

## Offshore Industry Taps Technology For Corrosion Monitoring

Corrosion can be considered one of the offshore oil and gas industry's worst enemies.

The cost of corrosion in the oil and gas production industry surpasses \$1.3 billion each year, according to NACE International's estimates.

Subsea technology-focused Teledyne Cormon, which specializes in corrosion monitoring equipment as well as the design and manufacture of corrosion sensors among other types, sees global spending on corrosion and erosion monitoring for the topside and subsea markets combined at more than an estimated \$150 million.

The offshore industry has seen advances in recent years with corrosion-resistant alloys designed for harsh offshore environments, intelligent pigs that detect cracking and pitting corrosion, biocides that aim to prevent or stop corrosion in its tracks and high-temperature corrosion inhibitors. Yet corrosion is still considered one of the leading causes of subsea pipeline failures.

"We estimate about half of [subsea pipeline] failures to be related to corrosion or erosion within the equipment,"

Teledyne Cormon's Tom Wollam told *SEN* in a statement. "Costs can vary to replace a subsea pipeline but

include much more than simply the cost of materials and labor to replace it. Often the cost is driven up exponentially by ancillary costs such as offshore vessels, engineering, testing and any environmental or safety impact the failure may have caused.

However, having an "effective asset integrity program can be an operator's best insurance against preventable corrosion-related problems. ... The risk of pipeline failure far outweighs the costs associated with installing, monitoring and maintaining effective corrosion control systems."

Effective pipeline corrosion control comes down to quality design and installation of equipment, proper technologies and ongoing maintenance and monitoring by trained professionals, he added.

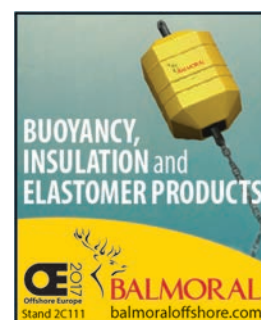
Corrosion and all of the problems it comes with is not new to the oil and gas industry. But the topic still commands attention considering its potential impact on oil and gas operations as facilities—particularly those in areas such as the North Sea and Gulf of Mexico (GoM)—get older. About half of the platforms in the GoM are more than 20 years old, while some in the North Sea are even older. More than 50% of the world's oil rigs will be more



Teledyne's corrosion monitoring system provides true real-time information on metal loss rates, allowing operators to take corrective action in a timely manner to prevent or limit corrosion within the process. (Source: Teledyne)

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than 30 years old within the next decade, said Wollam, regional sales manager for Teledyne Cormon.

“Older infrastructure is at higher risk of corrosion damage, especially as operators face tighter budgets and are faced with tough choices such as extending the life of aging rigs, or reducing monitoring programs and personnel,” he added. “The simple fact of the matter is that as soon as a steel platform hits the saltwater it begins to corrode and therefore should be subject to monitoring, inspection and maintenance soon after deployment.”

The industry has typically used corrosion coupons with electrical resistance (ER) probes for monitoring. Ultrasonic inspections also have been used to measure wall thickness to determine corrosion and erosion rates in pipelines. Pigging is another common technique.

Improvements in the corrosion monitoring area continue.

Teledyne recently updated its data storage and transfer instrumentation for its ER probes to help determine metal loss caused by corrosion or erosion.

“Our transmitters now offer direct Modbus RS485 output straight from the transmitter without the need for any post processing or conversion. The updated transmitter is especially well paired with our CEION technology, which offers unrivalled response time and probe life,” Wollam said. “Often there is a tradeoff between these two aspects of ER probe monitoring; however, with CEION we combine both, giving the customer a very fast response time without the traditional concern of a short probe life.”

For real-time data acquisition, the technology can be combined with an online transmitter system.

Robotics is also playing a role in combating corrosion.

Companies are using AUVs and ROVs for close-up inspections of assets using lights, cameras and multi-beam sonar systems. “This application is gaining traction in the

offshore industry as a low-logistics method to collect data on structural integrity of pipelines or other equipment,” Wollam said.

But the advent of Big Data and machine learning could usher in another way of advances for corrosion monitoring.

While the measurement of metal loss, described by Wollam as the “principal benchmark of corrosion monitoring” is unchanged, technology has brought to the industry higher resolution measuring electronics that speeds up the detection of changes in measurements.

“The value of this faster detection lies in the ability to respond more quickly to increases in the metal loss rate, which can reduce the total metal lost, and thereby extend asset life,” Wollam added. “We now can see real-time changes in metal loss, enabling the operator to respond more quickly to issues that may arise or develop an optimized maintenance plan with greater confidence with the help of data to support and justify the plan.”

However, these same advances could pose obstacles. One challenge could lie in technology itself, specifically the ability to get large amounts of data quickly.

Wollam posed these questions:

- How do you manage, store and use all the data in a practical sense?
- What kind of IT infrastructure needs to be in place to handle all the data coming in?
- How can operators ensure the data give them actionable information?

“Without applications or analysis to transform the data into recommendations, alerts or reports, the data are essentially worthless regardless of the quality or size,” Wollam said. “The measurement technology has evolved, but our data management systems may be in need of upgrades as well.”

—Velda Addison

## DEVELOPMENT

### Reliance JV Revises Development Plan For KG Satellites

India’s Reliance Industries Ltd. (RIL) and its partners BP Group and Niko Resources are revising the development plan for satellite gas fields in the deepwater KG-DWN-98/3 (KG-D6) Block in the Bay of Bengal to integrate two new gas finds.

“We will submit the revised development plan for the discoveries in the satellite area by December-end,” an RIL official said.

The revised plan, the official said, involves developing four gas finds—D2, D6, D19 and D22—with D29 and D20 in the satellite area, located on the eastern side of the gas producing D1 and D3 fields in KG-D6 Block. The fields have water depths of more than 2,000 m (6,562 ft) in the Bay of Bengal.

The operator is preparing to develop the satellite area fields as a subsea tieback to the existing control and riser platform developed for the producing D1-D3 fields. The

plan envisages drilling up to 14 development wells and constructions of subsea structures and pipelines from the wells to the existing control and riser platform to transport the produced gas to the onshore processing terminal at Gadimoga. The deepwater project is expected to produce 15 million standard cubic meters per day (MMscm/d) of gas from 2020.

The revised development plan is expected to cost about \$2 billion.

The initial plan, approved by the regulator Directorate General of Hydrocarbons in 2012, had targeted development of four of the six satellite fields (D2, D6, D19 and D22) with an estimated investment of \$1.529 billion. It involved drilling eight development wells to a peak gas production level of 10.30 MMscm/d. However, the plan was put on hold due to the low gas prices.

The operator has discovered 11 prospects—D2, D4, D6, D7, D8, D16, D19, D22, D23, D29 and D30 in—the

satellite area. These are estimated to have exploitable gas reserves of about 51 Bcm (1.8 Tcf).

**Integrated Plan**

The satellite area development project is the second of three projects planned by the operator to increase gas production from the KG-D6 Block.

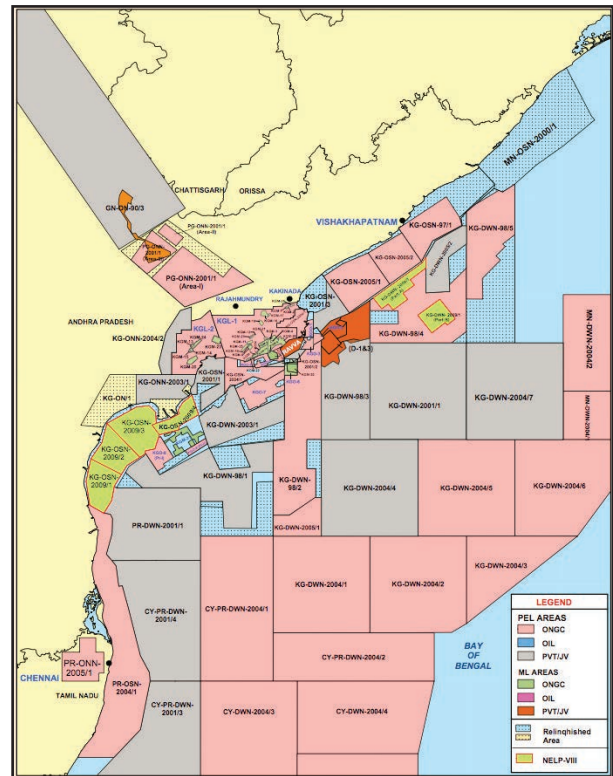
In July RIL launched preconstruction work for development of the R-Series gas field (D34) in the deepwater block. It involves drilling eight development wells in water depths of more than 2,000 m in the southern part of the producing D1-D3 area. The field will be developed as a subsea tieback to the existing control and riser platform at an estimated cost of \$3.1 billion with expected gas production of between 12 MMscm/d and 15 MMscm/d for 13 years, starting in 2020.

The third plan relates to the development of the ultradeepwater MJ Field (D55) located 2,000 m below the producing D1-D3 field, or about 4,000 m (13,123 ft) below the seabed. The official said the plan for the MJ Field would be finalized by mid-2018. BP Group CEO Bob Dudley said the three new deepwater projects will be developed in an integrated manner with a total investment of up to \$6 billion to monetize more than 85 Bcm (3 Tcf) of gas.

“As part of the early monetization of existing discovered resources in the KG D6 Block, efforts are underway to leverage the deflation in markets for optimizing capex for future development,” RIL said in a report to its shareholders recently. “The contracting process is underway for R-Cluster development with optionality for use in MJ and satellite development.”

