2014 – a staggering 24% increase year-on-year. But growth periods such as these are usually followed by a cool down, so the current decline in the Norwegian field development market is not unique.

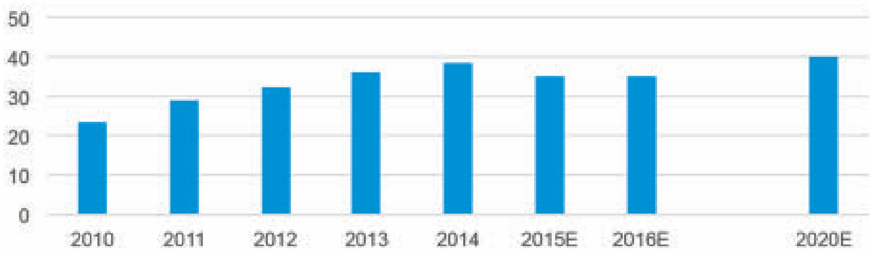
Fields in operation. Brownfield investments offshore Norway (including infill drilling) did not tail off markedly during the previous downturns, experiencing a 3% decline in 1992, a 1% drop in 2002, and 2% in 2010. Last year, however, there was a 14% fall in Norwegian brownfield spending, the largest ever recorded in this seg-

NCS capex growth by segment.



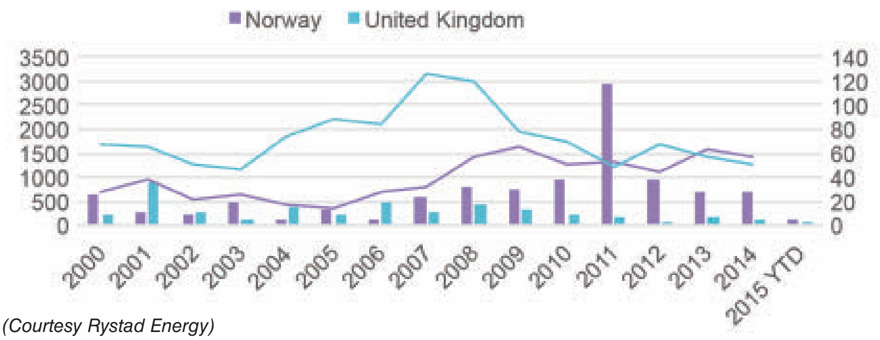
Source: Statistics Norway.

Total NCS E&P expenditure between 2010 and 2020.



(Courtesy Rystad Energy)

Discovered resources and exploration wells drilled since 2000 offshore Norway and the UK.



(Courtesy Rystad Energy)

ment. Most recent estimates suggest a further drop of 10% in 2015, and another 14% for 2016. If that happens, the 2016 brownfield market will be some 60% below the peak year of 2013. Three years of double-digit (%) decline in the brownfield market is not normal – the brownfield market has not been cyclical – it is unique for the current declining market.

As for MMO (maintenance, modifications and operations), the number of frame agreements entered into was down by 20% last year, the largest cut ever seen, with bigger modification projects being postponed or canceled. Only a few large contracts have been awarded over the last six months, notably the modification program on the Kristin complex to receive production for Wintershall's Maria tieback – a NOK 600-million ($71.6-million) contract awarded to Reinertsen this March was one of the biggest.

Using Rystad Energy's database of historic and forecast spend field-by-field, a complete picture can be drawn encompassing investments (including those for unsanctioned field developments) and operational expenditures. Total Norwegian upstream expenditures ended up close to $39 billion in 2014, up 7% from 2013. The decline estimated for 2015 is around

8% and suggests a lower overall investment than figures released by the NPD imply, which are actually driven by higher investments in fields under development, among others. Additional cost overruns and carry-overs are expected on major Norwegian offshore facilities currently under construction in Asia or in the hookup phase, such as Goliat in the Barents Sea. Other major projects such as Aasta Hansteen and Martin Linge are believed to be experiencing difficulties meeting planned budgets and delivery schedules. Similarly, investments for 2016 are expected to be slightly down from 2015 levels, with several projects in the completion phase, while the modification market may possibly end up higher than reported by Statistics Norway.

Looking toward 2020 there are many uncertainties surrounding investment estimates, specifically regarding the sanctioning of new projects and exploration levels. For example, Statoil has pushed back final investment decisions for Johan Castberg in the Barents Sea and Snorre 2040 in the North Sea – both expected to be multi-billion dollar projects with new floating production platforms – to second half 2017, with start-up around 2022-2023. With this current timeline, these projects are important to meet forecast 2020 development expenditure for the Norwegian sector of around $40 billion. Other forthcoming key projects are Johan Sverdrup phases 1 and 2 and potential developments of the Skarfjell, Pil and Alta/Gohta. However, the exploration market looks set to level off at around $5 billion/yr from 2016 onward after peaking at $6 billion in 2013.

UK exploration decline

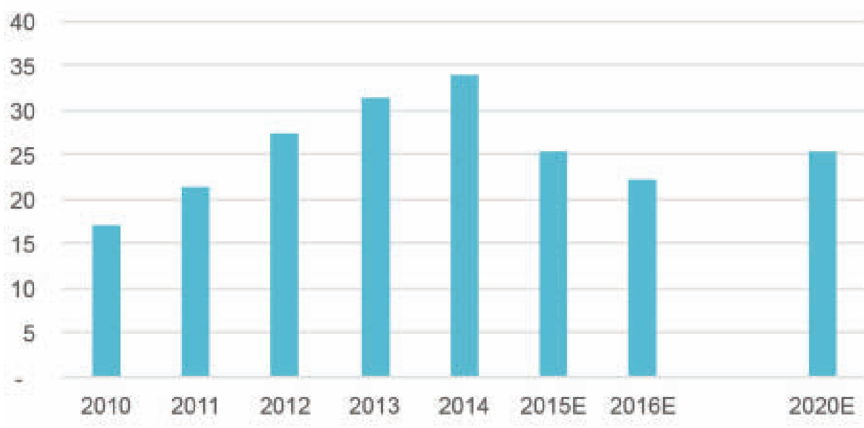
Norway's current field development boom includes a healthy mixture of old discoveries having matured into economic projects (e.g. Martin Linge and Valemon) and discoveries made over the last decade (e.g. Edvard Grieg and Goliat). The latter were a direct result of the previously mentioned government initiatives APA and "cash back." A comparison of volumes discovered in recent years offshore Norway and the UK highlights one of the key issues for the UK continental shelf (UKCS). Here exploration results have been persistently poor and in decline since activity peaked in 2007/08. In 2008, 121 wildcat and appraisal wells were drilled across the UKCS with oil and gas discovered totaling 444 MMboe. Since that period exploration activity has consistently decreased, with only 38 exploration wells drilled during 2014 and only 98 MMboe discovered.

Some of the finds over the last 10 years and currently under development are EOG's Conwy, discovered in the East Irish Sea in 2009 and developed with an unmanned platform; Dana Petroleum's Western Isles Development Project (WIDP), discovered east of the Shetlands in 2008 and developed with a $1.5-billion circular Sevan FPSO; and Premier Oil's Catcher field, discovered in the UK central North Sea in 2010 and also under development with an FPSO.

Many of the newer programs on the UKCS have been redevelopments of existing fields. BP is currently redeveloping its Schiehallion and Loyal fields West of Shetland for £3 billion ($4.64 billion) with the replacement FPSO expected onstream in 2016. Nearby, the company is also progressing the £4.5-billion ($6.9-billion) Clair Ridge project, the second-phase development of the giant Clair field; while Talisman/Repsol are working on the £1.6-billion ($2.45-bilion) Montrose area redevelopment in the UK central sector.

Going forward toward 2020, however, the portfolio of stand-alone candidates that could spur UK greenfield investments is limited to a handful, led by Maersk's HP/HT Culzean project in the UK central North Sea, approved early last month by the UK government. The development plan calls for a bridge-linked complex comprising a wellhead platform, a central processing facility and utilities/living quarters, with a total investment of over $4.7 billion. Start-up is scheduled for 2020-21. Statoil is expected to decide shortly on a concept for the Bressay heavy oil field East of Shetland, and Chevron has not given up on its challenging deepwater Rosebank development west of Shetland.

Total E&P expenditure (including opex) (billion USD), nominal.



(Courtesy Rystad Energy)

The UK's brownfield market differs from the Norwegian model with its historically large EPC contracts. The NCS has been developed with fewer but larger platforms, many of which now have spare capacity to tieback multiple new subsea fields. This provides a greater incentive in current conditions to undertake large-scale modifications. Due to its more limited development agenda, a smaller brownfield market and a lack of appetite for exploration, the current outlook for the UKCS is not promising in the short term, with total E&P expenditure likely to fall by 25% this year, followed by a further drop of 12% in 2016. Given the current market, future UKCS spending looks highly unlikely to approach the historic highs of 2013 and 2014. However, the British government has recently unveiled various tax reduction measures to support investments in maturing offshore prospects and exploration. Sir Ian Wood's Review has also presented recommendations on how to maximize recovery over the long term from the UK North Sea. These, combined with the current cost-cutting schemes observed in the industry, could change the outcome going forward.

The recent downturn has affected investment levels on both the NCS and the UKCS. On the NCS we expect to see an investment cut across exploration, field development, and operations in 2015. This is a unique observation for the current downturn. Total upstream expenditure is estimated to decline by 8% from the peak in 2014 to 2015 and stay flat in 2016. In the longer term however, the activity level is expected to pick up on the NCS, largely driven by the Johan Sverdrup development. 2014 investment levels could potentially be reached by 2020. On the more mature UKCS, poor exploration results and low exploration activity over recent years are evident through a small backlog of potential developments. A drop of 25% in total E&P expenditure is expected in 2015 followed by a further drop of 12% in 2016. The government is, however, introducing new tax measures that could have a positive effect on investment.

Despite challenges, companies remain undeterred by expense of Lower Tertiary

Shell's Perdido field was the first to commercialize the Lower Tertiary. Pictured is the Perdido spar lying horizontal in the Gulf. Shell's Stones, also located in the Lower Tertiary, is on track to start up in 2016 through the *Turitella* FPSO. (Photo courtesy Shell)

Sarah Parker Musarra
Editor

After a run of prolific discoveries in the last few years, including Kaskida, Tiber, Gila, Anchor, and more, the Gulf of Mexico's Lower Tertiary reservoirs, also termed the Paleogene play, have been likened by industry experts to a modern-day gold rush for the offshore industry.

However expensive it is to explore and develop, even without signs of recovery for the currently depressed market, the Paleogene has retained its importance in the eyes of seismic contractors, oilfield service providers, and operators alike. Despite the down market, despite the cost, despite the frontier challenges, exploration and maturation of the Lower Tertiary is still ongoing.

Four projects are currently producing in the Lower Tertiary, with Chevron's Jack/St. Malo complex most recently brought online. Developmental drilling is ongoing at the Jack, St. Malo, Julia, and Stones fields.

The area's infamously difficult salt canopies present several challenges to development. They can run more than 4,000 m (13,120 ft) thick, and are often located in isolated and remote field locations; and they often have low rock porosity and low permeability. Each challenge has in turn driven the industry to advance the technology necessary in these respective areas to hit pay in one of the world's deepest water and toughest regions. In this process, advances in seismic and drilling technologies have been vital to any celebrated success.

Recently, *Offshore* discussed these challenges with several industry experts, who offered their thoughts on how the current market might affect the future of the play.

Seismic advances

One thing is clear. The question becomes not if activity will continue in the Lower Tertiary, but how and when. To this end, innovations in seismic technology are a critical component to recent and future successes in the region.

"The deepwater Lower Tertiary trend in the central Gulf of Mexico continues to see exploration success," said Mike Celata, US Bureau of Ocean Energy Management (BOEM) Gulf of Mexico acting regional director. "Over the past 12 months, the industry announced Paleocene/Eocene Wilcox discoveries at KC642 (Leon), KC10 (Guadalupe), and GC807 (Anchor). Success has been enabled by improved subsalt imaging through wide-azimuth, depth-migrated 3D seismic data acquisition and processing."

While located in a world-class petroleum basin, the Paleogene is a frontier area rife with risk. Schlumberger's Mohamed El-Toukhy, Western Hemisphere multiclient exploration service manager, explained that Lower Tertiary wells, which include high-pressure/high-temperature wells, could stretch some 30,000 ft (9,144 m), pushing costs for exploratory and developmental wells into the $200-million and $300-million range, respectively.

"With this kind of investment, you would really like to ensure that you select the best drilling location with the highest probability of success by getting the best image of the subsurface," El-Toukhy observed.

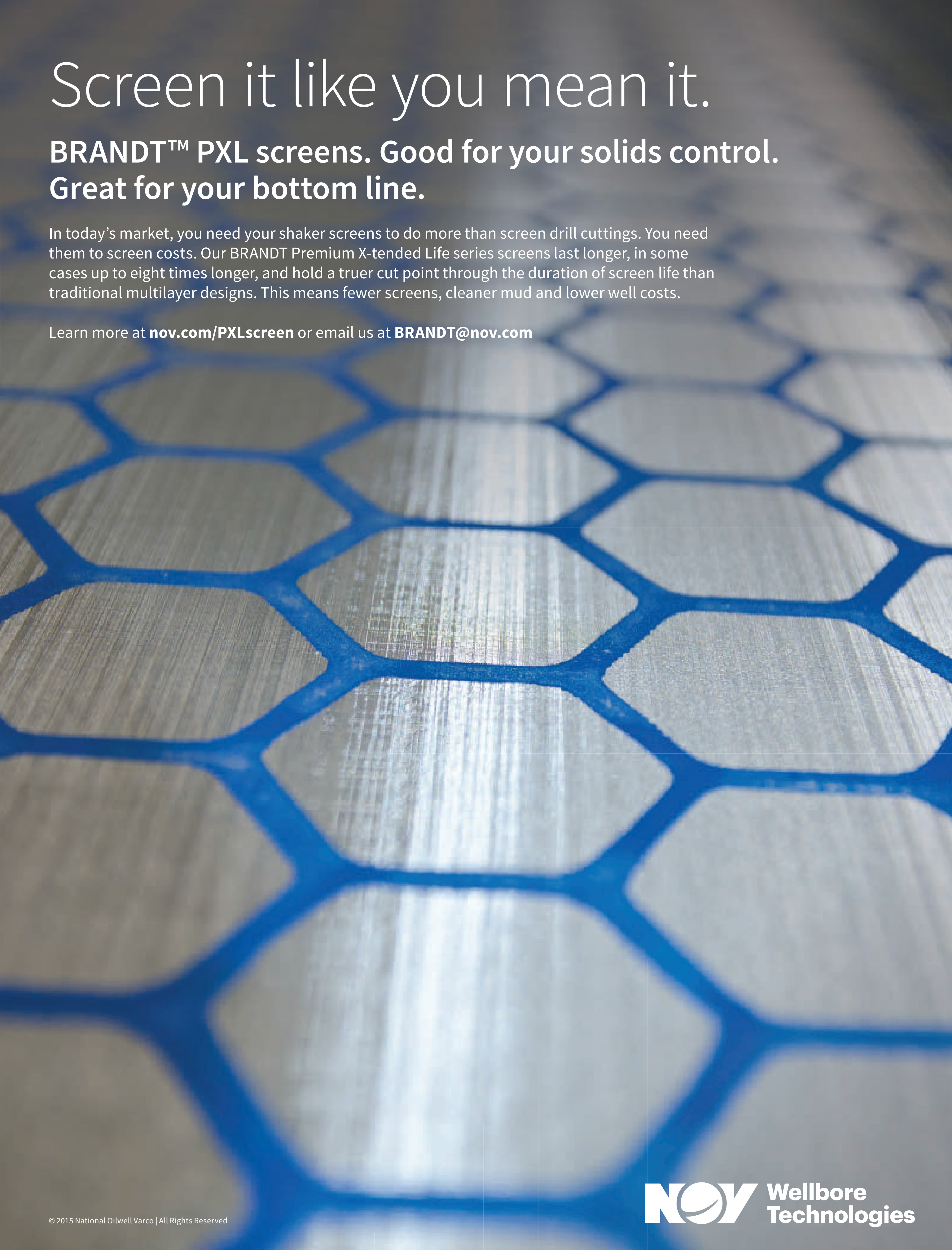
Additionally, El-Toukhy points out that volumetrically, the trend has large upside potential and extends into the Mexican sector. Success here could translate into big finds for operators interested in the Mexican side of the Gulf as well.

"It is very much underexplored in both the US and Mexico, so the play extends into Mexican side as well in a big way, which means that whatever technology we develop on [the] US side would be applicable also on the Mexican side," he explained. In Mexican waters, across the international boundary from the Perdido Foldbelt, four discoveries have been announced in analogous structures and reservoirs: Exploratus, Trion, Maximino, and Supremus. PEMEX is actively exploring and appraising the Paleogene trend in deepwater Mexico.

At this point, it is unquestionable that the reward is there, running throughout the basin. Estimations of the reserves in the Lower Tertiary range from 5 to 15 Bboe. Speaking at May's Offshore Technology Conference in Houston, Chevron's Steve Thurston, vice president, Deepwater Exploration & Projects, said that the deepwater GoM alone has produced 9 Bboe. There has been 24 Bboe discovered to date, with another 14 Bboe that can be produced in the future.

"The salt canopies are a blessing and a curse because they trap oil, but complicate seismic surveying and drilling," Thurston said at the time. He noted that of the 55 wildcats in the Lower Tertiary trend, about 23 hit oil. In discussing challenges that the industry needed to overcome in order to enjoy continued success in the Lower Tertiary, he commented that the industry needed to continue to focus on seismic imaging.

