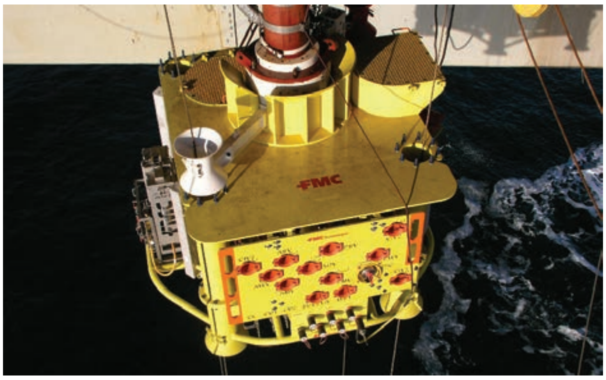
SEN
SUBSEA ENGINEERING NEWS

HARTENERGY

vol. 33 - no. 10 August 12, 2016

Subsea Tieback Potential Grows As Priorities Shift



Horizontal subsea trees are preferred by many operators, particularly for high flow-rate gas developments. (Source: FMC Technologies)

As the lower for longer oil and gas price environment persists, pushing some high-dollar offshore developments out of reach, subsea tieback development potential is leaving the door wide open for oil and gas production growth.

Some experts say the world is ripe for subsea developments, with tiebacks limited only by the capacity of their host facilities.

In the U.S. Gulf of Mexico (GoM) alone, at least 10 projects could become subsea developments between second-half 2016 and 2018, according to Houston-based Quest Offshore, which flagged BP's Mad Dog 2 and Anadarko Petroleum Corp.'s Shenandoah among the near- and medium-term possibilities. This could mean a much-needed payday for some project management, engineering and construction companies along with subsea tree manufacturers as the need grows for deepwater developments to meet energy demand in the medium term.

"Adding three or four subsea trees is a far more economical solution to increasing production compared to other options out there," said Caitlin Shaw, senior director of market research and data division for Quest Offshore.

Although the number of global tree awards and infill wells has fallen in recent years due to a downturn-driven spending cutback, aging and increasing subsea infrastructure is expected to spawn more global subsea tree installations.

There have been more than 3,000 subsea tree completions in the past 10 years, and another 1,300 could be installed by 2020, according to Shaw, who noted water depths also are getting deeper.

"A lot of the opportunities in North America are brownfield opportunities," Shaw said. Similar opportunities exist elsewhere, including the North Sea, Africa/Mediterranean region and offshore Brazil. "Since 2008, roughly 30% of global subsea trees have gone to this type of activity. … These trees don't traditionally come with extra infrastructure," such as tens of kilometers of pipeline and production umbilical.

Some companies—including large independents like Anadarko—are identifying tieback opportunities for new fields.

Tieback potential

Subsea tiebacks is one of the areas that Anadarko CEO Al Walker said gives the company "strong line-of-sight for attractive capital-efficient, short-cycle oil investments as crude prices recover."

The company has identified up to 30 low-cost tieback opportunities in the GoM. These, according to Anadarko's second-quarter 2016 operational report, include:

- Caesar/Tonga, five to eight wells. Located in the Green Canyon area, the field had record production of 55,000 bbl/d in the second quarter;
- K2, four to seven wells plus two potential new fields. This Green Canyon area development produced more than 28,000 bbl/d, an eight-year record high;
- Heidelberg, three to six wells plus two potential

WHAT'S INSIDE

Technip reported "strong subsea activity" for second-quarter 2016 across the regions where it operates. (Source: Technip)

new fields. Also located in Green Canyon, Heidelberg—which reached first oil in January—includes two drill centers tied back to a truss spar via an 8-in. flowline and steel caternary risers; and

- Lucius, three to seven wells plus one potential new field and third-party developments. The Keathley Canyon area field surpassed its 80,000 bbl/d nameplate capacity last quarter. Its six subsea wells are tied back to a truss spar.

Subsea tiebacks are also proving to be crucial to unlocking barrels in the GoM for Noble Energy Inc., which brought the two-well Gunflint oil development online in mid-July. The field, which joined the Big Bend and Dantzler subsea tiebacks, is ramping up and is expected to hit gross production of at least 20 Mboe/d, Noble said.

"This is the third Middle Miocene tieback to commence production in the past 12 months, contributing to the almost doubling of our Gulf of Mexico volumes this year," said Gary Willingham, executive vice president of operations for Noble.

Noble's GoM sales volumes for the second quarter skyrocketed by 125% compared to a year ago to average nearly 27 Mboe/d.

Shifting priorities

It is these types of developments that subsea-focused companies are depending on to stay afloat.

Technip CEO Thierry Pilenko recently addressed his company's clients' shifting priorities brought on by current market environment. The company expects to see more phased developments and more tieback opportunities emerging, particularly in the GoM.

In addition, "preference will be given to shorter-term subsea projects, brownfield, extension of life and tieback to existing facilities," Pilenko said speaking on the market outlook during the company's latest earnings call. "Pressure on cost will be tactical, taking advantage of the overall industry deflation, but also structural, through improved efficiency, FEED-focused design, standardization and alternative sourcing or fabrication." Technip believes merging with FMC Technologies will give birth to a new generation of subsea solutions that does just that, while also lowering project costs and enhancing life-of-field productivity. The transaction is expected to close in early 2017.

The subsea services provider reported "strong subsea activity" across the regions where it operates, with vessels active on the Kraken and Edradour projects in the North Sea, Girassol Resources Initiatives offshore Angola, TEN offshore Ghana and the Moho Nord project offshore Congo plus renewed charters for the Skandi *Niteroi* and *Skandi Vitoria* pipelay vessels offshore Brazil.

Although Technip's subsea revenue fell by nearly 12% for the quarter, the situation is expected to improve as commodity prices rebound and supply chain deflation give the company confidence.

"We are therefore seeing continued focus from clients seeking to get upstream projects to work—notably fast-track projects like tiebacks and brownfield but also larger strategic investments," Pilenko said in a statement.

Technip increased its adjusted subsea revenue 2016 guidance to between about \$5.3 billion to \$5.6 billion from about \$715 million to \$760 million.

Changing subsea

However, it appears that the lower commodity price environment already has begun to usher in a different breed of subsea design.

In their market analysis, both Shaw and Pilenko foresaw more projects being carried out in phases. Mad Dog Phase 2, Exxon Mobil's Liza development, Noble's Leviathan and Statoil's Snorre 2040 were among Shaw's examples.

Instead of large 40-well subsea projects with an FPSO vessel, the industry will perhaps see two or three phases spread across five or six years, Shaw said. Breaking the large projects into phases makes substantial capital investments a little easier for oil companies to digest, she said, while also providing more supply chain transparency regarding projects in the queue.

The new era also could see more subsea collaboration and consolidation, with companies opting to combine expertise, efforts and energy on innovation solutions. This already is happening: Technip-FMC, the Aker Solutions-ABB partnership, and OneSubsea, now a Schlumberger Co.

Another future subsea strategic adjustment involves maintaining hubs by leveraging lower input costs to maintain or improve existing facilities, Shaw said.

"The effects of that won't be immediate, but we do see these efforts moving forward," she added.

—*Velda Addison*

PROJECT UPDATES

Kosmos: TEN Development Offshore Ghana Nears First Oil

The *Prof. John Evans Atta Mills* FPSO vessel will produce and store oil from the TEN oil fields offshore Ghana. (Source: Tullow Oil)

On schedule and on budget with a mere 1% of the project incomplete, the Tweneboa-Enyenra-Ntomme (TEN) project offshore Ghana could deliver first oil shortly, according to Kosmos Energy.

Kosmos and its partners also are pondering whether to speed up gas exports from the field, considering fabrication of the gas export facilities were completed early and can be installed by year-end 2016, enabling connection to existing gas infrastructure in early 2017, Kosmos said.

The update was delivered Aug. 8 as the Dallas-based company, which targets underexplored regions along the Atlantic Margin, shared news about its second-quarter 2016 earnings. The company's revenues plummeted to about $45.7 million from $121.8 million a year ago.

TEN is one of the main developments offshore Ghana that the company is depending on to help it sustain and grow cash flow as it also moves forward on the exploration front, uncovering hydrocarbon potential at offshore places such as Mauritania and Senegal.

