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2016

OFFSHORE

Technology Yearbook

Global Offshore Oil and Gas Review

2016 Offshore Technology Yearbook

A supplement to *E&P*

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2016 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 second 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, the Top 10 Projects of 2015 and profiles of the Top 15 offshore oil and gas operators. A full-color wall map also is included.

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Clockwise from the top: the Shah Deniz platform in the Azerbaijan sector of the Caspian Sea, (photo courtesy of BP); the *EnQuest Producer* FPSO in the U.K. North Sea, (photo courtesy of EnQuest); a subsea production system, (image courtesy of DNV GL); the *Maersk Integrator* ultra-harsh environment jackup drilling rig, currently drilling for Statoil in the Norwegian North Sea, (photo courtesy of Maersk Drilling).

'Lower for Longer' Fuels Innovation Drive

By Mark Thomas, Editor-in-Chief

With the global offshore market's major and minor players approaching new and existing developments with caution born through financial necessity, the sector's ability to provide upstream technologies that can tick the boxes in terms of improved performance, efficiency and reliability is critical.

Striking the balance between the need to invest in pioneering technologies that can unlock previously inaccessible offshore resources such as ultradeep water or extreme HP/HT reservoirs while simultaneously demanding cheaper standardized off-the-shelf solutions is a tough challenge.

Walking that technology tightrope between funding and embracing new or greatly improved solutions—with all the added costs and usually higher risks often associated with doing so to gain "first-mover" advantage—or pushing for more standardized "one size fits all" solutions in more of a factory approach to offshore developments requires a sense of balance most circus acrobats would be proud of.

Add to that the element of achieving these tasks in an offshore market that has morphed from one that enjoyed several years of strong growth and record investment fueled by high oil prices into a period of desperate stagnation, with capital expenditure budgets slashed and the majority of project schedules either stalled or delayed for further "reengineering," and you have an industry at the crossroads of a crucial new phase.

Double-dip capex drop

The facts speak for themselves. The global offshore market (with onshore equally affected) has suffered one of its single biggest drops in investment and is expected to suffer the first consecutive two-year capex double-dip drop since the 1980s.

As a result, cost efficiency and capital discipline are the order of the day for every offshore company, with virtually all having long since acknowledged that, to a greater or lesser extent, the industry comprehensively dropped the ball in terms of controlling exploration and development budgets in the mistaken belief that global energy demand would stay strong and ensure a consistently high oil price.

But as analyst John Westwood of Douglas-Westwood pointed out toward the end of 2015, the Brent oil price in mid-December 2015 was \$38.57/bbl, compared to January 1990 when Brent was \$23.73/bbl. Applying the U.S. inflation index equates that 1990 price to about \$43.40. So the industry has been here before—and more than once.

Vital statistics

So what are the offshore industry's vital statistics in 2016?

More than 33% of the world's oil and liquids production figure in 2015 of 93 MMbbl/d came from offshore fields. About two thirds of that flows from shallower continental shelf waters, while the remaining and slowly growing final third (esti-

The *Maersk Integrator* ultra-harsh-environment jackup rig is currently drilling for Statoil in the Norwegian North Sea. It is set to be followed onto the rig market by up to 100 further newbuilds, which is expected to prompt substantial cold stacking and scrapping of up to 200 older units in order to hit market equilibrium. *(Photo courtesy of Maersk Drilling)*

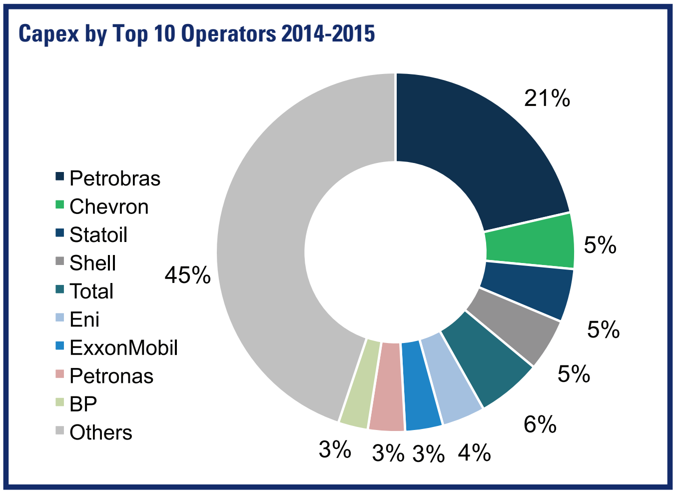
mated at approximately 10MMbbl/d to 11 MMbbl/d at present) comes from deep water (400 m [1,312 ft] or more).

In terms of capex, analyst Infield Systems has said spending will fall as operators continue to look to cut costs and reassess the economic viability of increasingly marginal prospects. The challenging current market conditions are forecast to continue throughout 2016, said the company.

According to Infield's senior associate, Adrian Dorsch, speaking at Hart Energy's Offshore Executive Conference in Houston in November 2015, global offshore engineering, procurement, installation and construction (EPIC) capex is anticipated to fall by 9% compared to the previous year, from $91 billion in 2014 to $83 billion in 2015. This will be followed by a forecast further decline to $78 billion in 2016.

This decline is exemplified by spending cuts by industry majors such as Petrobras, which had previously been driving the record spending in new developments. The operator sliced its E&P capex budget by one-third to $108.6 billion in its 2015-2019 business and management plan from its previous plan, deciding mainly to focus on its crown jewels in the producing Brazilian presalt. The five-year production development capex budget of $89.4 billion was 21% less than the 2014-2018 E&P budget for Brazil but still represents 83% of the total production budget, with $64.4 billion pencilled in for new production systems in Brazil. Of that a huge 91% will be specifically for the presalt fields.

The company's five-year exploration capex budget of $11.3 billion was slashed by 52% compared to its previous plan, reflecting the company's decision to focus on its producing assets. Further cuts could be coming, however, as even these revised spending plans were made assuming an average Brent oil price of $60/bbl in 2015 and $70/bbl in 2016-2019—a price assumption that is certainly debate-



(Source: Infield Systems)

able, especially when combined with the strength of the U.S. dollar currency.

Breakeven moving lower

This is something that the industry is obviously acutely aware of, however, especially with an oil price that has struggled at below the $40/bbl mark after December 2015 and even dipped below $30/bbl mid-January 2016.

BP admits "around 80% of our potential investments are currently expected to break even below a $60 Brent oil price, and we would expect this breakeven to move lower as we further take advantage of deflation."

All the majors are following suit, with capital budget cuts planned for 2016 averaging around the 25% mark on top of continued production efficiency initiatives, including Chevron, ConocoPhillips, Shell and Exxon Mobil.

ConocoPhillips, for example, highlights the severity and abruptness with which the cuts have had to be implemented. The U.S. major's spending (including both on and offshore but with offshore suffering the lion's share) has plunged 55% from $17.1 billion in 2014 to $10.2 billion in 2015 and a planned $7.7 billion capital budget for this year. There is an upside, however. The company still plans to grow production by 1% to 3% to between 1,530 MMboe/d and 1,560 MMboe/d, typifying the heightened focus that virtually all operators will have on their producing assets over the next two years.

Exploration's key role

The fact remains that finding new reserves is still a must. It's no accident that out of the 10 largest discoveries made in 2015, virtually all were made offshore and in deep water, with Eni's world-class Zohr find in the Mediterranean Sea's Shorouk Block offshore Egypt topping the list with a potential 850 Bcm (30 Tcf) of lean gas (5.5 Bboe) in place.

Already on a fast-track development schedule, Eni is expected to adopt an approach for Zohr that will increasingly be taken onboard by other operators making similar large-scale finds in regions with existing infrastructure, avoiding heavy upfront capex solutions and opting instead for a more measured, phased development utilizing a series of subsea tiebacks and the latest drilling and downhole EOR techniques to access the reserves and exploit them using existing infrastructure.

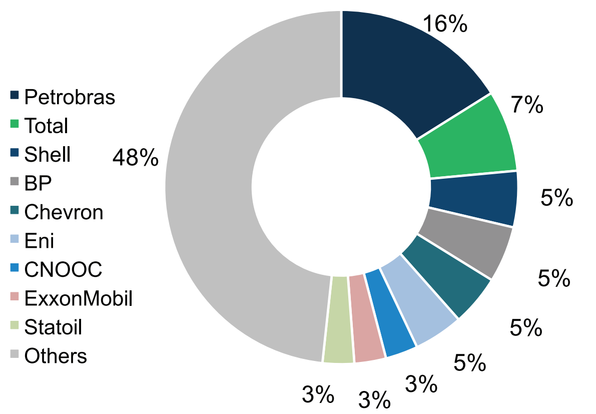
One U.S. independent, Noble Energy, has been a prime proponent of this kind of development when the circumstances are suitable. According to its CEO, Dave Stover, in the U.S. Gulf of Mexico (GoM) the company has been maintaining a high exploration success rate where he says "the resource visibility has probably never been greater." He pointed out that research by Goldman Sachs on the world's top 420 oil projects revealed the breakeven for the GoM was as low as $40/bbl (as of May 2015).

The company is putting its money where its mouth is, recently starting production from its operated Big Bend and Dantzler deepwater projects in the Mississippi Canyon area, which both benefitted from short cycle times and prolific rates to show how offshore projects can compete economically with usually lower cost, faster cycle unconventional plays.

The two subsea tiebacks to the producing Thunder Hawk platform saw Big Bend go from discovery to production within three years, while Dantzler went from find to production in just two. It has similar plans for its Gunflint discovery in the same area, expecting it to be flowing by mid-2016.

BP is following a similar approach in terms of focusing on production-related advances that deliver better cost efficiencies in operations in the near term. According to a recent Lloyds Register

Capex by Top 10 Operators 2016-2017



(Source: Infield Systems)

Energy "Technology Radar" report, BP's innovation priorities are focused on waterflood and gas-based EOR, with the operator's group head of technology, David Eyton, saying these specific EOR technologies are price-competitive. "They don't have the same kind of downside from a change in the oil price that other technologies might," he said. "They're much lower cost to develop than, for example, thermal EOR technologies."

Rig market ramifications

No offshore article can discuss the market without highlighting the dire straits currently faced by the oversupplied drilling rig market, which according to Credit Suisse analyst James Wicklund still has a long way to go before seeing any green shoots of recovery. Highlighting deepwater rigs, he pointed out that recently the sixth-generation and currently cold-stacked *Deepsea Metro II* drillship, built in 2011 and worth $600 million, had received a best bid at a recent auction of just $150 million. That bid came about because there are about 40 other rigs that will go to work before the *Deepsea Metro II* does, he said at Hart Energy's Offshore Executive Conference. Companies now need to be able to afford to mothball rigs for up to five years before they are put to work, he said.

Wicklund added that at a recent International Association of Drilling Contractors (IADC) meeting, executives at Ensco and Diamond said the rig market would only emerge from its bottom "by 2018 to 2020." The IADC recently determined that up to 200 rigs will need to be stacked to hit market equilibrium, and Wicklund specified that these would be made up of 100 jackups and 100 floaters—with 100 more rigs waiting in the wings to be delivered.

The $40/bbl technology challenge

As it moves through 2016, the offshore industry will face these and many other challenges, not only technical but economic, political and ethical. But the development and implementation of real-time technologies and solutions remain the constant factors that the E&P sector knows it must rely on to help it meet the world's ever-increasing demands for more energy, accompanied as they are by ever-more stringent demands for better energy efficiency.

Those demands mean that offshore will continue to need to delve deeper to find and produce more reserves, to 3,050 m (10,000 ft) and beyond. Most experts expect 3,658 m (12,000 ft) to be achieved in the near future, and this likely means bigger rigs and bigger risers and handling systems as well as having to deal with greater reservoir depths, higher pressures and other metocean factors such as loop currents.

This is where industry collaboration will remain key to unlocking much of these reserves and on a much wider scale than previously attempted. It will take the combined efforts of operators, drilling contractors and service companies to solve problems through established organizations such as the Research Partnership to Secure Energy for America and the U.S. Dept. of Energy's National Energy Technology Laboratory (NETL), which are active in various joint industry projects covering subjects like cementing, early kick detection, MPD, subsea processes and 20,000-psi pressure control systems.

Roy Long, ultradeepwater technology manager at NETL, commented, "I think $40 oil is going to be the pressure that is going to get people to collaborate. When ideas for cutting costs come out, I think there's an opportunity again for collaboration. When you're talking about a standardization environment where everybody is going to have the same technology, there might be things that become very cost-effective to do as a joint industry project versus trying to have your own industry project." ■

The Fall and Rise of Offshore

By Catarina Podevyn, Infield Systems

Regional bright spots will increasingly emerge from the gloom as the global offshore field development market recalibrates.

How has the challenging oil price environment impacted the different offshore regions of the world, and how will it continue? In this article Infield examines and assesses where the current market conditions are likely to prevail and where demand is expected to strengthen over the next two years to 2017.

Since the oil price collapse in second-half 2014, the offshore industry has undergone significant turmoil, with budgets reassessed and a sizeable number of high-profile projects taken back to the drawing board in vigorous cost-cutting efforts by operators around the world. As of year-end 2015, the resulting impact upon different regions has been varying, with some hit harder than others. But that also means some areas will regain their former strength sooner.

Europe

The European offshore sector saw mixed fortunes over the course of 2015, with an overall fall in capex of 7% compared to 2014.

Going into 2016, a further decline in demand of about 9% is anticipated across the region as a whole, although beyond this Infield Systems expects a general improvement in market conditions.

Europe's overall forecast demand is driven by the Northwest Continental Shelf, which has certainly been adversely affected by the decline in the oil price. Decreasing demand within the Northwest Continental Shelf overshadows the capex increases seen across the southern and eastern European areas, where projects such as the Trans Adriatic Pipeline and IGI Poseidon pipeline are expected to require significant investment going forward.

Operators active within the Northwest Continental Shelf, in particular the North Sea, have faced significant challenges over the past year, with the volatile market conditions having a direct impact on more marginal field developments with narrow project economics, which currently characterize the region.

Indeed, for the period covering 2014 to 2016, Infield expects Northwest Continental Shelf capex to plunge by about 28%. The largest declines are expected to be seen offshore Norway, predominantly as a result of the giant Aasta Hansteen Field and its associated Polarled pipeline reaching completion.

Offshore U.K. declines in capex have primarily been a specific result of project delays, with a number of planned capital-intensive developments simply uneconomical at the current oil price. Statoil's Mariner Field was one of the latest projects to suffer such a delay, while Chevron's Rosebank deepwater development also remains in question as the U.S. major continues to look to cut its forecast costs.

However, with new U.K. legislation designed to bolster the struggling sector, key projects such as Maersk's Culzean Field are now receiving the green light.

Offshore Norway, Johan Sverdrup is expected to dominate spend over the 2016 to 2017 period, despite operator Statoil revising its capex estimate downward in September 2015 relating to the first phase of the project. Altogether, the field is estimated to hold between 1.7 Bboe and 3.3 Bboe, with the development to consist of a processing platform, drilling platform, riser platform and living quarters.

Africa

After witnessing a decline in capex levels during 2015, Infield expects 2016 to be a year of growth across Africa's offshore market, particularly within West Africa's resiliently strong deepwater sector, where French giant Total dominates spend.

With giant projects such as the Egina Field and Kaombo Field cluster under development, the deepwater pioneer is expected to represent a quarter of Africa's forecast capex during the 2016 to 2017 period.

Angola has seen some of the largest relative falls in expenditure over 2015 within the region, declining by a dramatic 50% compared to 2014 demand levels. Going forward to 2017, however, the country is expected to get back to a strong demand growth pattern, with 84 fields expected to require investment.

While Angola's capex is expected to be driven by the giant Kaombo project, the development has not been immune to the market downturn, and operator Total has worked extensively to reduce costs on it over the course of 2015.

Elsewhere within the West African region, Total's deepwater Egina project continues to progress, with fabrication of the giant FPSO topside modules commencing in third-quarter 2015 at the LADOL free zone, Lagos, as part of a joint venture with Samsung Heavy Industries (SHI).

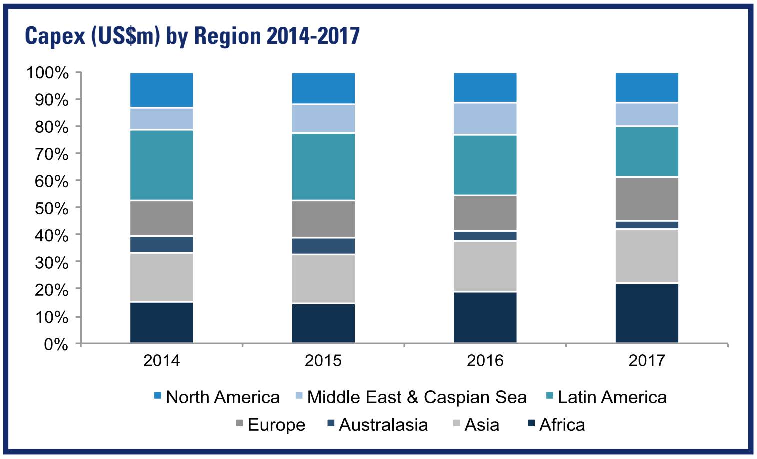
Over the forthcoming two years, Infield also expects significant capex on the Addax/Sinopec-operated Udele West Field offshore Nigeria, where an FPSO is expected to be installed during 2017.

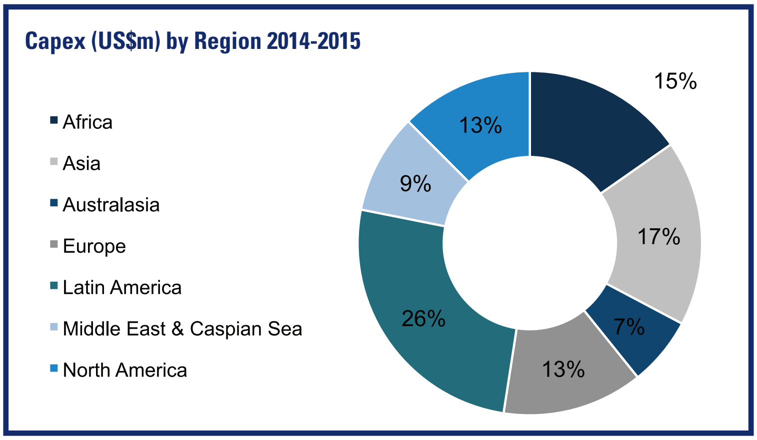
Offshore Ghana, Tullow is expected to remain the key operator in terms of demand, with spend expected to be driven by the TEN (Deepwater Tano) projects. In 2016, significant capex demand is expected from the subsea element of the Tweneboa and Enyenra fields in particular, while the Eni-operated Sankofa East Field development is anticipated to also contribute a substantial proportion of Ghana's demand during the year, with both its FPSO facility and its associated pipeline anticipated to require significant expenditure.

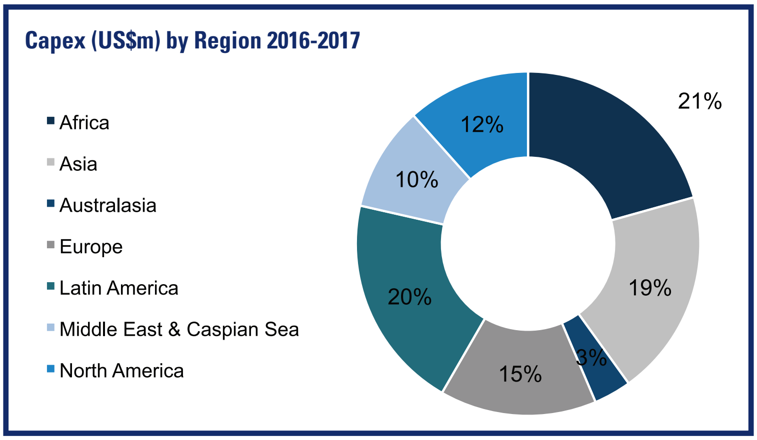
Within the North African sub-region, BP is expected to remain the largest operator in terms of capex spend going forward to 2017, representing a 37% share of forecast expenditure, with the West Nile Delta field developments expected to account for the majority of the company's spend.