The success companies have seen in the last few years in the Lower Tertiary has not abated, and data from the US BOEM's Celata seems to back up Thurston's assertion regarding the salt canopies. "Overall exploration success for the trend stands at 51% of 49 drilled structures," Celata said. "Four-way closures more common in the salt-cored anticlines and folds beneath the leading edge of the Sigsbee Salt Canopy have been more successful (59%) than the three-way traps against salt and salt welds (41%) typical of the inboard por-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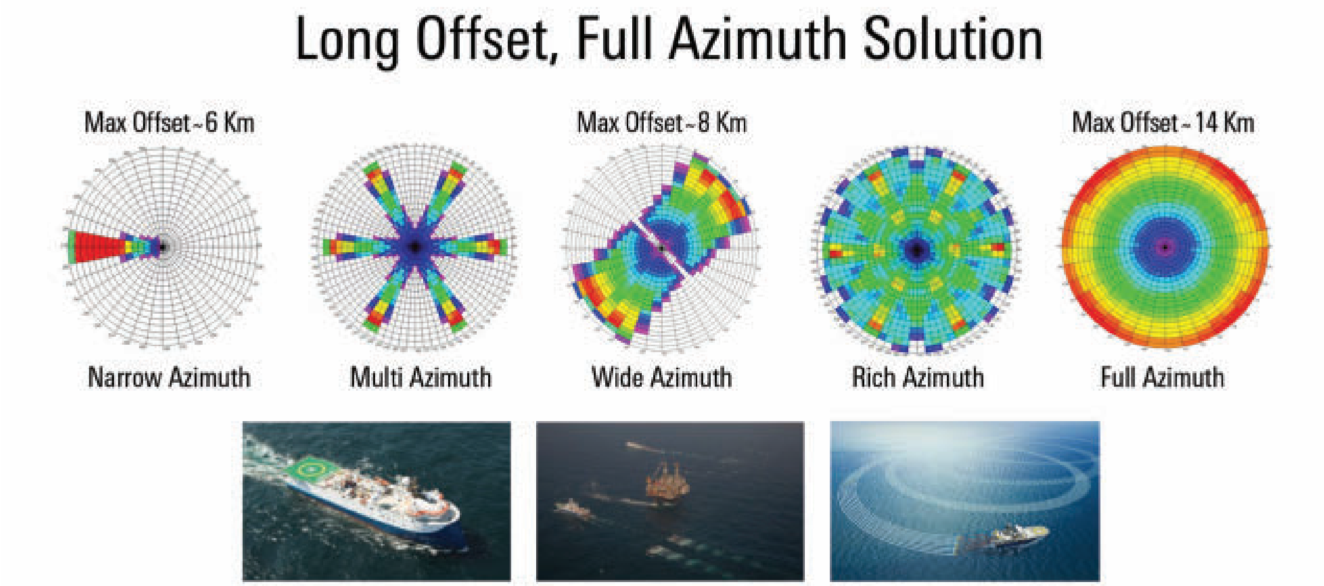

The evolution of seismic technology from limited viewing angle (narrow azimuth) into 360 (full azimuth) enables explorers to get the best image of the subsurface and mitigate risks. (Image courtesy Schlumberger)

tions of the trend. Particularly encouraging is the Anchor discovery, which represents the northern-most extension of the trend beneath the salt canopy."

Craig Beasley, chief geophysicist and Schlumberger Fellow, WesternGeco, also explained that high-quality seismic was necessary to ensure that investments made in the Lower Tertiary paid off, noting that the salt canopies and salt domes historically resulted in blind spots in the collection of seismic data.

"There are big prizes out there, and a lot of risk and a lot of financial muscle is needed to do these projects," Beasley said. "You need to de-risk them as much as possible. The best way to do that is with high-quality seismic data."

WesternGeco, according to Beasley, has been working to solve the challenges presented by the salt for more than two decades.

"Depth migration, which is needed to unravel the complexities in seismic data due to the salt came into its own more than 20 years ago but success was limited when the salt got very complex. In the mid-2000s, we began to realize that we could solve some of this with seismic acquisition if we were just willing to invest in better seismic data," Beasley said. "At that time, a lot of modeling was done. We understood finally that to image beneath the salt, we really needed to give ourselves the best chance of recording reflections beneath the salt. This involved so-called wide azimuth surveys which gave dramatic improvements in images."

Beasley said that the company proceeded from wide to full azimuth surveys, with the progression corresponding to improvements in the images of the salt. Full-azimuth has now ascended to one of Schlumberger's main tools when the company is shooting in the Lower Tertiary and other technically challenging areas.

"This technology has evolved over time to the point that it's absolutely essential," he explained, while pointing out the evolution of a particular seismic data business model that allows Schlumberger to deploy this and other technologies as cost-effectively as possible in the Lower Tertiary.

"One of the things that lets us use such high-end technologies is the multi-client data model in the Gulf of Mexico," Beasley said. "That's something that has evolved in the US waters. Over time, it has become a very well-known practice. It's one of the most attractive places to explore in the world because of the cost savings that come out of the multi-client model."

E&P companies and investors alike are impacted differently by the low oil prices currently impacting the market. Some have deemed the expense of exploring too expensive, while others expect to take advantage of the lower costs that such a downturn inevitably brings. Beasley observed that to keep competitive in this environment, WesternGeco and Schlumberger took a multi-faceted approach. In advance of the downturn, the company embarked on a transformation initiative that, among other things, aimed to streamline processes, improve reliability, lower costs, and improve supply chain management. Further, it continues to invest in and advance its seismic technology, creating new products while looking to combine new offerings with current ones. One example of how the company's technology is evolving can be seen in its Quad Coil Shooting, which sprung from its Dual Coil Shooting multi-vessel full-azimuth acquisition method.

This acquisition method collects data at every azimuth with longer source-receiver offsets, around 12 to 15 km (7 to 9 mi). In Quad Coil, four recording vessels are driven in in overlapping circles, while four other shooting vessels are deployed far away to obtain the azimuths and the offsets needed.

Schlumberger is also examining the possibilities of bringing technology developed in other harsh environments to the Lower Tertiary, including its IsoMetrix marine isometric seismic technology, which Beasley referred to as the company's "largest single technology development ever undertaken." IsoMetrix enables detection of fine-scale structures in the subsurface in all directions.

While it is ideal to deploy cables as far apart as possible for efficiency's sake, Beasley explained, that method presents its own set of problems. Information can be missed in the gap between the cables. Beyond fine-tuning the directions in which information can be acquired, Schlumberger also set out to deploy the cable deeper under the water – 15-20 m – to further decrease environmental noise.

"We solved these two problems together by putting new measurements in the cable. One of them is a vertical accelerometer and the other one is a lateral accelerometer that measures the particle motion in the water, both in the vertical sense and laterally, which allows us to see that data between the cables," he said.

Beasley said that one of the most important reasons to continue to invest in high-quality seismic shooting goes far beyond those of improving imaging.

"The process from exploration to production used to be 10 years for such challenging prospects," Beasley said. "The industry has brought that time down and today, around four years is possible. An important factor is the multi-client data model, which provides excellent-quality data, is available immediately, and [enables]


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companies to move from exploration to appraisal and development without acquiring the new data. That's really one of the key drivers for operators as well as for WesternGeco to acquire very high-quality data in the Gulf of Mexico."

Drilling developments

On the drilling side, efforts in the Lower Tertiary have pushed current technology to its boundaries while forcing service companies to look ahead to the future, says Baker Hughes' Talmadge Wright, regional manager, Evaluation and Specialty Services.

"Pressures are at the upper end of operating specs for most drilling tools," he explained. "Temperature has really not been an issue to date because you get a lot of cooling effect from the long riser as long as you're circulating, [but] we can see looking a few years out in the future that temperature is going to be a concern also."

Based on that, from the service provider point of view, he added that "we've had to go back through and redesign our equipment pretty much component by component to engineer the safe and reliable performance we need under these conditions. Especially when it comes to downhole electronics. That means going back to the drawing board and doing a total redesign because we have to go to different electronic components."

Wright also explained that, in addition to the tough environment that the Lower Tertiary presents, mud windows are particularly tight, particularly in the subsalt. For drilling contractors, that can translate into additional casing strings and additional design constraints. A well might balloon or breathe without engineers knowing if they are looking at ballooning or the start of a well kick or well control situation.

"We are coming up with more exact or more precise understanding of pressures and volumes when it comes to the fluid. We're also monitoring flowback fingerprints, which are a normal part of operation," Wright said, explaining that pump shut-offs would monitor and record to ensure that each shut-off is consistent. Variations in that data could indicate the start of a well control situation.

Baker Hughes says it continues to advance technology development in this area. The goal is to address the complications of drilling in the Lower Tertiary while ensuring that the wells are designed and executed within the cost constraints of both the operator and the service providers. The best way to achieve that is through the collaboration between operators and service companies. Though this practice has been ongoing, Wright said that companies were beginning to work together earlier in the process, a paradigm shift in the traditional operator–contractor relationship.

In environments like the Lower Tertiary, where best practices are sparse, such collaboration could be a key to success, particularly in a down market. By working with the operator on the well construction and completion plan instead of just working with the operator-approved plans, Wright said service companies could better address cost-efficiency issues. There are other benefits to the modified relationship, too.

"Technology is changing. We're coming out with new technology," he noted. "The operators are pushing the boundaries. I think having the discussion earlier is of great benefit to both."

One of Baker Hughes' newest technologies, designed specifically for the Lower Tertiary and environments with similar conditions, is the Hammerhead completions system, which debuted at this year's OTC. The company says it is the industry's first fully integrated wellhead-to-reservoir ultra-deepwater completion and production system.

The system includes an upper completion, a lower completion, an isolation assembly and intelligent production capabilities, and is fully compatible with subsea boosting. Designed and tested for conditions in well depths up to 33,000 ft (10,060 m) and water depths up to 10,000 ft (3,050 m), including temperatures to 300°F (150°C) and pressures to 25,000 psi (1,700 bar).

"We expect the Hammerhead system to improve recovery factors by 2% in the Lower Tertiary through enhanced reservoir stimulation, higher drawdown capability and long-term optimized production," said Richard Ward, president, Global Products and Services at Baker Hughes. "Using a standard well in a Lower Tertiary field as an example, a 2% improvement could translate to more than $4 billion at prices of $50 per barrel over the life of the well."

Looking ahead

Although the Lower Tertiary's sheen has not seemed to dull, it is unlikely that we will see activity continue in the Lower Tertiary and elsewhere at the same breakneck pace at which it has been developing. That analysis was recently expressed by Dr. Michelle Michot Foss, Chief Energy Economist at The University of Texas at Austin.

"We are coming off of one of the toughest high-price cycles for mega-projects ever," Foss told *Offshore*. "It has been phenomenal watching companies pursue things that have accelerated at the pace that they have around the world in cost, [despite] schedule delays and technical problems and everything else that the industry has faced. That's a whole new paradigm."

Foss also said that having the technology to unlock areas like these is just one piece of the puzzle. Companies also need to consider financing throughout the project development cycle while ensuring that their business models are sound. Vertically integrated IOCs will typically shuffle cash flow from their downstream businesses to fund upstream operations. Non-integrated companies don't have that luxury. An increasing amount of external funding is flowing into deepwater projects, exposing companies to new performance pressures.

"The dilemma is how on earth to do the pre-front-end engineering and design, the FEED, the FID, and the EPC contracting in ways that can put some better boundaries around the costs of these projects," Foss observed. "I think that in a lower price environment, if you can't figure that out, you simply cannot proceed with these projects. That is a challenge that everybody really needs to give some serious thought to."

She said that one of the major challenges in developing these mega-projects was ensuring strong risk management by all parties throughout these stages. "This includes external investors jumping into these projects via equity funds or other vehicles for the first time," she said.

Another factor that could affect the cost of development in an ultra-deepwater play like the Lower Tertiary is the recent activity amongst companies in the subsea sectors, where joint ventures aligning to jointly handle all aspects of subsea development have been springing up in an unprecedented rate. On the service and seismic company sides, fleets have been downsized and other organizational changes made to lower cost ceilings, observes James West, Evercore ISI's senior managing director. But he notes that only the future will tell what model changes, if any, will succeed.

"If pricing is coming down just in general for all this offshore equipment and services, and then you have new business models that also bring down pricing, then your economics start to look more attractive," West said. "That said, the Lower Tertiary will probably start at $80/bbl; it's not $45 or $50, as it is in the rest of the Gulf of Mexico deepwater. There are much more challenging economics for the Lower Tertiary."

Foss said that the initial reactions after the 2008-2009 oil price collapse and now the downward-trending, lower, flatter oil price curve would be to immediately right the ship and reset major projects with matching major cost de-escalation curves. But in the longer term, companies will need to resolve the technical, cost, and financing issues affecting these major ultra-deepwater projects and continue forging ahead, albeit in a modified model.

"The reality is that they cannot continue to go forward at the same pace and probably not in the same way as they were," she commented. "Yet, deepwater plays are where the material reserves and production volumes are. That leaves the larger oil companies, especially, with few choices except to continue to push ahead."

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MPD rig configuration augments deepwater well control

Unique application saves $18 million on project offshore Indonesia

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Managed pressure drilling (MPD), the technique that maintains bottomhole pressure (BHP) in wellbores where conventional drilling methods present costly and risky limitations, is no stranger to the oil and gas fields of Indonesia's Makassar Strait. Situated between the islands of Kalimantan and Sulawesi, the area's deepwater carbonate formations have been drilled with MPD methods, typically using a light mud, to drill through severe circulation losses and reach target depth (TD).

In a unique application of the approach, an international operator deployed a multi-purpose MPD system for a deepwater exploratory well on the non-carbonate side of the strait to address early kick detection issues, and navigate narrow pressure windows en route to the zones of interest. Although total losses were not anticipated in drilling through the clastic formation, the operator wanted to configure an MPD system that could seamlessly transition from one MPD mode to the other, if necessary, and drill more efficiently while ensuring optimum well monitoring and control. The project was designed to meet the three-fold objective of MPD: drillability, efficiency, and safety. The operation was completed safely, reached the target with no environmental incidents, saved time, and reduced the anticipated cost by several million dollars.

The approximately 20,000-ft (6,000-m) well is near the Kalimantan side of the Makassar Strait in approximately 7,500 ft (2,300 m) of water, which at the time of drilling was the deepest water in which the Weatherford automated MPD control system had been used. The system was engineered and installed on a moored semisubmersible rig to meet the requirements of the geologically diverse formations throughout Indonesia. The operator's objectives were to drill through the narrow mud-weight window while safely diverting gas to reach TD. The plan called for using a mud weight less than the pore-pressure gradient while drilling and maintaining bottomhole pressure higher than the equivalent circulating density (ECD) during connections to increase operational efficiency.

Managing small kicks

The MPD implementation created a safe closed-loop drilling system that detected gas influxes before they migrated and dissolved into the drilling fluid. Equipment to accommodate the multi-mode functionality of the MPD system included:

- A deepwater rotating control device (RCD)
- An annular isolation device (AID)
- A flow spool
- An MPD choke manifold with an integrated dual choke system, mass flow meter, hydraulic power unit and systems intelligent control unit (ICU), which monitored and controlled the operation. The function of the integrated ICU is to prevent any problems with data acquisition and communication.

For this challenging well in the Makassar Strait in Indonesia, a surface buffer manifold enabled automatic flow diversion and aided in multiple flow routing options. (Photos courtesy Weatherford)

An MPD riser stack, equipped with a deepwater RCD and an annular isolation device, in mid-deployment.

For this configuration, a surface buffer manifold was installed to augment automatic flow diversion and facilitate multiple flow routing options, including advanced kick detection and managing bottomhole pressure during connections. The buffer manifold is versatile in its ability to route and reroute return flow. For detecting losses or kicks, the device can route the flow to the MPD manifold. To maintain minimum pressure on the well, it immediately reroutes flow to the mud trough.

The automated MPD system is designed to detect and automatically manage and minimize the size of gas or fluid influxes to prevent potentially dangerous kicks. It maintains constant BHP (CBHP) so that the pressure exerted during the drilling process remains between the pore pressure and fracture pressure gradients. In this case, the system was configured to complement the conventional well control equipment on the rig, leaving the existing flowlines intact. The layout enabled switching operations between the sophisticated MPD capabilities and conventional drilling at any time.

The surface hole section of the well was drilled conventionally. Drilling switched to MPD in the subsequent hole section, and the MPD system was used to drill all the way to TD using a synthetic-based mud that was less than the pore-pressure gradient.

The RCD, a key component of the MPD system, was installed in the mud-return system to contain annular fluids while drilling and to seal the well. A bearing assembly installed into the RCD body facilitated transformation of the open fluid-return system on the rig to a closed-loop circulating system, effectively isolating the rig floor from any wellbore fluids and diverting the fluids back to the mud shakers. The RCD and MPD manifold manage riser gas by immediately detecting it, exerting pressure and processing the gas in a controlled manner—a capability not available with conventional diverter systems.

The return flow from the well was safely routed through the automated choke manifold to a real-time Coriolis mass flow meter. The meter captured critical data, including mass and volume flow, mud weight and temperature, by analyzing the annular fluid returns in real time. The data provided by the mass flow meter is essential for quick reaction to well control events and distinguishing between ballooning and more serious events, such as kicks.

Surface back pressure

The system's well monitoring capability and well model calculations were used to apply surface back pressure (SBP) during drilling by adjusting the choke opening to keep BHP higher than the ECD. This was accomplished by controlling the annulus pressure profile through the wellbore, especially when the main pumps were off during connections. The rig booster pump continuously pumped fluid into the riser and to the choke manifold, keeping flow within the optimum detection settings of the flow meter and enabling better pressure management. While the drillstring mud pumps were turned off to make drillstring connections, SBP from the choke manifold compensated for the loss of ECD, enabling accurate control of the desired BHP.