"It's been a tough year and a half for the industry and for a lot of companies in our space. Low oil prices have squeezed liquidity forcing some companies out of business and others to dilute their investors to deleverage," Kosmos Energy CEO Andy Inglis said on a conference call Aug. 8. "Only in this business environment have the assets, balance sheet and management of Kosmos differentiated themselves."

But the company is at an inflection point, he added, as production and cash flow are set to rise while capex falls.

The TEN project is expected to add an average of about 55,000 bbl/d of oil gross during 2016. The development will use an FPSO vessel, which has a production capacity of 80,000 bbl/d, tied in to subsea infrastructure. So far, eight of 11 wells have been completed and hookup and commissioning of the FPSO unit is approaching the finish line.

"A gradual ramp-up in oil production toward the FPSO capacity of 80,000 bbl/d is anticipated around the end of 2016 as the facilities complete performance testing and well production levels are increased to optimal rates," Inglis said.

Until export begins, plans are to reinject associated gas produced at TEN into the Ntomme reservoir gas cap, the company said.

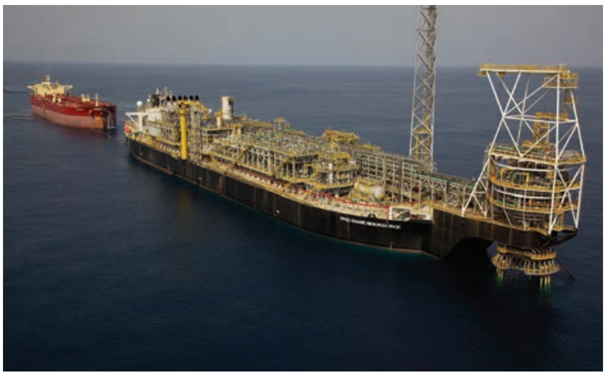
Kosmos has a 17% interest in the Tullow-operated TEN development area. Tullow holds a 47.18% equity interest; other partners include Anadarko Petroleum Corp., 17%; Ghana National Petroleum Co., 15% and Petro SA, 3.82%.

The TEN project along with exploration and appraisal drilling accounted for the bulk of Kosmos' second-quarter capex of $184 million. But the company warned that a second-half ramp down is expected.

"We paused our drilling program in late May and expect to see a reduction of TEN spending after achieving first production during the third quarter," Kosmos said. "The forecast for full-year 2016 capital expenditures remains approximately $650 million."

—Velda Addison

Ghana's Jubilee $150 Million FPSO Conversion Plan



Tullow Oil and partners plan to convert the FPSO unit to a permanently spread moored facility. (Source: Tullow Oil)

An issue with the turret bearing of the *FPSO Kwame Nkrumah* that is operating on the Tullow Oil-operated Jubilee oil field development offshore Ghana "has resulted in the need to implement new operating and offtake procedures."

The turret issue was discovered in February and impacted production rates significantly. Prior to the turret issue, output at Jubilee—which came onstream in December 2010—was averaging 102,600 bbl/d of oil. This dipped to an average of 62,900 bbl/d in first-half

2016 due to the turret issue, with output expected to be about 85,000 bbl/d during second-half 2016. This would give an average production rate of 74,000 bbl/d for 2016.

However, once the work is completed, the partners are confident of returning Jubilee to the peaks before the turret issue caused output to plummet.

"Tullow and its partners have established that the preferred long-term solution is to convert the FPSO [unit] to a permanently spread moored facility, with offtake through a new deepwater offloading buoy," Tullow explained.

"If we spread moor the vessel, the bearing within the turret, which was causing the problem, becomes obsolete," Tullow told *SEN*.

Phase 1 of this work will see the installation of a stern anchoring system to replace the three heading control tugs currently in the field. This is due to be completed around year-end 2016 and will require short periods of reduced production.

Phase 2, which is awaiting approval from the government of Ghana, will rotate the FPSO unit to its optimal spread moor heading and is expected to be completed in first-half 2017.

The cost for these two phases is expected to be up to $150 million gross, and it is estimated that the *FPSO Kwame Nkrumah* will need to be shut down for eight to 12 weeks during first-half 2017 to complete Phase 2.

Japan's Modec operates *FPSO Kwame Nkrumah,* and its unit Sofec supplied the turret for Jubilee.

"Upon completion of the spread mooring, the partners will review opportunities to improve the efficiency of offtake procedures by mid-2017. This should allow production to return to levels seen before the turret issue occurred," Tullow added.

A deepwater offloading buoy is scheduled to be installed in first-half 2018. This will remove the need for the dynamically positioned shuttle and storage tankers and the associated operating costs.

"Market enquiries are ongoing to estimate the cost to fabricate and install the buoy, which is expected to require a shutdown of four to six weeks to install," Tullow noted.

The additional gross operating expenditure of the revised procedures is currently expected to be about $115 million for 2016, $105 million for 2017 and $35 million for 2018.

"The partners will review potential opportunities to improve the efficiency of offtake procedures, which may include the use of a larger DP [dynamic positioning] shuttle tanker," partner Kosmos Energy said.

In December 2015, Tullow submitted the Greater Jubilee Full Field Development Plan to the government of Ghana.

"This project, to extend field production and increase commercial reserves, was redesigned given the current oil price environment, to reduce the overall capital requirement and allow flexibility on the timing of capital investment. In light of current circumstances, approval of the plan by the government of Ghana is now expected in mid-2017," Tullow added.

The Jubilee Field has a water depth of up to 1,737 m (5,700 ft) and is located about 129 km (80 miles) southwest of the port city of Takoradi.

Jubilee is a series of subsea wells tied back to the 360-m (1,181-ft) long *FPSO Kwame Nkrumah* vessel that has the capacity to produce 120,000 bbl/d of oil.

Jubilee was discovered in 2007 by the Mahogany-1 (M-1) and Hyedua-1 (H-1) exploration wells. The two wells were drilled some 5 km (3 miles) apart and intersected large continuous accumulations of light sweet crude oil. The M-1 and H-1 wells discovered large net pays of 95 m (312 ft) and 41 m (135 ft), respectively, in high-quality stacked reservoir sands. The Jubilee Field straddles the West Cape Three Points and Deepwater Tano licenses.

Kosmos added that the partners expect that the financial impact of lower Jubilee production, as well as the additional capex and operating costs associated with the damage to the turret bearing, "will be mitigated through a combination of the comprehensive Hull and Machinery insurance, procured on behalf of the partnership, and the Loss of Production Income (LOPI) insurance."

"Claims under both policies have been notified to our insurers. As and when the claims have been accepted, the recovery of some past losses is expected before the end of 2016 and further costs are expected to be recovered as they are incurred," added Tullow.

The partners in the Jubilee development are operator Tullow Oil (35.48%), Anadarko Petroleum (24.08%), Kosmos Energy (24.08%), Ghana National Petroleum Corp. (13.64%) and Petro SA (2.73%).

—*Steve Hamlen*

Cobalt Ponders Options For North Platte In GoM

Cobalt International Energy Inc. is not ready to tie itself down to any one development concept as it continues to appraise the North Platte development in the U.S. Gulf of Mexico.

But the operator appears to be leaning toward a tension-leg platform or another type of floater, probably not an FPSO unit.

Cobalt CEO Tim Cutt spoke about possible development plans for the Garden Banks area field during the company's earnings call on Aug. 2. "I'm a bigger fan of subsea kits vs. the dry tieback," he said.

Companies would love to build these facilities, and some companies are evaluating whether to build subsea kits. There could be cost-savings.

"There are ways that you can actually offset that capital demand upfront and then charter it into a tariff. The key is to get a tariff that you can afford based on the reservoir and the reservoir performance."

Drilling costs and surface facilities costs are already down, he said.

Earlier this year Cobalt said a North Platte sidetrack appraisal well hit about 152 m (500 ft) of net oil pay with fluid, core and pressure samples indicating the "rock and reservoir properties were the best that Cobalt has encountered in the Inboard Lower Tertiary trend with respect to porosity and permeability."

The company is planning to move the Rowan Reliance drillship from Goodfellow to North Platte to drill the North Platte #4 appraisal well.

The *Rowan Reliance* drillship will move from the Goodfellow prospect in the U.S. Gulf of Mexico to North Platte to drill the North Platte #4 appraisal well. (Source: Cobalt)

A 2021 production start is "absolutely doable" in Cutt's opinion.

