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Subscribe at HartEnergy.com/subscribe**The Return of the Bakken****By Nissa Darbonne, Editor-at-Large, Oil and Gas Investor**

North Dakota's production is setting new records, far exceeding the 2014 high. Bigger production volumes are coming from increasingly rubble-izing the rock.

Increasing Profitability for Small Fields with Innovative Flow Control Strategies**By Mark Venables, Contributing Editor**

In the North Sea, many small oil fields remain stranded due to the perception that the extraction of these resources will be overly onerous. Ensuring these fields are produced profitably requires accurate information and a clear strategy when it comes to flow assurance.

Essar, GEEL Chase Shale Gas Leads in India**By Ravi Prasad, Contributing Editor**

Preliminary studies indicate the presence of shale gas resources in the Indo-Gangetic Basin's Raniganj East and Raniganj South blocks, the companies said.

Analysts Forecast Frac Demand Growth, Tighter Market Ahead for US Shale**By Velda Addison, Senior Editor, Digital News Group**

The Haynesville is expected to account for more than 35% of total active horsepower growth in the second quarter of the year.

Eyeing Brazil, Bolivia Works to Grow Its Natural Gas Output**By Brunno Braga, Contributing Editor**

A 26-well exploration campaign this year by Bolivia's YPFB is expected to double the country's gas reserves from about 303 Bcm to 566 Bcm (10.7 Tcf to 20 Tcf) by 2025.

Looking Toward the Shale Horizon**By Steve Toon, Editor-in-Chief, Oil and Gas Investor**

Will the shale revolution come to an end? Mark Papa, one of the founders of the shale revolution, weighs in.

Encana Gears Up For Its First Anadarko Basin Cube Development**By Richard Mason, Chief Technical Director**

The cube development protocol is Encana's approach to full field development in which it co-develops several wells in multiple stacked layers within a sizable geographical footprint.

HARTENERGY VIDEOS:**■ Saudi Sand Treatment Providing Opportunity in the Kingdom**

Saudi Aramco worked for years developing a treatment that allows more efficient use of local sand.

■ Cybersecurity Expert Warns of Innovation Theft

Black OPS Partners' CEO says companies need to be vigilant in this 'new world of rivalries' we are in.

■ ADNOC Urges STEM Education for Industry's Future

ADNOC's Tashim Al Mzaini discusses a recent study that reveals where the opportunity lies in recruiting the millennials and Gen Z workforce.

*By Jessica Morales,
Video Reporter,
Digital News Group*

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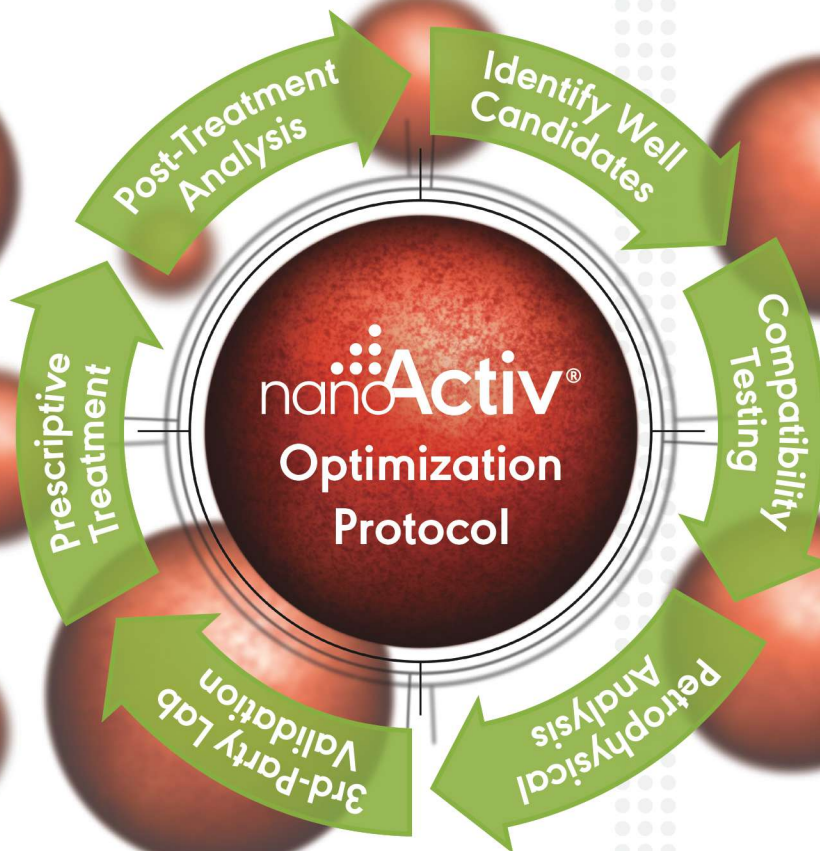
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Simplicity Is Key

Offshore appears to be back in fashion as companies adopt a simpler approach to developing its resources.

As I mentioned last month, I spent several months at sea onboard a research drilling ship. A crewmate of mine liked to say, “Simplicity is the key to succeeding at sea.” I heard that particular earworm so often that it lodged itself nicely in my frontal lobe and, every so often, it will play softly, reminding me of good times. Here lately, it has been playing several decibels louder, especially after reading reports out of last month’s Scotia Howard Weil Energy Conference that an offshore revival was underway.

While there is nothing simple about drilling and producing a well that is located hundreds or thousands of feet below water and seafloor, it does appear that “simple” has replaced “mega” in the lingo dictionary. Field development projects like Shell’s Kaikias that tie new production back to pre-existing infrastructure demonstrate the success of simplified well designs.

The approach was pioneered by LLOG Exploration Offshore in 2011 at its Who Dat Field located in the Gulf of Mexico’s (GoM) Mississippi Canyon 547 protraction block using the semisubmersible Opti-Ex floating production system (FPS), and it was duplicated in 2015 at its Delta House FPS located in Mississippi Canyon 254.

The simplified approach continues as the Covington, La.-headquartered company awarded in January a subsea tieback contract to McDermott International for development of its Stonefly Field in the GoM’s Viosca Knoll Block 999 protraction area. The scope of work includes project management, installation, engineering, subsea structure and spoolbase stalk fabrication, and installation of the subsea infrastructure to support a two-well subsea tieback from the Stonefly development site to the Ram Powell platform owned by Talos Energy.

The tieback will be made possible via an 18-km (11-mile), or 18,288-m (60,000-ft), 6-in. pipeline at water depths ranging from 1,005 m to 1,250 m (3,300 ft to 4,100 ft), according to a press release. McDermott also will design, fabricate and install a steel catenary riser, a pipeline end manifold and two in-line sleds. Installation of the tiebacks and structures is scheduled for the third quarter of this year using McDermott’s *North Ocean 105* lay vessel.

Upon its completion, Stonefly will join a host of other LLOG fields in the GoM developed using subsea tiebacks, including Blue Wing Olive, Claiborne, Crown & Anchor, La Femme and Red Zinger. Two other fields, Buckskin and Nearly Headless Nick, also are planned to come online this year as subsea tiebacks, according to an operational update issued in January.

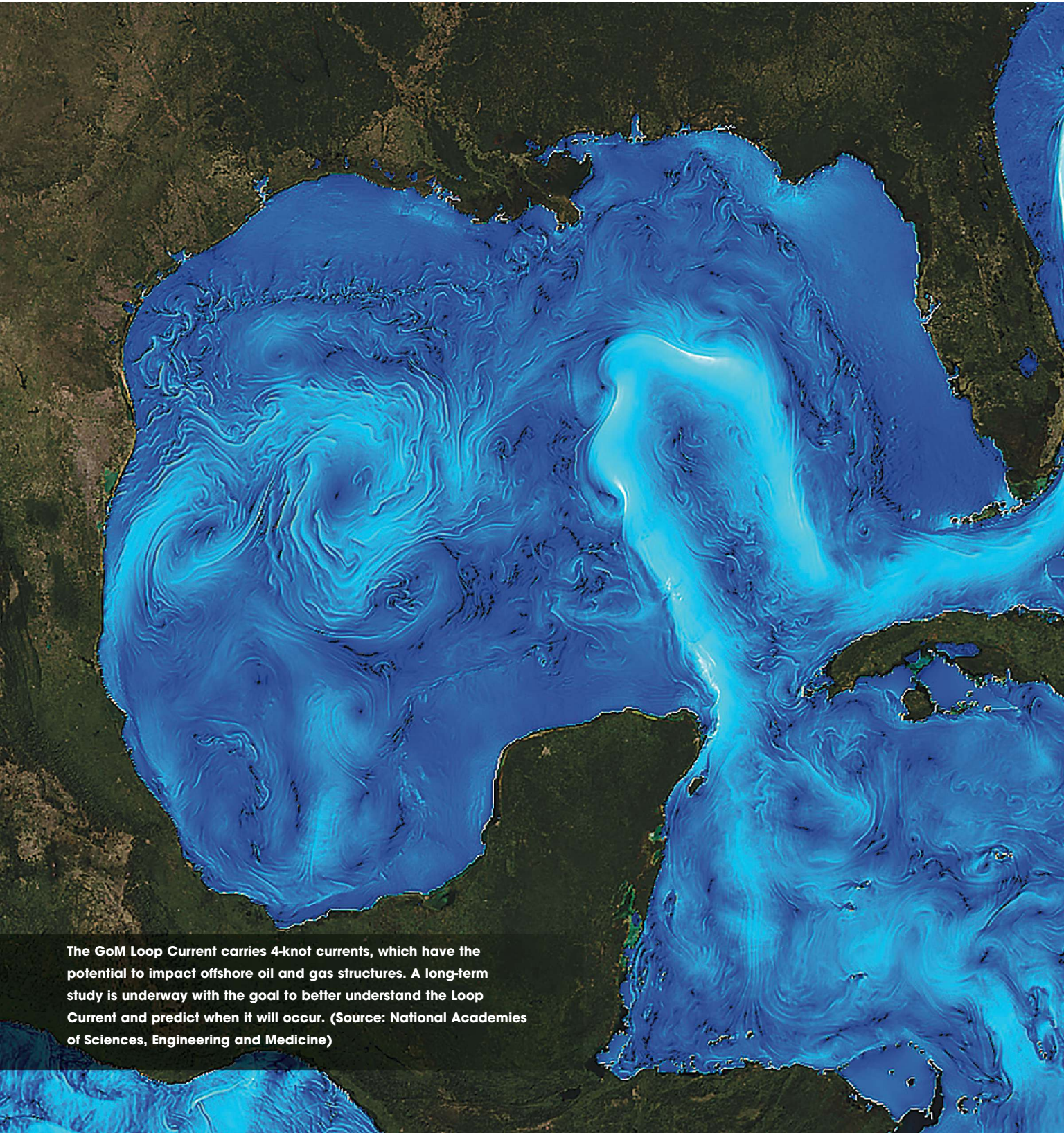
LLOG noted in a September 2018 operational update that it was evaluating the need for a

third FPS in the GoM to co-develop its Khaleesi and Mormont discoveries. Located in the Green Canyon protraction area, the discoveries were successfully drilled by LLOG as operator in 2017 in about 1,189 m (3,900 ft) of water to a total depth of as much as 9,335 m (30,625 ft). Each of the two discoveries has been delineated by two wells and a sidetrack that discovered multiple oil-bearing Miocene horizons, according to the company. If the company holds to its pattern of creative names for its FPSs, then I’m anxiously awaiting its decision to sanction a third one. Perhaps in another nod to *Game of Thrones*, we’ll soon have a Vaes Dothrak, a Red Waste or a Great Stallion to pair with *Animal House*’s Delta House? **ESP**

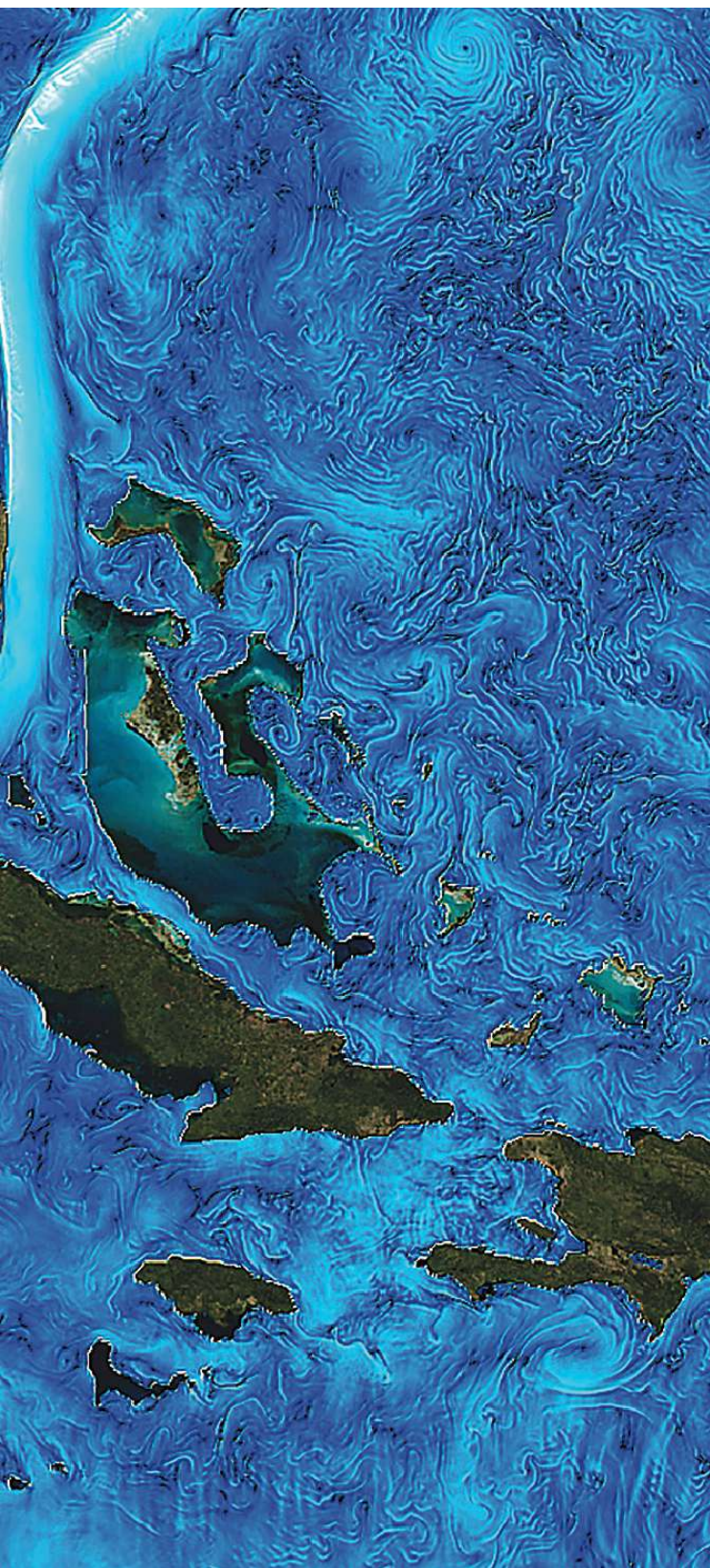


Gulf of Mexico operators are finding success lies with subsea tiebacks to existing infrastructure.
(Source: Bruce Rolff/Shutterstock.com)

Jennifer



The GoM Loop Current carries 4-knot currents, which have the potential to impact offshore oil and gas structures. A long-term study is underway with the goal to better understand the Loop Current and predict when it will occur. (Source: National Academies of Sciences, Engineering and Medicine)



Understanding the Loop Current

A long-term study analyzes a Gulf of Mexico phenomenon and its impact on the industry.

By **Brian Walzel**, Associate Editor, Production Technologies

Operating in the Gulf of Mexico's (GoM) deep waters presents significant and numerous challenges, both technological and logistical. Drilling through thousands of feet of water, through hundreds of feet of rock and into a speculative reservoir can result in a production and economic windfall, but it's also fraught with risk, namely those presented by Mother Nature.

A better understanding of offshore conditions can help eliminate risks, improve disaster response and potentially aid in severe storm prediction. It is to that end—at least in part—that the National Academies of Sciences (NAS) Gulf Research Program (GRP) has initiated a study of the GoM Loop Current. The Loop Current is a flow of warm water that travels through the GoM up from the Caribbean, entering through the Yucatan Peninsula and exiting through the Florida Straits. The current is present in the GoM about 95% of the time, according to a study by Weather Underground, and about every six to 11 months the current sheds a clockwise-rotating eddy that drifts toward Texas and Mexico.

Impacts to offshore facilities

The Loop Current features some of the fastest currents in the Atlantic Ocean, and, according to the Joint Ocean Commission Initiative, it generates forces strong enough to damage the infrastructure of oil and gas rigs. For example, in 2015 nine of the 16 tendons on Chevron's Big Foot project were significantly damaged, resulting in substantial project delays.

"Industry experts and scientists believe that one potential cause of the incident was the strong eddies created by the Loop Current, which may have knocked down the tight, vertical tendons that anchor the platform to the seafloor," the Joint Ocean Commission Initiative reported in a study.

"The Loop Current has 4-knot currents on the outer edge in the boundary currents but goes down approximately 1,000 meters," said Kelly Oskvig,

program officer for the GRP. “So imagine that on a riser and the vibrations that it would experience because of these strong currents.”

During an 18-month period between June 2014 and December 2015, the Loop Current persisted and was active for an unusually prolonged period, according to the NAS, which resulted in detrimental effects to offshore oil and gas operations across the northern, central and some portions of the western GoM.

“Most operators in the Mississippi Canyon, Atwater Valley, Green Canyon and Walker Ridge lease areas observed significant delays and downtime due to the adverse impact of elevated currents on critical current-sensitive operations, including ... platform installation, hull wet tows, spar upending, drift-ins, riser installation, suction pile installation, unlatching the rig, subsea tree installation, pipelaying, remotely operated vehicle deployments and dynamic positioning,” the NAS reported.

In addition to the potential damage to offshore structures the Loop Current presents, the spun-off eddies and the current’s warm water create an incubator of sorts for strengthening hurricanes.

“Hurricane Katrina built up very quickly as it went over that warm water, so when the Loop Current intrudes into the Gulf—if it stays there for a while—it turns the Gulf into a bathtub,” Oskvig said. “You have all this warm water, and that feeds the hurricane. You can be watching it, and it just becomes a nightmare. So if we can better predict within a month to three months what the Gulf might look like, then we can have a better idea of what kind of hurricane season we’re going to have.”

The study

In December 2018, the GRP announced \$10.3 million in initial grant funding into understanding and predicting the GoM Loop Current. According to the GRP, the grant funds eight new projects to conduct studies and collect data and observations that will inform the planning and launching of a long-term research campaign.

“The campaign being planned is a major undertaking,” Oskvig said. “Scientists have been trying to get a handle on the Loop Current for decades, and they’ve made great progress, but there’s never been a long-term, comprehensive, internationally and multi-institutionally coordinated effort.”

Dr. Stephan Howden, an associate professor of marine science at the University of Southern Mississippi, is the project director of a team that will install and operate high-frequency radar systems on

two offshore platforms in the GoM to study surface currents. Howden said data from the systems will provide new, real-time data for model assimilation and validation to better understand the evolution of the Loop Current system.

“The long-range systems that my team will operate in the northern Gulf were used during the *Deepwater Horizon* Macondo spill,” Howden said. “We’ll use those for determining which of the several models that were used for forecasting where the surface oil was going to go. And we use the currents that we were measuring to determine which model was performing better at any particular time.”

Different members of the consortium will be applying radar systems at different ocean depths, with the goal of achieving a 3-D model of GoM ocean currents.

