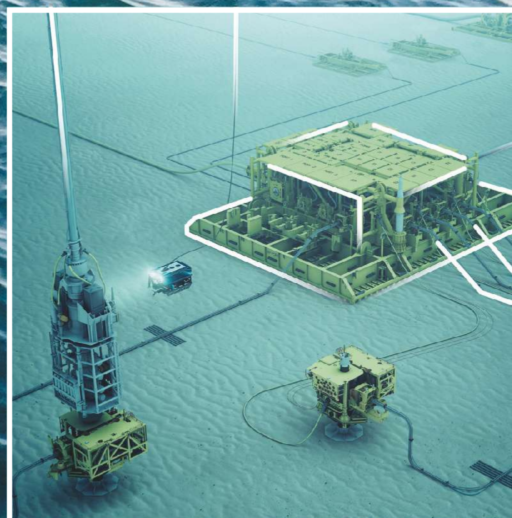
2018 OFFSHORE Technology Yearbook



E&P

HARTENERGY

Global Offshore Oil and Gas Review


A global leader in engineering, project and technical services.
www.woodplc.com

E&P

2018 Offshore Technology Yearbook

A supplement to *E&P*

HART ENERGY
1616 S. Voss, Suite 1000 | Houston, Texas 77057
Tel: +1 (713) 260-6400 | Fax: +1 (713) 840-8585
hartenergy.com

2018 Offshore Technology Yearbook

In an extension of Hart Energy's Unconventional Yearbook series, known for its industry-leading analysis of the top resource plays, the Offshore Technology Yearbook series presents key market and technology trends shaping the global offshore E&P business. This fourth in an annual series of yearbooks provides an overview of current upstream activity, with authoritative insights into the global and regional offshore markets, exploration, drilling and field development activity, and exclusive access to capex data, facts and forecasts on projects, facilities and infrastructure. Also highlighted are the key emerging and established technologies being employed and profiles of the top offshore oil and gas operators.

Table of Contents

On the cover, clockwise from the top: Noble Energy's Tamar platform *(photo courtesy of Noble Energy)*, artist rendering of a subsea installation *(illustration courtesy of Baker Hughes, a GE company)*, the Malikai tension-leg platform *(photo courtesy of Shell)* and the PFLNG Satu at the Kanowit Gas Field *(image courtesy of PETRONAS)*.

Global Offshore Oil Production Outlook to 2025

By Shuqiang Feng, Stratas Advisors

The offshore industry is expected to continue to grow in the next several years due to new developments and field expansions.

Global offshore has contributed about 25 MMbbl/d of oil production since 2012, which accounts for about 30% of the global total. The Middle East, Africa and Latin America have been the top three regions in offshore oil production with combined production of about 15.5 MMbbl/d, or about two-thirds of the global total (Figure 1). About 70% of offshore production (about 17.7 MMbbl/d) has been produced from shallow water (water depth less than 1,000 ft). Ultradeep water (water depth greater than 5,000 ft) has emerged as the new production growth frontier as production from both shallow water and deep water (deeper than 1,000 ft but less than 5,000 ft) has been flattened (Figure 2).

With the tailwind momentum of the long offshore investment cycles, offshore is expected to continue to grow at a speed of about 2% to 4% annually in the next several years to the end of the decade. The growth will be driven by new developments and field expansions in the Gulf of Mexico (GoM), Brazil presalt, Africa and the Persian Gulf. Investment cuts made by the industry on offshore investments in the past couple of years can only slow down offshore production growth starting in 2022, when the annual growth rate will start to drop and reach 0.6% by 2025. Stratas Advisors currently expects oil prices to reach a minimum threshold for justifying new developments around 2019 to 2020. At that time Stratas Advisors forecasts that companies will start investing offshore again, especially in the ultradeep water. However, new investment cycles will take at least three to five years, and new production will not come online until about 2023 to 2025.

FIGURE 1. Global Offshore Oil Production by Region

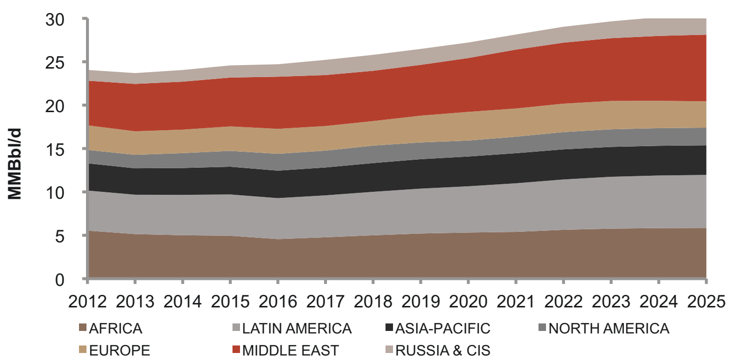
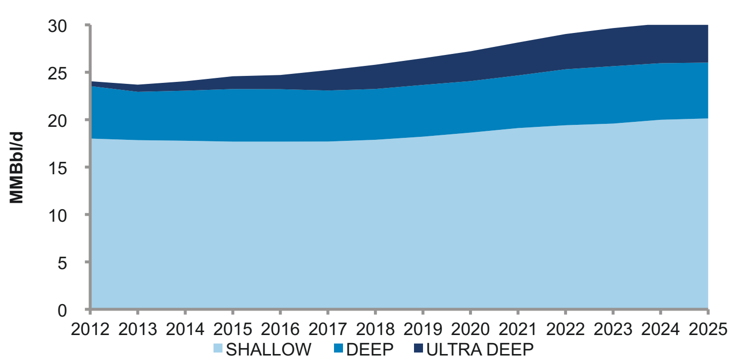


FIGURE 2. Global Offshore Oil Production by Water Depth



(All data and charts courtesy of Stratas Advisors)

BP Trinidad and Tobago produced first gas from the Juniper platform offshore Trinidad. *(Photo courtesy of BP)*

North America

About 83% (1.43 MMbbl/d) of the oil production in North America (U.S. and Canada) was produced from the U.S. GoM in the past five years. Canada offshore production from east Canada only accounts for about 12% (200 Mbbl/d) of the region's total (Figure 3).

Deepwater lower tertiary fields have been the major driving force of growth in the GoM, in part due to high oil prices before 2014. These prices helped spur technological breakthroughs in ultradeep reservoir development. As prices begin to increase to what might be considered a sustained level, big discoveries in deep water will once again become the focal point of portfolio optimizations.

With operators in the GoM cutting investment in the last couple of years, new projects were pushed off their schedules. Only a few small projects were scheduled to come onstream in 2017. BP's Thunder Horse South Expansion project is one of the larger ones with a peak production about 30 Mbbl/d. However, U.S. GoM oil production is expected to top 1,700 Mbbl/d and maintain the same level over 2018, as several major projects starting on or before 2016 ramp up their production.

Looking forward, the new project start drought will continue beyond 2017. Only four major new source projects are expected to start production in the three years from 2018 to the end of the decade. Hess' Stampede project, which was sanctioned in 2014 and is now under construction, is scheduled to start production in 2018. Chevron's Big Foot project has postponed its start date from 2015 to 2018 due to a tendons failure during the platform installation. BP's Atlantis East Phase 3 is expected to start by 2020 as a subsea tieback development. Shell's Appomattox project was sanctioned in 2015 and is in the construction stage with an expected production startup by 2020.

As base production continues to decline, new source projects start to lose steam. The industry will see GoM oil production decline in 2018 and reach the bottom in 2020 at about 1,560 Mbbl/d, a 170 Mbbl/d drop compared to the high-production level of 2017. Assuming an oil price recovery, developments of lower tertiary discoveries should help production within the deepwater and ultradeepwater segments pick up again in 2021.

FIGURE 3. North America Offshore Oil Production by Country

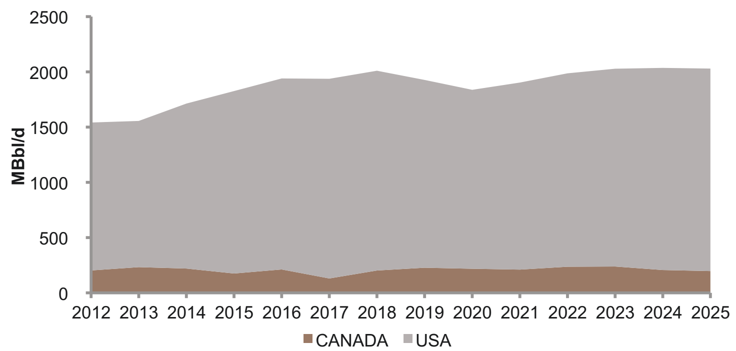
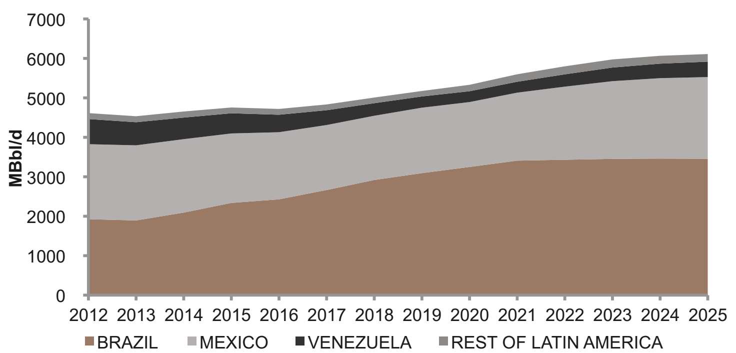


FIGURE 4. Latin America Offshore Oil Production by Country



Latin America

About 50% (4.7 MMbbl/d) of Latin America oil was produced from offshore fields over the past five years. Brazil and Mexico have been the two main producers in the region (Figure 4) with a combined production of about 4 MMbbl/d. This volume represents about 85% of the region's total offshore oil output. About three-quarters of the offshore production is from shallow water, contributed mostly from the southern portion of the GoM.

Over the next 10 years, as shallow-water production in both Mexico and Brazil decline, presalt developments in ultradeepwater Brazil will pick up the momentum and drive the region's production growth. Production is expected to reach 6.1 MMbbl/d by 2025.

Presalt oil production in Brazil will continue to grow in the near to medium term. Production is expected to reach 2.3 MMbbl/d on average by the

end of the decade, and that figure is expected to continue to climb to 2.8 MMbbl/d by 2025. Even considering the high risks associated with the developments, the risked output could still easily reach 1.8 MMbbl/d in 2020 and 2.3 MMbbl/d in 2025.

In Mexico shallow water accounts for more than 75% of Mexico's total oil production. Deep and ultradeepwater E&P are still in their infancy stages. No commercial oil will be produced from deep and ultradeep water until 2023, when increased foreign investment and advanced technology bring hydrocarbons onstream. However, production increases from these new developments will be too marginal to counter the production decline from shallow-water fields.

Europe

About 90% (2.7 MMbbl/d) of European oil came from offshore fields in the North Sea and the Norwegian Sea in the past five years, with most of them in shallow water. Norway and the U.K. are the two main producers in the region (Figure 5), contributing about 2.46 MMbbl/d (88%) of the total offshore oil output.

Norway's oil production had been recently increasing, but the country will not post any new gains until its giant Johan Sverdrup development comes online. Phase 1 is planned to start up in 2019. Phase 2 is expected to start up by 2022. These two phases will generate an incremental 500 Mbbl/d at peak production rates. There are some smaller projects that will at least mitigate the decline over the next few years. For example, Total's Martin Linge development is scheduled to come onstream in 2018 and Johan Castberg in 2021.

Oil production in the U.K. had been declining rapidly for more than 15 years as North Sea oil fields matured. However, new projects that had been in development due to support from high prices will help the country reverse the trend in the next couple of years. Among the projects are Clair Ridge, which is expected to start production in 2018 and contribute more than 100 Mbbl/d at peak; Schiehallion Quad 204, which started first oil in early 2017 and will add about 125 Mbbl/d; and the Mariner, Catcher and Kraken field developments combined are expected to produce 140 Mbbl/d at peak starting from 2017 and 2018.

But in the long term (post 2020), the country's production is expected to continue to decline as most of its North Sea fields reach the end of their production cycles. New sources are uncertain and beyond reach within 10 years.

FIGURE 5. Europe Offshore Oil Production by Country

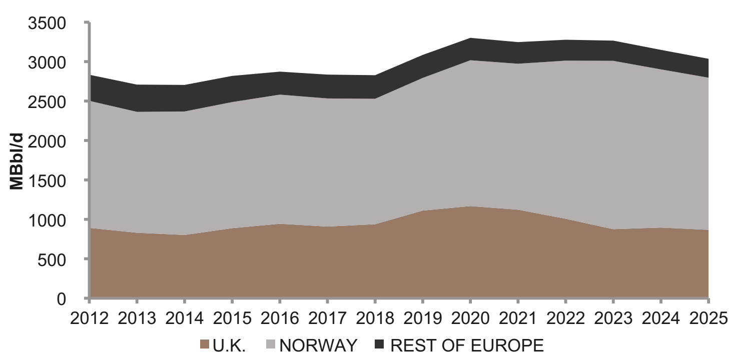
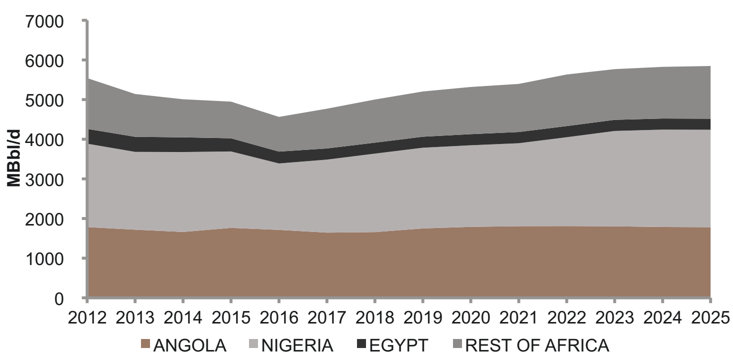


FIGURE 6. Africa Offshore Oil Production by Country



Africa

In the past five years Africa has produced about 5 MMbbl/d of oil from offshore fields, which is about 60% of the continent's total output. Nigeria and Angola are the top offshore producers with a combined production of about 3.7 MMbbl/d (Figure 6). Deep water has been the main producing area of offshore Africa and accounts for 60% (2.9 MMbbl/d) of the total offshore production.

The downturn has depressed investment in future offshore oil and gas projects. In Nigeria projects that are on hold or are being deferred include Shell's

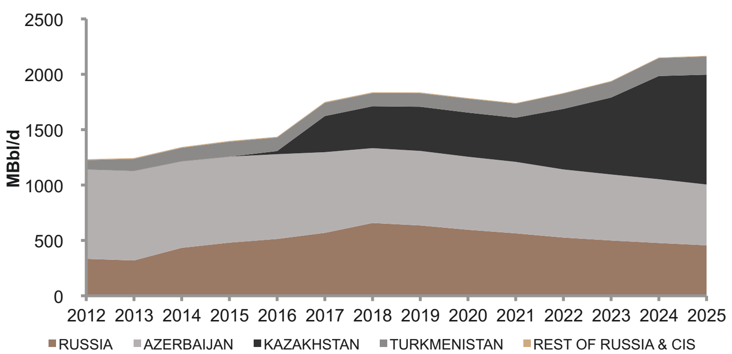
Bonga South West-Aparo, Chevron's Nsiko development, Eni's Zabazaba-Etan, and ExxonMobil's Bosi Field and smaller satellite projects in the Uge Field complex. In Angola those projects include Maersk Oil's Chissonga; Chevron's Negage and Lucapa fields and Greater Longui development; and Cobalt's Cameia project, which has been halted because the company is seeking to exit Angola entirely.

However, companies keep spending on major deepwater projects that entered the construction stage before the oil price collapse. Those developments include Tullow Oil's Tweneboa-Enyenra-Ntomme development, which came onstream in August 2016; ENI's Block 15/06 Eastern Hub development, which was sanctioned in 2013 and started first oil in February 2017; Total's Kaombo project, which was sanctioned in April 2014 with an onstream date of 2018; and the Egina development, which was sanctioned in 2013 and is expected to be onstream in 2018.

Like offshore developments elsewhere around the globe, the long development cycle and intensive capital expenses required for deepwater projects make them fairly immune to spending cuts once they have reached a final investment decision and have started investing large amounts of money. As a result, in the short term—within two to three years—the industry will not see much of an impact from the price collapse on oil and gas production supply from deepwater developments because the ongoing projects will get to the finish line without much interruption. The supply impact will be after 2019 and be intensified around 2021, when the deferred future development projects would have come onstream.

Stratas Advisors expects that nearly 600 Mbbl/d of oil production from deepwater West Africa will be deferred from around 2021 to beyond 2023. The total oil production capacity of those deferred projects will be about 1 MMbbl/d.

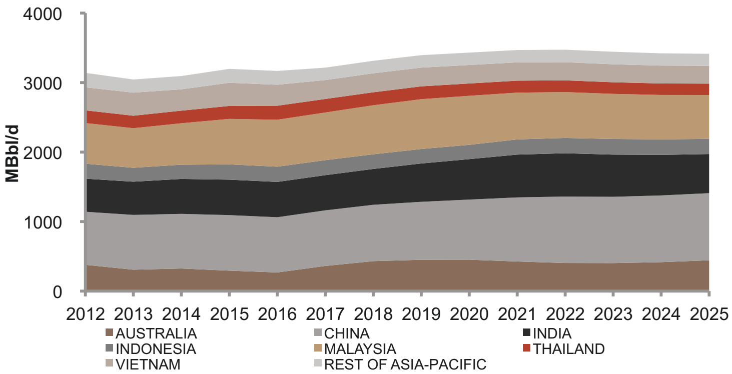
FIGURE 7. Russia and CIS Offshore Oil Production by Country



Russia and CIS

Azerbaijan and Russia have been the top two offshore producers in the Russia and CIS region over the last five years. Offshore oil production in the region has grown from about 1.2 MMbbl/d in 2012 to about 1.7 MMbbl/d in 2017, contributed mostly from Russia and Kazakhstan (Figure 7). Starting later 2016, when Kazakhstan's Caspian shallow-water field Kashagan resumed production, the field will ramp up and significantly power the region's supply of offshore oil by 370 Mbbl/d at peak in Phase 1. Phase 2 is expected to add an additional 450 Mbbl/d in future development before the end of the decade. All of the offshore production from the region is from shallow water.

FIGURE 8. Asia-Pacific Offshore Oil Production by Country



Asia-Pacific

Offshore oil production accounted for about 40% (3.2 MMbbl/d) of the total in Asia-Pacific over the past five years. China, Malaysia and India are the top offshore oil producers in the region with a combined production of about 1.9 MMbbl/d (Figure 8), and most of the region's offshore production (about 90%) comes from shallow water.