However, "to do that, we need to get the results of the #4 well and then be positioned fairly quickly after that" and proceed through what could be a rigorous process, he said.

Cobalt, the operator, has a 60% working interest in the field. Partner Total E&P USA Inc. holds the remaining 40%.

—*Velda Addison*

Anadarko Gears Up For Shenandoah-6 Appraisal Well

The jury is still out on when Anadarko Petroleum Corp. will make a financial investment decision (FID) on the Shenandoah development in the U.S. Gulf of Mexico's Lower Tertiary trend.

But the prospect looks attractive and Anadarko appears to have confidence in its potential, considering the company recently upped its working interest in Shenandoah to 33%.

The Shenandoah-5 well hit more than 305 m (1,000 ft) of net oil pay during second-quarter 2016, extending the resource to the eastern extent of the field, Anadarko said July 27.

The company hopes to gain more insight on the field's resource potential and find the oil-water contact by spudding the Shenandoah-6 appraisal well—farther east and downdip. This is expected to happen by year-end 2016.

"We really have to see what the Number 6 tells us. … We're still in appraisal mode," Robert Daniels, executive vice president of international and deepwater exploration, said in response to what appraisal or technical information is needed to reach a FID for Shenandoah.

Anadarko CEO Al Walker pointed to Mad Dog Phase 2, which BP recently indicated sanctioning is likely this year, for takeaways: productions costs have been chopped by more than half and a significant EUR exists. BP's project doesn't relate to Shenandoah, he said. But Walker seemed to indicate that economics and EUR will factor into its Shenandoah FID decision.

"We're hopeful that some of those ingredients will work into our favor as that decision comes to us over the next couple of years," Walker said.

—*Velda Addison*

BP Plans To Unleash Second Phase Of Mad Dog

Mad Dog Phase 2 could be sanctioned by year-end 2016. (Source: BP)

The highly anticipated Phase 2 of BP's Mad Dog project in the U.S. Gulf of Mexico's Green Canyon area could be among the projects sanctioned within the next 18 months.

During its latest earnings call, BP executives said costs for the project have fallen as the company continues to simplify some of the engineering, further improving the economics.

BP has said that costs for the development are now less than half of the $20 billion originally estimated a few years ago.

"We are making sure the breakeven cost or the cost that allows us to receive a reasonable return on our capital is coming down, down, down," BP CEO Bob Dudley said, according to a Seeking Alpha transcript of the call. "Mad Dog will be under $40 per barrel by the time we're done on that, for example."

The Phase 2 subsea development will be tied back to a new floating production hub, which will have up to 24 wells from four drill centers, according to BP.

Currently, the Mad Dog Field is producing from a truss spar, designed to process 80,000 bbl of oil and 1.6 MMcm/d (60 MMcf/d) of gas, with dual barrier production risers and dry trees.

Phase 2 could be sanctioned by year-end 2016, but BP Upstream Chief Bernard Looney noted the expansion is subject to partner approval. Partners are BHP Billiton and Chevron Corp., which respectively hold 23.9% and 15.6% interest.

The project is among those that BP is counting on to add 800,000 boe/d of new production by 2020. Other projects that could be sanctioned include Angelin and a compression project, both in Trinidad, Platina in Angola Block 18, Snadd in Norway, India gas projects and additional development of the Khazzan Field in Oman.

"The expectation remains the same, and that is twofold. Number one, it has to hit—each has to hit the hurdle rates, which is driven by value over volume, mid-teens for greenfield and greater than 20% for brownfield and infill," Looney said. "And the project has got to be the best that it can be."

—*Velda Addison*

PROJECT BRIEFS

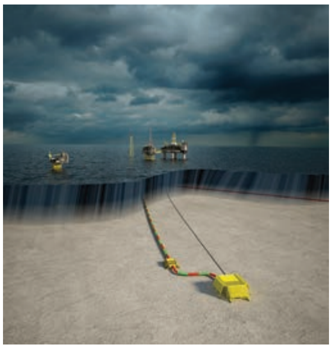
Statoil Outlines Plan For Utgard Discovery In North Sea

Statoil presented a plan for development and operation of the British-Norwegian Utgard natural gas, NGL and condensate field in the North Sea. The estimated investment in the Utgard Field is US$413.99 million.

Norway's Oil Minister Tord Lien told Reuters he expects oil companies to submit additional plans by year-end 2016 for development and operations of other offshore fields.

Statoil said Utgard is scheduled to come onstream at year-end 2019; in the plateau phase, the field will produce about 44 Mboe/d. The recoverable reserves are estimated at 56.4 MMboe.

The field, which was previously known as Alfa Sentral, will be remote-controlled from the Sleipner A platform and will be developed as a subsea facility tied back to the Sleipner Field, where CO_2 will be removed and stored in the ground.



Utgard is scheduled to come onstream by year-end 2019. (Source: Statoil)

About 60% of the resources are located on the Norwegian Continental Shelf, according to Statoil, which had previously estimated investments in the field to range between 4 billion Norwegian crowns and 4.5 billion Norwegian crowns.

"The project illustrates how measures to improve efficiency and productivity lead to new profitable field developments. The petroleum industry is, and will remain, Norway's most important industry for years to come," Tord Lien said in a separate statement.

As the operator, Statoil holds 100% of the British part of the Utgard Field and 62% of the Norwegian license. Lotos holds 28% of the Norwegian license, while Total holds 10%.

OMV Lowers Stake In Rosebank Project Offshore UK

In a move to further optimize its portfolio and reduce investment requirements, OMV has agreed to sell a 30% interest in the Rosebank oil and gas project offshore the U.K. to Suncor Energy.

The transaction, if approved by regulators, would leave OMV with a 20% interest in the project.

Under the terms of the agreement, Suncor will initially pay $50 million on closing, which is expected in fourth-quarter 2016, OMV said in a news release on Aug. 9. After OMV and partners Chevron North Sea Ltd. (40% interest) and DONG E&P (U.K.) Ltd. (10% interest) approve the Rosebank final investment decision, OMV could get up to $165 million more.

OMV, however, said it also is realizing a EUR 530 million pre-tax impairment, which will be booked in second-quarter 2016, for its 50% Rosebank stake.

Currently in the FEED phase, which began in 2012, the project will include an FPSO vessel, production and water injection wells as well as subsea facilities and a gas export pipeline. The field, discovered in 2004, is about 130 km (81 miles) northwest of the Shetland Islands in water depths of about 1,110 m (3,642 ft).

Erin Plans Nitrogen Lift For Oyo-8 Offshore Nigeria

After an emergency shutdown on July 1 at the Oyo-7 well offshore Nigeria, Erin Energy is planning efforts to bring the well back through use of a nitrogen lift via subsea infrastructure to the well, the company said in a statement.

The well's high water content prevented production from resuming following a planned production curtailment in the Oyo Field. The incident resulted in a production loss of about 1,400 bbl/d of oil. Erin plans to perform the nitrogen lift following its next crude lifting, which is set for the week of Aug. 15.

Erin was, however, successful in bringing the Oyo-8 well back online after the *Island Constructor* vessel carried out light well intervention service to open the subsurface controlled subsurface safety valve, which Erin said had failed to reopen after the planned curtailment.

Meanwhile, the company is gearing up for the next drilling campaign, which kicks off in the fourth quarter, by procuring well and subsea equipment. "The Oyo-9 production well is planned as an additional development well within the central area of the Oyo Field in Oil Mining Lease 120 and will be tied into the existing production facilities to increase the company's production by about 6,000 to 7,000 barrels of oil per day," the company said.

'World's Largest Jackup Rig' En Route To Mariner Field

Noble Corp. has tapped Aqualis Offshore to oversee the load-on, transportation and load-off operations of the first journey of the Noble Lloyd Noble, Aqualis said in a news release.

The jackup is traveling from Singapore to Port Elizabeth, South Africa. Its final destination is the North Sea. (Source: Aqualis Offshore)

The jackup rig is being called the largest in the world by its builder Sembcorp Marine and Aqualis. The rig, which has an operational air gap of 69 m (226 ft), can operate in water depths of up to 150 m (492 ft) and has a maximum total drilling depth capacity of 10,000 m (32,808 ft). Its design is based on the GustoMSC CJ70 and Statoil's Category J specifications.