The automated MPD control system was instrumental in enabling early kick and loss detection and responding to small influxes before they became problematic. While drilling to TD, the system detected a 1.5-bbl influx. Flow rate was subsequently reduced to confirm the influx, and SBP was quickly applied before closing the annular blowout preventer (BOP). The system allowed for continuously applying SBP while the riser was circulated to ensure it was free of gas. After the Coriolis mass flow meter confirmed that there was no gas influx, pressure was equalized on the riser before opening the annulus.

Just as important was the ability of the system to distinguish between false kicks and wellbore ballooning. In clastic formations with a narrow mud-weight window, wellbore ballooning is common if the mud weight is already high because of the pressures exerted on the formation. The pressure relief that occurs while making drillstring connections can sometimes cause a false kick, which can cause problems.

Responding to a false kick by increasing the mud weight aggravates wellbore ballooning and may lead to severe fluid loss issues. Activating well control emergency measures, such as closing subsea BOPs, is expensive and ill-advised because the full capability of the BOP must be reserved for processing real kicks and handling well emergencies. By distinguishing real kicks from ballooning, the MPD system helped the operator avoid this costly pitfall. When ballooning did occur during drilling, the MPD seal mimicked closure of a subsea BOP.

The MPD operation was completed five days ahead of plan. Total well cost was $18 million below the authorized amount. The operator was able to navigate the narrow mud-weight windows, maintain control of gas influxes and reach desired depth according to the planned casing program, an outcome that would not have been feasible using conventional drilling methods.

Digitized underreamer achieves successful lateral well placement

Steven Radford
Baker Hughes

Expandable reamers have historically been used to improve efficiencies and reduce risk while drilling through problematic formations in deepwater and other offshore wells. They are particularly applicable where wellbore stability is a major challenge, and play a significant role in supporting lean-profile well designs.

At first, ball-activated reamers could only be activated once and could not be deactivated until the flow was stopped. An improvement made to these reamers enabled crews to deactivate the reamer while allowing flow thru the tool using a second ball to improve hole cleaning. Concentric reamers enabled larger opening ratios, flexibility in pilot bit selection, high flow rates, better hole cleaning, and the ability to enlarge a previously drilled hole or back reaming with improved reliability.

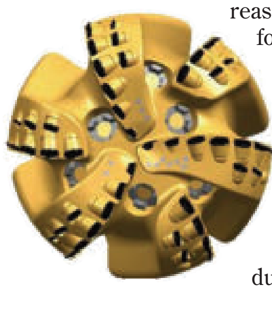
Digital underreamer

During this time, operators were always looking for ways to improve insight on reamer condition and operation downhole, in real time. In recent years, Baker Hughes and a customer began to develop an integrated, digital reamer with real-time communication capability through measurement-while-drilling (MWD). The prototype was used exclusively in the Norwegian and UK sectors of the North Sea. It was powered by the MWD turbine and used hydraulic power to activate and deactivate the reamer. Control was achieved by downlinks from surface.

This new reamer added a host of new capabilities to underreaming operations. It can be activated and deactivated as many times as needed. Activation is achieved with a downlink within four minutes and does not require any shoulder testing. Blade status and extension is confirmed using real-time communications through mud-pulse or wired pipe. Real-time visualization of tool data includes enlarged hole diameter thru the measurement of blade extension, pressure, temperature, and tri-axial vibration measurement. This new reamer can also be placed closer to the bit to minimize the rat-hole down to around 15 ft. The new reamer also operated independently of flow rate, revolutions per minute (RPM) or weight on bit (WOB).

Case history

The Harding field is located in the North Sea, about 320 km (~199 mi) north-east of Aberdeen, Scotland. The field contains six heavy oil and gas accumulations reservoired in massive and injected sands of the Balder and Horda formations. The Harding reservoir quality is exceptional with permeability in excess of 10 Darcies.



Optimized six-bladed PDC bit, IADC M223. (All images courtesy Baker Hughes)

However, wellbore stability has been a major challenge in the Harding field. Fragile sands and weak shales combine to provide a tight window of 0.7-1 ppg. Sands fracture at approximately 12.5 ppg and shale collapses between 11.5-11.8 ppg.

Mud losses are another challenge on Harding and have been encountered in all hole sections. The grid sands, injected sands, and Balder massive sandstones have had severe mud losses on many wells. Losses varied from low volume to total losses, which in turn led to hole abandonment and side-tracking. Extensive modeling carried out in-house and with the mud supplier identified the need to underream the overburden section of the IS6 well. This was to ensure that the formation fracture gradients were not exceeded, even if the minimum predicted values were encountered during drilling.

Underreaming has been required as standard especially in the overburden and reservoir sections. Through careful mud weight consideration, and the expectation that there would be no significant shale in the reservoir, it was decided that well IS6 would be drilled conventionally without the use of managed pressure drilling.

The pilot hole of the well IS6 was kicked off from the existing 9⅝-in. casing and drilled to total depth (TD) and partially underreamed. Once the fluid contacts were determined, a cement plug was set across the underreamed ledge, and a side-track was subsequently drilled to place the main bore of the well. The cement plug was also to act as a barrier to isolate the reservoir sands at the IS6 Pilot TD.

The main bore was drilled as an 8½-in. by 9⅞-in. hole section interval, planned to TD of 11,020 ft MD (measured depth). It was drilled with a minimum mud weight of 11.6 ppg OBM (oil-based mud) with simultaneous underreaming required to reduce equivalent circulating density (ECD), and allow drilling and cementing operations to be conducted within a narrow pressure window between formation fracture and collapse. This hole section was to be cased off down to a planned depth of 10,924 ft MD with a 7⅝-in. liner. The liner was to be cemented using a light-weight slurry (~12.5 ppg) to avoid formation fracture and losses during cementing operations.

Matching bit to reamer

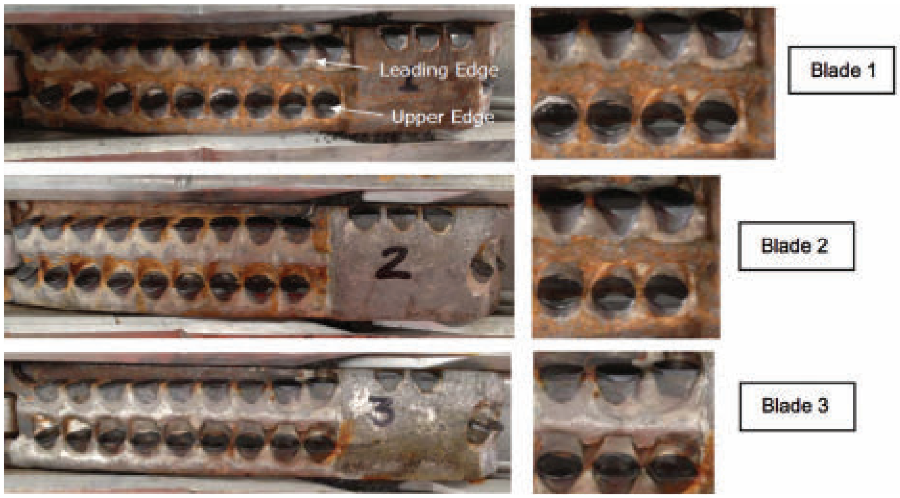
As typical rotary or directional bottomhole assemblies (BHA) have reamers placed many feet behind the bit, the reamer loads can vary compared to the bit loads. This is due to two reasons: the bit and reamer can be in different formations; and the aggressiveness of the bit does not match the aggressiveness of the reamer.

The bit design and aggressiveness of the bit and reamer was analyzed and coordinated to better balance the loads seen while drilling through homogenous formations.

A common misconception in the industry is that matching bits with reamers means having the same cutter sizes on both tools, or following a set of simplistic equations. These assumptions fail to consider some aspects of

the drilling process. The bit and the reamer interact with the formation differently and drilling dynamics are consequently different. Even mechanical rock properties may vary. For example, by the time the reamer starts drilling a new formation, some of the inner formation stresses of the said formation may have been released. Typically, the reamer would have a higher aggressiveness than the bit.

Matching bits and reamers is not a simple task, as various complexities come into play with the drilling and underreaming processes. Baker Hughes uses a total system approach, and the entire system (BHA design, reamer, bit, formations, drive mechanisms, etc.) was taken into consideration. The goal was to eliminate or reduce the occurrence of the pilot bit out-drilling the reamer, which may cause damaging vibrations or cutter damage.



Blades after the first integrated underreamer run.

Case study: first run

The objective of this project was to ensure smooth drilling dynamics throughout the long overburden section while maintaining ECD and acquiring relevant geological data to optimize the placement of the lateral main bore. The intent was to underream to the planned side-track point then close the reamer and continue drilling to TD.

Using drop-ball reamers in the past has yielded mixed results. The success ratio was not high. The operator was keen to use new technology that provided better insight into the reamer operation and condition. Using the on-command activation and deactivation of the reamer in tandem surface downlinks, the unknown was eliminated and confidence was gained in successful reaming of the said interval and the subsequent deactivation of the reamer.

The integrated reamer was run in conjunction with the AutoTrak rotary steerable system (RSS) with an 8½-in., six-bladed PDC bit, properly synchronized to the reamer and formation. When drilling started, a downlink was sent for the reamer to activate and begin reaming the hole. Although not required, a quick test was carried out by drilling several feet with the activated reamer then pulling back circulation, and noting the increasing resistance or hookload when the opened reamer was pulled into fresh formation. Measuring the increased load indicated that the reamer had likely opened.

The reamer's performance was monitored in real time, visualized on the surface displays. The displays show a combination of downhole measured parameters, which allows a quick evaluation of drilling and underreaming status. Real-time display on surface confirmed that the tool was fully open and activated. Status of the tool and its activation modes were tracked by the operators on surface as well as a team of technical experts in the tool development center in Celle, Germany, via remote monitoring services. When ECD started to gradually increase to critical levels, steps were taken to manage it. These included reducing ROP, flow, and RPM. Mud weight was gradually reduced to acceptable levels by increasing frequency of pumping sweeps, and adjusting fluid rheology. Therefore, it was decided to keep the new integrated underreamer (IUR) activated and open throughout the run to section TD, reaming the full 4,489 ft of the section. The IUR performed well even with overall high dog-legs, and the tool pulled out with an excellent dull grading of 1-1-WT. In the end, the open-close-open function was not needed as it had been originally planned.

The bit-reamer-BHA synchronization resulted in no reported vibrational issues throughout the run, greatly improving the performance of the system, and increasing the reliability and longevity of the drilling system.

Case study: second run

Following the first run, the lateral side-track BHA included the same components, the on-command reamer and the AutoTrak RSS assembly with the synchronized drill bit. Again, the BHA performed as expected. The reamer delivered reliable hole enlargement and the RSS delivered the well path, meeting the challenging demand for high dog-leg severities. Stick-slip and lateral vibrations were seen intermittently during the run. The plan was to use 2,235 ft of the pilot open-hole section as a part of the main bore.

As the well progressed, approximately 2,000 ft of pilot openhole interval was used in the main bore, as a result of successfully managing the narrow pressure margins. With this method, the crew was able to effectively underream the borehole. The second underreamer assembly drilled 2,165 ft to TD and was pulled out with blades dulled at 1-2-WT. Overall, the integrated on-command reamer run was successful and it fully achieved the objectives without any issues noted. Again, the open-close-open function was not needed.

Reaming in this manner on both the sections allowed the 7⅝-in. production liner to be run to bottom with relative ease.

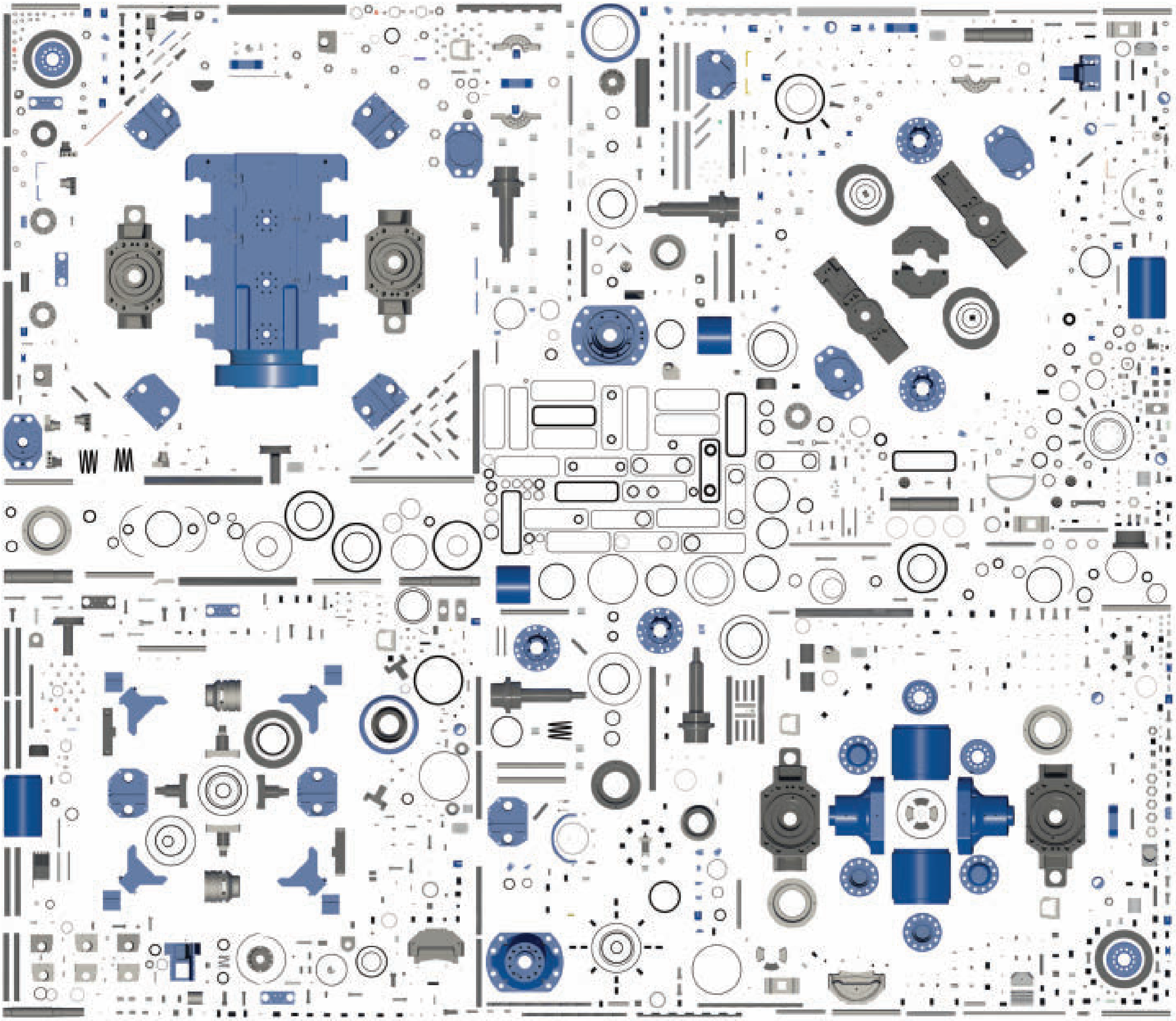
Conclusion

The new integrated on-command underreamer selected for reaming the Harding 9/23b-A32Z (IS6) well was successful. It reamed a full-sized enlarged borehole and the liner was run and cemented easily and without incident. The synchronized bit and reamer were successful since vibrations were almost nonexistent on the first run and minor during the second run. This has allowed for improved rate of penetration and improved BHA reliability and longevity, as damage was minimized and energy was better conserved.

On the first run, the reamer blade wear was dull graded as minor at 1-1-WT on a zero to eight severity scale. On the second run, the blade dull grade was also very good at 1-2-WT.

The on-command integrated reamer achieved the objective it set out for, underreaming the pilot well and lateral well on Harding. During the course of the first run, it recorded its longest run for that size – 4,480 ft under-reaming distance, in 194.6 hr of drilling time with a maximum dog leg severity of 5.07°/100 ft and up to 90° inclination at TD, for the first run. Second run also made the distance of 2,165ft to TD in the lateral hole as planned without vibration dysfunction.

A total distance of 6,645 ft was underreamed on this project using the integrated underreamer. The integrated on-command underreamer succeeded in opening and closing as needed upon instruction from the rig floor via downlinking.



Deepwater drilling analysis tool addresses wellhead/conductor strains

GoM experience underlines need for more detailed evaluations

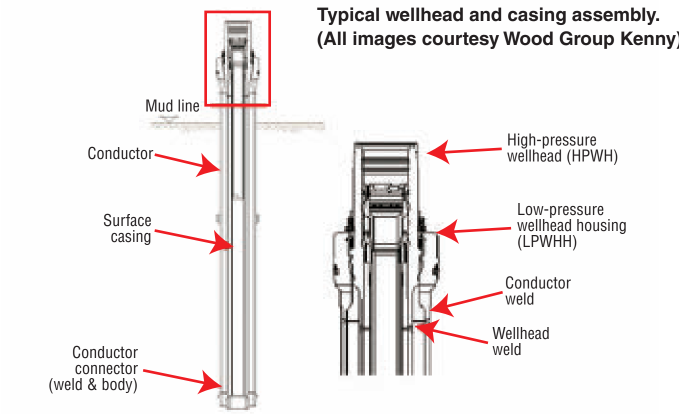
Michael Lane
Wood Group Kenny

Ultra-deepwater capacity semisubmersibles and drillships can operate in water depths of up to 12,000 ft (3,658 m). At these depths, more complex and heavier BOP stacks are required. The wellhead and conductor system is the key load-bearing structure that supports the BOP and the various casings that collectively link the hydrocarbon reserve to the drilling rig or vessel. It must ensure stability and structural integrity of the well for the duration of drilling operations in order to avoid critical failures.