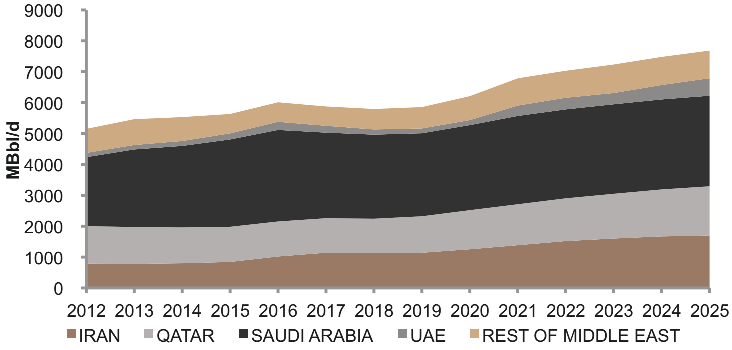
Not being an offshore growth frontier in oil, the region is expected to continue to play an insignificant role in offshore production by 2025 and exhibit a mild growth rate of less than 1% on average annually.

Middle East

Offshore oil production in the Persian Gulf (including field condensate) has accounted for about 21% (5.7 MMbbl/d) of the Middle East's total production in the past five years. Almost all of the offshore production comes from four countries: Saudi Arabia, the United Arab Emirates (UAE), Iran and Qatar (Figure 9), and all of the offshore fields in Persian Gulf are in shallow water.

Oil and condensate production in the Persian Gulf is expected to continue to grow through 2025 as Iran continues to develop its giant offshore gas field, South Pars. The field produces rich condensate. Other than big gas projects being developed in the Persian Gulf, a couple of oil projects will contribute the oil production in the next several years—the UZ750 project in the UAE with 250 Mbbl/d incremental production capacity starting in 2018 and Qatar's Bul Hanine Redevelopment with 100 Mbbl/d capacity starting in 2020. ■

FIGURE 9. Middle East Offshore Oil Production by Country



A platform operates in the Gunashli Field in the Caspian Sea offshore Azerbaijan. *(Photo courtesy of BP)*

Building Momentum Through Strategy, Efficiency

By Bethany Farnsworth, Contributing Editor

Offshore activity is picking up, and these standout players are setting themselves up for success now and in the future.

Offshore activity began to pick up in 2017 after a slow 2016. In just the first half of this year, 31 offshore field projects received FIDs, and 48% of them were projects with estimated capex of at least $500 million, according to Clarksons Research. The 15 operators players listed here are boosting efficiency, reducing costs and investing in strategic offshore plays and projects.

Many of the companies saw increased profits, production, or both, thanks to smart strategy and the beginning of a recovery. These operators started up production all over the globe and made significant progress on major projects, such as the *Prelude* floating LNG facility, which arrived in Australia; the second phase of Clair Ridge, which is expected to begin production next year; and drilling in the Leviathan Field, which will boost reserves.

The following operators are building momentum to stay ahead of the competition offshore this year and into the 2020s.

BP

- **Ranked No. 12 on 2017 Fortune's Global 500 list**
- **Starting production from 7 major projects in 2017**

BP operates in 72 countries around the world, employing 74,500 workers. With proved reserves of 17,810 MMboe, the company produces 3.3 MMboe/d, according to its website.

In second-quarter 2017, BP saw profits of $144 million, compared with a $1.4 billion loss in second-quarter 2016. Upstream production in second-quarter 2017 was 10% higher than in that period in 2016, and first-half 2017 production rose 6% over the first half of 2016, according to the quarterly results announcement. Organic capex for 2017 was set at $15 billion to $17 billion with flexibility at the lower end.

BP plans to bring 800 Mboe/d of new production online by 2020, and to this end, the company expected to start production from seven major projects in 2017 including five offshore. Projects started up in 2016 and 2017 were anticipated to add 500 Mboe/d net to BP's production capacity by the end of 2017.

BP Trinidad and Tobago announced first gas from the Juniper development, BP's first subsea field development in Trinidad, in August. The Juniper platform produces gas from the Corallita and Lantana fields off the southeast coast of Trinidad, and it's estimated the project will increase BP Trinidad and Tobago's production capacity by 16.7 MMcm/d (590 MMscf/d).

The Persephone two-well subsea tieback, operated by Woodside, from the Persephone gas field offshore Western Australia, came online in July and is expected to produce about 50 Mboe/d. BP has a 16.67% stake.

The Quad 204 project offshore U.K. in Schiehallion Field began producing oil in May and included the construction and installation of the world largest harsh-water FPSO, the *Glen Lyon*. The project is expected to ramp up to 130 Mboe/d. BP is operator with 36%, Shell has a 54% stake, and Siccar Point Energy holds the remaining 10%. In the next few years, BP aims to double its U.K. North Sea production, with a goal of 200 Mboe/d by 2020. The Clair Ridge project is scheduled to start up in 2018.

Glen Lyon, the world's largest harsh-water FPSO is shown. *(Photo courtesy of BP)*

Production from the first two fields of the West Nile Delta project offshore Egypt started in March, eight months ahead of schedule and with higher production than estimated. The development will include five gas fields, split into two separate projects, which will produce almost an estimated 42.5 MMcm/d (1.5 Bcf/d) when completed in 2019.

The first phase of the Eni-operated Zohr development offshore Egypt, in which BP has a 10% stake, is on track to produce first gas by the end of 2017. It is expected to bring 40 MMboe/d net to BP.

The BP-operated Shah Deniz consortium launched a subsea construction vessel, the Khankendi, which will perform installation and construction work during the next 11 years in the Caspian Sea for Stage 2 of the Shah Deniz project. *bp.com*

Chevron Corp.

- **Ranked No. 45 on Fortune's Global 500 list**
- **88 LNG cargos shipped from Gorgon in first-half 2017**

As of year-end 2016, Chevron was the second-largest integrated energy company headquartered in the U.S. based on market capitalization. Chevron and its subsidiaries operate around the globe with about 55,200 employees. Net oil-equivalent production from operations worldwide was 2.78 MMbbl/d in second-quarter 2017. That number was 2.53 MMbbl/d in the same period in 2016.

Chevron Corp. reported second-quarter 2017 earnings of $1.5 billion; in second-quarter 2016, the company reported a loss of $1.5 billion. Upstream earnings in first-half 2017 were $2.37 billion compared with a $3.92 billion loss in first-half 2016.

Chevron's capital and exploratory budget for 2017 was $19.8 billion, with more than 70% of the upstream investment slated to generate production in the next two years. In the first half of 2017, Chevron's capital and exploratory expenditures were $8.9 billion, down from $12 billion in the first half of 2016. Upstream represented 89% of the companywide total of these expenditures in second-quarter 2017.

Chevron Australia remains the largest holder of natural gas resources in Australia, with around 1.4 Tcm (50 Tcf) of resources. It also operates two major LNG projects: Gorgon, which began LNG production in March 2016 and Wheatstone, which began production in October 2017. About $2 billion of the 2017 capital spending plan is budgeted to complete the Gorgon and Wheatstone LNG projects. Eighty-eighty LNG cargos were shipped from Gorgon in the first half of 2017, and second-quarter production averaged about 333 Mboe/d.

Chevron subsidiary Cabinda Gulf Oil Co. Ltd. started production from the Mafumeira Sul project's primary production facility offshore Angola in March after starting early production through a temporary system in late 2016. Ramp-up is expected to continue through 2018. The Mafumeira Sul project has a design capacity of 150 Mbbl/d of liquids and 9.9 MMcm/d (350 MMcf/d) of natural gas, according to a press release.

In November 2016, Chevron North Sea Ltd. produced first gas from the HP/HT gas-condensate

Alder Field in the U.K. North Sea. The project has a design capacity of 14 Mbbl/d of condensate and 3.1 MMcm/d (110 MMcf/d) of natural gas. *chevron.com*

CNOOC Ltd.

- **Ranked No. 115 on Fortune's Global 500 list**
- **13 new discoveries in first-half 2017**

With an average net production of more than 1.3 MMboe/d, CNOOC is the largest producer of offshore oil and gas in China. The company's core operations are offshore China, but CNOOC has assets around the globe. CNOOC has more than 19,000 employees and about 3.88 Bboe in reserves as of the end of 2016.

The company estimated the total capex for 2017 would be between $8.7 billion and $10.1 billion. About 18% of that is for exploration, 66% is for development, and 15% is for production, according to a press release.

In the first half of 2017, CNOOC had made 13 new discoveries and 12 successful appraisal wells offshore China and produced net 237.9 MMboe. In this same period, three out of four new offshore projects scheduled for 2017 had begun production, plus an onshore SAGD project. The projects planned for 2017 are Penglai 19-9, Enping 23-1, BD and Weizhou 12-2 Phase II.

In August, the BD gas field offshore Indonesia began production. While currently producing 7,200 boe/d, the field is anticipated to hit about 25,500 boe/d in 2018. Enping 23-1 oil fields in the South China Sea and the Penglai 19-9 comprehensive adjustment project in Bohai began production in January. Weizhou 12-2 Phase II in the South China Sea is in the installation and commissioning phase with startup expected before year-end.

The company has more than 20 projects under construction, and in 2017, it planned to drill 126 exploration wells. CNOOC drilled two successful appraisal wells of Bozhong 36-1 located east of Yellow River Mouth Sag in Bohai in the Yellow Sea and anticipate mid- to large-sized oil fields.

The final investment decision for the Buzzard Phase II Development offshore U.K. has been approved, with production expected to start in 2020 with peak production of 35 Mbbl/d, according to an interim results presentation. The company has a 25% interest in the Stabroek Block offshore Guyana, and a final investment decision for the Liza Phase I development in the block was made in June.

CNOOC's net profit in first-half 2017 was $2.47 billion (16.25 billion Chinese yuan). "In the first half of 2017, CNOOC Ltd. continued to forge ahead, stepped up its efforts in reform and innovation, strived to seek opportunities for future development, and achieved a satisfactory performance," Chairman of CNOOC Ltd. Yang Hua said in a press release. *cnoocltd.com*

A platform operates in the Golden Eagle Area Development, operated by CNOOC subsidiary Nexen Petroleum U.K. Ltd. in the U.K. North Sea. *(Photo courtesy of CNOOC)*

Eni

- **Ranked No. 132 on Fortune's Global 500 list**
- **Operates in 73 countries**

Italian multinational energy company Eni is considered a global supermajor, operating in 73 countries and employing about 33,000 workers, according to the company website. The company produced 1,783

Mboe/d of hydrocarbons in the first half of 2017, up from 1,734 Mboe/d in the same period in 2016. First-half 2017 adjusted operating profit was 2.85 billion euros ($3.3 billion) compared with 771 million euros ($893 million) in first-half 2016. The adjusted operating profit from E&P in the first half of 2017 was 2.26 billion euros ($2.62 billion), and capex was 4.97 billion euros ($5.76 billion), an 18% change from the 6.03 billion euros ($6.99 billion) of capex in first-half 2016.

In 2017, Eni started production from the Integrated Oil and Gas Development Project in the Offshore Cape Three Points Block offshore Ghana, the Jangkrik Development Project in deepwater offshore Indonesia and the East Hub Development Project in deepwater offshore Angola. Production

Eni has started up production from the East Hub Development Project in deepwater offshore Angola. *(Photo courtesy of Eni)* from the super-giant Zohr gas field is also expected to start up in 2017.

The estimated resource in place for Contractual Area 1 in the Campeche Bay offshore Mexico was raised to more than 1.4 Bboe after Eni successfully drilled the Miztón-2 well. The company plans to start up Phase 1 of the Amoca Field in early 2019. It also was awarded three licenses for Blocks 7, 10 and 14 in the Sureste Basin.

Eni launched the Coral South project to develop the resources in the Rovuma Basin offshore Mozambique, entering the execution phase with the signing of the floating LNG unit and finalizing financing.

A discovery of gas and condensates was made in the Gamma Prospect in Contract Area D operated by Eni North Africa BV offshore Libya. Eni gained majority stakes in two exploration blocks, CI-101 and CI-205, in the Tano Basin offshore the Ivory Coast. Norway awarded Eni three licenses including one with Eni as operator. *eni.com*

Exxon Mobil

- **Ranked No. 10 on Fortune's Global 500 list**
- **Made FID on Phase 1 of Liza Field**

Exxon Mobil's first-half 2017 earnings increased 110% over the same period in 2016, from $3,510 million to $7,360 million. Capital and exploration expenditures declined from $10,285 million in first-half 2016 to $8,094 million in first-half 2017. The company produced 3.9 MMboe/d during second-quarter 2017.

"These solid results across our businesses were driven by higher commodity prices and a continued focus on operations and business fundamentals," Chairman and CEO Darren W. Woods said in a news release. "Our job is to grow long-term value by investing in our integrated portfolio of opportunities that success regardless of market conditions."

In June, Exxon Mobil made a final investment decision to move forward with Phase 1 development of the Liza Field offshore Guyana in the Stabroek Block, with production expected to begin by 2020. That's less than five years after the field was discovered. Eni awarded key contracts for the development in late 2016. The FPSO that will serve the field has a production capacity of up to 120 Mbbl/d of oil. The Liza Field could also get a Phase 2 development, underpinned by the reservoirs encountered by the Liza-4 well second-quarter 2017.

Also in the Stabroek Block, Exxon Mobil made an oil discovery in the Turbot-1 well and is planning another Turbot well in 2018. It discovered additional oil in the Payara reservoir in the block as well and made a discovery in the Snoek well. Gross recoverable resources for the Stabroek Block are estimated at 2.25 Bboe to 2.75 Bboe, according to the second-quarter results announcement. Exxon Mobil affiliate Esso Exploration and Production Guyana Ltd. is operator of the block.

In the second half of 2016, Exxon Mobil made a significant discovery in the Owowo Field offshore Nigeria and is working with partners and the Nigerian government to form development plans for the field. *corporate.exxonmobil.com*

INPEX Corp.

- **Japan's largest oil and gas company**
- ***Ichthys Explorer* and *Ichthys Venturer* arrived offshore Australia**

INPEX is Japan's largest oil and gas company and is involved in about 70 projects across more than 20 countries. The company's operating income for the three months ended June 30, 2017, was 87.2 billion yen ($763.8 million) and its ordinary income was 95.5 billion yen ($836.5 million). The operating income for the same period in 2016 was 70.7 billion yen ($619.3 million) and ordinary income was 60.7 billion yen ($531.7 million).

By the early 2020s, INPEX is targeting a net production volume of 1 MMboe/d, according to the company's medium- to long-term vision.

The INPEX-operated Ichthys LNG Project offshore Western Australia is moving forward, with the offshore arrival of the *Ichthys Explorer* central processing facility and the *Ichthys Venturer* FPSO facility. The project is expected to begin production during the fiscal year ending March 31, 2018. The discovery of gas-condensate in the Ichthys Field is regarded as the largest discovery of liquid hydrocarbons made in Australia in more than 50 years, with more than 339 Bcm (12 Tcf) of estimated gas and 500 MMbbl of condensate estimated in the field. The project, which includes the world's largest semisubmersible production platform in Australian waters, is one of the world's largest LNG developments that includes the whole production chain. The project will operate for 40 years.

Through subsidiary INPEX Norge AS, INPEX has obtained a 40% participating interest in exploration license PL767 in the Barents Sea offshore Norway, the company's first project in the country. INPEX and partners extended their production-sharing agreement with the State Oil Co. of the Azerbaijan Republic through 2049 for the Azeri-Chirag-Deepwater Gunashli fields in the Caspian Sea offshore Azerbaijan, in which INPEX now has a 9.31% participating interest.

The company's production-sharing contract for the Offshore Mahakam Block offshore Indonesia expires at the end of 2017, but INPEX and operating partner TOTAL are exploring options for continuing participating in the block. INPEX has also agreed in principle to continue to jointly developing the Satah and Umm Al Dalkh oil fields offshore United Arab Emirates with Abu Dhabi National Oil Co. through 2042.

In late 2016, INPEX, along with Chevron and PEMEX, was awarded a lease to explore Block 3 in the Perdido Fold Belt in the Mexican sector of the Gulf of Mexico. *inpex.co.jp/english*

The National Iranian Oil Co.

- **Iran's state-owned oil and gas company**
- **Expects to bring in up to $15 billion in foreign investments from August 2017 to April 2018**

The National Iranian Oil Co. (NIOC), a government-owned corporation under the direction of the Ministry of Petroleum of Iran, is an oil and natural gas producer and distributor headquartered in Tehran. In 1901, Iran became the first country in the Middle East region to begin operations to produce oil.

Iran inaugurated five megaprojects in the South Pars gas field in the Persian Gulf, increasing gas production by 150 MMcm/d (5.3 Bcf/d) and condensate production by 200 Mbbl/d, NIOC announced in an April press release. These megaprojects include South Pars Phases 17, 18, 19, 21 and 22. The country also inaugurated production of 35 Mbbl/d of oil from the South Pars Oil Layer, which could produce as much as 60 Mbbl/d. Iran has developed 12 phases of the South Pars Field so far, and the field, which Iran shares with Qatar, is believed to be the world's largest gas field with estimated reserves of 51 Tcm (1,801 Tcf) of natural gas and about 50 Bbbl of condensate.

Iran expects to bring in up to $15 billion in foreign investments in its oil and gas projects between August 2017 and April 2018, said Gholamreza Manouchehri, the deputy director for development and engineering affairs of the National Iranian Oil Co. Iran and Russia's Lukoil have agreed to jointly explore the southern parts of the Caspian Sea, the first time the countries will cooperate on an energy-related venture in the Caspian Sea. Brazil's Petrobras has expressed interest in cooperating with National Iranian Oil Co. subsidiary Khazar Exploration and Production Co. to explore in the Iranian sector of the Caspian Sea. Total has signed a 20-year contract to develop and produce from Phase 11 of the South Pars gas field in the Persian Gulf in partnership with China's CNPC and NIOC subsidiary Petropars.

Iran is considering multiple options for developing the Farzad B gas field in the Persian Gulf, beginning preliminary talks and signing a basic agreement with Russia's Gazprom while continuing negotiations with India. *en.nioc.ir*

Noble Energy

- **Year-end 2016 proved reserves of 1.44 Bboe**
- **Sanctioned first phase of Leviathan project**

Noble Energy has discovered more than 3 Bbbl of net resources since 2005 and has established offshore operations in the Eastern Mediterranean,

Noble Energy's Tamar platform fuels more than 60% of Israel's power generation, and the company is targeting first gas from its Leviathan project by year-end 2019. *(Photo courtesy of Noble Energy)*

West Africa and U.S. Gulf of Mexico. Noble is looking to replicate the company's offshore success in the Atlantic Basin and elsewhere in the Mediterranean Sea and GoM, and it holds offshore exploration licenses in Suriname, Gabon, Newfoundland, and the Falkland Islands.

Noble Energy's year-end 2016 proved reserves totaled 1.44 Bboe. In September 2017, the company raised full-year estimated sales volumes to between 342 and 352 MBoe/d, proforma for asset divestments executed earlier in the year, while maintaining 2017 capex estimates of between $2.3 and $2.6 billion, excluding Noble Midstream Partners funded expenditures.