**Falling Production**

The operator is pushing development of these projects in the wake of falling oil and gas production from the D1 and D3 (gas) and MA (oil) fields in the block. The two gas fields, which started production in April 2009, produce less than 4 MMscm/d, down from the peak output of 69.43 MMscm/d in March 2010. Several



(Source: Directorate General of Hydrocarbons)

wells were shut down recently due to the water and sand ingress.

The three new deepwater projects, according to the Dudley, are expected to bring in between 30 MMscm/d and 35 MMscm/d of additional gas during 2020-2022 in phases. The KG-D6 Block, which spans 7,645 sq km (2,952 sq miles) with a water depth ranging from 400 m to 2,700 m (1,312 ft to 8,858 ft), is estimated to have probable gas reserves in the range of 116 Bcm to 170 Bcm (4.1 Tcf to 6 Tcf).

Operator RIL owns 60% participating interest in the block, while BP and Niko Resources hold 30% and 10%, respectively.

—Ravi Prasad

**Woodside Makes Progress On LNG, Subsea Tieback Projects**

With Wheatstone LNG nearing first production, Greater Western Flank at the halfway point and Greater Enfield more than 25% complete, Woodside is checking off the boxes on its to-do list for major development projects underway.

Leading the list is the Wheatstone LNG project the company is developing with partner Chevron, the operator, PE Wheatstone and Kyushu. Wheatstone, which

develops the resources of the Wheatstone and Iago fields, is nearing commissioning with startup anticipated in mid-2017.

“At Wheatstone, the platform and pipeline are fully operational, and the final commissioning of LNG Train well 1 is well-advanced and nearing completion,” Woodside CEO Peter Coleman said on the company’s earnings call. “Of course, Chevron is leading, but we’ve had 25



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Woodside people embedded to aid the safe and reliable startup. And when fully operational, Wheatstone LNG is expected to contribute more than 13 million barrels of oil equivalent to Woodside's annual production."

The company provided an update on the projects during its half-year and second-quarter 2017 reports in August.

If all goes as planned LNG Train 2 will startup about six to eight months after LNG Train 1's startup.

As work continues at Wheatstone, the Woodside-operated Julimar Phase 2 development has moved into the concept definition phase, Woodside said in its half-year report. The four subsea-well project develops the resources of the Julimar and Brunello fields, which will connect to the Wheatstone offshore platform and supply gas to the Wheatstone onshore plant. The company anticipates making a final investment decision in 2019.

Meanwhile, Woodside is accelerating its North West Shelf subsea tiebacks, following the July startup of Persephone. The Persephone project, which was estimated to cost \$A1.2 billion in 2014, develops the Persephone Field via two subsea production wells and a manifold, which is connected to the North Rankin Complex platform by a 7-km (4-mile) 12-in. flexible flowline and control umbilical.

In addition, Woodside said the Greater Western Flank Phase 2 project—which develops the Keast, Dock-



Key milestones continue to be achieved on the Wheatstone Project with first LNG expected in mid-2017. (Source: Chevron Australia)

rell, Sculptor, Rankin, Lady Nora and Pemberton fields—is about 50% complete. Woodside is targeting first-half 2019 for startup.

"The reservoir drilling program continued at the Lady Nora Pemberton drill center with all top-hole drilling completed," Woodside said. "Well completion activities commenced as planned in July 2017, while the man-

ufacturing of subsea production equipment is ongoing and remains on track."

Woodside also reported the:

- Greater Enfield is 28% complete and is on schedule for first oil by mid-2019. "Detailed design is nearing completion and manufacturing of subsea and floating production storage and offloading (FPSO) facility topsides production equipment remains on schedule to carry out offshore and shipyard construction activities in 2018," the company said. "Production from the Ngujima-Yin FPSO will be suspended from Q2 2018 for approximately 12 months to enable shipyard modifications."
- The Browse joint venture and Woodside are also narrowing the alternative development concepts for the Browse LNG project. The proposed development concept involves two gas FPSO units. The partners anticipate selecting a development concept in second-half 2017 with FEED work starting in 2019.

—Velda Addison

## BP Cranks Up Juniper Offshore Trinidad and Tobago

BP is moving closer toward its goal of starting up seven major projects this year, with news Aug. 14 of two more projects—Juniper offshore Trinidad and Tobago as well as the Woodside-operated Persephone offshore Australia—coming online.

The latest startups mean BP has brought five of its seven major 2017 projects onstream.

"This year's projects will deliver a key part of the 800,000 barrels equivalent a day production from new projects that we expect by the end of the decade," BP Group CEO Bob Dudley said in a company statement. "Importantly, these new projects, with their lower development costs and higher margins, also further improve BP's resilience to the price environment."

Delivered on time and on budget, Juniper is BP's first subsea field development offshore Trinidad. The \$2 billion project, which produces gas from the Coralita and Lantana fields via the new Juniper platform, is expected to increase BP Trinidad and Tobago's (BPTT)

gas production capacity by about 590 million standard cubic feet a day (MMscf/d), the company said in a news release. Gas flows to the Mahogany B hub via a new 10-km (6-mile) flowline.

The Juniper startup comes about four months after BP began operating its Trinidad onshore compression project.

"Together they represent a significant portion of the new production capacity we expect to bring online in

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2017,” Bernard Looney, CEO of BP’s upstream unit, said in a separate news release.

The company’s operations in the area are expected to continue growing with development of the Angelin Field, which cleared the final investment decision hurdle in June. The development, which includes four wells and a production capacity of about 16.9 MMcm/d (600 MMcf/d) of gas, is slated to start production in 2019.

Further upside offshore Trinidad lies within two gas discoveries BP announced in June—the Savannah and Macadamia discoveries, which combined could unlock about 57 Bcm (2 Tcf) of gas.

The feats could help Trinidad and Tobago, a two-island Caribbean nation about 11 km (7 miles) offshore northeast Venezuela, reverse declining gas production. BP’s latest Statistical Review of World Energy shows gas production from the nation has fallen from 1.3 Bcm (44.8 Bcf) in 2010 to 1.1 Bcm (39.6 Bcf) in 2015. That’s

close to the amount of gas produced more than a decade ago—40.1 Bcf in 2006.

Juniper is operated by BPTT, which is jointly owned by BP (70%) and Repsol (30%).

Offshore Western Australia, BP holds a 16.67% interest in the Woodside-operated Persephone project. Other partners include BHP Billiton, Chevron, Japan Australia LNG and Shell. BP said the project is expected to have peak production of about 48 MMscf/d of gas net for BP.

The other two BP projects slated for startup in 2017 are the Eni-operated Zohr Field, which holds an estimated 849.5 Bcm (30 Tcf) of gas in place, and the Khazzan Phase 1 in Oman.

BP’s major project startups in first-half 2017 included West Nile Delta-Taurus/Libra in Egypt in March; Trinidad onshore compression in April; and the North Sea Quad 204 oil project, with the *Glen Lyon* FPSO vessel, in May.

—Velda Addison

## Israeli Exploration Group To Return Daniel Natural Gas Field Licenses

An Israeli exploration group said on Aug. 20 it would return its licenses to develop the Daniel natural gas field offshore Israel’s Mediterranean coast to the government, citing a number of factors including a lack of investors.

Returning the license to all rights to develop the fields could be a significant blow to Israel, which is seeking to become energy-independent and an exporter while developing competition in its existing gas sector. The group is led by partners Isramco Negev and Modiin Energy.

A resource report showed there could be an estimated total of 252 Bcm (8.9 Tcf) of natural gas at the Daniel East and West fields.

The group’s decision to give up its rights was based, among other things, “on assessments regarding the level of geological risk in the licenses, the difficulties expected in

commercializing the gas, if and when it is discovered, and the lack of interest by new investors,” Modiin Energy said in a news release.

The licenses expire in April 2018, seven years after they were granted and may not be extended, Modiin added in a statement to the Tel Aviv Stock Exchange. At the same time, the group does not have the resources to raise its portion.

Isramco holds 65% of the licenses while Modiin owns 15%. Isramco also has a stake in a nearby gas field of similar size called Tamar.

The government has been under pressure from regulators, lawmakers and the public to open the sector to competition. Up to now, the sector has been dominated by a partnership of Noble Energy and Delek Group, which controls both Tamar and the much larger Leviathan fields.

Tubular Bells  
First Oil  
November  
2014



Lucius First Oil  
January 2015





Jack/St. Malo  
First Oil  
December  
2014



## Three Successful Startups, One Common Denominator

Leader in Topsides Design

Experts estimate there are between 10,000 Bcm (353 Tcf) and 10,000 Bcm (353 Tcf) of gas in the eastern Mediterranean basin that includes Israel, Egypt and Cyprus,

enough to supply domestic needs as well as Europe, Energy Minister Yuval Steinitz said.

—Reuters

## DEVELOPMENT BRIEFS

### KBR Lands Work On BP, ADNOC Projects

BP has awarded KBR Inc. a pre-FEED and project support services contracts for development of the Tortue (Ahmeyim) Field offshore Mauritania and Senegal.

Under KBR's global services agreement with BP, the contract covers design of the subsea, pre-treatment FPSO facility, inshore hub/terminal and interfaces for floating LNG for the Tortue project, according to a news release. This work will build on the earlier concept phase work completed by KBR's subsidiary Granherne for BP's partner Kosmos Energy. The pre-FEED work is expected to be carried out over the next six months.