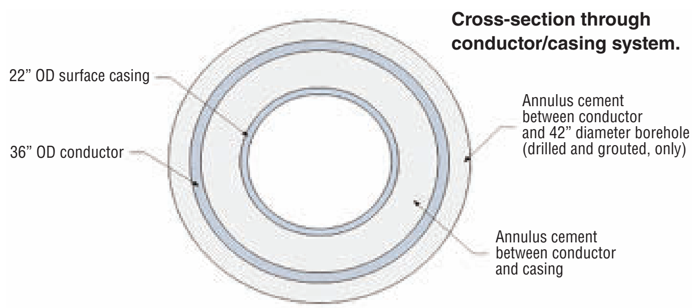
Many modern ultra-deepwater rigs are equipped to accommodate 20,000-psi (1,379-bar) capacity BOPs with up to seven shear/seal rams, typically 45-55 ft (13.7-16.7 m) tall and weighing up to 800 kips. A larger BOP means more bending on the wellhead due to the higher elevation of its top section, and increased P-δ effect as the heavy weight is shifted off-center.

This combination can also shift the natural period of the BOP/wellhead/conductor assembly into the range of typical wave periods, leading to increased dynamic effects from wave frequency loads.

Fatigue caused by the transmission of cyclic loading (bending and tensile) from the vessel and riser system into the wellhead or conductor is a major concern, which needs to be addressed through accurate estimation of the potential impact in the design of these components.



Typical wellhead and casing assembly. (All images courtesy Wood Group Kenny)



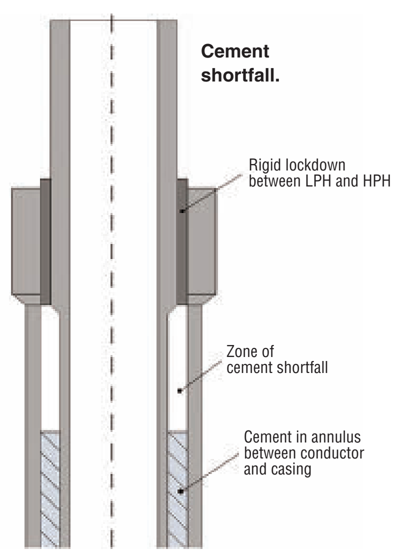
Cross-section through conductor/casing system.

Intuitive interface

Wood Group Kenny has updated its DeepRiser software to provide enhanced capabilities in wellhead and casing modeling. The software is a Windows-based tool developed specifically for the analysis and design of drilling risers. It combines an intuitive user interface that simplifies building the riser model with a comprehensive finite element structural analysis methodology.

Traditionally drilling riser analysis models did not include wellhead and casing at all, or modeled them as single-bore tubulars. But the loading transmitted to these components in deepwater and ultra-deepwater systems necessitates a new approach.

To accurately simulate the behavior of the wellhead, it is modeled as two sections: the high-pressure wellhead (HPWH) and low-pressure wellhead housing (LPWHH). The user inputs properties for the HPWH section, which runs the full length of the wellhead, and for the LPWHH section, which covers the HPWH from the bottom of the wellhead to a specified elevation. The overlap region is then modeled using a composite section approach.



Cement shortfall.

A single line of finite elements runs from the bottom of the wellhead to the top of the LPWHH region. This set of elements is assigned equivalent properties, calculated automatically and without user intervention from the user inputs. This composite model approach is acceptable because the wellhead is being analyzed in "rigid lockdown" mode, whereby the HPWH is landed and locked onto the top of the LPWHH with no relative motion between them.

A similar composite approach can be employed for modeling casing, in which separate properties input by the user for the various casings and cement are automatically combined to define properties for an equivalent single tubular. Given the potential multiplicity of layers, these calculations must be performed carefully

Two modeling approaches adopted for drilling riser design.

Approach	Details
1	Complex wellhead/casing model
2	Simplified wellhead/casing model

Minimum predicted fatigue lives for the two approaches.

Approach	Minimum Fatigue Life (years)	
	1,088 ft (331 m) WD	8,588 ft (2627 m) WD
1	25	256
2	16	163

to deliver a realistic model. Having the calculations done internally by the software minimizes the potential for user error.

A second, more complex casing modeling option involves a pipe-in-pipe approach. In this case separate lines of collinear elements are applied to model the individual casing layers. The properties of each set of elements correspond to the user-specified properties for that layer.

The additional mass per unit length of the cement and the contribution of the cement to bending stiffness is automatically added in. Interaction between layers is controlled by the specification of pipe-in-pipe connections, basically non-linear springs.

The composite and pipe-in-pipe models show close agreement for the majority of cases. However, in certain instances the pipe-in-pipe model offers a distinct advantage. One is a cement shortfall which occurs when cement in the annulus between the outer conductor and inner casing does not extend to the full height of the area of overlap between them. When that happens, there is no load share between conductor and casing in the shortfall section. The pipe-in-pipe model can be used to accurately model this scenario.

GoM experience

Recent drilling riser design experience of Wood Group Kenny engineers in Gulf of Mexico locations in both shallow water (1,088 ft/331 m) and deepwater (8,588 ft/2,617 m) allowed a comparison of the varying levels of complexity provided by DeepRiser. The key parameter examined was the minimum fatigue life along the casing and wellhead. Two modeling approaches were adopted:

In Approach 2, the casing model was one where only the conductor casing was accounted for. For the complex wellhead/casing model in Approach 1, the casing was assumed to be cemented back to the seafloor, so the composite casing model was employed everywhere: no pipe-in-pipe modeling was used.

When the outer conductor casing layer alone was included in the model, the estimated fatigue life was roughly 50% less than when both the conductor and surface casing layers were included. This finding underlines the importance of detailed modeling in modern drilling riser analysis.

Automated drilling gains momentum in offshore operations

Ekaterina Minyaeva
OTM Consulting

While the oil and gas industry is not expected to fully automate its drilling facilities, it has been moving toward production automation, especially for offshore topsides and subsea applications. Several challenges, such as high costs and strict HSE requirements can be addressed through automation.

However, the industry will most likely follow the same route as the aviation industry where a plane operates on autopilot, but is supervised by pilots that have override authority. The reason behind not opting for full automation is not the lack of technology. Rather, it is because challenges persist around the lack of standardized equipment, poor software interoperability, lack of alignment with government regulations, and the negative public perception of fully-autonomous robots. The technological advances made also reinforce the need for human override in certain scenarios.

Operators and service companies working in the offshore environments agree that the industry needs technologies that improve safety, optimize operations, and reduce associated costs.

Drilling automation, particularly drill floor automation, is one of the critical technologies that address these issues. It can minimize the human presence in harsh offshore environments (e.g. North Sea, Arctic regions, Sakhalin, Caspian) while improving efficiency through increased precision and faster execution, thus reducing costs.

But, there is still another challenge. While the oil and gas industry is developing drilling automation technologies, there is little cooperation between companies. This is because automation is seen as an ultimate game-changer, and therefore an area of competitive differentiation.

These siloed approaches are evident in current developments. A number of major service companies already provide hydraulic systems and semi-automated systems for drill floor optimization – but these systems lack interoperability. Once an operator installs a given system, it can only work with equipment provided by that service company. It will not work with equipment provided by alternative service companies.

There is a similar situation with downhole equipment, such as rotary steerable systems (RSS) and managed pressure drilling (MPD) systems; it will only work with equipment provided by the same service company. The lack of interoperability between systems is due to the lack of industry standards for automated equipment, as well as the significant difficulty in adjusting the control systems of current hydraulic equipment.

Drilling company officials indicate that standardization and interoperability is a key challenge for the successful implementation of automation technologies in the oil and gas industry. Thus, the key factor slowing down automation is not the lack of technology, but the lack of interoperability, as it makes the equipment very expensive, difficult to maintain, and nearly impossible to replace.

Category	Subcategory	Robotic technologies capabilities
Drilling	Downhole instrumentation	Robotic steering technologies
	MPD control systems	Safety of drilling operations
	Drilling rigs	Fully automated drilling
Inspection	Above surface sensor systems	Unmanned air vehicles
	Internal inspection robotics	Corrosion inspection, metal loss, crack detection
	External inspection robotics	Inspection of isolated facilities, multiple inspection tasks
Monitoring & repair	Welding	Welding as a method of repair
	Miniature robots	Automated operation, planning,adaptation
	Double purpose robots	Inspection, problem location, repair
Intervention	Well intervention	Perforation, clean-outs, pipe cutting
	Robotic well/facilities handling	Handling of equipment and objects

Technological spread of robotic technologies across the oil and gas production sector. (Courtesy OTM Consulting)

Robotic systems development

A large number of companies are involved in the research and development of robotic systems for the oil and gas industry, and offer automated technologies across the production sector: drilling, inspection, monitoring, and repair and intervention.

A large number of R&D groups are focused on the development of internal and external inspection technologies for offshore topsides applications. The technology currently available on the market varies significantly, but a few things in common are:

- The majority of inspection technologies currently available are not ATEX-certified despite offering services for internal inspection
- Research efforts are very disjointed, therefore many small-medium sized R&D companies are struggling to develop inspection robots required (including quality of output data, signal quality, ability to operate in various fluids, temperature and pressure ranges, etc.).

The remaining three categories: drilling, monitoring, and repair and intervention, are a lot less popular amongst small-medium size companies since they require major testing and

Left: The systems working together retrofitted on an existing rig. Right: The robot installed at the Ullrigg Test Centre in Stavanger. (Images courtesy Robotic Drilling Systems AS)

development. Therefore, only a limited number of companies can afford the investment.

Monitoring and repair robots, or double-purpose robots that are capable of inspecting and repair, are in their infancy. There are a limited number of companies looking into this technology. At the moment, it is more distant future rather than feasible reality.

Semi-automated intervention technologies are available on the market, but they are supplied only by the major service companies. In large part, this is due to the significant testing and expensive development required to certify the equipment.

Automated and semi-automated drilling systems – including MPD systems, RSS, and robots for drill floor automation – are also offered only by major service companies. Each offer a slightly differentiated service, and almost all state that their systems can be interconnected with other systems running on the field such as MWD/LWD (measurement/logging-while-drilling). However, based on previous experience and the operators' claims, in order for RSS or MPD to communicate with LDW/MWD, both services are needed by the same company. Thus, the challenge of interoperability remains.

In addition to limited interoperability, most of the technologies for robotic drilling are hydraulically powered. Hydraulics have a number of associated issues, such as problematic control systems, poor robot awareness, space requirements (which poses a significant challenge for offshore applications), and challenges with hydraulics reacting to pressures that cause physical problems.

Commercialized technology

Robotic Drilling Systems AS (RDS), a Norwegian provider of robotic drill floor system, offers automated, fully electric (as opposed to hydraulic) elements for the drill floor. If these elements were combined, then theoretically humans could be removed from the drill floor. RDS was originally established as a "subsea drilling rig" – it was focused on the development of the subsea robotic drilling rig to address challenges posed by operations in offshore Arctic conditions. However, with decreasing activity in the Arctic (regulations and diversification of supply from other regions) and the decreasing oil price, the company changed its name to RDS to address a wider market of robotic technologies for offshore topsides facilities.

Those elements include the pipehandler, iron roughneck, and the industry's first drill floor robot. RDS has also developed a dynamic control system that allows communication between all robots operating on the drill floor. The control system is adjustable for control software that might be present on the rig (MDP systems, RSS systems, etc.). Importantly, these technologies can be retrofitted to any drill rig to provide interoperability, potentially delivering full drill floor automation.

The drill floor robot is a high-performance technology that uses seven-axis articulation and can operate stationary, or on rails. It allows both automatic and hands-free operation as it performs a variety of functions on the drill floor depending on what tools it is given, such as grippers, spinners, or clamping tools. The drill floor robot easily switches between using different tools while being fast and precise. Its inductive interface makes it possible to transfer power while communicating, thereby creating smart tools to measure or film for inspection purposes.

The drill floor robot was prototyped in 2010 and tested in 2013, and is now on a semi-commercial pilot stage on a land rig in Norway.

Findings from the field

Following the field trials of the drill floor robot in 2010, RDS suggested that in practice there are two recurring findings. First, enduring hydraulic systems are not easily amenable to external control software; and second, human operation is required.

The control system initially posed a number of challenges during the trial as the robots were partially hydraulically operated. This caused leaks at high pressures and significant inaccuracy in the robot's performance. In addition, the control software for the hydraulic systems is considerably less open to interoperability when compared to electric systems. This became a major challenge, and company officials have indicated that the final control system took a number of years to develop. It was concluded that electrical motors and drivers are open to interoperability with other systems, allow more flexibility, and are more precise and easier to use. The dynamic control system, the final product, is now compatible with a wide range of software systems and can be retrofitted.

During the field trial, RDS also concluded that a human operator is critical to the successful performance of any operation involving robots. The human operator was involved throughout the trial, and it was demonstrated that robots need human operation for commands and decision making. Robots need an initial task to develop an execution plan and for implementation. However, if the robot is faced with an unexpected challenge, it would send a signal to the operator to ask for intervention. Thus, the human operator is a critical component of any process involving robots.

Similarly, the field trial proved that the operator can always intervene in case of an emergency. One of the critical aspects being explored by the developers of robotic technologies is safety. Having a human operator control the robotic system can help calm fears about loss of control.

Study provides insight into optimal weight, size for FLNG vessels

Analysis suggests that limits are commercial rather than technical

Nick White
Granherne

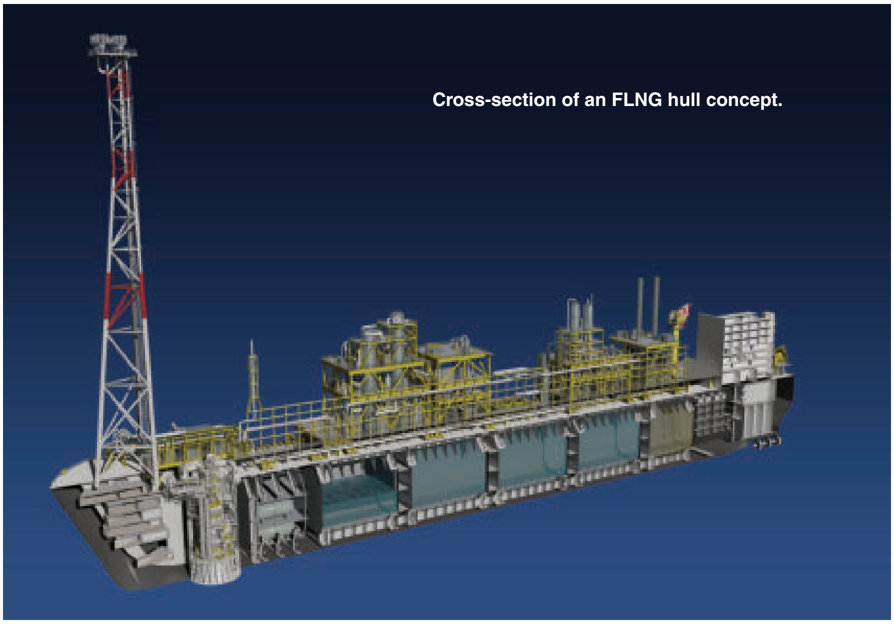
A concept for an FLNG project, showing topsides modules. (All images courtesy KBR)

The first floating liquefied natural gas (FLNG) projects are nearing completion and will soon enter operation. A review of the information available in the public domain on these projects has been undertaken as part of an effort to identify the underlying trends. From this data, correlations were developed for estimating the size and weight of an FLNG vessel.

A high-level model was developed from these correlations, and studies were performed to provide insights into the key weight drivers for the FLNG vessel topsides and hull. Also included in this analysis were a breakdown of FLNG weight; FLNG economies of scale; and the limits on ultimate FLNG capacity.

FLNG hull

The FLNG hull has to provide a seaworthy and stable platform not only for production and product offloading, but also for the safe accommodation of the crew in a remote and possibly hostile environment. It also has to accommodate the required product storage and provide a flat deck area to support the topsides process, utility, product offloading, and support facilities.



Cross-section of an FLNG hull concept.

Hull aspect ratios

Open ocean, ship-shaped floating facilities have limits on the allowable hull aspect ratios (i.e., ratio of length to breadth [L/B] and breadth to depth [B/D]) for stability reasons. With the current FLNG projects and concepts, the aspect ratios are similar to LNG carriers.

Product storage capacity

The required LNG storage capacity is a primary function of the parcel size of LNG, plus typically two to five days production as contingency against unforeseen events that could delay offloading. The parcel size is equal to the capacity of the largest LNG carrier to be loaded, since these vessels cannot accept partial loads due to issues with sloshing.

The condensate storage capacity and LPG storage capacity, if produced as a separate product, would be less than the LNG storage, since the parcel sizes are considerably less. This is due not only to the availability of oil tankers and LPG carriers of smaller capacity than LNG carriers, but also the ability of these ships to accept partial loads. Furthermore, the daily production rates of LPG and condensate, and so contingency volumes, are considerably less than for

Hull size and product storage capacity.