In the Eastern Mediterranean, Noble Energy's Tamar Platform now fuels more than 60% of Israel's power generation. The company is moving forward with the Leviathan natural gas project offshore Israel, and sanctioned the first phase in February 2017 with first gas targeted for year-end 2019. Initial proved reserves associated with the first phase of development were booked at about 550 MMboe net, a boost of more than 35% to Noble's total reserves at the end of 2016. Noble is also working to finalize the development plan for its Aphrodite discovery offshore the Republic of Cyprus in the Eastern Mediterranean. The company had 991 Bcm (35 Tcf) of discovered gross resources in the Eastern Mediterranean at year-end 2016.

Noble Energy currently has eight producing fields in the deepwater Gulf of Mexico, where Gunflint came online in mid-2016. In the second quarter of 2017, the company saw strong performance from its Big Bend, Dantzle, and Gunflint fields.

The company operates the Alen Platform and Aseng FPSO offshore Equatorial Guinea and is a partner in the Alba Field. The governments of Equatorial Guinea and Cameroon signed a memorandum of understanding in 2017 confirming the Yolanda discovery in Block I offshore Equatorial Guinea and the Yoyo discovery offshore Cameroon are in a contiguous reservoir that they plan to jointly develop as the Yoyo-Yolanda condensate gas field with Noble Energy as the operator. *nblenergy.com*

Oil and Natural Gas Corp.

- **Largest producer of oil and gas in India**
- **Ranked world's No. 1 E&P company by Platts**

Oil and Natural Gas Corp. (ONGC) is a state-owned oil company in India, the largest producer of crude oil and natural gas in the country, accounting for 72% of India's domestic oil and gas production. The company employs more than 33,900 people. The Platts 2016 Global Energy Companies Standings ranked ONGC as the world's No.1 E&P company.

ONGC made 23 new discoveries in fiscal year 2017 with 10 of those in offshore wells. Two discoveries in the Kutch and Saurashtra basins offshore India have helped lead ONGC to upgrade the basins to Category 1 (producing) basins through fast track monetization. A discovery offshore KG Basin indicates potential for syn rift/deeper play in the shallow water of India's east coast.

ONGC Videsh Ltd., ONGC's wholly owned subsidiary, operates in 18 countries, participating in 39 oil and gas projects. It was responsible for about 23.4% and 18.9% of India's domestic oil and natural gas production respectively in fiscal year 2017.

ONGC's Perspective Plan 2030 outlines its growth plans, with the goal of 130 million tonnes of oil equivalent (MMtoe) annually by 2030 and accumulation of more than 1,300 MMtoe of proven reserves. The company intends to grow ONGC Videsh Ltd. to 60 MMtoe per year of international production.

Oil and Natural Gas Corp. acquired a 30% participating interest in the exploration license 0037 for blocks 2112A, 2012B and 2113B offshore Namibia. It also acquired the entire 80% participating interest and operatorship rights of Gujarat State Petroleum Corp. Ltd. for the Deen Dayal West Field in Block KG-OSN-2001/3 offshore India at the end of 2016. *ongcindia.com*

Pemex

- **Ranked No. 152 on Fortune's Global 500 list**
- **Largest company in Mexico**

Pemex is the largest company in Mexico with upstream through downstream operations. The average liquid hydrocarbons production in 2017, as of the end of August, is about 2.3 MMbbl/d, and average natural gas production is about 150 MMcm/d (5.3 Bcf/d), compared with approximately 2.5 MMbbl/d and 164 MMcm/d (5.8 Bcf/d), respectively, in 2016. Offshore production accounted for 81% of crude oil production and 58% of natural gas production as of the end of August 2017, according to Petroleum Statistics.

Pemex saw a positive net result in the first half of 2017 of 121 billion pesos ($6.3 billion), and

Pemex's 2017-2021 Business Plan outlines how the company is to reach its primary surplus in 2017 and achieve financial balance in 2019/2020. *(Photo courtesy of Pemex)*

second-quarter 2017 was the third consecutive quarter that the company saw positive net results. Net income in second-quarter 2017 was 33 billion Mexican pesos ($1.7 billion), compared with a net income loss of 83 billion Mexican pesos ($4.3 billion) in the second quarter of 2016.

In 2016, Pemex discovered two fields in deepwater GoM and three in shallow water. Nobilis and Doctus were discovered in the deepwater of the Cinturón Plegado Perdido and contain 301 MMboe. Teca, Pokche and Uchbal were discovered in shallow water near Tabasco, Mexico, with 383 MMboe.

Pemex implemented a $5.4 billion (MXN 100 billion) budget cut in 2016. Pemex has opened the bidding process for farm-outs in four blocks: Trion, Ogarrio, Cárdenas-Mora and Nobilis-Maximino. BHP Billiton signed a farm-out agreement to develop the deepwater Trion Block with a consortium of Pemex. The push for farm-outs is in line with Pemex's financial strategy to share risks and stabilize and increase production.

During Mexico's National Hydrocarbons Commission Round 1.4, Pemex, in consortium with Chevron and INPEX, was awarded Block 3 north of the Plegado Perdido Belt in the GoM. In CNH's Round 2.1, Pemex was awarded two blocks in Round 2.1: Block 2 in the Tampico-Misantla Basin, west of the Gulf of Mexico, and the Southwestern Basins. Pemex signed contracts with Deutsche Erdoel AG in Block 2 and Ecopetrol in Block 8 to jointly explore the areas. Pemex is operator of both blocks with a 70% stake in Block 2 and a 50% stake in Block 8.

The Ogarrio and Cárdenas-Mora blocks were awarded to Deutsche Erdoel AG and Cheiron, respectively.

In addition, the bidding process for Nobilis-Maximino will be held in January 2018. Pemex was assigned a new area in deepwater Gulf of Mexico in the Cinturón Plegado Perdido area, located southwest of Nobilis and the Chachiquin exploratory prospect. *pemex.com*

Petrobras

- **Ranked No. 75 on Fortune's Global 500 list**
- **Began production in Lula South area**

Petrobras, Brazil's state-run energy company, is active in 19 countries with more than 68,800 employees. The company produces more than 2.7 MMboe/d. The company's operations are focused in Brazil. Its portfolio is concentrated in the southeast region, with most of the oil reserves located in maritime fields in deep and ultradeepwater located in the Campos, Santos and Espírito Santo basins.

In first-half 2017, Petrobras achieved a net income of R$4.765 billion (US$1.45 billion), compared with a loss of R$876 million (US$266 million) in first-half 2016. During this period, Petrobras recorded an average production of oil and natural gas of 2,791 Mboe/d, with 2,671 Mboe/d produced in Brazil, 6% higher than in the first quarter of 2016.

By 2021, Petrobras expects to achieve total production of 3.41 MMboe/d, and will have invested US$60.6 billion in upstream operations, with an emphasis on deep water according to the 2017-2021 business and management plan. This equates to 82% of the company's total investment, up slightly from the 81% share of capex for upstream in the 2015-2019 plan. Overall, capex is down 25% for the 2017-2021 plan period compared with the 2015-2019 business and management plan, from US$98.4 billion to US$74.1 billion. Petrobras is prioritizing deepwater production, working primarily in strategic partnerships. The company has also sought to reduce costs and maximize the productivity of their portfolio. Another of the company's goals is to strengthen the management of reservoirs through new opportunities for incorporating reserves.

In 2017, Petrobras began oil and natural gas production in the Lula South area, in the presalt from the Santos Basin, through the P-66 ship platform, the seventh unit of the Lula Field. In December 2016, Petrobras reached 1 Bbbl of production from the presalt and 1.6MMbbl/d from ultradeep water. Ten new production systems are expected to come online in coming years.

Petrobras and Statoil are continuing to cooperate on optimizing recovery from deepwater mature fields, focused primarily on post-salt Campos Basin offshore Brazil. In August, Petrobras announced the discovery in the presalt layer of the Campos Basin in the Marlim Sul area, indicating that new discoveries can be made in mature basins. Petrobras was awarded seven blocks, six of which are offshore in the Campos Basin, by Brazil's National Petroleum Agency. Petrobras will operate the offshore blocks with a 50% interest, and Exxon Mobil will hold 50%. *petrobras.com.br/en*

Petrobras recently celebrated 60 years of activities in Espírito Santo. *(Photo by Gabriel Lordêllo, courtesy of Petrobras)*

PETRONAS

- **Ranked No. 184 on Fortune's Global 500 list**
- **Active upstream presence in more than 23 countries**

Petroliam Nasional Berhad (PETRONAS) is Malaysia's state-owned oil and gas company, participating in upstream ventures in more than 23 countries. PETRONAS has a presence in 216 producing fields with 381 offshore platforms and 21 floating facilities. The company has an LNG production capacity of 34.7 million tonnes per annum and has delivered more than 10,000 LNG cargos over three decades. PETRONAS promotes the sustainable development of the Malaysia's petroleum resources through 96 active petroleum arrangement contracts.

First-half 2017 revenue was RM108.1 billion (US$25.5 billion), 15% higher than first-half 2016 revenue of RM93.7 billion (US$22.1 billion), according to second-quarter results. Total production volume in first-half 2017 was 2.3 MMboe/d.

PETRONAS commissioned the world's first coal bed methane-to-LNG projects in Gladstone Australia, Train 9 at the PETRONAS LNG Complex in Bintulu, Malaysia, and the PETRONAS Floating LNG Satu (PFLNG Satu).

PFLNG Satu, a floating LNG facility, successfully loaded its first cargo at the Kanowit gas field offshore Sarawak, Malaysia, in April 2017. The company expects the floating facility to play an important role in unlocking gas reserves in remote and stranded fields offshore Malaysia, according to the *PFLNG SATU* project overview.

PETRONAS LNG Train 9 at the PETRONAS LNG Complex in Bintulu, Sarawak, started commercial operations during 2017.

PETRONAS subsidiary PC Carigali Mexico Operations, in partnership with Ecopetrol, was awarded a shallow-water block in the Mexican Gulf of Mexico's Salina Basin. Block 6 will be operated by PC Carigali Mexico, and each company has a 50% stake. In 2016, PETRONAS gained deepwater blocks 4 and 5 in the Gulf of Mexico in Mexico's first deepwater auction. *petronas.com.my*

Shell

- **Ranked No. 7 on Fortune's Global 500 list**
- ***Prelude* FLNG facility arrived offshore Australia**

Royal Dutch Shell operates in more than 70 countries and has about 92,000 employees. The company produces 3.7 MMboe/d, according to 2016 numbers.

Shell's income for first-half 2017 was $5.08 billion, a 206% increase over first-half 2016 income of $1.66 billion. Capital investment for first-half 2017 was $11.5 billion; this is down from $65.3 billion in first-half 2016, which included $52.9 billion related to the acquisition of BG Group, according to the second-quarter results.

"The external price environment and energy sector developments mean we will remain very disciplined, with an absolute focus on the four levers within our control, namely capital efficiency, costs, new project delivery, and divestments," CEO Ben van Beurden said in a statement about the second quarter.

Shell's *Prelude* floating LNG facility arrived offshore Western Australia in July. *Prelude* will serve as a production platform for the Prelude and Concerto fields in the Browse Basin while also liquefying, storing and transferring LNG to carriers for the next 20 to 25 years. The facility has a production capacity of at least 5.3 million tonnes per annum of liquids. Shell anticipates seeing cash flow from the Prelude project in 2018, according to a press release.

Production started from Stones Field, the world's deepest oil and gas project, in September 2016 in ultradeepwater U.S. Gulf of Mexico (GoM). The water depth is 9,500 ft (2,900 m) and, at peak production, it produces an estimated 50 Mboe/d. The Stones Field currently has two production wells, with six more planned.

The Appomattox project is more than 65% complete, with first oil anticipated by the end of the decade. The development is in the U.S. GoM and will produce from the Appomattox and Vicksburg fields initially. Average peak production is estimated to hit about 175 Mboe/d.

The Malikai tension-leg platform started up production in December 2016. *(Photo courtesy of Shell)*

The Shell-operated Malikai project, Malaysia's first tension-leg platform, started up production in December 2016. Peak annual production is 60 Mbbl/d.

In February, Shell and Mitsui Oil Exploration announced a final investment decision to develop Phase 1 of the Kaikias deepwater project in the U.S. GoM. *shell.com*

Statoil

- **Ranked No. 207 on Fortune's Global 500 list**
- **Obtained 29 licenses in mature areas and 5 in frontier areas offshore**

Statoil is the world's largest offshore operator with more than 40 assets over more than 30 fields in the North Sea, the Norwegian Sea and the Barents Sea, according to its website. Statoil produces about 70% of all oil and gas production on the Norwegian Continental Shelf (NCS). With about 20,500 employees worldwide, the company currently operates in more than 30 countries.

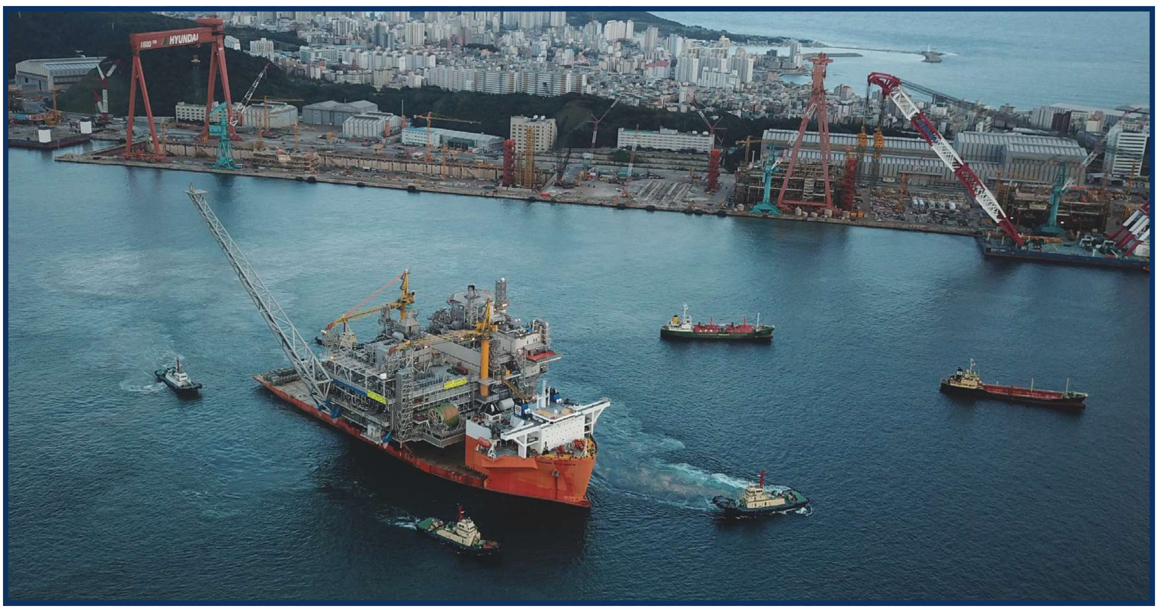
At the end of 2016, Statoil had 5,013 MMboe of proved oil and gas reserves. Statoil participated in 14 exploration wells in 2016 and made 11 discoveries, and it expected to drill around 30 wells in 2017, already having drilled 14 with nine discoveries in the first half of the year. The company obtained 29 licenses in mature areas in Norway's 2016 awards round 16 as operator and 13 as nonoperating partner—announced in January 2017. Statoil was awarded five licenses in frontier areas—four as operator and one as partner.

Adjusted earnings in second-quarter 2017 were $3 billion, and equity production was almost 2 MMboe/d, up from about 1.96 MMboe/d in the same period in 2016.

"Our solid financial results and strong cash flow are driven by good operational performance with high production efficiency and continued cost improvements," Eldar Sætre, president and CEO of Statoil ASA, said in a statement regarding second-quarter 2017 results.

The Gina Krog oil and gas field in the North Sea started up production in June 2017. It has 20 well slots, with an initial plan to drill 11 production wells and three injection wells.

Statoil is making progress on Johan Sverdrup, one of the largest oil discoveries ever made on the NCS. Johan Sverdrup has expected reserves of between 1.9 Bboe and 3 Bboe. The jacket for the riser platform has been installed as part of Phase 1, which will have four platforms and is almost 60% complete. First oil from Phase 1 is scheduled for late 2019. The Johan Sverdrup partnership is proceeding with development of Phase 2, which



In September, the Aasta Hansteen topside sailed away to the Norwegian Sea. *(Photo by Lee Hyeongjin, courtesy of Statoil)* is expected to start up in 2022. Phase 2 will add another processing platform to the field center, bringing total processing capacity to 660 Mboe/d, and development of Avaldsnes, Kvitsøy and Geitungen satellite areas.

Statoil plans to begin a drilling campaign on the Aasta Hansteen gas field in the Norwegian Sea in late 2017 or early 2018. The estimated recoverable reserves are 1,660 Bscf (47 Bscm) of gas. *statoil.com*

Total

- **Ranked No. 30 on Fortune's Global 500 list**
- **Acquired Maersk Oil & Gas**

Total is the fourth largest oil and gas company in the world, operating in more than 130 countries with 98,000 employees. It produces 2.45 MMboe/d and plans to add more than 700 Mboe/d by 2020. The company's adjusted net income in the first half of 2017 was $5 billion, up 32% from the same period in 2016. Adjusted net operating income from E&P was $2.74 billion, up from $1.43 billion in first-half 2016.

In August, Total announced its 100% acquisition of E&P company Maersk Oil & Gas, a wholly owned subsidiary of A.P. Møller–Maersk, expected to close in first-quarter 2018 with an effective date of July 1, 2017. Through the acquisition, Total has gained about 1 Bboe of 2P/2C reserves (85% of which are in OECD countries); 160 Mboe/d of additional production in 2018, which is estimated to grow to more than 200 Mboe/d by the early 2020s; and operational, commercial and financial synergies that total more than $400 million annually.

Offshore Republic of the Congo, Total started production this year from the Moho Nord project on the Moho Bilondo license. Operator of the project, Total is using both a floating production unit and a tension-leg platform to produce the field, totaling about 100 Mbbl/d in production. Total's ultradeepwater project Kaombo offshore Angola is expected to produce first oil in 2018 with an estimated combined oil production capacity of 230 Mbbl/d. The project will develop six fields in Block 32. Offshore Nigeria, the development of Total's Egina Field, launched in 2013, is underway; first oil is expected in 2018 with output reaching 200 Mbbl/d at plateau.

Total also holds a 30% interest in the INPEX-operated Ichthys LNG project offshore Australia, expected to start up in first-half 2018.

In deepwater Gulf of Mexico, Total has entered into an agreement to participate in seven prospects across 16 blocks in the Wilcox and Norphlet plays. Total's participation in these Chevron-operated prospects will be between 25% and 40%.

A tension-leg platform in Moho Nord offshore Democratic Republic of the Congo is shown at dusk. *(Photo by Malfere Damien, courtesy of Total)*

The company has started production in the Edradour and Glenlivet gas and condensate fields offshore U.K. The fields will add up to 56 Mboe/d of production capacity. Additionally, Total has signed a 20-year contract to develop and produce from Phase 11 of the South Pars gas field, the world's largest gas field, in partnership with China's CNPC and NIOC subsidiary Petropars. *total.com* ■


#MakeThingsBetter
total.com
Oil, natural gas and renewable energy – 98,000 women and men
COMMITTED TO
BETTER ENERGY
TOTAL
Committed to Better Energy

Global Exploration Takes an Upward Turn

By Judy Murray, Contributing Editor

Operators test the boundaries of established plays as well as promising new areas following a year of marginal exploration activity.