The contract award followed receipt of another contract—a project management consultancy contract from Occidental of Abu Dhabi Ltd. on behalf of Abu Dhabi National Oil Co. (ADNOC) to manage the FEED phase of the Dalma gas field development and the detailed design and surveys phase of the Hail and Ghasha Islands project at Abu Dhabi.

ADNOC is developing both of the fields offshore Abu Dhabi. Together, the Hail and Ghasha fields are one of the largest sour gas fields the company has undertaken. The project is forecast to produce about 28.3 MMcm/d (1 Bcf/d) of sour gas.

KBR said its work for the projects will be performed over 24 months. The contract, the value for which was not disclosed, has a 12-month extension option.

### Norway Clears ConocoPhillips To Start Dismantling Historic Ekofisk Platform

ConocoPhillips has won permission to prepare for the removal of the first permanent oil platform built offshore Norway more than 40 years ago, the country's industry regulator said.

The U.S. company applied in July to remove Ekofisk 2/4 A, which started producing oil from the North Sea in 1974 and shut permanently in 2013.

Production at the Ekofisk Field began in 1971 from the Gulftide jackup rig, a temporary installation standing on removable legs. Gulftide was replaced with production platforms permanently fixed to the seabed in 1974. Discovered in 1969, Ekofisk was the first oil field to begin production off Norway.

While the field's oldest installations are being removed, new equipment was put in place and production is ongoing, with the field expected to continue pumping oil toward 2050. The Norwegian Petroleum Safety Authority said it had granted consent for ConocoPhillips to prepare for the removal of 2/4 A and three other installations.



Norwegian authorities have given ConocoPhillips permission to prepare for the removal of 2/4 A and three other installations at the Ekofisk Field. (Source: ConocoPhillips)

With the exception of some smaller parts, the actual removal will depend on a later permit, it added.

ConocoPhillips plans to start preparations in fourth-quarter 2017. The removal plans also include two accommodation platforms, Ekofisk 2/4 H and Ekofisk 2/4 Q, and a riser platform called Ekofisk 2/4 FTP.

Dutch company Heerema was awarded the removal contract, and all four platforms will eventually be taken to AF Decom yard at Vats on Norway's western coast for dismantling and steel recycling, a spokesman for ConocoPhillips said.

Operator ConocoPhillips has a 35% stake in Ekofisk with Total (40%), Eni (12.4%), Statoil (8%) and Norwegian state-owned Petoro (5%).

### Cosmo Expects Abu Dhabi's Hail Oil Field Startup In October

Japan's Cosmo Energy Holdings said the Hail oil field offshore Abu Dhabi is set to start production in October. The startup has been slightly delayed from last year's projection of the end of June; however, the Hail oil field operated by Cosmo's joint venture (JV) is set to reach full output by the end of this year, company officials said.

Cosmo has an undisclosed stake in the field through its 63%-owned JV with other Japanese firms. The company declined to comment on production targets, but industry sources have said the field is likely to produce more than 20,000 bbl/d at its peak.

Cosmo, owned nearly 21% by Abu Dhabi's state-owned investment vehicle, expects Hail project to contribute about 20% of this business year's projected \$238 million profit from upstream business, Senior Executive Officer Kenichi Taki told reporters during the first-quarter earnings conference.

## Bumi Armada Seals EPCI Deal With Lukoil In Caspian Sea

Malaysian player Bumi Armada's wholly owned subsidiary Bumi Armada Caspian has signed a supplementary agreement with Russia's Lukoil-Nizhnevolzhskneft for more engineering, procurement, construction and installation work in the Caspian Sea.

The additional scope will involve two of Bumi Armada's subsea construction vessels laying subsea pipelines and undertake post trenching and back-filling works on sections of the Filanovsky Field in the Russian sector of the Caspian Sea.

The company plans to use its *Armada Installer* and *Armada Constructor* vessels for the job, which is expected to be finished in second-half 2018. The contract is valued at \$134 million.

## Kvaerner Wins Subsea Compression Pilot Decommissioning Contract

Kvaerner has landed a contract with A/S Norske Shell to dispose and demolish the Subsea Compression Pilot at Nyhamna plant, according to a news release.



(Source: Kvaerner)

The scope of work consists of removal and demolition of about 2,200 tonnes of modules, which Kvaerner said will be transported from Nyhamna to its facilities at Stord for dismantling and recycling. The work was scheduled

to begin immediately with the first part of the project—removal of modules from the test pit—to be completed this year. The rest of the modules will be removed in 2018, the company said.

Currently, Kvaerner serves as the main contractor for Nyhamna plant expansion project. The company also pointed out that it was the main contractor when the first part of the plant was built in 2007.

## BOEM Publishes Draft EIS For Liberty Oil, Gas Project In Beaufort Sea

The U.S. Bureau of Ocean Energy Management (BOEM) has published the draft Environmental Impact Statement (EIS) for Hilcorp Alaska's proposed Liberty offshore oil and gas development and production plan in the Beaufort Sea.

Similar to artificial islands where oil and gas are produced in nearby state waters, Hilcorp proposes to build a small artificial gravel island in 6 m (19 ft) of federal water in the Beaufort Sea, about 32 km (20 miles) east of Prudhoe Bay, on a nine-acre site.

The company plans to install a pipe-in-pipe subsea pipeline to deliver oil to shore. The offshore portion of the pipeline will be laid in a trench, and then buried, BOEM said in a news release. Onshore the pipeline would connect with the Badami pipeline, which connects with the existing oil and gas infrastructure at Prudhoe Bay.

Hilcorp's offshore pipeline will have automatic leak-detection and temperature-monitoring technology, according to BOEM. The company also has committed to minimize disruption to subsistence activities, including whaling.

The EIS, which analyzes the possible environmental impacts of the activities of the proposed development, is open for public comment through Nov. 18. The draft EIS and instructions for commenting may be found at [boem.gov/liberty](http://boem.gov/liberty).

—Staff & Reuters Reports

## EXPLORATION

### US GoM Lease Sale Brings In \$121 Million In High Bids

Oil and gas companies shelled out about \$121 million in high bids for blocks in the U.S. Gulf of Mexico (GoM), mostly targeting the Lower Tertiary trend, in the country's first gulf-wide lease sale since 1983.

The results, deemed a success by the U.S. Bureau of Ocean Energy Management (BOEM) officials despite bringing in less than half that of the March 22 lease sale that covered less territory, showed offshore interest still remains. Lower commodity prices, which cut deep into profit potential, have prompted many to reduce spending and seek more efficient ways of generating value. For some GoM producers, this has meant maximizing use of existing infrastructure with use of subsea tiebacks.

Statistics from the Aug. 16 sale—Lease Sale 249—show



(Source: Shutterstock.com)

that 27 companies participated and submitted 99 bids on 90 tracts. More than 84% of the blocks attracting bids were in water depths of 800 m (2,625 ft) or more. The

last GoM lease sale, which only included blocks in the central GoM region, attracted 28 companies that submitted 189 bids on 163 blocks in March. High bids for the March lease sale was nearly \$275 million.

“While the results of today’s Gulf of Mexico oil and gas lease sale reflect market realities, they also demonstrate the offshore oil and gas industry’s commitment to the U.S. Gulf of Mexico, even with extended low commodity prices and lingering regulatory dysfunction,” Randall Luthi, president of the National Ocean Industries Association, said in a statement following the sale.

Based on preliminary results released by BOEM, companies’ appetites for blocks in the Alaminos Canyon, East Breaks, Garden Banks, Keathley Canyon and Mississippi Canyon were the greatest, with each area receiving at least two bids. But it was Garden Banks 1003—located in a water depth between 800 m and 1,600 m (2,624 ft and 5,249 ft)—that fetched the most with Total E&P USA bidding \$12.1 million.

Total E&P is working with Cobalt International in the Garden Banks area to develop the deepwater North Platte discovery. Total has a 40% working interest in North Platte, while operator Cobalt holds the rest. Earlier this year, the North Platte #4 Sidetrack 2 hit about 122 m (400 ft) of high-quality Lower Wilcox oil pay and a subsequent bypass for core operation adjacent to the sidetrack led to the recovery of about 61 m (200 ft) of Lower Wilcox conventional core.

The discovery, which is adjacent to Garden Banks 1003, is being marketed.

The second and third single highest bids came from ExxonMobil Corp., which pledged \$10.8 million and \$5.7 million for two Mississippi Canyon blocks. Both blocks have water depths of more than 1,600 m.

“It’s a continued show of the strength of deep water,” Mike Celata, director of BOEM’s GoM region, said during a media call following the sale. He pointed out that 76 of the 90 blocks receiving bids had water depths greater than 800 m. “It’s a continued investment in the gulf looking at the Lower Tertiary and Miocene trends.”

Wood Mackenzie analyst William Turner saw the results as a deepwater win.

“Deepwater (400-plus m [1,312 ft] depth) blocks won the day [Aug. 16], with 76 blocks receiving 98%

of high bid value at \$118 million. The deepwater industry is emphasizing short-cycle, low-risk prospects above high-impact, wildcat drilling,” Turner said. “Today we saw operators continue to focus on areas near existing infrastructure with a majority of bids close to existing hubs or appraised developments.”

Besides North Platte, bids made were also near Chevron’s Guadalupe development in Keathley Canyon. At about \$27.9 million Chevron topped the leaderboard in the sum of high bids submitted.

“Bids from Chevron, Shell and Total near pre-FID [final investment decision] discoveries, Guadalupe and North Platte, were a vote of confidence in higher-risk, standalone developments with potential for higher rewards,” Turner added.