Project	Total MTPA	Aspect Ratios {L/B}	Aspect Ratios {B/D}	Days LNG Contingency (Note 1)
Exmar	0.5	4.4	1.6	4.8
Petronas FLNG 1	1.49	6.1	1.8	2.7
Petronas FLNG 2	1.95	6.0	2.1	2.2
FLEX	1.5	5.9	1.6	1.5
Hoegh	2.0	6.3	1.8	3.2
ConocoPhillips (2)	~3.9	6.7	1.9	3.6
Lloyds Energy	4.0	5.0	2.0	3.5
Lavaca Bay	4.4	5.5	1.9	3.2
Shell Prelude	5.3	6.6	1.7	2.7
Qmax	N/A	6.4	2.0	N/A
LNG Lagos	N/A	6.5	1.6	N/A

LNG. It should also be noted that as the condensate is contained by the steelwork of the hull rather than in specialized cryogenic storage tanks, additional contingency can be provided at minimal cost if there is "spare" space in the hull.

The study assessed total product storage volume (LNG, LPG, and condensate) against the nominal hull volume (length x breadth x depth) for various FLNG projects and concepts. The findings indicated that the product storage would typically take up about 28% and 37% of the nominal hull volume for offshore and jetty-moored FLNG, respectively.

The remainder of the hull would be occupied by the insulation around the cryogenic tanks and the void between the inner and outer hulls. The analysis also took into account the required machinery rooms, workshops, storage tanks (for production chemicals and solvents, refrigerant make-up, diesel fuel, and water); and, for offshore FLNG, an internal turret.

Required topsides area

The study also analyzed the nominal hull area (i.e., length x breadth) against FLNG production capacity. The best fit was obtained by plotting the data in two groups, namely offshore turret moored concepts, and inshore/jetty-moored concepts against the total hydrocarbon production capacity – i.e. LNG, LPG, and condensate, rather than against the LNG production capacity alone.

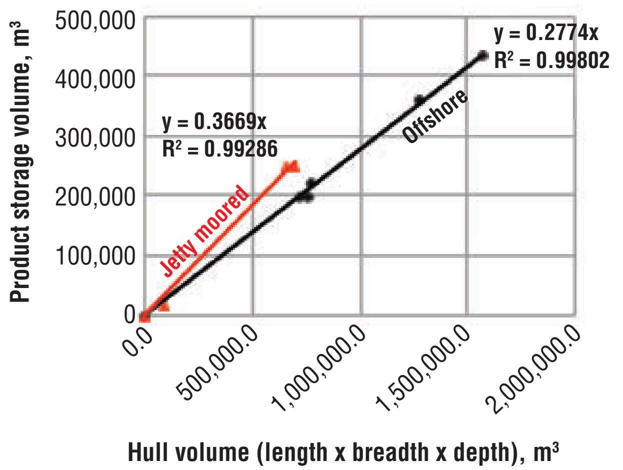
The results indicated that for both data sets, the required topsides area has a fixed component and a component that is dependent on production capacity. Whereas both data sets have approximately the same gradient, the intercepts are significantly different. This can be explained as follows:

- Deck space required for the topsides processing systems would be expected to be proportional to production capacity; and this relationship is similar for both offshore and jetty-moored FLNG
- For offshore, completely standalone FLNG projects, the deck space taken up by those elements that are not directly related to throughput – including the turret, product offloading equipment, large living quarters and lifesaving equipment – would be significantly greater than for jetty-moored concepts.

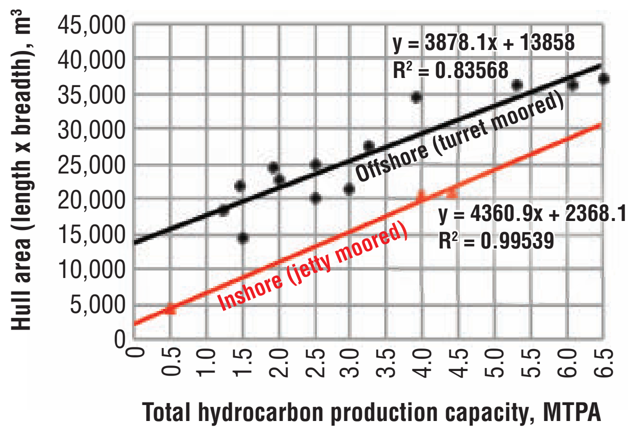
The required hull volume is the greater of the two requirements, and when the storage capacity and topsides area requirements result in the same sized hull, the design is said to be "balanced."

Finally, in this analysis total hydrocarbon production capacity was employed. This is because it is a better metric than LNG capacity for comparing FLNG concepts that process lean gas containing virtually no NGLs with those processing more conventional natural gas.

Ratio of FLNG product storage volume to total nominal hull volume.



Required FLNG topsides area.



FLNG weights

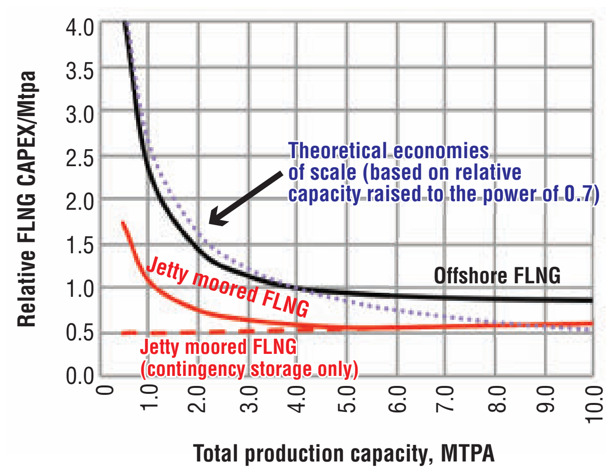
The relationship between the topsides and hull weights reflects the fact that the topsides weight is comprised of a variable component, including the process units and some utilities, that is proportional to production capacity; and a fixed component that is not – including product offloading, safety equipment, some utilities, material handling, and crew support facilities.

Although there is currently topsides weight data for only one jetty-moored FLNG project (i.e. Exmar), the following correlation is postulated for the topsides weight of jetty-moored concepts.

The actual FLNG weight is the greater of that based on product storage capacity and topsides area requirements. When the two result in the same-sized hull, the design is said to be "balanced." The exact capacity at which this occurs depends on the metocean conditions (which influence the choice of mooring type and the L/B and B/D ratios), the topsides process facilities required, and the storage volume. For an offshore FLNG, the "balanced" design corresponds to a total hydrocarbon production capacity of approximately 3.5 Mtpa, and for a jetty-moored FLNG about 6.5 Mtpa. Furthermore, for the concepts currently proposed, the hulls are either close to a "balanced" design or topsides driven.

FLNG weights.				
Project	Total Mtpa	Topsides Wt., Te	Hull Vol., m³	Hull Wt., Te
Exmar	0.5	5,000	89,600	N/A
Total	1.25	28,000	N/A	N/A
Petronas FLNG 1	1.49	45,000	722,700	85,000
Petronas FLNG 2	1.95	~44,000	755,900	~108,000
ConocoPhillips (1)	~2.5	48,000	N/A	N/A
Prelude	5.3	80,000	1,570,000	180,000
Qmax	N/A		501,438	48,008
LNG Lagos	N/A		300,797	30,933

FLNG economies of scale.



Economies of scale

The study also compared the relative FLNG capex per Mtpa of total hydrocarbon production. The study assumed that all costs were relative to a 4 Mtpa offshore FLNG, and that topsides capex per metric ton was four times hull capex per metric ton, with the turret representing 10% of the total FLNG capex. The results indicated that:

- Offshore FLNG is significantly heavier and more expensive that jetty-moored FLNG due to the additional facilities required for standalone operation in a remote, potentially hostile, environment
- For offshore FLNG and jetty-moored FLNG, storage in hull economies of scale apply strongly at small capacities; but this largely disappears at higher production capacities when the hull design is topsides-area driven
- For jetty-moored FLNG where there is only contingency storage in the hull, there are no economies of scale for the FLNG itself. Although this analysis did not include the cost of storage in a converted LNG carrier moored alongside, this could potentially be cost effective even at small capacities
- For small-scale FLNG where the hull size is driven by storage volume, capex would be minimized by specifying the minimum feasible storage volume
- For large-scale FLNG where the hull size is driven by topsides area, capex would be minimized by selecting the longest, thinnest feasible hull, since this achieves the required B/D ratio with the smallest hull depth and so volume.

Ultimate FLNG capacity

The ultimate capacity of an FLNG facility will be dictated by the size of the dry docks available for construction of the hull. Furthermore, there are only a limited number of shipyards available with large dry docks and the capabilities to build such hulls.

The largest dry dock in the world measures 990 m x 100 m x 14.5 m (3,248 ft x 328 ft x 47.6 ft). Based on these dimensions, the ultimate theoretical FLNG capacity would be

> **The ultimate FLNG capacity would be dictated by the size of the dry docks available for construction of the hull.**

approximately 13 Mtpa for offshore FLNG and 14 Mtpa for jetty-moored FLNG, based on the required topsides areas and the allowable hull aspect ratios. There are another four dry docks that could theoretically accommodate FLNG more than 10 Mtpa.

However, there may be other practical limits as well. For example, the required breadth to depth ratio may mean the height of the hull above the dock side is so great that it imposes limits on the weight of modules that can be lifted. Furthermore, as there is only one yard in the world that would be able to build a hull this large, the ultimate limit may be commercial rather than technical.

Conclusions

From the analysis of the information available in the public domain, it has been possible to develop correlations for the size, weight, and relative capex of FLNG. For example, at small LNG capacities, FLNG hull size is driven by the product storage requirement, which is driven in turn by the LNG parcel size. Whereas at larger capacities, hull size is driven by the topsides area required. Where the two requirements are equal, the hull design is said to be "balanced" and the ratio of hull weight to topsides weight is at a minimum.

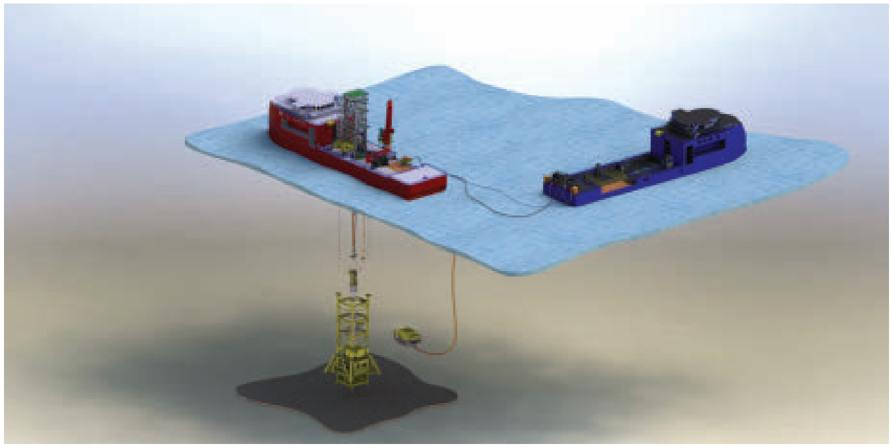
At LNG capacities less than that required for a "balanced" hull design, the economies of scale are strong; whereas at large capacities, they largely disappear. However for jetty-moored FLNG where there is only contingency storage in the hull, there are no economies of scale.

Offshore FLNG is significantly heavier and more expensive than jetty-moored FLNG due to the additional facilities required for standalone operation in a remote, potentially hostile environment. Consequently, small-scale offshore FLNG does not look attractive since there is insufficient production capacity to offset the "fixed" costs. However, small-scale, jetty-moored FLNG does look attractive where low-cost storage, such as a converted LNG carrier, is available and only contingency storage has to be provided in the hull.

The ultimate FLNG capacity would be dictated by the size of the dry docks available for construction of the hull. Based on the largest currently available this would indicate a theoretical ultimate total production capacity (LNG, LPG, and condensate) of approximately 13 Mtpa and 14 Mtpa for offshore and jetty-moored FLNG, respectively.

Connector facilitates live reservoir stimulation on North Sea well

Paul Armitage
SECC Oil & Gas



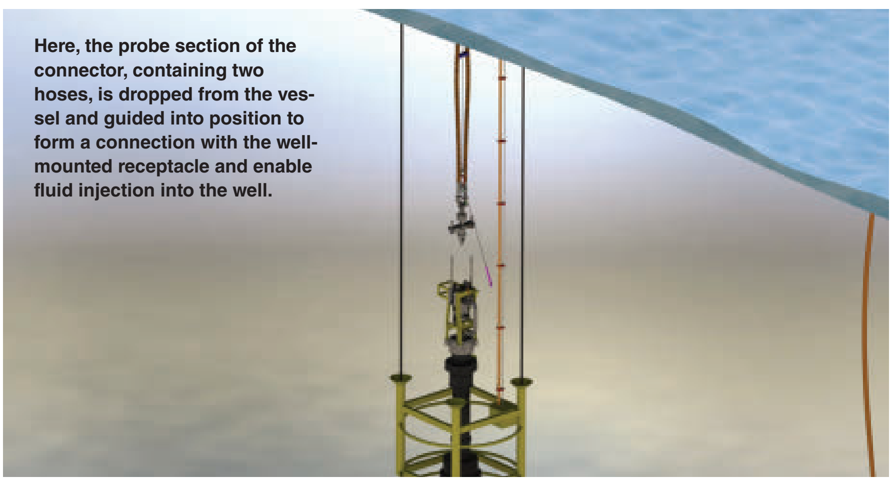
In this rendering, the red vessel is Helix Well-Ops' *Scandi Constructor* and the blue vessel is StimWell Services' *Island Patriot.* SECC's 4-in. Hot Make Hot Break connector is used as the fluid connection point and the emergency breakaway system in case of a vessel drift-off. (All images courtesy SECC Oil & Gas)

Live stimulation of subsea wells is still a relatively underused method of increasing oil recovery across the industry, largely because performing this sort of procedure in open water is considered too high-risk. The practical difficulties and potential dangers involved in working in unstable, high sea-state conditions, and the specific issue that a vessel may be pulled off position while in operation, make this sort of intervention challenging.

Added to this, a shortage of suitably-equipped vessels also reduces the feasibility of live intervention projects. Vessel availability is a perennial problem in this sector, with light workover intervention vessels typically being on hire to a handful of operators, or even a single operator, often for very long periods. According to speakers at Aberdeen's Offshore Well Intervention Conference, Europe, held in April 2014, decommissioning work is accelerating, with some 800 wells, 40% of which are subsea, due to be decommissioned by 2022. Therefore, the issue of vessel availability is expected to intensify in the coming years.

Despite the general understanding that this is a low-cost, high-value way to increase production compared to drilling new wells, industry figures provided at the same conference suggest only 5% of interventions carried out are subsea interventions, even though they generally give a 75% success rate. As a result, statistics also show that subsea wells produce around 30 to 40% less than their potential when compared with platform wells.

Faced with the prospect of underproduction from valuable subsea assets, operators are motivated to identify and understand new technologies that will help them to enhance production and ultimately extend field life. One breakthrough in the industry's pursuit of better, more reliable ways to carry out subsea intervention has been the emergence of a new generation of dynamic-positioned technologies. These perform a critical safety role, allowing operators to control the risk of a vessel being pulled off position and the potential for loss of containment, or fluid spill.



Here, the probe section of the connector, containing two hoses, is dropped from the vessel and guided into position to form a connection with the well-mounted receptacle and enable fluid injection into the well.

SECC Oil & Gas has developed a series of emergency quick disconnect technologies which are designed to be used with DP-enabled vessels. These have been used by operators and service companies involved in improving production from a rising number of maturing oil fields, using methods such as acid stimulation, scale squeeze, water wash, hydraulic fracture, and foam lift.

As part of this series, a self-sealing dry breakaway created by SECC is being used to help operators enhance well production through open water, riserless intervention. The Hot Make Hot Break pressure-balanced connector was designed as a safety mechanism to increase the feasibility of live subsea intervention, particularly in high sea-state conditions where potential drift-off is an inherent risk. Recently, the product was used by BP in a central North Sea field.

BP case study

After a review of its existing reservoir stimulation capabilities in 2012, BP began designing a vessel-deployed high-rate acid stimulation solution to enhance production from its central North Sea subsea reservoirs. Its challenge was to create a high-rate, high-pressure, high-volume solution that would enable back-to-back live stimulations at a rate of 50 b/min.

The possibility of conducting the pumping operations from the host installation was discounted because of logistical and engineering limitations. Having used light well intervention monohull vessels over many years to conduct subsea well work, BP decided to enhance the existing technologies and pair them with the new generation of dynamic positioned vessels in a bid to reach new levels of reservoir stimulation previously achieved only using a mobile offshore drilling unit with riser systems.

Dr. Paul Armitage, managing director, SECC Oil & Gas

While a conventional scale squeeze would typically involve flow rates of 10 b/min, BP's target stimulation rate needed to be five times that.

One of the primary challenges facing the project designers was managing the risk of a vessel losing dynamic-position during the pumping phase. Mitigating loss of containment when activating the vessel's emergency shutdown (ESD) function meant that sourcing market-leading self-sealing quick disconnect coupler technology was critical to the success of the project.

BP commissioned Helix Well-Ops' light well intervention vessel, *Skandi Constructor*, to work alongside StimWell Services' *Island Patriot* stimulation vessel and equipment. The company used SECC's Hot Make Hot Break emergency breakaway connector with a 4-in. bore to accommodate the high rate of pumping that needed to be achieved.