The level of exploration activity in 2017 was a welcome change from the previous year. Although operating companies were still juggling the numbers to determine what plays were likely to be most profitable, they were willing to move forward to explore a number of resource basins around the world, some of which were seeing a drillbit for the first time.

Mexico shows its colors

Deregulation in Mexico resulted in much needed exploration in 2017. This high-potential energy sector attracted international investment from companies encouraged by the transparent process with the national hydrocarbons commission, Comisión Nacional de Hidrocarburos, extensive datasets available for bidders, well-defined work programs and large tracts of acreage in proven basins.

Talos Energy and Premier Oil, in partnership with Sierra Oil and Gas (Mexico's first independent oil company), bought acreage in the first bid round in 2015. The partners spudded the Zama-1 exploration well in May, drilling what would be the first exploration well on acreage awarded in that bid round and the first offshore exploration well drilled by the private sector in Mexico's history. And it turned up big. This discovery on Block 7 in the shallow-water Sureste Basin, 37 miles offshore Tabasco State, holds an estimated 1.4 Bbbl to 2.0 Bbbl of oil.

Pemex was busy in the Gulf of Mexico (GoM) as well, testing an ultradeepwater play in the Cinturón Plegado Perdido area near Shell's Perdido Field, where more than 30 Bbbl of oil is estimated to lie on the Mexican side. The Doctus-1 well, drilled 90 miles offshore in more than 5,000 ft water depth not only confirmed the existence of oil, but proved the NOC's capabilities in new and highly complex plays.

In September, the company began looking for a partner to help develop the Nobilis-Maximino deepwater area in the Perdido Fold Belt, 25 miles from BHP-operated Trion Field and 16 miles from Shell's Great White, in 10,000 ft water depth. This 1,528 sq mi play holds 3P reserves of 502 MMboe, with estimated production of 300,000 bbl/d. More activity is anticipated in 2018.

US GoM still turning up deepwater plays

The U.S. sector of the GoM saw several discoveries in 2017, all of them in deep and ultradeep water. LLOG hit with its Mormont and Khaleesi wells in the Green Canyon Block, finding smaller reserves similar to its earlier Delta House developments. Anadarko had a small discovery in the Green Canyon Block as well with the Calpurnia well near its Holstein development. And Deep Gulf Energy Companies Corp. reported a find in early September with the Rampart Deep well on Mississippi Canyon Block 116. Partner Stone Energy, encouraged by these results, is planning additional drilling on the Derbio prospect, up-dip from Rampart Deep. Positive results at Derbio could lead to joint development of the two plays, developed as a multiwell tieback to Stone's Pompano platform in 2019.

BHP spudded the Wildling-2 ultradeepwater well on Green Canyon Block 520 in 4,030 ft water depth, discovering oil in multiple horizons, and Shell hit oil with the its deepwater Whale exploration well on Alaminos Canyon Block 772, approximately 200 miles offshore.

Transocean's ultradeepwater drillship, the *Deepwater Invictus*, drilled the Wildling-2 well for BHP in the GoM. The vessel joined Transocean's fleet in 2014. *(Photo courtesy of Transocean)*

Drilling continues in Latin America

In early March, Anadarko found gas in the Caribbean in deepwater offshore Colombia with the Purple Angel-1 well, reporting a second find the following day with Purple Angel-2. The wells are within 3 miles of the operator's play-opening Kronos-1, drilled in July 2015. Purple Angel-1 encountered between 70 and 110 net feet of natural gas pay, confirming a gas column greater than 1,700 ft. Two months later, Anadarko hit gas again with the Gorgon exploration well, approximately 20 mi northeast of Kronos.

June saw two significant shallow-water gas finds for BP Trinidad & Tobago (bpTT). The Savannah and Macadamia exploration wells discovered approximately 2 Tcf of gas in place. Savannah was drilled into an untested fault block 50 miles off the southeast coast of Trinidad uncovering approximately 650 net feet of pay. Based on the success of the Savannah well, bpTT expects to develop these reservoirs via future tieback to the Juniper platform, which came online in August. Macadamia penetrated hydrocarbon-bearing reservoirs in seven intervals with approximately 600 feet net pay. Combined with existing reservoirs, the Macadamia discovery is expected to support a new platform sometime after 2020.

Meanwhile, Exxon Mobil met with great success offshore Guyana, reporting in January the Payara-1 well encountered more than 95 ft of high-quality, oil-bearing sandstone reservoirs in 6,660 ft (2,030 m) water depth on the Stabroek Block 10 miles (16 km) northwest of the giant Liza discovery. In March the operator reported its Snoek well encountered more than 82 ft (25 m) of high-quality, oil-bearing sandstone reservoirs 5 miles (8 km) southeast of Liza-1. And in July, the company announced it had discovered additional oil in the Payara reservoir, increasing the total Payara discovery to approximately 500 MMboe. Payara-2 confirmed the second giant field discovery in Guyana. According to Exxon Mobil, Payara, Liza and the adjacent satellite discoveries at Snoek and Liza Deep provide the foundation for world class oil developments.

In a year that was troubled for Petrobras, the NOC had good fortune with exploration efforts in the Campos Basin offshore Brazil that led to a presalt discovery in August. The company reported its Poraque Alto well hit oil on the Marlim Sul Field, marking the first commercial presalt oil discovery in this area. This success demonstrates potential for new discoveries in Brazil's mature basins.

The Seadrill *West Elara* jackup hit oil with the shallow-water Valemon West exploration well in the Norwegian Sea in February. The well was tied back to the already producing Valemon platform. *(Photo courtesy of Seadrill)*

Norway's Statoil saw success early in the year with a shallow-water oil discovery offshore Bergen. The seventh exploration well drilled on production license 193 D, near the Valemon Field, came onstream two years ago. The discovery, called Valemon West, contains between 20 Mboe and 50 Mboe.

Statoil's 2017 Barents Sea exploration campaign also saw success throughout the year, beginning in January with the Cape Vulture well. One year after license award, Statoil discovered between 20 Mbbl and 80 Mbbl of oil and gas. The operator made two more finds in July. The Kayak well on the Johan Castberg license discovered between 25 Mboe and 50 Mboe of recoverable reserves, proving for the first time resources in this type of play in the Barents Sea.

Statoil said efforts will be made to find a commercial solution for the Kayak discovery toward the Johan Castberg license and to bring out other similar prospects in the area. In its search for oil, Statoil also discovered gas between the Snøhvit and Goliat fields with the Blåmann well, which found 1.5 Bcm to 3 Bcm, equivalent to 10 Mboe to 20 Mboe.

Lundin Norway also had a Barents Sea success. The operator of production license 533 drilled wildcat well 7219/12-1 and appraisal well 7219/12-1 A on the Filicudi prospect. Well 7219/12-1 proved a total oil column of about 200 ft and an overlying total gas column of a similar size.

Husky Canada continues to add reserves

Atlantic Canada saw another drilling success in 2017 as well with Husky Energy's White Rose Northwest discovery offshore Newfoundland in May. The company announced the well results along with plans to continue developing the West White Rose Project. The find adds to the recoverable resources in this extension project, which the company says is on a scale approaching the original White Rose development. The new project will use a fixed wellhead platform tied back to the *SeaRose* floating production, storage and offloading (FPSO) vessel, which is producing the White Rose Field.

Europe, Scandinavia drilling opens new plays

Hansa Hydrocarbons Ltd. announced that its shallow-water N05-1 exploration well drilled offshore The Netherlands confirmed gas. The Ruby discovery, which proves up a substantial volume of gas in the basal Rotliegend sands, extends across the N04, N05, N08 and Geldsackplate licenses in the Dutch and German North Sea sectors in 9 ft water depth. Plans are in place to commercialize the field and to appraise adjacent prospects.

More discoveries of Mediterranean gas

Following earlier successes in the area, Eni discovered gas and condensates offshore Libya on the Gamma Prospect in Contract Area D, 86 miles offshore Tripoli. Shallow-water discovery well B1 16/3, southwest of the Bouri Field, is part of the company's "near-field" exploration strategy, targeting opportunities that can exploit synergies with existing infrastructures. According to Eni, the well has the capacity to deliver more than 7,000 boe/d.

BP continued exploration offshore Egypt, discovering gas with the Qattameya Shallow-1 exploration well in the North Damietta Concession of the East Nile Delta in March.

Qattameya marks the supermajor's third discovery in the block.

Africa drilling opens frontiers

Senegal was the most productive exploration area in Africa in 2017. In May, Cairn Energy found oil with the ultradeepwater FAN South-1 well 55 miles offshore in the Sangomar Deep Offshore Block. The operator found hydrocarbons in its first pure exploration well offshore Senegal since the discovery wells of FAN-1 and SNE-1 in 2014. Three months later, Cairn hit again with the SNE North-1 well on the same block.

BP and Kosmos Energy also had deepwater success offshore Senegal with the Yakaar-1 exploration well in the Cayar Offshore Profond block approximately 60 miles offshore. The well intersected a gross hydrocarbon column of 394 ft in three pools within the primary Lower Cenomanian objective encountering 148 ft of net pay. Kosmos estimates Yakaar-1 discovered a gross gas resource of about 15 Tcf. This well is the first in a four-well series of independent tests of the basin floor fan fairways, outboard of the proven slope channel trend opened with the Tortue-1 discovery. Kosmos has drilled six consecutive successful exploration and appraisal wells in this fairway with a 100% success rate.

In February, Noble Energy Inc. discovered oil in the shallow-water Carmen prospect on Block O offshore Equatorial Guinea, encountering approximately 26 ft of net oil pay and 13 ft of net gas pay. Carmen is Noble's first oil discovery on the block.

New plays offshore Russia

Russia's Rosneft had success mid-year with the northernmost exploratory well on the Eastern Arctic Shelf in the Laptev Sea. The shallow-water Tsentralno-Olginskaya-1 well was drilled from the shore of the Khara-Tumus Peninsula on the shelf of Khatanga Bay. Studies of Rosneft's acreage in the Laptev Sea since 2014 have identified 114 promising oil- and gas-bearing structures.

More good news followed in early October with Gazpromneft's giant oil discovery on the Ayashski Block offshore Sakhalin Island in Russia's Far East. Initial in-place reserves are estimated at 1.86 Bboe, making the Ayashskoye Field the biggest discovery in Russia and one of the largest in the world in 2017.

Exploratory drilling continues in India, Asia

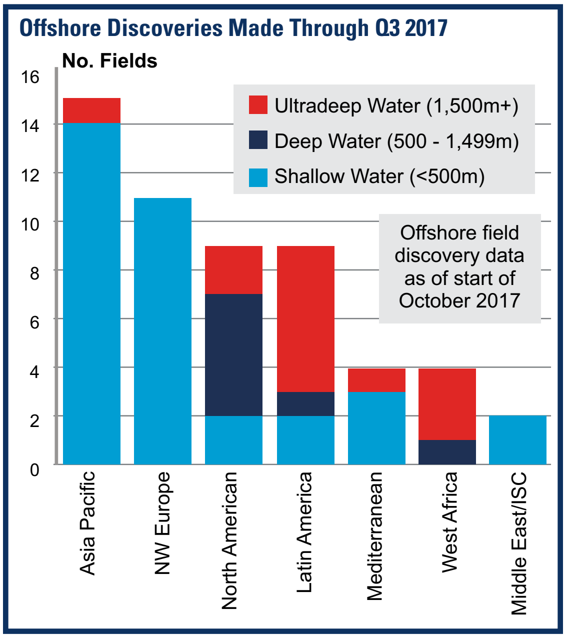
India's Oil and Natural Gas Corp. Ltd. reported three offshore discoveries during the first quarter of its fiscal year, including the SW-WO-24 well in the shallow-water Mumbai basin. Three zones were tested and flowed gas and condensate. The GD-10-1 well tested two zones in the Krishna-Godavari (KG) basin, drilling the Godavari Clay Formation to identify a new prospect. The GS-29 No. 11, also in the KG Basin, was classified as a new pool discovery as well.

While India delineated known plays, Woodside focused on drilling underexplored acreage offshore Myanmar. In August, the operator announced that its Pyi Thit-1 exploration well in Block A-6 in the Southern Rakhine Basin intersected a gross gas column of approximately 210 ft. The gas discovery at Pyi Thit-1 follows previous Woodside finds with the Shwe Yee Htun-1 well in Block A-6 and the Thalin-1A well in Block AD-7 early in 2016.

Offshore Vietnam, Murphy Oil tested its acreage on Block 11-2/11 in the Nam Con Son Basin, discovering oil with the CT-1X well. The second exploration well was delayed following this discovery, but Murphy has plans for continued exploration in the region.

China steps up exploration drilling

CNOOC had an active 2017, announcing early in the year plans to drill 126 exploration wells. While the NOC did not share the results of all its planned wells, it reported four new discoveries and five appraisal wells offshore China in the first quarter. Among them were the Bozhong 29-6 and Bozhong 29-6S wells drilled in the mature area of Bohai Bay. These wells were followed by Bozhong 29-6 South later in the year.



Asia and Europe saw most of the shallow-water discoveries in 2017 while in the Gulf of Mexico, the biggest successes were in deep and ultra-deep water. *(Source: Clarksons Research)*

An additional eight wells were drilled across the South China Sea, testing a range of targets, with the results laying the foundation for next year's drilling program.

Nearshore drilling hits oil in Western Australia

Offshore Western Australia, Norwest Energy Ltd. Group saw success with the group's Xanadu-1 wildcat on inshore permit TP/15 in the north Perth basin, drilled as a directional well from an onshore coastal location. Plans are now underway for an up-dip sidetrack appraisal from the Xanadu-1 casing shoe. According to Norwest, the first well in the Cliff Head oil field discovery farther offshore identified a 4.8-m oil column at the top of the Irwin River Coal Measures—the same stratigraphy encountered in Xanadu-1. The company is evaluating acquiring more seismic data with a mini-survey of short infill lines over the Xanadu discovery prior to drilling Xanadu-2.

Winds of change

Analysts at Wood Mackenzie have taken a look at the reasons behind the move to more exploration in 2017 and evaluated the impact it could have on future exploration drilling, asking hundreds of senior leaders, NOCs, majors and independents about their plans in the coming years. In its "Future of Exploration Survey 2017," the company gathered data from across the industry, interpreted the results, and used that information to construct the industry's collective outlook for exploration. After reviewing the data, vice president of Exploration Research at Wood Mackenzie, Andrew Latham, offers valuable insights.

Among these is the fact that operators believe exploration is a better investment at present than mergers and acquisitions (M&A). Survey results reflect the belief that drilling offers better returns than M&A, which introduces the challenge of how to create value in a competitive, acquisitive environment.

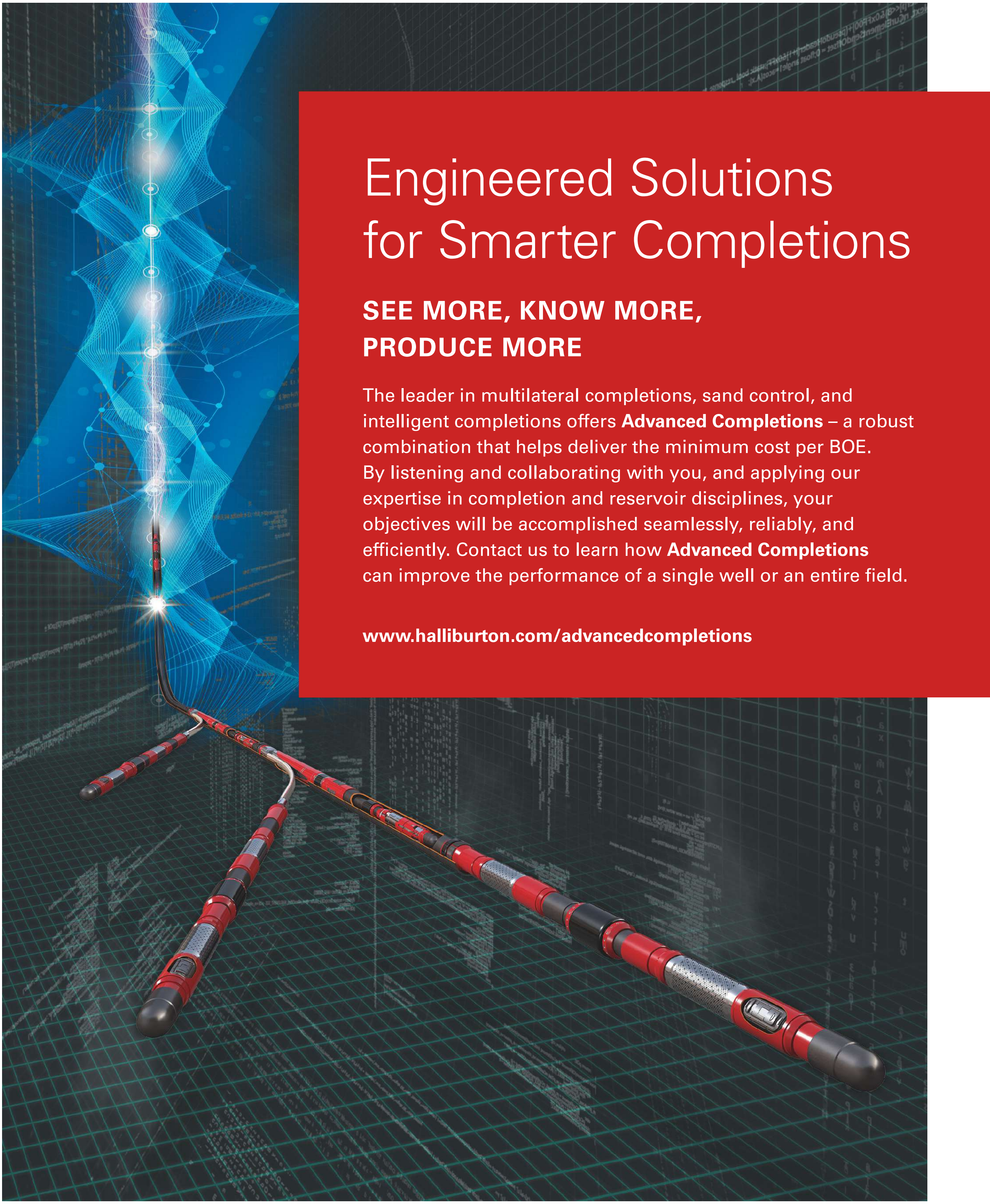
Key performance metrics also have changed since the preceding survey, Latham says. In 2017, the most important criterion identified by survey participants is value creation, followed by investment returns and capital efficiency. "This is quite different to several years ago when volume and cost performance were the primary focus," he said.

The data suggest there is reason for optimism, but it is important to take a look at the numbers, which paint a somewhat less rosy picture. According to the McKinsey Energy Insights report, "Offshore drilling market outlook to 2030," rig utilization is still very low—around 65% relative to 2014 levels—and day rates have dropped to approximately 50% of 2014 levels. With fewer active rigs, newbuilding delays continue.