The North American region is expected to make up 12% of global offshore capex over the course of 2016-2017, with Anglo-Dutch major Shell the leading spender. This is largely due to its investment in the Stones development in the Walker Ridge area of the Gulf of Mexico, which includes the *Turritella* FPSO, set to become the world's deepest producing facility in 2,900 m (9,515 ft) of water when it begins operations mid-2016. *(Photo courtesy of Shell)*

With the discovery of Eni's Zohr deepwater field offshore Egypt in August 2015, capex demand within the North African sub-region could increase further. Zohr has a reserve potential initially put at 850 Bcm (30 Tcf) of gas, making it one of the largest discoveries ever found in the Mediterranean Sea. Eni is expected to fast-track its development, and as such Infield's demand forecast for North Africa over the 2016 to 2017 time frame could increase.







(Source: Infield Systems)

The South and East African sub-region, in particular within Mozambique's highly prospective Rovuma Basin, has been touted as a potential new global LNG hub going forward, with fields such as Coral and Prosperidade/Mamba expected to commence development over 2016 and 2017. However, with substantial investment required as a result of limited existing infrastructure in the country and with oil and gas regulatory legislation (in particular local content demands) yet to be finalized, operators embarking on developing the huge resource potential of Rovuma and its neighboring East African basins are faced with a significant challenge.

A more positive market outlook will therefore be crucial in supporting the investment decisions of operators such as Anadarko, Eni and the China National Petroleum Corp. in the region.

Australia

Australasia is expected to make up a 3.5% share of global offshore capex during the 2016 to 2017 time frame, which compares to 6% over the 2014 to 2015 period.

This predominantly results from the high capital costs of the giant Inpex-operated Ichthys and the Shell-led Prelude developments over the previous two years. Inpex and partner Total have faced delays and significant cost increases on Ichthys, with Infield now ranking the project as the world's most expensive greenfield development over the past two years.

The Prelude FLNG project has been the 10th highest capex-demanding project globally during 2015.

Going forward to 2017, Infield forecasts development spend could take place on 82 fields within the region, 79 of which are located offshore Australia. While Prelude and Ichthys are expected to remain key projects in terms of capex levels, it also is forecasted that there will be significant spending on projects such as Wheatstone and Brecknock during the 2016 to 2017 period.

In terms of demand growth, Australasia, the Middle East and Caspian Sea, and Latin American regions are all expected to see decreases in capex during both 2016 and 2017, reflecting the decline in new project sanctions in an increasingly competitive global LNG market.

Latin America

The Latin American region is expected to represent a 20% share of global capex demand going up to and including 2017, which is a decrease from the 26% share seen over the previous two years.

Brazil and its national oil company Petrobras lead demand as usual. However, with the decline in oil prices and the significant financial difficulties experienced by the operator during 2015, several sizeable planned field developments have suffered delays.

Going forward to 2017, key developments expected to drive demand in the region include the multiphase Buzios Field, with Phase 1 anticipated to require 9% of the region's forecast offshore capex over the 2016 to 2017 time frame. Infield also expects substantial demand on the ultradeepwater Lula Central and Lula Alto projects, with 82 fields offshore Brazil anticipated to require capex over the period. This compares to 91 field developments over the previous two-year period.

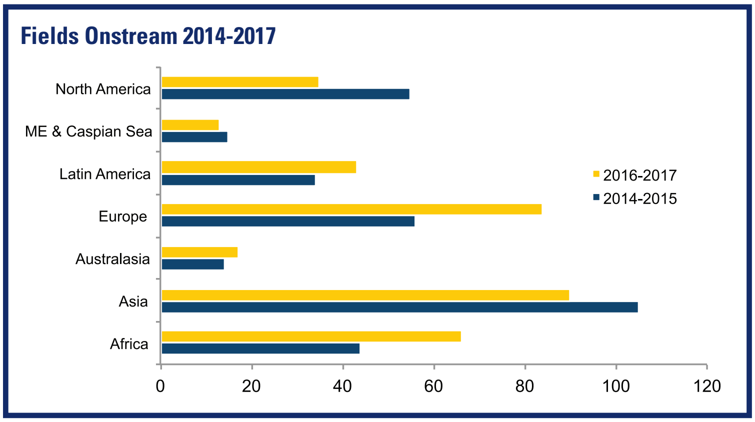
Elsewhere within the Latin America region, Colombia's Caribbean floating LNG project has also suffered delays during 2015 as a result of the challenging market conditions, while within Mexico's unshackled offshore sector the first bid round following industry reform proved somewhat disappointing, with only nine bidders out of the 34 prequalified companies entering the process and only two out of 14 blocks awarded.

It appears that many of the larger international oil companies are taking a wait-and-see approach to the area. While future bid rounds are planned to include more attractive deepwater areas, it may be the case that more favorable contract terms and improvements in world oil prices are necessary before the potential of Mexico's offshore zone is realized.

Over the 2016 to 2017 time frame, Infield expects capex offshore Mexico to be dominated by the deepwater Lakach project, where several contracts were awarded during 2014, including the engineering, procurement, construction and installation contract to Saipem, with Aker Solutions contracted to supply the steel tube umbilicals that will connect the subsea gas development to onshore processing facilities.

North America

The North American region is expected to comprise 12% of global offshore capex over the 2016 to 2017 time frame, consistent with the proportion of spend seen over the previous two years. Going forward into 2017, 139 field developments are expected to require capex, with 39 operators directing investment toward the region.



(Source: Infield Systems)

Shell is expected to lead investment, with Infield forecasting the Anglo-Dutch major will be responsible for 25% of capex between 2016 and 2017. Shell's expenditure is expected to be driven by its ultradeepwater developments within the Gulf of Mexico (GoM), in particular its pioneering Stones Field, where the project's subsea elements are anticipated to require the largest proportion of the operator's investment over the forthcoming two years. The field's FPSO unit will be Shell's first such facility in the GoM, and it is expected to be installed during 2016.

Elsewhere within the North American region, it is expected that continued investment will take place on the Exxon Mobil-led Hebron project in the Jeanne d'Arc Basin, Canada, with the operator remaining on track for first production in 2017. The large standalone concrete gravity based structure is expected to produce 150,000 bbl/d at peak, with the operator having signed an agreement with Aker Solutions mid-2015 for the maintenance, modifications and operations contract on the field.

Middle East and Caspian Sea

Within the Middle East and Caspian Sea regions, demand is expected to continue to be driven by Azerbaijan, Iran, Qatar and Abu Dhabi during the 2016 to 2017 period, with several capital-intensive projects under development.

However, as developments such as Shah Deniz (Phase 2) offshore Azerbaijan and various South Pars phases offshore Iran come to a close, Infield anticipates capex will fall by 17% between 2016 and 2017. BP's Shah Deniz Field is expected to remain the most capital-intensive project in the region over the next two years. A number of key contracts were awarded in 2015 on the development, such as the contract issued to FMC Technologies for the field's subsea production systems for well clusters 3 to 5 for a reported $297 million.

Offshore Qatar, key projects are expected to include the Barzan gas development and redevelopment of Bul Hanine. These projects are seen as crucial in bolstering the kingdom's position within the global hydrocarbon market after having suffered recent declining output.

In terms of market sector, pipeline developments are expected to continue to demand a considerable proportion of regional spend (60%). This is the highest proportion of forecast pipeline demand by region globally over the time frame. Shallow-water conventional pipeline developments are expected to drive this trend, with substantial development expected offshore Qatar and Abu Dhabi.

Elsewhere in the Middle East, capex is expected to continue growing offshore Israel, with that government's investigations into Noble Energy and partner Delek Petroleum's stakes in a number of prospects resulting in a ruling in favor of the partners continuing their development of the giant Leviathan gas field, which is expected to see spending kick off by 2017.

Asia

Asia is expected to see total capex making up 19% of the global figure over the 2016 to 2017 time frame, a healthy rise from the 17% share seen over the previous two years.

Demand is anticipated to continue to be driven by Malaysia's expanding offshore activity, with the deepwater Rotan Field development, home to the giant *PFLNG 2* facility, expected to demand the highest levels of capex. The FLNG unit saw construction start in June 2015 at the SHI shipyard in South Korea, with the entire facility once complete expected to weigh about 152,000 tonnes and have a production capacity of 1.5 million tonnes per annum.

Along with the pioneering *PFLNG 1* facility, which was expected to near completion by year-end 2015 for installation on the Kanowit Field, the Petronas-led project is a highly significant milestone for Malaysia. The country's government is looking to attract increasing foreign investment to transform its offshore sector into a new hub for LNG production and trade.

Offshore India, the capex forecast is considerably lower than the forecast for the previous period, but despite this the country is expected to remain the region's second largest destination for offshore demand during the 2016 to 2017 period. The redevelopment of the Mumbai High project is expected to drive the country's offshore capex demand in particular.

The changed market conditions over the course of 2015 have significantly affected planned project timescales on a number of Asian developments. While remaining driven by the Southeast Asian sub-region, in particular Malaysia, continued uncertainty offshore Indonesia surrounding Chevron's Indonesia Deepwater Development project in the Makassar Strait offshore Sulawesi, which has seen input costs escalate, has cast a shadow over the region's planned development.

Despite this, Asia remains one of the few regions that is actually expected to see continued forecast capex demand growth over the 2014 to 2017 period, with a compound annual growth rate of 12.6% expected between 2015 and 2017.

Further to fall before the rise

Overall, 2015 proved to be a most testing year for the global offshore industry, with capex levels decreasing by -9.2%. As operators look to cut costs and reassess the economic viability of increasingly marginal prospects, Infield expects the current market challenges to prevail throughout 2016, with capex forecast to further fall by about 6%.

However, that is not a situation that is set to assail all areas. While a continued market decline is expected in 2017 for areas such as Latin America, the Middle East and Caspian Sea, and Australia—predominantly as a result of a number of capital-intensive projects coming to a close—elsewhere the longer-term outlook appears more positive. Somewhat surprisingly, the highest growth in capex between 2016 and 2017 is expected to take place offshore Europe, driven by the giant Johan Sverdrup development, and also Africa, where capex is expected to be focused on Total's West African Egina and Kaombo projects. ■

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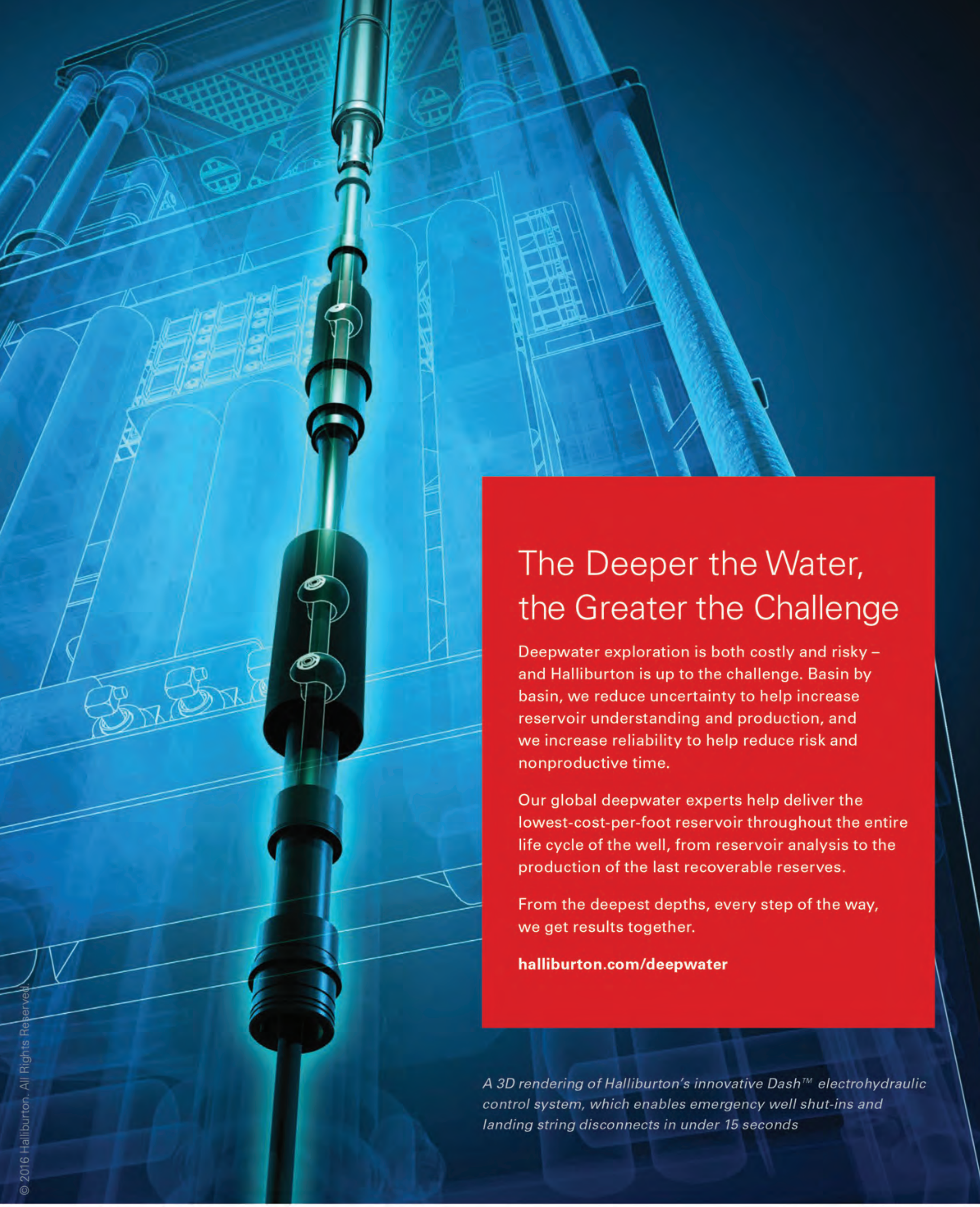

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Eni's *Goliat* FPSO, based on Sevan Marine's unique circular Sevan 1000 design, is now moored over what will be the first oil field developed in the Barents Sea. It was being prepared for production at year-end 2015 and was expected to come onstream in early 2016. It has, however, suffered substantial cost overruns and schedule delays, with the total development cost now put at $6 billion. *(Photo courtesy of Eni)*

Focus on Core Assets

Helps Top Players Stay Afloat

By Ariana Benavidez, Associate Managing Editor

Adapting to the low oil price has been a massive task, but these key players tackled the challenge by maximizing returns from existing assets and taking advantage of cost deflation on major developments.

Oil and gas companies have to keep going despite the toughest of years, which 2015 undoubtedly was. Severe cuts were made to both capital and operational budgets upstream, and a substantial number of major projects were either put on hold or deferred for reengineering and to take advantage of industry cost deflation. Some also increasingly turned toward wider industry collaboration to help adjust to the downturn.

According to a September 2015 report by the U.S. Energy Information Administration (EIA), the number of active offshore rigs worldwide declined by about 20%. There were 304 offshore rigs operating in August last year, substantially down from 377 in August 2014. The Gulf of Mexico, particularly, took a big hit with the number of active rigs dropping by 46%. Most of the more recent growth in active offshore rigs outside the U.S. has occurred in Angola and Nigeria, while rig contractors themselves have accelerated their programs for the large-scale scrapping and cold-stacking of older or underutilized units, especially with about 50 further newbuilds expected to enter the market in the near future (ordered in better times when the oil price was well above $100/bbl).

Through a combination of using innovative technologies, strategic planning and keeping a cool head, the following key players endured a testing 2015 to leave themselves on a surer footing to face what is expected to be an equally challenging year ahead.

Top 25 Oil and Gas Companies by Global Offshore Capex

2014-2015	2016-2017
Petrobras	Petrobras
Total	Total
Chevron	Shell
Statoil	BP
Shell	Chevron
Eni	Eni
Exxon Mobil	CNOOC
Petronas	Exxon Mobil
BP	Statoil
Inpex	Petronas
NIOC*	ONGC
CNOOC	PEMEX
PEMEX	Noble
ONGC	ADNOC BP JODCO Total
ADNOC BP JODCO Total**	Qatar Petroleum
Anadarko	Tullow
LLOG	Murphy
Husky	Galsi Spa
Murphy	Maersk
Tullow	Woodside
PTTEP	Hess
Noble	Premier
Shell Brunei Government	Shell Brunei Government
DNO RAK	PTT
Saudi Aramco	NIOC

* National Iran Oil Co. *(Source: Infield Systems)*

** Abu Dhabi Marine Operating Co. (ADMA-OPCO)

This section highlights the top 15 players, based on their known and estimated offshore capital investment programs for 2014-2015 (according to data supplied by Infield Systems), and some of the world-class technologies and projects they are driving forward.

Abu Dhabi Marine Operating Co.

- **Umm Lulu supercomplex will be largest facility installed offshore Abu Dhabi**
- **Umm Lulu is part of company plan to hit 1.75 MMbbl/d of offshore oil production by 2017**

Abu Dhabi Marine Operating Co. (ADMA-OPCO), a producer of oil and gas from the offshore areas of the Emirate of Abu Dhabi, operates in Umm Shaif and Lower Zakum. The company also has recently started production from new fields, including Satah Al Razboot, Nasr and Umm Lulu.

It is currently ranked 15th in terms of its offshore capex for 2014-2015, according to Infield.

In November 2014, ADMA-OPCO signed three contracts totaling $3 billion for the full development of the Nasr oil field with National Petroleum Construction Co., Hyundai Heavy Industries and Technip.

Earlier that year Larsen & Toubro's hydrocarbon business had progressively commissioned the $400 million Umm Lulu Phase 1 and Nasr Phase 1 development projects for ADMA-OPCO, with Umm Lulu flowing first oil in October that year via the existing Umm Al-Dalkh facility. Nasr achieved production in January 2015.

The company said the full-scale Umm Lulu complex will be the largest facility to be installed offshore Abu Dhabi and one of the biggest in the Middle East. The development will consist of six new wellhead towers and six further bridge-linked platforms including a gas treatment facility, separation platform, riser platform, utilities platform, accommodation quarters, a water disposal facility and two flare platforms. In all, it will weigh in at more than 90,000 metric tonnes, the company said. Installation of the full development will take place throughout 2016 and 2017, with full output expected to be producing by 2018.

In September 2015, Sparrows Group won a five-year deal with ADMA-OPCO covering the latter's offshore installations, which include the Umm Shaif, Zakum West and Zakum Central super-complexes. The work involves providing the total integrated management of cranes and other lifting equipment. *adma-opco.com*

BP

- **Ranked No. 6 on 2015 list of Fortune 500 Global companies**
- **2015 capex put at close to $19 billion**

BP operates in nearly 80 countries, employs 84,500 people and currently produces 3.2 MMbbl/d of oil both on and offshore.

It is currently ranked ninth in terms of its offshore capex for 2014-2015, according to Infield.

BP's replacement cost profit for third-quarter 2015 was $1.8 billion, compared with $3 billion for third-quarter 2014, according to its third-quarter 2015 results. The company expected its capex for 2015 to be close to $19 billion, well down on the $24 billion to $26 billion expected to be spent just a year earlier, as it continues to scale back investment in marginal projects and the exploration sector.

Organic capex will range between $17 billion to $19 billion through to 2017. It also had sold off $7.8 billion in assets as of third-quarter 2015, part of its plan to divest up to $10 billion in assets by year-end 2015. It also expects to shed a further $3 billion to $5 billion in 2016.

In January 2015, it formed an alliance with Chevron and ConocoPhillips to unlock the ultradeepwater Tiber and Gila discoveries in the Paleogene trend of the Gulf of Mexico and to pursue development of a new production hub in Keathley Canyon.

In March 2015, it also made its second significant gas discovery in Egypt's East Mediterranean Sea. The Atoll-1 deepwater exploration well penetrated about 50 m (164 ft) of gas pay, with BP holding 100% equity in the find.

It also saw its Greater Plutonio Phase III project offshore Angola start production in second-quarter 2015. *bp.com*

Chevron

- **Ranked No. 3 in terms of its offshore capex for 2014–2015, according to Infield**
- **Ranked No. 12 on 2015 list of Fortune 500 Global companies**

Chevron has been around for more than a century with its activities covering the full spectrum of E&P, downstream and refining. First-half 2015 net production reached 2.57 MMboe/d to 2.65 MMboe/d, according to a September 2015 investor presentation, and the company reported earnings of $2 billion for third-quarter 2015, compared to $5.6 billion a year earlier.