As part of the contract, Aqualis said it will provide marine warranty services for the load-on, transportation and load-off operation of the jackup. The first leg of the journey is from Singapore to Port Elizabeth, South Africa. The rig's ultimate destination is Statoil's Mariner Field in the U.K. North Sea, Aqualis said.

Expro Secures Well Testing Contract In India

India's Oil and Natural Gas Corp. Ltd. (ONGC) has turned to Expro for well testing for assets, including assets offshore Mumbai, onshore Rajamundry and the Krishna Godavari Basin.

The contracts, which total more than $17 million, are for three years. Expro said the contracts comprise its 15K and 10K surface well testing packages for HP/HT and conventional wells.

Two sets of 15K surface well test packages will be delivered for 10 offshore and 22 onshore wells in eastern India. The onshore package will be deployed for the testing of exploratory and completed wells onshore at Rajahmundry, Expro said.

Four sets of 10K packages will be delivered offshore Mumbai and includes the provision of a well test supervisor and operator on a call-out basis. Plans are to use the 10K packages for production testing of exploratory wells in addition to testing, flow back and measurement of worked-over and platform wells, the company said.

Statoil Taps Claxton For Huldra Decommissioning

Claxton, an Acteon company, is set to begin the "rigless recovery" of seven abandoned wells on the Huldra platform in December after Statoil awarded the company a contract.

The company will be responsible for the full scope of decommissioning work, including project planning, severance and full multiple string recovery. The project in the Norwegian Continental Shelf is expected to be complete within 21 days.

The company said it will use its SABRE unit, an abrasive cutting system, and its recovery tower for conductor and casing severance for the project.

—Reuters & Staff Reports

FLOATERS

Awaiting Balance: Attrition Pushes Floating Rig Supply, Demand Closer

With total global well demand down to half of what it was a year ago, the contracted rig supply continues to suffer as drilling contractors cold-stack or scrap retired rigs for cash and E&Ps slow spending amid tough market conditions.

But attrition could help balance the oversupplied floating rig market.

Noble Corp. and Rowan Cos. Inc. both saw Freeport-McMoRan Oil & Gas Ltd. bow out of drilling contracts for drillships during second-quarter 2016. In its earnings release July 26, Freeport-McMoRan, which restructured its oil and gas business, said it agreed to pay $755 million plus potential contingent consideration depending on future oil prices for three terminated drilling contracts.

While some rigs have been left without work, others have been sent to their death.

Just last week U.K.-based Ensco Plc said it sold two semisubmersibles, two drillships and two other rigs for scrap value. The global deepwater drilling sector will probably see more drilling contractors scrap or retire some of the rigs they have pulled, according to Leslie Cook, senior research consultant for Quest Offshore Resources.

"There are plenty of rigs that are cold-stacked that are 30 or 40 years old. They are dying on the vine," Cook said. "They will never come back to work, certainly not back to their glory days."

Figures from the advisory and consulting firm show the estimated contracted rig demand for 2016 is forecast at 124 units. Of these units, roughly 80%, or 98 units, are needed for drilling wells. The 2016 forecast contracted floating rig supply is 143 units, representing an oversupply of 19 units, Cook said. The outlook shows drilling supply exceeding demand through 2016.

Rig attrition

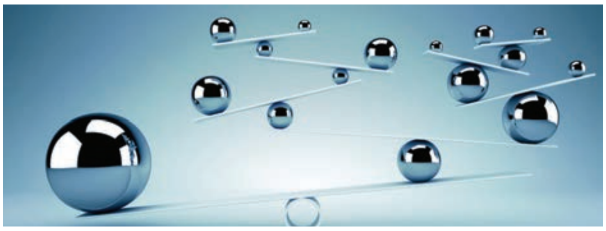
In addition to the 52 rigs idled in first-half 2016, 31 additional rigs could roll off contract in the second half, according to Quest.

High attrition is expected to ease the excess drilling supply, bringing a supply and demand balance in 2017.

"I think what we'll see next year is less attrition but not a whole lot of rigs coming back quite yet," she said. "Obviously, this is not good news if you are a drilling contractor."

The firm does not expect more rigs to return to the market until closer to 2019-2020.

Of the 353 total floating rigs in Quest's database, 50% of the supply is with six contractors—Transocean, Seadrill, Diamond Offshore, Ensco, Noble Drilling and Ocean Rig. Average utilization among these six companies is about 57%, Cook said.



The average day rates for all rig types are trending down, she added, as rigs at the higher end of rate range begin to roll off contract with new contracts (leading-edge) down 25% to 40%.

Currently, about 84% of the existing fleet has been delivered with the remaining 16% in shipyards or being delayed or canceled.

Looking up

But the news was not all bleak for global deepwater drilling. There are some silver linings, Cook said.

Heading into second-half 2016, supply and demand is balanced at about 25 rigs for the Africa-Mediterranean region. More than 430 new wells, including 135 exploration/appraisal wells, are forecast through 2020 for the region.

"Africa is really a sleeping giant. The growth potential there is exponential at the right commodity price," Cook said, noting 21 discoveries were made there in the last 18 months with new play openings in Senegal, Mauritania, Ivory Coast and in the Black Sea.

Offshore North America more than 365 new wells are forecast through 2020. Drilling opportunities exist in ultradeepwater Mexico along with brownfield opportunities in the Gulf of Mexico and frontier potential offshore Nova Scotia, the Bahamas and Cuba, she said.

"Asia is a long-term gas proposition while oil potential has yet to be realized. … North Sea maturity breeds longevity and with a little luck of the Irish new plays to come," Cook continued. "South America is your presalt prize combined with exciting new plays outside of Brazil" from companies such as Exxon Mobil offshore Guyana.

—Velda Addison

FLOATER BRIEFS

DOF Subsea Lands Shell's IRM Contract For Prelude FLNG Facility

Shell Australia has awarded a five-year inspection, maintenance and repair (IRM) contract for its Prelude FLNG facility to Bergen, Norway-based DOF Subsea.

The contract has two options for two-year extensions to provide full-time underwater services and a multipurpose supply vessel to Prelude, the largest floating facility every built, which will be deployed offshore Western Australia.

DOF Subsea will provide project management, engineering and integrated services as well as the dedicated vessel and options for other vessels.

"This is a very important contract award for DOF Subsea, and the award further strengthens DOF Subsea's position in the global subsea IMR market," CEO Mons Aase said in a prepared statement. "We look forward to working with Shell Australia on the world-leading Prelude FLNG facility."

Ocean Installer Wins Malta Mooring Work

ElectroGas Malta has chosen Stavanger, Norway-based Ocean Installer to procure and install a spread mooring chain system for a floating storage unit (FSU) in Malta. The FSU in Marsaxlokk Bay will provide regasified LNG to fuel onshore electricity generators at Delimara power station.

"With this project, we further consolidate our position as a provider of competitive mooring services, and by that we again prove our strategy of casting a wider net in a challenging market successful," Ocean Installer CEO Steinar Riise said in a prepared statement. Onshore engineering for the project, to be managed from Ocean Installer's headquarters, is expected to begin immediately.

FPF-1 Starts Sail-Away To Stella Field

The FPF-1 floating production facility has finished final marine system trials and has begun sail-away to the Stella Field, Ithaca Energy said Aug. 5.

The company expects first hydrocarbons from Stella about three months after sail-away.

FPF-1 departs the Remontowa yard in Gdansk, Poland. (Source: Ithaca Energy)

Located in the central part of the U.K. North Sea in the Graben area, the Greater Stella Area development consists of subsea wells tied back to FPF-1. "To maximize initial oil and condensate production and fill the gas processing facilities on the FPF-1, the hub will start up with five Stella wells," according to Ithaca. Additional wells will be drilled after startup.

Ithaca holds a 54.66% working interest in the field with partners Dyas and Petrofac holding 25.34% and 20%, respectively.

—*Staff Reports*

DEVELOPMENT

ONGC Lines Up Integrated Development Plan For KG Fields

India's state-run ONGC Ltd. is preparing to launch an integrated development plan for gas fields in two adjacent shallow-water blocks—KG-OSN-2004/1 and GS-49-2—in the Bay of Bengal.