Fortunately, McKinsey analysts believe activity has reached bottom, which indicates things are looking up. The "good" news, according to the report, is that with demand recovery and a balancing of supply, utilization levels will be back up by 2022. Pragmatically speaking, however, the industry is looking at five more years before reaching parity with 2014 utilization levels.

McKinsey expects the demand for jackups to hit bottom this year, followed by 2% growth per year through 2030. Expectations are for utilization rates to exceed 80% by 212, with a lot of old, low-spec rigs leaving the market and fewer high-spec units entering it.

It appears that 2017 marked the beginning of the end of depressed exploration activity. If operators follow through with their current drilling plans, 2018 will be an even better year. ■


Engineered Solutions for Smarter Completions
SEE MORE, KNOW MORE, PRODUCE MORE
The leader in multilateral completions, sand control, and intelligent completions offers **Advanced Completions** – a robust combination that helps deliver the minimum cost per BOE. By listening and collaborating with you, and applying our expertise in completion and reservoir disciplines, your objectives will be accomplished seamlessly, reliably, and efficiently. Contact us to learn how **Advanced Completions** can improve the performance of a single well or an entire field.
www.halliburton.com/advancedcompletions
HALLIBURTON

Offshore Technology Aims at Lowering Breakeven Economics

By Scott Weeden, Contributing Editor

From cost-effective RSS to higher bandwidth mud pulse to lower vibration underreamers, service companies are designing tools to meet industry demands.

The deepwater offshore drilling industry is changing with a focus on the "highest-specification assets [that] are at a critical inflection point as few such assets are in the global rig supply," according to Ensco Plc in its September 2017 investor presentation.

There is an "industry-wide focus on lowering breakeven costs for offshore projects through re-engineering, standardization and simplification," the company stated.

There will be fewer offshore drillers due to consolidation. Ensco backed up that statement with the completion of the acquisition of Atwood Oceanics Ltd. in early October 2017.

According to the company, "Larger customers [will] contract rigs with service providers that can help to continue improving breakeven economics for offshore projects through technology, innovation and new contracting models."

Service and manufacturing companies are responding to the call for more cost-efficient and higher performance tools to meet customer demands. The largest advantage offshore operators have to improving drilling operations is data. The more real-time data that is available and leveraged, the more accurate and efficient is the placement of the wellbore.

"We saw the opportunity to develop a high-performance but simple and cost-effective rotary steerable system [RSS] as part of a back-to-basics approach that we're taking to design tools for the current environment," said John Clegg, director of R&D and engineering for the Drilling and Evaluation Segment for Weatherford.

The new RSS represents "a very good, competitive option for somebody looking to drill efficiently in the $50 or even sub-$50 oil price environment," Clegg explained.

Other companies have developed technology for getting useable data to the surface more quickly so the industry can drill longer, smoother laterals and wells with ultra-extended-reach drilling (ERD).

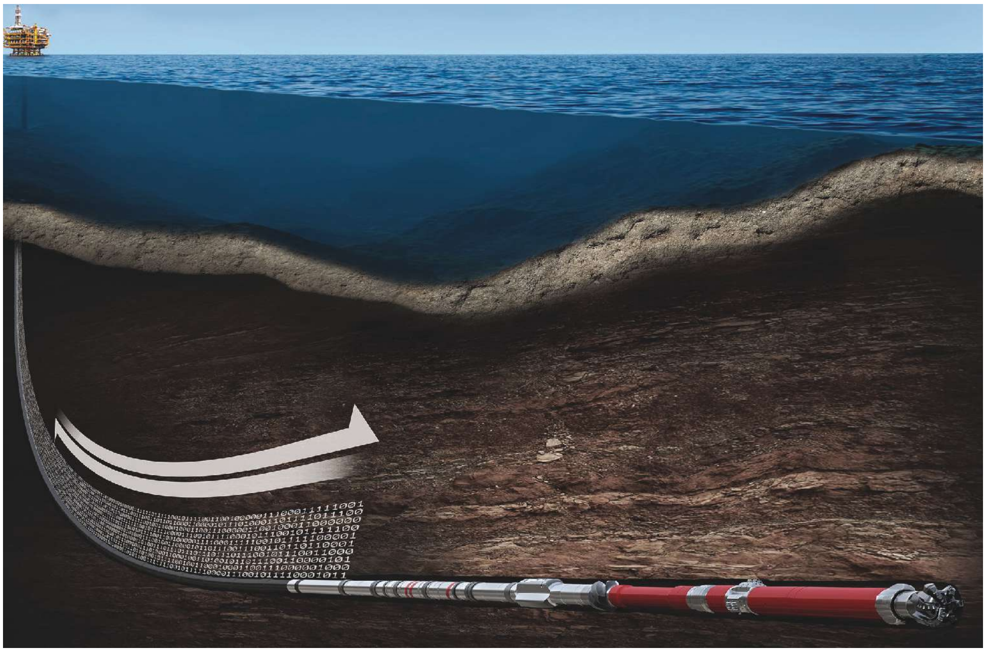
Expanded mud-pulse telemetry

The industry standard for getting data to the surface in a real-time stream is mud-pulse telemetry. As more tools are added for logging-while-drilling (LWD), a larger amount of data needs to be pulsed to the surface.

"What we've done is introduced a new pulse system called JetPulse that has a higher data rate that is double or triple the bandwidth we were able to get previously," said Tim Parker, Sperry Drilling, a Halliburton business line. "We can now use tools that are more data intensive such as the azimuthal lithodensity (ALD) tool, azimuthal acoustic tool or other azimuthal imaging tools that generate a lot of information. Having a faster pulsing system means that the operator doesn't necessarily have to slow down the drilling to get good quality data."

He explained that with a higher data rate an operator can still get good log data to the surface even while drilling a section in less time. "The other aspect is that with a particular drilling speed, by having a higher data rate, you can have a more detailed log. You can get more data points per foot as you're drilling the well."

The JetPulse is designed to operate in any kind of mud. "One thing we find is a general principle that applies to telemetry—the deeper you go, the more attenuation of the signal you see. Heavier muds tend to attenuate more than lighter muds. We have found the performance of this new sys-tem is actually very consistent as far as depth is concerned," Parker continued.



ALD provides downhole density measurements, including high-quality borehole image logs, to help optimize wellbore placement through geosteering and to reduce geological uncertainties. The measurements, delivered via LWD, also eliminate costly wireline conveyance runs and capture data immediately after drilling when the borehole is in the best condition. *(Image courtesy of Halliburton)*

There is very little loss of data rate with increasing depth. "We can work in some of the deepest wells that are drilled in the Gulf of Mexico [GoM] to about 30,000 ft," he added.

The system also is able to maintain a high data rate that is similar to what other systems would get at much shallower depths.

The company also has a new software system that is an add-on to its data acquisition system, which is a more sophisticated filtering and tuning system than the company had before. It helps to detect the pulses more easily as they come to the surface. The new system takes into account the characteristics of the entire drillstring in filtering out drilling noise, he explained.

When the system first begins operation it sends out a predetermined sequence that the surface system analyzes and decides how best to handle the subsequent data that comes up from the tool. "It's like a sort of auto-tuning to take account of variations in the drillstring, depth, etc." he said. Previously it was a manual system that people on the surface had to monitor and adjust.

The JetPulse is being used for the more high-end markets such as deepwater markets and more mature markets where a lot of tools are being run. In general the customers are happier the more data they have. They appreciate not having to moderate their drilling rate significantly now that there is a higher data rate. The system can provide a good log at typical drilling speeds in the GoM.

"I've got examples where we've run the JetPulse system with multiple sensors in the string where you can plot the real-time and memory logs next to each other, and it's very difficult to tell them apart," Parker emphasized.

Cutter block for underreamer reduces vibration

If there is a limitation to underreamers, it is the cutting structure or what that structure does to the entire bottomhole assembly (BHA). Underreaming operations can be notorious for having high levels of vibration. That is one of the things Schlumberger wanted to address with its Sting-

The StingBlock cutter block is the industry's first geometry cutter block that features a stage gauge pad design and Stinger conical diamond elements. *(Image courtesy of Schlumberger)*

In a conventional underreaming-while-drilling BHA, the assembly is susceptible to vibration because of the great distance between the two cutting structures drilling simultaneously—the underreamer is typically about 150 ft from the bit. Because of the distance, quite often the tools will be drilling in different kinds of rock, which can generate a lot of vibration into the drillstring, he explained.

What helps reduce vibration are the staged pads that better stabilize the cutting structure. It provides more contact area for the cutting block and the extra level of stability that is needed.

The rows of PDC cutters on its conventional reamers are symmetrical. "Symmetry might sound nice but in things with moving parts it can be susceptible to harmonic vibration levels. With StingBlock cutter we're creating an alignment with PDC cutters and Stinger elements more broadly distributed across the width," he noted.

Block advanced stabilization conical element cutter block along with providing a cutting structure that increases overall durability and allowing it to last longer and drill faster.

The StingBlock cutter is essentially the cutting structure of the Schlumberger Rhino integrated borehole system. There are a few key features that are used on the StingBlock cutter to better stabilize the BHA and improve the overall cutting structure durability. The underreamer has the company's proprietary staged profile, which helps to better distribute the cutter loads and to stabilize the overall cutting structure element, explained Wiley Long, product champion for StingBlock cutter for Schlumberger.

"You can imagine it as multiple gauge pads as you go up the cutting structure. Increasing that gauge pad area helps smooth out vibrations during underreaming operations. Our experience shows that the majority of damage that occurs on the reamer cutter structure is due to impact damage. For the cutting structure we've taken a page out of our bits playbook and incorporated the Stinger conical diamond. The Stinger conical element has a much superior impact resistance than a conventional PDC cutter," he said.

Schlumberger devised a different system that would incorporate two Rhino StingBlock reamers into the same BHA. It is called the Rhino RHE rathole elimination system. "For that system you have your top Rhino reamer in the conventional location above the LWD tool. Your second Rhino reamer would be just above the RSS about 20 ft to 25 ft from the bit," he continued.

The top reamer would be used while drilling the majority of the interval. Once the bit reaches total depth the upper reamer is deactivated, and the lower reamer is activated. "We can then underream that 120 ft-plus of rathole and eliminate an additional trip to underream that rathole," he added.

In the MWD and LWD tools there are sensors measuring vibration. In lab tests and field operations the company found the ability of StingBlock cutter to reduce vibration levels.

"We've had several runs in the GoM and offshore Brazil. The first one we had in the GoM was with our 11625 Series of StingBlock cutters. That one was underreaming a pilot hole from 12$^1/_4$-in. to 14$^1/_2$-in. Immediately on back-to-back runs the customer saw an increase of footage of 97% compared to the offset runs and a 32% increase in ROP," he said.

RSS built for sub-$50 oil price

Weatherford is taking a back-to-basics approach to designing its tools for the current price environment. The company began developing a new RSS in second-quarter 2016 that is simple to build, simple to operate and simple to repair and maintain even in remote locations.

"We've seen a lot of different RSS models come on the market over the years, some of which have gotten very complex and are suited for a higher oil price environment like $100 per barrel," Weatherford's Clegg said. "Many of the options that exist for RSS at the moment are not suitable for a $50 price environment."

The company was careful to listen to customer input before designing the tool. "We designed it so that it uses the already established push-the-bit operating principle. The fundamental steering principle is the same as a number of tools that have been around for a while, but we also took into account our lessons learned from years of directional drilling to optimize control of the tool," he explained.

A very high degree of control in terms of toolface control and also true proportional bias control were included. "You can drill straight with the RSS or you can switch it to maximum dogleg, or you can pretty much have any combination in between," he continued.

The tool is brand-spanking new, literally out of the box. It's so new the name hasn't yet been finalized. "We've had about six controlled field tests in the U.S., including a couple of horizontal sections. Toolface control has been excellent on every occasion," he added.

The tool was designed as a very slick assembly to minimize hole problems, such as getting stuck for example, and to maximize the pass-through volumes for cuttings from the bit.

"Speaking of bits, we also designed the RSS to work with any bit typically used with the most popular RSS tools currently on the market. That way the operator doesn't need to purchase a specialized bit for each directional system," he said.

"The ability to provide precise proportional control in terms of dogleg coupled with the ability to provide precise toolface control will be very attractive when you're drilling offshore," Clegg said.

The tool is expected to be commercially available in early 2018. Weatherford is working with a national oil company in the Middle East to deploy the tool in the first quarter.

"In terms of application, I believe it is going to improve ROP and, more importantly, allow longer laterals to be drilled," he added.

Downhole data in 45 seconds

High quality gas analysis has been based on taking samples every 30 ft, 90 ft or 120 ft, storing the samples in a tube or jar and sending them to a lab, which takes time before the results are available to the operator.

"For most offshore drilling environments with this service, we typically see around a depth resolution of less than 1 ft per sample, as opposed to the typical lab environment of a sample point every 10 ft to 120 ft per sample," said Alex Bruns, global product champion for surface logging for Baker Hughes, a GE company (BHGE).

The BHGE TRU-Vision quantitative gas extraction and analysis service provides a baseline separation of more than 27 gases—light hydrocarbons from C1 to C8 (alkanes, alkenes and aromatics) and key inorganic compounds such as carbon monoxide, carbon dioxide, helium, etc. The system uses a gas chromatograph on the offshore rig for the analysis.

"You're getting laboratory quality analysis at the rig with much better depth data and resolution than you would get in the laboratory, without compromising data quality," he emphasized.

The higher resolution provides a clearer understanding of formation fluid properties, such as fluid contacts, for a more detailed analysis of the formation. All of this happens within 45 seconds.

The BHGE TRU-Vision system provides a baseline separation of more than 27 gases using a gas chromatograph on the offshore rig for the analysis. *(Image courtesy of Baker Hughes, a GE company)*

"I called on different labs to try to correlate my samples to what they were doing for analysis. For example, they can't do the analysis that we are doing at the rig even in the lab as part of a standard analysis. They lump different gases together and give a combination of gases. However the real value is in separating those different isomers so that we can lead to a better understanding of the formation," Bruns explained.

The system works by sampling drilling fluid through a low-maintenance, self-cleaning strainer that removes drill cuttings. The sampling is done in the return line as close to the bell nipple as possible.

The sample then goes through a progressive cavity pump and then to an aluminum heater, which is designed to maintain the desired temperature of the mud. From there the mud is measured by a coriolis flow meter and then to a constant-volume gas trap where the gas is extracted, explained Rocio Brendle, marketing and commercial manager for BHGE.

The gas goes to a gas distribution panel and then is analyzed by this high-speed gas chromatograph. Multi-columns and multi-ovens in the chromatograph allow baseline separation of compounds and isomers, Brendle added.

The TRU-Vision gas equipment doesn't take up any additional deck space on the rig. Two people can lift it into place. With most rigs' return flowline being high enough off the deck in the "shaker house" the extraction apparatus fits nicely underneath that, Bruns said.

Density data from large-bore holes

Until now, the only way to get density data for porosity measurements from sections in $14\frac{1}{2}$-in. to $17\frac{1}{2}$-in. holes was to run a wireline. Of course, that costs operators rig time, and they were looking for ways to eliminate that, said Sperry Drilling's Parker.

"It started off with a major operator in the Gulf of Mexico suggesting we should build a larger version of the density tool—the azimuthal lithodensity (ALD) tool that measures density while drilling—and we agreed," he continued.

Since then the tool has been used by the operator and a number of other customers in the GoM. What the operators wanted was to log zones that are potentially hydrocarbon bearing and eliminate some of the wireline runs.

"There's another benefit from the fact that the tool is azimuthal. The tool is basically measuring all around the wellbore as the tool rotates as part of the drillstring. You can generate an image inside the borehole based on variations in density. From that you can estimate the formation dip angle and orientation," he explained.

"There are some areas in the Gulf of Mexico where they drill through salt layers. The seismic data through salt is very poor. When the ALD tool exits below the salt, the issue is understanding the orientation of the bedding. What is the dip angle? Which way are the formations dipping? Having that kind of information in that hole size is important. The ALD tool can give an estimate of the dip angle and a chance immediately to better plan the well and decide which way to drill when they get out of the salt," he said.

That approach has been available for much smaller holes for some time. Sperry now has a much larger tool for the bigger bore sizes in the GoM.

The ALD tool is built into the drillstring along with other tools. "We have a three-bladed stabilizer on the tool. Built into one of the blades are the actual detectors that we're using for the sensor readings for measuring formation density. Because we're in a drilling situation, we use a stabilizer blade to bring the sensors close to the formation to get a good measurement," he continued.

The advantage over a wireline is that the tool is rotating and able to generate those images that are not available from the wireline density tool.

"The deepest we've gone so far with this tool is 24,000 ft measured depth [MD]. So far we've been working in the range of 12,000 ft to 24,000 ft roughly," he added.

Parker said Sperry is the only company with these larger size tools.

Running the density tool for real-time data and dip estimation below salt in the larger bore sizes seems to be a more popular application now. "Eliminating the wireline run provides the real savings potential for the customer. They can get the data without having to make a special trip or spending extra time on the rig," Parker emphasized.

RSS designed for ERD wells

Operators are looking for cost-effective ways to drill faster and longer laterals since the more footage that they can expose, the higher the level of returns, said Juan Restrepo, product champion for RSS for Schlumberger.

"When you measure drilling efficiency, it can be seen in two ways—drilling faster and minimizing the number of BHAs used to drill to the objective. All the development we have had in recent years has to do with how to have the system provide a quality hole for our client in the shortest period of time," he continued.

There are three points that have to be hit to reach new levels of performance—drill faster, the ability to drill longer wellbores in the target zone and provide high quality holes. "No matter how far you drill, if you don't have a hole that can be used, it is going to be a waste of time and money for the whole well construction and production process," he added.

Schlumberger has added two new members to its PowerDrive RSS family. The PowerDrive Xcel RSS is focused on offshore and ultra-ERD wells, while the PowerDrive Orbit RSS is focused on land operations, including super laterals.

"The ERD wells are getting longer and longer so downhole automation is becoming more critical for the consistent performance of directional tools building micro-tortuosities across the extended lengths reduces the amount of energy required for the actual drilling process," Restrepo explained.

Each RSS has a distinctive design, but both the PowerDrive Orbit RSS and the PowerDrive Xcel build on their direction and inclination sensors close-to-the-bit to provide automated closed-RSS loops simultaneously on inclination and azimuth. Closing this loop downhole allows us to automatically hold any 3-D orientation vertically and laterally for a given target, minimizing the interaction from the surface in the drilling process for faster penetration rates.

"There are no more commands to be sent to the tool. The tool is going to measure its orientation downhole and do exactly what it needs to keep the target set," he said. That takes the human out of the equation.

The PowerDrive Xcel RSS was designed for use in high-profile directional drilling operations. It provides inertial directional control in deviated sections—a feature that can be toggled on and off by a downlink. *(Image courtesy of Schlumberger)*

The Extreme HeatWave HP/HT LWD tool has a temperature rating of 200 C and a pressure rating of 30,000 psi. Data can be recorded at ROPs up to 720 ft/hr. *(Image courtesy of Weatherford)*

At 350 revolutions per minute, the tool can still measure downhole both inclimation and azimuth. "One of the quests we had [in the design] was to accurately measure the inclination and azimuth dynamically to confidently let the tool decide for itself what to do without requirements from the surface. That is a very important point of this," he emphasized.