“In order to improve the forecast, we really need data from the surface down to the seafloor, and we are providing some of the surface data that will be used,” Howden said. “If you couple that with the bottom-mounted equipment that the University of Rhode Island’s going to provide, we’re going to have a really good view of where the coverage overlaps, so a 3-D flow field of the Loop Current.”

Howden said applying sensors to large offshore rigs comes with several logistical and cost challenges, and that his team hopes to have sensors in place by the fall.

“Then there are challenges with how the radars operate in an environment where there’s a lot of metal and how that affects how the antennas respond to the scattered energy from the radar,” he said. “There are some newer technologies that will allow us to, hopefully, overcome that challenge.”

According to the NAS, the GRP is an independent science-based program founded in 2013 as part of the legal settlements with the companies involved in the 2010 *Deepwater Horizon* disaster. The GRP was awarded \$500 million to use over 30 years to fund grants, fellowships and other activities in the areas of R&D, education and training, and monitoring and synthesis, the NAS reported.

The Loop Current study is one such project and will receive funding of about \$100 million over the course of the 10-year study.

“We have a standing committee of nine experts helping us develop the program and write future requests for applications, and there’s no set time line on when those are going to come out,” Oskvig said. “There could be some improvement within the first five years on the predictions, but it takes time. It takes a lot of time.” **ESP**

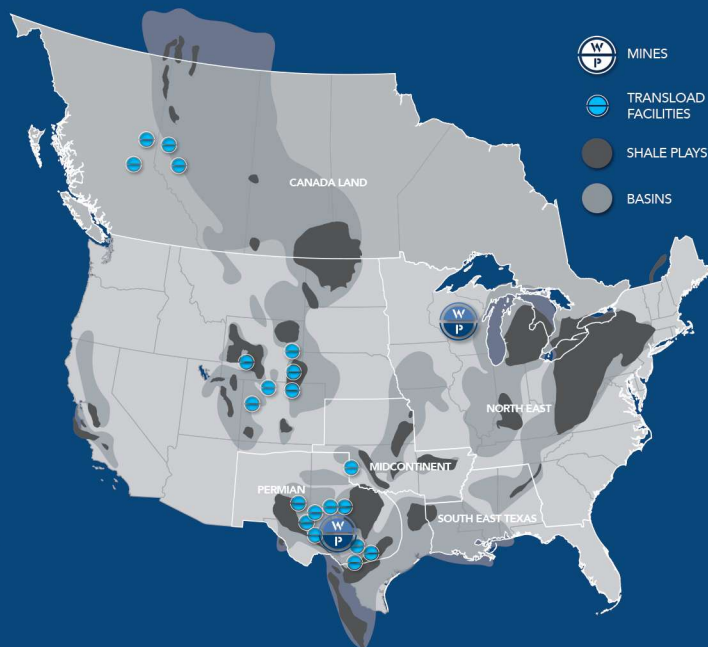


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Ready for the Recovery

By harnessing the power of data, digital and more, oilfield service provider NOV is transforming its approach to tackling the industry's toughest challenges.

By Jennifer Presley, Executive Editor

As a company with predecessors that have been around since 1862, National Oilwell Varco (NOV) has certainly witnessed the petroleum industry's highs and lows. Shortly after taking the reins in 2014 as the chairman and CEO of NOV, Clay Williams faced what he today cites as the greatest challenge in his time with the company, the market downturn. In the five years since, both industry and NOV alike have worked to transform the business and position it for the recovery.

E&P recently spoke to Williams at the company's headquarters in Houston.



Clay Williams

E&P: What technologies do you foresee as having the greatest impact in the upcoming years?

Williams: It is an exciting time from a technology development standpoint. When I look at the ways that our industry is being transformed—things like Big Data, digitalization of processes, machine learning, artificial intelligence and high-speed data transmission—I see an industry that's evolving and changing quickly. Technology is shifting how this industry operates globally, resulting in more efficient, safer production with less environmental impact.

NOV's been at the forefront of bringing high-speed data transmission from the bottom of the borehole to surface rig equipment and then using that stream of data in conjunction with artificial intelligence and heuristic algorithms to optimize the drilling process.

What we've found are some significant gains in drilling productivity by letting the software take over what was previously a very manual process. Drillers would previously focus on trying to optimize the speed of the drilling rig, getting the right weight and the right rotational speed to try to drill a particular formation. What we found is that software can perform those tasks more effectively while freeing up the driller to focus on rig processes.

E&P: What work has NOV done to optimize drilling systems?

Williams: There are two levels to optimizing drilling systems.

The first is that we can automate the dozens of discrete steps necessary to drill an oil or gas well, applying software applications that increase performance and efficiency while drilling. As the foundation for automating those processes, our NOVOS operating system controls the entire drilling process.

The second level is controlling drilling parameters—using software applications to discover the best weight on bit or rotational speed to drill a section of rock, for example. On most rigs, those steps are now done by human drillers who are working a brake handle or performing other activities manually, but our drilling optimization system can do it much faster and achieve that optimal combination of weight on bit and rotational speed. This enables the driller to then use their experience to oversee operations and think about things like, 'What do we do next? What do we need to be ready for? How's my crew doing? Is everybody safe?' To me, it's more important for a driller to focus on those functions rather than trying to precisely land the connection at the right height for the roughneck to swing in, for example.

I think the potential for automation to unleash that human experience, get it focused on the right things on a rig—process control, safety, planning—helps redirect that individual skill set to a higher and better purpose. In many ways, automation empowers drillers.

We also are doing the same sorts of things when it comes to hydraulic fracturing and coiled tubing operations. We want experienced people on site to be able to run equipment safer and more efficiently.

E&P: Equinor and NOV signed a frame agreement for your IntelliServ wired drillpipe. Can you explain more about the pipe and how it will help enable future drilling operations?

Williams: I'm pleased with Equinor's decision to move forward with putting wired drillpipe across its offshore rig fleet, and I'm looking forward to working with them.

We're very excited about the overall prospects for wired drillpipe. It's a technology that transmits data from downhole to surface at an incredible 57,600 bits per second; compare that to conventional mud-pulse telemetry, which runs about 10 bits per second. Wired drillpipe is a dramatic leap forward in terms of seeing what's happening downhole in real time, which is a view drillers have never really had before. What we find is that high-speed data [and] microsecond data fed into surface controls that drive rigs and other pieces of equipment at the surface really offer the opportunity to make operations a lot safer and more efficient. We've ran wired drillpipe in several major campaigns, including for BP in Alaska, Total on the Martin Linge Field, Equinor in the Barents Sea and Lundin Norway on the Edvard Grieg Field. The results in all of these operations demonstrate the remarkable telemetry-related time savings of running wired drillpipe as well as the performance benefits of integrating downhole drilling dynamics tools and drilling applications into the drilling process.

E&P: What are your thoughts on the recovery of the offshore sector, and how has NOV prepared for it?

Williams: Through these past four years of the downturn, the owners of the resource base in the deepwater sector have been focused on reducing costs and becoming more efficient, and they've made real progress.

We're seeing lots of green shoots, and we're hearing more and more from our E&P customers that they're moving closer to sanctioning large projects offshore. Additionally, many of our drilling contractor customers are focused on reactivating offshore rigs to address the rising number of tenders in the marketplace.

Through the downturn, we've invested more in shale due to shifting activity levels and economic priorities. But importantly, we haven't sacrificed any of our capabilities in the offshore; if anything, we've continued to enhance them.

We're well-known for providing drilling equipment in the offshore market, but over the past several years, we've also expanded into offshore production systems as evidenced by a couple of acquisitions in that area. We have a great team dedicated to production systems, and it's very focused on reducing the cost of development, reducing the lifting costs of our customers' barrels and helping them be more competitive in a slightly lower commodity price environment. We're ready for the offshore recovery.

E&P: Speaking of opportunities, what's next for NOV?

Williams: We foresee adoption of newer drilling and production equipment and technologies outside of North America. National oil companies have seen the success that North America has achieved with shale drilling and want to replicate it in their fields.

As I mentioned, in the offshore environment we're starting to see signs of more drilling rig reactivations. As previously stacked rigs are made operationally ready to participate in tenders and go back to work, these will be good opportunities for NOV. I think the future is very bright. **E&P**

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Awaiting a Clear 2019 Outlook

Commodity prices cloud the 2019 oilfield services outlook.

By **Richard Mason**, Chief Technical Director

Talk to investors lately about oilfield services? Their No. 1 question concerns what will happen in the second half of 2019. With the first quarter in the history books, the fact that industry observers have a hazy view is telling. Much of that is related to commodity price, to be sure. But a significant influence is the Wall Street mandate to E&P companies about living within cash flow, generating a profit and sharing that profit with shareholders/investors.

Investors are worried E&P companies are front-loading projects as part of 2019 capital spending, and a sizeable volume of those projects will be directed to a reduction in drilled but uncompleted wells (DUCs), especially in the Permian Basin. As the DUC inventory declines, so will demand for well stimulation.

That is just another way of pointing to the chronic uncertainty evident in current trends for oilfield services.

There are several ongoing themes, particularly on the well stimulation side. Short on Northern white sand? Blame flooding in the upper Midwest on top of cold winter weather. The latter keeps premium sand providers from operating mines. The former makes it difficult to transport bulk proppant via barge to customers in the southern oil fields where the availability of 40/70 proppant is becoming an issue.

Excess stimulation capacity still plagues the industry. However, a significant tranche of excess capacity stems from greater efficiency on the job site. Several E&P companies and multiple well stimulation firms have reported at recent industry conferences that stage count is up about 35% currently versus the same time last year. In many cases, the stage count is approaching 9 to 10 stages daily. Those are remarkable numbers when considering it still takes about two hours to do a stage. The change stems from more wells drilled on pads and the reduction in mobilization time between wells.

Additionally, well stimulation firms have improved ancillary processes thanks to enhancements such as subsurface automation, better performance at the stage level and greater experience among stimulation crews. As for excess pumping capacity, equipment is running harder for longer, and there is a natural and accelerating rationalization process underway that will address the supply side of well stimulation equipment.

The trend among E&P companies to self-source sand appears to be topping out at about 20% of the sand market. E&P companies are exceptional at finding oil and gas. The manpower and supply chain requirements associated with field work makes it difficult for all but the very largest E&P companies to operate successfully on the procurement side.

Word is, established stimulation firms view electric fleets as a niche opportunity. The rationale is that it is possible to find mechanics locally that can work on the existing fleet. When it comes to turbines, support personnel has to be flown in to the job site because there are so few out there. The way the issue is

handled for mechanical fleets involves having excessive hydraulic horsepower on site so that if a crucial piece of equipment goes south, it can be pulled out of line and replaced simultaneously with existing inventory. The niche most amenable for electric stimulation fleets is found in full field development programs where equipment is employed on pads in a tight geographical footprint.

At a broader level, questions on the equipment supply and demand balance reflect a change in world view on behalf of the investor class. Few investors are interested in waiting 30 years to realize an energy investment based on higher EURs fully. Rather, the view on Wall Street is that the oil and gas industry is a decade or two from peak demand. If investors are going to provide money to energy, they want the return now as dividends or share buybacks rather than waiting a half decade or more for returns in an uncertain future. **ESP**

- **Energy investors are unclear on the pace of 2019 activity.**
- **Investors are concerned with the oilfield services supply/demand balance.**

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Center Set to Deliver Advanced Drilling Tech

A new research and manufacturing facility dedicated to the improvement of drilling motors opens in Oklahoma.

If one considers the drillbit to be the tip of the driller's spear, then the drilling motor is the oomph that drives it. Chewing through expanses of nearly impenetrable rock at faster speeds for longer intervals puts tremendous pressure on the bit, motor and more. Through advancements in engineering and manufacturing technologies, the design and development of drilling motors has improved significantly. Those advancements are set to continue with the opening of a new manufacturing and technology center by Baker Hughes, a GE company (BHGE), that is dedicated to advancing the performance, quality and reliability of downhole drilling motors.

In April the BHGE Motor Center of Excellence (COE) opened in Oklahoma City. To address the challenges placed on drilling motors to drill faster and longer, the company will incorporate "cutting-edge robotics, automation and process control to create a step change in drilling motor precision and quality," according to a press release.

"We are excited to open the Motor Center of Excellence in Oklahoma City, in the heart of North America—the world's largest market for drilling motors," said Maria Claudia Borras, president and CEO for Oilfield Services at BHGE, in the release. "The technologies and engineered solutions we develop here will drive smarter well construction and deliver better drilling efficiencies to our customers throughout the world. We're proud of the facility and the potential it brings."

According to the company, advanced monitoring systems and a state-of-the-art plant control center at the Motor COE will enable BHGE to design and man-



JENNIFER PRESLEY
Executive Editor
jpresley@hartenergy.com

Read more commentary at
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ufacture drilling motors to exacting tolerances, resulting in better motor quality. Co-located on BHGE's Oklahoma City Supercenter campus, the 11,891-sq-m (128,000-sq-ft) facility includes manufacturing, engineering, repair and maintenance as well as an elastomer and materials laboratory.



From left to right, Oklahoma Governor Kevin Stitt, BHGE's Oilfield Services President and CEO Maria Claudia Borras and senior plant manager Karen Lane toured BHGE's new Motor COE facility in Oklahoma City. (Source: BHGE)

At the grand opening of the Motor COE, the company's next-generation Navi-Drill DuraMax high-performance motors also were introduced. The redesigned line of motors provides increased horsepower and torque. The Navi-Drill DuraMax motor will be manufactured and maintained at the Motor COE, according to the release.

The Motor COE is the newest of research and technology centers for the company. Other centers include the Artificial Lift

Research & Technology Center located in Claremore, Okla., for the R&D of electric submersible pumping systems under extreme downhole conditions. Researchers at the company's Celle Technology Center located in Celle, Germany, perform engineering and testing of drilling systems, telemetry and LWD systems. **ESP**

Jennifer



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Offshore Faces Its 'Prove It' Moment

Operators know they need large projects at lower costs.

Offshore E&P, particularly in deep water, is not for the faint of heart. Project costs range from the tens of millions of dollars to the billions, and a failed project or underperforming well could prove debilitating to some companies. Additionally, even those companies that are successful in offshore development must maintain a growth approach, particularly to appease investors and analysts. However, as panelists noted during a CERAWeek session focused on deep-water development trends, it's not particularly easy to replace the hydrocarbons that are being produced.

"Growth is difficult in the upstream," said Stephen Greenlee, vice president of Exxon Mobil Corp. "Our company has made for some time about 4 MMbbl/d, with a 5% decline on top of that. Just to stay still, you've got to replace 20,000 bbl/d of production capacity, which is a lot."

As Greenlee and his co-panelists explained, offshore oil and gas is facing a "prove it" moment. Kevin McLachlan, senior vice president of exploration at Total, explained that the industry "has to learn from our mistakes" in spending when prices were \$100/bbl or more—often with underwhelming results.

The challenges facing oil companies, particularly supermajors, that work offshore are to continue to find large fields, develop them at much lower costs than before and replace significant amounts of production. Development costs have already substantially improved—down to about \$21/bbl from \$71/bbl, said Torgrim Reitman, executive vice president of development and production international at Equinor, during the CERAWeek session.

More than 50 years after modern development was initiated, the Gulf of Mexico (GoM) continues to be one of the world's great offshore areas with several recent announcements proving there is still a place for large-scale developments. In November Chevron announced first oil from its Big Foot deepwater project. Discovered in 2006, Big Foot contains resources of more than 200 MMboe and has a projected life of 35 years, according to the company. The project is designed to produce 75,000 bbl/d and 707,921 cu. m/d (25 MMcf/d) of natural gas. And in January 2018, Chevron, in partnership with Total, announced a major discovery



BRIAN WALZEL
Associate Editor,
Production Technologies
bwalzel@hartenergy.com
Read more commentary at
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at the Ballmore project in the Norphlet play. According to Total, the discovery encountered 205 m (672 ft) of net oil pay—a potentially massive resource.

Shell's biggest offshore project, Appomattox, is expected to achieve first oil by the end of the year with peak production expected at 175,000 boe/d. Conceived during a period in which oil prices were about \$100/bbl, Shell slashed costs for Appomattox by 30% to keep the project feasible in the lower price environment.

To kick off the year, BP announced a major expansion at its Atlantis Field and also identified "significant" oil resources that the company said could create further development opportunities. Phase 3 of the Atlantis project includes the construction of a new subsea production system from eight new wells that will be tied to the current platform. The new system is expected to come onstream by 2020 and produce about 38,000 boe/d at its peak. In addition, thanks to improved seismic imaging techniques, BP has identified an additional 1 Bbbl of oil in place at its Thunder Horse Field. As if those weren't enough, BP also announced two oil discoveries in the GoM at the Manuel and Nearly Headless Nick prospects, the latter of which is operated by LLOG.

The size of these projects and their financial solvency are indications that the offshore industry can thrive in the current price environment. And as Greenlee noted, they should prove to be the beginning of new abilities.

"I think we need to prove our ability to replicate these profitable projects," Greenlee said. "Only when we do that will the market be completely comfortable with us being able to create long-term sustainable value with our deepwater exploration programs." **ESP**



(Source: nikkytok/Shutterstock.com)

Back to Deep Water

By **Jennifer Presley**, Executive Editor

Activity in the Gulf of Mexico is increasing as new players, technology and tiebacks deliver change.

Memories are long in the oil patch, but thankfully, the sea has no memory. Every day on the water begins fresh and new, ripe with opportunities for those daring few willing to risk it all. The time-tested Permian Basin of Texas and New Mexico has held much of the energy industry's focus in recent years. However, another proven basin, the Gulf of Mexico (GoM), has quietly staged a comeback in the roughly five years since the market downturn sent crude prices plummeting.

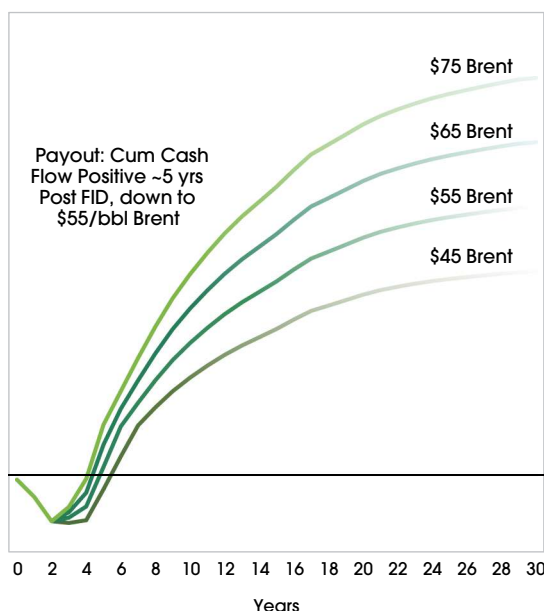
A quick check of the U.S. Energy Information Administration's (EIA) GoM statistics shows a steady increase in production, from 1.3 MMbbl/d in January 2014 to 1.9 MMbbl/d in January 2019.

The EIA expects the increased output to continue in the years ahead. According to the February 2019 update in its Short-term Energy Outlook, the EIA predicts U.S. crude oil production will average 12.4 MMbbl/d in 2019 and 13.2 MMbbl/d in 2020. The overall increases in crude oil production are, according to the EIA report, the result of continued growth in the Permian Basin as well as the expectation of 19 new projects to start in 2019 and 2020 in the GoM.