The Aug. 16 lease sale marked the first offshore sale under the new Outer Continental Shelf Oil and Gas Leasing Program for 2017–2022, which was approved during the Obama administration, and the first under the Trump administration.

During the next 90 days, bids submitted will be evaluated for fair market value and awards will be posted as they are completed on BOEM’s website. The gulf-wide sale offered about 13,725 blocks ranging from three to 230 miles offshore in the GoM’s western, central and eastern planning areas in water depths ranging from 3 m to more than 3,400 m (9 ft to more than 11,115 ft).

“I characterize this as a very successful sale. We made \$121 million, and last August for Lease Sale 248 we made \$18 million,” Katharine MacGregor, assistant secretary for Lands and Minerals Management, said during the media call. “There is something to be said about having a gulf-wide sale that offers more acreage for competitive leasing.”

Lease Sale 248 offered blocks in the western GoM—an area that traditionally sees fewer blocks on offer and generates fewer bids compared to central GoM lease sales.

MacGregor later referred to the March sale, saying “Coming right on the heels of a central gulf sale, there’s a lot to be said for companies accumulating capital to bid again on area-wide leasing. ... It proves opening more acreage gives folks a lot more options when it comes to investing in offshore leases.”

—Velda Addison

## Gas Discovery Brightens Exploration Scene In Southeast Asia

The Southeast Asian exploration scene was buoyed recently with a new discovery, while there was also plenty of hustle on the licensing front.

Australia’s Woodside has hit gas with the Pyi Thit-1 exploration well in Block A-6 in the southern Rakhine Basin offshore Myanmar.

The well intersected a gross gas column of about 65 m (213 ft). A net gas pay interval of about 36 m (118 ft) has been interpreted within the primary target sandstone reservoir.

“The Pyi Thit-1 discovery is another success in an underexplored region,” said Woodside’s CEO Peter Coleman. “This result builds on our understanding of the potential resources in the southern Rakhine Basin and will further inform our consideration of development options.”

The Pyi Thit-1 well was spudded on June 10 and drilled to a total depth of 4,570 m (14,994 ft). Wireline logging was conducted and confirmed the presence of a gas column through pressure measurements and gas sampling.



A drillstem test was subsequently performed across a 29-m (95-ft) section of the reservoir and flowed at about 1.42 MMcm/d (50 MMcf/d) on a 44/64-in. choke over 44 hours with strong reservoir pressure support.

Woodside operates Block A-6 with a 40% stake, while MPRL E&P holds 20% and Total has 40%.

Woodside has had other success in the area with the Shwe Yee Htun-1 well in Block A-6 (January 2016) and the Thalín-1A well in Block AD-7 (February 2016).

### Nido's Philippines Extension

Nido Petroleum has been given approval to extend the suspension on activities on Service Contract 54A (SC 54A) offshore the Philippines.

Block A in SC 54A lies in shallow waters offshore Palawan and holds the undeveloped Yakal and Tindalo oil fields. Nido, as the operator of the SC 54A joint venture, unsuccessfully tried to develop the Tindalo Field in 2010; the project was abandoned in 2011 because it was not considered commercial at that time.

In third-quarter 2014, Nido was granted a three-year moratorium for SC 54A. The moratorium period extended from Aug. 5, 2014, to Aug. 5, 2017, to allow for sufficient time to study the sub-commercial areas and other areas of interest within the licenses and to review commercialization options.

The moratorium deadline has now passed; however, Hague and London Oil (HALO), a 15% partner in SC 54A, said it had been informed by operator that the approval has been received from the Philippines Department of Energy for a further three-year suspension to the license exploration period.

HALO noted that the extension has been approved as a result of force majeure regarding the West Philippines Sea dispute, a territorial dispute in the South China Sea, which is the subject of international arbitration.

The suspension now runs until Aug. 5, 2020, unless the dispute is settled before that time. No activity beyond care and maintenance is expected on the license for the foreseeable future, HALO said.

—Steve Hamlen

## EXPLORATION BRIEFS

### Petrobras Makes Presalt Oil Find In Marlim Sul Field

Petrobras said the company has made its first commercial oil discovery in the Marlim Sul Field's presalt area in the Campos Basin.

Located about 115 km (71 miles) offshore Brazil's Rio de Janeiro state, the Poraquê Alto well was drilled to a final depth of 4,568 m (14,987 ft) with a water depth of 1,107 m (3,632 ft), Petrobras said in a news release.

"The discovery was confirmed by profile data, gas detector, formation testing by cable and fluid samples," the release said. "Analysis of current data indicates carbonate reservoirs of good porosity and permeability features at 4,420 m [14,501 ft] depth and 45 m [148 ft] thick with oil presence."

### ION Adds To 2-D Data Library With Acquisition Offshore Panama

ION Geophysical Corp. has undertaken a new 2-D multi-client acquisition program offshore Panama, marking the area's first seismic survey acquired in about 30 years, the company said in a news release.

The PanamaSPAN, which is supported by industry funding, aims to evaluate the hydrocarbon potential in unexplored areas offshore Panama as the country's inaugural license round approaches.

"Hydrocarbon exploration in Panama has identified various sedimentary basins, proving the existence of geological structures that may contain oil and gas, although there hasn't been a commercially exploitable discovery," Panama's Energy Secretary Víctor Urrutia said in the release. "Today, through the use of new and more sophisticated techniques, it is possible to identify prospective areas that previously were

not considered economically viable such as deepwater deposits and/or those that are geologically more difficult to locate."

ION said initial deliverables will be available in fourth-quarter 2017 with complete interpretation of the data available by mid-2018.

### Philippines Says China Agrees On No New Expansion In South China Sea

China has assured the Philippines it will not occupy new features or territory in the South China Sea, under a new "status quo" brokered by Manila as both sides try to strengthen their relations, the Philippine defense minister said.

Philippine Foreign Secretary Alan Peter Cayetano also said the Philippines was working on a "commercial deal" with China to explore and exploit oil and gas resources in disputed areas of the South China Sea with an aim to begin drilling within a year.

The defense minister, Delfin Lorenzana, told a congressional hearing the Philippines and China had reached a "modus vivendi" or a way to get along, in the South China Sea that prohibits new occupation of islands.

"The Chinese will not occupy new features in the South China Sea nor they are going to build structures in Scarborough Shoal," Lorenzana told lawmakers, referring to a prime fishing ground close to the Philippines that China blockaded from 2012 to 2016.

China claims almost the entire South China Sea, a waterway through which about \$3 trillion worth of sea-borne trade passes every year. Brunei, Malaysia, the Philippines, Taiwan and Vietnam also have conflicting claims in the area.

## Erin Energy Spuds Oyo-9 Well Offshore Nigeria

Erin Energy Corp. said it has begun drilling the Oyo-9 well offshore Nigeria using the *Pacific Bora* sixth-generation drilling rig.

The company plans to spend about 62 days to drill and complete the well, which will be tied to the FPSO unit for production that is expected to begin in fourth-quarter 2017.

Erin said it expects to add 6,000 bbl/d to 7,000 bbl/d to the Oyo Field's current production.

## Tullow Launches Oil, Gas Exploration In Zambia

Tullow Oil has started exploring for oil and gas in Zambia, Africa's No.2 copper producer, as the country pushes to diversify its economy and reduce its reliance on the industrial metal.

Copper mining earns Zambia more than 70% of its foreign exchange but the southern African state has been trying to move into other commodities to insulate itself from price shocks.

Zambia does not produce oil, but the government said soil samples sent to European laboratories have shown good traces of crude.

Tullow Executive Vice President Ian Cloke said in a speech during the launch in northern Zambia that exploration would take between two and 10 years, development three to 10 years and production in 20 to 50 years.

"We are exploring over a large area that includes Northern and Luapula provinces," Cloke said, referring to regions in the north of Zambia. "With Tullow's exploration credentials, I can confidently say that if there is any oil to be found in this area of Zambia, Tullow will find it."

—Reuters & Staff Reports

## TECHNOLOGY

### Inspection Teams Aim To Stem Unseen Containment Risk Offshore

Impact due to loss of containment on offshore production assets through degradation of minor infrastructure is a growing concern for operators looking to extend the life of their assets.

Such infrastructure includes small-bore tubing (SBT), in many cases installed decades ago, which has until now largely gone without the level of exhaustive inspection, maintenance and/or replacement investment afforded to larger engineering infrastructure.

This is a cause for concern since continued production from aged assets invariably means sweating of assets connected to mature wells and further recovery via older infrastructure. With many assets dating from the 1970s and 1980s, which are far beyond their original design life, this could in itself contribute to the potential for hydrocarbon release.

Hydrocarbon releases originating from SBT failures have been a focus for industry regulators and all North Sea operators, and much has been done to reduce the number of minor/significant hydrocarbon releases. Failures to date have primarily been gas- or diesel-system-related and, while limited in scale—the largest reported being around 1 tonne of produced gas—in a zero-incident-target environment, any unmitigated risk is unacceptable.

Major hydrocarbon releases are still unpredictable. Depending on the size and pressure, an SBT system failure could lead to a major classification hydrocarbon release. Additionally, pressurized containment loss poses a significant risk of injury since the force of a fluid escape from degraded SBT could propel objects that then strike personnel, though incidences of this are comparably low.