Vibration affects where energy is going in the drillstring. "For drilling performance, characterization of the vibration patterns is critical. Both technologies provide triaxial measurement of shocks and vibration," Restrepo continued.

The PowerDrive Xcel RSS also was shown to be effective in open-hole and closed-hole sidetracks due to the inclusion of a gyro and a customizable bend offset. The tool can measure rotation and stick-and-slip in magnetic interference environments. It also maintains directional control through the zone of exclusion, he added.

LWD tool designed for 200 C environment

Operators drilling in the Gulf of Thailand know to expect high bottomhole temperatures (BHT) and high ROPs. One Weatherford customer had drilled several wells in the area very quickly and wanted to use LWD to log the well, however the BHT was around 200 C.

"It has been a real challenge for the industry to produce an LWD tool that operates at 200 C. It requires a very different approach to design, manufacture and then test the electronics in particular to get the tool up to that temperature rating and operate reliably in that kind of environment," said Weatherford's Clegg.

"If you look at the inside of the HeatWave Extreme HP/HT LWD tool, it is very different from conventional LWD tools. During the R&D process we worked with die manufacturers and ceramic packaging vendors to combine multiple functions into hybrid modules," he explained.

After completing the design part of the LWD tool, the company began testing and qualification with very rigorous and extreme tests up to 250 C. "We also did some very extreme excursions from temperatures above 200 C down to below the freezing point and back up again. This simulated the kind of things you'd see if you trip out of a hot reservoir onto a cold deck and then back down," he continued.

The company also did the same vibration and shock testing as it would on a conventional LWD tool. "The functions of the tool are the same as they would be in a low-temperature tool. We didn't make any sacrifices in terms of functionality or data quality," he emphasized.

The tool has a temperature rating of 200 C and a pressure rating of 30,000 psi. The HP/HT LWD tool includes Weatherford's vibration and monitoring technology so that the tool is able to monitor, measure and account for things like lateral vibrations at high frequency and torsional oscillation, Clegg continued.

There is no time limit on how long the tool can stay downhole. "We don't have that constraint because we designed all of the component parts to operate at 200 C. We can record data at ROPs up to 720 ft/hr," he added.

Operators appreciate the HP/HT LWD tool because of the accuracy of the service and the ability to maintain calibration of the tool at that kind of temperature, he said. They are also impressed by its ability to drive improvement in performance by providing reliable measurements," he said. ■

Awards, Activations Engender Optimism

By Judy Murray, Contributing Editor

Contract awards and resumed construction indicate the formerly stagnant fixed and floating systems market is beginning a long-awaited revival.

Increased activity in the fixed and floating systems sector suggests things are looking up–at least in relative terms. After what was a particularly inactive 2016, companies have made the move to advance projects and resume construction.

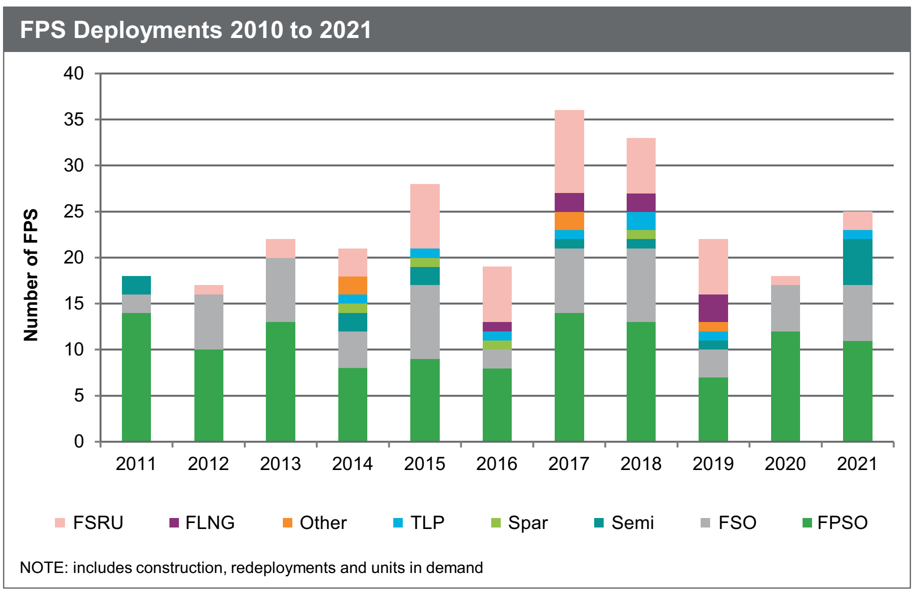
A sign of the times

The floating production system (FPS) market fared poorly in 2016. The market was shaky in 2015, and then the oil price dropped precipitously at the beginning of the year, hitting its lowest point since the price began to decline in mid-2014. That somber note set the tone for the industry, and conservatism was the watchword for the ensuing year.

Fortunately, prices did not remain at this nadir for long, but the slow climb back up never took oil to anything remotely resembling its earlier price point. The most recent apex was reached at the beginning of 2017, when the oil price hit $55 for the first time in 18 months and remained above $50 for the first few months of the year. While the price since that time could not be characterized as particularly stable, it has evened out at a level that has given the industry sufficient confidence to begin resurrecting development plans that had been put on indefinite hold.

In a news release published by Singapore-based Energy Maritime Associates (EMA) in early August 2017, Managing Director David Boggs expressed optimism based on EMA data for the floater sector. "The recovery that began in Q4 2016 has continued," Boggs said, cautioning that while one floating production unit per month is well below the historical average of 1.5 orders/month, the consistent emergence of orders paints a slightly more positive picture.

"Confidence appears to be retuning," Boggs said, pointing to the sanctioning of a number of projects and indicators that several companies had begun tendering for FPSOs. Even though oil prices are expected to remain low, he said, there are viable offshore projects that will move ahead as a result of lower supply chain costs and revised development plans.

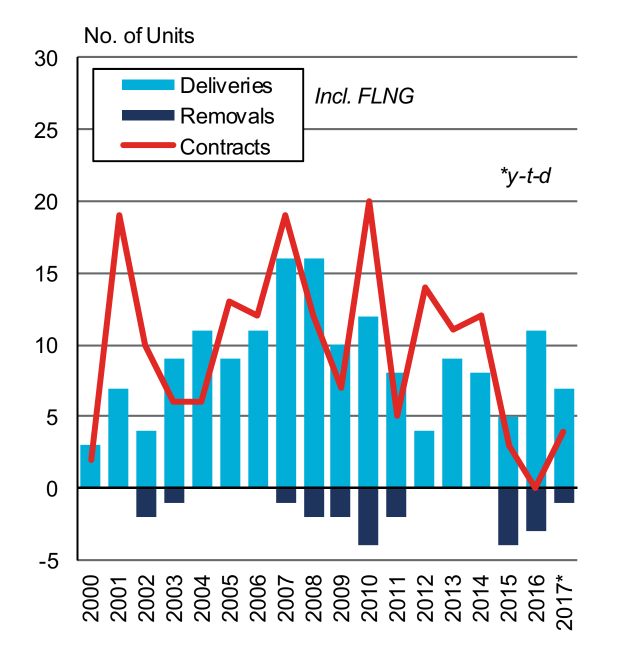


After a spike in deployments this year, the forecast indicates a tapering off through 2020. *(Source: IHS Markit)*

Signs of recovery for FPSOs

Analysts following the fixed and floating structure market at IHS Markit reported some of the first good news of the year in February with the Ophir Production contract to Malaysia-based MTC Engineering to supply the floating, production, storage and offloading (FPSO) vessel, *Ledang.* An oil tanker named *Puteri Bangsa* will be converted into an FPSO with processing capacity of 15,000 bbl/d of fluid and storage capacity of 350,000 bbl of oil. The vessel was scheduled to begin producing the shallow-water, marginal Malaysian Ophir Field this year.

FPSO Deliveries, Removals and Contracts



Data indicate that the FPSO/FLNG sector is more stable than it was a year ago. *(Source: Clarksons Research)*

Other FPSO awards followed, with Repsol announcing a Final Investment Decision (FID) in May to develop the Ca Rong Do (aka Red Emperor) discovery in Block 07/03 offshore Vietnam. Yinson Holdings Bhd, based in Malaysia, was contracted to supply and maintain the FPSO. Data from EMA indicates the development will use a wellhead TLP connected to the FPSO. A contract for the construction of the TLP was awarded to Petrovietnam Technical Services Mechanical & Construction Co. Ltd., which will build the unit in Vietnam.

In mid-June Exxon Mobil published a press release announcing an FID for the first phase of the Liza Field, approximately 118 miles offshore Guyana in water depths of 4,900 ft to 6,200 ft on the Stabroek Block, which covers 6.6 million acres. Liza is one of the largest oil discoveries of the past 10 years according to Exxon Mobil, which estimates gross recoverable resources between 2 Bboe and 2.5 Bboe. Phase 1 includes a subsea production system and an FPSO to be supplied by SBM for production beginning in 2020. The FPSO is designed to produce up to 120,000 bbl/d of oil.

Perenco affiliate Dixstone Holdings Ltd. also made an announcement in the summer, awarding Keppel Offshore & Marine Ltd. subsidiary, Keppel Shipyard Ltd. a contract to convert the M/T *Tempera* into an FPSO for the Yombo Field offshore the Republic of the Congo. The conversion work was expected to begin in third-quarter 2017. Upon its expected delivery in third-quarter 2018, the FPSO will replace the *Conkouati* FPSO (converted by Keppel Shipyard in 1991), which has served the field for more than 25 years.

There also were several FPSOs redeployed this year. The first announcement came in April, when Alpha Petroleum issued a press release outlining an exclusivity agreement with Teekay Offshore to carry out front-end engineering and design on its *Varg* FPSO (removed from Repsol's Varg Field in the Norwegian North Sea in July 2016). *Varg* will be redeployed on the Cheviot Field, which the company describes as one of the largest undeveloped oil fields in the U.K. sector of the North Sea. Alpha expected to achieve sanction for the development during third-quarter 2017 and is targeting first oil production in 2019.

In an official statement, Alpha Petroleum Executive Chairman Andy Crouch called the agreement, "a key milestone in the development of Cheviot Field," noting that it is the product of "innovative thinking and continued investment during a downturn in the market."

COSCO Nantong Shipyard in Qidong, China, completed work on the *Western Isle* FPSO, a Sevan

Marine cylindrical design in February, which was towed to the North Sea for final construction. The Dana Petroleum-operated Western Isles Project will develop the Harris and Barra oil fields in the Northern North Sea, 100 miles east of the Shetlands. First oil, originally targeted for 2105, was rescheduled for year-end 2017.

In April, BW Offshore announced an extension of the lease agreement with Nigerian Agip Exploration Ltd., a subsidiary of ENI S.p.A, for the *Abo* FPSO that extends the contract to March 31, 2018, with options until 2023. Another of the company's vessels, the FPSO *BW Catcher* left the Keppel Shipyard in Singapore in August en route to the Catcher Field in the central North Sea. Once onsite in the fourth quarter, the FPSO will begin work for Premier Oil on a seven-year fixed term contract, with extension options of up to 18 years. First oil was expected by year-end. *BW Catcher* has oil storage capacity of 650,000 bbl and processing capacity of 60,000 bbl/d.

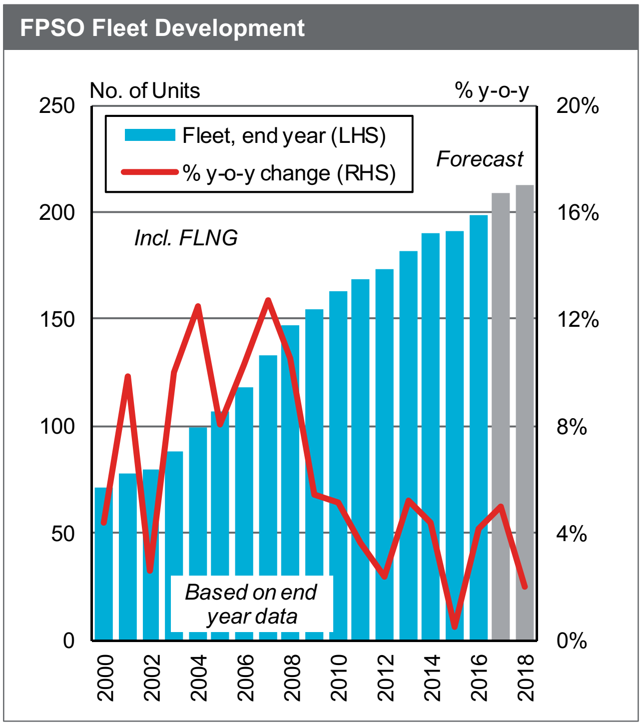
According to analysts at IHS Markit, the company also plans to redeploy the floating, drilling, production, storage and offloading (FDPSO) vessel *Azurite* to work at the BW Energy-operated Dussafu project offshore Gabon following minor modifications at the Keppel FELS shipyard. The FDPSO is the world's first (and only) vessel of its type, with a storage capacity of 1.3 Mbbl of oil and processing capacity of 40,000 bbl/d. Its unique design allows it to be used for drilling and completing production and injection wells. This is welcome news for a vessel that has been idle since the beginning of 2014, when production on the Azurite Field offshore Congo ceased. First oil on Dussafu is targeted for the second of 2018. IHS Markit anticipates a second redeployment by the end of the year, with Nigeria-based First Exploration & Petroleum Development Co. Ltd. expected to use an existing FPSO for its Anyala/Madu development offshore Nigeria.

More work is upcoming as well for the *Aoka Mizu* FPSO, owned and operated by Bluewater Energy Services B.V., which has been contracted by Hurricane Energy to supply the vessel for use in the early production system phase of Hurricane's shallow-water Lancaster Field in the Rona Ridge area West of Shetlands. The FPSO left its berth at the Remontowa yard in Gdansk, Poland, arriving at the end of September at the Drydocks World Dubai Shipyard, where it will undergo updates. Subsea installations will be carried out onsite ahead of *Aoka Mizu*'s arrival next summer. Production is anticipated in the first half of 2019.

Bluewater's *Aoka Mizu* FPSO has been contracted by Hurricane Energy for use in the early production system phase of the shallow-water Lancaster Field in the Rona Ridge area West of Shetlands. *(Photo courtesy of Bluewater)*

Hurricane Energy Chief Executive Dr. Robert Trice called this award, "an essential step in planning for the full field development of the company's Rona Ridge assets," confirming that more development work is anticipated. The choice of an FPSO by a relatively small operator is an encouraging sign. According to Bluewater President and CEO Hugo Heerema, the award shows that, "even in a low but improving oil price environment, developments can be made economical."

This year saw signs of movement again in the FPSO fleet operating offshore Brazil. In February, the BrasFELS shipyard in Angra dos Reis, Rio de Janeiro, delivered the *P-66* FPSO to Tupi BV for work on the Lula Sul Field in the Santos Basin. In May, Teekay Offshore took delivery of *Pioneiro de Libra* from Sembcorp Marine's Jurong Shipyard. This vessel, which also is deployed in the Santos Basin, will be the first to produce the ultra-deepwater Libra Field. In October, Petrobras moved a third unit into its FPSO fleet with the delivery of the *Cidade de Campos dos Goytacazes MV29* from BrasFELs. The vessel moved to the Bananal Bay offshore Brazil for eventual deployment on the Tartaruga Verde and Tartaruga Mestiça fields, in the Campos Basin.



The FPSO/FLNG fleet is continuing to grow. *(Source: Clarksons Research)*

Other floater types bounce back

Developments in the FPSO sector introduce a welcome note of optimism to the fixed and floating asset market, and there is some good news from other segments of the sector as well.

In April, the world's largest semisubmersible platform to date, the Ichthys Explorer, was delivered for the Ichthys Field in the Browse Basin. About 135 miles offshore Western Australia,

Ichthys is the largest hydrocarbon discovery in Australia in 40 years. The semi, which was built at the Samsung Heavy Industries (SHI) shipyard in South Korea, was towed approximately 3,730 miles to the field, where it is permanently moored onsite. Production is expected by March 2018.

The only newbuild semisubmersible award this year came from BP. In January, the supermajor contracted SHI in Korea to build a semisubmersible for Mad Dog Phase 2, the US$9 billion project sanctioned in December 2016. The new semi will be moored approximately 6 miles southwest of the existing Mad Dog platform, which lies in 4,500 ft water depth on the Green Canyon Block in the Gulf of Mexico (GoM) about 190 miles south of New Orleans. Discovered in 1998 and beginning production in 2005, Mad Dog is BP's biggest discovery in the GoM. The newbuild semi will be moored in 4,440 ft of water in Green Canyon Block 780.

This announcement had been anxiously anticipated. BP spent two years revising its development concept for Mad Dog 2, reducing the overall project cost by 60%, a necessity for this deepwater development in the present market.

BP Group Chief Executive Bob Dudley said in an official statement that progressing Mad Dog 2 "shows that big deepwater projects can still be economic in a low-price environment in the U.S. if they are designed in a smart and cost-effective way."

The other semisubmersible of note this year is the Appomattox, the largest semi ever built by Shell. The hull left South Korea in August conveyed by COSCO's heavy transport vessel *Xin Guang Hua* on its way to Ingleside, Texas, where the topsides will be added and construction completed. The Appomattox Field is 80 miles offshore Louisiana in the GoM, in approximately 7,200 ft water depth. The semi initially will produce from the Appomattox and Vicksburg fields, with average peak production

In April, the world's largest semisubmersible platform to date, the Ichthys Explorer, was delivered for the Ichthys Field in the Browse Basin. This field is the largest hydrocarbon discovery in Australia in 40 years. *(Photo courtesy of INPEX Corp.)*

Statoil's Aasta Hansteen topside is loaded out on the Dockwise *White Marlin* heavy-transport vessel at Hyundai Heavy Industries en route to Norway. This will be the first spar offshore Norway and the largest in the world. *(Photo by Lee Hyungjin, courtesy of Statoil)*

estimated at 175,000 boe/d. First production is anticipated in 2019.

Statoil's Aasta Hansteen is the only spar on the orderbook at present. This unit will be the first spar offshore Norway and the largest in the world. The spar was upended at Klosterfjorden off the west coast of Norway and will eventually be moved to the Aasta Hansteen Field in the Vøring area, 186 miles offshore, where it will produce gas in 4,265 ft water depth, opening up deepwater development in the Norwegian Sea. First production is scheduled for September 2018.

The Hess Stampede TLP will produce the Stampede Field in approximately 3,500 ft water depth, 115 miles south of Fourchon, La., on the Green Canyon Block in the GoM. *(Photo courtesy of Hess)*

Other than the wellhead TLP being built for the Ca Rong Do Field offshore Vietnam, there is only one other TLP on the scene this year. The Hess Stampede TLP will produce the Stampede Field in approximately 3,500 ft water depth, 115 miles south of Fourchon, La., on the Green Canyon Block in the GoM. With recoverable reserves in the range of 300 Mboe to 350 Mboe, Stampede is one of the largest undeveloped fields in the region. First oil is planned for the first half of 2018.