Many of those new projects were made possible through the careful combination of cost cutting, new technologies and the use of subsea tiebacks to existing infrastructure. This combo helped bring

	Guyana Liza Phase 1 Development	Delaware Basin Illustrative 50,000 Net Acre Development
Peak Production	120,000 boe/d	120,000 boe/d
Peak Production Oil	120,000 bbl/d	90,000 bbl/d
Initial Investment to Peak Production	3 years	10+ years
Reservoir Quality	Multidarcy	Microdarcy
Total Production Wells	8	1,500
Avg. EUR / Production Well	~63 MMbbl of oil	~1.1 MMboe ~0.7 MMbbl of oil
Development Capex	\$3.7 Billion	\$12.8 Billion
Unit Development Costs	~\$7/bbl of oil ~\$6/boe	~\$12/bbl of oil ~\$8/boe
Cost Environment	Deflating/flat	Inflating
Required WTI price for 10% Cost of Supply	~\$30/bbl	~\$40/bbl

Liza Phase 1- Cumulative Cash Flow



According to Hess CEO John Hess, the Liza project in Guyana's Stabroek Block offers a breakeven superior to premier U.S. shale plays. (Source: Hess)

offshore breakeven costs down in response to the market downturn. The average pre-final investment decision breakeven dropped to \$49/boe in 2018 compared to \$78/boe in 2014, according to a November 2018 report by Wood Mackenzie.

The lower breakeven costs have made offshore competitive with shale plays. Speaking at the Marine Technology Society's Offshore Industry Market Outlook 2019, Barry Donovan, managing director of FMI Capital Advisors, shared his thoughts with attendees on the offshore versus shale position.

"There is an amazing opportunity in the offshore market, and it should have an extra appeal to people because these wells can be prolific. Offshore wells can produce 10 times what a shale well can produce right off the bat and then—more importantly—it can hold that volume better than a shale well," he said. "Interestingly, analysts and operators have been presenting a lot of evidence that the offshore breakeven costs have come down and are competitive."

It is a position that John Hess, CEO of Hess Corp., also put forward in his presentation at the Scotia Howard Weil Conference held in March. According to Hess, the Liza project in Guyana's Stabroek Block offers a breakeven superior to premier U.S. shale plays.

In his presentation Hess compared the development capex for Liza Phase 1 against that of a 50,000-net-acre development project in the Delaware Basin. The Liza project, with peak production of 120,000 boe/d from eight production wells with an average EUR of about 63 MMbbl of oil per well, is \$3.7 billion. To produce 120,000 boe/d from a Delaware Basin development, it would require 1,500 production wells with an average EUR of about 0.7 MMbbl of oil per well and would ring up a development capex of \$12.8 billion.

Donovan noted that, for the foreseeable future, the offshore industry has provided 30% of the global oil and gas production for the past decade. "There are many analysts out there telling us that the offshore is going to continue to provide that 30% of the world's oil and gas production," he said. "Offshore is important. It is not being replaced by onshore production, and I'll go so far as saying that it can't be."

Adding to the appeal of lower breakevens in the GoM is current market dynamics, oil shortages and stable political climate, according to a Morningstar Commodities Research report. "The quality of Gulf crude, as well as the longer life of offshore wells, make it just as attractive as shale to large producers," said Sandy Fielden, director of oil products research for Morningstar Commodities Research, in the report. "On top of that, in a market where OPEC cuts, Iranian sanctions, Venezuela's meltdown and Canadian production controls have created a shortage of medium and heavy crude, Gulf of Mexico grades are valuable to both domestic and overseas refiners."

One need only look to the results of the recent GoM regionwide lease sale that occurred in March for evidence of increased interest in the basin. The sale attracted 257 bids from 30 companies, with high bids totaling \$244.3 million, a 37% increase (or about \$66 million more) from the last lease sale in August 2018. The highest bid of the round came from Equinor with \$24.5 million for Block 801 of the Mississippi Canyon protraction area.

"We saw a modest increase in overall spend, but it was outpaced by the increase in acreage leading to a lower amount per acre, furthering our hypothesis that it is a buyer's market in the Gulf of Mexico," said William Turner, senior research analyst at Wood Mackenzie, in a release.

"The number of companies participating has thinned out, with the only notable absence being Exxon Mobil. It seems those left in the Gulf of Mexico are committed to the region and taking this opportunity to quietly strengthen their prospect inventory," Turner added.

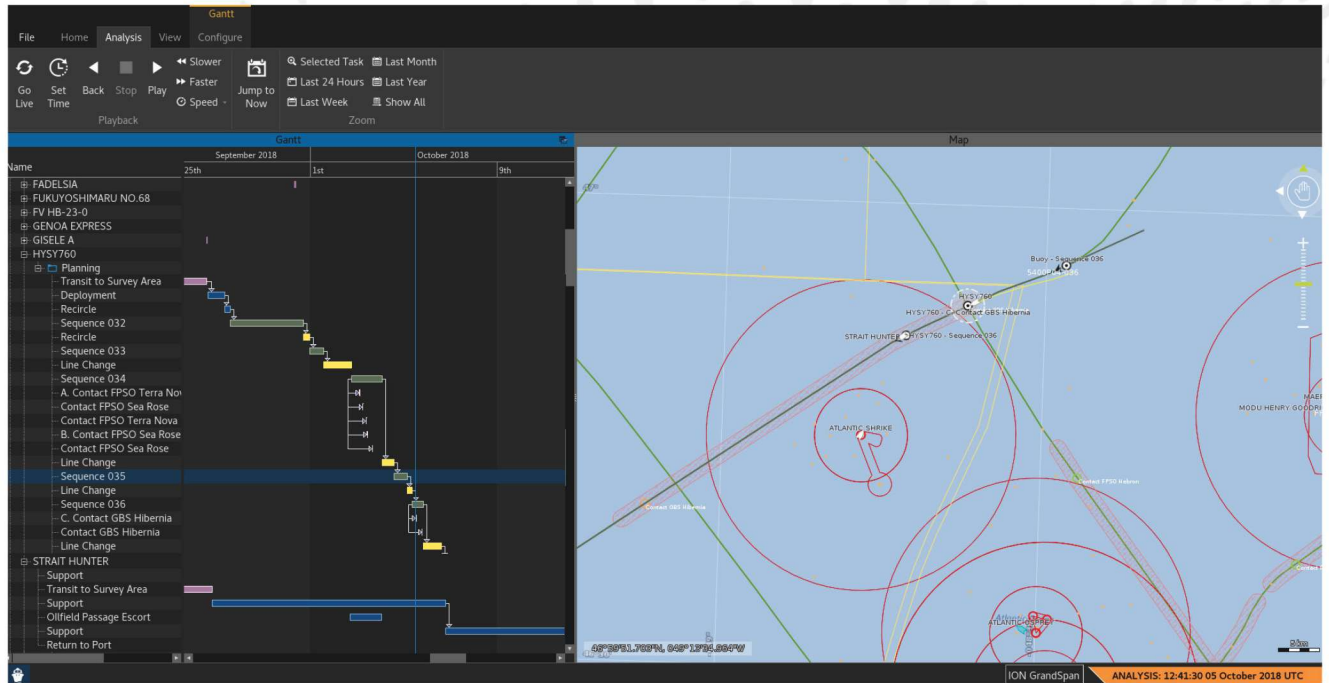
In reviewing details of the sale, it would be difficult to miss the number of what Turner called "unique partnerships" between the majors and smaller players.

"Kosmos with Equinor, Fieldwood Energy with Chevron, LLOG with BP and Talos with EcoPetrol—this demonstrates a shrinking pool of players but also an increased willingness of the majors to partner with these more nimble players," he said in the release.

In an interview with *E&P*, Turner added that the emergence of these more nimble players has been

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an interesting shift to watch over the last four years. “LLOG, for example, is focused in the Gulf of Mexico and is a smaller operator, but it has turned some heads in just how quickly it is able to turn around projects. Its lead times, even on standalone facilities, are very low,” he said. “Then you have Talos, which is in the U.S. Gulf of Mexico and also on the Mexican side as well. We’re seeing the emergence of these smaller but more regionally focused players juxtaposed with those larger players that exited. These operators are stepping into the gap left from these more globally diversified independents. Kosmos is a great example of one company that has stepped in with the capability to actually operate in the region.”

Building on greatness

While Guyana is far removed from the GoM, the breakeven comparison still rings true in the basin.

Take, for example, the final investment decision announcement by Shell regarding its Vito deepwater development in the GoM. The operator noted that the project’s forward-looking, breakeven price estimated to be less than \$35/bbl. The field, located over four blocks in the Mississippi Canyon protraction area, is about 240 km (150 miles) south of New Orleans. Peak production for the Vito Field is expected to be about 100,000 boe/d, and it holds an estimated recoverable resource of 300 MMboe, according to the announcement. Production is scheduled to begin in 2021.

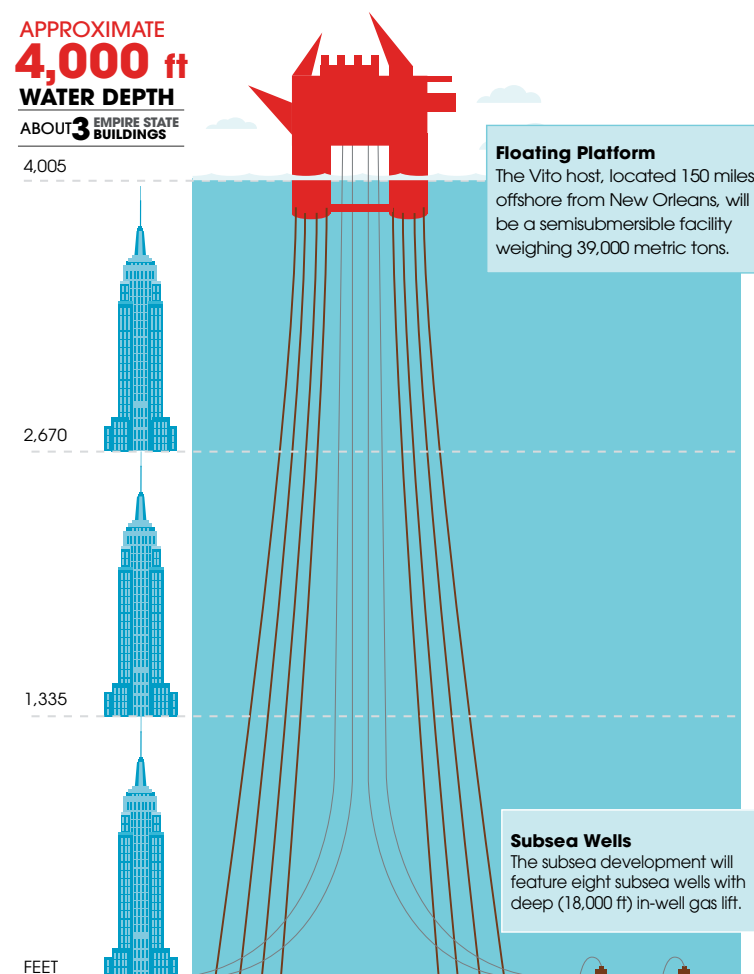
“With a lower cost developmental approach, the Vito project is a very competitive and attractive opportunity industrywide,” said Andy Brown, Shell Upstream director, in the release. “Our ability to advance this world-class resource is a testament to the skill and ingenuity of our development, engineering and drilling teams.”

According to the company, in 2015 the project was redesigned, resulting in cost estimate reductions of more than 70% from the original concept. The company credits the savings to a simplified design and through collaboration with the project’s vendors.

In July 2018, Subsea 7 announced that it was contracted by Shell for the project management, engineering, procurement, installation and pull-in of two 12-in. infield production flowlines with 10-in. steel catenary risers (SCRs), one gas-lift flowline and SCR, and an umbilical system at Vito. Installation activities are scheduled for 2020 and 2021, according to Subsea 7.

“We have a collaborative partnership across our management teams, where synergies and shared goals are powerful drivers in delivering a differentiated and value-added service,” said Craig Broussard, Subsea 7’s vice president for the GoM, in a release. “This award will draw on our expertise to ensure our client is given the competency, cost-efficiency and project capability they need to unlock the full potential of this significant deepwater development.”

In November 2018, the company was awarded a second construction contract for the Vito project by Enbridge Offshore Facilities for the transportation and installation of 80 km (50 miles) of 18-in. oil export pipelines, 27 km (17 miles) of



Vito will be the 11th deepwater host that Shell has in the GoM. (Source: Shell)

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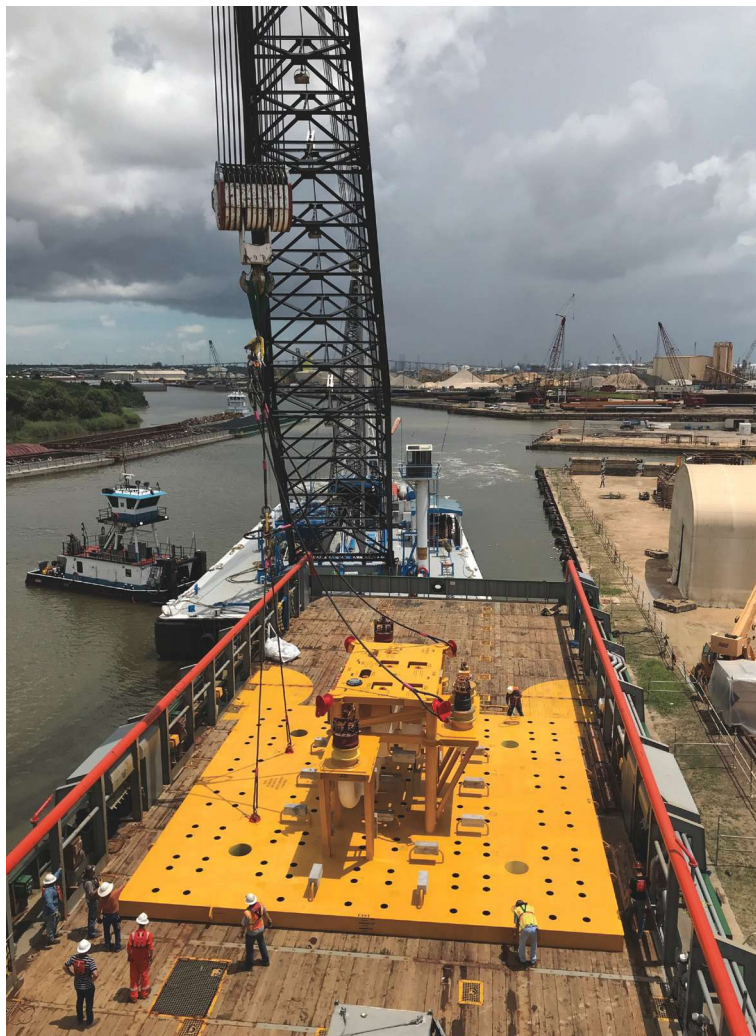


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A subsea manifold for BP's Thunder Horse Northwest Expansion project is loaded onto an offshore supply vessel at the Houston Ship Channel. (Source: BP)

10-in. gas export pipelines and 4.8 km (3 miles) of associated SCRs and pipeline end terminations. The activities are scheduled for 2019 and 2020, according to the release.

Technology advances

Deepwater projects contribute to much of the production growth in the GoM, with advances in technology making it possible to do more with in-place infrastructure. In October 2018, BP's Thunder Horse Northwest Expansion came online, boosting production at Thunder Horse by an estimated 30,000 boe/d at its peak, taking gross output at one of the largest oil fields in the GoM to more than 200,000 boe/d. Initially planned for startup in early 2019, the project started up four months ahead of schedule and 15% under budget, according to the company.

In January, BP announced its approval of the \$1.3 billion Atlantis Phase 3 development that will significantly expand the production capabilities of the field. Advanced seismic imaging and reservoir characterization revealed an additional 400 MMbbl of oil in place, according to the company. The development will produce an additional 38,000 bbl/d when it comes online in 2020.

According to BP, an additional 1 Bbbl of oil in place at the Thunder Horse Field also was identified using the same advanced seismic imaging technology and analysis.

"Atlantis Phase 3 shows how our latest technologies and digital techniques create real value—identifying opportunities, driving efficiencies and enabling the delivery of major projects. Developments like this are building an exciting future for our business in the Gulf," said Starlee Sykes, BP's regional president for the GoM and Canada, in a release.

Atlantis Phase 3 will include the construction of a new subsea production system from eight new wells that will be tied into the current platform located about 240 km (150 miles) south of New Orleans.

Longer distance tieback and greater water depth present increased flow assurance challenges. Subsea 7's electrically heat-traced flowline (EHTF) technology ensures the right temperature within the flowline is maintained to reduce the risk of blockages from hydrates or wax.

In December 2018, Subsea 7 announced the award of a subsea umbilicals, risers and flowlines (SURF) contract by BP for the Manuel project in the GoM. The Subsea Integration Alliance (SIA), the partnership between Subsea 7 and OneSubsea, a Schlumberger company, will deliver a fully integrated solution to the project, according to a release. The Manuel project is a two-well development tieback to the Na Kika production facility and will be the first in the U.S. to use the EHTF technology.

"The award of the Manuel project is a clear demonstration of the power of collaboration between all stakeholders. Together with our SIA partner, OneSubsea, and the BP team, we have produced an optimized solution that will see the deployment of EHTF technology," Broussard said

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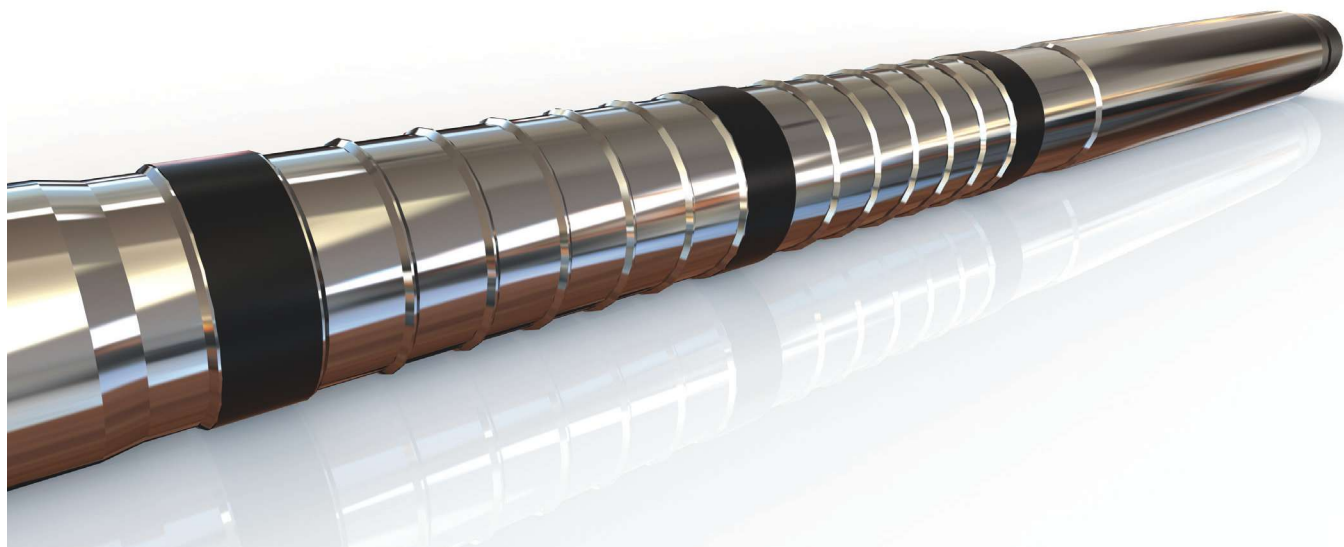
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Halliburton installed 37 XtremeGrip expandable liner hangers across seven wells as of September 2018. (Source: Halliburton)

in a release. “This has enabled us to reduce the total cost of the project, while accelerating the first oil target date to just 24 months from discovery. SIA has been able to deliver this accelerated schedule by removing critical path challenges through early engagement, on both SPS [subsea production system] and SURF scopes of work. This has ultimately allowed us to achieve a solution that creates sustainable value for all parties despite a challenging cost environment.”