Reflecting the crude price decline of nearly 50% from a year earlier, the company's upstream businesses were hard hit, Chairman and CEO John Watson said at the time of the company's second-quarter 2015 earnings. "Multiple efforts to improve future earnings and cash flows are underway. We're getting our cost structure down through renegotiations across the supply chain and by sizing our contractor and employee workforce to reflect lower activity levels going forward," he said in a release.

Despite the downturn, the company continues to move forward with major projects, although much more cautiously. Chevron is already a major producer of oil and gas in the Gulf of Mexico (GoM) via deepwater projects including Blind Faith, Tahiti and Jack-St. Malo.

Among the largest fields in the GoM, the Jack and St. Malo fields began production in December 2014. Six wells are producing more than 80 Mboe/d, and development drilling is ongoing with drilling efficiency increased by about 30%, according to the investor presentation.

Its Big Foot Field in the GoM also was originally scheduled to start flowing last year but initial problems with the installation of the tendons now look set to delay production from the $5 billion development's dry-tree tension-leg platform (TLP) until 2018. The TLP is currently back at the Kiewit Offshore Services facility in Ingleside, Texas.

Better progress was made offshore Western Australia, however, where Chevron completed the dredging program and installed platform topsides in 2015 for its giant Wheatstone project. The company was on schedule to deliver all Train 1 and common modules and finish the drilling of all development wells by year-end 2015. The equally large Gorgon LNG project (15 MMtpa) is also more than 90% complete, although it is several months behind schedule. *chevron.com*

Chevron Corp.'s subsidiary, Chevron Overseas (Congo) Ltd., and partners started production from the deepwater development Moho Bilondo Phase 1b offshore the Republic of Congo, according to a December 2015 company press release. Phase 1b is located about 75 km (46 miles) off the coast of Pointe-Noire. *(Image courtesy of Business Wire)*

CNOOC Ltd.

- **Made six new discoveries in first-half 2015**
- **Largest producer of offshore oil and gas in China**

CNOOC is the largest producer of offshore oil and gas in China, with the company's average net production at almost 1.2 MMboe/d at year-end 2014. CNOOC operates in Bohai Sea, Western South China Sea, Eastern South China Sea and East China Sea offshore China, and holds oil and gas assets worldwide.

It is currently ranked 12th in terms of its offshore capex for 2014-2015, according to Infield.

In first-half 2015, the company made six new discoveries and drilled 21 successful appraisal wells. Five of the finds were offshore China and the other was in Algeria. Mostly due to production from two of the company's newly commenced projects, a mid-sized light crude oil discovery in the Eastern South China Sea and mid-sized discovery in the Bohai Sea, first-half 2015 total net oil and gas output reached 240.1 MMboe (up 13.5% from the 211.6 MMboe reported in first-half 2014).

In August 2015, CNOOC said its 2015 full-year production target of 475 MMboe to 495 MMboe remained unchanged.

"Effective cost control laid a solid foundation for [CNOOC] to manage in the current oil price environment," the company said in its 2015 mid-year review presentation. In an effort to lower costs, the company's all-in cost of $41.24/boe was down 4.5% year-on-year (yoy). In addition, "[CNOOC] maintained an intensive exploration program to support sustainable growth. The success rate of independent exploration wells offshore China reached 34% to 59%." Furthermore, opex of $9.60/boe was down 18.5% yoy because of cost control measures.

CNOOC had seven projects planned for 2015, and as of September 2015 five were onstream. Four projects in Bohai Sea and the Dongfang 1-1 gas field Phase 1 adjustment project in the Western South China Sea began production. The latest phase of the already-producing Weizhou oil development in the Western South China Sea, Weizhou 12-2 and Weizhou 11-4N, also were both expected onstream before year-end 2015. *cnoocltd.com*

Eni

- **Made biggest 2015 offshore discovery**
- **Ranked No. 25 on 2015 list of Fortune 500 Global companies**

Despite the lower oil prices, Eni's 2015 remained "stable" compared to the prior year, according to the company's second-quarter 2015 results, reporting $6.3 billion in cash flow for first-half 2015.

It is ranked sixth in terms of its offshore capex for 2014-2015, according to Infield.

The company's 2015 exploration plans included shifting its focus to proven plays and near-field exploration as well as reducing capex by 35%. In addition, it received a massive boost thanks to the discovery of a giant gas field in the Mediterranean Sea offshore Egypt in August 2015. The Zohr prospect is said to be the largest ever found in Egypt and the Mediterranean, with the find believed to hold potentially up to 849 Bcm (30 Tcf) of lean gas in place and covering an area of about 100 sq km (39 sq miles).

In July 2015, Eni also hit gas on the Nooros exploration prospect, located within the Abu Madi West license in the Nile Delta, 120 km (74.5 miles) northeast of Alexandria, Egypt. The company said the discovery was the result of its strategy to refocus on its near-field activities and "incremental exploration opportunities with high-potential value."

Additionally, Eni kept busy with its many development projects. The Perla Phase 1 offshore gas field in Venezuela started production in July 2015, with the field estimated to contain up to 481 Bcm (17 Tcf) of gas in place (3.1 Bboe), according to Eni's second-quarter 2015 report.

The company also was expected to start production from its much-delayed Goliat oil field in the Barents Sea by early 2016.

Six startups were achieved during first-half 2015: Kizomba Satellite Phase 2 offshore Angola; Cinguvu in the West Hub development project in Block 15/06 in Angola; Nené Marine Field in Congo; Hadrian South Field in the Gulf of Mexico; West Franklin Phase 2 in the U.K.; and Eldfisk 2 Phase 1 in Norway. The Litchendjili gas development offshore Congo also was scheduled to start production by year-end 2015.

First oil from its Offshore Cape Three Points development in Ghana is expected in 2017, with first gas in 2018 and production expected to peak at 80 Mboe/d by 2019.

In October 2015, Eni won a 100% share for a production sharing contract to appraise, develop and exploit the oil fields of Amoca, Miztón e Tecoalli, located in the Campeche Bay offshore Mexico. *eni.com*

Exxon Mobil

- **On track to increase production to 4.3 MMboe/d by 2017**
- **Ranked No. 5 on 2015 list of Fortune 500 Global companies**

Exxon Mobil has a total resource base of more than 92 Bboe, according to its available data.

It is currently ranked seventh in terms of its offshore capex for 2014-2015, according to Infield.

Early in 2015, CEO Rex Tillerson went on record in a press release to state that the supermajor expected to start up 16 major oil and gas projects over the following three years, with the company on track to increase production to 4.3 MMboe/d by 2017. The company's planned 2015 capex was put at about $34 billion, 12% less than in 2014, according to the release.

In third-quarter 2015, Exxon Mobil produced upstream volumes of 3.9 MMboe/d, up 2.3% over the same period in 2014. Overall, third-quarter 2015 earnings were $4.2 billion, almost exactly the same as in the second quarter, but third-quarter 2015 upstream earnings specifically were down more than $5 billion compared to third-quarter 2014, according to an investor presentation.

The startup of seven new major developments was scheduled for 2015, including Hadrian South in the Gulf of Mexico (GoM) and deepwater expansion projects at Erha in Nigeria and Kizomba in Angola.

In March 2015, the company started production in the deepwater GoM at Hadrian South with the subsea production facilities tied back to Anadarko's nearby Lucius truss spar, reducing additional infrastructure requirements. Hadrian South is located about 370 km (230 miles) offshore in the Keathley Canyon area in about 2,332 m (7,650 ft) of water. Projected gross production is about 8.4 MMcm (300 MMcf) of gas and 3 Mbbl of liquids from two wells, according to a press release. With the startup of Hadrian South and Lucius earlier the same year, Exxon Mobil's total GoM net production capacity has increased by more than 45 Mboe/d.

Subsidiary Esso Exploration and Production Nigeria Ltd. also began oil production five months early in 2015 and—impressively—$400 million under budget from its deepwater Erha North Phase 2 development project offshore Nigeria. The project is expected to produce an additional 165 MMbbl from the already-producing Erha North Field. Peak production from the expansion is estimated at 65 Mbbl/d of oil and will increase total Erha North Field production to about 90 Mbbl/d.

Another subsidiary, Esso Exploration Angola Ltd., started oil production at the Kizomba Satellites Phase 2 project in April 2015. This is a Block 15 subsea infrastructure development of the Kakocha, Bavuca and Mondo South fields, with the latter field the first to start flowing and the others were due to start producing before year-end 2015. The project will develop about 190 MMbbl of oil and is expected to increase total Block 15 production to 350 Mbbl/d. *exxonmobil.com*

INPEX

- **Ranked No. 10 in terms of its offshore capex for 2014-2015, according to Infield**
- **Japan's largest oil and gas E&P company**

With more than 70 projects across 25 countries, INPEX is Japan's largest integrated energy company and is directly involved with three world-class LNG megaprojects—Ichthys, Prelude and Abadi.

The company's key focus areas include E&P, appraisal, development and sales. INPEX operates upstream assets in Australia, Indonesia, the Middle East, Caspian Sea region, Gulf of Mexico, North America and Brazil.

For the six months from April to September 2015, Inpex's net production rose to 503 Mboe/d, compared to 395 Mboe/d for the same period in 2014 (thanks largely to an onshore acquisition in Abu Dhabi). Proved reserves were put at 2.43 Bboe, as of first-quarter 2015.

INPEX has 21 major assets in production worldwide, with another two in development and one preparing for development. These include two that began flowing in 2015 offshore Western Australia—the Van Gogh oil field, which restarted production in April 2015, and the Coniston Field, which started up in May 2015.

In fiscal year 2016, the company plans to undertake exploratory drilling campaigns in Malaysia's deepwater blocks S and R (where it found oil in the latter in April 2015) as well as in Suriname's Block 31.

In addition, the company also plans to continue progress on two world-class offshore projects that it operates: the Ichthys LNG Project in Western

When the Ichthys LNG Project is completed, the facilities will include two LNG processing trains, LPG and condensate plants, product storage tanks, a combined cycle power plant, administration facilities, utilities and a product load out jetty. *(Photo courtesy of INPEX)*

Australia and the Abadi LNG Project in the Arafura Sea, Indonesia.

Construction of the Ichthys LNG Project surpassed the 78% mark as of November 2015. However, production from the project is not expected to start until third-quarter 2017, around nine months later than originally planned and with a 10% addition rise in costs, it confirmed in September 2015.

The same month saw it release good news, however, as it launched the Ichthys Central Processing Facility (CPF)—the world's largest production semisubmersible unit—from the floating dock at the Samsung Heavy Industries shipyard in Geoje, South Korea, where it has been constructed. Once complete, the CPF will be towed 5,600 km (3,480 miles) to the field location in the Browse Basin, offshore Western Australia, where it will be permanently moored for the life of the project—more than 40 years.

"For the Abadi LNG Project, INPEX submitted to the Indonesian government a revised Basis of Design that envisions the adoption of a floating LNG [FLNG] plant with an annual LNG processing capacity of 7.5 MMtons, subject to the approval of the Indonesian government," a company representative told Hart Energy. This plan was much expanded from the one it replaced. INPEX's original design for an FLNG unit on Abadi had one-third the capacity of the revised design.

Additionally, the company plans on starting production on the Shell-operated *Prelude* FLNG project offshore Australia in 2017. *inpex.co.jp*

National Iranian Oil Co.

- **One of the world's largest oil companies by reserves**
- **South Pars Phase 19 and Phase 21 to come onstream by March 2016**

The National Iranian Oil Co. (NIOC) is Iran's state oil company founded in 1951, and directs and makes policies for E&P, drilling, R&D, refining, distribution and exports of oil, gas and petroleum products.

The company is one of the world's largest oil companies in terms of reserves, with 156.53 Bbbl of liquid hydrocarbons and 33.79 Tcm (1.1 quadrillion cubic feet) of natural gas under its control.

NIOC is currently ranked 11th in terms of its offshore capex for 2014-2015, according to Infield.

The organization consists of 17 production companies, eight technical service companies, seven managements, six divisions (administrative units) and five organizational units.

In October 2015, NIOC announced plans to launch Phase 15 and Phase 16 of the giant South Pars gas field, the world's largest gas field that it shares with Qatar after discovering it in 1990 in the shallow waters of the Persian Gulf. The company is trying to bring part of the South Pars Phase 19 and Phase 21 onstream before the end of March 2016. Production from the gas field's oil layer is predicted to begin in February 2017, it added. The company expects phases 12, 15 and 16 as well as parts of phases 17 and 18 to produce about 169 Bcm/d (6 Tcf/d) of natural gas after full commissioning. Phase 19 will be made operational to produce 28 Bcm/d (1 Tcf/d) of natural gas, according to a press release.

Also in October 2015, NIOC granted Russian state-owned Zarubezhneft several projects totaling $6 billion in Iran's oil industry. The two countries have devised a package of projects that are collectively worth $35 billion to $40 billion. Zarubezhneft has shown interest in participating in Iran's upstream projects since 2008. It isn't clear which Iranian projects or sectors it plans to make investments in, according to a release. *nioc.ir*

Oil and Natural Gas Corp.

- **Largest oil and gas producer in India**
- **Company has 1,184 offshore oil wells, 151 offshore gas wells**

State-run company Oil and Natural Gas Corp. (ONGC) contributes 69% to India's total crude oil production, 70% of its natural gas and has established more than 7 billion tonnes of in-place hydrocarbon reserves in the country.

It is currently ranked 14th in terms of its offshore capex for 2014-2015, according to Infield.

Six out of the country's seven producing basins were discovered by ONGC, which said in its corporate literature that it has made more than 400 discoveries in these basins. Of those finds, 22 were made in 2015.

As of April 2015, it had drilled 1,184 oil wells and 151 gas wells offshore. Many of the later ones have been drilled off India's eastern coast in the productive Krishna-Godavari deepwater basin, where it is underway with the phased development of several clusters of small fields in the prolific KG-D5 Block, with first gas expected in 2018 and first oil in 2019.

But ONGC has and continues to invest in squeezing more oil and gas from its existing mature oil fields in the waters it knows so well off its western shore. That includes giant fields such as Mumbai High in the Arabian Sea, where the company has used EOR techniques to maintain its production levels. It recently announced it would invest a further $1 billion by 2017 in the further redevelopment of Mumbai High, a field that began producing oil and gas in the 1970s.

Western coast offshore production was reportedly up by 7.5% in 2015 compared to a year earlier, according to a company publication.

Elsewhere, India and Kazakhstan launched in mid-2015 the first exploratory drilling at well STP-1 in the Satpayev Block offshore Kazakhstan in the Caspian Sea. The block is operated by ONGC's international subsidiary ONGC Videsh and Kazakh company KazMunaiGaz. The block has potential reserves of 1.8 Bbbl of oil and gas. *ongcindia.com*

Pemex

- **About 75% of Pemex's oil output is produced offshore**
- **Eighth largest oil producer in the world**

The globally integrated state-owned company is the third largest oil exporter to the U.S. and presently the sole producer of crude oil, natural gas and refined products in Mexico. As of November 2015, Pemex's 2015 capex for the entire company was estimated at $23.5 billion, down from $26.8 the previous year.

It is currently ranked 13th in terms of its offshore capex for 2014-2015, according to Infield.

In February 2015, the board approved a $4.16 billion spending cut and decided to delay deepwater exploration plans, in addition to cutting jobs to maintain stability in the price downturn.

Pemex said in November 2015 its crude production in Mexico was at 2.265 MMbbl/d, a slight drop from the year before but about 30% down from Pemex's oil production peak in December 2003 of 3.441 MMbbl/d, largely due to the inevitable decline in production from its giant but fading Cantarell Field. The company has made extensive and largely successful efforts over the past decade or so to arrest that production decline, by investing largely in EOR techniques on many of its fields. About 75% of Pemex's oil output is produced offshore.

Mexico's Congress also finalized new legislation that put an end to the monopoly held by Pemex, opening the sector up to private producers and bringing in new investment.

In 2015, the country began auctioning 169 oil blocks in onshore and offshore fields in the "Round One" series of auctions, following on from "Round Zero" in 2014 where Pemex was assigned some of its exploratory plays, already having been given its currently producing and developed fields. The company now has 12.4 Bboe of 1P proved reserves.

The company is expected to form partnerships with several western majors, in particular, to access their technological expertise and develop its existing deepwater discoveries in the Perdido Foldbelt area such as Trion, Exploratus and Maximino. Prospective resources in that area are put at up to 1.6 Bboe, but that is believed to be a conservative figure. Farther south in the deepwater Gulf of Mexico, Pemex also will eventually joint venture with international operators on the development the Kunah and Piklis gas fields. *pemex.com*

Petrobras

- **Ranked No. 1 in terms of its offshore capex for 2014-2015 and 2016-2017, according to Infield**
- **2015-2019 business plan proposes $130 billion of investment**

Petrobras is a semi-public Brazilian multinational energy corporation that operates in E&P among many other energy sectors, but it is widely recognized as one of the world's leading offshore players.

Far right: The Modec-owned FPSO *Cidade de Itaguaí* was installed in July 2015 on the deepwater Iracema North area of the Lula Field in the presalt Santos Basin, where it is producing for operator Petrobras. The vessel can produce up to 150,000 bbl/d of oil and store 1.6 MMbbl. The FPSO began producing five months ahead of schedule. *(Photo courtesy of Petrobras)*

Founded in 1953, the company has more than 135 offshore production platforms, with 90% of its oil reserves located in deep and ultradeep water.

Recent times have not been easy, however. Dogged by a massive ongoing corruption scandal and subject to a stringent and very public investigation, the company also announced in June 2015 a $130 billion 2015 to 2019 strategic plan. This cut its planned spending by 40% from the previous five-year plan, citing the plunge in oil prices and Petrobras' soaring debt.

Purely from an offshore perspective, however, Petrobras has several world-class projects underway. The company is leading the consortium exploring and developing the giant Libra Field area, which is expected to flow first oil via an extended well test in early 2017. Libra contains an estimated 8 Bbbl to 12 Bbbl of recoverable oil and equivalent natural gas.

The company's five-year plan prioritizes E&P projects in Brazil focusing on the presalt. New production systems in Brazil will total $64.4 billion, of which 91% will be for the presalt, *Subsea Engineering News (SEN)* reported in July 2015. "Of total E&P investments, the company said 86% will be allocated to production development, 11% to exploration and 3% for operational support. Petrobras expects to reach total production of oil and gas (Brazil and international) of 3.7 MMbbl/d in 2020 and estimates that, by then, the presalt will represent more than 50% of total oil production," *SEN* reported.

The company was acknowledged for its presalt efforts in May 2015 at the Offshore Technology

Conference (OTC) in Houston. It received the 2015 OTC Distinguished Achievement Award for Companies for its work in the presalt, where it "successfully implemented ultradeepwater solutions and set new water depth records." OTC's statement said, "Petrobras increased its efforts in technology development to exploit this hard-to-access resource in waters up to 2,200 m [7,218 ft]. By year-end 2014, Petrobras was producing more than 700,000 bbl/d of oil in the presalt layer of the Campos and Santos basins. The oil and gas production in this challenging environment demanded the development of different riser systems, which were successfully applied and are now available for the industry. Additionally, Petrobras achieved a significant reduction in the drilling and completion time for wells." *petrobras.com*

Petronas

- **Nearing completion of industry's first pioneering FLNG vessel**
- **24 EOR/IOR offshore projects currently underway**

Malaysian national oil company Petronas was founded in 1974. With a focus on E&P, the company has 91 wholly owned subsidiaries and 39 partly owned subsidiaries.

It is currently ranked eighth in terms of its offshore capex for 2014-2015, according to Infield.

Crude oil, condensate and natural gas production volume in third-quarter 2015 increased to 2,278 Mboe/d from 2,181 Mboe/d during the same period in 2014. Petronas attributes this to the increase in crude oil and condensate volume from Malaysia's new domestic offshore production stream, higher production entitlement in Iraq and new production from Azerbaijan.

The company's key upstream projects include the Petronas Floating LNG (PFLNG) project, Sabah-Sarawak Integrated Oil and Gas Project (SSIOGP), its Iraq operations and the Pacific Northwest integrated LNG.

Petronas said its PFLNG project will be a game changer for marginal fields and stranded gas developments. The first unit, weighing in at 132,000 tonnes and some 365 m (1,198 ft) in length, will produce up to 1.2 million tonnes per annum (mtpa) of LNG. The company expects its PFLNG facilities to enable the liquefaction, production and offloading of remote stranded gas fields lying hundreds of kilometers offshore.