There is also some interesting news in the jackup sector. Saka Energi in Indonesia has decided on a jackup FPU for its Sidayu satellite project in the Pangkah working area in the Madura Sea offshore East Java. And the Petrobaltic, a Polish flagged jackup built in 1980, has been converted from a drilling rig to a production unit at the Remontowa Shiprepair Yard in Gdansk. The rig is to be the central production facility in the B8 Field in the Polish economic zone in the Baltic Sea.

Of the floating, storage and offloading (FSO) units being tracked by IHS Markit, three came onstream in 2017. The *Benoa* FSU offshore Indonesia, the *Randgrid* FSO for Statoil's Gina Krog Field in the Norwegian North Sea, and the *Nautica Bergading* in the North Malay Basin in the Gulf of Thailand. Five additional FSOs currently on order are expected to come onstream in 2018 with another following in 2019.

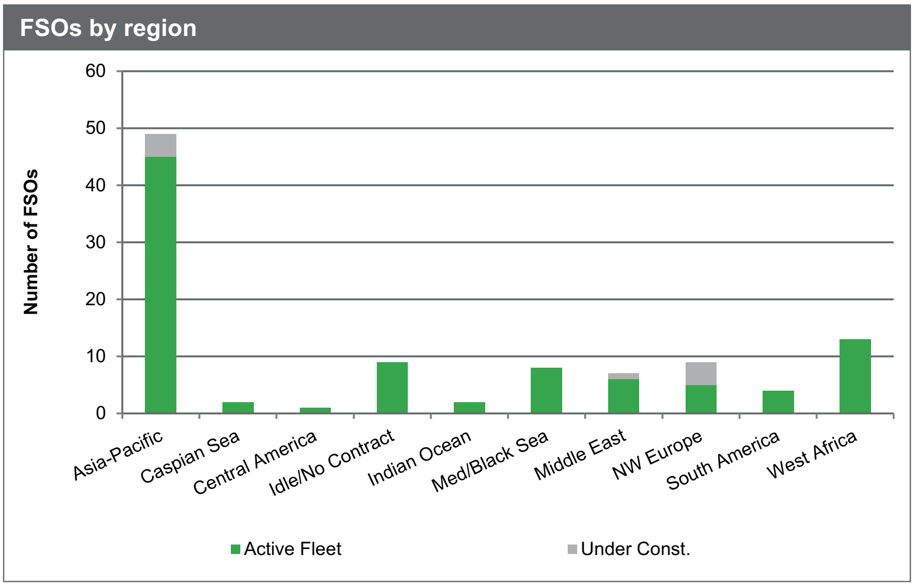
FLNG

After a period of stagnation, the LNG sector is beginning to see some movement as well. EMA analysts point to studies underway in Congo, Cameroon, Equatorial Guinea and the U.S. as evidence that growth is in the cards, noting that many of these will focus on monetize existing production rather than developing new fields.

Among recent news was the announcement by shipping company Golar LNG in early October that the FLNG *Hilli Episeyo,* the world's first converted FLNG vessel, moved to deepwater anchorage, where Keppel completed final commissioning. The vessel left Singapore on October 12 and will begin work offshore Kribi, Cameroon, for Société Nationale des Hydrocarbures and Perenco Cameroon.

Meanwhile, Shell's *Prelude* FLNG arrived at the Prelude Field in the Browse Basin, 295 miles offshore Western Australia in July, where the next phase of the project has begun. Work continues on this vessel, which will deliver at least 5.3 million metric tons per year (mtpa) of liquids, including 3.6 mtpa of LNG. First production is expected in 2018.

A report by analysts at Clarksons notes that Keppel FELS also received a contract to convert the *Gandria* LNG vessel into the *Gandria* FLNG for work on the Ophir-Energy-led Fortuna FLNG project offshore Equatorial Guinea. This conversion is expected to be completed in 2020.



The Asia-Pacific region leads in FSO deployments and orders. *(Source: IHS Markit)*

Petronas Carigali's *PFLNG 2*, which received FID in February 2014, also is moving toward completion. The vessel will be deployed on the deepwater Roatan Gas Field in the South China Sea 150 miles off the east Malaysian state of Sabah. First production is now expected in 2020.

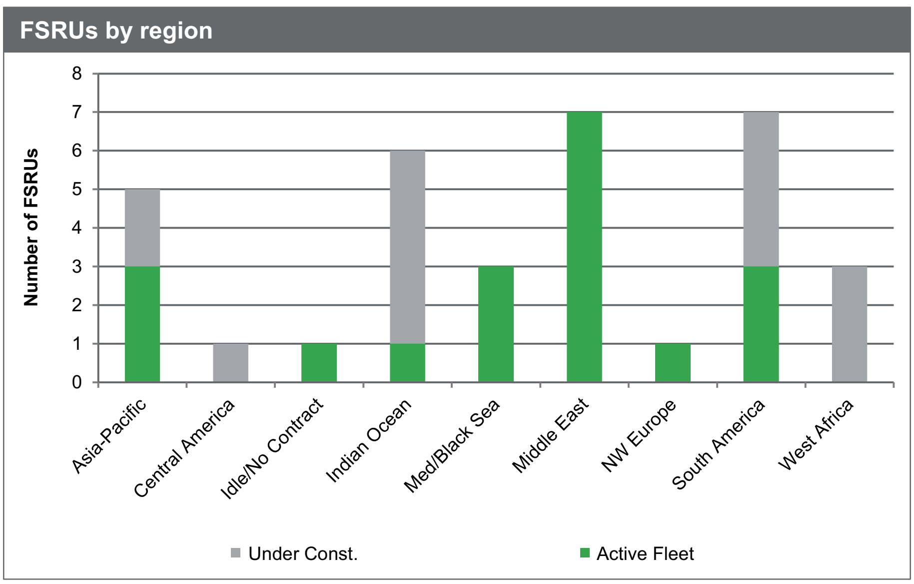
And Eni has awarded the *Coral South* FLNG project in the Rovuma Basin Area 4 offshore Mozambique to a consortium formed by TechnipFMC, JGC and SHI. This will be the first newbuild FLNG facility to be installed in Africa.

FSRUs

According to IHS Markit, six FSRUs were scheduled for delivery in 2017, and six more are on order for 2018. Three of the 2017 vessels belong to Golar LNG. The *Gas Atacama Mejillones,* which will work in the Bay of Mejillones offshore Chile, the *Golar Tundra*, which is to work offshore Ghana, and the *Golar Nanook*, to be part of the Sergipe Power Project, Latin America's largest gas power plant, offshore Brazil. Hoegh LNG's *Quintero Bay* FSRU is slated to work offshore Chile, and an FSRU owned by Saipem is contracted to work for Petroci off the Ivory Coast.

The final vessel is to be delivered by Exmar.

Schedules for some of the 2017 deliveries could slide into the following year, and the six deliveries slated for 2018 might follow suit. If the schedules



Most of the active FSRU fleet is working in the Middle East, but a large number of units on order will work in the Indian Ocean and offshore South America. *(Source: IHS Markit)*

While activity in the fixed and floating asset sectors has gained momentum, the road ahead will not be smooth. Wavering oil prices will continue to challenge developments ...

hold, Hoegh LNG will deliver three more units next year. Excelerate Energy will add two, and JSK will contribute the sixth new unit to the global fleet.

In 2019, Exmar's *Jafrabad* is scheduled for delivery to Swan Energy, and HHI plans to complete work on the *Karnataka* for Fox Petroleum. PREPA plans to deliver the *Aguirre GasPort* the following year.

Innovative concepts

While more units move onsite and begin operations, R&D efforts are delivering more technologies with the potential to improve drilling and production. Early in 2017, Frontier Deepwater Appraisal Solutions LLC introduced its ultradeepwater Appraisal Production System (APS), which the company says is feasible with oil at $50. This concept converts sixth-generation semisubmersibles to produce a unit that can be deployed early in the appraisal process, providing direct vertical access for drilling, completion and well intervention to collect production data that will enhance understanding of the reservoir.

According to designers, the APS increases safety by removing the subsea BOP, drilling riser, dynamic positioning system and associated hardware and installing a movable wellbay that supports dry-tree well tieback risers with a polyester taut leg mooring system that the company says will allow it to weather a 1,000-year hurricane in the GoM. The arrangement of the APS allows wellheads to be located beneath the center of the drilling derrick for drilling and completion operations.

A new concept developed by Japan's Chiyoda Corp. offers a novel approach to delivering new sources of power. The conceptual design is based on converting existing LNG carriers into floating power plants with small- (~72 MW) to medium- (~400 MW) scale power generation capabilities. The design combines FLNG and FSRU concepts for a hybrid that the company says has a shorter delivery time and can significantly lower costs. By supplying electricity directly to land from these units via heavy-duty electrical cable, Chiyoda plans to offer LNG power generation facilities in remote areas, eliminating the infrastructure required by traditional LNG plants, such as receiving and onshore power generation facilities.

Hyundai Heavy Industries (HHI) also has introduced a new FLNG design that HHI Senior Vice President, Shipbuilding Division Jae-Eul Kim announced, "can be constructed for about half the cost as compared to a standard FLNG hull." According to the company, a newbuild conversion FPSO hull concept design that follows the same process is under development as well.

Meanwhile, BP has introduced a versatile new concept, called the JackSemi, as an alternative to traditional hull designs for either drilling or production systems. The hull of the JackSemi incorporates a jacking system positioned above the water line to raise and lower the deck. Support columns can be fitted with strakes to minimize vortex induced motions, and keel structural framework can be installed in the pontoons to accommodate risers. It is designed for both fixed and variable ballast, which allows the height of the center of buoyancy to be increased above the center of gravity to improve motions and increase stability. Constructability makes this design particularly desirable, according to BP. Because the deck can be lowered quayside, smaller cranes could be used to move topsides equipment into place, which means more yards would be able to construct these units.

2018 and beyond

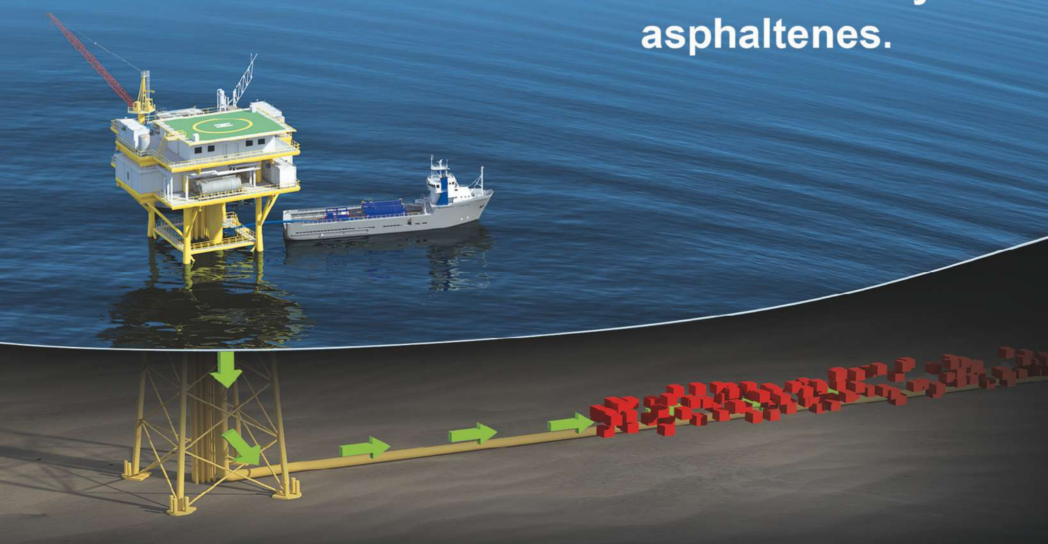
While activity in the fixed and floating asset sectors has gained momentum, the road ahead will not be smooth. Wavering oil prices will continue to challenge developments, and companies will have to continue sharpening their pencils to find ways to make developments profitable, particularly in deep water. The number of units delivered in 2017 and on order for the next five years is a sign of renewed activity, but only time will tell if the momentum will be sustained. ■

IDEAL
ENERGY SOLUTIONS, LLC

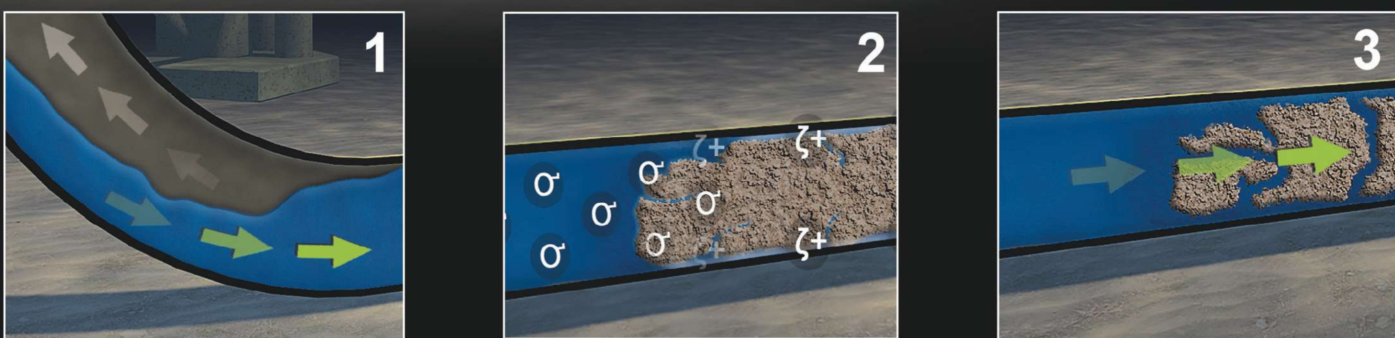
WellRenew™

INNOVATIVE CHEMISTRIES
to Ensure the Flow of Hydrocarbons
www.idealenergysolutions.com

The only non-hazardous, environmentally friendly remediation solution in existence that effectively removes paraffin wax and asphaltenes.



Remove Paraffin and Asphaltenes in Any Situation



	Any Temp	Any Length	Any Shape
WellRenew™	✓ Yes	✓ Yes	✓ Yes
Line Heating	No	No	
Warm Solvent	No	No	
Hot-Oil Treatments	No	No	
Coil Tubing		No	No

www.idealenergysolutions.com 337.247.9719 Renderings by designvision

Can Technology Save Subsea?

By Steve Sasanow, Contributing Editor

Because of the price crash, subsea operators are finding new ways to develop their assets.

It is now three years since the great oil price collapse of late 2014–you know, the one that nobody saw coming–which resulted in the price of a barrel of oil dropping like a rock from more than $100 to close to $30. While it has now recovered to the $50-to-$60 range, no one is jumping up and down with glee.

The offshore sector in general, and the subsea-deepwater portion specifically, the most expensive in terms of drilling and development costs, have yet to really recover. There are scraps of projects going forward, but there is not a sustained improvement that would suggest that all is well.

The question that seems to have eluded many analysts and forecasters is this: Did no one realize that a correction was due? Anyone who was paying attention would clearly have been alerted that something was amiss. At least 18 months prior, around the spring of 2013, a number of operators, both large- and middle-sized, had put the boot firmly on the development brake and began to question how it was possible for projects with significant reserves–and with oil at $100/bbl–to be marginally economic.

The capital cost of deepwater and subsea projects had been growing inexorably with demand since the year 2000 as manufacturers provided increased capacity and with it ever more sophisticated highly engineered hardware. Subsea had become "outer space," with a relatively small number of suppliers trying to meet demand for ever more complex equipment and making hay while the sun continued to shine.

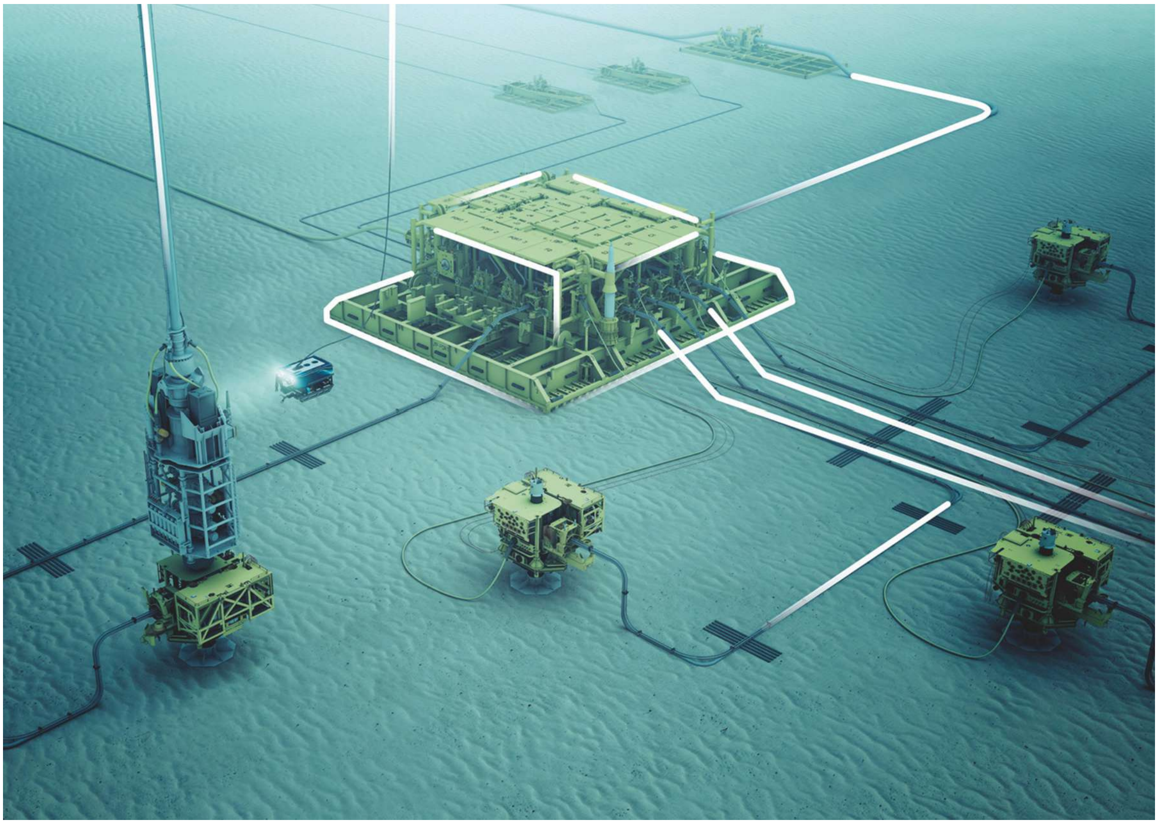
Was there to be no way to halt to the rising cost of projects? There just had to be, and when it came, it was very painful. With the industry suddenly stuck on pause, how would it be possible to get the flow of projects going again?