Another challenge operators face in the GoM is the need to isolate multiple hydrocarbon-bearing sands across the drilling and production liners. At Hess’ Stampede deepwater development project, Halliburton installed 37 XtremeGrip expandable liner hangers across seven wells as of September 2018, with no liner-top leaks or remedial work required, according to a press release.

The Stampede Field is located 185 km (115 miles) south of Fourchon, La., in Green Canyon blocks 468, 511 and 512 in about 1,067 m (3,500 ft) of water. Hess achieved first oil in January 2018, just over three years after project sanction.

The liner hangers were installed to a depth of 9,425 m (30,924 ft), setting a record depth for the XtremeGrip system. The system provides an unrestricted flow path prior to setting, and its ability to rotate while cementing provided effective and reliable isolation without costly cement remediation. Each Stampede well includes up to five XtremeGrip

liner installations, making the consecutive liner runs a major part of the well construction process, according to the release.

The installations began with hanging a 13 $\frac{7}{8}$ -in. drilling liner inside a 16-in. casing. The subsequent hangers support another drilling liner, followed by two production liners, through multiple reservoirs. Each well then had a production liner tied back with a scab liner for structural integrity, according to the release.

“In technically challenging offshore environments, safe and flawless execution is vital to the ultimate success of the project,” said Mark Dawson, vice president of Halliburton Completion Tools, in the release. “We are very pleased with the reliability of the XtremeGrip system in ultradeep wells. Supported by Hess’ highly collaborative work environment, we delivered the excellent results achieved on the Stampede wells. The overall scope of these projects cumulated in hanging over 143,000 ft [43.6 km] of liner casing over 27 miles [43.4 km] at a total buoyed weight of 9.3 million pounds. Halliburton provided these impressive results without any costly liner top remediation for our customer.”

After five long years, it is good to see operators step back into the GoM spotlight. While the sea has no memory, the persistent poking and prodding by humans into the seafloor have provided plenty of surface and subsurface landmarks to guide future operations. **ESP**



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The Zama Field was discovered in 2017 and could achieve first oil in 2022.
(Source: Premier Oil)

Mexico Finding Its Place in Offshore Landscape

By **Brian Walzel**, Associate Editor, Production Technologies

The massive Zama project is leading recent shallow-water discoveries.

With one of the world's largest recent oil discoveries and geology similar to the prolific Gulf of Mexico (GoM), offshore Mexico has the potential to be one of the world's next great offshore fields, potentially producing more than 1 MMbbl/d by 2040, according to the International Energy Agency.

But recent shifts in the country's energy policies under President Andrés Manuel López Obrador

have the potential to put the brakes on the progress Mexico initiated with its 2014 energy reforms. The energy reforms opened up foreign investment in the country's oil and gas industry for the first time in nearly 90 years. In February of this year, López Obrador froze new joint venture contracts with national oil company (NOC) Pemex. Although Pemex reported that contracts in place would continue to be honored, CEO Octavio Romero

Oropeza said the energy company would instead focus on developing oilfield services contracts rather than farm-out deals.

Despite the regulatory unrest, Mexico still could emerge as a major offshore player with many shallow-water projects being fast-tracked for production by 2025. Hokchi is an oil and gas field in 30 m (98 ft) of water located in Area 2. The field has potential reserves of 147,800 boe and 1.2 Tcm (45.4 Tcf) of natural gas and is being operated by Hokchi Energy. Located in Area 4, the Ichalkil-Pokoch Field is being operated by Fieldwood Energy and has reserves of 450 MMbbl of light crude. Production is expected to peak at 110,000 bbl/d and 4.1 MMcm/d (145 MMcf/d) of natural gas by 2026 to 2027.

According to Wood Mackenzie, fields coming onstream as part of Mexico's energy reform will contribute up to one-third of the country's production by 2025.

In August 2018, Eni announced that Mexico's National Hydrocarbons Commission had approved the development plan for the discoveries at Amoca, Miztòn and Tecoailli, located in Area 1. According to Eni, Area 1 is estimated to hold 2.1 Bbbl of oil in place and full-field production will start in late 2020 utilizing an FPSO with treatment capacity of 90,000 bbl/d. Two additional platforms will be installed on the Amoca Field and one in the Tecoailli Field.

"Fast-forwarding four years from now, these projects should start to make a significant impact on Mexico's production outlooks," said Maria Cortez, Latin America upstream senior research manager at Wood Mackenzie. "Because they are being fast-tracked, they are privately funded, and they aren't affected by the politics or issues that Pemex faces. Because of the current environment, there is an incentive to show results. Not all projects are

going to be able to do that, but these early ones are really positioned to show that."

Zama

The most substantial recent project that is key to Mexico's offshore development is Zama in the Sureste



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Basin. The Zama Field was discovered in 2017 by the Zama-1 well, which was drilled to a depth of 3,383 m (11,100 ft) and encountered an oil interval of 338 m (1,110 ft). When the field was discovered, Wood Mackenzie reported that it was one of the 10 largest shallow-water fields to be discovered in the past 20 years.

According to operator Talos Energy, Zama holds reserves of between 1.4 Bboe and 2 Bboe. Talos Energy holds 35% as the operator, while Sierra Oil and Gas holds 40% and Premier Oil holds 25%. “One of our motivations is to progress Zama to first oil as quickly as possible,” said Tim Davies, group exploration manager for Premier Oil.

Talos President and CEO Timothy Duncan has stated the company hopes to achieve first oil by the second half of 2022. Talos announced in January that the Zama-2 appraisal well, the first of three appraisal wells drilled by the consortium, was drilled 28 days ahead of schedule and reached the top of the Zama discovery and encountered 177 m (581 ft) of gross true vertical depth oil pay.

During Talos’s fourth-quarter 2018 investor call, Duncan said the company will move to the Zama-3 location next and repeat coring operations. “The appraisal program should be completed by mid-year, at which point the resource range will be narrowed when we get closer to an FID [final investment decision] and book these reserves and prove them probable,” he said.

The Zama Field is planned to be developed with three production platforms, each of which will comprise a single jacket and topsides and will support 100,000 bbl/d of production.

Infrastructure challenges

With only about 50 wells drilled offshore Mexico to this point, Cortez explained how the region is essentially a blank slate from which to develop, particularly compared to the GoM, where infrastructure and technology is well-established.

“Infrastructure is probably going to be one of the most complex parts of all projects because in many areas there isn’t any, or where there is infrastructure, it has historically been held by the NOC,” Cortez said. “We’ve seen some really unique solutions to infrastructure. For example, there is a shallow-water project that’s operating in 30 meters

[98 feet] of water that will be using an FPSO. But infrastructure takes time, and getting all the right upgrades can get very complex.”

In some cases, Cortez added, companies are building pipelines to shore to move product. Deep-water projects would likely require more collaboration between operators, she said. For the Zama project, oil will be transported via pipeline to the Dos Bascos onshore terminal, located about 70 km (43 miles) away. According to Pemex, the NOC signed contracts in January that include the development of 172 km (107 miles) of offshore pipelines.

Production rebound

This year Pemex has stated its primary goal for its E&P operations will be to stabilize production. Since 2006, when it produced about 3.2 MMbbl/d, production has steadily declined, down to 1.7 MMbbl/d so far this year. According to a study of Mexico’s oil and gas industry conducted by the Energy Policy Research Foundation Inc. (EPRINC), the oil sector’s direct contribution to Mexico’s GDP peaked at 10% in 1996-1997. Since then, that contribution has steadily declined to about 5%, according to EPRINC.

Not only has production declined, so have its reserves, a result of low levels of investment, EPRINC reported. According to its study, Mexico’s oil reserves peaked in the early 1980s with about 50 Bbbl. That amount has declined to less than 10 Bbbl.

However, Mexico’s regulatory policies have provided the opportunity for both onshore and offshore to be authorized much more rapidly. Pemex estimates that by 2024, daily crude production will ramp back up to nearly 3 MMbbl/d by 2024. And while recent shallow-water developments are likely to help turn declining production numbers around for the country, the real potential lies in its deep-water prospects.

“Mexico is rich with opportunity in its deep waters,” Cortez said. “This is also where numerous explorers will focus to meet contract commitments. Our yet-to-find estimates suggest that new deep-water exploration in the Perdido area could start to add meaningful production by the middle of the next decade. This could grow to half a million barrels of oil per day by the early 2030s. But gas infrastructure and project delivery could change that time line.” **E&P**

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Middle East Offshore Market Treads Recovery Path

By **Faiza Rizvi**, Associate Editor

International project agreements promise bright outlook for Middle East offshore operators.

Although offshore production was hit hard as uncertainty loomed over the oil and gas industry over the past few years, 2019 appears to be a silver lining for the Middle Eastern offshore market. Rystad Energy experts forecast global offshore spending to outgrow spending on onshore shale this year, adding that 30% of the year's offshore project value sits in the Middle East. According to Barclays Global 2019 E&P Spending Outlook, Middle East offshore spending is likely to increase by 8%, meaningfully outpacing 2018 levels.

"There are a number of major upcoming offshore upstream projects in the Middle East that will bring opportunities for the equipment and services sector," said Will Scargill, senior oil and gas analyst at GlobalData. "Abu Dhabi is planning new

projects such as the Ghasha sour gas development as well as expansions at its existing offshore oil producers. Saudi Arabia is also planning expansion at fields including Marjan, Berri and Zuluf, while Qatar will see offshore activity at its North Field expansion project."

Ahmed Kenawi, Halliburton's senior vice president, Middle East and North Africa, told *E&P*, "Increased offshore activity is expected to come from areas where we predict a substantial uptick in rig counts." He added that the United Arab Emirates (UAE) projects an increase of 6% to 8% offshore service activity using forecasted rig and workover barge count. "In offshore Egypt, gas reservoirs will continue to grow as service companies deliver new technologies to help operators increase production and bring new efficiencies to reduce their costs. Offshore activity will also increase in Oman, Bahrain and Saudi Arabia," he said.

Significant activity was reported in the first half of the year, which began with a spate of foreign project agreements sanctioned in the region. With international service companies deploying world-class technologies to execute complex projects, activities offshore Saudi Arabia, UAE, Qatar, Egypt and Israel were reportedly most active in the world's most prolific oil and gas region.

Saudi Arabia

In Saudi Arabia Aramco recorded a strong start to the year and awarded two offshore exploration engineering, procurement, construction and installation (EPCI) contracts worth \$1.3 billion to Saipem in the offshore fields of Berri and Marjan. In an interview with *E&P*, Massimiliano Bellotti,



The TP-18 platform is located in the Marjan Field offshore Saudi Arabia. The EPCI contract was awarded to McDermott by Aramco earlier this year for the upgrade of two existing platforms. (Source: McDermott)



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Saipem offshore manager for the Persian Gulf and Arabian Sea, said, “During the next three years, we expect a marked increase of projects within the offshore EPCI market, which is 50% higher compared to last year.”

Aramco also awarded two EPCI contracts to McDermott for development of the offshore Marjan Field, in line with McDermott’s strategic focus to strengthen in-Kingdom content. “This award is testament to Aramco’s confidence in McDermott’s ability to execute this complex type of project,” said Linh Austin, McDermott’s senior vice president of the Middle East and North Africa, in a press release.

Continuing its wave of international project agreements, Aramco finalized a six-year offshore agreement with TechnipFMC, in consortium with Malaysia Marine and Heavy Engineering. This agreement covers engineering, procurement, fabrication, transportation and installation for the development of Aramco’s offshore projects.

In March Khalid Al-Falih, the minister of Energy, Industry and Mineral Resources of Saudi Arabia, announced the discovery of massive natural gas reserves in the Red Sea, with plans to intensify exploration work during the next two years.

UAE

UAE holds the world’s seventh largest proven oil reserves, with the vast majority in Abu Dhabi. In a first of its kind, Abu Dhabi National Oil Co. awarded Eni and PTT Exploration and Production two offshore exploration blocks as part of Abu Dhabi’s first competitive open block licensing round. The concessions cover a combined area of more than 8,000 sq km (3,089 sq miles) in the Emirate’s northwest area and both companies will invest \$230 million for oil and gas exploration.

“Eni’s new licenses are part of a major growth strategy for the Middle East. It has significant development projects in Abu Dhabi, and the company is hoping that it will be able to quickly commercialize any discoveries made in its new exploration acreage to secure long-term growth,” GlobalData’s Scargill said.

Egypt

Following a spur of major offshore discoveries in the giant Zohr offshore gas field, which holds approxi-

mately 850 MMcm (30 Bcf) of gas, Egypt has been “witnessing keen interest of U.S. companies in its offshore exploration of oil and natural gas resources,” according to Petroleum Minister Tarek El Molla.

In February a supermajor consortium of Exxon Mobil, BP, Eni, Total, Shell and Petronas were awarded offshore exploration rights in the Mediterranean. In March Eni, in participation with Egyptian Natural Gas Holding Co., made a new gas discovery in the North Sinai Concession of the Eastern Egyptian Mediterranean. Eni is Egypt’s leading hydrocarbons producer by volume, producing more than 340,000 boe/d.

Moreover, the West Nile Delta project completed a milestone when DEA and operator BP commenced production from two gas fields, Giza and Fayoum. Gas is flowing ashore from the recently completed eight wells through new subsea infrastructure and pipelines.

Israel

In March Mediterranean-focused oil and gas producer Energean announced commencement of its 2019 drilling program offshore Israel, which consists of three development wells and Karish North. Energean plans to batch drill the top-hole sections of the wells, which will allow significant operational efficiencies and cost savings. Karish North will target 36.8 Bcm (1.3 Tcf) of gas and 16 MMbbl of liquids.

Recording a milestone earlier this year, Trendsetter completed the design and build of subsea production equipment for Noble Energy’s Leviathan project, a large natural gas field development in the Eastern Mediterranean Sea off the coast of Israel. The Leviathan Field, which was discovered in 2010, holds about 623 MMcm (22 Bcf) of gross recoverable resources and is one of the largest natural gas discoveries in the world. It is being developed using a subsea system that will connect production wells to a fixed platform located offshore with tie-in onshore in the northern part of Israel.

Other countries

While Bahrain, Turkey and Lebanon invested in offshore exploration activities, countries such as Qatar, Iran and Kuwait focused on increasing production capacity.

In Bahrain Eni signed a memorandum of understanding for petroleum exploration in a largely unexplored block. According to Reuters, Bahrain also plans development of an offshore oil and gas discovery it disclosed last year with U.S. oil companies because of their experience with low-permeability reservoirs.

In Turkey Exxon Mobil and Qatar Petroleum (QP) discovered significant natural gas offshore Cyprus. However, reports revealed that infrastructure and territorial issues could slow development of the gas find.

Lebanon's energy ministry also plans to step up its offshore exploration. A Total-led consortium will spud Lebanon's first offshore exploration well, which could prove transformational for the country. However, delay in forming the new Lebanese government has created obstacles for drilling and exploration.

According to Bloomberg, QP's four new liquefaction plants, known as "trains," which are expected to be completed by 2025, will increase gas-rich Qatar's LNG capacity from 77 million to 110 million tonnes per year.

In March Iranian President Hassan Rouhani formally inaugurated four new phases of South Pars, the world's largest gas field in the Persian Gulf, which it shares with Qatar. Iran has invested \$11 billion to complete the four phases, which will increase the country's gas production capacity by up to 110 MMcm/d (3.89 Bcf), according to a statement issued by the Iranian Oil Ministry on Twitter.

Kuwait Oil Co. is using EOR techniques for Lower Fars heavy oil field development, a commercial project that aims to produce 270,000 bbl/d by 2030. The advanced recovery techniques are expected to achieve both higher recovery rates and a longer production plateau. **ESP**

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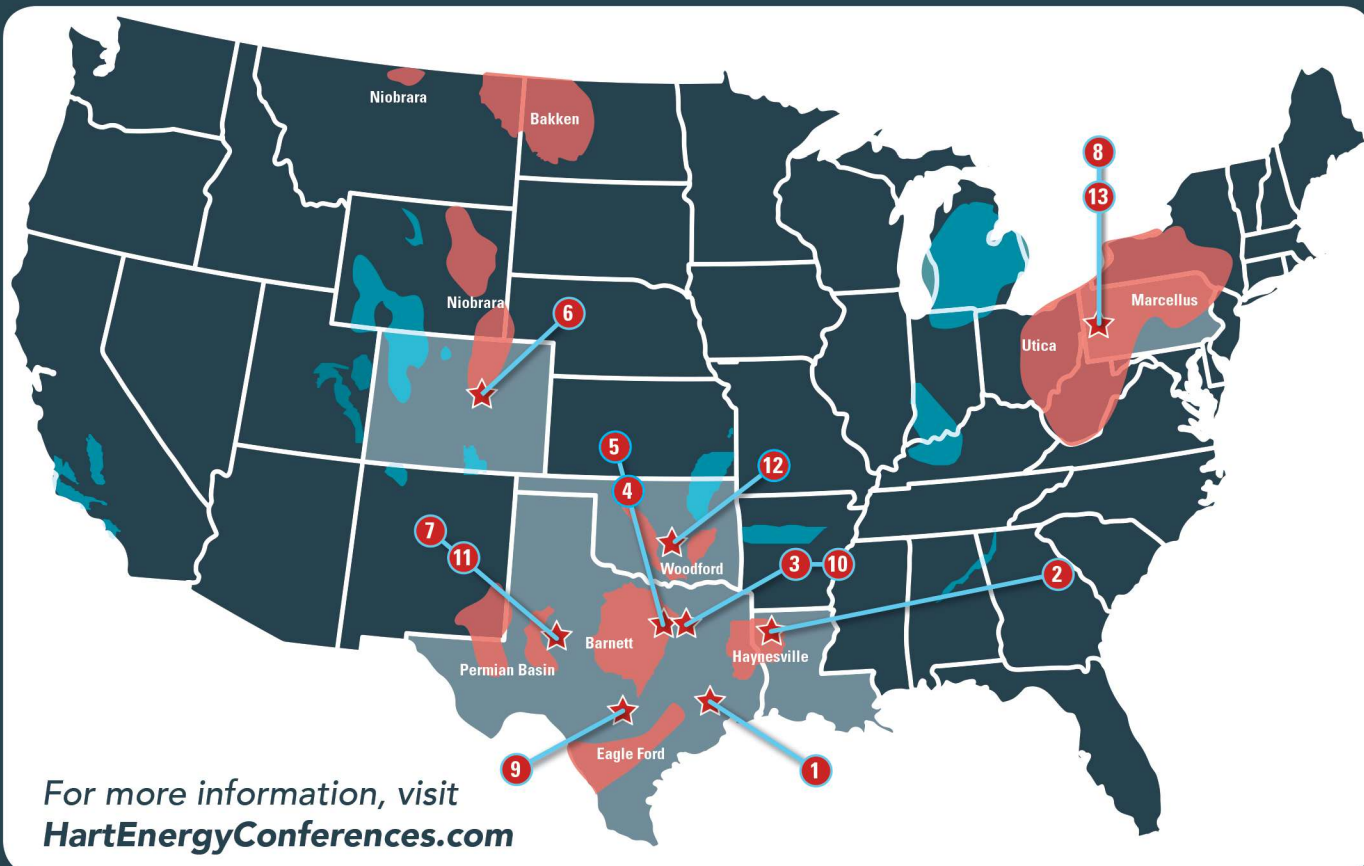
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Production at the *SeaRose* FPSO resumed operations at the end of January and will continue to ramp up through the second quarter as additional subsea drill centers are brought online. (Source: Husky Energy)

Operators Foresee Vast Potential

By **Ariana Hurtado**, Associate Managing Editor

These 25 offshore key players are increasing production and efficiencies.

New technologies, keen strategies and a sharpened focus keep offshore operators determined and decisive. Activity is picking up, and these key players are focused on increasing profits and production.