The product connects to the subsea asset via a vertical injection hose. In BP's case, the connector's receptacle was installed on a vessel-mounted subsea intervention lubricator which was deployed to the seabed and stationed on the well. The hose, fitted with the injection probe, was then guided into position by an ROV. Operators can also deploy the technology from a vessel of opportunity teamed with an ROV and a stand-alone intervention skid unit to host the female. In this scenario, which would be appropriate at depths of less than 200 m (656 ft) and in light currents – conditions typical of the central North Sea sector, for example – a standalone skid unit is lowered to the seafloor and connection with the injection hose is made by the ROV. A jumper is then used to connect the skid with the tree so that fluid injection can begin.

The receptacle can be permanently fitted onto existing subsea trees or manifolds. In this way, the need for additional intervention skids or specialized intervention vessels is removed.

The coupler-based technology works by sealing instantly at the point of connection and disconnection, eliminating the risk of fluid loss and the impact of a spillage on the marine environment, while helping to protect the safety of personnel. If the host vessel fails to maintain its position, its movement applies tension to the line on which the connector sits. The connector automatically disconnects when a pre-determined load level is reached. The disconnected hose can be retrieved and reconnected by ROV, without the need to reel in and replace or reseal the hose.

The product also offered BP the ability to maximize flow volume and production rate. The connector's full-bore design allowed BP to sustain the 50 b/min rate it needed to achieve.

"This is a significant and exciting development because it expands the potential and illustrates the benefits of live open water stimulation as a viable, safe, convenient and cost-effective approach to intervention," said Mark Henderson, global business development manager at SECC Oil & Gas.

Total upgrades remote control operations at Al Khalij

Environment conditions pose unique challenges for operators, systems

Nicolas Lacour
Snef Technologies

Cyril Rolland
Codra

Total Exploration & Production Qatar (TEPQ) selected Codra's Panorama E^2 system to monitor and control its installations on the Al Khalij oilfield 120 km (74 mi) offshore Qatar. Marseille-based Snef Technologies designed and implemented the installation, which entered service in June 2013.

Al Khalij has been developed through a cluster of seven unmanned platforms linked by a network of subsea pipelines. All share the same design model, comprising a process control system to manage production and a fire and gas system/emergency shutdown (FGS/ESD) controller to manage safety.

Around 25,000 b/d of oil is piped 40 km (25 mi) to the island of Halul for processing by two separation trains. At the Halul Island oil terminal, operated by Qatar Petroleum, two PCSs manage production for two trains, respectively. In addition, there is a controller to manage the burner management systems for both trains and an FGS/ESD controller to manage safety.

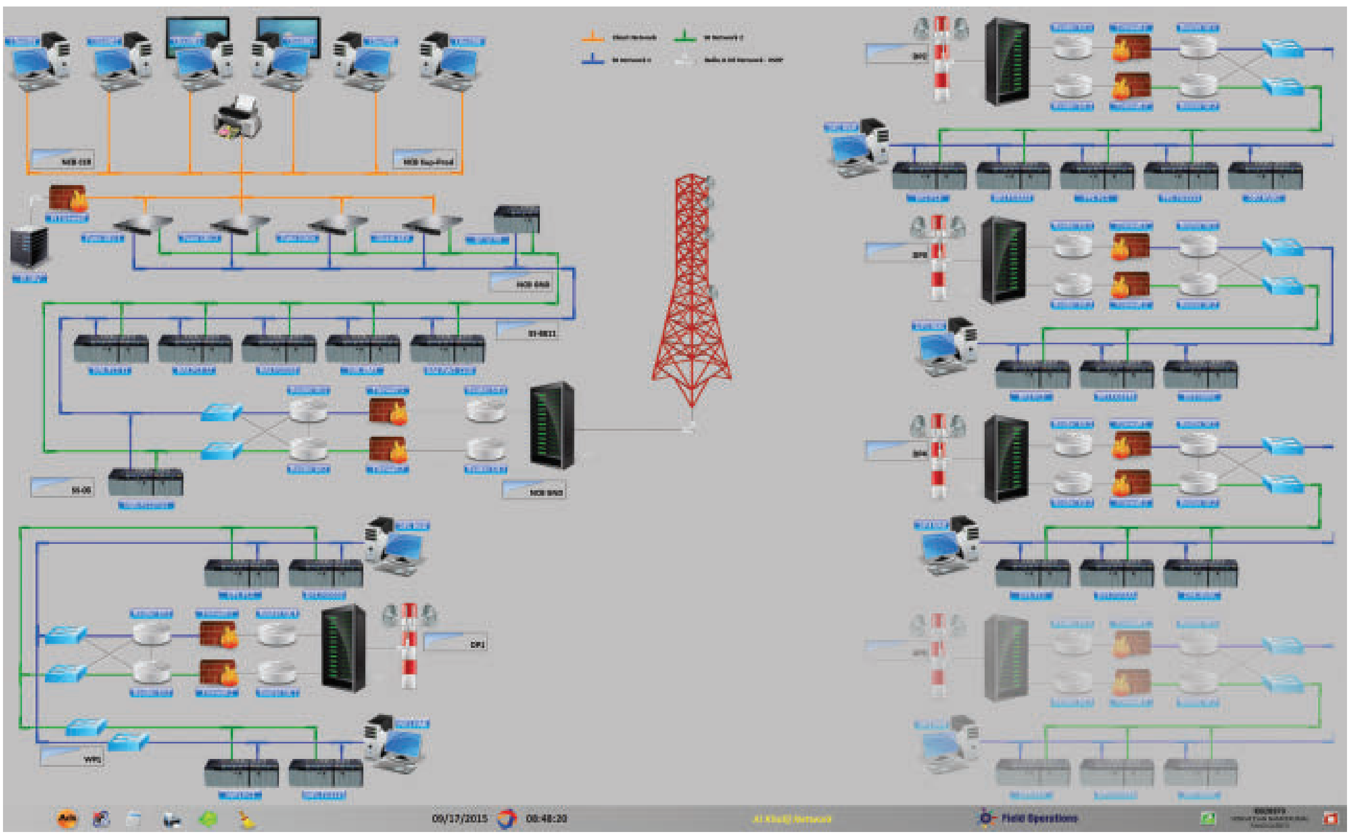
Communication between Halul Island and the platforms as well as between the platforms is via a redundant telecoms network. Total wanted to investigate the possibility of replacing the current integrated control and safety system with a view to improving the performance of its installations. The replacement control system had to meet the company's general specifications as well as the constraints of the Al Khalij site.

Control system features

Codra's Panorama E^2 system complied with the roughly 40 criteria listed in the call for tender. Development was assigned to Snef.

Critical elements of the system included component development using object-oriented technology (functions and interactions grouped into a model); tree structure navi-

Network architecture of the Al Khalij oilfield facilities. **(Image courtesy Snef Technologies)**

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gation; user profile management; structured query language database-based history; enhanced redundancy (up to 12 servers); and logical servers distinct from the physical architecture. Additionally, Panorama E² offers network control; alarm reporting (masking and inhibits); interfacing with other applications such as OSIsoft PI System for transfer of production data to TEPQ's head office in Doha; and the possibility of incorporating video surveillance.

The switchover from the old system to Panorama took place over five weeks with no interruption to production.

Total did not opt for a distributed control system for this project. The changes to the existing system would have had a considerable impact on cost. Panorama met not only the technical criteria but also the financial constraints and avoided the need for shutting down production on switchover.

Operations at Al Khalij started in 1997; Total decided to embark on a new 25-year period of activity in late-2012. The environmental conditions are difficult for both the operators and the machines: The temperature in Qatar varies between 40°C - 50°C (104°F - 122°F) in the summer, with humidity levels exceeding 90% offshore. All the platforms are self-operating and produce continuously, and all are managed from the control room on Halul Island.

In the control room, which operates round the clock, the Panorama system was designed to manage several different systems, including the offshore production units (oil wells, water treatment and injection system); two separation trains on the island; fire and gas detection and safety systems; data collection; interfacing with the OSIsoft PI system; and reporting and traceability.

Snef's work on the project was monitored by a Total engineer, with technical support provided by Codra's engineers. In May 2012, the company achieved the first milestone, developing all the components in compliance with Total's specifications. Using object-oriented programming, it created the iconography as well as all the animation principles.

Once Total in Qatar had accepted the proposal, the project team moved on to the second phase – designing the system for one separation train and one platform, before proceeding to do so for all the platforms based on the specific data from each PLC. The application was developed using version four of Panorama and then migrated to version five, leading to improved performance. The switchover from the old system to Panorama took place over five weeks with no interruption to production.

Several days of technical support were allowed for in the project scope. A Panorama specialist was on hand throughout the entirety of the project. The same specialist later transferred to Qatar to deal with any issues that arose during start-up

Snef Technologies is responsible for site maintenance and provides technical support to the control room operators. Total's methods engineer was trained on the system at Codra's head office and can manage day-to-day development of the application independently. The system was designed such that new equipment could be added, so Panorama will be able to handle any future expansion of the oil field.

The Lucius oil field is located in the Keathley Canyon block in the Gulf of Mexico. (Courtesy Wood Group Mustang)

Standardized platform approach gains momentum

New designs reduce costs, project timetables

Robin Dupre
Sr. Technology Editor

As spiraling project development costs continue to strain investor returns, the goal to standardize the design of offshore platforms is gaining momentum as a means of reducing costs and accelerating project delivery times.

Of course, standardization in the offshore market is not new. Over the past three decades, offshore drilling rig equipment has become increasingly standardized. In the 1970s and 1980s, each rig was customized by the contractor or operator behind the order, and equipment providers were fragmented. Today, there are just a few equipment providers, and contractors are likely to order multiple copies of the same design to improve supply chain and downtime metrics.

But when it comes to offshore production systems, only a handful of companies have taken the route of platform standardization. Wood Group Mustang has been a leader in the engineering and design of standardized facilities. "The key thing is identifying properties that you can live with, and only modify the things that absolutely have to be changed," said Kent McAllister, executive vice president of Offshore at Wood Group Mustang to *Offshore*.

Wood Group Mustang, which designed the topsides for the last three Gulf of Mexico start-ups – Tubular Bells (first oil November 2014); Jack/St. Malo (first oil December 2014); and Lucius (first oil January 2015) – created a one-for-two design approach. It involved building two multi-billion-dollar deepwater production facilities for separate GoM development projects, Heidelberg and Lucius, using a single basic topsides design.

Anadarko had previsouly used its "Design One, Build Two" approach on its Boomvang and Nansen twin spars. The success of that effort led the company to employ a similiar approach on the design and construction of the large spar floating production platforms Lucius and Heidelberg.

During the development of Lucius in the Keathley Canyon area offshore Louisiana, Anadarko realized that the nearby Heidelberg field in the Green Canyon region held sufficient reserves to warrant another standalone facility.

The main objective in the "Design One, Build Two" approach is the opportunity to reduce costs in engineering and construction of facilities replicated from a proven design.

"The savings to the operator is when you get into the detailed design, where you're already working with a known design, and then modifying that," said McAllister. "And the other savings component is at the construction site, when you already know what the steel requirements are, for the most part. So, early forged steel can be made much easier and can reduce the overall construction time, which reduces the construction cost as well."

When Anadarko started to look at Heidelberg, the company noticed a lot of similarities between that field and Lucius, and then brought Wood Group Mustang in. "We realized that we could utilize a lot of what we had, and only modify the things that needed to be done," McAllister added. "So that was a fairly early decision that allowed Anadarko to accelerate the schedule of Heidelberg, as well as reduce their overall costs, not only on engineering, but on construction equipment, too."

Anadarko chose companies that it had worked with in the past for the design, engineering, construction, and follow-on of its previous deepwater facilities. By using this approach, the learning curve and applied knowledge of the project participants from previous projects reduced risks, and provided a compatibility and communication that helped to ensure reliability and predictability for the delivery.

Technip Offshore was chosen for the hull,

The Heidelberg field is located in the US Gulf of Mexico, at a water depth of 5,310 ft (1,620 m). (Courtesy Wood Group Mustang)

which designed and constructed Anadarko's previous spars at its fabrication yard in Pori, Finland. Technip was also tasked with transporting the Lucius hull across the Atlantic to the GoM. Kiewit Corp. was contracted to fabricate the multi-level deck structure at its Ingleside, Texas, construction facility.

Anadarko chose Wood Group Mustang to design and engineer the topsides production facilities. The two companies have had a long-standing relationship, dating back to previously provided FEED and detailed design services for four of the operator's existing spar facilities – Boomvang, Nansen, Gunnison, and Constitution. Wood Group Mustang also provided expansion and brownfield modifications for the Neptune and Constitution spars.

These projects and the ensuing relationship between the two companies helped Anadarko with cost savings and schedule reductions in reaching first production.

McAllister observed that the relationship between Anadarko and Wood Group Mustang "goes back to our 15 years of working together, of building on that partnership, and developing the trust between the two organizations. It is a partnership and not just an owner and a contractor relationship. It truly is a team working for the benefit of the overall goal. By keeping the owner's team and the engineering team together, who just completed the work, who knows how each other work, gives one the efficiency and consistency in the design approach. This helps with saving time from the learning curve."

With the goal in mind of optimizing project economies through cost and schedule efficiencies for Lucius and Heidelberg, Wood Group Mustang's approach was to provide a flexible solution to allow future developments to tieback to the two. Several key design elements were standardized based on prior successes and lessons learned, with the only changes made to the technicalities required to operate the facility. While the Lucius design progressed, revisions were incorporated into early documents for Heidelberg, accelerating the FEED for that project.

Wood Group Mustang's design package was deemed an essential part of achieving the financial decision (FID) for the two developments. The "copy" method for Heidelberg enabled a reduction in the pre-engineering, procurement, and construction phases. It also allowed for swift production of a complete set of engineering deliverables including process and instrument diagrams for Heidelberg.

While Lucius commenced production at the beginning of this year, the Heidelberg facility is on schedule to achieve first production in mid-2016. Its pre-FEED and FEED phases have already reduced man hours by more than 60% with benefits extending throughout the detailed design and fabrication.

Another company that has helped shape the offshore standardization process is Williams Partners, which designed and constructed the Gulfstar FPS – a three-deck, wet-tree spar design – for the Tubular Bells development in the Gulf of Mexico. The Gulfstar One project is the first spar-based floating production system with major components built entirely in the US. This created about 1,000 domestic jobs, allowed quick parts replacement, and reduced platform downtime. Williams owns the topsides/spar facility, while Hess operates it.

It is expected that the Gulfstar design will be used on other projects with design requirements similar to Tubular Bells, including 3,000-8,500 ft (914-2,591 m) water depths, in compliance with new maximum storm specifications. Gulfstar will also serve as a tieback facility for nearby developments, including the Gunflint field.

Stafford Menard, manager, Gulfstar Development, spoke to *Offshore* recently about the advantages of the design. "Gulfstar provides a complete 'floating production system to market clearing point' solution for producers in the Gulf for their oil, gas and liquids production, designed specifically to maximize their net present value and minimize risk," Menard said. "The 'design one, build many' construction concept allows for standardized design options and enhanced safety and reliability of each unit. The repeatable concept also increases speed to market."

Menard commented that the Gulfstar vision is to develop core design with "plug and play" options that enhance safety and reliability with each follow-on unit, and provide significant reduction in delivery schedule. That vision is also designed to reduce the risk of engineering and construction cost overruns, and provide meaningful producer-operator infrastructure alignment. He notes that Gulfstar's standard design approach allows customers to reduce their cycle time from discovery to first oil. From sanctioning a project to completion, Gulfstar can be delivered in 30 months, Menard says.

"We look at standardization mainly from the benefits of having a better defined scope of work from the start, which obviously can reduce your overall project schedule by having accepted the standard rather than going through a concept selection stage," Menard said. "The other benefit of standardization is the repeatability with a standard which allows for the focus to be placed on safety, reliability, and uptime."

"The downside," he noted, " is the reduction in creativity and spontaneity of the engineers to come up with something new and better, but there's still a lot of improvements by using the standard." There is still a lot to be gained by going to the standard and recognizing that one size may not fit all projects, Menard noted. "You may have two or possibly even three standards, some driven by water depth, some driven by the reservoir, whether you need a rig or you don't, depending on how much well intervention one needs for a specific reservoir." There may be a standard for a wet tree solution, a standard for a drilling rig solution, and varying water depths may require different hull types. "But it's still a standard," Menard added, "and it's a better start than having just a blank sheet of paper."

Fit-for-purpose ROVs can help remediate flow assurance issues

Fernando C. Hernandez
Reaching Ultra

Presently, the deepwater realm continues to garner global attention, as illustrated by wells located in the Gulf of Mexico's Lower Tertiary play, and off the western coast of Australia. And in this realm, subsea production schemes are inseparably linked with the risk of hydrate blockages. Should a blockage occur in an export line that ties in to multiple wells, it can lead to a field being entirely shut-in.

Composition wise, hydrates are crystalline molecular complexes that arise when gas and water molecules comingle in a high pressure and low-temperature setting. Moreover, in deepwater, the hydrostatic pressure increases with the water depth of a well; and depth also causes the ambient temperature to decrease. When this is coupled with a pipeline that is exporting gas with traces of water in such depths, it creates an ideal environment for blocked export line(s).

Thus, when complete loss of production occurs, an operator will initiate the crucial process of quantifying and locating a hydrate by employing subsea or topsides methods/techniques, or a combination of the two. This article, however, will focus on the subsea approach; composed of mobilizing an ROV—with fit for purpose equipment—from a multi-service vessel (MSV).

Locating a hydrate

Zeroing in on the affected area(s) where pressure anomalies are present is key when quantifying a blockage's location. Sequentially speaking, quantification is the first and highly crucial step required prior to attempting to remove/remediate a blockage. It should be noted that there are different schools of thought on whether to locate hydrates via internal or external means; the former method is highlighted here.