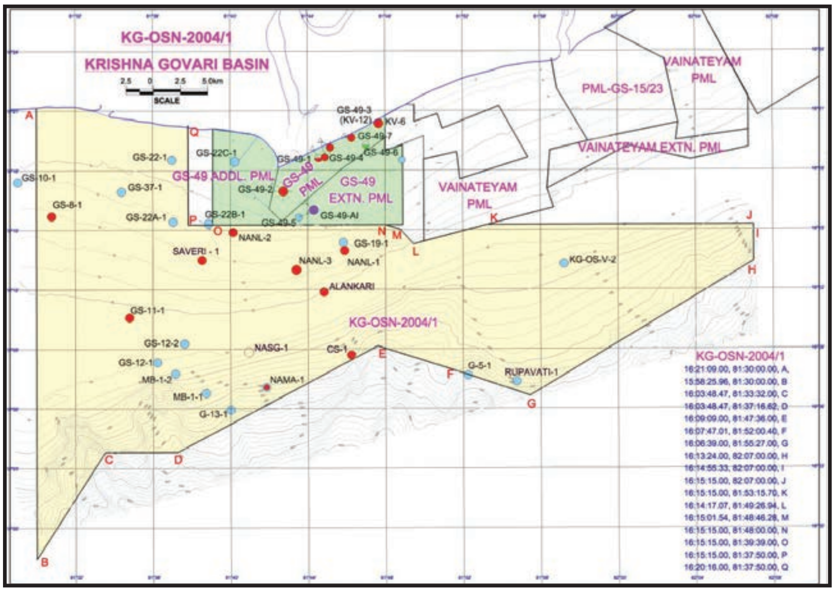
Many of the gas fields are "marginal and economically not viable on a standalone development basis," a senior ONGC official said.

The plan involves drilling and completing seven new wells in KG-OSN-2004/1 and two new wells in GS-49-2. The seven wells in KG Block (AL-1-A, SA-1-A, SA-1-B, NL-2-A, NL-3-A, NL-3-B and CS-1-A) will be drilled at water depths of 16 m to 140 m (52 ft to 459 ft) with cased-hole gravel pack completion, while two wells in GS Block (GS-49-2/1 and GS-49-2/2) will be developed at a water depth of 7 m (23 ft) with dual packer and dual string completions with 2⅞ tubing.

The plan also includes building five unmanned production platforms (SA-1A, SA-1B, NANL-2A, AL-1A and NANL-3A) in the KG Block and one (GS-49-2) in the GS Block.

Seven wells will be tied with five platforms in the KG Block, and two wells will be tied with one platform in GS. The produced well fluid from SA-1A WHP will flow to SA-1B. Combined, the fluids will move to NANL-2A WHP and onto NANL-3A.

Two subsea wells, CS-1-A and NL-3-B, will be tied with AL-1A WHP through a loop line, and the produced fluid will flow to the centralized NANL-3A.



ONGC plans to build five unmanned production platforms in the KG Block and one in the GS Block. (Source: ONGC)

"Development of [the] KG-OSN-2004/1 Block along with GS-49 has a total production potential of 6.4 MMcm/d [226 MMcf/d] of gas with nine producers to deliver a cumulative gas production of about 14.14 Bcm [499 Bcf] over a period of 16 years," the operator said in a report.

The integrated development plan is estimated to cost about $500 million.

During the exploration stage, ONGC drilled nine wells in KG-OSN-2004/2 Block, out of which five were discovery wells—CS#1, AL#1, SA#1, NANL#2 and NANL#1. One well NANL#3 established the extension of CS#1 pay to the north, and the NAMA#1 well had gas indications. The NARV#1 and NANL#4 wells were dry. The CS#1 channel is believed to extend south. The block is spread across 1,131 sq km (437 sq miles) at a water depth of up to 350 m (1,148 ft) in the Bay of Bengal.

In the GS-49-2 Block, the operator discovered gas prospects in one of the two exploration wells. GS-49-2, the second well drilled on the structure on the southwestern culmination, encountered multistack reservoirs. The total gas initially in place is estimated at 3.94 Bcm and the ultimate producible reserves are believed to be about 3.04 Bcm (107 Bcf). The first well GS-49-1 drilled on the northeastern culmination went dry.

In addition, ONGC is looking to build an onshore facility near the landfall point at Mori or Odalarevu on Andhra coast to process the collected fluids from centralized NANL-3A platform. The well fluid gathered at NANL-3A will be transported to the Mori onshore facility through an 18-in. by 20-km (12.4-mile) flowline.

Production from GS-49-2 WHP will be pumped to the centralized platform.

Five flowline segments of 8 in., two segments of 12 in. and one 10-in. segment—with a cumulative length of 47 km (29 miles)—will be developed between the platforms.

In addition to accommodating the risers of incoming and outgoing pipelines, the substructure of the AL-1A platform will make way for the I/J tube to accommodate umbilical for the subsea wells. Furthermore, each NANL-2A, SA-1A, SA-1B and GS-49-2 platform will be designed to accommodate one future riser of 8 in. The AL-1A and NANL-3A platforms will be designed to accommodate two 12 in. future risers.

The subsea pipeline from the centralized NANL-3A platform will be tied to a new onshore facility at Mori/Odalarevu, with capacity of 8 million metric standard cubic meters per day of gas.

—Ravi Prasad

DEVELOPMENT BRIEFS

Subsea Consortium Clinches $1.6 Billion Saudi Aramco Contract

Saudi Aramco has awarded the EMAS CHIYODA Subsea and Larsen & Toubro Hydrocarbon Engineering consortium a US $1.6 billion engineering, procurement, construction and installation (EPCI) contract for a project in the Arabian Gulf.

The work is for development of the second phase of the Hasbah offshore gas field offshore Saudi Arabia, EMAS CHIYODA said in a news release.

The two will be involved in constructing two streams of three wellhead platform topsides, one tie-in platform with flare platforms and bridges tied together by umbilicals and in-field pipelines, the release said. Interconnecting trunk lines to transport produced gas from the offshore gas field to the Fadhili Gas Plant is also part of the scope of work.

EMAS CHIYODA said fiber optic cables and other cables for power and communication networks will be installed in tandem. The consortium will also be responsible for installing onshore facilities, including the beach valve station, a sectionalizing valve station and four scraper traps.

Onshore engineering and fabrication has already begun, the company said, and the offshore execution phase is expected to begin in fourth-quarter 2017.

"The project is scheduled to be completed over a period of three and half years and will serve Saudi Aramco's strategy to supply an additional 2,500 MMscf/d of clean natural gas through the Fadhili Gas Plant to meet Saudi Arabia's growing domestic energy demand," the release said.

Technip Lands Greater Enfield, North Sea Work

Technip has been awarded a subsea contract, valued at between $279 million and $558 million, by Woodside for the Greater Enfield project offshore Western Australia in a water depth between 340 m and 850 m (1,115 ft and 2,789 ft).

As part of the contract, Technip said it will handle project management as well as the design, engineering, procurement, installation and precommissioning (EPIC) of the carbon steel production flowline, carbon steel water injection flowline, flexible risers and flowlines, totaling 82.2 km (51 miles); 38.9 km (24 miles) of dynamic and static umbilicals; subsea structures and valves; and the transport and installation of a multiphase pump system.

Technip plans to execute the contract from its operating center in Perth, Australia, with support from its Asia-Pacific subsea hub in Kuala Lumpur and office in India. Offshore installation, which will use several vessels from Technip's fleet, is set for completion in 2018.

Technip also was successful in lining up work in the North Sea. Repsol Sinopec Resources UK Ltd. awarded the company a contract for inspection, repair and maintenance jobs on its subsea infrastructure in the North Sea.

The agreement, as stated in a news release, covers provision of equipment, including diving equipment, underwater intervention and engineering services; onshore management and engineering support, provision of ancillary personnel and equipment to support Technip's performance of the work; and diver inspection, ROV inspection, maintenance, repair, construction and decommissioning. The contract is for 2016, but it could be extended for two more years.

VESSELS

Osbit Delivers Equipment For Helix Energy Solutions Vessel

Osbit Ltd. has completed a £3 million (US$3.97 million) delivery of more than 300,000 tonnes of well intervention equipment to Houston-based Helix Energy Solutions Group Inc., part of a series of projects to supply three Helix vessels.

The equipment, scheduled to be installed this past week in Schiedam, The Netherlands, on *Siem Helix 1*, include a BOP maintenance and storage tower, intervention tension frame and moveable deck. *Siem Helix 1* will be deployed offshore Brazil on a long-term well intervention services charter for Petrobras.