The company reported in August 2015 that the first pioneering vessel, *PFLNG 1*, was nearing completion at the DSME yard in Okpo, South Korea and due onstream over the Kanowit Field offshore Sarawak, Malaysia in first-quarter 2016. In addition, construction is well underway at Samsung Heavy Industries shipyard in Geoje, South Korea for a second and significantly larger unit, *PFLNG 2*, which will be commissioned in 2018 and be located over the deepwater Rotan Field in Block H offshore Sabah, Malaysia. *PFLNG 2* will have a design capacity of 1.5 mtpa and weigh in at 152,000 tonnes. Both will be operated by Petrobras.

SSIOGP is the largest integrated oil and gas terminal in Malaysia and the company's largest greenfield project, according to the company, receiving oil and gas from several deepwater fields offshore Sabah and also entailing a connecting pipeline between the facilities onshore Sabah and Sarawak.

The company also has set out a clear strategy to "extract maximum value from existing [offshore oil] reservoirs" by rejuvenating brownfields via investment in IOR and EOR technologies. A total of 24 IOR and EOR production enhancement projects are underway, according to the company. *petronas.com*

Shell

- **Stones Field in GoM to host deepest production facility in the world**
- **Undertaking eighth and largest floating platform in GoM on Appomattox**

Royal Dutch Shell was founded in 1907 and grew to be one of the largest oil and gas companies in the world.

It is ranked fifth in terms of its offshore capex for 2014-2015, rising to third for the 2016-2017 period, according to Infield.

Shell successfully carried out the lifting of the 13,800-tonne topsides onto the hull of its Malakai tension-leg platform (TLP) at the fabrication yard in Pasir Gudang, Johor, Malaysia, in July 2015. The 27,500-tonne TLP is the first-ever to be fabricated and installed in Malaysia. It is due onstream in late 2016 or early 2017. *(Photo courtesy of Shell)*

In 2015 it reduced its capital spending by about $7 billion compared to the previous year as it reacted to the oil price plunge, and operating costs also were projected to fall by more than $4 billion, about 10%, as the company restructured and decreased costs.

Shell has several world-class projects underway offshore include the Appomattox development and the ultradeepwater Stones Field in the U.S. Gulf of Mexico (GoM), the deepwater Malampaya Phase 2 and Phase 3 project offshore the Philippines, and the *Prelude* Floating LNG (FLNG) facility destined for western Australia.

In July 2015, Shell made its final investment decision to advance the Appomattox project, authorizing the construction and installation of what will be its eighth and largest floating platform in the GoM. The development will initially produce from the Appomattox and Vicksburg fields, with average peak production estimated to reach about 175 Mboe/d. In September 2015, FMC Technologies was awarded a contract from Shell to provide enhanced vertical deepwater trees, subsea manifolds, topside controls, a control system and a distribution system for the Appomattox development.

The company also is moving toward completion of its massive *Prelude* FLNG project, which was the industry's first such project to get the go-ahead for development. Aimed at unlocking stranded gas resources offshore, the vessel will be stationed about 200 km (125 miles) off the northwestern coast of Australia and is due onstream during 2017.

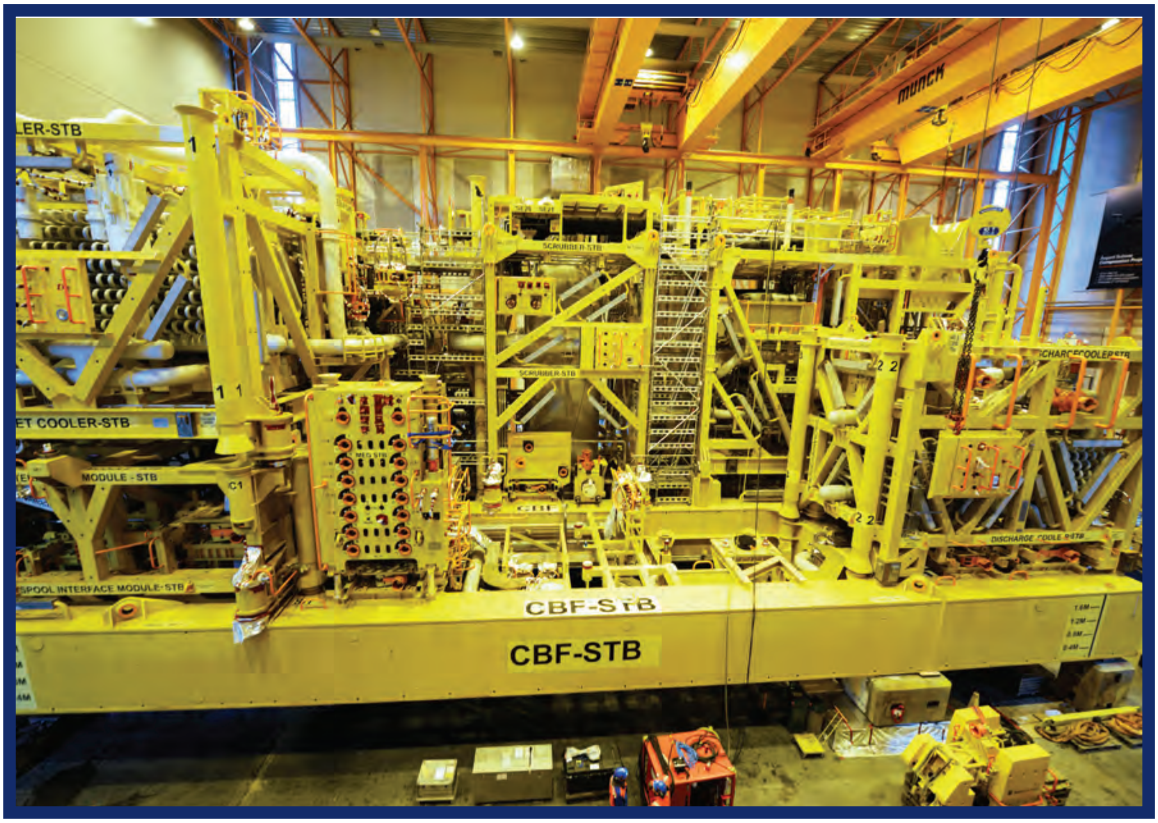
In the U.S. GoM, Shell's 100%-owned and operated ultradeepwater Stones Field will host the deepest production facility in the world with an FPSO unit situated in about 2,900 m (9,500 ft) of water. The field is estimated to contain more than 2 Bboe and will feature the use of several innovative offshore technologies in the initial and later development phases, including the first application of steel lazy wave risers with a turret and disconnectable buoy. *shell.com*

Statoil

- **Achieved world's first subsea wet gas compression on Gullfaks Field**
- **Celebrated 20-year anniversary of first oil from Troll Field**

Statoil has E&P operations worldwide, is a major operator on the Norwegian Continental Shelf and is recognized as one of the world's leading offshore technology pioneers.

It is currently ranked fourth in terms of its offshore capex for 2014-2015, according to Infield.



Statoil kicked off subsea gas compression on its Åsgard Field offshore Norway in September 2015. *(Photo by Harald Pettersen, courtesy of Statoil ASA)*

The company has discovered 4.4 Bboe in the last four years and in 2015 spent $3.2 billion in exploration, according to a presentation earlier in 2015. Statoil's production reached 1.909 MMboe/d in third-quarter 2015, up 4% compared to the same period in 2014, according to a company financial report.

The company made a number of discoveries around the world during 2015, including a gas and condensate find on the Norwegian Continental Shelf in second-quarter 2015 on the Julius prospect in the King Lear area of the North Sea. It estimates reserves at between 15 MMbbl and 75 MMbbl of recoverable oil equivalent. The company also made an oil discovery in its Miocene Yeti prospect in the Gulf of Mexico as well as an eighth discovery in its prolific Block 2 offshore Tanzania.

However, 2015 is mostly significant for Statoil because of its technological achievements over the past year. In October, Statoil and its partners Petoro and OMV started up the world's first subsea wet gas compression on the Gullfaks Field in the Norwegian North Sea. The company states the technology will increase recovery by 22 MMboe and extend plateau production by about two years from the Gullfaks South Brent reservoir. In addition, it was also the first company to apply subsea gas compression, starting up its long-awaited system on the Åsgard Field offshore Norway in September 2015.

The same month it also celebrated the 20-year anniversary of first oil from its flagship Troll Field. Troll has produced 1.56 Bbbl since then and brought in nearly $57 billion in income, the company stated.

The company's joint-venture Johan Sverdrup project in the North Sea also continued to progress as planned. The field is operated by Statoil (40%) with partners Lundin Norway (22.6%), Petoro (17.36%), Det norske oljeselskap (11.57%) and Maersk Oil (8.44%). Construction got underway and contracts worth more than $4.9 billion were awarded. In August 2015, the first building block of development was completed and installed on the field. *statoil.com*

Total

- **Ranked No. 2 in terms of its offshore capex for both 2014-2015 and 2016-2017, according to Infield**
- **Twenty startups by 2017; eight took place in 2015**

Total, with 100,000 employees worldwide, reduced its 2015 capex to between $23 billion and $24 billion as part of its response to the lower oil price.

However, the company reported a production increase of 11% year-on-year during first-half 2015 and expects production to grow an average of 6% to 7% per year between 2014 and 2017 due to 20 startups, eight of which took place in 2015, according to a September 2015 presentation. The company also plans to further increase its opex reduction target by 50% from $2 billion to $3 billion by 2017.

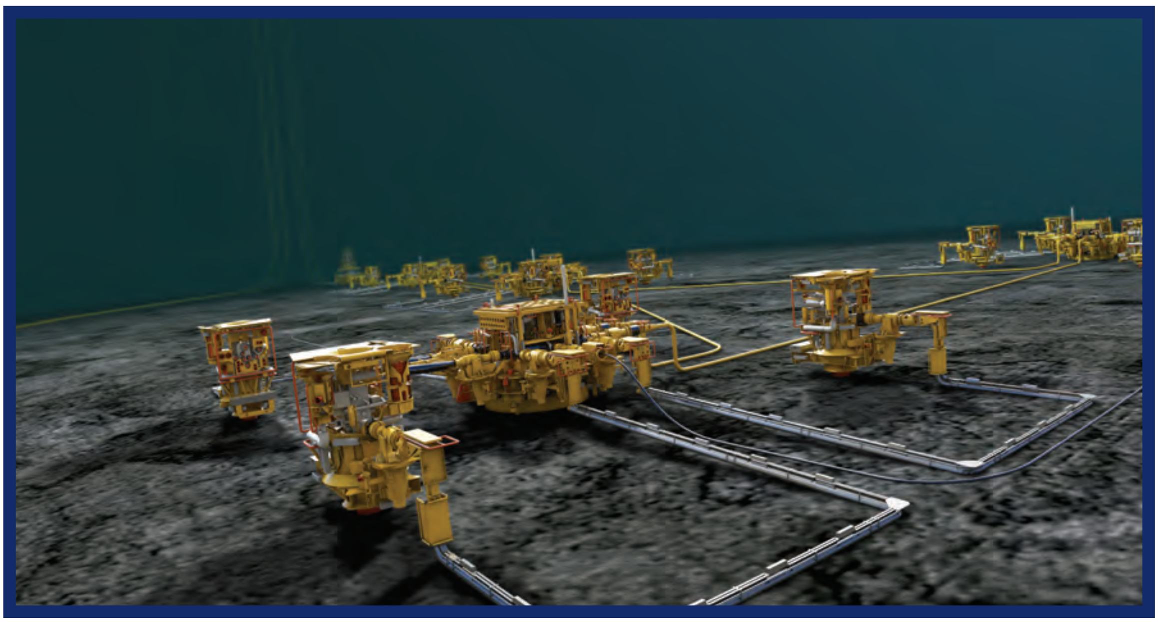
Total is a pioneer in executing projects in the deep and ultradeep water. "By the year 2020, a water depth of 3,000 m [9,843 ft], from an oil development perspective, seems to be achievable," Jeremy Cutler, head of technology innovation at Total E&P UK, told delegates at SPE Offshore Europe 2015, according to an *E&P* article. "We see that by 2025 the expectation is that 4,000 m [13,123 ft] will be achieved."

In January 2015, Total started gas and condensate production from the West Franklin Phase 2 project in the Central Graben area of the U.K. North Sea. The project is expected to supply 40 Mboe/d to the Elgin/Franklin hub.

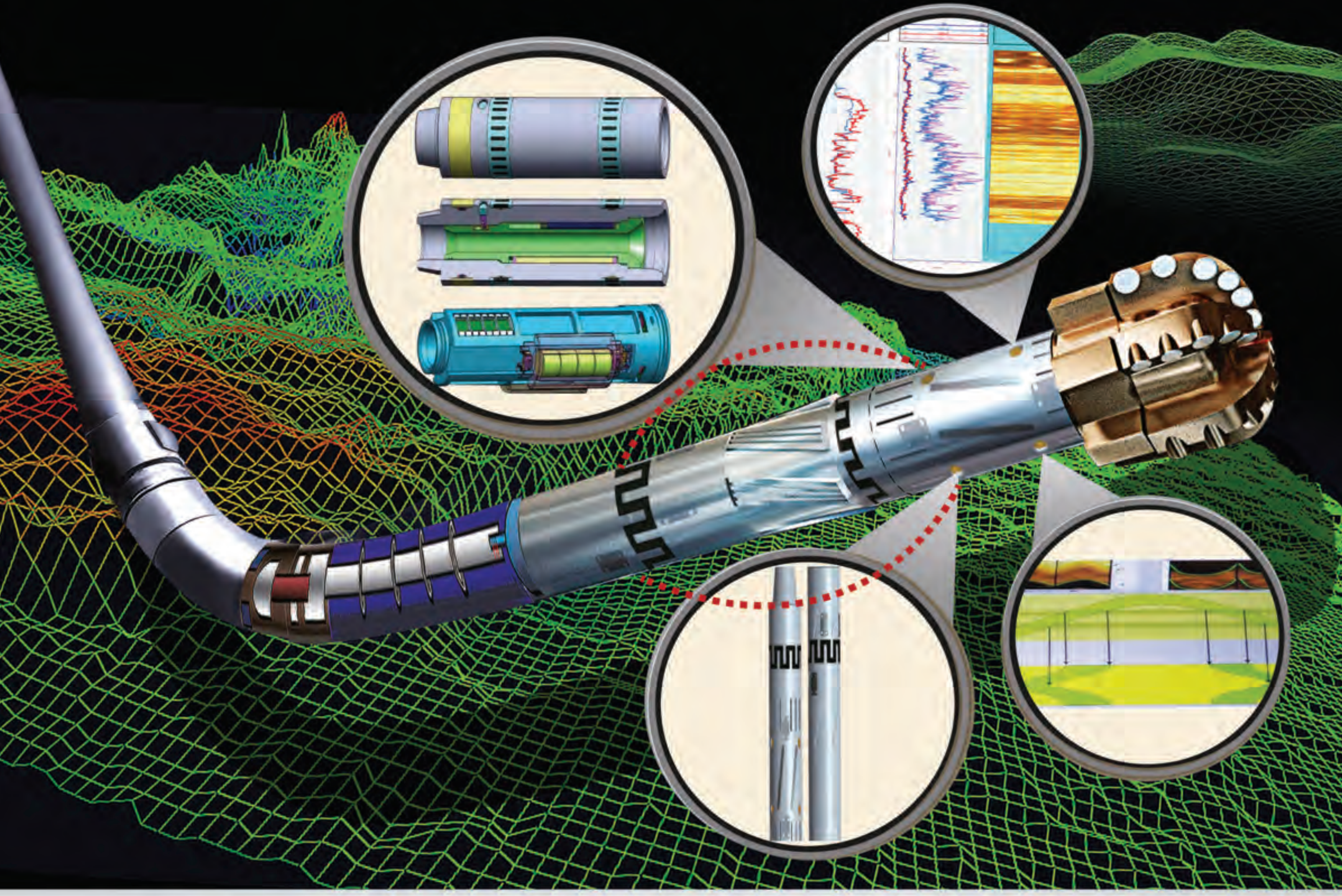
In May 2015, it also achieved 2 Bbbl of production from its operated deepwater Block 17 offshore Angola. "With the recent startup of CLOV, Block 17 has become Total's most prolific site with production of more than 700,000 bbl/d," it stated in a May 2015 press release. In July 2015, the company started production from Dalia Phase 1A, a new development in the same block. Dalia Phase 1A is expected to develop additional reserves of 51 MMbbl and contribute 30,000 bbl/d to the block's production.

Total also continued with its innovative development of the 125-km (78-mile) subsea-to-shore deepwater Laggan-Tormore gas field located offshore the U.K. west of Shetland. The field was originally scheduled to be operational by year-end 2015 but is now expected onstream during the early part of 2016, with the project also involving the building not only of the two-manifold subsea system but also a new gas processing plant and two major pipelines.

In July 2015, the company agreed to sell 20% of its interests in the Laggan, Tormore, Edradour and Glenlivet fields located west of Shetland to SSE E&P UK Ltd. for about $876 million. Total will still hold a 60% operated interest in the fields. *total.com* ■



With the recent startup of CLOV offshore Angola, Block 17 has become Total's most prolific site with production of more than 700,000 bbl/d. *(Image courtesy of Total)*



Brazil and Australian Mega-projects Dominate the Top 10

By Mark Thomas, Editor-in-Chief, with data courtesy of Infield Systems

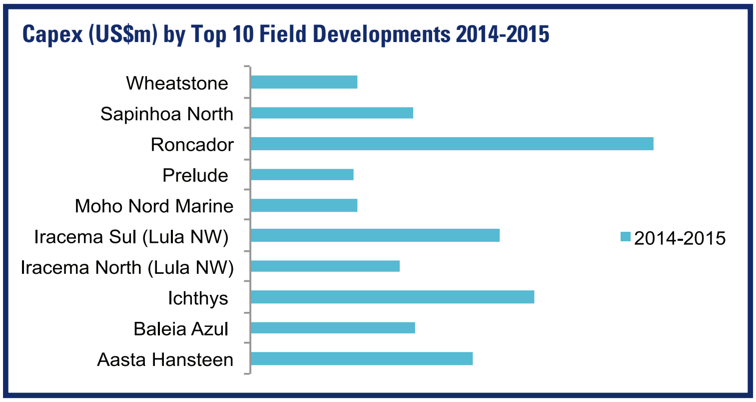
According to Infield's capex analysis, the biggest global projects are centered mainly in just two countries.

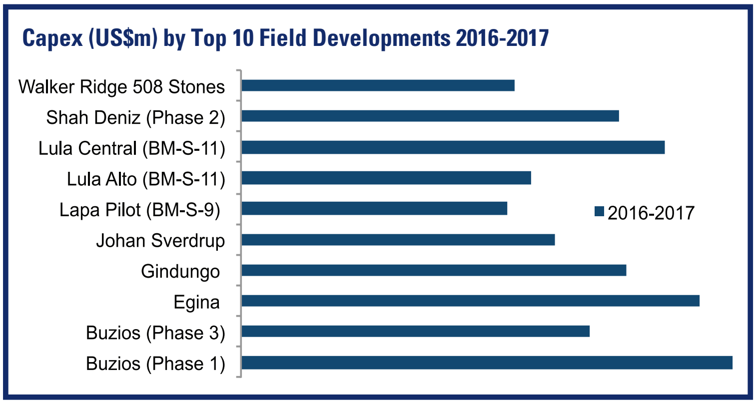
Chevron's Wheatstone steel gravity substructure semisubmersible platform in the Northern Carnarvon Basin offshore Western Australia. Hook-up and commissioning activities were on schedule and the first permanent systems completed in the fourth quarter of 2015, with the facility to flow 2 Bcf/d of gas at peak production. *(Photo courtesy of Chevron)*

"Show Me The Money!" So said Jerry Maguire in the Hollywood film of 1996. A decade later, much the same is being said by the offshore oil and gas industry, following a year in which the oil price sank lower than just about everyone expected–and which is stubbornly refusing to rise again.