An ROV's mobility allows it to traverse through a production scheme with relative ease. This enables them to conduct/acquire multiple pressure logs from hot stab ports accessible on pipelines. The acquisition of such logs is accomplished via pressure instrumentation installed on an ROV, permitting an operator to interpret a pipeline's internals. This helps the operator to not only detect where pressure anomalies exist, but also compare differences in pressure throughout a subsea infrastructure. The greater number of ports that can be accessed, the better the chances for quantifying hydrate locations. This enables the operator to gain a better understanding of the most optimal section of the production scheme to focus on when planning a remediation program. Moreover, the use of pressure instrumentation also allows an operator to capture and compare pressure readings that are seen by a topsides facility, and provide "back up" readings should said facility lose communication with transducers on a subsea infrastructure.

Export line impacted by blockage. (Photos courtesy Reaching Ultra)

ROV configuration

Prior to an ROV carrying out any localization operations, it must first be equipped with the proper hot stab(s) to access hot stabs ports on a production scheme. Additionally, the appropriate hoses/conduits must be selected, to enable the ROV's pressure instrumentation (analogue gauges, or transducers with digital displays) to take pipeline readings.

Furthermore, an ROV must also be outfitted with auxiliary ROV equipment and tooling. It is important to note that the aforementioned equipment must be properly configured so as to communicate with a hydrate without compounding it, as illustrated by overpressurizing a pipeline via an ROV's auxiliary pump.

Fit-for-purpose equipment

It is vitally important to properly outfit and equip the ROV for these purposes. Failure to do so can severely limit the effectiveness of quantification operations. The first item to be discussed is hot stabs. Identifying the proper stab to be used on a subsea scheme is of the utmost importance.

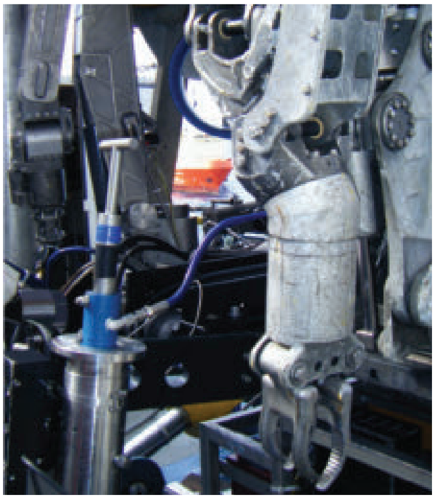
This is due to the fact that in a production scheme, a 17H hot stab—as referenced by the American Petroleum Institute (API)—is needed to engage the corresponding receptacles on a production scheme. The precise specification is vitally important. For example, should an ROV be equipped with a 17D (not a 17H) stab, engagement will be impossible. This would force an operator to source the appropriate stab from land or from an adjacent vessel, resulting in downtime.

Further, it is not uncommon for schemes to have one off stabs that are not API defined. In this backdrop, sourcing such stabs is complicated by the fact that they are non-standardized, and are typically manufactured by a single company. For this reason, analyzing a production scheme's most up to date schematics/drawing is paramount.

ROV conduits

Hoses are the next most important component, since they are instrumental in establishing a path of continuity between an ROV and a pipeline access point. Methanol is at times introduced into a pipeline from the platform in an effort to disassociate a hydrate, as methanol has been observed to have greater effectiveness over glycol, once a hydrate has formed. Because of this, the hose must be able to handle methanol. The hose must also be able to withstand the array of contents present in a pipeline, and not lose integrity. If breaching occurs once full communication with a pipeline is established, it can cause a pipeline's internals to expel, especially if the pipeline's pressure is above ambient pressure. Conversely, if the pipeline's pressure is below ambient pressure, this can cause sea water ingress, compounding a pipeline's hydrates.

Additionally, the hose must be properly pressure rated to ensure that it can withstand several stresses. These include the pipeline's pressure once a path of continuity is established, and also the pressure introduced by an ROV's auxiliary pump—and consequent


ROV outfitted for quantification operations.

Diagnostic Configurations

Method	Configuration	Additional Features
1	**Porch Based:** Pressure instruments are mounted on an ROV's porch: a hose serves as a conduit between a stab and pressure instruments. This method does not employ purpose built automation or interpretation software.	Requires an auxiliary pump capable of pulling a vacuum, as well as conducting injections. Said pump is integrated with pressure instrumentation. Separate and independent collapsible bladder assemblies are needed: One for injection operations, and a secondary one for returns from a production scheme. Both bladders must be encaged and mounted on an ROV's exoskeleton.
2	**ROV Skid:** Bypasses the ROV porch and houses all equipment/kit listed in method 1. Skids can be configured with greater equipment which includes: multiple auxiliary pumps, pressure instruments, automated valves, etc., thus requiring proprietary software and a topside laptop for actuation, and taking pressure readings.	ROV skids are commonly utilized when an operator is looking not only to conduct diagnostic work but also conduct hydrate remediation.
3	**Hot stab Direct Mount:** Pressure instruments are directly mounted on to a stab.	No ROV integration is required. However, this method does not allow for auxiliary pumps to carry out stabilization operations with a pipeline's gateway valve.

fluctuations—during pressure equalization maneuvers that are executed before engaging a pipeline.

Equalization and interfacing

Equalizing the pressure at a pipeline's access point is highly critical. It is achieved by tactfully pumping methanol, for example—at the hose end—via said pump(s) mounted on an ROV. In addition, the reciprocating pump will require a valve manifold plumbed directly to it, so as to switch the input and output arrangement, from a source standpoint, as follows:

ROV as source. In this backdrop, the pump draws methanol from the bladders (input), while pumping outward toward a pipeline (output). The intent here is to not deplete the methanol as this will rupture the collapsible bladders. Both bladders operate independent of each other.

Pipeline as source. Here the manifold is manipulated so as to pull vacuum on the pipeline end (input) while pumping outwardly into bladders mounted on an ROV (output). It is critical that bladders are not over-filled/pressurized.

The encaged bladders that are attached/mounted on an ROV must be used tactfully during quantification operations due to their volume limitations. Further, due to a bladder's volume constraints, the amount of pumping, as well as the intake of a pipeline's content is limited (depleting the bladder's volume can lead to their complete rupture/collapse).

Gateway valve engagement

Through all the above actions, one must be sure to safely operate the subsea valves which serve as the gateway for pipeline communication. Prior to such manipulation taking place, it is critical to analyze a production scheme's drawings to ensure that the proper ROV tooling is sourced. This is especially true when the valve is not designed to be operated by an ROV's manipulator, but instead requires a class 1-4 torque tool.

Once the means of engagement—manipulator or tooling actuation—is defined, it is necessary to bring pressure equalization to the forefront as well as methodical valve manipulation. To accomplish this, the reciprocating pump's rate will need to be methodically controlled prior to opening the gateway valve on a pipeline or asset.

Next, the gateway valve will need to be carefully opened to allow minor communication to take place between the ROV-mounted equipment and the pipeline, prior to the valve being fully opened. Fine tuning the pump's output, while meticulously manipulating the subsea valve and observing the pressure instruments, is key to avoiding damage to the ROV equipment via hydraulic shock.

Pressure instrumentation

Once the gateway valve is fully open, it is here that having fit-for-purpose pressure instrumentation is critical. As previously stated, said instruments allow an operator to: monitor a pipeline's behavior; take pressure readings; and establish a pressure log. However, for said instruments to optimally function, they must have the duality of being able to detect increases in pressures as well as being able to detect a vacuum. More importantly, said instruments must be hermetically sealed at 0 psi (absolute), for example.

Conversely, a non-hermitically instrument referencing 0 psi (gauge) will not function if the pressure within a pipeline is below hydrostatic pressure, as its function is based on referencing ambient pressure. Consequently, if ambient pressure registers at 3,500 psi, and the pipeline is at 400 psi, a non-absolute gauge will not be able to detect the pipeline's pressure.

Once the pipeline's pressure readings have been obtained and logged, it is imperative to methodically close the valve of interest. After this has been completed, the hose linked to the hot stab must be cleared of any of the pipeline's content that may have comingled with the previously pumped methanol, to avert the pipeline's residual content from expelling into the sea when the stab is disconnected.

To prevent such expelling, a vacuum must be pulled—very cautiously—with the auxiliary pump, in order to route the residual content to the appropriate bladder. In this setting, the hose must be non-collapsible to ensure that it is not crimped or crushed by the ambient pressure when a vacuum is applied. Here too, the bladder must be designed to handle all the content introduced into it, to prevent it from being breached.

Conclusion

As offshore projects continue to favor deepwater, this will require maintaining a "right tool for the right job" philosophy to ensure that quantification and localization operations are carried out in a manner that does not compound existing hydrates. Moreover, referencing the methods and field-proven techniques described herein will provide a significant advantage in ensuring that interfacing with an anomalous pipeline can be conducted safely, so as to bring a non-producing wells back online.

The author

Fernando Hernandez is the subsea technical advisor at Reaching Ultra, a Houston-based market research firm. He has extensive field experience in the dynamic positioning, ROV tooling, automated controls, subsea and well Intervention sectors. Hernandez's offshore background has given him a firm understanding of the best practices for outfitting vessels and rigs for offshore operations, so as to properly have topside and subsea equipment operate in synchronicity via divers and ROVs. His field experience and tri-lingual fluency has facilitated the execution of several offshore operations, as well as the development of a number of international commercial relationships.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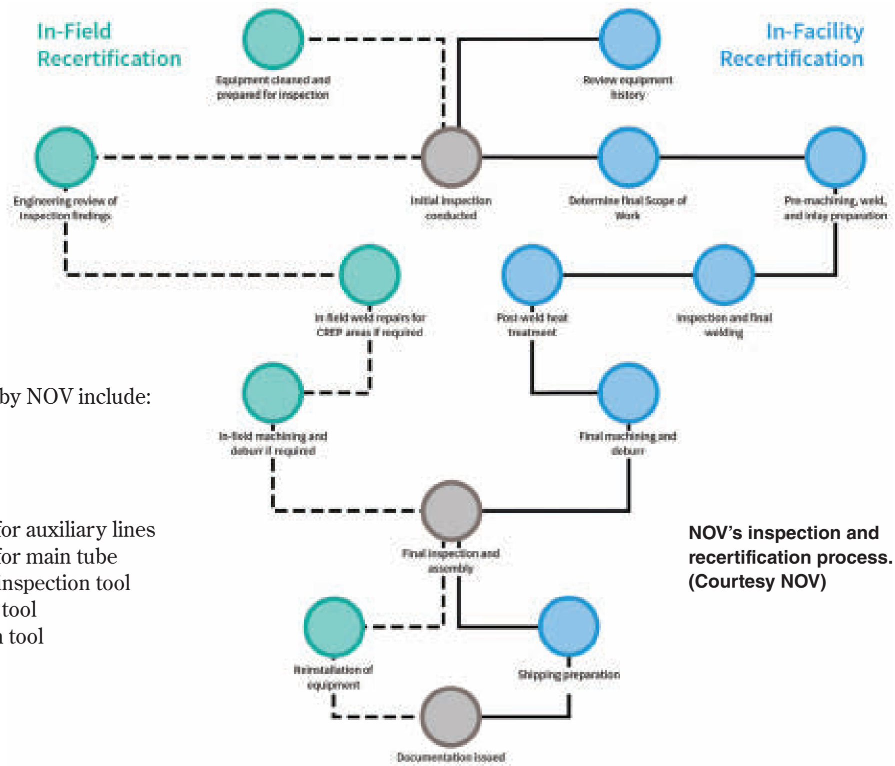
New tools and technology for the offshore industry

In-situ pressure control inspection lowers costs

A variety of in-situ inspection and remediation tools have been designed to reduce the amount of time and money required to inspect and repair subsea equipment. NOV's aim is to lower the total cost of ownership for drilling contractors by reducing the need to transport large assets to a shore-based repair facility.

If equipment fails an in-field inspection, the drilling contractor can weigh the option of replacing equipment or scheduling an in-facility repair to correct the issue. For infield repairs, it is important to note that only a working pressure test is required, removing the need for a dedicated test bunker.

In-situ inspection or remediation tools offered by NOV include:
- BOP bore seal seat machining
- BOP door face machining
- BOP phased array stud inspection tool
- BOP ring groove machining
- Riser UT wall thickness corrosion mapping for auxiliary lines
- Riser UT wall thickness corrosion mapping for main tube
- Riser main tube phased array flange pocket inspection tool
- Riser main tube phased array UT inspection tool
- Riser auxiliary line pulse echo UT inspection tool
- Riser hydraulic seal sub removal tool
- Riser box honing tool
- Riser pin honing tool.



NOV's inspection and recertification process. (Courtesy NOV)

For equipment requiring in-facility repair, care is taken to pre-machine and inspect parts to ensure that satisfactory surface conditions are achieved before beginning the welding or inlay process. All equipment is machined to precise dimension according to NOV engineering prints and then checked by the quality assurance personnel. Documentation is then reviewed by the quality assurance department to verify that all required information has been included in the drilling contractor's final documentation package.

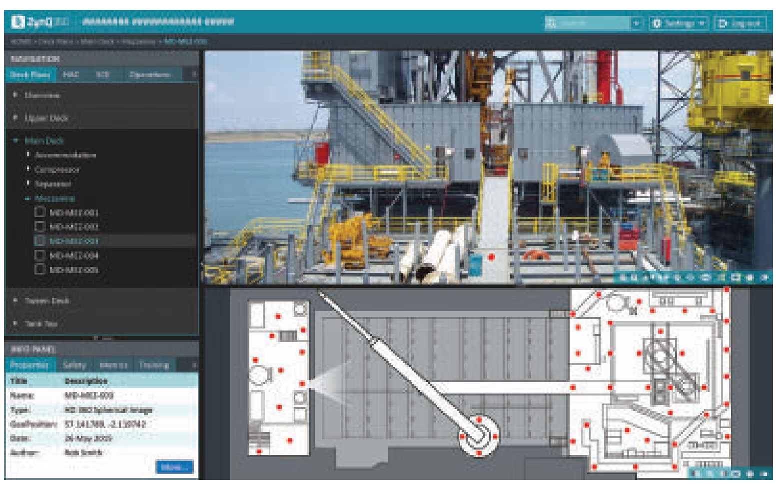
To ensure drilling contractors' products are returned to their optimal condition, all inspections are carried out using the latest revisions of the OEM bill of materials and engineering drawings.

AIMS Global Consulting launches ZynQ 360

AIMS Global Consulting LLC has launched ZynQ 360, a web-based software solution that utilizes high definition, 360-degree spherical photo and video technologies. The company says that ZynQ 360 complements its asset integrity management services that help clients with regulatory compliance and reduce operational costs and risk on their physical assets.

AIMS says that the software can help users:
- Reduce operation costs, risk, and operational downtime
- Review operations, allowing operators to identify what is most important
- Collaborate with workers on a global scale
- Increase sustainability for engineering and regulatory compliance information
- Obtain ubiquitous access to key asset information
- Comply with regulatory requirements.

"ZynQ 360 enables real-time collaboration and visual review of an asset," said Robert Smith, Head of Americas for AIMS Global Consulting. "We complement the model by building a bridge between existing systems and users, making information more readily available and easy to extract."



The ZynQ 360 software solution enables users to review operations and collaborate on a global scale. (Courtesy AIMS Global Consulting LLC)

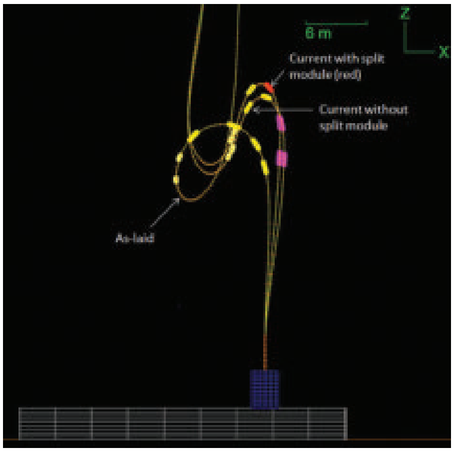
Umbilical survey reveals integrity issues with modified buoyancy

Ryan Diver
Jee

Earlier this year, a major international operator commissioned Jee to perform a study on a subsea main control umbilical (MCU). Installed in the 1980s, the unit serviced two subsea control modules via a junction box beneath the client's floating production vessel (FPV). The study was needed after a recent ROV survey of the MCU identified anomalies with the buoyancy modules.

A review of the footage revealed several issues. The first module was missing from the base of the umbilical. The second module had split in half but remained tethered to the MCU, sliding up the line and stopping at the base of the third module, causing both to slide up toward the hog bend. Also, over the hog bend and into the sag bend, the remaining modules had all relocated a few meters from their as-laid positions up toward the hog bend.

To reinstate buoyancy, the client had attached two new modules to the MCU of similar design and positioned both close to the as-laid locations of the detached and split modules. The split module, now made redundant following the addition of two new modules, remained tethered to the MCU.



Comparative analysis of the MCU showing the worst case MBR at the hog bend. (Image courtesy Jee)

The combined effect of the new and relocated buoyancy modules, including the redundant split module, was a shift in the umbilical's configuration which now differed from as-laid. Jee was therefore asked to perform a comparative assessment between the current and previous umbilical configurations to identify any integrity issues that might occur if the MCU were left untouched. Objectives of the program were to identify differences in the MCU's minimum bend radius (MBR) – a critical measurement of umbilical and flexible integrity – and elevations above seabed between the as-laid and current buoyancy module arrangements (the latter with and without the split module attached). Additionally, Jee was tasked with concluding if any remedial work would be necessary to relocate the buoyancy modules back to their as laid elevations or to remove the redundant split module from the line, as well as identifying any additional concerns raised from the assessment.