Northumberland, U.K.-based Osbit will provide a second suite of identical systems later in the year for *Siem Helix 2*. The series of projects, which total £11 million (US$14.56 million) worth of equipment, also includes Helix's *Q7000*.

"We have worked with Osbit on multiple projects, and they continue to impress us with their diligence and flexibility," Paul Shotton, Helix's special projects manager, said in a written statement. "Osbit is a supplier that listens to our requirements and translates them into practical, high-quality and cost-effective results, time and time again."

The delivery includes:

- **Maintenance tower:** safe environment to assemble and maintain subsea equipment, incorporating a 125-tonne capacity lifting system to enable progressive assembly of stack modules;
- **Intervention tension frames (ITF)**: developed with Helix, each ITF provides a safer working environment from which coiled tubing and wireline operations can be conducted; the ITF has three platform levels for personnel to conduct operations using dedicated skidding systems with access provided by a telescopic gangway, which removes the need for engineers to use rope-access methods to operate the well intervention systems mounted within the ITF; and
- **Moveable deck:** adjacent to the maintenance tower, it is a specialized mezzanine that provides an additional support and work area over the vessel's moonpool.

"The design and build of these complex systems demonstrates Helix's confidence in us to deliver safe, innovative, integrated equipment packages to meet their strict schedules and budgets," Dr. Tony Trapp, executive chairman of Osbit, said in a prepared statement. "The extensive experience of our skilled engineers and commitment to delivering on spec, to budget and in time has allowed us to develop a strong relationship with Helix and to secure multiple large projects for the company, which support our growing presence in the international offshore industry."

—Joseph Markman

Bibby Lands Contact For Work In North Sea

Bibby Offshore has lined up work for its construction support vessel *Olympic Ares*, diving support vessel *Bibby Topaz* and subsea support and construction vessel *Olympic Bibby* after securing a contract with a U.K. E&P for air diving, and ROV inspection and construction services.

The work for the unnamed E&P is five of the company's North Sea assets. The contract, which already has begun, is expected to be complete by year-end 2016, Bibby Offshore said in a news release.

Vessel-based engineering work includes installing a cathodic protection system on one platform and performing air diving services to complete routine and nonroutine inspection, repair and maintenance support at three other facilities, Bibby said. The company's scope of work also includes routine pipeline inspection surveys at all five assets.

EXPLORATION

Shell Makes GoM Discovery In Norphlet Trend

Royal Dutch Shell is adding to its deepwater hits in the U.S. Gulf of Mexico's (GoM) Mississippi Canyon area, unveiling on July 28 that it has made a discovery at its Fort Sumter prospect.

The discovery was announced the same day Shell delivered its second-quarter 2016 results and updates on its $30 billion divestment program and growth priorities such as global deepwater.

Initial estimates show the discovery in the deep Norphlet geologic trend could hold recoverable resources of more than an estimated 125 MMboe, Shell said. Fort Sumter was drilled in a water depth of 7,062 ft (2,152 m) to a total vertical drilling depth of 28,016 ft (8,539 m) measured depth.

"Further appraisal drilling and planned wells in adjacent structures could considerably increase recoverable potential in the vicinity of this particular well," Shell CFO Simon Henry said on the company's earnings call. "That in itself builds upon recent Norphlet exploration success at Appomattox in 2010, Vicksburg in 2013 and Rydberg in 2014, bringing the total resources added by exploration in the Gulf for Shell since 2010 to over 1.3 billion [barrels of oil equivalent]."

Resources from the discoveries could be produced through Shell's Appomattox project, which is currently under construction. The project includes a semisubmersible, four-column production host platform. Its subsea system will feature six drill centers as well as 15 producing wells and five water injection wells.

Fort Sumter's proximity near other discoveries adds to the area's prospectivity, added Ceri Powell, executive vice president of exploration for Shell.

"Our growth priorities have a clear pathway toward delivering strong returns and free cash flow in the medium term," Royal Dutch Shell CEO Ben Van Beurden said. (Source: Royal Dutch Shell)

"These successes demonstrate there is still running room in the producing basins of our heartlands where large, high-value discoveries have the potential to further strengthen our deepwater competitiveness," Powell said in a statement about the discovery.

Delivering profits from new projects is among the levers Shell said it is pulling to manage finances during the downturn. Like other oil and gas companies, Shell has reacted to lower oil prices by reducing costs—including cutting thousands of employees—selling assets, lowering operating costs and merging with peers to strengthen presence and offerings.

Shell, which completed its acquisition of BG Group in February, reported its second-quarter current cost of supplies, or net income, was about $1 billion. This was down from about $3.8 billion in the same quarter last year, mostly due to losses in the upstream segment, but not far off from the $1.5 billion reported in the first quarter. Cash flow from operating activities dropped 62% to about $2.3 billion.

In the second quarter, oil and gas production increased to 3.51 MMboe/d from 2.73 MMboe/d in second-quarter 2015.

—*Velda Addison*

Bay Of Bengal Discovery Boosts Gas Hydrate Prospects

The U.S. Geological Survey (USGS) has helped India to discover "a large, highly enriched accumulations of natural gas hydrate" in the Bay of Bengal—the first such discovery in the Indian Ocean that has the potential to be produced, the USGS said.

The USGS added that the discovery is the result of the most comprehensive gas hydrate field venture in the world to date—the Indian National Gas Hydrate Program Expedition 02 (INGHPR-02)—with participation of scientists from India, Japan and the U.S. Japan's *Chikyu* deepwater drilling vessel was used for INGHPR-02.

So far, only four countries have collected samples of gas hydrates: the U.S., Japan, India and China.

There is currently no technology to commercially produce hydrates, although industry experts say that commercial, scaled development could be possible after 2030. Smaller scale output has even been touted as possible by 2018.

There has been growing interest in the search for natural gas hydrates, which are a naturally occurring, ice-like combination of natural gas and water found beneath the world's oceans and polar regions, as it could potentially be an alternative energy source given that the amount of gas within the world's gas hydrate accumulations is estimated to exceed the volume of all known conventional gas resources, the USGS noted.

Indian find could spark tech push

The India expedition conducted ocean drilling, conventional sediment coring, pressure coring, downhole logging and analytical activities to assess the geologic occurrence, regional context and characteristics of gas hydrate deposits offshore India.

The deepwater D/S Chikyu, deployed during NGHP-02, was designed by the Japanese government for international scientific drilling operations. (Source: JAMSTEC)

"Advances like the Bay of Bengal discovery will help unlock the global energy resource potential of gas hydrates as well as help define the technology needed to safely produce them," USGS' Energy Resources Program Coordinator Walter Guidroz said.

INGHPR-02 is the second joint exploration for gas hydrate potential in the Indian Ocean after the first, also a partnership between scientists from India and the U.S., discovered gas hydrate accumulations, albeit in formations that are currently unlikely to be producible.

The USGS noted that while it is possible to produce natural gas from gas hydrates, there are significant technical challenges, depending on the location and type of formation. Previous studies revealed that gas hydrate at high concentrations in sand reservoirs is the type of occurrence that can be most easily produced with existing technologies.

INGHPR-02 therefore focused the exploration and discovery of highly concentrated gas hydrate occurrences in sand reservoirs. The USGS noted that the gas hydrate discovered during the expedition are located in coarse-grained sand-rich depositional systems in the Krishna-Godavari Basin and is made up of a sand-rich, gas-hydrate-bearing fan and channel-levee gas hydrate prospects.

The research team will now proceed to production testing in these sand reservoirs to determine if natural gas production is practical and economic.

"The results from this expedition mark a critical step forward to understanding the energy resource potential of gas hydrates. The discovery of what we believe to be several of the largest and most concentrated gas hydrate accumulations yet found in the world will yield the geologic and engineering data needed to better understand the geologic controls on the occurrence of gas hydrate in nature," said Tim Collett, USGS senior scientist.

Japan plans 2017 testing

Japan also has an ongoing methane hydrate project, which is looking to tap the fuel offshore the country's southeastern coast.

Japan's Ministry of Economy, Trade and Industry is now progressing plans for a second round of production testing in 2017 for methane hydrates off the coast of Aichi and Mie prefectures, which is believed to hold sufficient reserves to provide the country with a decade's supply of natural gas.

If the production test is successful, Japan plans to start commercial methane hydrate production as soon as technology allows, although this will depend on the pace of technological development.