Offshore the U.K., the production forecast is looking more positive. “Development activity in the U.K. offshore sector is expected to improve after historical lows in the past few years,” according to a March 2019 GlobalData report. “There are 16 planned greenfield projects with identified development plans and 29 announced greenfield projects forecast to start production between 2019 and 2025. These are estimated to cost around \$6.7 billion and \$11.4 billion, respectively.”

In other areas, such as offshore Argentina, exploration is the main focus for operators. “Any big discovery in Argentina’s offshore frontier area will be a great prize for companies looking into building up a portfolio for future development. However, such long-term strategies will compete with a current preference for exploration in offshore areas with more seismic and well information available and where logistics to commercialize production is already known,” GlobalData said in a September 2018 report.

Moreover, E&P activity has heightened drastically in the Gulf of Mexico in the last year. Wood Mackenzie recently reported that 2019 “is shaping up to be a good one in the U.S. Gulf of Mexico, with the first increase in drilling in four years, first-ever production from a Jurassic play, key new project sanctions and an uptick in M&A [mergers and acquisitions] all in the cards.” Wood Mackenzie expects exploration activity to increase 30% this year. “Shell and Chevron will lead the way, but the actual growth in exploration will come from new entrants—Kosmos Energy, Equinor, Total, Murphy

and Fieldwood,” the report stated.

The following is a sampling of offshore operators, their recent production updates and strategies moving forward.

Editor’s Note: *These profiles were written based on fourth-quarter and year-end 2018 reports and 2018-2019 press releases. As of press time, first-quarter 2019 results had not been released.*

Aker BP ASA

Aker BP is the operator for Valhall, Ula, Ivar Aasen, Alvheim and Skarv offshore field centers. According to the company, it is one of the biggest independent listed oil and gas companies in Europe, measured by production. The company’s net production in 2018 was 155,700 boe/d, and total production volume was 56.8 MMboe. In the fourth quarter of 2018 production volumes increased due to improved efficiency and new wells, according to the company.

According to the company’s fourth-quarter 2018 report released on Feb. 6, “Aker BP continued its positive development and strong growth in 2018. Total income increased by 46% from 2017 and all major field development projects progressed as planned. Reserve replacement was above 100%, and the company continued to grow its resource base through acquisitions and exploration success.”

Aker BP has shown an increased interest in the Valhall Field. Fourth-quarter 2018 net production from the area was 39,600 boe/d, representing a 10% increase from the previous quarter, driven by the ramp-up of production from new wells and high production efficiency.
(Source: Aker BP)



In the development arena, Aker BP said Phase 1 of the Johan Sverdrup development project is progressing steadily toward planned production start in November 2019. “Johan Sverdrup is a major discovery and ranks among the five largest oil fields on the Norwegian Continental Shelf [NCS],” the company said on its website. “The development of the field will be one of the key industrial projects in Norway over the next 50 years.”

The company is an active explorer on the NCS. “In recent years about two-thirds of Aker BP’s exploration budget has been invested in the mature areas in the North Sea, where the infrastructure is good and the discovery rate is still high. The remaining resources have been invested primarily in the Barents Sea and in the more immature areas in the North Sea,” the company said.

Aker BP reported fourth-quarter 2018 production of 58,400 boe/d for the Alvheim area, 23,300 boe/d for Ivar Aasen, 23,500 boe/d for Skarv, 8,400 boe/d for the Ula area and 39,600 boe/d for the Valhall area, according to the report.

In the Alvheim area, the Skogul project is progressing according to plan and production start is scheduled for the first quarter of 2020, the report stated. In the first quarter of 2018, an oil discovery was made in the Frosk prospect near the Bøyla Field, and a new well was scheduled to be drilled in the first half of 2019. Aker BP will continue its exploration of the Frosk area this year.

In the Valhall area, drilling from the IP platform continued with the G22 well coming onstream during the fourth quarter of 2018. The G11 well was subsequently drilled and completed using the Fishbones technology in one section of the well. Test production began in February.

In the Ula area, development of the field is in its final stages. Drilling operations were completed in the fourth quarter last year. As of Feb. 6, Aker BP is performing the final preparations to start production, which is expected during the first half of the year, the report

stated. There is the possibility the company will add a new platform at Ula in mid-2020.

Additionally, “Aker BP considers the resource potential in the Ula area to be significant, both from increased oil recovery in the Ula and Tambar fields, from potential tiebacks of other discoveries including the newly acquired King Lear discovery, and from exploration opportunities,” according to the report.

In the Skarv area, production start for the Ærfugl development is planned for the fourth quarter of 2020.

Anadarko Petroleum Co.

Anadarko’s offshore operations are located in the Gulf of Mexico (GoM), offshore Ghana and Mozambique. “Anadarko operates the largest number of floating facilities in the deepwater Gulf of Mexico with additional exploration prospects, discoveries, large-scale developments and hub-and-spoke opportunities,” the company said on its website. “Anadarko is among the largest independent leaseholders and producers in the deepwater Gulf of Mexico, with expansive infrastructure that includes 10 operated deepwater facilities.”

Anadarko’s GoM sales volume averaged 142,000 boe/d in the fourth quarter of 2018, which included 120,000 bbl/d of oil. “The company’s leading infrastructure position continues to provide highly



Anadarko’s Horn Mountain development is located in 1,646 m (5,400 ft) of water and approximately 161 km (100 miles) southeast of New Orleans in the GoM. (Source: Anadarko Petroleum Co.)



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economic tieback opportunities, including new wells and developments at its 100%-owned Constellation, Horn Mountain, Holstein and Marlin platforms,” the company stated in its fourth-quarter 2018 results report released Feb. 5. “This year Anadarko plans to operate up to two drillships and two platform rigs and bring approximately 10 wells to sales in the areas near its Constellation, Holstein, Horn Mountain, K2, Lucius and North Hadrian producing assets.”

Anadarko also holds interest in deepwater exploration blocks in the GoM, South America and South Africa. It also is working to develop one of the world’s largest natural gas accumulations offshore Mozambique. Anadarko expects to make a final investment decision on the Mozambique LNG project in the first half of this year.

On April 12 Chevron Corp. entered into a definitive agreement with Anadarko Petroleum Corp. to acquire all of the outstanding shares of Anadarko. The total enterprise value of the transaction is \$50 billion, according to a press release. The transaction is expected to close in the second half of the year.

BHP

BHP, formerly known as BHP Billiton, has operating assets in the Shenzi, Neptune, Atlantis and Mad Dog fields in the Gulf of Mexico (GoM) as well as

in several fields offshore Australia. Other offshore production operations are located in the Greater Angostura Field offshore Trinidad and Tobago.

Petroleum exploration expenditure for the second half of 2018 was \$316 million, and activity for the period was largely focused in the GoM and Trinidad and Tobago, according to BHP’s second-half 2018 results report released Feb. 19. This year a \$750 million exploration and appraisal program is being executed.

In the U.S. GoM, “Samurai-2 and Samurai-2 ST01 drilling has delineated the accumulation of oil,” the report stated. “Further appraisal and development planning at Samurai is in progress. In the southern portion of the Wildling sub-basin, we continue to assess the potential resource, with further appraisal drilling now expected in the 2020 financial year.”

In the Western U.S. GoM, an ocean-bottom node seismic acquisition was completed in early January 2019 and processed data are expected to be delivered during March 2020. “This is the world’s first deepwater exploration ocean-bottom node seismic acquisition,” according to the company.

In addition, BHP spudded the Trion-2DEL appraisal well in the GoM in November 2018 and encountered oil in line with expectations. “This was followed by a planned downdip geologic sidetrack, which encountered oil and water, as predicted, further appraising the field and delineating the resource,” the report stated. “Following the recent encouraging results in the Trion Block, an additional appraisal well (3DEL) to further delineate the scale and characterization of the resource is expected to be drilled in the second half of 2019.”

Looking ahead, other major projects include the development of the Atlantis Phase 3 project in the deepwater GoM.

Offshore Trinidad and Tobago, the company encountered hydrocarbons at the Bongos-2 exploration well in the first half of 2019, and Phase 3 of BHP’s deepwater exploration drilling campaign will start in the second half of the year, according to the report. Phase 3 will test three wells on three prospects in the northern license area.

Offshore Eastern Canada, BHP was the successful bidder in October 2018 for licenses in the

BHP operates the Shenzi Field in the GoM with 44% interest. (Source: BHP)



Orphan Basin, and the company has begun working with the Canada-Newfoundland and Labrador Offshore Petroleum Board to meet all regulatory requirements for the exploration phase. The licenses became effective in January.

BP

BP has offshore operations and development projects in the Gulf of Mexico (GoM) and offshore Trinidad and Tobago, the U.K., Egypt and Australia.

As of February, BP had already completed three major upstream project startups this year: Constellation in the U.S. GoM, the second stage of the West Nile Delta development offshore Egypt and gas production at Angelin offshore Trinidad.

In the last few years, BP has been very active in West Africa, accessing about 80,000 sq km (30,888 sq miles) of acreage with resource potential of 8 Bboe.

“In drilling, over 70% of our offshore wells are now top quartile—from 25% just five years ago. And during the same period, our percentage of non-productive time for completions has reduced by around 30%,” Bernard Looney, BP’s Upstream chief executive, said during an investor day presentation in December 2018. “Mad Dog 2 [in the GoM] is a great example of our drilling performance. ...Three of our last four wells are the best ever drilled.”

Over the next few years, the company plans on wrapping up construction projects for Angelin offshore Trinidad, Constellation in the GoM, Culzean in the North Sea and West Nile Delta-Raven offshore Egypt this year; the KG D6 R-Series in the Bay of Bengal, Alligin and Vorlich in the North Sea, and Zinia 2 offshore Angola in 2020; and Mad Dog Phase 2 in the GoM, KG D6 Satellites and Manuel in the GoM in 2021.

In addition, the company has had a strong focus on improving efficiencies via new technology developments and upgrades. “In Trinidad we are using the latest digital modeling technology—think 3-D visualization of our offshore facilities. This allows us to complete detailed activity planning on our normally unmanned installations without having to go offshore, improving safety through reduced visits and saving \$450,000 so far,” Looney said.

“In the Gulf of Mexico, our project teams have been using our latest agile ways of working and challenging themselves to bring our new subsea tiebacks online quicker. They are making good progress with seven tiebacks either in execute or operate with an average 10-month improvement in cycle time.”

He also noted that the application of seismic techniques, like ocean-bottom nodes, full waveform inversion and new ways of working at Thunder Horse, has unlocked an additional 1 Bbbl of oil in place (gross). “We now see the potential for the GoM to run at around 400,000 barrels of oil equivalent per day through the middle of the next decade,” he said.

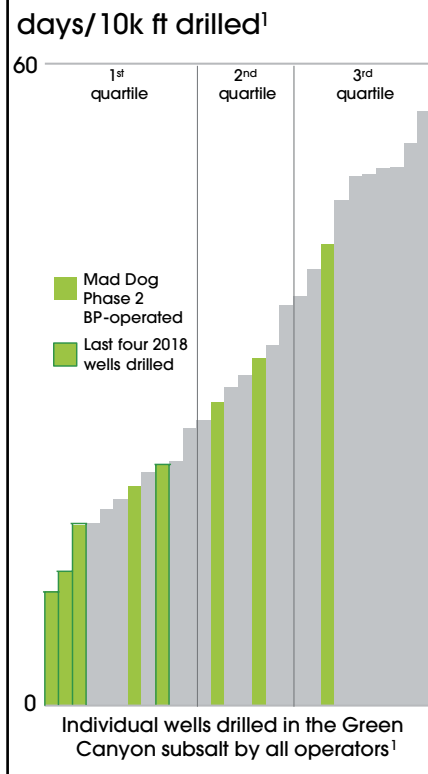
Chevron Corp.

Chevron, through its subsidiaries and affiliates, has offshore projects located in the deepwater U.S. Gulf of Mexico (GoM) as well as offshore Western Australia, New Zealand, South America, the U.K., West Africa and in the Gulf of Thailand.

During 2018, net daily production in the GoM averaged 186,000 bbl of crude oil, 3.3 MMcm (117 MMcf) of natural gas and 13,000 bbl of NGL, according to the company’s 2018 annual report supplement. As of early 2019, Chevron has an interest in 218 leases in the GoM. At year-end 2018, the company was the second largest leaseholder in the GoM.

Chevron’s signature deepwater project in the GoM is Jack/St. Malo, which is located about 451 km (280 miles) south of New Orleans. The project’s development phases progressed in 2018; Stage 2 was accomplished with all four wells on production and Stage 3 advanced, as two of the three planned

MAD DOG PHASE 2 DRILLING PERFORMANCE



The chart above shows how many days it has taken to drill 3,048 m (10,000 ft) for wells drilled in Green Canyon by all operators. The green bars represent BP. Three of BP’s last four wells are the best ever drilled, according to the company. (Source: BP Upstream and IHS Rushmore)

wells were completed. Stage 4 includes water injection at the St. Malo Field and is expected to reach a final investment decision in the third quarter of 2019. Total daily production from the Jack and St. Malo fields averaged 139,000 bbl of liquids (71,000 net) and 594,654 cu. m (21 MMcf) of natural gas (11 million net) last year, according to the 2018 annual report supplement.

Also in the GoM, the Chevron-operated Big Foot deepwater project, located 362 km (225 miles) south of New Orleans, achieved first oil in November 2018 with ramp-up expected to continue during 2019. The field is estimated to contain total recoverable resources in excess of 200 MMboe, according to the company.

At the Tahiti Field, 2018 net daily production averaged 51,000 bbl of crude oil, 622,971 cu. m (22 MMcf) of natural gas and 3,000 bbl of NGL. The Tahiti Vertical Expansion Project is developing shallower reservoirs and achieved first oil from three wells in June 2018, and the fourth well was scheduled to come online in the second quarter of 2019.

Chevron also operates the Anchor Field located in the Green Canyon area off the coast of Louisiana. FEED activities commenced in 2018. The planned

facility has a design capacity of 75,000 bbl/d of crude oil and 792,872 cu. m/d (28 MMcf/d) of natural gas, according to the 2018 annual report supplement. The total potentially recoverable oil-equivalent resources for Anchor are estimated to exceed 450 MMbbl.

In January 2018, Chevron announced a significant oil discovery at the Ballymore prospect in the Mississippi Canyon area in the deepwater GoM. The initial Ballymore well reached total measured depth of 8,898 m (29,194 ft) and encountered more than 204 m (670 ft) net oil pay with excellent reservoir and fluid characteristics, according to the company.

Offshore Western Australia, the Jansz-Io gas field is part of the Chevron-operated Gorgon project. In March 2019, Chevron contracted Aker Solutions to support delivery of a subsea compression system for the Jansz-Io with the aim of recovering gas more cost-effectively and with a smaller environmental footprint, according to news reports.

Jeff Schmoll, Chevron Australia's general manager for major capital projects, said in March that "the Jansz-Io compression project will prolong the life of Gorgon's Jansz-Io fields and was part of the

The Chevron-operated Big Foot deepwater project, located in the U.S. GoM, started crude oil and natural gas production in November 2018. (Source: Chevron)





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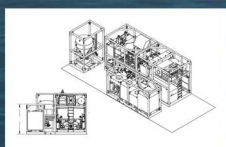
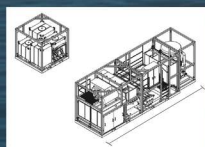
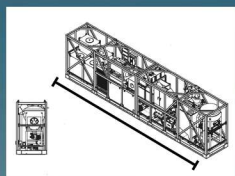
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original development plan for the project,” according to a *miningweekly.com* report.

Offshore Brazil, Chevron won six deepwater blocks in the presalt trend within the Campos and Santos basins in 2018. The six new blocks in the Brazil presalt cover 470,000 net acres.

On April 12 Chevron Corp. entered into a definitive agreement with Anadarko Petroleum Corp. to acquire all of the outstanding shares of Anadarko. The total enterprise value of the transaction is \$50 billion, according to a press release. The transaction is expected to close in the second half of the year.

CNOOC Ltd.

CNOOC Ltd. has offshore operations worldwide. The company holds a 100% interest in two exploration blocks offshore Newfoundland, Canada.

The company also owns interests in two major deepwater development projects, Stampede and Appomattox, and a number of other exploration blocks in the U.S. Gulf of Mexico (GoM) through its wholly owned subsidiary, Nexen Energy ULC, according to CNOOC Ltd.’s website. Among these, Stampede commenced production in February 2018.

Offshore Mexico, the company owns a 100% interest in deepwater exploration Block 1 and Block 4 of the Cinturón Plegado Perdido.

In addition, CNOOC Ltd. holds a 25% interest in the Stabroek Block offshore Guyana. Twelve exploration discoveries have been made in the block. The Liza oilfield Phase 1 construction was in good progress and is scheduled to commence production in 2020, the company reported in early April. The field development proposal design of Liza oilfield Phase 2 was completed and pending government approval as of early April. The final investment decision is planned to be made this year. In 2018 the Liza reservoir in the block was further successfully appraised. Five new successful discoveries, Ranger, Pacora, Longtail, Hammerhead and Pluma, were made and have further expanded the scale of reserve, according to the company’s 2018 annual report.

Offshore Brazil, the company also holds a 10% interest in the Libra deepwater presalt project, a 100% interest in Block 592 and a 20% interest in the Alto de Cabo Frio Oeste Block. Additionally, a 30%

interest in the Pau Brasil Block was obtained by the company in 2018.

Near West Africa, CNOOC Ltd. owns a 45% interest in the OML130 Block offshore Nigeria, and in 2017 the company obtained a 65% operating interest in the AGC Profond Block offshore Senegal and Guinea-Bissau.

In the Norwegian Sea, the company holds a license issued by the government of Iceland for undertaking oil exploration operations northeast of the country.

CNOOC Ltd. also holds several frontier exploration licenses offshore Ireland.

In the North Sea, the company’s asset portfolio includes projects under production, development and exploration, mainly including a 43.2% interest in the Buzzard oil field and a 36.5% interest in the Golden Eagle oil field. These make the company the largest crude oil operator in the North Sea, according to CNOOC Ltd.’s 2018 annual report. The U.K. is one of CNOOC Ltd.’s key overseas development areas, with projects such as Buzzard and Golden Eagle substantially contributing to the company’s production.

Earlier this year, CNOOC Ltd. announced a new discovery on the Glengorm prospect offshore the U.K. Central North Sea, a January press release stated.

The Eastern South China Sea is the company’s other important crude oil producing area. As of year-end 2018, reserves and daily production volume in the Eastern South China Sea reached 599.2 MMboe and 216,877 boe/d, respectively, representing approximately 13.1% of the company’s total reserves and 17.4% of its daily production, according to the company’s 2018 annual report.

The Western South China Sea is one of the company’s most important natural gas production areas. As of year-end 2018, the reserves and daily production volume in the Western South China Sea reached 845.8 MMboe and 154,248 boe/d, respectively, representing about 18.4% of the company’s total reserves and 12.4% of its daily production. The Weizhou 6-13 oil field commenced production during 2018. In addition, the Wenchang 13-2 oil-field comprehensive adjustment project is expected to start production this year.

Looking ahead, six new projects are expected to come onstream in 2019. The Egina Field offshore



Buzzard is the highest producing field offshore the U.K.
(Source: CNOOC)

Nigeria; the Huizhou 32-5 Field comprehensive adjustment and Huizhou 33-1 Field joint development project offshore China; the Appomattox project in the U.S. GoM; and the Bozhong 34-9 Field, the Caofeidian 11-1/11-6 comprehensive adjustment project and the Wenchang 13-2 comprehensive adjustment project offshore China are all scheduled to begin production this year, according to CNOOC Ltd.'s "2019 Business Strategy and Development Plan" press release. CNOOC Ltd. also plans to drill 173 exploration wells and acquire approximately 28,000 sq km (10,811 sq miles) of 3-D seismic data this year.