CAN Group's in-house training program includes general and close visual inspection. (Source: CAN Group)

### Handling The Problem

To address SBT integrity, the U.K.'s Health and Safety Executive (HSE) has introduced new requirements which, if properly applied, will help eliminate the risk inherent in mature assets worldwide, protect the integrity of new assets as they age and enhance process safety.

Generally, asset integrity is the focus for inspection works. However, this is not necessarily defined as the primary means to ensure that process safety is achieved. Process safety is in turn crucial to maintaining operational integrity—protecting people, the environment and long-term production status of the asset as a consequence.

In many cases, operators—particularly those acquiring aged assets—might find that the standard of SBT is not

what they expected. Finding losses of containment or identifying potential weaknesses involves a mass of permutations, with multiple root causes requiring evaluation after initial inspection and analysis has been carried out.

The age of some components and the widespread issue of SBT having been improperly installed to the specific standard required are key causes in exterior degradation, with a number of environmental corrosion mechanisms then taking hold. In the 1970s when a significant volume of SBT was installed, stainless steel was meant to last forever. However, it is starting to fail and at a rate higher than expected from more modern construction materials.

Identifying the risk, managing the spread of potentially containment-compromising corrosion, reducing the number of hydrocarbon releases and ensuring that the HSE's requirements are being met is the absolute focus for operators, inspectors and maintenance providers. This requires a management system specifically targeted to the inspection and maintenance of SBT.

### Integrity Management

The HSE has called for an asset registry of all SBT assemblies to be maintained, with likely failure mechanisms being identified and assessed.

At present, the strategy used is generally "find and report." This strategy should change to allow the problem to be arrested and where possible fixed since there are limitations on what can be fixed, so this must be carefully considered.

Most SBT inspection is carried out "hands-off." There is no physical intervention of any kind due to the risk that high pressures within the tubing could result in a fracture and cause a leak. All hands-on work in a high-pressure scenario needs to be carried out on a depressurized line. However, that isn't necessarily confined to a shutdown.

### Tablet Reporting

CAN Group is introducing tablet reporting designed to significantly improve the speed, quality and accessibility of data collation being achieved during SBT inspection.

Tablet reporting, which has moved forward rapidly through the availability of Zone 1-approved devices in production environments, enables real-time data transfer, allowing faster detection and notification of potential weaknesses. It also streamlines the reporting process, enhancing productivity and efficiency and allowing technicians more time to conduct actual inspections—ultimately providing the cost savings sought in the continued low oil price environment.

With regard to competence, the HSE has stated that installation operators and duty holders must have arrangements in place to ensure personnel required to work with SBT are competent where, at present, no standard exists for inspection workscopes.

It also lists a program of SBT inspection as a requirement for scheduling on the basis of risk using visual methods combined with gauge checks for joint tightness, with



Tablet reporting enables real-time data transfer, allowing faster detection and notification of potential weaknesses. (Source: CAN Group)

a follow-up intrusive inspection or maintenance campaign where faults are identified or suspected. The initial focus is to ensure technicians have SBT inspection competence.

### SBT Competence

CAN Group has developed the industry's first route to achieving competence specifically designed for SBT inspection through the delivery of a comprehensive in-house training program, which is delivered to the company's experienced inspection and maintenance personnel.

It includes general and close visual inspection, options for remedial action in terms of replacing weaknesses in the system and replacement of minor components using Energy Institute-approved methods.

The accepted route to competence involves maintenance contractors gaining industry certification for SBT installation. This program works well for installation workscopes; however, it does not cover in-service SBT inspection, which is necessary to ensure safe operation of SBT is maintained.

CAN's SBT inspector competence is supported with certification in visual inspection. This course is CSWIP-endorsed and delivered. CSWIP is the internationally recognized certification arm of The Welding Institute.

The holistic approach brings together services from three of the company's business streams. The initial inspection is delivered by qualified technicians who have completed CAN's SBT-specific training program.

ENGTEQ, the company's integrity management and engineering business stream, will then provide corrosion management and engineering guidance for the appropriate replacement of old systems determined by the asset's life cycle.

CAN's trades business stream would then carry out any required maintenance, repairs or replacement of affected

infrastructure, including managing common failure points such as SBT clamps.

Additionally, since CAN is a rope access contractor, all field personnel are rope access-qualified, enabling CAN to carry out SBT inspection and maintenance in difficult-to-access locations safely and efficiently.

The industry needs to assure all stakeholders that the inspection approach is applied appropriately and that its efficiency and efficacy move forward to meet the technological achievements seen in other engineering disciplines to allow remedial action in line with the Energy Insti-

tute's guidelines for SBT to be taken expediently and not wait another 30-plus years before collectively addressing the elephant in the room.

To meet the HSE's requirements, operators and the supply chain will need to agree on supporting action that will significantly increase the attention given to SBT, investment in training and technology used to improve inspection and mitigation works, all of which will reduce the risk of an escalating problem within the upstream and downstream sectors.

—*Aaron Kinney, Small Bore Tubing Technical Authority, CAN Group*

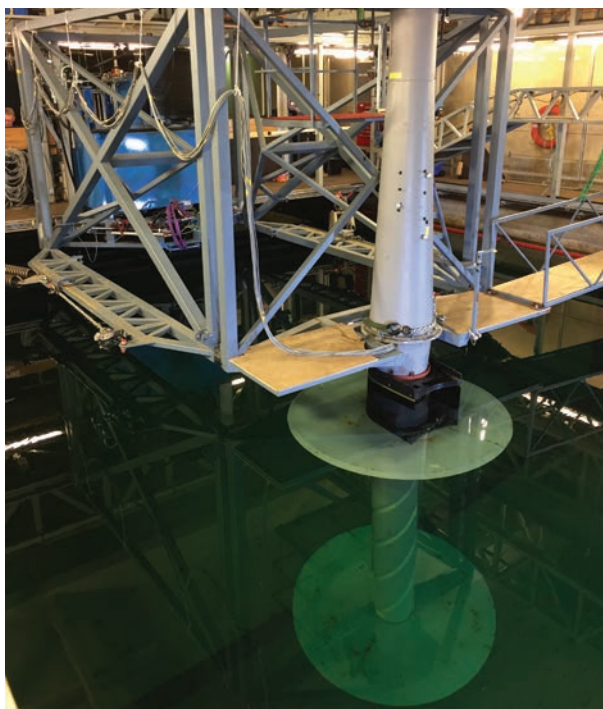
## TECHNOLOGY BRIEFS

### Buoyancy Design Eliminates VIV In High Currents, Minimizes Drag

A major milestone was successfully completed under the joint development agreement between Diamond Offshore Inc. and Trelleborg, which focuses on creation of a helically grooved buoyancy design with enhanced performance for drilling riser operations in high current conditions.

Test results revealed that when using the patented design vortex induced vibration (VIV) is effectively eliminated in high currents, with the added bonus that drag loading on the riser is also reduced to a level comparable with fairings, a press release stated. In June tow tank testing on the helically grooved design was performed in Trondheim, Norway. The extensive test program provided valuable hydrodynamic data confirming the design's drag reduction and VIV suppression performance.

Fixed and dynamic drag coefficients of the new design were recorded during separate fixed and free vibration tow testing. Drag coefficients at an average of 0.65 were observed for relevant flow regimes, which is compara-



ble to the performance of riser fairings. This is achieved through the highly successful VIV suppression of the design, effectively eliminating VIV response and subsequent drag amplification in the high excitation response range of offshore drilling risers. Forced motion testing of the helically grooved design was also performed to better understand excitation of the riser under high current conditions and for the development of lift coefficient data for use in analytical fatigue damage prediction programs.

The helical drag reduction and VIV suppression performance shows strong independence of current speed, which is consistent with the behavior of an external helical strake. However, the underlying flow physics causing the suppression are quite different, leading to the suitability of the helically grooved design for large diameter drill riser buoyancy.

### Software Enables Data-driven Decisions To Improve Certainty

Baker Hughes, a GE company (BHGE), has released its CIRCA coiled tubing (CT) simulation software, which enables CT service providers to maximize equipment performance and improve operational efficiency in well interventions, a press release stated.

Based on learnings from the field and built and refined over three decades, the software allows CT providers and operators to build better job models for more predictable results. Operational guidelines for CT applications are typically based on experience rather than on hard data. Applying these methods in today's more complex wells—particularly in unconventional wells with longer laterals and numerous stages—can compromise job performance and even damage downhole equipment.

Historically, CT simulation software has lacked real-world feedback and adequate support, producing inferior models that fail to adequately identify risks, espe-

Tow tank testing on the patented helically grooved design was performed at SINTEF Ocean's Tow Tank facility in Trondheim, Norway. The joint facility, under SINTEF and the Norwegian University of Science and Technology, tested the buoyancy design in the supercritical flow regime representative of offshore current conditions. (Source: Trelleborg)

cially in complex environments, the company said. The CIRCA software suite validates theoretical models with empirical data from the field to help CT providers move from experience-dependent operations to data-driven execution. The software delivers valuable insights into the subsurface, such as downhole conditions, flow rates and safe operating envelopes, enabling operators to calculate outcomes with more certainty to improve job planning and execution.

### **DNV GL Creates Remote Surveillance For Subsea Equipment Manufacturing**

DNV GL developed a solution for remote surveillance

service for subsea equipment manufacturing, a press release stated. The primary goal of this new alternative was based on cost savings; improved safety for surveyors; increased flexibility on testing schedules; availability of experts; and transparency for all stakeholders. Remote witnessing equips technicians with hardware and software that provide remote support or, depending on the type of test and its critical points, a standalone camera system that can be installed to increase savings and flexibility. At the local office, a DNV GL surveyor is connected to the technician delivering technical expertise in a timely manner.