South China Sea discovery

In 2014, China made a major gas hydrate discovery in the northern part of the South China Sea.

China's Ministry of Land and Resources (MLR) said the gas hydrate accumulation covers 55 sq km (21 sq miles) in the Pearl River Mouth Basin, with controlled reserves equivalent to 3.53 Tcf to 5.30 Tcf (100 Bcm to 150 Bcm) of natural gas.

This made the hydrates field equivalent to a major conventional natural gas field, such as in China's Sichuan province.

Guangzhou Marine Geological Survey Bureau, a unit of MLR, collected samples of "high purity" gas hydrates over nearly four months of surveys and drilling of 23 wells in the waters off south China's Guangdong province.

Two gas hydrate layers with a thickness of 15 m to 30 m (49 ft to 98 ft) were found just below the seabed at a water depth of 600 m to 1,000 m (1,969 ft to 3,281 ft).

"It marks a breakthrough in investigating the resource and proves that the Pearl River Mouth Basin is rich in gas hydrate," said the MLR.

Hydrates potential

"Methane hydrates could, in theory, revolutionize the energy industry, potentially providing significant upside to natural gas production. However, to date, there haven't been any commercial-scale developments," said Michelle Gomez of consultant Douglas-Westwood.

"Whether methane hydrate projects off Japan can be commercialized at a competitive price is unknown, and there are significant technical issues to overcome, not least that the most viable accumulations are located in difficult environments, posing technical and environmental challenges. Indeed, Canada is abandoning its own 15-year U.S. $10 million program.

"With natural gas prices at four times U.S. levels, Japan has a greater incentive and has been drilling in its Nankai Trough since 1999. In March 2003, they produced 120 Mcm (4.24 MMcf) of methane gas from a depth of 1,000 m (3,281ft).

"It is reported that if test drilling continues to yield positive results and if technical issues can be resolved, commercial production could begin during as early as 2018. But one constant of the energy industry is that most projects take much longer than planned," Gomez added.

—*Steve Hamlen*

TECHNOLOGY

TGS, Schlumberger Tap Latest Technology For GoM Surveys

With the Schlumberger WesternGeco Q-Marine point-receiver marine seismic system and dual coil shooting acquisition technique at hand, TGS and Schlumberger have kicked off full-azimuth shoots in the U.S. Gulf of Mexico (GoM).

Schlumberger said use of the technology and technique will improve illumination and imaging of the subsalt and other complex geologic features in the region.

The multivessel full-azimuth acquisition Revolution XII and XIII surveys will span 306 blocks in the Green Canyon, Atwater Valley and Ewing Bank, recoding offsets greater than 14 km (8.6 miles) for imaging, the company said in a news release. As part of the work, the companies plan to deploy autonomous marine vehicles, which will simultaneously acquire offsets of more than 20 km (12 miles). The coverage area spans about 7,150 sq km (2,760 sq miles).

The surveys are expected to "provide the E&P industry with critical information to support exploration and drilling activity in a region that is expected to remain a priority for our customers," TGS CEO Kristian Johansen said in the release.

If all goes according to plans, the industry-funding supported acquisition should be complete in first-quarter 2017. Final processed data will be available in early 2018.

Geo Oceans Sets New International Benchmark For Diverless UWILDs

In what is being called a world first, Geo Oceans said it has carried out a diverless underwater inspection in lieu of dry docking (UWILD) using new subsea robotics technology.

A three-man ROV team carried out the survey work from a control room on an FPSO facility with mini-ROVs because the area being surveyed was deemed too dangerous for divers to access, GeoOceans said on its website.

The work included surveying nine mooring legs to a 100-m (328-ft) water depth, all of the vessel's hull, 38 penetrations, two active caissons and a 500-sq-m (5,382-sq-ft) section of hull that had not been previously inspected, the company said, adding the diverless inspection resulting cost savings, reduced health and safety risk and less facility downtime.

Features of Geo Oceans' Mini ROV Class Survey System include advanced nondestructive testing, sensors, cleaning and tooling technology that are controlled remotely.

Weatherford, IBM Will Develop Analytics-leveraged Production Solutions

Weatherford International said it has signed a joint initiative agreement with IBM to collaborate on developing new products and services for oil and gas producers that leverage IBM advanced analytics and Internet of Things capabilities on the IBM Cloud.

The two companies plan to develop new analytics solutions based on Weatherford's production optimization and engineering software platform, SCADA, and its sensors and controllers, according to a news release.

The jointly developed solutions will be part of Weatherford's new reservoir solutions global business unit. Launched in early 2016, the unit provides integrated offerings that aim to reduce operating costs and increase production.

For more technology news, read the Offshore Northern Seas Technology Showcase featured in the August edition of *E&P*.

BUSINESS

Sources: Eni, Exxon Mobil Reach Deal on Mozambique Gas Project

Italian oil firm Eni has wrapped up long-running talks to sell a multibillion-dollar stake in its planned Mozambique LNG development to Exxon Mobil, two sources with knowledge of the matter said.

"The deal is done, but won't be announced for several months at Exxon's request," one of the sources said.

Eni declined to comment, while a spokesman for Exxon said, "We do not comment on market rumors or speculation."

The offshore gas reserves already discovered by Eni in Area 4 are large enough to need a giant land-based LNG export plant whose proximity to Asian and Middle Eastern growth markets makes it potentially a highly lucrative project.

But talks to bring in a technically savvy partner with deep pockets like Exxon have dragged on due to a difference over valuations in the light of falling oil and gas prices.

In 2013 Eni sold 20% of its Area 4 license to China's CNPC for $4.2 billion, but since then oil and gas prices have come down by more than half.

However, last year Mozambique awarded Exxon three offshore exploration license blocks of its own, which sit to the south of Eni's discoveries, giving a new dimension to development prospects.

"As you are aware, on October 28, 2015, Exxon was awarded three offshore blocks in Mozambique," the spokesman for Exxon said.

"We look forward to further discussions with the Mozambique government on the development of a production-sharing contract for the blocks."

Eni has been reluctant to sell too much of its 50% stake in the Area 4 permit where as operator it already has found 2.4 Tcm (85 Tcf) of gas.

But in recent weeks Eni CEO Claudio Descalzi has raised the possibility of it selling up to a 25% stake, up from the 10% to 15% previously on offer.

The two sources said after lengthy talks, Eni and Exxon have now agreed terms and "sealed" a deal that could give Exxon its desired operating stake in the onshore LNG export plant while Eni would retain control over the Area 4 gas fields feeding it.

Last week Descalzi reiterated Eni's desire to remain operator for the gas fields.

"Our model is to remain and keep the operatorship or keep, in any case, a clear control on the asset—the asset that we discovered," he told analysts.

While Eni will export gas as LNG from at least one floating offshore platform in the Coral Field development in Area 4, the main focus of work will be on the larger land-based plants.

The Coral Field will remain outside the scope of the deal with Exxon, the sources said, and Eni has earmarked LNG from the Phase 1 development of Coral to BP.

—Reuters

Petrobras Sells Oilfield Asset To Statoil For $2.5 Billion

Petrobras agreed to sell one of its largest oil and gas prospects on July 29 to Statoil for $2.5 billion, the boldest step yet by the company to advance its stagnant asset-sale plan and repair its battered finances.

The agreement will give Statoil 66% ownership and operator status in a block that is home to Carcará, a prospect that Statoil said contains 700 MMbbl to 1.3 Bbbl of oil and equivalent natural gas. That would equate to all petroleum needs in the U.S. for at least five weeks and up to two months.

The deal is for the BM-S-8 offshore exploration license now owned by Petrobras, the companies said in statements. The stake gives state-controlled Statoil two-thirds of the oil and gas produced in Carcará, bolstering non-Norwegian output as production from mature fields declines.

Statoil exploration chief Tim Dodson told Reuters he expected production from Carcará to start in the mid-2020s.

"That's good for us ... because that means that there is limited ... capital outlay up until 2020," he added.

Output from Statoil's mature fields is expected to decline after 2020, Dodson said.

About 60% of the Carcará discovery extends beyond the limits of BM-S-8 into acreage Brazil's government hopes to sell next year. Statoil plans to take part in the bidding.

Statoil's partners in BM-S-8 will be Portugal's Galp Energia SGPS SA (14%), Brazil's QGEP SA (10%) and privately owned Barra Energia do Brasil Petróleo e Gás Ltda (10%), backed by U.S. investment funds Riverstone Holdings LLC and First Reserve Corp.