But billions of dollars are still being spent by the E&P sector, and listed below alphabetically are the Top 10 offshore projects around the world, based on their capital expenditure for the years 2014 to 2015, according to expert analysis by Infield Systems. The individual spending represented by these top 10 projects over the two-year period ranges from close to $2 billion for the No.10 entry up to more than $7 billion for the No.1 entry. For more or updated information contact Infield (*infield.com*).

These are not projects still on the drawing board or pre-final investment decision but world-class developments well underway or already producing and being invested in by their committed operators and project partners, despite what many observers now believe is the worst oil price downturn the sector has ever experienced. ■





(Source: Infield Systems)

Project	Aasta Hansteen
Operator	Statoil
Field Location	Blocks 6706/12 and 6707/10, Vøring area, Norwegian Sea
Production Facility	The first spar facility installed offshore Norway, and it is the world's largest so far, tied back to three subsea templates.
First Production	Late 2017 or early 2018
Production Rate	812 MMcf/d of gas
Water Depth	1,300 m (4,265 ft)
Estimated Reserves	47 Bcm of recoverable gas

Notes: Discovered in 1997 and originally called Luva, Statoil's Aasta Hansteen development is a flagship project for the Norwegian operator. The spar will have conventional topsides with processing facilities, while the risers lifting the gas from the seabed to take it onwards via the Polarled pipeline will be pure steel, the first of their kind offshore Norway. The spar hull will be the first in the world to be fitted for condensate storage, able to hold up to 160,000 bbl, which will be offloaded to shuttle tankers. The platform will have a total hull length of 195 m (640 ft) and a diameter of 50 m (164 ft) and weigh in at 70,000 tonnes. A total of 17 suction anchors will anchor the spar in place, with a further eight to hold the risers. The three seabed well manifolds linked to the spar will also be Norway's deepest subsea production facilities to date.

Project	Baleia Azul
Operator	Petrobras
Field Location	Parque das Baleias (Whale Park), Campos Basin, Brazil
Production Facility	FPSO *Cidade de Anchieta* is linked to 10 subsea wells (seven producers, three water injection)
First Production	September 2012
Production Rate	Average of 85,000 bbl/d, 3.5 MMcm/d of gas
Water Depth	1,221 m (4,006 ft)
Estimated Reserves	Recoverable reserves of 500 MMboe

Notes: The FPSO has a storage capacity of 1.6 MMbbl and is on an 18-year lease contract lasting until 2030 with Petrobras on the presalt field. The unit–operated by SBM–averaged more than 99% oil uptime in 2014. It can produce up to 100,000 bbl/d of 28º API oil at peak. This project also includes receiving presalt production from the Jubarte and Pirambu fields. The produced gas is piped via the Capixaba North-South pipeline to the Natural Gas Treatment Facility in Cacimbas, on the coast of Espírito Santo.

Project	Ichthys
Operator	INPEX
Field Location	Permit WA-285-P, 220 km offshore Western Australia
Production Facility	Permanently moored FPSO with nondisconnectable turret and a semisubmersible central processing facility (CPF) linked to five drill centers (four to six subsea wells each) and a 6,500-tonne seabed steel riser support structure.
First Production	September 2017
Production Rate	Annual production of 8.9 MM tonnes of LNG and 1.6 MM tonnes of LPG, along with approximately 100 Mbbl/d of condensate at peak.
Water Depth	250 m to 280 m (820 ft to 919 ft)
Estimated Reserves	12.8 Tcf of recoverable gas, 500 MMbbl of condensate

Notes: The Ichthys LNG Project is led by Japan's INPEX, and involves piping natural gas lifted from the Ichthys gas-condensate field offshore Western Australia 889 km to an onshore gas liquefaction plant in Darwin, Northern Territory, after preliminary processing aboard the CPF to remove most of the condensate. The CPF will be Australia's first production semisubmersible facility and the largest semisub in the world. It is planned to be operational for 40 years. Most of the condensate will be transferred from the CPF approximately 3.5 km to the 336-m- (1,102-ft-) long FPSO for further processing. Total subsea infrastructure and equipment weight is 30,000 tonnes. Total project cost is estimated by INPEX at $34 billion, although it was recently confirmed that costs had risen by 10%.

Project	Iracema Norte (North)
Operator	Petrobras
Field Location	Block BM-S-11 (Lula Area), Santos Basin, 240 km offshore Brazil
Production Facility	FPSO *Cidade de Itaguaí*, a moored floating production facility, is linked to eight subsea production wells and nine injection wells.
First Production	August 2015
Production Rate	150,000 bbl/d oil, 16 MMcm/d (280 MMcf/d) gas
Water Depth	2,200 m (7,218 ft)
Estimated Reserves	500 MMbbl to 900 MMbbl of recoverable oil

Notes: Part of the giant Lula (formerly Tupi) presalt field area, the Iracema North's FPSO, chartered for 20 years from Schahin-MODEC, has the capacity to store 1.6 MMbbl of oil and inject 264,000 bbl/d of water. It came onstream in August 2015 several months ahead of schedule. The field also features the use of 114 km of flexible piping, including gas lift, gas injection and gas export lines for sour service application. The gas is exported to shore via a subsea gas pipeline.

Project	Iracema Sul (South)
Operator	Petrobras
Field Location	Block BM-S-11 (Lula Area), Santos Basin, 240 km offshore Brazil
Production Facility	FPSO *Cidade de Mangaratiba*, a moored floating production facility, is linked to eight subsea production wells and eight injection wells.
First Production	October 2014
Production Rate	150,000 bbl/d of 30° API oil, 16 MMcm/d (283 MMcf/d) gas
Water Depth	2,200 m (7,218 ft)
Estimated Reserves	500 MMboe to 900 MMboe of recoverable oil

Notes: The FPSO *Cidade de Mangaratiba* was the first production unit to permanently produce from the presalt Iracema Field, following its discovery in 2009 and earlier well tests. The unit had the highest production capacity of any operational vessel in the Santos Basin when it began flowing, with its production capacity of 150,000 bbl/d of oil and 283 MMcf/d of gas. Petrobras expects it to hit peak production during the first half of 2016. Like the FPSO on Iracema North, it was chartered from the Schahin-MODEC consortium for 20 years.

Project	Moho Nord (North) Marine
Operator	Total
Field Location	Moho-Bilondo Permit, 75 km offshore Republic of Congo
Production Facility	Tension-leg platform, floating production unit and 45 subsea production wells
First Production	December 2015 (Phase 1b) and Q2 2016 (Moho Nord)
Production Rate	140,000 boe/d of oil at peak in 2017
Water Depth	650 m to1,100 m (2,133 ft to 3,609 ft)
Estimated Reserves	485 MMboe recoverable reserves

Notes: The first phase of the Moho-Bilondo oil field first came onstream via an floating production unit (FPU) in 2008 with the completion of the Moho Bilondo Phase 1E project in the southern part of the license. The current phase has total project investment estimated at $10 billion and is targeting additional reserves in the southern portion (Moho Phase 1b) as well as new reserves in the northern sector (Moho Nord). First oil from Phase 1b began flowing via 11 subsea wells to the field's first FPU in December 2015 and is producing 40,000 boe/d. It is also utilizing two of the most powerful subsea pumps ever built. Moho Nord will flow via a newbuild TLP (17 wells) and a 100,000 boe/d processing capacity FPU (with another 17 wells). The TLP weighs in at 13,000 tonnes and will have 27 wells slots. The subsea kit includes manifolds, 230 km of rigid pipelines, 23 km of flexibles, 50 km of umbilicals and 50 subsea structures.

Project	Prelude
Operator	Shell
Field Location	WA-371-P North, Browse Basin, 200 km offshore, Western Australia
Production Facility	Permanently moored floating liquefied natural gas (FLNG) unit, two six-slot subsea manifolds and one riser base manifold
First Production	Mid-2017
Production Rate	5.3 MM tonnes per annum (mtpa) of liquids, consisting of 3.6 mtpa of LNG, 1.3 mtpa of condensate and 0.4 mtpa of liquefied petroleum gas
Water Depth	250 m (820 ft)
Estimated Reserves	3 Tcf of recoverable gas (Prelude plus Concerto fields)

Notes: The Prelude FLNG facility will be an offshore giant, becoming the largest floating offshore facility in the world when it becomes operational in 2017. It is 488 m (1,600 ft) long, 74 m (240 ft) wide and once complete will weigh around 600,000 tonnes. It will feature the largest turret mooring system in the world, at almost 100 m (328 ft) in height. An initial seven gas wells will flow to the FLNG facility via flexible risers.

Project	Roncador
Operator	Petrobras
Field Location	Block P-36, Campos Basin, 125 km offshore Brazil
Production Facility	*P-62* FPSO linked to 22 subsea wells
First Production	Originally in 1999, latest phase (Module 4) in May 2014
Production Rate	460,000 bbl/d of oil
Water Depth	1,600 m (5,250 ft)
Estimated Reserves	3 Bbbl recoverable oil

Notes: The Roncador Field has largely been Petrobras' deepwater technology development pioneer since first coming onstream in 1999. Because of its size the operator divided the field into four slices: Modules 1, 2, 3 and 4, then further sub-dividing those into additional phases. Currently producing are the FPSO *Brasil* (Module 1A, Phase One), the P-52 platform (Module 1A, Phase Two), the *P-54* FPSO (Module 2), the P-55 platform (Module 3), and the *P-62* FPSO (Module 4), the last of which came onstream in late 2014 and is producing a further 180,000 bbl/d via 22 wells. It can also inject more than 250,000 bbl/d of water and 6MMcm/d of gas, and store 1.6 MMbbl of oil.

Project	Sapinhoa North
Operator	Petrobras
Field Location	BM-S-9 (Guara) Block, Santos Basin, Brazil
Production Facility	FPSO *Cidade de Ilhabela*, linked to 16 subsea wells
First Production	December 2014
Production Rate	150,000 bbl/d of oil
Water Depth	2,140 m (7,021 ft)
Estimated Reserves	2.1 Bboe recoverable oil and gas

Notes: The first FPSO producing on the presalt Sapinhoa Field was the *Cidade de São Paulo*, which began producing in early 2013 and can produce up to 120 Mbbl/d. For the north of the field Petrobras opted for another FPSO, the *Cidade de Ilhabela*. With a production capacity of 150 Mbbl/d of oil and 212 MMcf/d of gas, the unit is connected to nine production wells and seven injection wells and was expected to reach its peak production rate during the latter part of 2015. The unit can inject up to 180 Mbbl/d of water and store 1.6 MMbbl/d of oil. The gas not reinjected is offloaded via the Sapinhoá-Lula-Mexilhão pipeline to the Monteiro Lobato Gas Treatment Unit in Caraguatatuba.

Project	Wheatstone
Operator	Chevron
Field Location	Permits WA-253-P, WA-17-R, WA-16-R, Northern Carnarvon Basin, 145 km offshore Western Australia
Production Facility	Steel gravity substructure platform linked to nine production wells and by trunkline to shore
First Production	Q4 2016
Production Rate	2 Bcf/d of gas; 8.9 million tonnes per year of LNG
Water Depth	70 m to 260 m (229-853 ft)
Estimated Reserves	4.5 Tcf of gas

Notes: This is one of Chevron's current crop of mega-projects, with the Wheatstone and Iago fields' offshore infrastructure linked by pipeline 225 km to two initial onshore LNG trains near Onslow. The steel gravity substructure central processing platform is located in 70 m (230 ft) of water, after being installed in May 2015. The hull weighed in at 22,000 tonnes, while the topsides came in at 37,000 tonnes, representing Chevron's largest single integrated floatover installation. Other gas will also be fed to Wheatstone from the Julimar and Brunello fields in a phased 20-year program, with up to 20 subsea wells to eventually be connected to the Wheatstone infrastructure via three eight-slot subsea manifolds.

All the subsea equipment and flowlines have been installed on Chevron's Wheatstone mega-project offshore Western Australia. The umbilical fabrication is also complete, and offshore installation was underway as of early 2016. First production is planned for before the end of this year. *(Photo courtesy of Chevron)*

Exploration Leads the Way

By Rhonda Duey, Executive Editor

The complexity of many deepwater fields means that explorationists need an arsenal of sensing tools at their disposal.

Developing offshore fields is always an expensive proposition. Wells at intermediate depths can cost up to $120 million, and ultradeepwater wells can cost as much as $400 million, according to Offshore Technology Conference paper 15OTC-P-1347-OTC-MS, "High-quality and Efficient Seismic Acquisition for Frontier Deepwater Areas." So acquiring high-fidelity geophysical data prior to drilling is of the essence.

But the drop in commodity prices means that operators are trying to push their investments farther out and lowering costs in every way they can. "That makes for a very challenging business environment, one that we are working to address," said Craig Beasley, chief geophysicist and Schlumberger fellow. "The industry is focusing more on the efficiency and the value of the technology, which has become even more important than in the past."

The geophysical contracting industry has responded to the need for better imaging by developing technologies and techniques that have truly pushed the boundaries of exploring the subsurface. New seismic acquisition and processing methods are being used side-by-side with gravity and electromagnetic (EM) methods to obtain the clearest images possible.

Gravity

Surveying large swaths of the ocean prior to launching a seismic survey can help companies fine-tune their exploration targets. Gravity gradiometry surveys can be acquired either by boat or plane to measure minute changes in the Earth's gravity.

These surveys employ a gravity gradient instrument that contains a slowly rotating disk equipped with four accelerometers. The combination of the accelerometer arrangement and the rotation allows the instrument to detect very small gravity signals to measure the differential curvature of the Earth's gravity field, which in turn provides a density measurement. This provides explorers with a regional geologic framework. Gravity surveys also can provide additional information to existing earth models.

CSEM

Controlled-source EM (CSEM) surveys also can be used throughout the life cycle of the field. During the exploration phase, their ability to measure resistivity anomalies in the subsurface can highlight prospective areas. The surveys are acquired by vessels and seabed devices.

CSEM surveys are acquired using an EM source towed behind a boat with nodes on the seafloor that pick up the resistivity signal. The source uses a positioning system since its position must be accurately known.

This technology has advanced considerably since its introduction 15 years ago. Processing algorithms have advanced to keep pace with acquisition advances.

PGS has recently commercialized towed-streamer EM surveys, which it often pairs with traditional seismic surveys. "The complementary seismic and EM data allow entirely new opportunities to accurately and efficiently estimate net volume of hydrocarbons [and] pursue robust de-risking at basin scale," said Andrew Long, chief scientist at PGS.

Simultaneous sources

Simultaneous sources have long been used on land surveys, but their uptake in marine surveys has been quite recent, and again this uptake is being driven by efficiency. "It used to be that we would get a shot record, and we would listen for a certain period of time and then go to the next one," said Mike Bahorich, recently retired from Apache, in the TLE Interview Series. "Now we're shooting on top of each other, in essence, and sorting it out later in processing. We're becoming much better at sorting these things out so that the cost of seismic has come down substantially.

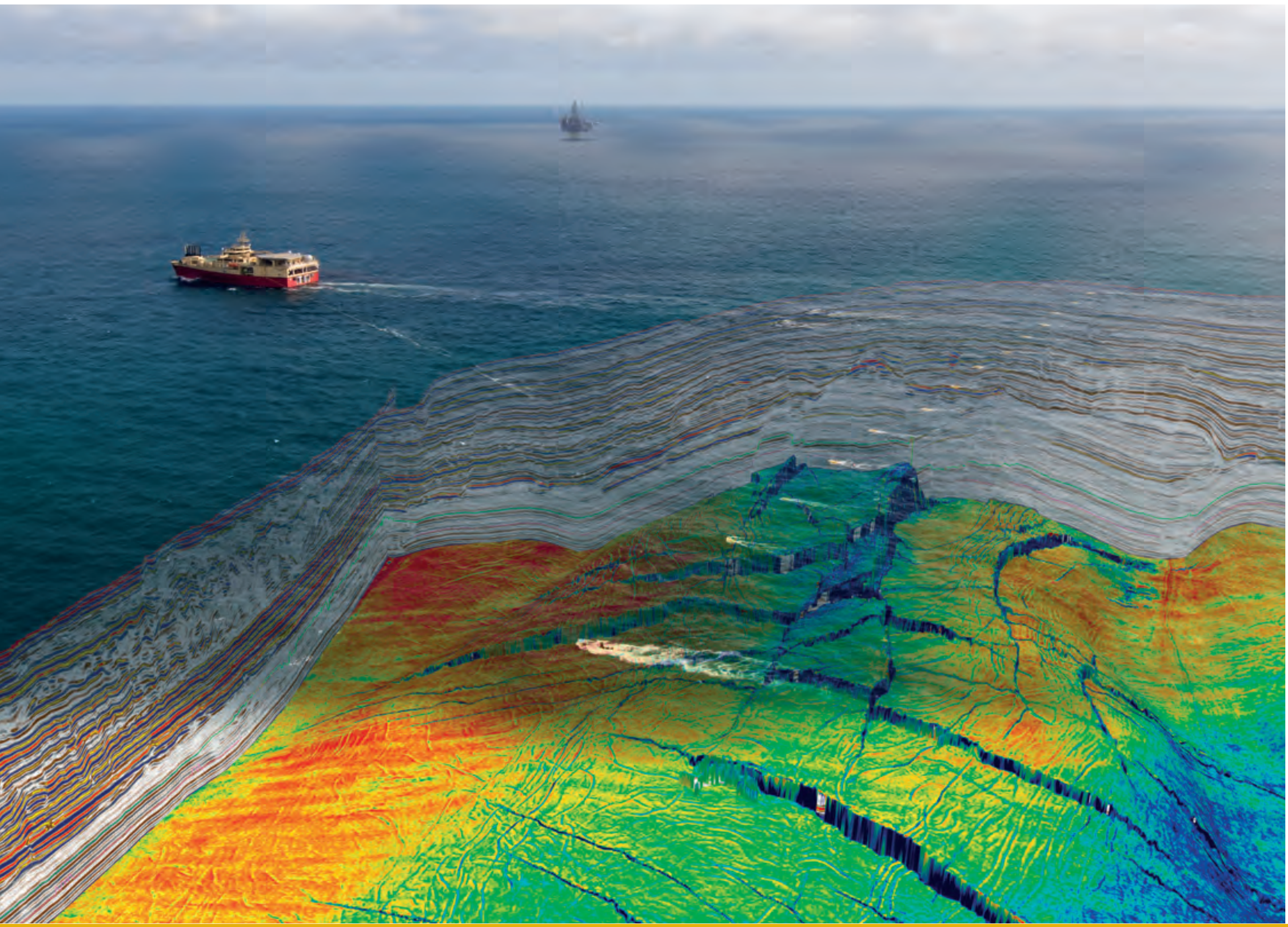
"In fact, we had a recent survey that we shot in the Gulf of Mexico [GoM] where we saved about $60 million using multiple source technology." He added that Apache would not have shot the survey if it had been unable to realize these savings.

Beasley said that WesternGeco has recently completed its first simultaneous source multiclient survey. The survey used four acquisition boats, each with two sources. The company is currently processing the data.

"Clients are naturally looking for more value, and in this case we were able to improve the survey characteristics—small shot spacing, higher fold and increased long offsets, which combine to give better sampled data without the high increase in cost that would come if we tried to do that with conventional shooting," he said.

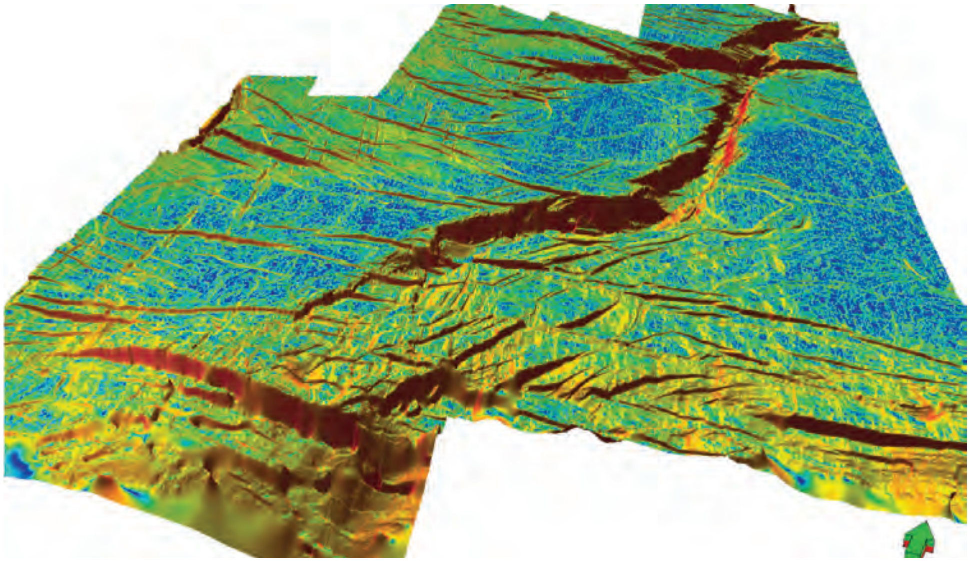
WAZ seismic

One of the most remarkable breakthroughs in exploration methodology in recent years has been the move to wide-azimuth (WAZ) seismic surveys. The approach can be undertaken in a number of ways, but



New offshore acquisition and processing technologies are leading to better imaging and, ultimately, greater offshore exploration success. *(Image courtesy of PGS)* it essentially involves multiple vessels traveling in different directions over the target to provide a fuller image of the subsurface.