—*Staff Reports*

## **FLOATERS**

### **Brazil Leads Opportunities For FPSO Industry**

RIO DE JANEIRO—With the necessity of the development of ultradeepwater projects located in the presalt layer, many FPSO unit building companies eye Brazil as a good opportunity to ensure new contracts. In fact, Brazil plays an important role within this scenario that still faces uncertainties around the world where dozens of offshore vessels remain idle, according to Energy Maritime Associates.

“We are very excited about great opportunities offered in the country. We are certain that we could contribute to the development,” said SBM Offshore Brasil CEO Oliver Kassam. “Brazil’s offshore segment has been constantly evolving, and we have made a great effort to adapt and grow together with the country, building a solid partnership and relationships that will last for many decades.”

SBM Offshore operates eight FPSO units along the Brazilian coast.

In August SBM Offshore opened a new office in Rio de Janeiro to be closer to the upcoming bids to be launched by Petrobras over the next three years.

The Brazilian state-owned oil giant has four FPSO units scheduled to produce first oil in 2017, followed by five in 2018 and another two in 2019. Also, Petrobras, which is still working to overcome its worst crisis, has been assembling the modules for FPSO units to be operated in the presalt.

This year floater operators are submitting bids for three FPSO tenders launched by the Brazil oil major. The floaters will be designed to be operated in Libra, S epia and B uzios. All of those oil fields are located in Santos basin.

Amid controversy over Brazil’s local content rules, the highly disputed FPSO tender, also known as Libra Phase II, has been delayed several times by Petrobras. Yet, although it has not been officially announced, local sources said the contract will be awarded to the Japanese operator Modec, beating competitors such as SBM Offshore and BW Offshore.

According to the contract, the winning floater company may choose to build a new unit or convert an existing hull. The Libra phase II FPSO charter agreement will last 22 years.

The unit will have the capacity to produce 180,000 boe/d and process 12 MMcm (423 MMcf) of gas and Libra Phase II’s first oil is scheduled to be produced in 2022.

After contracting the second unit, the Libra consortium plans to return to the market in late 2018 to charter a new FPSO unit for Phase III.

The prolific Buzios Field also poses nice business opportunities for floater companies. In July Petrobras launched tender for its fifth FPSO unit to be deployed in that field where the state-owned oil company holds a 100% stake.

According to Petrobras’ press office, commercial proposals are scheduled to be received by Sept. 15. The FPSO unit will be designed to have the capacity to produce 180,000 bbl/d of oil and 6 MMcm/d (212 MMcf/d) of natural gas.

The shipbuilding scenario in Brazil does not only show a favorable outlook for floater companies but also for their suppliers.

Petrobras has recently announced that the company intends to acquire another FPSO unit to revitalize production at the aging Marlim Field in the Campos Basin. The floater is scheduled to begin production in 2020—the first of two forthcoming units designed.

Besides launching tenders for acquiring FPSO units, Petrobras is carrying out activities in some Brazilian shipyards. The FPSO units *P-69*, *P-74*, *P-75*, *P-76* and *P-77* are scheduled to enter operation by first-quarter 2019.

EBR is presently performing integration of the *P-74* at its shipyard in Sao Jose do Norte in the state of Rio Grande do Sul.

A consortium formed by TechnipFMC and Techint is in charge of integration work on the *P-76* at the Pontal do Parana shipyard.

The QGI consortium will carry out the integration of the *P-75* and *P-77* later at the Honorio Bicalho shipyard, but the bulk of the work is being done in China by Cosco Shipyard, which is responsible for the fabrication of most topsides modules.

—*Brunno Braga*

## Australia's \$180 Billion LNG Megaproject Boom Enters Final Stretch

MELBOURNE—The last massive component of Australia's \$180 billion LNG construction boom arrived on Aug. 14, stepping up a race between Anglo-Dutch giant Shell and Japan's Inpex to start chilling gas for export in 2018.

Company reputations are at stake, as well as first access to overlapping gas fields and Australia leapfrogging Qatar as the world's largest exporter of LNG.

The *Ichthys Venturer*, an FPSO facility, traveled 5,600 km (3,500 miles) from a South Korean shipyard and will be moored 220 km (137 miles) off Western Australia to handle condensate from the Ichthys Field.

Japan's top oil and gas explorer, Inpex Corp., is running Ichthys, both the country's biggest overseas investment and first LNG megaproject.

"This project is a huge source of pride for Japan and an important addition to ... energy supplies," said Tom O'Sullivan, head of energy consultancy Mathyos Japan.

"All eyes are on Inpex to see if they can pull this off without any more budget blowouts and delays," he said.

First production, due by March 2018, will be more than a year behind target. Costs have ballooned more than 10% to \$37 billion since the project's approval in 2012.

Nearby, Royal Dutch Shell's \$12.6 billion *Prelude* project—the world's largest floating LNG (FLNG) facility—is also behind schedule. Shell lost out on becoming the first producer of FLNG when Malaysia's Petronas started up a smaller FLNG facility this year.

Shell's facility, six times the size of the biggest aircraft carriers, with a deck longer than four soccer fields, arrived last month.

Shell expects hookup and commissioning to take up to 12 months, meaning startup between April and July 2018.

Whichever project starts first will pump gas away from the other's field as the two straddle the same reservoirs. The race means more to *Prelude* than *Ichthys*, as *Prelude* is smaller, said Wood Mackenzie analyst Saul Kavonic.

Inpex also has an each-way bet: It owns 17.5% of *Prelude* as well as 62.2% of *Ichthys*.

Stumbles and contract disputes are normal for megaprojects. Chevron Corp. had numerous problems with its \$54 billion Gorgon project in Western Australia when it started in 2016.

Ichthys's contractors are mired in claims from two major engineering firms, although Inpex has said those disputes won't slow the project.

*Prelude* and *Ichthys* also might see delays during the tropical cyclone season from November through April.

Wood Mackenzie expects a relatively long commissioning for *Prelude* due to its large scale and new technology but sees Shell's long experience on LNG projects as an advantage.

"Experience really matters during the commissioning process, which is one of the most challenging parts," Kavonic said.

Inpex and Shell declined interview requests for this story.

—Reuters

### FLOATER BRIEFS

#### Kosmos Awards Atwood Subsidiary Contract For Ultradeepwater Rig

Offshore drilling contractor Atwood Oceanics has extended its drilling operations for Kosmos Energy with a contract for the Atwood Achiever ultradeepwater rig.

Atwood said one of its subsidiaries agreed to a one-well contract with Kosmos for operations offshore Northwest Africa. The day rate for the drillship was not disclosed.

Plans are for the new contract to begin after the completion of a well in progress under the existing contract, Atwood said in the release.

The new contract includes six one-well priced options. If no options are exercised, the rig would become available again in March 2018, the company said. However, the next availability date extends to about December 2018 if all six options are exercised.

#### Golar LNG Acquires Interest In FLNG Hilli Epeseyo

Golar LNG Partners LP in mid-August said it would purchase equity interests in Golar Hilli LLC and indirectly own the floating LNG *Hilli Epeseyo*.

The \$658 million agreement was struck with Golar LNG Ltd. and affiliates of Keppel Shipyard Ltd. and Black and Veatch. The acquired interests will represent 50% of two liquefaction trains—part of an eight-year contract to Perenco Cameroon SA and Societe Nationale Des Hydrocarbures. The deal is less net lease obligations under the financing facility for the Hilli that are expected to be between \$468 million and \$480 million.

Along with execution of the agreement, the partnership paid \$70 million to Golar, upon which it will receive annual interest of 5%.

#### Fortuna Floating LNG Offtake Contract Goes To Gunvor

Gunvor Group Ltd. has been named the preferred LNG buyer for the Fortuna FLNG project offshore Equatorial Guinea.

Gunvor has committed to take the full-contract capacity of the *Gandria* FLNG vessel's 2.2 mmtpa, which will be purchased on a Brent-linked, Free on Board basis for a 10-year term. The contract structure allows flexibility for up to 1.1 mmtpa of the Fortuna capacity to be marketed

on an alternate basis. The agreement gives the Fortuna partners the potential to sell volumes to higher-priced gas markets in Africa and elsewhere while retaining a share in the profits.

The final investment decision remains on track for 2017 for Fortuna and project funding is the last major milestone.

“The selection of Gunvor sets a landmark moment in the development of the Fortuna Project,” Gabriel Mbaga Obiang Lima, minister of mines and hydrocarbons for

the Republic of Equatorial Guinea, said in a statement. “The partnership with Gunvor also paves the way for the government’s objective to deliver important projects that monetize our gas, promotes local content and brings world-class petroleum technology to Equatorial Guinea. The Fortuna Project will target becoming the first choice supplier of LNG for the LNG to Africa initiative, furthering Equatorial Guinea’s leadership position in Africa as an LNG exporter.”

—*Staff Reports*

## VESSEL BRIEFS

### M<sup>2</sup> Subsea Secures Vessel Alliance In Gulf Of Mexico

Global independent ROV services provider M<sup>2</sup> Subsea Ltd. has partnered with vessel operator Harvey Gulf International Marine to provide subsea ROV services in the Gulf of Mexico.



Mike Arnold, CEO of M2 Subsea Ltd. (Source: M2 Subsea Ltd.)