While QGEP and Galp both welcomed the sale, Barra plans to study its right of first refusal, a source with direct knowledge of the company's thinking told Reuters. If invoked, the right could overturn the sale to Statoil or start a bidding war.

Petrobras unions oppose any asset sales and plan to pressure Congress to refrain from passing laws needed to make next year's auction happen.

—*Reuters*

BUSINESS BRIEFS

Subsea 7 Scoops Up Swagelining Ltd.

Norway's Subsea 7 has acquired U.K.-based Swagelining Ltd., which specializes in polymer lining technology, the company said Aug. 10.

The acquisition builds upon their partnership focused on designing and installing reeled and bundled polyethylene-lined water injection flowlines in the North Sea for operators and developments.

Subsea 7's Vice President of Technology Thomas Sunde said in a statement, "The acquisition of Swagelining Ltd. will enable Subsea 7 to enhance its flowline and riser technology portfolios, and supports Subsea 7's commitment to develop and apply technologies that reduce cost, enhance production and extend field life."

About 50 people work for Swagelining.

Shelf Subsea Buys Fugro's Asia-Pacific Subsea Services Business

Australia-based Shelf Subsea Pty Ltd, has purchased Fugro's subsea services business in the Asia-Pacific for $15.53 million and a 25% equity stake in Shelf Subsea.

Shelf Subsea, formed in 2015, will gain one owned ship, three chartered vessels and 18 ROVs. The company also will take over Fugro's subsea offices in Perth, Australia, and Singapore, and add 285 Fugro employees to its rolls. The divestment is another step in its strategy to focus on its core survey and geotechnical businesses, the Netherlands-based Fugro said in a statement.

Fugro reduced its workforce by 585 people in first-half 2016 as it navigates through the offshore slump. The company has indicated that it plans more job losses.

Chevron Elects New Board Members

Dr. Dambisa Moyo and Dr. Wanda Austin have been elected Chevron Corp.'s board of directors, the company said Aug. 9.

Moyo's appointment is effective Oct. 11. She will serve on the company's Audit Committee. Austin's appointment is effective Dec. 1; she will serve on the company's Board Nominating and Governance Committee and Public Policy Committee.

Moyo, who has a doctorate in economics and is an economist, is the founder and has been the CEO of Mildstorm LLC since 2015. Austin, who holds a doctorate in engineering, has served as president and CEO of The Aerospace Corp. since 2008 and holds an adjunct research professor appointment in the University of Southern California's Viterbi School of Engineering.

Transocean Buys Out Transocean Partners

Transocean Ltd. has agreed to acquire Transocean Partners LLC in a deal that would give it ownership interests in two drillships and an ultradeepwater semisubmersible currently owned by Transocean Partners.

On Aug. 1 Transocean Ltd. said it agreed to acquire all of the outstanding common units of Transocean Partners that it does not already own in a share-for-unit merger transaction, according to a news release. If Transocean Partners' common unitholders approve the transaction and customary approvals and conditions are granted, the deal could close in fourth-quarter 2016, resulting in Transocean Partners being 100% owned by Transocean.

Transocean said it already has committed to voting in favor of the merger.

If the deal goes through as planned, Transocean will have indirectly acquired the 51% ownership interests in Transocean Partners' *Discoverer Inspiration* drillship, the *Discoverer Clear Leader* drillship and the *Development Driller III* ultradeepwater semisubmersible, the release said.

"Transocean Partners common unitholders will benefit from a premium to the current unit price and receive shares in an entity with significant financial flexibility, a demonstrated access to capital and meaningfully improved market liquidity of its shares," said Transocean Partners CEO and CFO Kathleen McAllister. "Additionally, we expect that common unitholders also will benefit from Transocean's significantly larger and more diverse fleet and its industry-leading contract backlog."

Subsea 7 Earnings Fall In 2Q

Subsea 7 reported on July 28 that its second-quarter 2016 earnings dropped by 29% to $961 million as the industry recovers from challenging times.

"Financial performance continued to be impacted by the industry downturn with diminishing activity levels as planned work was completed and client investment in oil and gas production remained low," Subsea 7 CEO Jean Cahuzac said in a statement.

The results were delivered following news in June that the company was taking additional cost reduction steps. These include reducing workforce of 9,200 people to about 8,000 by early 2017 and removing up to five vessels from its active fleet.

Cahuzac, however, noted that the company's adjusted EBITDA of $280 million and margin of 29% "reflected good execution and reduced risk profiles and costs on certain projects as offshore phases progressed."

The U.K.-based company saw its active vessel utilization jump to 82% in the second quarter compared to 71% in the prior quarter. The rise was attributed to the progression of several offshore projects, an uptick in seasonal work in the North Sea and two vessels returning to work after being stacked.

"Subsea 7's order intake was $1.6 billion, including approximately $1.3 billion related to the Beatrice wind farm project and a pipeline bundle solution for the Cal-later project, both offshore U.K.," Cahuzac said. "Order backlog at the end of June was $7.1 billion, $0.6 billion higher than at the start of the quarter."

Copus Becomes CEO of Subsea Data Provider Getech

Subsea data and risk management services provider Getech Plc has appointed Jonathan Copus as CEO, effective immediately, the company said Aug. 3.

Copus succeeds Raymond Wolfson, who stepped down from the board on July 31.

Most recently, Copus was CFO at Salamander Energy Plc, which was acquired by Ophir Plc in 2015. Copus also previously worked as an exploration geologist at Royal Dutch Shell and as an E&P sell-side equity analyst at several companies including Investec and Deutsche Bank.

Mexico's Deputy Energy Minister For Hydrocarbons Will Step Down

Mexico's deputy energy minister for hydrocarbons, Lourdes Melgar, a key player behind the country's three-year-old energy reform, will step down from her post at the end of the week, two sources with knowledge of the decision said on July 27.

Melgar, who previously served as deputy energy minister for electricity, will leave the government as it continues to implement the reform, including a series of oil auctions designed to lure investment and reverse a decade-long slide in crude production.

The reform ended national oil company Pemex's decades-long monopoly and clears the way for private companies to begin operating on their own.

Oceaneering Completes Meridian Ocean Services Acquisition

Oceaneering International Inc. has completed its acquisition of Meridian Ocean Services, which conducts surveys on mobile offshore drilling units and floating production systems using ROVs.

The surveys satisfy the underwater inspection in lieu of drydocking requirements of all major classification societies, according to a news release.

PressureFab Ltd. Appoints Joint Administrators

Blair Nimmo and Tony Friar of KPMG LLP were appointed joint administrators of PresureFab Ltd. on July 28 at the request of its director. They also were appointed as joint administrators of its parent company, Twickler Industries Ltd., and a further four group companies.

The joint administrators will be helping the employees to claim their entitlements and will enlist their support, where appropriate, in realizing the assets across the group.

—Reuters & Staff Reports

UPCOMING

The next issue of Subsea Engineering News will be distributed Aug. 26. Until then, visit *epmag.com*.

JOBS

Looking for a new job in the industry? Find opportunities in the jobs section at *epmag.com/jobs*.

CONTACT INFORMATION

MARK THOMAS Editor-In-Chief, E&P Franchise
mthomas@hartenergy.com

VELDA ADDISON Senior Editor
vaddison@hartenergy.com
(713) 260-6400

CONTRIBUTORS
Steve Hamlen (UK)
Ravid Prasad (India)
Joseph Markman (Houston)
Erin Pedigo (Houston)

Subsea Engineering News (ISSN 0266-2205) is published twice monthly by Hart Energy Publishing LLP, Houston TX, USA. Telephone: +1 713 260 6400; Email: sen@hartenergy.com or custserv@hartenergy.com; Website: www.epmag.com/subsea-engineering. Email for subscriptions: mpigozzi@hartenergy.com.

2016 ANNUAL SUBSCRIPTION: £425 + VAT (WHERE APPLICABLE), $675 USA. FOR MULTI-USER SUBSCRIPTIONS, CONTACT US OR CHECK THE WEBSITE. CREDIT CARDS ACCEPTED SUBJECT TO CHARGES.

HARTENERGY
1616 S. Voss, Suite 1000 • Houston TX 77057-2627 • USA
www.hartenergy.com | www.a-dcenter.com

Follow us on Twitter @Hart_EPMag