ConocoPhillips

Upstream company ConocoPhillips has offshore operations located in the North Sea and offshore China, Indonesia and Malaysia as well as nonoperated assets in several offshore areas worldwide.

ConocoPhillips has significant developments offshore the U.K. in the North Sea and Norwegian Sea. Operated assets in Europe include the Greater Britannia and J-Area fields in the U.K. and the Greater Ekofisk Area in Norway.

"The company has leveraged its existing operations, infrastructure and basin expertise to create

incremental growth projects in recent years, and development opportunities still exist in ConocoPhillips' legacy areas in the North Sea," according to the company's website. "Production from the Southern North Sea in the U.K. ceased in 2018, and the focus of activity has now changed to decommissioning."

During the fourth quarter of 2018, the company achieved first production from the Aasta Hansteen project in the Norwegian Sea and the Clair Ridge project west of the Shetland Islands, according to the company's fourth-quarter and full-year 2018 results report.

ConocoPhillips also produces from fields in Bohai Bay offshore China. Block 11/05 in the Bohai Sea contains the Penglai 19-3, 19-9 and 25-6 oil fields, in which ConocoPhillips has 49% interest and CNOOC (the operator) has 51% interest. The project had 36 wells completed and online as of year-end 2018. According to a March 2019 company fact sheet, the Penglai 25-6 Phase 4A project was sanctioned by ConocoPhillips in 2018, and this project consists of one new wellhead platform that could add up to 62 wells. First production from Phase 4A is expected in 2021. Additional appraisal drilling and development studies are underway to assess further Penglai development opportunities.

A full-field 3-D seismic program at Penglai continued in 2018 and is expected to be completed in 2019. The production periods for Penglai 19-9, 19-3 and 25-6 end in 2027, 2037 and 2045, respectively. ConocoPhillips reported 2018 average net production of 30,000 bbl/d of crude oil and 30,000 boe/d in Penglai.

In the South China Sea, one ILX well in the CNOOC-operated Panyu 4-1 area will be drilled prior to April 2020. The production period for the Panyu 4-1 area is 15 years upon commencement of commercial production, the fact sheet stated. ConocoPhillips has 49% interest in Panyu 4-1.

In Malaysia, ConocoPhillips holds 2.2 million net acres across six blocks in varying stages of exploration, development and production. Three of these blocks are located off the eastern Malaysian state of Sabah: Block G, Block J and the Kebabangan Cluster (KBBC). Three other blocks, Block SK304, Block SK313 and Block WL4-00, are operated by ConocoPhillips and are located off the eastern Malaysian state of Sarawak. Production growth continues from several fields in Block G, Block J and the KBBC.

Offshore Australia, ConocoPhillips is the operator (with 56.9% interest) of the Bayu-Undan Field in the Timor Sea. Last year the final development phase at Bayu-Undan was completed. ConocoPhillips reported 2018 average net production of 4,000 bbl/d of crude oil, 3,000 bbl/d of NGL, 6.7 MMcm/d (240 MMcf/d) of natural gas and 47,000 boe/d in Bayu-Undan, according to the company fact sheet.

ConocoPhillips also has E&P activities offshore Indonesia.

Eni

Eni's primary offshore operations are located off the coast of Africa, Indonesia, Mexico and Norway, though the company has interests in other offshore areas.

Offshore Algeria, Eni, Sonatrach and Total signed two agreements that include an exclusive partnership for offshore exploration in Algeria in a virtually unexplored geological province.

In Egypt, Eni operates through its subsidiary leoc. In March the company announced a new gas discovery in the Nour prospect in the Eastern

Egyptian Mediterranean offshore Egypt, a press release stated. Eni is the operator (40% stake), with BP (25%), Mubadala Petroleum (20%) and Tharwa Petroleum Co. (15%).

Throughout 2018 and again in March of this year, Eni announced several new oil discoveries offshore Angola. "Agogo is the third discovery of commercial nature since the Block 15/06 Consortium decided to launch a new exploration campaign in 2018, leading to the discoveries of Kalimba and Afoxé," according to a March 2019 press release. "The [latest] discovery opens new opportunities for oil exploration below salt diapirs in the northwest part of the prolific Block 15/06, thus creating new chances for unlocking additional potential value."

Eni is the operator of Block 15/06 (36.8% interest), along with partners Sonangol P&P (36.8%) and SSI Fifteen Ltd. (26.3%). According to the release, the companies plan on appraising the discovery and starting the studies to fast track the block's development.

Offshore Ghana, Eni started gas production in July 2018 from the Sankofa Field in the Offshore Cape Three Points Integrated Oil and Gas Project. "The field will provide 180 million standard cubic feet per day [5.1 MMcm/d] for at least 15 years, enough to convert to gas half of Ghana's power generation capacity," a press release stated.

In December 2018, Eni announced a Merakes East gas discovery in the East Sepinggan Block offshore Indonesia, a press release stated. Eni is the operator of the East Sepinggan contract area through its subsidiary Eni East Sepinggan Ltd. (85% interest) with PT Pertamina Hulu Energi East Sepinggan (15%).

Offshore Mexico, Eni's wholly owned subsidiary Eni Mexico S. de R. L. de C. V. holds rights in six E&P blocks in the Sureste Basin, all as the operator. In October 2018, Eni signed a participating interest swap with Lukoil whereby Eni gave Lukoil a 20% stake in both the production-sharing contracts (PSC) for blocks 10 and 14, and at the same time acquired a 40% stake in Lukoil's PSC for Block 12.

In October 2018, Eni announced a new oil discovery in the western Barents Sea offshore Norway. Equinor is the operator in the Skruis Prospect in PL 532 (50% interest), along with Eni (30%) and Petoro

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(20%). “The well will be permanently plugged and abandoned after an extensive data collection and sampling program,” a press release stated. “The Skruis discovery is part of Eni’s near-field exploration strategy that, in case of success, allows the exploitation of these thanks to the synergies with future infrastructures.”

Equinor

In addition to its name change of Statoil to Equinor in May 2018, the Norwegian multinational energy company has had quite an eventful 2018 and 2019.

In April 2018, in partnership with Total, the company acquired Cobalt International Energy’s 60% operated interest in the North Platte discovery in the U.S. Gulf of Mexico for \$339 million.

In Brazil, Equinor has interests in the BM-S-8 and Carcará North in the presalt area of the Santos Basin as well as in the BM-C-33 in the Campos Basin, containing the Pão de Açúcar discovery. In June 2018, Equinor deepened its position in Brazil’s presalt area with 28% interest in the Uirapuru production-sharing contract in the Santos Basin.

In March 2018, the company acquired 50% interest in two offshore wind development projects offshore Poland.

On the Norwegian Continental Shelf (NCS), Equinor was awarded 31 new exploration licenses early last year.

In November 2018, Equinor began construction of the *Johan Castberg* vessel at Kværner’s yard at Stord. “*Johan Castberg* is the next major development on the Norwegian Continental Shelf and will

open a new area in the Barents Sea for Equinor. *Johan Castberg*’s development will have ripple effects equivalent to 47,000 man-years in Norway during the development phase,” said Anders Opedal, Equinor’s executive vice president for technology, projects and drilling, in a press release.

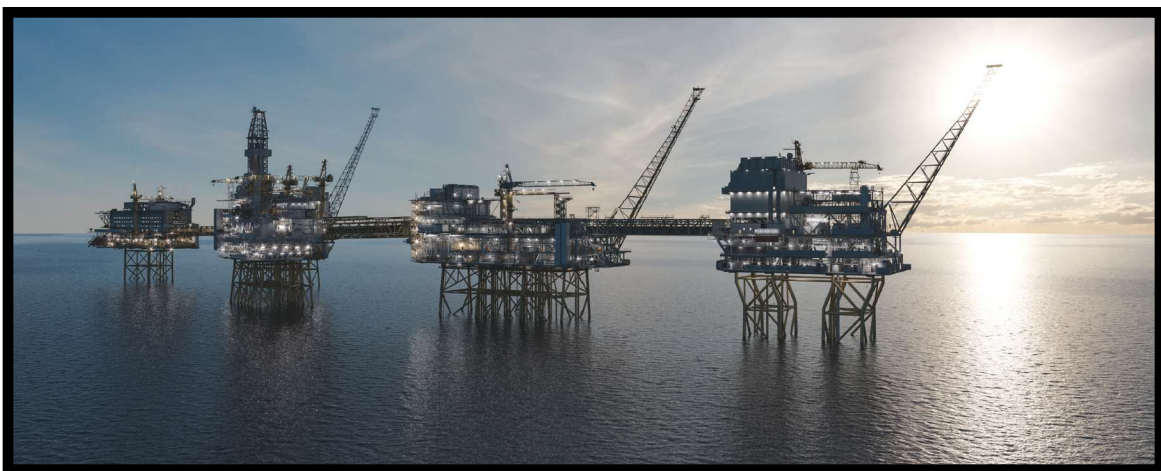
In December 2018, Equinor (operator) and partners began production at the deepwater Aasta Hansteen Field on the NCS. The Aasta Hansteen is the first deepwater development on the NCS and the world’s largest single-point articulated riser platform, according to a press release.

Earlier this year, Equinor and its partners, Petoro, Exxon Mobil and Total, have proven gas and condensate in the Norwegian Sea Ragnfrid North (6406/2-9 S) exploration well. Recoverable resources are estimated at 6 MMboe to 25 MMboe, a January press release stated.

In March Equinor received approval for extending the life of eight installations on the NCS: Gullfaks A, B and C (2036), Oseberg East (2031), Snorre A and B (2040), Norne (2036) and Åsgard A (2030), a press release stated. Equinor plans to extend the life of more than 20 NCS installations in total and expects to apply for extending the life of all older and relevant installations by 2031.

The company also has been busy offshore the U.K. In March 2018, the company became the operator of the Martin Linge Field and Garatiana discovery in the North Sea. Then in the second half of 2018, Equinor acquired a 40% operator share in the Rosebank project on the U.K. Continental Shelf from Chevron. Other partners in the field are Suncor Energy (40%)

Equinor is the operator of the Johan Sverdrup Field with partners Lundin Norway, Petoro, Aker BP and Total. Phase 2 development began in December 2018. (Source: Equinor)



and Siccar Point Energy (20%). This “agreement allows [Equinor] to buy back into an asset in which we previously had a participating interest, demonstrating our strategy of creating value through oil price cycles,” said Al Cook, Equinor’s executive vice president for global strategy and business development and U.K. country manager, in a press release.

In October 2018, the company started production at the Oseberg Vestflanken 2 Field in the North Sea. “Remote-operated from the Oseberg field center, the new Oseberg H platform is the first unmanned platform on the Norwegian Continental Shelf,” according to a press release.

In addition, in March of this year, Equinor (operator) and its partners, Petoro, ConocoPhillips and Repsol, made an oil discovery from the Visund A platform in the Telesto exploration well in the North Sea. The resources are estimated at 12 MMbbl to 28 MMbbl of recoverable oil, a press release stated.

Exxon Mobil

Exxon Mobil explores and operates in offshore areas worldwide.

In February Exxon Mobil made two additional discoveries offshore Guyana at the Tilapia-1 and Haimara-1 wells, bringing the total number of discoveries on the Stabroek Block to 12, a company press release stated. The estimated gross recoverable resource from the Stabroek Block is about 5.5 Bboe. Exxon Mobil affiliate Esso Exploration and Production Guyana Ltd. is the operator (45% interest) in the Stabroek Block with Hess Guyana Exploration Ltd. (30%) and CNOOC Petroleum Guyana Ltd. (25%). According to the release, there is potential for at least five FPSO vessels on the Stabroek Block to produce more than 750,000 bbl/d of oil by 2025.

Additionally, the Liza Phase 1 development offshore Guyana is progressing on schedule and is expected to begin producing up to 120,000 bbl/d of oil in early 2020, utilizing the *Liza Destiny* FPSO. Liza Phase 2 is expected to start up by mid-2022.

Last year Exxon Mobil increased its holdings in Brazil’s presalt basins after it won the Uirapuru exploration block with co-venturers Equinor and

Petrogal Brasil during Brazil’s fourth presalt bid round, the Titã exploration block with co-venturer Qatar Petroleum during Brazil’s fifth presalt bid round, and eight additional exploration blocks during Brazil’s 15th bid round, according to company press releases.

In addition, in June 2018, Exxon Mobil completed the purchase of half of Equinor’s interest in the BM-S-8 Block offshore Brazil, which contains part of the 2-Bbbl presalt Carcara oil field.

Last year Exxon Mobil added 1.3 Bboe to its resource base, which included additions from new discoveries and strategic acquisitions, mainly in Guyana and Brazil, according to a March 2019 press release.

In addition, in February of this year, Exxon Mobil Exploration and Production Cyprus (Offshore) Ltd. made a natural gas discovery offshore Cyprus in the Eastern Mediterranean at the Glauco-1 well. Further evaluation of Block 10 potential continues. Exxon Mobil is the operator (60% interest) in the block with Qatar Petroleum International Upstream O.P.C. (40%).

Hess Corp.

Hess is the sixth largest gross operated deepwater producer in the Gulf of Mexico (GoM). The company also has offshore assets in Europe, the Asia-Pacific and South America.

In the Stampede Field in the GoM, production started and first oil was achieved in January 2018. Production was scheduled to ramp up over the following 18 months. Hess is the operator (25% interest) in the field with co-venture owners Union Oil Co. (25%), CNOOC (25%) and Equinor (25%).

According to the company’s fourth-quarter 2018 results report, net production from the GoM was 68,000 boe/d, compared to 40,000 boe/d in the prior-year quarter.

In Nova Scotia, where BP Canada is the operator, Hess has 50% interest. The operator completed drilling of the Aspy exploration well in 2018 and is currently evaluating the data from the well, according to the fourth-quarter 2018 report.

In addition, Hess has a 50% working interest and is operator of the North Malay Basin natural

Hess Corp.'s North Malay Basin is a long-life natural gas asset with gross recoverable resources of more than 42.4 Bcm (1.5 Tcf) of natural gas and more than 20 MMbbl of condensate—enough energy to power a city like Kuala Lumpur for more than 30 years. (Source: Hess Corp.)

gas asset, which includes nine discovered natural gas fields adjacent to the company's existing interest in the Joint Development Area (JDA) between Malaysia and Thailand, operated by a joint venture called Carigali Hess. Petronas Carigali holds the remaining 50% of the North Malay Basin and also is Hess' partner in the JDA.

Earlier this year, Hess announced positive results from the Tilapia-1 and Haimara-1 wells offshore Guyana, bringing the total number of discoveries on the Stabroek Block to 12, a Feb. 6 press release stated. Esso Exploration and Production Guyana Ltd. is the operator (45% interest) in the Stabroek Block with Hess Guyana Exploration Ltd. (30%) and CNOOC Petroleum Guyana Ltd. (25%).

Hess reported year-end 2018 offshore net production of 41,000 bbl of crude oil, 5,000 bbl of NGL and 1,897 cu. m (67,000 cf) of natural gas, according to the company's report.

a subsea production system, subsea pipeline transportation and onshore gas-processing infrastructure. Husky holds 49% interest and operates the deepwater infrastructure while partner CNOOC Ltd. operates the shallow-water facilities. In addition, construction is underway at the third deepwater field, Liuhua 29-1, in which Husky holds 75% interest. A gas sales agreement is in place, with first production expected around year-end 2020, the company stated on its website.

Moreover, in the northern part of the South China Sea, Husky has production-sharing contracts in place for two exploration blocks, 15/33 and 16/25, in the Pearl River Mouth Basin.

Offshore Indonesia, Husky is advancing gas projects in the Madura Strait. These projects include the liquids-rich BD Project as well as the shallow-water MDA-MBH and MDK fields, which are being developed in tandem, with first gas anticipated in 2020, the company stated on its website. Husky holds 40% interest in these fields, which are being developed in partnership with operator CNOOC and an affiliate of Samudra Energy Ltd. Additional natural gas discoveries in the Madura Strait are being evaluated for commercial development.

Offshore Newfoundland and Labrador, Husky's focus is in the Jeanne d'Arc Basin and Flemish Pass Basin, where the company and its partner have made recent discoveries.

First oil at the West White Rose Project is expected in 2022. Two additional infill wells at the



Husky Energy

Husky Energy has operations and exploration prospects offshore China and Indonesia as well as offshore Newfoundland and Labrador. Husky reported offshore average production of 64,200 boe/d in its 2018 fourth-quarter and annual results report.

According to the company, the Liwan Gas Project was the first deepwater gas project offshore China. The Liwan 3-1 and Liuhua 34-2 fields share



Husky Energy's Liwan Gas Project was the first deepwater gas project offshore China. (Source: Husky Energy)

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White Rose Field are expected to be brought online before mid-year 2019.

Production at the *SeaRose* FPSO was suspended in November 2018 following an oil release from a flowline connector in the South White Rose Extension Drill Centre. Production at the *SeaRose* FPSO resumed operations at the end of January 2019 and will continue to ramp up through the second quarter as additional subsea drill centers are brought online, according to Husky's 2018 fourth-quarter and annual results report.

In the Flemish Pass Basin, Husky and its partner have made discoveries at Mizzen, Harpoon, Bay du Nord and Baccalieu. Husky holds a 35% working interest.

LLOG Exploration Offshore LLC

LLOG Exploration's activity is focused in the Gulf of Mexico (GoM). From January 2017 to January 2019, the privately owned E&P company boasts it made six of the 15 exploration discoveries in the deepwater GoM.

The majority of the company's activity is located in the Mississippi Canyon. LLOG operates two floating production systems in this area—Who Dat and Delta House. Production activity where LLOG is the operator with 100% interest takes place in Block 705. In addition, the company has production activity in Block 707 (100% interest), Block 751 (100%), Block 503 (50.25%), Block 547 (50.25%), Block 199 (50%), Block 208 (52.3%), Block 252 (52.3%), Block 209 (52.3%), Block 253 (52.3%), Block 301 (69.62%) and Block 79 (70%), among others.

LLOG also has leasehold interests in additional blocks across the Mississippi Canyon as well as development activity in Block 816 (operator with 100% interest), Block 74 (18%) and Block 609 (28.5%). Sea-drill's *West Neptune* drillship is currently completing exploration and development operations for LLOG in the Mississippi Canyon.

In a January operational update, the company announced it drilled a successful discovery on its exploratory prospect, Nearly Headless Nick, in Mississippi Canyon Block 387, and it is expected to be tied back to the nearby LLOG-operated Delta House facility in Mississippi Canyon Block 254.

Five of LLOG's GoM deepwater discoveries (eight wells) were placed on production in 2018, according to the January 2019 update. Nine wells, which include four development wells at Who Dat, Mandy and Red Zinger and five wells from three new fields, Stonefly, Buckskin and Nearly Headless Nick, are expected to be brought online this year.

The company also is operator with 100% interest in blocks 644, 687, 688 and 731 in the Alaminos Canyon. LLOG also has production activity in the South Timbalier area in blocks 231 and 232 with 75% interest each.

In the Keathley Canyon area, the company has development activity with 51.15% interest in Block 736 and 33.8% interest in blocks 785, 828, 829, 830, 871 and 872.

LLOG's production activity in the Green Canyon is located in Block 141 with 45% interest and blocks 157 and 201 with 85% interest each. The company has development activity in Green Canyon blocks 345, 389, 390, 434 and 478 with 34% interest each.



The LLOG-operated Delta House floating production system is located in the Mississippi Canyon. (Source: LLOG Exploration Offshore LLC)

LLOG also has leasehold interests in Green Canyon Block 154 (46.2% interest), Block 242 (47.5%), Block 472 (70%), Block 516 (70%), Block 728 (70%), Block 816 (70%), Block 987 (53.8%) and Block 955 (50%), among others.