"The transition from narrow- to wide- and now full-azimuth data in complex geologies, combined with longer offsets and broader bandwidths, has enabled step changes in subsalt imaging in areas such as the Gulf of Mexico," said Alan Clint, vice president, marketing, Marine at CGG. "This has been complemented by major advances in model building and imaging/inversion technologies to deliver unprecedented clarity of deep imaging. We have had huge interest in our StagSeis (full-azimuth, broadband and ultralong offsets) program in the Gulf of Mexico, with nine companies precommitting. The ability to deliver high-quality imaging results in a timely manner for this new generation of seismic was also crucial."



IsoMetrix technology enables fine-scale subsurface characterization of the Loppa High fault system in the Barents Sea. *(Image courtesy of WesternGeco)*

A variation on this theme is coil shooting, where the boats travel in overlapping circles rather than straight lines. Beasley said that WesternGeco currently has eight seismic boats shooting a WAZ over the Campeche Field offshore Mexico, and is planning to further acquire a full-azimuth coil shooting survey. The ability to control the movement of the streamers makes coil shooting feasible.

"The advantages of shooting in a coil configuration are many, but mainly it provides a full 360-degree look at the subsurface and very long offsets, something that is difficult to achieve with any other towed-streamer configuration," he said.

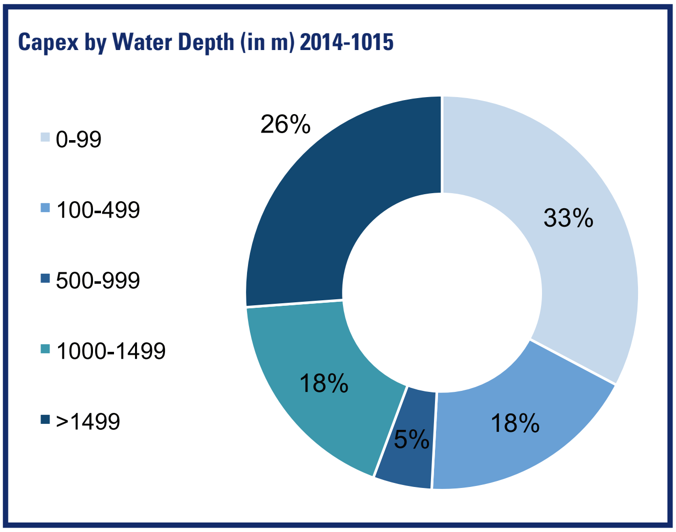
Broadband

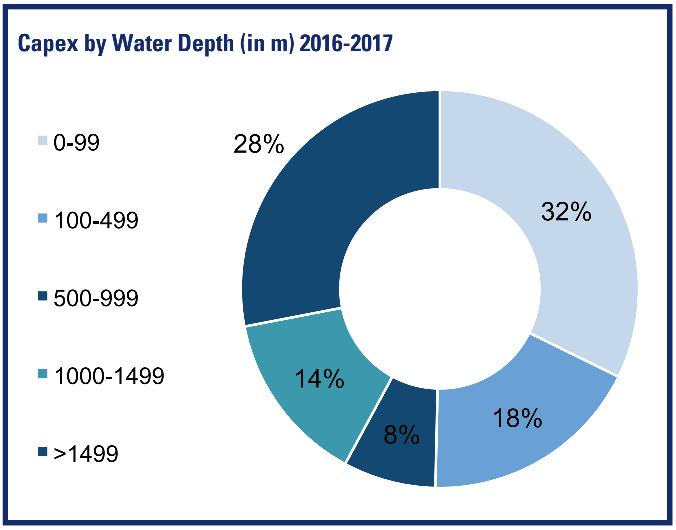
Broadband technology also has revolutionized marine seismic. Broadband acquisition enables companies to acquire lower frequencies, which translates into clearer imaging of deep targets. Broadband surveys allow interpreters to remove the "ghost" notch, which is an artifact caused by the upgoing signal reflecting off of the surface of the water. It also removes the need for a low-frequency model.

Most of the major geophysical contractors offer a broadband solution. Mohammed El-Toukhy, Western Hemisphere multiclient exploration service manager for WesternGeco, said the concept started in Southeast Asia and has since been adopted globally. "I would say that of the surveys that are being contemplated, a number of them are trying to achieve a broadband result," he said. "With some limitations we've been able to extend the band range without large increases in cost."

According to Clint, attention recently has focused on broadband sources. "We see amazing differences in data quality as we extend the spectrum toward both the low and high frequencies by removing the limits of the source and receiver ghosts," he said. "The broader bandwidth delivers sharp wavelets without sidelobes for clear definition of thin layers and small features. The low frequencies add texture to the reservoir, enabling discrimination of different facies and identification of traps and seals to reduce exploration risk.

"This is combined with exceptional resolution and detail of the near surface, which enables improved geohazard identification to reduce drilling risk. We've now shot more than 300,000 sq km [116,000 sq miles] of data worldwide. Broadband is the default choice, and there's no going back."





(Source: Infield Systems)

Dual-sensor wavefield separation is adding value beyond traditional imaging, according to Long. "Prestack amplitude vs. angle behavior is more robust, leading to more quantitatively accurate reservoir characterization," he said. "By extending the ultralow frequency content models after deghosting by more than an octave, we have less dependence on complementary low-frequency models built from interpolated well log data. Most notably, the angle-dependent gradient term is proven to be significantly more stable than typically observed on conventional hydrophone-only streamer data."

Many companies will argue that achieving a broadband result can be done through processing rather than acquisition, meaning that legacy datasets can be reprocessed. TGS and ION, for instance, have processing solutions that solve the ghost effect by computing an inverse operator to deconvolute the ghost from the data. TGS also varies the depth of its conventional streamers to compensate for one streamer's ghost notch with data from surrounding streamers.

Ocean-bottom systems

Beasley describes ocean-bottom seismic (OBS) as having been considered "the gold standard" in marine seismic. Ocean-bottom systems come in different forms. Ocean-bottom cables are similar to a land acquisition system in that cables are laid out on the ocean floor. Newer "nodal" systems are not cabled to each other.

"The receivers don't move, you get coupling to the seafloor and you get the opportunity to easily do up/down wavefield separation," he said. "The only downside is that the cost per kilometer tends to be higher, and it takes longer to shoot. But this is another area where simultaneous sources are making an impact by making OBS surveys more cost-competitive."

Shell has been acquiring node surveys since 2007 "very pervasively" across its deepwater portfolio in the GoM. It primarily uses the technology for development, meaning the survey areas are smaller.

"The main advantage of OBS is that full-azimuthal coverage is obtained," said Jan Stammeijer, deepwater 4-D time-lapse seismic coordinator for Shell Oil Co.

"In layman's terms, you could say that with this technique we get many 3-D seismic surveys, each illuminating the subsurface from a different angle. This is important, especially in complex settings such as close to salt." He added that in producing assets another advantage is the repeatability of the nodes—they can be placed in exactly the same location for each survey, reducing the noise level and making reservoir monitoring much more accurate.

The primary cost of a node survey is the fact that they must be positioned by ROVs. Shell has experimented with firing more shots at the surface than there are nodes on the seabed. "This asymmetry allows us to acquire large volumes of data (thereby suppressing noise) in a more efficient fashion," Stammeijer said.

Efforts are underway to get the cost down, which is expected to increase demand. "In time-lapse seismic, cheaper surveys allow for more frequent monitoring," he said. "This is already happening for deepwater fields with permanently installed seismic systems such as Shell's BC-10 North and Petrobras' Jubarte, where yearly surveys are the norm. Lowering costs also will enable the industry to start considering node surveys in an exploration setting. For shallow water, this is already happening because cheaper ways of deploying nodes are safely possible in that setting."

Remaining challenges

"Given the current climate of cost constraint and time pressure, operations are continually challenged to do more in less time and still deliver high-quality results," Clint said. "We are looking at a range of technologies across acquisition and processing to help with this.

"As an industry, we still do not provide a perfect image of the reservoir, but we strive to provide images and attributes ever closer to the geological truth. Within CGG, well-driven and reservoir-oriented processing quality control, which now features in some of our key multiclient projects, is moving us ever closer to the realities of the reservoir.

"Probably the most frustrating for our clients is time," he added. "They want results quickly to guide drilling programs and make field development decisions. We have been looking at turnaround very closely and how we can do more on board or during acquisition. We have had some fantastic results with our permanent reservoir monitoring contracts, delivering full 4-D attribute volumes in about two weeks after the last shot. We also are seeing excellent results on accelerated marine 3-D workflows."

Then there are the business challenges. "Everyone is obviously suffering in the current market conditions," Long said. "We hope the historical PGS mantra of using step changes in efficiency to enable high-end technology pursuits in cost-effective ways will be more relevant than ever."

Thierry Brizard, CTO of CGG, added, "CGG is working on game-changing technologies that may provide superior solutions to prepare for the future. These require long-term vision and finance to support that vision. Despite the current challenging times that favor short-term approaches, we believe the development of a long-term vision is still paramount."

Many of these new technologies are taking a backseat as customers push for the most efficient, cost-effective surveys possible. "They take a conservative approach," Beasley said. "New technologies always carry some risk. In this environment, customers need to be absolutely certain of the value proposition before embarking on a new technology.

"But on the other hand, there is a drive to achieve more for less, and the best way to do that is with enhanced technology."

An integrated approach

It's important to note that these are not, for the most part, competing technologies but rather complement each other in the types of data they provide. As the industry goes deeper, this becomes even more important.

"Over the last few years the industry has been moving into deeper prospects, more than 30,000 ft [9,144 m], and smaller prospects, subtle stratigraphic traps and very complex salt structures," El-Toukhy said. "All of these elements would require high-end imaging, which actually would need not only high-quality seismic data but all of the other tools like gravity, magnetics and CSEM. You really need to use them all.

"But above all, we have experienced that collaboration between different domain experts is paramount because it enables innovative solutions that address subsurface challenges ranging from acquisition to reservoir characterization."

Long added, "Higher end imaging and reservoir characterization projects have historically been prospect-specific and generally pursued at the later appraisal stage of the E&P life cycle. The fact is now, however, that our tools and computer platforms are capable of running such projects on massive exploration scales.

"The challenge for us is to raise awareness of these advances so that more companies have the confidence to accept 'high-end' pursuits as a fact of life rather than something exotic and possibly impractical." ■

Transocean's first enhanced Enterprise-class drillship, the *Discoverer Clear Leader*, is contracted to Chevron and operating in the U.S. Gulf of Mexico along with the *Discoverer Inspiration* (left). The latter enhanced Enterprise-class drillship is designed to operate in water depths to 3,658 m (12,000 ft) and drill to total depths of 12,195 m (40,000 ft). Both drillships are operated by Transocean Partners, a limited liability company formed by Transocean. *(Photo courtesy of Transocean)*

Downturn in Oil Industry Leads to Historic Changes

By Scott Weeden, Senior Editor, Drilling

Two of the original innovative offshore drilling rigs were sent to the scrap heap while seventh- and eighth-generation drillships and semisubmersibles are put on hold.

With oil prices hovering around $50 in early October 2015, the offshore drilling industry was retrenching. Within the past year, two pioneering rigs—the drillship *GSF Explorer* (formerly *Hughes Glomar Explorer*) and semisubmersible *Sedco 709*—were sent to scrap yards as Transocean realigned its rig fleet through attrition of older rigs. Other offshore drilling contractors are doing the same thing to reduce the average ages of their fleets.

The *Glomar Explorer* was built in 1974 apparently to mine manganese nodules on the ocean floor but in reality to recover a Soviet submarine that sank in 5,030 m (16,500 ft) of water in the Pacific Ocean. It was converted to a drillship in 1977. Some of the vessel's innovations included an automatic pipe-handling system, a gimbal system with hydraulic-pneumatic heave compensation and a 5,183-m (17,000-ft), tapered pipe string.

The *Sedco 709* rig was built in 1977 and was the first dynamically positioned (DP) semisubmersible. Sedco used its experience with its DP drillships (*Sedco 445, Sedco 471* and *Sedco 472*) in designing the DP system for the semisubmersible rig. The rig had eight 3,000-hp thrusters, 26,000 installed horsepower and riser-storage capacity for 2,439-m (8,000-ft) water depths.

As one era of technology ends, a new one is about to begin with rigs fitted with 20,000-psi pressure-control systems, able to work in 320 C (608 F) temperatures and reaching total well depths of 12,195 m (40,000 ft) in 3,658 m (12,000 ft) of water. But that switch to newer technologies is slowing down as drilling contractors delay and cancel construction on the newest generation of offshore rigs as oil companies reduce spending on deepwater projects.

Recovery pushed back to 2018

The most often heard words around rig contracts currently are lower day rates, hot stacked, cold stacked, for sale and scrapping. Since October 2014, 38 floaters have been retired, according to a Barclays Equity Research report on Aug. 13, 2015, with only three of those rigs retired since June 2015.

"Market attrition simply won't take place fast enough for the market to rebalance given the 51 floater newbuilds under construction that are expected to be delivered between now and year-end 2017," the report noted.

In an Oct. 7, 2015, fleet update, George Economou, chairman and CEO at Ocean Rig UDW Inc., said, "The market continues to remain challenging due to the massive spending cuts initiated by the oil companies. In this environment, cash preservation and liquidity remain our No. 1 priority, and we will adjust our available capacity to the new market conditions. For rigs that we cannot secure long-term employment that are coming up for their five-year SPS [special periodic surveys], we will cold-stack the units and, in the case of the semisubmersible rigs, seriously consider all our options including disposal or scrapping."

Transocean's patented Active Power Compensation hybrid system will debut on the ultradeepwater drillship *Deepwater Thalassa*. The system is designed to lower fuel consumption and emissions during drilling operations. Transocean's newest ultradeepwater drillships, including the *Deepwater Thalassa* and *Deepwater Proteus*, will be equipped with the company's patented dual-activity drilling technology and will be designed to be ready when a 20,000-psi BOP system becomes available. The *Deepwater Thalassa* will be the first of four new drillships to commence work for Shell on 10-year contracts totaling 40 rig years of work. *(Photo courtesy of Transocean)*

According to John Boots, vice president finance and treasurer at Pacific Drilling, at the Deutsche Bank Leverage Finance Conference Sept. 28-30, 2015, in Scottsdale, Ariz., oil demand is forecast to exceed supply plus excess storage by 2018. Other sources of oil beyond deep water cannot fill the entire demand gap, which will increase rig requirements. Floater rig demand is expected to exceed ultradeepwater rig supply by the 2017 to 2018 time frame.

Transocean intends to scrap 20 floaters. In its June 22, 2015, fleet update, the company added the *GSF Celtic Sea* and *Transocean Amirante* floaters to its list for sale. The *Amirante* will be recycled, while the *Celtic Sea* will either be sold for use in a nondrilling capacity or recycled.

Delaying rig deliveries, canceling orders

Transocean delayed delivery of its two newbuild, ultradeepwater drillships from Sembcorp Marine's subsidiary, Jurong Shipyard, by two years. The two drillships are now expected to be delivered in second-quarter 2019 and first-quarter 2020, respectively.

These latest generation ultradeepwater drillships are based on the proprietary Jurong Espadon III design and include drilling facilities, a large moonpool to accommodate a larger riser angle, large deck space with an enclosed riser bay, a flexible mud system for completion operations and Transocean's hybrid power system for lower emissions and improved fuel economy. The drillships can operate in water depths to 3,658 m and drilling depths to 12,195 m.

On Aug. 27, 2015, Seadrill issued its second-quarter 2015 report, listing 15 rigs under construction—four drillships, three semisubmersibles and eight jackups. During the second quarter, Seadrill successfully deferred deliveries of a number of its newbuilds. The drillships *West Draco* and *West Dorado* were deferred from third-quarter and fourth-quarter 2015 to the end of first-quarter 2017. The deliveries of eight jackups in 2015 also were deferred with one rig rescheduled to year-end 2015, five units to 2016 and two rigs to 2017. Discussions with shipyards are ongoing in regard to the delivery dates for the remaining units.

Scrapping, stacking older rigs

At the September 2015 Pareto Oil Conference, Ocean Rig talked about the overall market, noting that contract coverage of older units will decrease sharply over the next 12 months. The floater fleet (both marketed and cold-stacked) comprises 308 units, of which 157 units were built prior to 2005.

About 42% (67 units) of older floaters and 28% (43 units) of modern floaters are expected to come off contract in the next 24 months. The majority of these rigs likely will be scrapped or cold stacked. Sixteen rigs were scrapped in 2014, all in the fourth quarter. As Ocean Rig stated, no modern units have been scrapped.

Hercules Offshore, which operates a fleet of shallow-water jackups, filed for Chapter 11 bankruptcy on Aug. 13, 2015. Out of 18 rigs, only four were working as of a Sept. 22, 2015, fleet status report and all of those were scheduled to complete those contracts by Dec. 31, 2015. Three rigs were warm stacked, two were ready stacked and nine were cold stacked.

The contract for delivery of a sixth-generation semisubmersible to Seadrill was canceled due to the shipyard's inability to deliver the rig on time. The *West Mira* was scheduled for delivery in December 2014 but had not been delivered by Sept. 22, 2015. The rig was slated to work offshore Canada and Greenland for Husky Oil Corp. Ltd. under a five-year contract. Seadrill is in discussions with Husky for an alternate solution.

Ensco's discontinued operations include four floaters and two jackups held for sale. During fourth-quarter 2014, Ensco classified three rigs—*ENSCO DS-2, ENSCO 58* and *ENSCO 90*—as held-for-sale. All three rigs were cold stacked to significantly reduce expenses until these are sold. Four rigs in continuing operations began cold-stacking preparations since the start of 2015.

Ocean Rig is facing tough market conditions as well. The *Ocean Rig Olympia*, *Eirik Raude* and *Leiv Eiriksson* have no further contracts after current work is complete. The company noted there are few further prospects of employment for the rigs. If no contracts are signed the rigs will be cold stacked, and the company will consider all options including disposing or scrapping the rigs.

Some regions, companies remain active

The September 2015 Baker Hughes international offshore rig count showed regions outside North America holding fairly steady at 268 rigs, compared to 270 rigs in August and 333 rigs in September 2014. Two regions, Latin America and Europe, were up by two rigs and three rigs, respectively. The U.S. and Canada were down by four rigs to 34 rigs from the previous month.

Companies with high-specification rigs generally are able to keep rigs operating. Pacific Drilling has a 100% high-specification drillship fleet. In its second-quarter 2015 report, the company reported a 5% increase over second-quarter 2014 revenues. As of the July 7, 2015, rig status report, seven drillships were operating with one vessel under construction. Five of the drillships were under multiyear contracts while two were available. The *Pacific Zonda* was scheduled for delivery in first-quarter 2016.

Ensco is another company realizing new business. In its second-quarter 2015 report, the company pointed to 98% uptime for its jackup rigs. Carl Trowell, Ensco CEO and president, said, "In terms of new business, we earned three-year contracts for two premium jackups—*ENSCO 110* and *ENSCO 104*—in the Middle East, our largest jackup market. We also recently signed letters of intent for multiyear terms for two jackups in the North Sea, plus a six-month extension for another rig in the region. Newbuild drillships, *ENSCO DS-8* and *ENSCO DS-9*, are also projected to contribute to earnings this year."