*Harvey Bronco*, Harvey Gulf’s survey support vessel, will utilize M<sup>2</sup> Subsea’s ROVs and will focus on the survey and inspection market. It will also be used for light intervention activities.

M<sup>2</sup> Subsea will equip the *Harvey Bronco* with the 150-hp Triton XLX34 ROV system to assist with offshore heavy-duty work. The Triton is rated to 3,000-m (9,842.5-ft) depth. The system has a tether management system, a survey junction box and auxiliary hydraulics.

*Harvey Bronco* will port at Harvey’s Gulf’s Operation Yard in Port Fourchon, La. The deployment in August will conduct an underwater inspection in lieu of dry-docking project.

M<sup>2</sup> Subsea focused on reducing costs and risks to meet the demands of the low oil price environment.

### Topaz Lines Up Work For Vessels Offshore Turkmenistan

United Arab Emirates-based Topaz Energy and Marine has bagged deals worth \$100 million from Dragon Oil to supply six vessels for work on the Cheleken Area in the Turkmenistan sector of the Caspian Sea.

Under the five-year agreement, Topaz will supply five anchor handling tug and supply vessels and one emergency response and rescue vessel.

“This is a critical contract win for Topaz. It not only increases our revenue backlog above \$1.5 billion—the highest in the industry—but it also demonstrates the trust that Dragon Oil has placed in our ability to deliver the technology and safety capabilities our clients increasingly require,” said Topaz CEO René Kofod-Olsen. “Our solid funding also means that we are able to structure long-term commercial terms which offer predictability and value to our clients at very low counterparty risk.”

### Fugro Extends DOF Construction Vessel Contract

Netherlands-based Fugro NV has extended the contract for DOF Subsea Group’s *Skandi Carla* construction vessel.

In an Oslo Stock Exchange filing on Aug. 18, DOF said Fugro extended the firm period of hire for the *Skandi Carla* from July 2017 to the end of October 2019.

Until July, the vessel worked for Fugro under a contract awarded in 2012.

*Skandi Carla* is an ROV survey, inspection, repair and maintenance, and construction support vessel. Delivered in 2001, the DP2 ship is equipped with a diesel-electric engine, an advanced digital GPS, ultra-short base line acoustic system and a real-time kinematic data sensor called the Seapath 200 RTK.

*Skandi Carla* is fitted with a heave compensated, knuckle-boom-deck-styled crane called the Hydramarine 50T/15m, which has recovery speeds at depths down to 3,000 m (9,842.5 ft).

—*Staff Reports*

**BUSINESS**

**Total, Maersk Oil Deal Creates North Sea Powerhouse**

Total has deepened its roots in the North Sea and shored up core positions in other parts of the world with its \$7.45 billion deal to acquire Maersk Oil and Gas.

The acquisition, which is still subject to regulatory approval and other legal requirements, is expected to lift Total's output to 3 MMBoe/d by 2019, making the company the second-largest operated producer and the third-largest resource holder in the North Sea. The deal is expected to close in first-quarter 2018 with an effective date of July 1, Total said in an Aug. 21 news release announcing the acquisition.

"This is a compelling transaction for Total and one that will add significant value for our shareholders," Total CEO Patrick Pouyanné said on a conference call.

For assuming \$2.5 billion of Maersk Oil's debt and giving \$4.95 billion in Total shares—or 97.5 million shares—to Maersk Oil parent company A.P. Møller-Maersk, Total will grow its reserves by about 1 Bbbl, more than 85% in OECD countries.

It also substantially adds to the company's portfolio, mainly in the North Sea where Total will pick up Maersk Oil's 49.99% working interest in the Culzean gas HP/HT field in the North Sea, an 8.44% interest in the Statoil-operated Johan Sverdrup development and assets offshore Denmark, including the country's largest gas field, Tyra.

In addition, the acquisition allows Total to gain a stronger position in the U.S. Gulf of Mexico, where the two jointly develop hydrocarbons in the Wilcox Formation, and strengthen its position in Algeria.

Add to this possible upside offshore Angola, where Total pointed out the "potential cross-block development for deep offshore resources," and "promising onshore discoveries" in Kenya along with the diversification provided by producing onshore conventional assets in Kazakhstan and Iraq Kurdistan and deeper stakes in Brazil's presalt.

The deal, considered the biggest the North Sea has seen since Statoil's nearly \$30 billion acquisition of Norsk Hydro in 2006, comes as oil and gas companies continue to work toward lowering breakevens, keeping costs low and generating cash flow as they rebound from the prolonged downturn.

With free cash flow of more than \$3.1 billion for first-half 2017, Pouyanné said Total has seen the benefits of its efforts.

"We are now in a position to be able to take advantage of the low-price environment" by pursuing new projects and acquiring resources in attractive conditions,

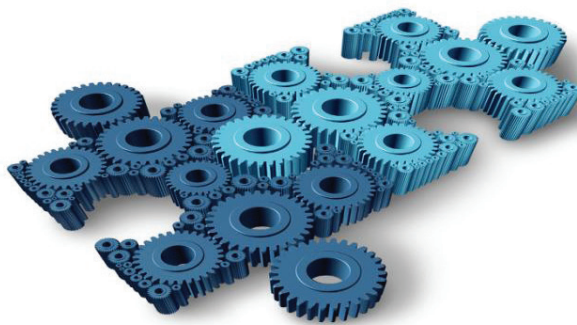
Pouyanné said.

Maersk said the agreement to sell is part of its strategy to separate its oil and oil-related activities as it focuses on integrated transport and logistics.

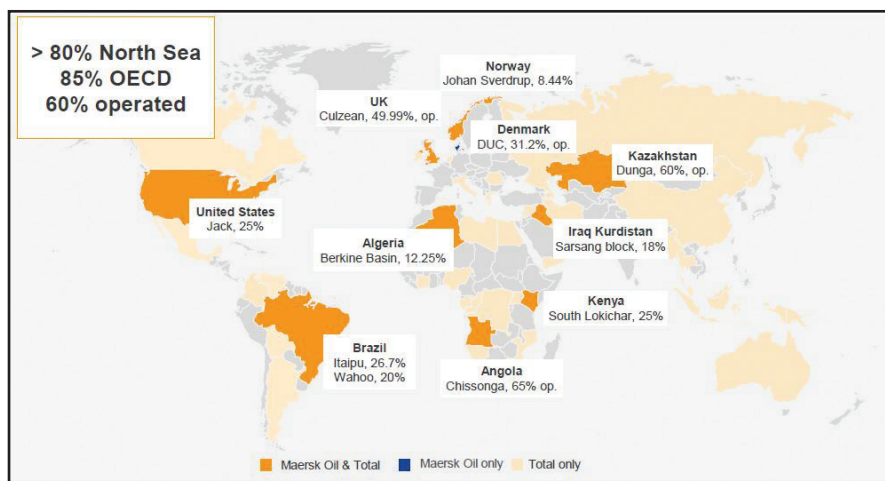
"The valuation of Maersk Oil and Total's commitment is a testament to the quality and standing of Maersk Oil," A.P. Møller-Maersk CEO Søren Skou said in a statement. "In addition, the agreement will strengthen the financial flexibility of A.P. Møller-Maersk and free up resources to focus our future growth on container shipping, ports and logistics."

Pouyanné said Total's main rationale for the acquisition was its conventional OECD assets, which complements other assets in the company's portfolio. It also complements the company's international portfolio and creates synergies, including more than \$200 million in cost synergies and about \$100 million identified fiscal synergies per year.

To cope with oil prices, Total had planned to cut costs by \$4 billion by year-end 2018, adjusting to lower oil prices, *Reuters* reported. Plans are to revise the target by mid-September. Pouyanné said the North Sea was one of the areas



(Shutterstock.com)



(Source: Total)



that face further cost savings to remain competitive, and the Maersk Oil deal offers it the opportunity to do so.

“In the U.K. in particular, we have two operations of similar size. There are 700 staff on both sides in Total UK and Maersk UK with more or less same size of assets,” he said in the *Reuters* article.

Job loss is a possibility given the overlap in operations.

“Obviously we’ll merge these two subsidiaries. At the end of the day, we will have the opportunity to do some rationalization,” Pouyanné said.

Valentina Kretzschmar, corporate service director for Wood Mackenzie, said the cost synergies should add value for Total, given the overlap in the North Sea.

Technology synergies are also present, Kretzschmar added, pointing out Maersk Oil’s expertise as a deepwater specialist skilled in EOR techniques.

“The deal will also reduce Total’s weighting toward areas of high aboveground risk,” Kretzschmar

said in a statement. “There are a number of strategic drivers at play here. The acquisition improves Total’s near-term growth outlook—it provides Total with an immediate 6% production increase and strengthen near-term growth.

“It will further shift Total’s weighting toward OECD regions, a core strategic driver for the company as it looks to balance the portfolio away from areas of high aboveground risk,” Kretzschmar added.

In 2018 Total expects to add 160 Mboe/d, mainly liquids production, and estimated free cash flow breakevens were said to be less than \$30/bbl. This could increase to more than 200 Mboe/d by the early 2020s.

Total is also maintaining its capex guidance, which remained unchanged at between \$16 billion and \$17 billion for 2017 and between \$15 billion and \$17 billion for 2018 to 2020.

—Velda Addison

## Transocean To Buy Norwegian Rig Firm Songa Offshore For \$1.1 Billion

Transocean Ltd., one of the world’s biggest drilling rig operators, has agreed to a deal to buy Norwegian competitor Songa Offshore SE for \$1.1 billion, the two companies said Aug. 15.