In the Walker Ridge area of the GoM, LLOG has development activity in Block 95 with 27.1% interest as well as leasehold interests in Block 149 (70% interest), Block 21 (23.1%), Block 23 (90%), Block 28 (47.5%) and Block 72 (47.5%).

Lundin Petroleum AB

Lundin Petroleum's operations are focused offshore Norway. The independent E&P company has interests in the Alvheim and Utsira High areas and in the Southern Barents Sea, Norwegian Sea and North Sea.

Lundin Petroleum's 2019 production guidance is between 75,000 boe/d and 95,000 boe/d, according to the company's website. Production for 2018 amounted to 81,100 boe/d, and the production from Edvard Grieg represented about 75% of that production.

President and CEO Alex Schneider said in the company's year-end 2018 report, "The 2018 exploration and appraisal campaign was one of our busiest, and we enjoyed significant success with new discoveries made near our core areas on the Utsira High and the Alvheim area. We matured our appraisal opportunities further toward development and now have seven potential new projects in the pipeline."

Lundin Petroleum recently completed several development projects in Norway, but the company said development of the Johan Sverdrup project is its main focus in the near term. Phase 1 is scheduled to come onstream in November of this year and expected to reach a gross production rate of up to 440,000 bbl/d of oil. Phase 2 is expected to begin production in the fourth quarter of 2022.

"Our production is set to double when the large Johan Sverdrup Field in the North Sea starts production in late 2019," according to the company's website.

In January Lundin Petroleum's wholly owned subsidiary, Lundin Norway AS, entered into an

agreement with Lime Petroleum AS to acquire its entire Utsira High acreage position covering the Rolvsnes and Goddo basement area, a press release stated. The acquisition takes Lundin Norway's working interest in the Rolvsnes oil discovery in PL338C and in the recently awarded, adjacent PL338E1 from 50% to 80% and the Goddo prospect in PL815 from 40% to 60%. An extended well test will be conducted at Rolvsnes in 2021, and an exploration well will be drilled in the Goddo area this year. The combined gross resource potential of the Rolvsnes and Goddo area is more than 250 MMboe, according to the release.

Murphy Oil Corp.

Murphy Oil's offshore operations are located offshore Southeast Asia, Eastern Canada and in the Gulf of Mexico (GoM). The company's offshore business produced 83,000 boe/d in the fourth quarter last year, according to Murphy's fourth-quarter and full-year 2018 results report.

Offshore Malaysia and Brunei, production in the fourth quarter last year averaged 46,000 boe/d. Block K and Sarawak averaged 28,000 bbl/d of liquids, while Sarawak natural gas production averaged more than 2.8 MMcm/d (99 MMcf/d), according to the report.

Offshore Vietnam, Murphy received the Declaration of Commerciality for the LDV Field in early 2019 and expects to move forward with sanction later this year.

In the GoM, production in the fourth quarter last year averaged 32,000 boe/d. During the quarter, the Dalmatian subsea pump was installed, and it is delivering gross incremental production of more than 10,000 boe/d, an increase of 250% from prior quarter production, with 96% uptime, according to the report.

Offshore Canada, production in the fourth quarter last year averaged 5,100 boe/d.

In March of this year, the company announced the sale of its Malaysian portfolio for \$2.127 billion. The sale is expected to close by the end of the second quarter, according to the company.

Looking ahead, Murphy is allocating about \$287 million of its 2019 capex to its global offshore



The BW Pioneer FPSO operates in Murphy's Cascade and Chinook fields in the GoM. (Source: Murphy Oil)

assets of which 75% will be spent in the GoM, 10% offshore Vietnam and Brunei, and the remainder offshore Canada.

The capex in the GoM is primarily related to field development projects, including the Dalmatian subsea pump and the Samurai Field development activities. Murphy also will be investing capital for a pre-FEED waterflood study for the St. Malo Field.

Noble Energy

Noble Energy's offshore operations are located off the coast of Arica and in the Eastern Mediterranean.

In the Eastern Mediterranean, the company has 564,000 gross acres (as of year-end 2016) and reported year-end 2016 results of 8 MMcm/d (283 MMcf/d) net sales volumes and 991 Bcm (35 Tcf) discovered gross resources, according to data provided on Noble's website.

In the Levant Basin, the company said it discovered two of the world's largest offshore natural gas fields offshore Israel and the first natural gas resources offshore the Republic of Cyprus. Noble's Tamar Platform supplies 60% of the country's power generation, and the Leviathan Field is on track for first production by the end of 2019.

"Our operations in the region stand to achieve more milestones in the coming years. The Tamar Field produced sales volumes of approximately 25.4 MMcm/d (900 MMcf/d) gross in 2016," the company said on its website. "The Leviathan Field is expected to provide a second source of supply to Israel while also delivering exports to meet the growing demand of neighboring countries, and finalizing the Aphrodite Field development plan is in progress."

According to the company's 2019 guidance report, first gas sales from Leviathan are expected by the end of the year, "delivering substantial production and cash flow growth in 2020."

Offshore Equatorial Guinea and Cameroon, the company has 296,000 net acres (as of year-end 2016) and reported year-end 2017 results of 65,000 boe/d sales volumes, 108 MMboe total proved reserves and 28 gross productive wells, according to Noble's website.

The company also holds 60% operated working interest in the 671,000-acre Doukou Dak Block in the South Gabon Basin, where it acquired and is processing a 2,500-sq-km (965-sq-mile) 3-D seismic survey.

Fourth-quarter 2018 net sales volumes from the company's assets offshore Israel totaled 6.3 MMcm (224 MMcf/d) of natural gas equivalent, and gross production from those assets averaged about 28.3 MMcm (1 Bcf/d) of natural gas equivalent, according to Noble's fourth-quarter and full-year 2018 results report. Sales volumes offshore West Africa were 60,000 boe/d, including 20,000 bbl/d of crude oil.

Oil and Natural Gas Corp. Ltd.

Oil and Natural Gas Corp. (ONGC) is the largest E&P company in India and has discovered six out of the seven oil and gas producing basins in and around the country. It has cumulatively produced 998 million metric tonnes of crude and 645 Bcm (22.7 Tcf) of natural gas, according to ONGC's website. The company has 14 seismic crews and 268 offshore installations.

"Overall, fiscal year 2018 was a solid year for ONGC," said Shashi Shanker, the company's chief managing director. "Our standalone hydrocarbon production increased year on year. The uptick in gas output was particularly impressive. Crude oil output increased marginally from fiscal year 2017 levels, and gas output increased by over 6% to 23.5 Bcm [about 830 Bcf] from 22 Bcm [about 777 Bcf] in fiscal year 2017."

In March 2019, ONGC won five out of 23 contract areas (all with 100% participating interest) in the Discovered Small Fields Bid Round-II, a press release stated. Of the five areas, one was onshore and four were offshore Mumbai. ONGC will undertake E&P activities, and the nearby existing facilities of the company will be used for processing/evacuation of oil and gas to be produced from these fields.

ONGC also is working on its mega deepwater development initiative for integrated development of the KG-DWN-98/2 (Cluster-2) Project off the east coast of India. "Cluster-2 development will have water depths ranging from 350 m to 1,400 m [1,148 ft to 4,593 ft] and is one of the most capital-intensive and technologically challenging projects off the east coast of India," the company said in an October 2018 press release. "Total peak gas production rate from Cluster-2 is envisaged to be about 16 MMscm/d [million metric standard cubic meter per day] and have a peak oil production rate of 80,000 bbl/d."

The company expects first gas production by December 2019, first oil by March 2021 and overall project completion by August 2021, according to the release.

In addition, ONGC has set up four 3-D virtual reality centers known as "Third Eye" for real-time dissemination and information of onshore and offshore applications. These centers are used for

E&P activities including real-time surveillance of producing oil and gas fields.

Pemex

Mexican state oil company Pemex reported that 82% of its crude oil production and 55% of its natural gas production is based offshore, according to its fourth-quarter 2018 results report. The company also reported that 54% of its development rigs and 54% of its exploration rigs were designated for offshore operations.

In 2018, 143 development wells were completed. Production from these fields amounted to 52,000 bbl/d of crude oil and 1.2 MMcm/d (43 MMcf/d) of gas, according to the report. Out of these 143 wells, 21 were offshore.

In deep waters, delineation well Doctus-1DL was successfully concluded, providing information leading to a new development area of light crude oil in the Perdido Area, the company stated in the report.

Additionally, Pemex expects to add 210,000 bbl/d and 9.9 MMcm (350 MMcf/d) of new production by year-end 2020 from the development of six shallow-water fields in the Gulf of Campeche, according to an October 2018 S&P Global Platts article. In the article, CEO Carlos Trevino said the six fields are at different phases: Xikin and Esah are in development, Koban and Kinbe are being assessed, and Mulach and Manik are in the early stages of exploration.

In October 2018, Pemex discovered seven reservoirs in two new wells in Mexico's Southeast Basin, named Manik-101A and Mulach-1, according to a company press release. The two wells are estimated to produce more than 180 MMboe in 3P reserves.

Pemex also is assessing its Kinbe and Koban fields. The Kinbe Field, located 28 km (17 miles) from Tabasco, Mexico, is expected to produce light crude. The Kinbe-1 well produced more than 5,000 bbl/d during production trials, and Kinbe holds 3P reserves estimated at more than 120 MMboe, according to a press release. Pemex also is delineating its Koban Field. The Koban well holds gas and condensate with estimated 3P reserves of 205 MMboe.

In an October 2018 press release, Pemex said it would soon begin developing its Xikin and Esah

shallow-water fields. Both fields hold a combined 360 MMboe of 3P reserves. Xikin is in shallow waters 24 km (15 miles) from the coast of Tabasco, Mexico. The total depth of the field is located between 6,400 m and 7,050 m and will produce light oil. It has 3P reserves estimated to be about 230 MMboe. Esah is located 94 km (58 miles) from Ciudad del Carmen, Campeche. The field will primarily produce crude with 3P reserves of 130 MMboe.

Petrobras

Brazilian company Petrobras' oil and gas E&P activities are the largest components of its investment portfolio and are focused on research, discovery, identification, production and acquisition of oil and gas reserves, both offshore and onshore.

Petrobras is the world leader in production in deep water and ultra-deep water, according to the company's 2018 annual report. The company's activities focus on oil reservoirs in deep and ultra-deep waters in Brazil, which in 2018 accounted for 85% of its entire production and were responsible for 92% of its proven reserves on Dec. 31, 2018. Petrobras also operates in mature fields in shallow waters and onshore fields. Outside of Brazil, the company operates in South America, the Gulf of Mexico and West Africa.

In 2018 the annual average production of oil and gas, considering Brazil and abroad together, was 2.63 MMboe/d, the company stated. Production in the presalt layer accounted for 45% of total oil and gas, post-salt deep water and ultra-deep water accounted for 39%, shallow water accounted for 5% and land fields accounted for 11%, according to the company's 2018 financial results report released Feb. 27.

Four new production systems started production in 2018, three in the presalt in the Santos Basin (P-74, P-75 and P-69) and one in the Campos Basin (FPSO *Cidade de Campos dos Goytacazes*). This year Petrobras began to produce in the presalt in the Santos Basin with the P-67, P-76 and P-77 production systems.

PETRONAS

Established in 1974, Petroliaam Nasional Berhad (PETRONAS) is Malaysia's fully integrated oil and gas multinational company. As the custodian of Malaysia's national oil and gas resources, the company explores, produces and delivers energy.

In 2018 PETRONAS made 10 exploration discoveries (nine Malaysia and one international), signed 16 new production-sharing contracts (five Malaysia and 11 international) and 27 of its

PETRONAS'
Semarang
offshore platform
s located off
the coast of
Terengganu,
Malaysia.
(Source:
PETRONAS)



projects achieved first hydrocarbon (eight greenfield and 19 brownfield), according to PETRONAS' fourth-quarter and year-end 2018 financial results announcement.

As of October 2018, PETRONAS has an average of nine to 10 jackup rigs, two to three tender-assisted drilling rigs, two to three hydraulic workover units, 10 wellhead platforms, one central processing platform and three heavy-lift campaigns, according to the PETRONAS Activity Outlook 2019-2021.

The company expects about 180 total metric tonnes for three subsea trees and one floating storage and offloading (FSO) unit this year, and it expects about 460 total metric tonnes for two subsea trees, one FSO and two vent platforms in 2020, according to the report. From 2019 through 2021, PETRONAS' plans for its offshore development will be about 20 greenfield projects (all with new facilities development; about 30% are oil projects) and about 30 brownfield projects (about 75% are oil projects; 10% involve new facilities development).

According to the report, the company's 2019 upstream activity outlook includes offshore fabrications (five to six wellhead platforms and one to two central processing platforms), offshore installations (eight to nine projects for heavy-lift barge and three to four projects for pipelay barge), floaters (one afra-max), underwater services (DP2 support vessels), marine vessels and decommissioning (one wellhead platform, three subsea trees, one FSO and 50 wells).

Santos Ltd.

Santos Ltd.'s upstream offshore assets are located off the coasts of northern and western Australia.

In November 2018, Santos enhanced its position in western Australia through the acquisition of Quadrant Energy.

Offshore the North West Cape, the Van Gogh and Coniston/Novara oil fields are serviced by the *Ningaloo Vision* FPSO vessel and the Pyrenees oil project includes oil from the Crosby, Ravensworth and Stickle fields and the *Pyrenees Venture* FPSO vessel.

In addition, the company has had exploration success in the Carnarvon's Bedout sub-basin with the Dorado and Roc discoveries and in the Crown and Lasseter discoveries in the Browse Basin.

The company's offshore resource positions across northern Australia include the Crown-Lasseter discoveries in the Browse Basin (Santos 30%) and the Petrel-Tern discoveries in the Bonaparte Basin (Santos 35% to 40%).

In February 2018, Santos reached an agreement with Beach Energy to become 50:50 joint venture partners across NT/P82, NT/P85, NT/P84 and WA-454-P in the Bonaparte Basin offshore Northern Australia. Santos will operate all four permits.

Saudi Aramco

One of Saudi Aramco's recent developments is the offshore Manifa oilfield megaproject located in the Arabian Gulf. Instead of building 30 offshore platforms, the company converted more than 70% of the field into an onshore field to avoid damaging the ecosystem. The design involved the creation of 27 man-made islands, all made from 45 MMcm (1.5 Bcf) of sand reclaimed from the seabed. The islands act as onshore drill sites above the offshore oil field, and they support equipment while elevated bridges allow normal flows of currents and sea life to continue. The development includes 14 bridges, 13 offshore platforms, 15 onshore drill sites, 350 new wells, injection facilities, multiple pipelines and a 420-MW heat and electricity plant. In 2017 the company reached its target of 900,000 bbl/d of oil.

"The result of the collaborative effort was an innovative plan to reach Manifa Field—primarily located in shallow water—through building a world-class causeway, bridges and laterals to connect the man-made islands," the company stated in a 2017 media release. "The computerized modeling of the 27 drilling islands, connected by a 42-kilometer [26-mile] causeway and 14 bridges to allow natural water circulation at Manifa Bay, has significantly contributed to enhance the natural flow of water, maintaining the bay as a perfect environment for shrimp and fish populations to grow."

Saudi Aramco said Manifa is one of the world's largest engineering projects, noting that the construction phase alone required more than 4 million man-hours to complete, according to news reports.

In December 2017, Saudi Aramco released a new AUV that can conduct offshore platform debris

surveys to identify seabed clearance and potential debris, a press release stated.

Shell

Shell operates in more than 70 countries and has offshore operations across the world.

In the Gulf of Mexico (GoM), Shell's operations produce about 355,000 boe/d, more than 50% of the company's U.S. oil and gas production. The company has an interest in about 400 federal offshore production leases.

Shell's largest operated deepwater assets in the GoM include Auger, Mars, Olympus, Perdido, Ursa, Appomattox and Stones.

Last year Shell announced one of its largest U.S. GoM exploration finds in the last 10 years from the Whale deepwater well, in which Shell is the operator with 60% interest, according to the company's 2018 annual report. It was discovered in the Alaminos Canyon Block 772.

In April 2018, Shell announced the final investment decision to develop the deepwater Vito Field (Shell has 63.1% interest). The field is expected to reach an average peak production of 100,000 boe/d, the report stated. The company also has continued with the development of the Appomattox project, with first oil expected this year.

In May 2018, Shell announced a large exploration discovery in the Norphlet geologic play from the Dover deepwater well. The Shell-operated Dover is the company's sixth discovery in the Norphlet and is located about 20 km (12 miles) from the Appomattox platform.

Also in May 2018, production started from the Kaikias deepwater project (80% interest). Kaikias is a subsea tieback to the Shell-operated Ursa platform. The Kaikias estimated peak production is 40,000 boe/d, the report stated.

The Stones project began production in 2016 and is the deepest offshore oil and gas producing project in the world (2,896-m [9,500-ft] water depth), according to the company. It is estimated to have a peak annual production of 50,000 boe/d.

Offshore Brazil, Shell operates several producing fields in the Campos Basin: the Bijupirá and Salema fields (80% interest) and the BC10 Field (50% interest). The company's operations portfolio also includes the Gato do Mato Field in the Santos Basin and the adjacent Sul de Gato do Mato area (80% interest). Additionally, Shell has 10 offshore exploration concessions in the Barreirinhas Basin (Shell's interest ranges from 50% to 100%) and a presalt production-sharing contract (PSC) for the Shell-operated Alto Cabo Frio Oeste (55% interest).

Shell's Stones ultra-deepwater oil and gas development project began production in 2016 and is the deepest offshore oil and gas producing project in the world (2,896-m water depth). (Source: Shell)



Offshore Nigeria, Shell's main deepwater activities are carried out by Shell Nigeria Exploration and Production Co. Ltd. (SNEPCO), which has interests in four deepwater blocks. SNEPCO operates oil mining licenses (OMLs) 118 and 135 and also has a 43.8% nonoperating interest in OML 133 and a 50% nonoperating interest in oil prospecting license 245.

Gumusut-Kakap, with a production capacity of 150,000 boe/d, was Shell's first deepwater development in Malaysia, which started production in 2014. A Phase 2 development is in the execution phase, with first oil targeted for the third quarter of this year. Malika, which was Malaysia's first tension-leg platform (TLP) and Shell's first TLP outside of the GoM, began production in December 2016.

Offshore Mauritania, Shell signed two PSCs with the government for the exploration and potential future production of hydrocarbons in blocks C-10 and C-19 (Shell has 90% interest as operator) in July 2018, according to the report. The blocks are located in the West African Atlantic Margin exploration basin.

Shell also won nine deepwater exploration blocks offshore Mexico last year and will be the operator of all nine blocks.

Talos Energy Inc.

Talos Energy operates off the Gulf of Mexico (GoM), acquiring, exploiting and exploring the region. The company reported year-end 2018 proved reserves of 151.7 MMboe, of which 76% is proved developed, according to the company's fourth-quarter and full-year 2018 financial and operational results report. Talos also reported production of 53,400 boe/d, or 4.9 MMboe, in the fourth quarter last year.

In May 2018, Talos Energy LLC and Stone Energy Corp. merged to form a new public company, Talos Energy Inc. The two companies completed a strategic transaction pursuant to which both became wholly owned subsidiaries of the company.

In the report, Talos CEO Timothy Duncan said, "The benefits of the combination have shown results immediately, as we are a stronger, free cash flow positive company with ample liquidity and a significant inventory of drilling locations in both the U.S. Gulf of Mexico and offshore Mexico. Our

strategy of executing asset management and drilling projects around existing infrastructure in the U.S. Gulf of Mexico complements our high-impact exploration and development projects in offshore Mexico."