Rowan Co.'s cantilevered jackup *Cecil Provine* casts a shadow over the Gulf of Mexico as it drills a well on Eugene Island 125 for Fieldwood Energy. *(Photo by Peter Piazza, courtesy of Hart Energy's* Oil and Gas Investor*)*

However, the market does change quickly; Ensco reported around the same time that ConocoPhillips terminated its three-year contract with the *ENSCO DS-9*. The drillship was recently delivered and had been scheduled to commence its initial drilling contract for ConocoPhillips in fourth-quarter 2015.

Transocean's June 22, 2015, fleet update included new contracts offshore Thailand, U.S. Gulf of Mexico, U.K. North Sea and Nigeria. One rig that was previously idle was stacked.

Offshore Angola was a good location for Ocean Rig. On Oct. 7, 2015, the company reported the *Ocean Rig Olympia* started its new contract offshore Angola. The rig is expected to move to the Ivory Coast for one well in fourth-quarter 2015 before returning to Angola to complete its remaining contract until June 2016. The *Ocean Rig Skyros* began its new six-year contract in Angola on Oct. 1, 2015.

In early September 2015 Odfjell Drilling signed a new contract for its sixth-generation semisubmersible *Deepsea Stavanger* rig for a six-well program with Wintershall for the development of the Maria Field offshore Norway. The contract is expected to begin in April 2017. According to Odfjell, the rig is currently employed by BP in Angola on a contract that was expected to end in November 2015. The company continues to market the rig to fill the gap before its startup on the Maria Field.

An Atwood Oceanics Inc. subsidiary agreed to a one-year extension and rate adjustment to its existing contract with Kosmos Energy Ventures for the ultradeepwater rig *Atwood Achiever* offshore northwest Africa. According to an Oct. 1, 2015, press release, the agreement adjusted the operating day rate to about $495,500, net of taxes, and extended the contract to Nov. 12, 2018. As part of the agreement, Kosmos Energy has an option, which might be exercised at any time through Oct. 1, 2016, to revert the contract to the original operating day rate and end date.

Technology waits for market

With the number of latest-generation rigs being delayed, the industry has added time to work on the eighth-generation designs.

The *Transocean Barents* is a harsh-environment, ultradeepwater semisubmersible rig with dual-activity capability. This high-specification rig is designed to operate in water depths to 3,049 m (10,000 ft) and to total depths of 9,146 m (30,000 ft). *(Photo courtesy of Transocean)*

Operators are now requesting the latest step change in offshore pressure-control equipment, going from 15,000-psi to 20,000-psi pressure at much higher temperatures. The sheer size of the metallic components of the HP/HT BOPs creates problems, said Harish Patel, director of drilling technology for ABS.

For example, GE's 20,000-psi stack right now weighs between 1.3 million pounds and 1.5 million pounds. "The drilling rigs will require total redesign to be able to handle these new stacks," he emphasized. "It is still debatable whether Generation 6 or 7 rigs can be modified for the new equipment."

The industry will need the time to finish the testing and verify the standards. The next generation is on the launching pad. ■

Adopting a Simpler Solution

By Jennifer Presley, Senior Editor

Fixed platforms offer an attractive option for the commercial development of smaller, shallower offshore fields.

The old design adage of "keep it simple, stupid" is seeing a resurgence of late as concerns regarding rising costs and delayed projects continue to mount. The increased design complexities of today's megaprojects are necessary to meet the increasing demands placed on facilities as E&P companies move farther from shore and into ever-deeper water to tap giant reservoirs buried thousands of meters below the seafloor. For those fields that are shallower, smaller and closer to land, the demands are less "mega," calling for a simpler approach.

Fixed platforms offer an attractive development option for smaller, shallower offshore fields.

Law No. 5 in John Maeda's book *The Laws of Simplicity* states that "simplicity and complexity need each other; that the more complexity there is in the market, the more that something simpler stands out." Maeda, a noted designer and computer scientist, added "that because technology will only grow in complexity, there is a clear economic benefit to adopting a strategy of simplicity that will help set a product apart."

Examples abound that support this view; take for instance, the various MP3 players that struggled to make a lasting impression on a market captivated by Apple's iPod. "Complex" is a word that fits the oil and gas industry nicely as a descriptor; one need only look to Shell's Olympus tension-leg platform in the Gulf of Mexico or its super-mega Prelude FLNG project in Australia as examples. However, fixed platforms are the yin to the megaproject's yang. Offering a sensible and cost-effective option, fixed platforms are seeing renewed interest as solutions for fields that are difficult to justify as commercially viable any other time.

Efforts are underway at two such fields—Arthit in the Gulf of Thailand and Oseberg on the Norwegian Continental Shelf—that when complete, will bring additional reserves to the market without breaking the banks for PTT Exploration and Production (PTTEP) and Statoil, respectively.

Minimalist approach at Arthit

Along with its growing population of 67 million people, so too is Thailand's appetite for natural gas. While demands grow incrementally, the supply of domestic gas in the region will become limited as many of the petroleum prospects within the Gulf of Thailand contain marginal and sub-commercial volumes of gas, according to T. Vuthiphon, *et al*. in the 2014 SPE Thailand Annual E&P Award paper. These fields, some located far from central processing facilities, would require a high cost of development.

In looking for options to develop the reserves in its smaller prospects in the Gulf of Thailand, PTTEP selected a minimum facility platform (MFP) design with lean facilities and optimum size over the traditional conventional wellhead platform (CWP) design that it has used with its other larger prospects, according to SPE paper No. 174740, "Minimum Facility Platform for Sub-commerical Reservoirs in the Gulf of Thailand."

The Arthit gas field, located 250 km (155 miles) northeast of the town of Songkhla, Thailand, in a water depth of 80 m (262 ft), was selected for this smaller MFP project. The field was developed using a four-legged CWP designed for 16 wells, 3.3 MMcm/d (120 MMscf/d) and equipped with an all-inclusive system for well production, testing and processing, according to the T. Vuthiphon *et al.* paper. In addition, the CWP can accommodate jackup and tender-assisted drilling. Since 2008, 32 CWPs have been installed in the Arthit Field, according to the paper's authors.

The MFP design calls for five years of production life, with maximum production capacities of 1.1 MMcm/d (40 MMscf/d) gas, 1,400 bbl/d of oil and 2,000 bbl/d of water. As compared to the CWP, the MFP has a reduced number of well slots, from 16 to 9-15 in the MFP, as noted in SPE paper No. 174740. The overall deck area was reduced by 20%. This reduction in size provided a similar reduction in the wellhead platform structural weight. Flowlines are commingled to reduce the number of actuated on-off valves, and the platform is powered 100% by solar energy with battery backup, per SPE paper No. 174740.

The subsea on slim legs concept selected by Statoil for its Oseberg Vestflanken 2 project provides a simpler solution for development of its smaller fields. (Image courtesy of Statoil)

"Compared to employing a conventional wellhead platform, in this case, the project team has achieved a target cost savings of approximately 20% more than would be gained from the use of a conventional design," the authors said. "With the development governed by the MFP concept, 24% of the sub-commercial field volumes could be potentially recovered to support the added sustainability of the energy supply in Thailand. These previously sub-commercial prospects could be reevaluated and reintegrated into new field development plans."

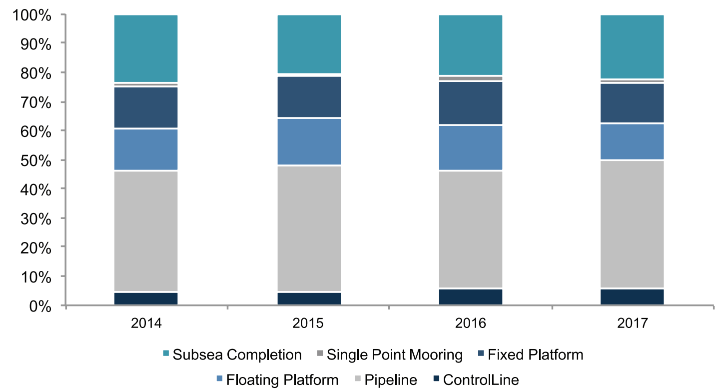
Installation of the MFP should be completed in 2017.

'Slim legs' for Oseberg

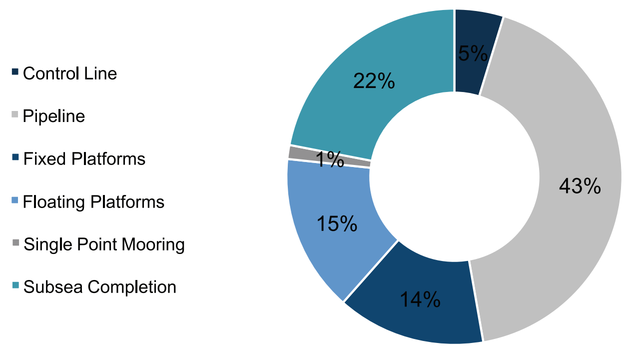
Statoil in 2013 celebrated its 25th year of operation of its Oseberg Field located on the Norwegian Continental Shelf some 140 km (87 miles) northwest of Bergen, Norway. The field is among the four largest oil and gas fields on the Norwegian Continental Shelf, producing from Oseberg Field Center, Oseberg C, Oseberg East and South. According to a press release issued by the company at the time of the field's silver anniversary, plans call for production to continue up to around 2040.

In February 2015, the company announced that it had selected an unmanned wellhead platform (UWP)

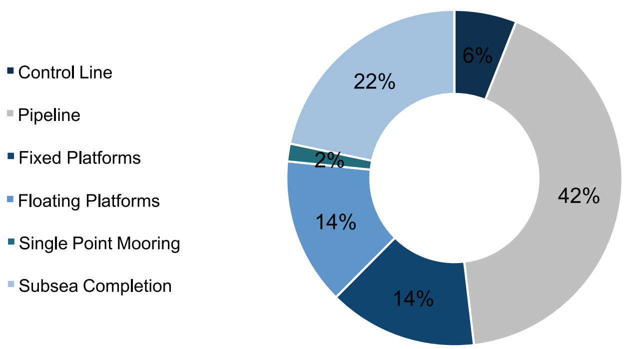
Capex (US$m) by Market 2014-2017



Capex (US$m) by Market 2014-2015



Capex (US$m) by Market 2016-2017



(Source: Infield Systems)

as the concept for its Oseberg Future Development Phase 1 project. The project, renamed Oseberg Vestflanken 2, selected a concept dubbed "subsea on slim legs."

"The Oseberg Vestflanken 2 Field is located alongside the Oseberg Main Field in the Oseberg area," said Hogne Pedersen, vice president and head of the project for Statoil. "The area's been in development since the late '80s. What we're facing now is the need to develop the remaining assets where the first phase is about 110 MMboe in recoverable reserves. The project is a three-stage development of those remaining assets, with Oseberg Vestflanken 2 being the first stage."

Focused on the minimization of facilities, equipment and costs down to water depths of 120 m (390 ft), the subsea on slim legs concept offers a cost-effective solution compared to conventional subsea tieback solutions, according to a Kvaerner-issued press release. In addition, the platforms are capable of using the new generation of jackup drilling rigs and reduce development costs, the release said.

In addition to the UWP, the remaining pieces in the puzzle include the addition of a Category J jackup rig now under construction at the Samsung yard in South Korea.

"The alternative was to place the wells on the seabed, but the costs of subsea wells have been tripled during the last decade. We have therefore chosen a jacket-based unmanned wellhead platform that will reduce costs by several hundred million NOK," Anders Opedal, senior vice president of projects at Statoil, said in a press release.

Total cost for such a UWP is found to be very competitive to a subsea concept, all elements of construction, equipment, wells and maintenance considered.

"Based on prognosis the costs of subsea systems are still rising. We challenge the industry to cooperate with us so we can turn this trend and develop smart solutions, both above and below water," added Ivar Aasheim, senior vice president of field development at Statoil, in the release.

A service vessel connected to the UWP by gangways will be used during maintenance campaigns after the jackup drilling platform has completed its well drilling operations. All supporting facilities will be found on the support vessel, with shorter distance to, for example, lifeboats and helicopter decks than on big installations.

The company and its partners submitted the plan for development and operation of the Oseberg Vestflanken 2 field to authorities in December 2015. According to a press release, production start is scheduled for Q2 2018. ■

Inherent Flexibility Helps Floaters Remain Weapon of Choice

By Mark Thomas, Editor-in-Chief

Floating production solutions continue to be the weapon of choice for operators around the world when it comes to deeper waters and remote locations. As a result, they have been heavily subjected to increased cost-deflation pressures.

The plunge in the oil price to its sustained lower level in the $30 to $40/bbl range—a situation expected to last throughout 2016 and into the following year—has seen the floating production systems market slow down dramatically after several years of rapid sustained growth.

Especially with regard to higher-specification floater facilities, where costs have risen more sharply than most other sectors of the offshore industry over the past several years (a latest-generation large FPSO newbuild generally cost between $1.5 billion to $2 billion in early 2015), as well as suffering much-publicized schedule delays, operators are today simply demanding "more for less."

This is not an easy task. Higher-spec floating production systems now require increased topsides capacities, must often deal with higher pressures and more complex processing, and therefore usually require larger topside modules as well as greater hull size, strength and stability. The industry push to cut costs and avoid schedule overruns works largely against many of these requirements.

Rising to the challenge

To its credit, floating production contractors are rising to the challenge, while the industry has also refocused its attention on lower-specification, more standardized surface solutions to keep development costs under tighter control.

As the extent of the requirement to reduce capital expenditures dramatically to reflect lower cash flows became evident, virtually all offshore operators opted during the second half of 2014 and throughout 2015 to defer or delay pre-final investment decision (FID) projects for extended design studies, scale down previously larger development solutions or revisit less costly options previously discarded, and take advantage of cost deflation to seek out savings of between 20% and 30% on their proposed field developments.

This was, of course, not just for floater projects, but with the vast majority of deepwater developments using them (approximately 88% of deepwater discoveries employed floating production solutions over the past 10 years), they have taken the brunt of the downturn.

Project upturn—eventually

Paradoxically, the lower costs of offshore drilling with rig day rates plunging in some cases to almost half their level of just a couple of years ago when a barrel of oil was more than $100 means that exploration and development drilling activity is now more affordable, and it is expected to lead to an upturn in development projects in both established and emerging areas over the medium-to-long term. As a result, the floating production market is set to—eventually—resume its upward trend of recent years.

Building for the future: Topsides modules are added to Petronas' *PFLNG 1* FLNG unit last year during its construction at the Daewoo Shipbuilding & Marine Engineering (DSME) yard in Okpo, South Korea. A true offshore pioneer, the 1.2 mtpa production capacity unit is close to completion and is expected to be the industry's first FLNG unit to begin operations when it is stationed over the deepwater Kanowit Field offshore Sarawak, Malaysia, later this year. *(Photo courtesy of Petronas)*

The E&P industry remains keen on accessing new reserves and production sources in areas such as the Lower Tertiary play in the Gulf of Mexico (GoM) as well as the newly opened up Mexican sector, while East and West Africa and SE Asia remain key growth areas.

Technologies, therefore, that can help to open up these new frontiers or improve field economics in challenging environments such as HP/HT reservoirs, will be in high demand.

In the short term, however, the fact remains that orders in 2015 have been thin on the ground, with very few solid contracts actually sanctioned.

Few orders in 2015

According to floating production market specialist Energy Maritime Associates (EMA), there are some bright spots on the horizon. In third-quarter 2015 EMA pointed out the award of two orders by Golar LNG worth more than $1.5 billion for one floating liquefied natural gas (FLNG) unit and one floating storage and regasification unit (FSRU). Three units were also delivered during the quarter: one redeployed FPSO unit, one FSRU and a floating storage and offloading (FSO) vessel for fuel storage.

EMA added that two floaters were scrapped during third-quarter 2015, including the FPSO *Par-*

INPEX's huge semisubmersible central processing facility for its Ichthys LNG project offshore Western Australia is under construction at the Samsung Heavy Industries yard in Geoje, South Korea. With an FPSO also to be used on the field, together they represent a combined investment of $4.7 billion. Overall development costs have risen 10% over the original budget, with the field due onstream in 2017. *(Photo courtesy of INPEX)*

agon 1 (the ex-*Seillean* production unit), which had lain idle for more than five years. A further three FPSOs are currently available.

On the downside there are currently 26 units laid up without contracts: 17 FPSOs, six production semisubmersibles, two FSOs and one mobile offshore production unit (MOPU). Up to half of these could be scrapped, EMA warned, as prospects for redeployment continue to diminish in the "lower for longer" oil price market and with increased competition.

"The pace of orders for floating production units is currently one per month," it said in its latest quarterly update, "but this has been slowing throughout the year: Four orders were placed in Q1, three orders in Q2 and two in Q3. We are not optimistic about the number of orders for the rest of 2015 and into early 2016. 2015 will likely end with nine to 10 total orders, which would be similar to the 1998-1999 downturn."

No rapid rebound in activity is expected in 2016, it added, unlike that which followed the 2009 crash, but the pace of orders is expected to pick up.

255 potential floaters

EMA went on to state that, out of the 255 potential floating production projects it was tracking, 20 had been shortlisted as likely awards in 2016 with a total capital investment of $22 billion. Half of that figure would go to LNG-related projects (FLNGs and FSRUs), and on Woodside's Browse FLNG project offshore Australia in particular.

The other potential orders include 10 FPSOs for Brazil, West Africa, SE Asia, Mexico and the North Sea.

EMA's managing director, David Boggs, commented in the report: "While there may be some further costs to be squeezed out of the supply chain, we believe much has already been realized, with ultradeepwater rigs now being contracted for under $300,000/day. A number of large projects are in the bidding and final design stage, with final investment decisions expected by third-quarter 2016.

"This includes over $10 billion of LNG-related floating production units (FLNGs and FSRUs). The industry has started to make changes in order to develop offshore hydrocarbon projects in this new low oil price environment, but these will not be seen until the projects reach FID in 2016 and beyond."

Fellow floater analyst International Maritime Associates (IMA) added in its own report in December 2015 that 72 production or storage floaters were on order, with 275 FPUs in service and 27 production units available for redeployment. The previous month it also pointed out that the oil price plunge had quickened the pace of FPSO decommissioning, with several units removed from fields and at least a half dozen more to be decommissioned this year.

Revised $68 billion spending plans

A third analyst, Douglas-Westwood, revised its forecast market expenditure figure for floating production systems downwards in November 2015, saying that the poor order levels and low oil price meant that capital expenditure on floaters was now being estimated at $68 billion for the period 2015-2019, from its previous estimate of $81 billion.

Analyst Ben Wilby said that with only four vessels awarded up to November 2015—a production semisub for the Appomattox Field, a large FPSO for Eni's Sankofa development in Ghana and one small FPSO unit each for the South Pars Field and the Brotojoyo redevelopment—the projected 2015 order capex stood at $4.5 billion. This is a massive 72% down on the 2014 figure, and the worst since 2003, he pointed out.

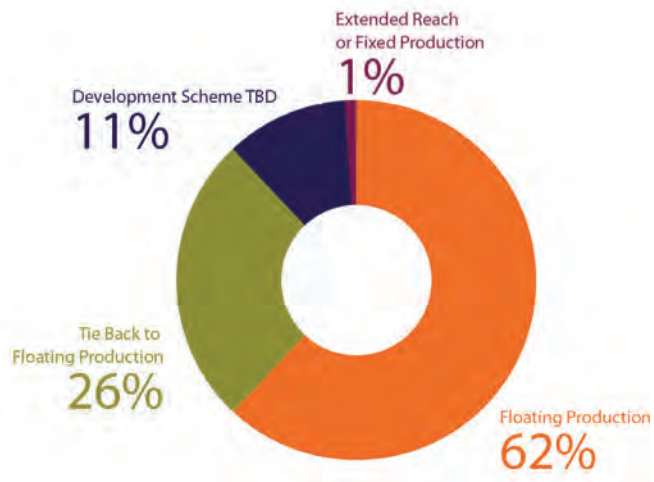
Industry efforts to avoid cost overruns and delays were ongoing throughout 2015, he added, but they have been hard to eradicate. He highlighted the Ichthys project offshore Australia. The field, which will utilize both an FPSO and a giant semisubmersible central processing facility, is so far expected to cost a combined $4.7 billion. The project was originally due onstream this year but has now been delayed until 2017, while overall development costs have risen 10%. "This is only one of the many examples this year, and cost overruns and delays remain key problems that operators need to resolve," he said.