The deal, which would be mostly paid for in shares and convertible bonds, would strengthen Transocean’s position in offshore drilling as Songa is Norwegian oil major Statoil ASA’s largest drilling service provider.

The offer values Songa shares at \$6 each, a 39.7% premium over the closing price on Aug. 14.

Shares in Songa surged 31% on news of the deal, which needs the backing of at least 90% of Songa shareholders. So far about 77% of shareholders have agreed to the offer, the company said.

Songa’s biggest shareholder Perestroika would become the largest shareholder in Transocean as a result of the acquisition with a stake of about 12%, the firms said.

“Songa Offshore is an excellent strategic fit for Transocean,” Transocean CEO Jeremy Thigpen said, adding the deal would increase Transocean’s order book by \$4.1 billion to a total of \$14.3 billion.

Including debt, the transaction sets Songa’s enterprise value at \$3.3 billion.

Transocean said it hopes to complete its purchase of Songa, which has a fleet of seven mid-water semisubmersible rigs, in the fourth quarter.

Norwegian investor Frederik Wilhelm Mohn, owner of Perestroika and chairman of Songa, will be nominated for a seat on Transocean’s board.

While demand for drilling has been hit by the fall in oil prices in recent years, the market for rigs able to operate in harsh environments is showing signs of recovery, Mohn said in the statement announcing the deal.

—Reuters

### BUSINESS BRIEFS

#### Chevron CEO Watson To Step Down, Wirth Likely Successor

Chevron Corp. CEO John Watson will step down by the end of next month and likely be replaced by Vice Chairman Mike Wirth, a source familiar with the matter told Reuters on Aug. 22.

The unexpected shake-up at one of the world’s largest oil and natural gas producers comes as pressure grows on the industry to further cut costs and control spending.

In Wirth, Chevron would pivot to a leader with experience in refining, where costs are regularly scrutinized down to the fraction of a penny.

Chevron’s shares are up about 35% since Watson took over as CEO in January 2010, but the Dow Jones industrial average has more than doubled in that time. The company’s shares are trading at the same level they were in early 2011.

Chevron spokesman Kent Robertson declined to comment. Neither Watson nor Wirth responded to requests for comment.

The California-based company is emerging from a global commodity price slump and is beginning to reap the fruits of a multibillion-dollar expansion spree. The exit is not acrimonious, and Watson sees it as an oppor-

tunity to hand over the reins of a growing enterprise to Wirth, according to the source.

The company's growth under Watson has not been painless. Chevron has struggled with cost overruns at two Australian LNG projects, faced major engineering challenges at its U.S. Gulf of Mexico expansions, and is now contending with growing uncertainty about its operations in strife-torn Venezuela, where it is the only remaining major U.S. oil producer.

One of the Australian LNG projects has now come online, and the other is expected to by next month. Combined, the two are expected to fund half the company's dividend by 2019.

### **Weatherford Appoints Blanchard As COO**

Weatherford International on Aug. 21 announced the appointment of Karl Blanchard as executive vice president and COO. In this role, he will oversee all region and product line operations; quality, health, safety, security and environment; sales; engineering, research and development; and supply chain.

Blanchard brings with him insights gained through more than 35 years in the oilfield services sector. Most recently, he served as COO for Seventy Seven Energy, where he oversaw drilling, pressure-pumping and rental tool operations. Previously, he spent more than 30 years at Halliburton Co., where he held senior leadership positions including vice president of cementing, vice president of production enhancement and vice president of testing and subsea.

### **Acteon Buys Viking SeaTech in \$12 Million Deal**

The mergers and acquisitions scene appears to be heating up with U.S.-based Actuant Corp. jumping into the action. The company has agreed to sell its Viking SeaTech business, which specializes in the design and installation of mooring systems among other marine services, to Acteon Group Ltd. for about \$12 million.

While the move helps Actuant simplify its portfolio, it brings to Acteon a company that has more than 20 years of experience in the mooring systems business. Viking SeaTech generated about \$20 million in revenue during the past 12 months, according to a Business Wire news release.

"The decision to divest Viking was not taken lightly, but it is consistent with our strategy to concentrate our energy offerings where we can provide the most value over the long term," said Randy Baker, president and CEO of Actuant, in the release. "It also helps to simplify and stabilize our portfolio by significantly limiting exposure to upstream, offshore oil and gas."

Actuant also announced it signed an agreement with Acteon to buy U.K.-headquartered Mirage Machines Ltd. for about \$16 million plus potential future performance-based consideration, the release said. Baker said Mirage is a strong complement to Hydratight, broadening its product line offerings and adding rental and service opportunities.

Both deals are subject to customary regulatory approvals and closing conditions.

### **Ecopetrol Names Felipe Bayon As New CEO**

Colombian state-run oil company Ecopetrol said Aug. 17 its current vice president, Felipe Bayon, will take over as CEO, replacing Juan Carlos Echeverry.

Echeverry, who has headed the company since March 2015 through difficult times caused by the global fall in crude prices, has resigned for family reasons, Ecopetrol said in a statement to the Andean country's financial regulator.

Bayon, an engineer who spent 20 years working at BP Plc, will take over Sept. 15, the company said. He has been a vice president at Ecopetrol since February 2016.

Echeverry told Reuters in an interview last week that the company will focus on exploring for unconventional deposits in the center and north of the country over the next few years in a bid to increase oil reserves.

Ecopetrol is Colombia's largest company and its top crude producer.

The government controls 88.49% of the firm.

### **Nigeria State Oil Firm Says Its Production Costs Cut To \$23/bbl**

Nigeria's production cost per barrel of crude oil is down to \$23, the state oil company said Aug. 16, after the country last month said the cost was \$29/bbl—one of the highest levels in the world.

The Nigerian National Petroleum Co. (NNPC) did not say in its statement how the firm had driven the cost down by \$6 in the three weeks since the government's cabinet approved a national petroleum policy that put the price at \$29, using data from Rystad Energy.

The state oil firm did not immediately respond to a request for comment.

The NNPC "has driven down the cost of crude oil production from \$78 dollars per barrel as at August 2015 to \$23 per barrel representing a 70.5% reduction," the company said.

Oil prices began crashing in 2014 and were under \$78 for the whole of 2015. All producers have worked since the crash to cut their E&P costs, with most succeeding in driving them down.

The NNPC aims "to bring the cost of production to between \$17 and \$19 for onshore and offshore production respectively," the company said.

### **Hunting Appoints New CEO**

Arthur James Johnson has been named CEO of Texas-based Hunting Plc, effective Sept. 1, the company said in a news release on Aug. 16.

Since 2011 Johnson has held a COO position with the company before succeeding Dennis Proctor, who will retire on Sept. 1, as CEO of Hunting Plc. As part of his responsibilities, he managed Hunting's global operations with regional managers in Africa, Asia-Pacific, Europe, Middle East and North America reporting directly to him on all matters.

Prior to that, he held a number of senior positions within Hunting from 2000 to 2001, including manag-

ing director of U.S. operations. During this time, he was instrumental in the development of Hunting's product offering and service capabilities.

The company's interim results for the six months, which ended June 30, remains scheduled for release on Aug. 24.

### Amec Foster's Proposed Asset Sale May Help Wood Group Deal Approval

Amec Foster Wheeler Plc's proposal to sell almost all of its upstream offshore oil and gas servicing assets may be adequate for regulatory approval of its merger with John Wood Group Plc, the U.K.'s Competition and Markets Authority said.

British oil and gas services company Amec Foster, which is being bought by Wood Group for \$2.8 billion, said earlier in August it was preparing its North Sea operations for sale, in response to the competition watchdog's concerns.

The market regulator said on Aug. 15 the divestiture, or a modified version of it, might be acceptable and that it would open a public consultation in due time.

Wood Group said the companies are not required to complete the sale of the assets before completing the merger.

As a result, the company sees no change in the expected date of completion and continues to expect the deal to close in fourth-quarter 2017, Wood Group said.

### McDermott Appoints Senior VP, General Counsel

John Freeman, who most recently served as special adviser to the integration of Technip and FMC, has been appointed senior vice president, general counsel and corporate secretary for McDermott International Inc., the company said in a news release.

He succeeds Liane Hinrichs, who plans to retire from McDermott by year-end 2017. The change took effect Aug. 14.

With more than 30 years of legal experience in the private and public sector, Freeman was the group (corporate) general counsel for Technip before the company's merger with FMC, the release said. He also held legal and compliance positions with Baker Hughes Inc. before joining Technip in 2009.

### Premier Oil Names Roy Franklin As Chairman

Premier Oil has hired oil and gas industry veteran Roy Franklin as its chairman to succeed Mike Welton, who said in March that he would step down on appointment of a successor.

Franklin, who is currently the interim chairman of Norway's Statoil, will assume the role of Premier Oil's nonexecutive chairman from Sept. 1, the company said.

During his 40 years in the industry, Franklin has worked with many companies, including oil major BP where he stayed for 18 years. He is also lined up to become deputy chairman of the combined group when oilfield services Wood Group completes its acquisition of rival Amec Foster Wheeler.

Premier Oil, which had been struggling with high levels of debt before agreeing to a restructuring deal in February, made a loss before tax in 2016, but its share price rose 52% as the crude oil prices recovered.

The North-Sea focused oil producer also named Dave Blackwood and Mike Wheeler as nonexecutive directors with immediate effect.

Welton is leaving Premier Oil after eight years at the helm.

—Staff & Reuters Reports

## UPCOMING

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