Much of the MCU's original installation and design documentation from the 1980s was either hard to locate or contradictory in its statements. Although some documents were tracked down for both the MCU and FPV, the project had to be progressed without key data relating to the MCU's bending stiffness, pay-out length and allowable service minimum break load (MBL).

The comparative study proceeded using assumptions in lieu of unknowns, based partly on a review of all available documentation. A sensitivity analysis followed covering a range of reasonable bending stiffnesses. The pay-out length was hand calculated based on a series of supplied documents and the allowable service MBL was estimated based on knowledge of similar flexible systems.

OrcaFlex, a software package for dynamic analysis of offshore marine systems, was deployed to complete the comparative assessment. The OrcaFlex model was built to comprise the full system which included the subsea template, junction box, MCU, FPV and all necessary buoyancy modules.

The analysis demonstrated that the radius of the hog bend was less than 3 m (9.8 ft) for a range of bending stiffness values at the lower end of the assessed spectrum. This put the hog bend at risk, as typical service MBLs are between 1 and 3 m (3.3 and 9.8 ft). If the MCU were to operate for long periods in its current configuration there was a high probability that storm conditions and significant dynamic affects could cause a further reduction in the MBL, leading to failure of the MCU; a costly result from avoidable risk.

On completion of the analysis, Jee issued several recommendations. At minimum, the split module should be cut from the line to improve the MBR at the hog bend. Additionally, Jee found that the buoyancy modules should be relocated to their as-laid positions to reduce the risk of compromising the hog bend MBR during service. Finally, regular general visual inspections of the umbilical should be conducted as part of the on going integrity management of the assets. Future unplanned changes to the buoyancy configuration of the MCU should be recorded and reviewed for any potential impact on integrity.

The program and recommendations provided the client with a clear view of the position and integrity of the MCU, and the justification needed to take action and avoid operational risks.

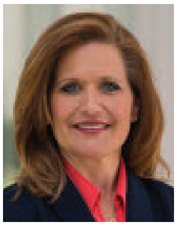
People

Alec Johnson has been named the 2016 Advisory Board Chairman of the sixth annual Topsides, Platforms & Hulls Conference and Exhibition. Since 2007, Johnson has worked for Petrobras as the lead mechanical engineer on the Cascade & Chinook FPSO project team.

Electromagnetic Geoservices has appointed **Stig Eide Sivertsen** as CEO. He succeeds **Bjarte Bruheim**.

Lisenbe

Wood Group Mustang has appointed **Elaine Lisenbe** as CFO and **Valencia Amenson** as vice president Human Resources. Both will join the company's Executive Leadership Team, including **Michele McNichol**, who became the first female to lead a major energy engineering firm when she was named CEO in February.



Amensun

Oceaneering International has promoted **Clyde Hewlett** to COO, **Alan R. Curtis** to senior vice president and CFO, **Eric A. Silva** to senior vice president of Operations Support, and **Suzanne Spera** as director of Investor Relations.

Shannon E. Young, III has joined Cobalt International Energy as CFO and executive vice president. He replaces **John P. Wilkirson**.

Oil & Gas UK has appointed **Alan Corbett**, managing director at Bristow Helicopters; **Dominic Macklon**, president UK for ConocoPhillips; and **Ray Riddoch**, managing director and senior vice president Europe of Nexen Petroleum U.K. Ltd., to its board of directors. Corbett will represent the aviation sector, while Macklon and Riddoch will represent the operator community. Existing board member **Craig May**, Chevron Upstream Europe Ltd.'s managing director, has taken over the role of treasurer. **Mick Borwell** has succeeded **Robert Paterson** as health, safety, security, and employment director.

Erin Energy Corp. has named **Segun Omidele** as COO, **Daniel Ogbonna** as senior vice president and CFO, **Chris du Toit** as vice president, corporate finance and country manager for South Africa, and **Christopher Heath** as vice president, corporate finance.

National Oilwell Varco has appointed **Jose A. Bayardo** as senior vice president and CFO. He succeeds **Scott K. Duff**, interim CFO.

Jersey Oil and Gas has named **Andrew Benitz** as CEO and **Ronald Lansdell** as COO.

In Memoriam

Offshore industry pioneer Edward E. Horton III passed away on Aug. 13, 2015. He was 87 years old. A Navy veteran, he invented both the spar and tension leg platforms. He received his BA in civil engineering from Yale University and his master's degree in petroleum engineering from the University of Southern California. In 2001, Horton received the National Academy of Science's Gibb's Brothers Medal for "visionary and innovative concept development and design of offshore platforms, mooring systems, and related technology that have significantly influenced development of deepwater operations." In 2002, Horton was inducted into the National Academy of Engineering.

Edward Horton (Courtesy Offshore Energy Center)

He was the recipient of many other honors and awards including the lifetime achievement award of the Offshore Technology Conference, Offshore Mechanics Division of the American Society of Mechanical Engineering, Society of Petroleum Engineers, and Petroleum Technology Division of the American Society of Mechanical Engineers. Horton was named an Offshore Pioneer by the Offshore Energy Center, Ocean Star; was chosen as a Rhodes Petroleum Industry Leader by ASME; and was the recipient of a Hall of Fame Award for OTC Papers in Civil Engineering by the ASCE in 2010. He served on the American Bureau of Shipping's Offshore Technical Committee and was an active member of the Marine Technology Society, American Concrete Institute, Yale Alumni Association, Houston Asia Society, and the Advancement Committee of the Civil and Environmental Engineering Department at Rice University.

Horton is survived by his wife Anne Watts Horton, three daughters, six grandchildren, three step-sons, and four step-grandchildren.

The CGG Corporate Committee (C-Com) is chaired by the CEO, **Jean-Georges Malcor**, and includes the CFO, **Stephane-Paul Frydman**; the two COOs, **Pascal Rouiller** and **Sophie Zurquiyah**; and the executive vice president, Human Resources, **David Dragone**. The C-Com will share global management of the group and responsibility for the various business lines, group functions, and group departments.

Benzie

The International Marine Contractors Association has named **Allen Leatt** as CEO and **Richard Benzie** as technical director.

Aquatic Engineering & Construction Ltd., an Acteon company, has appointed **Martin Charles** as group managing director.

Charles

Statoil has elected **Wenche Agerup** to its board of directors.

Cubility AS has appointed **Brandon Buzarde** as vice president, International Sales.

Lars Sjöbring, senior vice president and general counsel of Transocean Ltd., says he will leave the company when a replacement is hired, but before year end in any case.

Aker Solutions has appointed **David Clark** as regional president of the UK and Africa. The company also has appointed **José Formigli** to its innovation board and to serve as an adviser for overall strategic decisions.

Stephen Greenlee, president of ExxonMobil Exploration Co., has been named chairman of the University of Houston's Energy Advisory Board.

Lauenstein

The International Well Control Forum has appointed **Sarah Lauenstein** as its first regional manager for Australasia.

Royal Dutch Shell plc has named **Ronan Cassidy** as chief human resources and corporate officer with effect from Jan. 1, 2016. He will become a member of the Executive Committee and will succeed **Hugh Mitchell,** who will be leaving the company after 36 years.

Tauzin

Knight Oil Tools has named **Rickey Tauzin** as executive vice president of sales.

Glacier Energy Services has appointed **Alastair Gibbons** to the senior operations team of its non-destructive testing business, Professional Testing Services. The company

also has appointed **Martin Kilmurry** as managing director of its newly created specialist services division.


Hayes

Greene's Energy Group has named **Michael Hayes** as vice president and general manager of Pressure Testing and Services and the Engineering Group.

STATS Group has appointed **Derek Smart** as QHSE and HR director, **Lisa Mitchell** as commercial director, and **Ron James** as sales director.

Bill Smart has joined the Delmar Systems Inc. global business development team.

Company News

Schlumberger Ltd. and **Cameron** have announced a definitive merger agreement in which the companies will combine in a stock and cash transaction valued at $14.8 billion. The agreement was unanimously approved by the boards of directors of both companies. The transaction is subject to Cameron shareholders' approval, regulatory approvals, and other customary closing conditions. The transaction is expected to close in 1Q 2016. In addition, Schlumberger has acquired **Novatek Inc.** and **Novatek IP LLC**.

The **European Commission** has approved unconditional clearance for the combination of **Royal Dutch Shell** and **BG Group**.

SCF has acquired the Australian and Southeast Asian business of **Cal Dive International** in partnership with **Viburnum Funds** and **John Edwards**. The company which will be renamed **Shelf Subsea**, will be headquartered in Singapore, and will also have operations in Perth, Australia.

Ensco has consolidated its global operations reporting structure from five business units to three. Brazil will report to the North & South America Business Unit based in Houston. Asia/Pacific will report to the Middle East, Africa, Asia & Pacific Business Unit based in Dubai. Europe and the Mediterranean Business Unit is unchanged and continues to be based in Aberdeen.

Independent oil company **Trapoil** plans to rename itself **Jersey Oil and Gas**. The company's strategy will be to maintain, develop, and exploit North Sea interests with a greater focus than previously on producing. Additionally, it will seek potential acquisitions of other North Sea oil and/or gas producing interests, some of which have been identified and are the subject of commercial negotiations.

The **Oil Search Ltd.** board of directors has rejected **Woodside Petroleum**'s proposal to acquire the company.

The **Industry Technology Facilitator** has started a joint industry project with **Clearview Well Services** to develop a new drillstring camera. Clearview will build a prototype for a live test of its multi-function camera that will do jet blasting during visual inspections, said ITF. The CDFC can be deployed by helicopter to carry out the operations in one trip of the drillstring.

Proserv Group LLC has acquired **Nautronix.**

William Jacob Management Inc. has signed a master services agreement to provide engineering and project management services to an unnamed oilfield services provider.

OEG Offshore has merged its US business with Louisiana-based oilfield equipment provider **Cameron Rental and Tank Inc.**

Accenture has entered into an agreement to acquire **Schlumberger Business Consulting**. Terms of the acquisition were not disclosed, and completion of the acquisition is subject to regulatory approval and other customary closing conditions.

The **Well Control School** has launched its new introductory level System 21 e-learning course for drilling operations. The System 21 e-Learning Drilling Operations course is now available for IADC WellSharp and The Well Control School certifications. The course includes workshops, simulation exercises, chapter and lesson quizzes to provide basic well control training. It is designed for drilling and well servicing personnel, consultants, asset managers, engineers, and well-site personnel, according to the company.

Sparrows Group has formed a partnership with **Zamil Group** to provide its full range of services in Saudi Arabia.

Aptomar has opened its "Aptomarin" marine control center in Trondheim, Norway. The 24/7 field monitoring operation is available to offshore oil companies operating in the main oil and gas hubs around the world.

Indian Register of Shipping has opened an office in Abu Dhabi.

Stork has signed an agreement to acquire **Giovenco Industries Pty Ltd.** in Australia.

LQT Industries LLC has received a contract for the construction of an E-House, a temporary living quarters building, and a work station for use on a platform offshore of Trinidad. The steel modules will be fabricated and outfitted at the company's construction facility in Abbeville, Louisiana. Construction is expected to be completed by the end of the year.

Viking Life-Saving Equipment A/S has acquired **Nadiro A/S**, a lifeboat and rescue craft systems manufacturer.

ClassNK has opened a new exclusive survey office in Brunei.

Intermarine LLC has opened an office in Quito, Ecuador.

National Safety Apparel has acquired the TECGEN brand of technologically advanced safety apparel from **INVISTA Ashburn Hill LLC**.

Construction is under way on **Lloyd's Register**'s new Aberdeen energy headquarters. Located on the Prime Four business park in Kingswells, Aberdeen, the 100,000-sq ft (9,290-sq m) office complex is expected to be operational in 3Q 2017 and will have capacity for up to 900 staff.

Nylacast has been named a finalist at this year's East Midlands Chamber Awards in the category of People Development, which acknowledges organizations that demonstrate excellence in the promotion and implementation of a learning and development culture. The East Midlands Chamber Awards aim to recognize, reward, and celebrate business excellence across Derbyshire, Nottinghamshire, and Leicestershire. The company also has invested in a new website.

DNV GL is building a new conference center and large-scale fire and explosion demonstration area at its hazard testing and research center in Cumbria, UK. Scheduled to be completed by the end of the year, the facility will feature destructive and non-destructive test facilities. Remotely located within RAF Spadeadam Ministry of Defence land in the Cumbrian countryside, the company said it will be possible to conduct confidential large-scale major hazard tests, including flammable gas dispersion, fires, explosions, pipeline fracture tests, blast, and product testing in a safe and secure environment.

Hoover Container Solutions has acquired **Tech Oil Products Inc.**

Flowline Specialists is establishing an office and operating company in the UAE.

D'Appolonia has acquired a majority stake in Fano-based **SeaTech**.

Bureau Veritas has acquired **HydrOcean**, an engineering company formed in 2007 in Nantes, western France, to provide hydrodynamic digital simulation for offshore structures and the maritime industry.

GAC has formed a joint venture with the **Clearvac Group** to provide air hygiene and waste water management services in the UAE. Dubai-based **GAC-Clearvac** will serve offshore platforms and other vessels operating regionally.

Deborah Services Ltd.'s (DSL) industrial services division is teaming with Kazakhstan-based holding company **Lancaster Group**. Under the joint venture – **DSL Caspian LLP** – DSL will supply services including access solutions, insulation, protective coatings, and fire protection to various Kazakh offshore and onshore locations. The venture will employ a 500-strong team with around 450 in production and technical roles.

Weatherford International has added a sand-tolerant pump to its artificial-lift equipment. It prevents abrasion caused by sand accumulation in the barrel/plunger that results in decreased pump efficiency or total failure.

Offshore

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Over-reliance on KPIs hinders accurate performance measurement

We have accepted the mantra, "If it cannot be measured, it cannot be managed." Thus, individuals at every level of an organization need key performance indicators (KPI) to guide them to do the right thing, and they need to be rewarded with bonuses based on how well they perform to these KPIs. This author believes that we have become too rigidly enamored of this mantra, and it has had a negative effect on individuals' judgement in doing what is "right" rather than what is expedient.

KPIs are at best someone's forecast of what an individual should try to accomplish in a fiscal year which starts some months into the future and ends a year after that. However, we are not asking our people to perform routine tasks such as someone would do on an assembly line; a welder in a shop doing the same weld over and over; or numerous tasks that can be measured with time and motion studies to create statistical norms and standard deviations.

During the KPI periods of measurement, wells do not always behave as expected; unanticipated drilling problems can develop; and vendor and contractor problems can impede a project manager from both addressing the indicators and the problems. Since the KPIs are directly tied to bonuses, we are subtly telling the individual to spend more time on the KPI and less time on addressing the unanticipated real problem. The easiest fix gives more time to address what is really valued, the KPIs.

Once upon a time we expected our managers, supervisors, and employees to exercise good judgement in carrying out their responsibilities. We expected them to be "professionals." That is, we recognized that they were engaged in creative and intellectually challenging work, and we expected them to use their professional judgement to recognize what was important. We expected them to work in the most efficient manner to further the goals of the company, including safety, environmental, and community goals as well as financial goals. We paid them well and their salary increases were based on how well they exercised their judgement. Bonuses were not common and were not promised in advance according to a preconceived formula.

This required some form of subjective analysis of what the individual accomplished against what may have been expected for someone in that position to accomplish. This is a difficult calculus. One employee could direct a well to be drilled on an obvious target and discover a large reserve. Another employee using innovative thinking could direct a well to be drilled which discovered a smaller reserve, but one which would have been overlooked without the innovative thinking. A drilling engineer, through hard work and close cooperation with the drilling team on an especially difficult well, could bring it in only $100 million above budget while another engineer works on a routine well and brings it in $100,000 under budget. In administrating salaries, one has to decide which person is the more valuable employee. This is subjective, and as with any professional activity, the right answer is not always clear.

Consider the poor individual who has to choose between violating a safety process which does not seem important at the time and is not in a KPI (as long as it does not result in an incident); and meeting a KPI which will affect his bonus. Are KPIs creating a culture which encourages taking small safety risks which, if they do not result in an incident, will never appear on a KPI or affect the individual's bonus? Is it possible that KPIs, even safety KPIs, are actually encouraging a culture of blind compliance to processes rather than a true culture of safety?

Before dismissing these questions out of hand, remember that we can see examples of this problem in many industries and arenas. All those on Wall Street who received bonuses in 2009 in spite of taking such unethical actions such as misleading their clients, mischaracterizing risks, etc. In short, they were rewarded for not being professional even though their actions caused a worldwide recession. It seems few declined their bonuses and none were shunned by their peers for their actions. After all, they met their KPIs even though that meant cheating their clients.

Another example – we now have teachers who "teach to the test" and even cheat to meet their KPIs. They know we do not trust them to be professionals to use their judgement to teach learning and tailor their teaching to the needs of their students. We only judge them on meeting their KPIs.

KPIs are not inherently bad, and as a matter of fact, the author thinks they can do some good. The concern is blind reliance on KPIs and bonuses to encourage correct behavior and the concurrent dismissal of subjective evaluation of professional behavior. Are we an industry which encourages following instructions (i.e. KPIs, processes, etc.) rather than thinking about actions? Does the focus on KPIs send the wrong message to our employees?

Kenneth E. Arnold
K Arnold Consulting Inc.

This page reflects viewpoints on the political, economic, cultural, technological, and environmental issues that shape the future of the petroleum industry. Offshore Magazine invites you to share your thoughts. Email your Beyond the Horizon manuscript to David Paganie at davidp@pennwell.com.

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