Reduced costs

But resolving them they are, in a growing number of cases.

One such example is BP's Mad Dog Phase 2 development in Green Canyon Block 780 in the GoM, which was originally proposed to use a large Spar platform but was deemed "uneconomic" even when oil was $110/bbl after total forecast costs soared. With a major redesign effort the operator, helped by lower equipment prices for equipment and services in the downturn, is now expected to sanction the project using a production semisubmersible before the end of 2016, despite the low oil price. The new facility, not yet sanctioned, is expected to be installed by 2020.

Development Solutions Used on Deepwater Discoveries 2005-2015



Floating production solutions were used in 88% of the discoveries in deep water (more than 500 m or 1,640 ft of water) developed over the past decade, according to Infield Systems. *(Image courtesy of SBM Offshore)*

20% project savings

Another GoM project that highlights the industry's focus on reducing floating production costs is Shell's Appomattox semisub development. Sanctioned in July last year, the field is the first development in the Norphlet play. Shell's eighth and largest floating platform in the GoM, Appomattox will average peak production of approximately 175,000 boe/d.

The operator brought its full attention to bear on the project, succeeding in reducing its total cost by 20% through supply chain savings, design improvements and by reducing the number of wells required.

This used advances and lessons learned from its previous four-column facilities, such as the recently built *Olympus* TLP used on the Mars B Field, as well as ensuring a high degree of design maturity before construction, it said.

With these and other cost reductions, the go-forward project breakeven price is estimated to be around $55/bbl Brent equivalent—still higher than today's price but expected to be within the expected oil price range from 2017 onwards.

Standardized approach

On a smaller scale, but equally impressive from a cost-efficiency perspective, is U.S. independent LLOG Exploration's Who Dat and Delta House developments.

According to Eric Zimmerman, vice president of geology, speaking at Hart Energy's Offshore Executive Conference in late 2015, LLOG is "the

A standardized approach enabled LLOG Exploration to bring its deepwater Delta House Field in the Mississippi Canyon area of the GoM online in Q2 2015 in less than three years from starting the project. The platform hit its nameplate oil capacity of 80,000 bbl/d at the very end of 2015. *(Photo courtesy of LLOG Exploration)*

most boring exploration company in the Gulf." He meant this in a good way, with the company's standardized approach to its GoM developments meaning repeatable success.

Who Dat came onstream in much better times in terms of oil price back in 2011, but the company opted for a low-cost solution utilizing an Opti-Ex floating production system already built on spec by Exmar. The creative deal structure led to a much-reduced cost to startup, and saw it go from concept selection to installation in one year.

Zimmerman said the FPS, which is located in 945 m (3,100 ft) of water, has 10 wells and up to 300 MMboe of reserves at a projected total project cost of $2 billion.

For its Delta House project in Mississippi Canyon 254 LLOG used the same successful development plan, improving its returns through efficiency gains and cost reductions, he said. The use of standardized equipment enabled it to buy in bulk, achieve economies of scale, have interchangeable parts using the same trees and casing, and lead to shorter cycle times.

LLOG managed to bring the $2 billion FPS–another Opti-Ex—online in less than three years, installing it in third-quarter 2014 and bringing it onstream in the second quarter of last year. Early in 2016 it announced that Delta House had achieved its nameplate oil capacity of 80,000 bbl/d of oil. The operator recently brought the ninth well online several weeks ahead of schedule, with two additional wells to be brought onstream later this year.

The FPS nameplate capacity includes 50% redundancy of key rotating equipment, and the unit is designed for a peak capacity of 100,000 bbl/d of oil and 240 MMcf/d of gas.

FLNG queue

At the other end of the scale are the first generation of FLNG units, with the first one expected to become operational this year.

The world's first FLNG unit will start work for Malaysia's Petronas. The state-run company is planning to use two operated units, with the *PFLNG 1* producing up to 1.2 million tonnes per annum (mtpa) of LNG. Nearing completion at the DSME yard in Okpo, South Korea, this true offshore pioneer is due onstream over the Kanowit Field offshore Sarawak, Malaysia, in the first quarter of this year.

The second planned unit, *PFLNG 2*, is also being built but at Samsung Heavy Industries shipyard in Geoje, South Korea. This unit is significantly larger and will be sited over the deepwater Rotan Field in Block H offshore Sabah, Malaysia. Once onstream in 2018, it will have a design capacity of 1.5 mtpa, and weigh in at 152,000 tonnes.

Following on the heels of the *PFLNG 1* is Shell's giant Prelude facility, destined to come onstream in 2017, while further down the line is Japan's INPEX with its proposed and recently expanded plan for the 7.5 mtpa *Abadi* FLNG unit, destined for offshore Indonesia.

Last but not least is Woodside with its ambitious plan for three planned FLNG units on its Browse development off Western Australia, all of which will utilize Shell's FLNG technology used for *Prelude*.

In June 2015 the Browse Joint Venture partners, led by Woodside, entered the FEED stage for the proposed development. According to Woodside, the JV is targeting a final investment decision (FID) before the end of this year. The three units will be sited over the Brecknock, Calliance and Torosa fields in the Browse Basin, which are estimated to contain gross (100%) contingent resources (2C) of 15.4 Tcf of dry gas and 453 MMbbl of condensate.

For the floating production sector, despite the current lean times in terms of new orders, the FLNG market represents a significant proportion of future planned expenditure in the sector by majors in the long term, something that just five years ago was barely envisaged until Shell took the bold step of making the first FID for an FLNG project in May 2011. ■

Subsea Rises to the Challenge

By John Sheehan, International Editor

The past year has been a pivotal period for the subsea sector, which remains the offshore industry's most logical technology solution for increasing water depths.

Despite industry concerns about the rising cost of subsea solutions over recent years (and with those concerns only relatively being properly addressed of late), the fact remains that for the vast majority of developments in an operator's portfolio, subsea technologies will play an integral part.

Although the vision of a complete "subsea factory" on the seabed is still some way off, especially in today's more commercially cautious environment, that day is not as far away as some people believe.

Key parts of that solution are in action and have proven themselves to be more than viable. Look no further than the world-class advances on the producing Gullfaks and Åsgard fields offshore Norway. Both compression projects kicked off during 2015 on schedule and to plan, and they truly represent a watershed moment for the E&P sector.

To put this in perspective, Norway's state-owned operator Statoil has been dreaming the dream of seabed compressors for 30 years.

World-first wet gas compression

The world's first wet gas subsea compression started up on the company's Gullfaks Field in October 2015, with the technology planned to help increase reservoir recovery by 22 MMboe and extend the field's plateau production by about two years from the Gullfaks South Brent reservoir.

The subsea system consists of a protective structure weighing 420 mt, a compressor station with two 5-MW compressors totaling 650 mt in weight but with all the equipment needed for power supply and system control located on the platform.

OneSubsea supplied the wet gas compressor kit. According to Arne Birger Olsen, OneSubsea's director of sales for the European region, the advantage of the compressor is that it does not require gas and liquid separation before

The Gullfaks wet gas subsea compressor sits quayside at Horsøy before installation. *(Photo by Harald Pettersen, courtesy of Statoil)* compression, thereby simplifying the system considerably and requiring smaller modules and a simpler structure on the seabed.

During the Offshore Energy 16 conference in the Netherlands, he said, "The complete Gullfaks module weighs 1,000 mt, which is one-fifth the weight of the Åsgard system. Åsgard is bigger and heavier because it needs upstream separation scrubbers. We don't need that.

"These are very lightweight modules, and for maintenance purposes you can use light vessels of opportunity. None of the retrievable items here are more than 60 or 70 tonnes. They can easily be handled by normal intervention vessels."

The Gullfaks system has suffered some "teething troubles" since startup, due to problems with a leaking umbilical line, but the subsea compressors are not the issue, Statoil has confirmed.

Åsgard subsea compression

Just a month earlier, in mid-September 2015 Statoil also had started subsea gas compression on its Åsgard Field, which will add an estimated 306 MMboe of production over the field's life.

Recovery from the Midgard reservoir on Åsgard will increase from 67% to 87% and from 59% to 84% from the Mikkel reservoir.

An estimated 11 million man-hours have been spent on the $2.3 billion project from start until completion, and—impressively—more than 40 new technologies have been developed and employed after prior testing and verification, according to Statoil.

Unlike Gullfaks, the gas and liquids are separated prior to gas compression and then are recombined after pressure boosting and sent through a pipeline about 40 km (25 miles) to the Åsgard B facility.

Time and business wait for no one, however, and after the successful startup of this pair of industry-leading projects, the E&P sector now needs to push on toward full-scale subsea production, including power on the seabed, according to Kristin Moe Elgsaas, GE Oil & Gas' senior product manager.

"We are going into deeper waters and deeper reservoirs. We are going into ever-more remote locations and hostile environments. These drivers are putting subsea production under pressure, and they will put subsea power and processing under pressure," she said.

The industry needs to develop systems that produce power where it makes the most sense, Elgsaas continued. "We need to fully commercialize subsea distribution systems and place switchgears and variable speed drives subsea so we can supply multiple loads through one transmission cable rather than multiple cables. Cables are a significant cost driver in long step-out systems."

Composite pipe trends

With cost savings at the heart of everything in the current low oil price environment, some interesting trends are starting to emerge to try to achieve that need.

One world-first saw Dutch contractor Airborne Oil & Gas clinch a crucial deal to supply a thermoplastic composite pipe (TCP) flowline for a pilot project off Malaysia. The award is significant in that it comes after the successful completion of a three-year qualification program. The workscope

The Åsgard subsea compression project started up in September 2015. Field infrastructure was installed from the *Saipem 7000* vessel. *(Photo by Oyvind Hagen, courtesy of Statoil)* includes the delivery of a 550-m (1,804-ft) TCP flowline, ancillaries, offshore installation, engineering and field support.

The 6-in. flowline is to be installed in 30 m (98 ft) of water and will connect two platforms located on the West Lutong Field offshore Malaysia.

The technology has clearly piqued the interest of Shell Technology Ventures and Evonik, both of which have recently taken stakes in Airborne.

Meanwhile, Magma Global, which manufactures "m-pipe," a carbon fiber-based composite pipe, commissioned an independent report from energy advisory firm Calash on the potential economic benefits of using its polymer-based pipe vs. steel in riser systems.

The results, from Magma's point of view, look very encouraging. According to the report findings, its pipe would save more than 10% in capex compared to a steel catenary riser system, while a single leg steel offshore riser would cost 75% more than its m-pipe equivalent. This is bolstered by the light weight and strength of m-pipe, according to Magma.

The company has not manufactured a full complement of risers in m-pipe at this point, although its existing production facility has the capability to produce a continuous length of 6-in. pipe up to 3,000 m (9,843 ft). It is now building a new production unit that can handle continuous lengths of pipe up to 12-in. in diameter.

Tree trends

The subsea tree sector has seen clear moves by the main hardware manufacturers to steer away from the traditional vertical and horizontal trees.

OneSubsea has developed the HyFleX tree system, which has the tree and tubing hanger as two separate units in parallel rather than in series, meaning the tree and tubing hanger are completely independent in their installation and recovery.

This system is designed to be standardized, a key requirement being sought by operators. The tree module integrates onto the tubing head spool with the tree module designed to be configurable. This is where the project-specific requirements can be accommodated, OneSubsea said. The module would contain hydraulically actuated valves, chokes, control systems, chemical injection metering, any monitoring, sensors—everything that would be in the tree.

James Stewart, OneSubsea's tree product manager, said, "The benefit of that is that all that equipment would be more easily recoverable if required. Because these units are separate you have a lower lift weight, and they can be lifted individually rather than in one large assembly."

It takes two

While the tough oil price environment continued to bite hard throughout 2015, subsea players looked at all forms of cooperation or corporate mergers, with several notable alliances formed during the year.

FMC Technologies and Technip launched 50:50 joint venture (JV) Forsys Subsea in March 2015. According to FMC's Chairman and CEO John Gremp, the company has so far been very encouraged by industry response to the alliance.

According to Gremp, national oil companies (NOCs) as well as independent oil companies have expressed interest in the JV's goal, which essentially envisages the early involvement of vendors in field planning to maximize opportunities for equipment standardization and cost savings. An early indication of the level of interest in the JV is that Forsys already had picked up two integrated front-end engineering studies by third-quarter 2015.

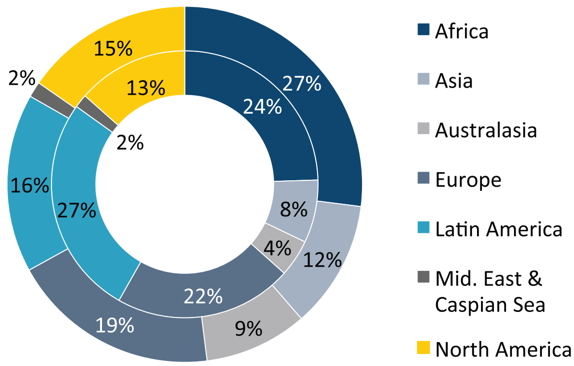
Gremp is a definite believer. "We believe this is the beginning of an industrywide change in the approach to developing deepwater projects," he stated.

Expanding into manufacturing

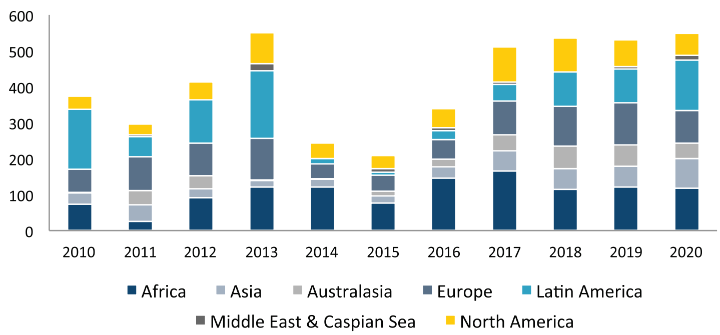
Another believer in that wider approach to field development is Schlumberger, whose $14.8 billion deal to buy JV partner Cameron International will expand the company into new territory in subsea and equipment manufacturing.

A strong motivator for the deal, of course, is OneSubsea, the jointly run Schlumberger and Cameron subsea company. The merger gives Schlumberger bottom-to-top control of wells from its reservoir and wellbore technologies to Cameron's portfolio of wellheads, processing and flow control offerings. Schlumberger will morph into a more broadly dual

Subsea Trees Regional Market Forecast, 2010-2015 vs. 2016-2020



Subsea Tree Orders (Units) by Region



(Source: Infield Systems)

manufacturing and service company that makes valves and rig equipment such as BOPs.

Not quite on the same scale but equally representative is another subsea tie-up between Ezra Holdings subsidiary EMAS AMC and Japan's Chiyoda Corp. The pair have teamed up to create EMAS Chiyoda Subsea, a 50:50 JV.

The companies said the rationale behind the deal was that EMAS Chiyoda Subsea would be able to undertake larger and more complex offshore engineering, procurement, construction and installation projects through a combination of capabilities and resources.

Alliances, JIPs

Also getting in on the act was Subsea 7, which also announced it was forming an alliance with KBR subsidiary Granherne to work on concept and front-end services.

Other relevant joint-industry projects (JIPs) also emerged, including one between OneSubsea and Chevron, which teamed up to develop subsea systems technology for 20,000-psi applications. The JIP, known as the 20Ksi Subsea System Development Program, will address the technical challenges presented by HP/HT reservoir environments for development of 20,000-psi subsea systems.

This is, of course, something that other companies such as BP also have been targeting for several years through its ongoing Project 20K initiative, working closely with contractors such as FMC and Maersk Drilling, while BP, Chevron, Shell and Anadarko also are directly involved with FMC's own ongoing JIP (started in mid-2014) focused on developing a new generation of standardized subsea production equipment and systems.

Subsea projects

Despite the industry downturn, the subsea development treadmill has continued to roll, albeit at a slower pace than in previous years, but there were still some highly notable achievements.

In the Gulf of Mexico (GoM), Technip landed a major contract from Shell for the development of subsea infrastructure for the operator's ultradeepwater Stones project. Included in the workscope are two subsea production tiebacks to the planned FPSO vessel. Stones lies in the Walker Ridge area of the U.S. GoM at a water depth of 2,930 m (9,613 ft). The contract covers engineering of the required second pipeline end terminations (PLETs), fabrication of the PLETs and piles and installation of the subsea production system and includes associated project management, engineering and stalk fabrication.

Preparation also continues for Shell's Appomattox deepwater hub development. FMC received an award for enhanced vertical deepwater trees, subsea manifolds, topsides controls, a control system and a field distribution system. Plans will see Appomattox developed via a four-column floating production facility that will serve a number of discoveries in eastern Mississippi Canyon and western Desoto Canyon.

Chevron, meanwhile, is moving rapidly to expand its pioneering Jack-St Malo project in the

Lower Tertiary GoM. McDermott International will transport and install subsea umbilicals, manifolds, jumpers and flying leads in a program it describes as a brownfield expansion, although Jack-St Malo itself only began producing for the first time in December 2014. The contractor said its latest round of Jack-St Malo work will start in second-quarter 2016.

Across the boundary line in Mexican waters, Wood Group picked up a three-year engineering deal with Pemex valued at up to $28 million that covers concept and basic engineering services for both shallow-water and deepwater projects. Its subsea riser division, Wood Group Kenny, and topside specialist Wood Group Mustang will get in on the action working on a spectrum of projects for the Mexican NOC, including Lakach and other unnamed deepwater prospects.

Australian projects

Offshore Australia, OneSubsea won a FEED contract for Woodside Petroleum's Greater Enfield Area development.

The FEED study, which will be undertaken by OneSubsea's local team in Perth, Australia, will include the design of the full subsea production system architecture solution, including subsea multiphase boosting for the field.

On the giant Inpex-operated Ichthys project, Saipem awarded Kongsberg Oil & Gas Technologies (KOGT) a contract for delivery of the subsea structures associated with the gas export system from the giant processing platform to Darwin. Ichthys lies 220 km (137 miles) off the coast of Western Australia in the Browse Basin and 820 km (509 miles) west of Darwin.

The subsea pipeline will be 882 km long (548 miles long) and then continue for a further 7 km (4 miles) onshore to the LNG plant at Bladin Point in Darwin Harbour. The contract involves delivery of adjustable pipe support structures to support the pipeline and bring it to the required height and orientation at the end termination. KOGT will do the engineering, procurement, construction and delivery of the structures. Saipem will do the installation.

Subsea to shore

Offshore East Africa, Statoil is planning a slimmed-down version of its Snøhvit Field subsea-to-beach development in the Barents Sea to tap the 620 Bcm (22 Tcf) of gas it has so far found off the coast of Tanzania.

The gas from Block 2 will be gathered by a subsea system and piped directly onshore to an LNG plant.

Harald Eliassen, Statoil's offshore project director for Tanzania, said the company had looked at what it had done before on subsea-to-shore at Ormen Lange and Snøhvit (both offshore Norway) to come up with the development solution.

"We started out to create a subsea system very similar to Ormen Læange with large manifolds, dual pipelines, dual service lines, dual umbilicals, loads of redundancy—basically a copy—for ultradeep water. But we soon realized this would be too expensive, so we looked at Snøhvit and decided to make it even simpler than that."

Statoil has now developed a far more commercially viable system with a daisy-chain layout with no manifolds and no large modules to be lifted.

Multiphase pumping

Subsea and deepwater pioneer Total also has been maintaining its reputation for offshore innovation, starting up its subsea multiphase pumping system for the Girassol Resources Initiatives project offshore West Africa's Angola.

The multiphase pump system, which has been installed in Block 17 in a water depth of 1,350 m (4,429 ft), will boost the rates from two production flow loops.

OneSubsea (Framo) provided a complete system of topside power and controls and two subsea pump modules. The pump system is based on the latest development of the helico-axial technology, capable of a record differential pressure of up to 120 bar.

Elsewhere offshore Africa, GE Oil & Gas scooped an $850 million order from Italy's Eni for turbomachinery and subsea elements for the Offshore Cape Three Points project off the coast of Ghana. The subsea production system will be delivered by a GE/Oceaneering consortium and includes the subsea production and control system and umbilicals engineering as well as project management, fabrication, transport and testing. ■