Enter technology

Since the advent of subsea technology about 35 years ago, the offshore industry has ridden a wave of innovation that has seen production move from less than 100 ft of water in the Gulf of Mexico to 328 ft to 656 ft of water and harsh environment in the North Sea and production tied back a few miles to platforms to more than 8,200 ft of water in the Brazilian and U.S. Gulf of Mexico sectors–and maybe West Africa as well–and long-distance tiebacks of 62 miles. And these numbers barely reflect the other challenges presented by environmental issues, such as cold waters and hot reservoirs, and the chemical makeup of the fluids.

When field development teams sought solutions to difficult technical problems, the answer quite often seemed to be some piece of new technology. The Shell/Esso Underwater Manifold Centre (UMC), installed on the Central Cormorant Field in the U.K. sector in 1983, is an early example of many of the technologies that are now taken for granted in the context of subsea developments–large and complex template-manifolds, electrohydraulic controls, on-template wells combined with satellites, complex pull-in systems for flowlines and umbilicals and the growing use of underwater robotics for inspection and maintenance, for example.

Even at the end of the 1970s, when the concept for the UMC was first hatched, it was more than a half-decade after Esso's Submerged Production System (SPS), which included a number of tech-



Just as our understanding of the subsurface has evolved, so too has our approach to designing subsea technologies. *(Illustration courtesy of Baker Hughes, a GE company)*

nologies that have only fairly recently become fully accepted (subsea boosting) and some that have never been used, such as a nuclear-based power unit.

In the decades since the SPS and the UMC, the subsea sector has propelled itself forward with a variety of technologies to meet the ongoing development demands, from variations of subsea processing (separation, boosting and compression) to steel catenary risers to electric christmas trees and more. Whatever has been asked for in the past three decades, the subsea industry has produced.

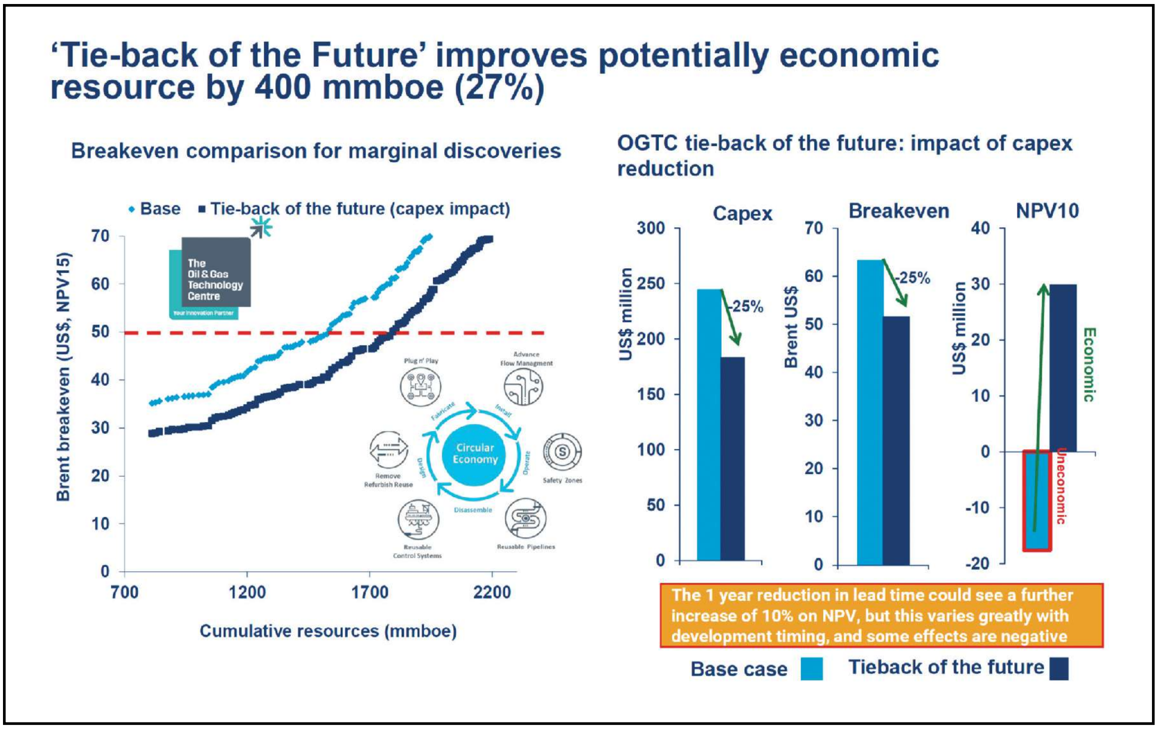
Hope for subsea?

So with the industry still mostly in the doldrums, can technology save it?

In the aftermath of the oil price crash, Sir Ian Wood, founder of the Wood Group, the U.K.'s biggest offshore engineering and support organization, was tasked with providing answers–and some hope–for a sector that was both aging and moribund. His eponymous report, which produced the catchphrase "maximizing economic recovery," or MER, recommended the creation of a new industry regulator. This resulted in the birth of the Oil & Gas Authority and a number of spinoff organizations that would help support the regulator in its onerous task of trying to revive a mature and costly sector.

One of these organizations is the recently launched Oil & Gas Technology Centre (OGTC). It sounds a bit bizarre that a sector like the U.K., which has been producing oil and gas for more than 40 years, has only just created a government-funded technology body, but nevertheless OGTC has jumped into its task with both feet and launched a number of projects aimed at creating new opportunities in the sector.

While one of its recently launched initiatives is correctly focusing on regional developments–how



OGTC program could reduce subsea facilities and abandonment costs by 50% and cut lead times by 1 year with the potential to add US$4 billion of value. *(Source: WoodMac, Oil and Gas Technology Centre)*

can a number of operators with smallish discoveries be brought together to create an economically viable development–the key project is the one dubbed "small pools." The U.K. has more than 3 Bboe in reserves left on its shelf, but most are relatively small, and this initiative aims to find ways to bring those barrels into production.

"Technology has a role to play" in bringing these reserves to shore, said Chris Pearson, who is heading up this initiative for OGTC, but, he added, "No one gets the impact of the life cycle" of fields when they begin a project. He said that he had recently spoken to an engineer from one of the supermajors who said decommissioning is never part of his company's thinking when they begin a project.

This has to change, Pearson said, although he admitted that with no legislation in place from the early days of the sector it would be hard to blame companies for not focusing on the abandonment issue.

Pearson also said that there are no "silver bullets" that will solve the small field issue, but there are some technologies being suggested that would assist the rapid and low-cost development of these finds, many of which are remote from existing infrastructure. Solutions could be production buoys–manned or unmanned–that might be linked to subsea or floating storage units, eliminating the need for flowlines, a major capex item for a long-distance tieback (LDT) and an area of focus in cost reduction.

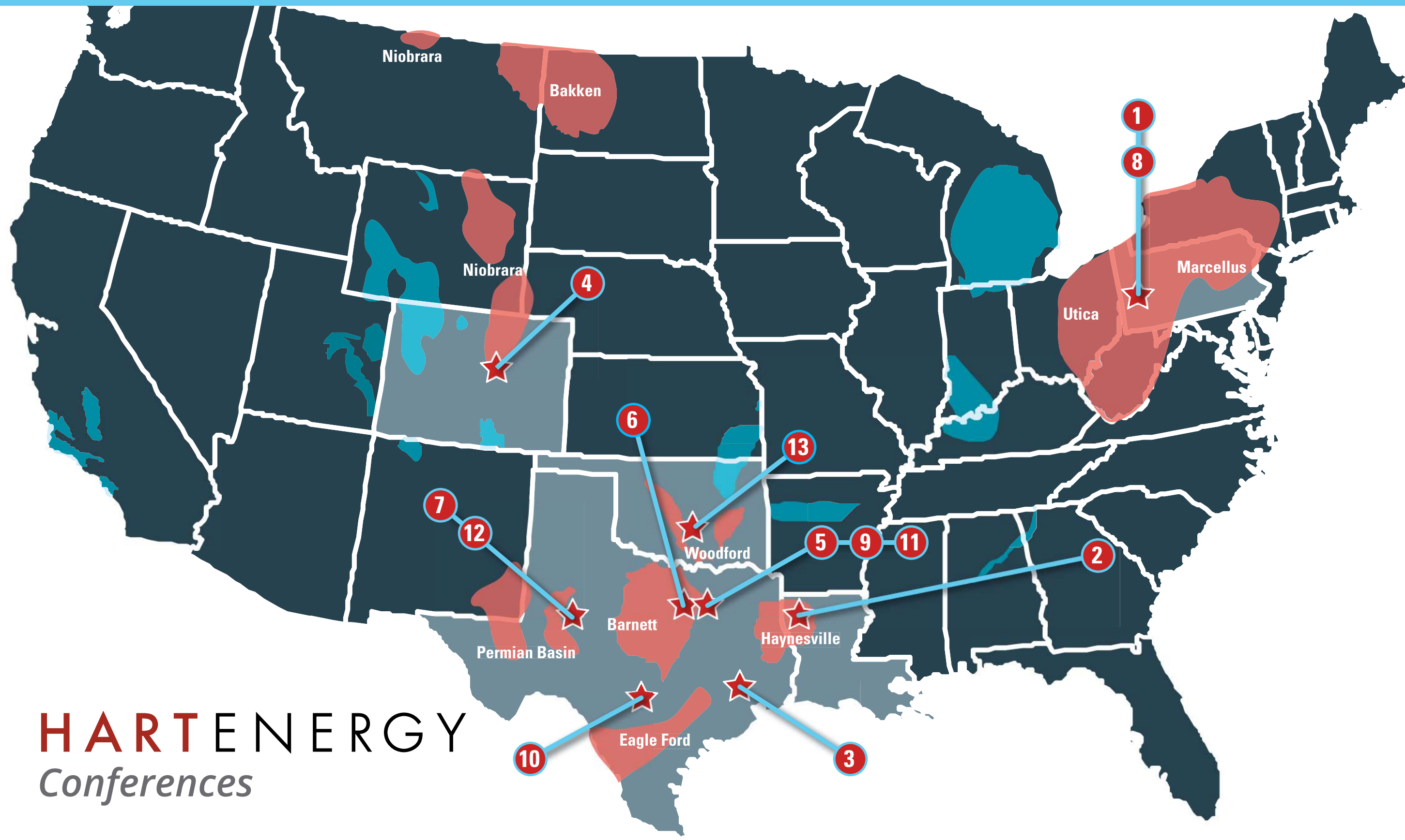
Another is an adjunct to decommissioning–the recycling of equipment. Recovering and redeploying flowlines, resurfacing production hardware and the general reuse of various types of equipment are all seen as possible ways to reduce project capex.

A new breed

One issue that is tangential to technology is the new, different set of operators, Pearson said, and their approach to trying something new. Pearson pointed out the North Sea has had three phases: the first in which most of the developments were undertaken by the big operators such as BP, Shell/Esso, Chevron, Texaco, etc.; Phase 2, in which the middle-sized companies like Talisman and Apache

2018 Hart Energy Conferences

Where Business Meets Opportunity



1 MARCELLUS-UTICA MIDSTREAM CONFERENCE & EXHIBITION
Jan. 30 – Feb. 1
Pittsburgh, PA

2 DUG HAYNESVILLE
Feb. 20 – 21
Shreveport, LA
NEW IN 2018

3 DUG EXECUTIVE
Feb. 26
Houston, TX
NEW IN 2018

4 DUG ROCKIES
April 24 – 25
Denver, CO

5 energycapital CONFERENCE
May 7
Dallas, TX

6 DUG PERMIAN BASIN
May 21 – 23
Fort Worth, TX

7 MIDSTREAM TEXAS
June 5 – 6
Midland, TX

8 DUG EAST
June 19 – 21
Pittsburgh, PA

9 A&D STRATEGIES AND OPPORTUNITIES Conference & Workshop
Sept. 5 – 6
Dallas, TX

10 DUG EAGLE FORD
Sept. 19 – 21
San Antonio, TX

11 MIDSTREAM FINANCE CONFERENCE
Oct. 22 – 23
Dallas, TX
NEW IN 2018

12 EXECUTIVE OIL CONFERENCE
Nov. 5 – 6
Midland, TX

13 DUG MIDCONTINENT
Nov. 13 – 15
Oklahoma City, OK

For more information, visit
HartEnergyConferences.com

took over older facilities and made more of them through lower-cost operations and clever engineering, and the current Phase 3, in which the operators, such as Alpha, IOG and Hurricane, are small and have a different business relationship with the supply chain.

Surprisingly, these smaller players are not put off the idea of adopting something new if it will allow them to get their reserves into production. While some of majors have balked at the idea of field trials of new equipment on their facilities, "the new guys," according to Pearson, could be thinking "bring it on" if it gets a cash-producing asset flowing hydrocarbons.

They also may be more amenable to collaboration. With nothing to hide and everything to gain, these new small players could just provide the impetus to get a new flow of projects in motion.

ITF

Another organization with its finger on the pulse of the innovators is the Industry Technology Facilitator (ITF). It is an open secret that some of the technology-based organizations have suffered just like everyone over the last three years. ITF, which under the leadership of Patrick O'Brien rose to its largest-ever membership of more than 30 before the crash, has now fallen back to half that size, although there still are a number of companies that participate in ITF projects, but not as members.

O'Brien, a founder of Irish engineering/design company MCS, later acquired by Wood Group, and with a long pedigree of innovation in riser design and operations, concurred with a number of focal points suggested by Pearson–long-distance tiebacks and reducing the cost of pipelines. The ITF leader made mention of simpler gas-liquid separation technology to make LDTs more viable, with at least one major engineering house already at work on a project.

ITF is also interested in alternative pipeline connection technology to bring down the cost of installation. O'Brien mentioned that a Dutch-sector operator had already qualified NOV's cold-forged Zap-Lok technology for an upcoming offshore project.

There are other areas that need addressing as well, according to O'Brien. The longstanding thorn in the subsea sector's side–standardization–remains an unresolved issue, but it's even more so in the context of "industrializing" the subsea industry. A field development executive from a Japanese company involved in a major project bemoaned the lack of a "Honda christmas tree," for instance. That would be a fine thing.

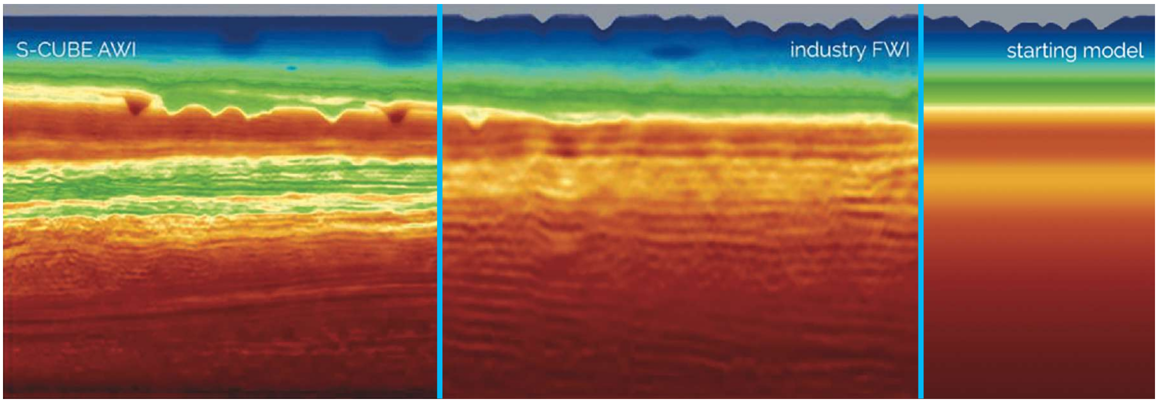
Outside of the subsea world there is other work, for instance in geophysics, that could aid the revival of a sector that needs a real boost. The discovery of the giant Johan Sverdrup Field in Norway, with 2 Bbbl to 3 Bbbl of oil in place, made a number of people sit up and notice. Not because its discovery was unexpected, but because some of the biggest companies in the industry, including Exxon Mobil, Total (actually Elf in an earlier guise) and Statoil drilled close to or even in the middle of the giant structure without actually seeing it. Subsurface work by Lundin Petroleum, headed by former specialists from Saga Petrolem, led to a different perspective on the geological structures and a more successful drilling campaign.

Work supported by ITF has been ongoing for more than decade at Imperial College on fullwave inversion analysis, which is already making a major impact on subsurface imaging. This work, dubbed FullWave Gamechanger, has resulted in collaboration with at least three major subsurface specialists and the establishment of a spinoff company, S-Cube.

Asset management

O'Brien also mentioned another ongoing issue, asset management and inspection. While much has been said in recent years about learning as much as possible about aging assets to keep them in operation, O'Brien noted a paper given at the Offshore Technology Conference this year by an ABB engineer who cited statistics showing that 80% of failures are not age-related.

What do those working at the sharp end think about technology as the answer to the industry's current woes?



Efforts supported by Imperial College and ITF for more than a decade led to significant advances being made in fullwave inversion analysis. *(Source: s-cube.com, courtesy of ITF)*

From TechnipFMC came the general view that operators are still interested in technology but the kind of technology that reduces cost, simplifies installation and reduces time and risk–which conveniently fits in with the result of the integration of Technip and FMC. There apparently is less appetite for the "deeper, harsher, longer" kinds of solutions, while some operators are also expressing the needs for technology to develop sustainable energy solutions.

More specifically, CEO Doug Pferdehirt said publicly that its "integrated EPCI" model has now been accepted for use on five projects, including two for Statoil, one being the recent award for Visund in the Norwegian sector. He added that project economics have improved considerably since the market peak, with many projects making economic sense below $50/bbl and some far below that level. He expressed confidence that reduced breakeven levels will allow for the return of the development of deepwater assets.

John Kerr, vice-president of engineering and technology at the newly formed BHGE, the merger of Baker Hughes and GE Oil & Gas, added, "While operators seek to reduce costs and optimize productivity ... cutting-edge technology is the way forward."

Kerr did acknowledge the basic conservatism of the industry, which requires the need to "de-risk" the adoption of new technology to clarify the benefits for the operators. Now, with a company whose areas of expertise run from downhole to seabed equipment and topside compressors and generators, it becomes even more necessary to prove to operators that it has what they need.

Finally comes the views from one of the main adopters of new technology over the last decade, Statoil.

Roald Sirevaag, chief subsea engineer, said, "New technology can be both an enabler and a cost reducer, so Statoil is still and continuously working with new technologies and technical solutions to enable value-creating opportunities."

Statoil's overall agenda is to balance cost reduction through "SSI," which stands for simplification, standardization and industrialization, plus using new technology to create value and reduce cost.

A recent example Sirevaag cited is the planned implementation of a direct current fiber-optic control and distribution system on the Johan Castberg development in the Barents Sea.

'We are (also) pursuing remotely operated factories, a mix-and-match of subsea and topside building blocks, qualifying the required missing remotely operable technology solutions. One step already in implementation is operation of ROVs from shore," he added.

It appears as the price crash has not totally killed off the desire to deploy new technology for at least one operator. It remains to be seen if others will continue apply to the technology gods to answer their technical challenges. ■