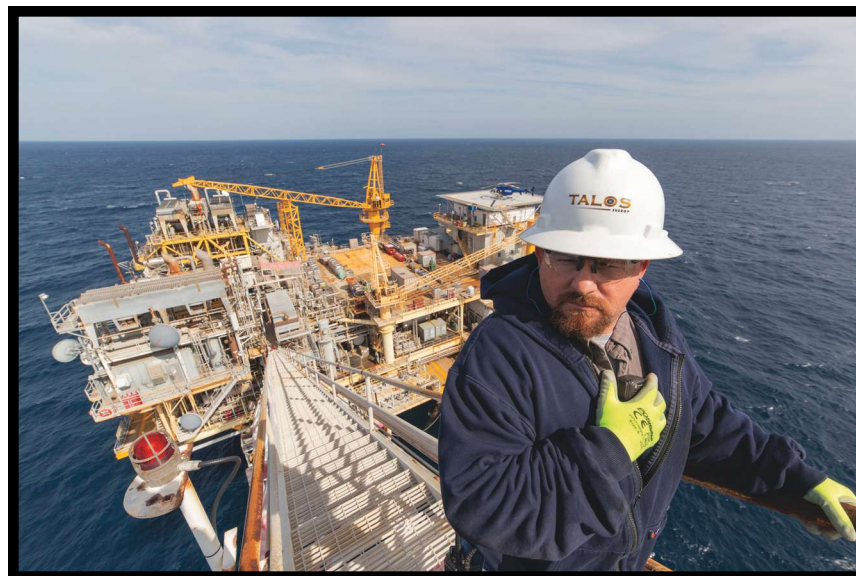
The Helix Producer 1 drydock project was executed in the first quarter of this year by Talos and partner Helix Energy Solutions. Production subsequently restarted at the Phoenix complex in March. In addition, Talos is executing a series of deepwater subsea tieback projects, namely the Mt. Providence, Tornado 3 and Boris 3 wells. Talos expects to bring the Tornado 3 and Boris 3 wells online in April and May of this year, respectively, "which will put Talos in a position to grow production year over year while continuing to generate free cash flow in the current price environment for 2019," the report stated.

In shallow water, the company's asset management and drilling activities have allowed assets, such as Ewing Bank 305/306, to achieve production levels not seen in the last 15 years, according to Talos.

In January of this year, Talos acquired the Antirim stranded discovery from Exxon Mobil and entered into partnerships to drill two deepwater projects this year, the Bulleit and Orlov prospects.

On the Zama project, the company's historic discovery offshore Mexico, Talos confirmed the oil-water contact per its geological model and

A Talos Energy employee conducts a safety inspection on the Pompano production facility. (Source: Talos Energy, David Duncan Photography)



encountered more sand than expected in the first down dip location, the report stated.

In addition, Talos will start to execute on the inventory it acquired as part of the cross-assignment of interest between Block 2 and Block 31, which includes the low-risk but high-impact Olmeca project on Block 31, according to the report.

Total S.A.

Total is the world's fourth largest energy major and an integrated operator working across the entire oil and gas value chain in more than 130 countries.

In 2018 Total's production grew more than 8% to a record level of 2,800 boe/d and led to a 71% increase in the company's E&P net operated income. The year was highlighted by the startup of Ichthys in Australia, Yamal LNG in Russia, deep-water projects Kaombo North in Angola and Egina in Nigeria, as well as the counter-cyclical acquisitions of Maersk Oil and new offshore licenses in the United Arab Emirates.

This year the company has two startups planned in the North Sea, where Total became the second largest operator: Culzean (operator) with 100,000 boe/d and Johan Sverdrup with 440,000 boe/d (expansion to 660,000 boe/d). In addition, an investment decision is expected on the Glendronach discovery. "The [North Sea] region will contribute in a major way to the growth of Total's production in the coming years," a press release stated.

Total's production in sub-Saharan Africa is led by the Gulf of Guinea comprising Angola,

Nigeria, Congo and Gabon. The region, where Total operates 11 FPSOs, accounts for 25% of the company's production.

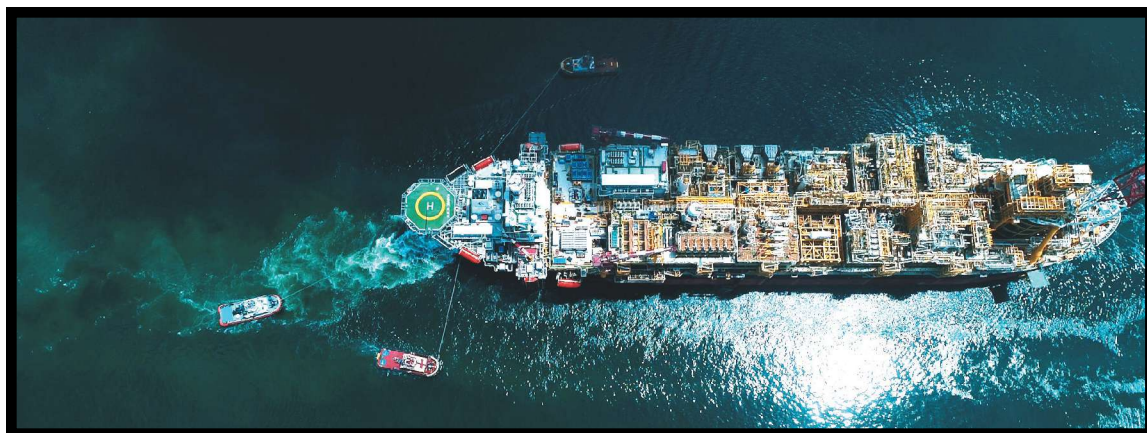
In 2018 Total delivered positive news on exploration. It first announced a new discovery in the Gulf of Mexico (Ballymore, Chevron-operated). "This major discovery gives us access to large oil resources and follow-on potential in the emerging Norphlet play," said Arnaud Breuillac, president of Exploration & Production at Total, in a company press release. "We will work together with Chevron on the appraisal of this discovery and a cost-effective scheme to ensure a rapid, low breakeven development."

Total also successfully appraised the A6 Block (Shwe Yee Htun-2 discovery) offshore Myanmar and later announced two new gas finds in the North Sea (Glendronach and Glengorm in the U.K.).

Earlier this year, Total also discovered a new gas province offshore South Africa with the discovery on the Brulpadda prospect. "With this discovery, Total has opened a new world-class gas and oil play and is well positioned to test several follow-on prospects on the same block," a company press release stated.

In addition, Total has set a number of objectives to integrate climate into its strategy, which includes reducing 15% greenhouse gas emission (scopes 1 and 2) by 15% on operated oil and gas facilities as well as reducing the intensity of methane emissions of the E&P segment's operated facilities to less than 0.2% of the commercial gas produced by 2025, the company stated in its 2018 Registration Document released in March 2019. **E&P**

The Kaombo Norte FPSO is located on the ultra-deep offshore Block 32 off the Angolan coast. Source: Total)





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Valhall is a giant oil field in the southern Norwegian North Sea. According to Aker BP, the field has the potential to continue producing for several decades. (Source: Aker BP)

New Generation of Offshore Drilling Tools Targets **Safety**, Wellbore Conditions

By **Scott Weeden**, Contributing Editor

By focusing on automation and artificial intelligence, equipment manufacturers are lowering costs and keeping personnel safe.

Offshore drilling contractors are seeking ways to improve efficiency, increase safety, save time and impact the bottom line. Equipment manufacturers recognize the need for improved drilling for accessing smaller targets and providing cleaner, smoother wellbores.

Managed pressure drilling (MPD) systems are being upgraded to improve safety and keep rig personnel out of harm's way. MPD is a process to control flow conditions to maintain bottomhole

pressure based on a modeled pore-pressure and fracture-gradient drilling window.

AFGlobal has developed a completely integrated, next-generation MPD system, which uses its Active Control Device (ACD) to replace the rotating control device (RCD), said Justin Fraczek, vice president of engineering for AFGlobal.

"With an ACD, there are no rotating parts whatsoever. The user always has active control, which is really important to the operators and drilling

contractors. They can adjust as necessary during operations. They're not standing there passively waiting for something to happen during the drilling process, but instead making changes as needed to maintain proper control over their MPD operation," he said.

Wallan Pessanha, product line manager of emulsion systems for Baker Hughes, a GE company (BHGE), explained that critical wells are those where the pore pressure and fracture gradients are very close, creating what is called a narrow mud window. One of the big risks in these wells is inducing fractures that could potentially lead to massive downhole losses.

"The industry is looking for what it calls low-ECD [equivalent circulating density] muds. Operators are drilling more wells in areas where there is a very narrow mud window. DELTA-TEQ is a very useful technology that gives an operator the ability to drill effectively in critical wells, keeping the pressures inside the mud window without compromising the project," he said. "Because of the innovative chemistry package, DELTA-TEQ provides low hydraulic impact to the well. With the ability to keep a low viscosity and excellent barite suspension, you can drill critical wells in a safe condition, avoiding losses."

Ultrahigh-pressure well control in offshore drilling remains a challenge, but it may soon be solved. In 2011 BP started its Project 20K with the goal of establishing a system capable of drilling and producing a reservoir of 20,000 psi and 177 C (350 F). Original equipment manufacturers (OEMs) like National Oilwell Varco (NOV) responded.

"The 20K market has had quite a few ups and downs with more downs than ups," said Bob Cowan, product line director for pressure control and subsea systems for NOV. "Obviously from 2015 to 2017, very little was done due to market conditions, but 2018 brought renewed interest from several operators," he added. "NOV is focused on the complete subsea system—the BOPs, BOP stack, riser system and everything below the rotary table as well as impacts to equipment above. Final development and qualification testing will be completed in 2019 as some operators head to the project stage. It is the new frontier today."

The cost of drilling a deepwater well is considerable and anything that saves time has a direct impact on the bottom line. Frank's International designed its VERSAFLO tool to allow operators to quickly form a hydraulic seal to run either casing or drillpipe and take flowback while running on elevators rather than screwing into the top drive, explained Matt Weber, vice president of drilling technologies for Frank's International.

"Every time you have to make a connection with the top drive that is typically 12 to 15 minutes. With the VERSAFLO tool, you are able to trip on elevators and make that hydraulic connection with that extendable shaft. Our typical connection is 5 to 7 minutes. If you look at time savings on a 30,000-ft [9,144-m] well, you're saving up to 8 minutes per pipe stand. That results in significant time savings per application of the tool," he said.

Anthony Spinler, vice president of MPD for Weatherford, added, "What we've seen happening now with MPD is that by controlling the bottom-hole pressure throughout the drilling process you get more efficient drilling operations, increased rate of penetration, fewer drilling days and cost savings."

Weatherford's new offshore technology, the Automated MPD Riser System, is really the second generation. "The new system really brings an efficiency and safety to the industry. We've taken all the connections that exist in the riser system for communication, mud, sensors and hydraulics [and] made it into a single hub. You automate that process and take a two-day process down to less than 20 minutes," he said.

Offshore drilling technology continues to focus on artificial intelligence, safety and automation to improve operations and enhance efficiency.

ACD for next-generation MPD

"There are multiple benefits when you look at an ACD versus an RCD, particularly in deepwater operations," said AFGlobal's Fraczek. "The first benefit is continuous active control. The second benefit is the real-time, condition-based monitoring system that brings efficiency to the drilling contractor's operation. Lastly, the seal chemistry itself has been developed to last the drilling contractor an entire hole section."

In deepwater environments, the ACD offers a significant departure from conventional RCDs with a purpose-built, nonrotating, hydraulically controlled sealing sleeve around the drillpipe. (Source: AFGlobal)



In comparing the two systems, the RCD is a passive system. Once it is installed on the drillpipe and landed in the RCD body, the driller has no control over it. The interference between the element and the drillpipe rotates the bearing inside it. The RCD has dynamic seals that hold the fluid to protect the bearing and maintain the pressure, he explained.

The ACD consists of a seal-sleeve assembly that includes two drillpipe seals, consisting of co-molded polytetrafluoroethylene (PTFE) inner cages inside of a urethane matrix. “The reason we use those is that both materials offer different benefits. The PTFE acts as a limiting agent for the wear of the urethane, while the urethane is helping to provide the drillpipe seal,” he continued.

The ACD is landed between locking dogs. The seal on the drillpipe is created by using annular BOP technology to squeeze the outside of the seal sleeve, which then contacts the drillpipe, Fraczek said.

The monitoring system gives a visual warning to the operator when the seal sleeve has reached a change-of-life state. This eliminates typical failure mechanisms seen in conventional RCDs such as splitting or tearing.

“Because we constantly monitor the pressures applied to the ACD, we know how much material is left on the seal sleeves at all times,” he said. “We increase the life of the seal sleeves by injecting clean drilling mud between the upper and lower seals. Between the upper and lower seal, we inject clean drilling mud. We keep it at a pressure slightly higher than the required surface backpressure. This not only lubricates the seal sleeves to extend their operational life, but it also creates a third barrier of protection.”

Fraczek noted that AFGlobal has made improvements in the entire MPD system to help them reduce installation time. “That has to do with our safe-stab gooseneck connection. This safe-stab connection is semi-hands-free, eliminating any pinch points during installation. Additionally, the time for this installation has been reduced in half,” he said.

In the system, there is an ACD, a drillstring isolation tool (DSIT) and the flow spool. Wellbore returns go through the flow spool and up to the topside manifolds. The goosenecks are what stab into the flow spool to allow that path to be opened up, he added. The DSIT is based on a field-proven 21¼-in. by 2K sealing element.

When the seal sleeve is ready to be changed, the first step is to close the DSIT to maintain applied surface backpressure and then strip out the seal sleeve. The seals are changed, run back in the hole and the DSIT is reopened, making the MPD system ready for drilling again, Fraczek said.

In a June 2017 report, Noble Corp. said it awarded a contract to AFGlobal to supply and install the next-generation MPD system. The current system is now being commissioned in the Black Sea.

Reducing risks of induced fractures

Typical low-ECD drilling mud can sag when the drilling operation has to be paused. When the pumps restart, pressure in the wellbore spikes. Most low-ECD fluids are simply not formulated to protect the wellbore against pressure spikes, BHGE’s Pessanha said.

Its DELTA-TEQ low-impact, nonaqueous drilling fluid outperforms typical ECD fluids and reduces the delta between static and circulation density, thus lowering the risk of induced fractures.

BHGE developed the drilling fluid using olefins for the synthetic-based mud. A new viscosifying package was developed to provide independent control of the viscosity. The fine-grind barite is used to increase the sag resistance, he continued.

In a narrow mud window, the operator is close to the upper limit pressure. When a company has conventional drilling fluids, that pressure can be reached easily and they fracture the well, resulting in massive losses, Pessanha explained. “In a

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deepwater well, this is very critical because of the logistics and safety issues. With losses, you need to add more fluid to keep the well full all the time, which increases the cost of the project,” he said.

This new drilling fluid provides very low viscosity. “Pressure is directly related to viscosity. One of the big advantages of the system is the independent control of the rheology. There are two kinds of rheology in the rheology profile—low end and high end. The low-end viscosity is responsible for the cleaning/suspension of the mud, and the high-end viscosity is responsible for the pressure in the system,” Pessanha said. “The system has the ability to increase the low-end viscosity without affecting the high-end viscosity.”

The BHGE system also has the ability to avoid the external cold-water effect on the fluid. When the fluid is coming up the riser in 3,048 m (10,000 ft) of water, the annulus is very cold. “When conventional low-ECD mud comes back into the hole, it is going to increase the pressure in the annulus due to the high viscosity caused by the effect of the cold water, a risk to fracture the formation,” he said.

When DELTA-TEQ is being used in these areas, the rheology is steady. “You have a system with a very constant and very low rheology all of the time, so the pressures remain very stable,” Pessanha added.

The system is designed to work in temperatures up to 165 C (330 F). The product could be used in most of the wells in the Gulf of Mexico (GoM) and the Western Hemisphere.

According to Pessanha, operators already have used DELTA-TEQ to drill two wells, one in the U.S. GoM very successfully and one offshore Mexico. He added, “We’re going to start a well offshore Brazil in deep water.”

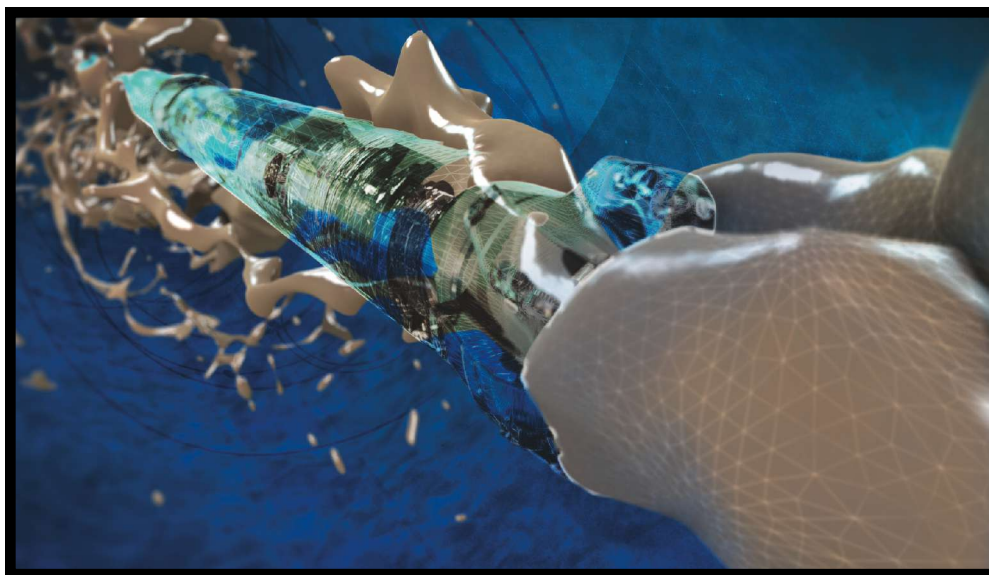
Challenges in developing 20,000-psi stack

The demand for 20,000-psi equipment in the industry is picking up. Chevron and Transocean signed a rig design and construction management contract and a five-year drilling contract for one of Transocean’s two dynamically positioned ultradeepwater drillships currently under construction at the Jurong shipyard in Singapore, according to a December 2018 press release.

The rig will be the first ultradeepwater floater rated for 20,000-psi operations and is expected to commence operations in the GoM in the second half of 2021. “There are two other operators with known assets that would require 20,000-psi equipment as well. The industry has a need right now,” NOV’s Cowan said.

“NOV’s 20K [20,000-psi] BOP system is an 18¾-in., 20,000-psi stack with connector, valves, choke and kill stabs, BOP mandrel and more,” he said. “The APIS53 Class 7-A1-6R BOP stack has six ram cavities (three double bodies) and one annular BOP. Two LFS [low-force shear] rams are fitted in the upper cavities, with newly designed 4½-in. to 7⅝-in. multirams fitted in the four lower cavities. A newly designed 20K wellhead connector has also been added along with various fail-safe dual block valves coming off the BOP.”

Cowan added, “When we started developing our 20K BOP in 2011, we began with



The low hydraulic impact of BHGE’s DELTA-TEQ drilling fluid absorbs pressure spikes and surges. This protects the wellbore, helps stop losses and keeps operators consistently in the drilling window.

(Source: Baker Hughes, a GE company)

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a blank sheet of paper combined with decades of experience. Our engineers did a significant amount of design work on every aspect of the 20K BOP. The rams are new, the connector is new, the valves are new and the mandrel is new.”

Significant design has gone into the rams. “We have what we call an LFS, low-force shear ram. Rather than mash the pipe like traditional V-shear technology, we puncture the pipe, coming through the center then moving out as the rams close. It is a new patented technology that enables shearing bigger and thicker material with less force,” Cowan explained. “An additional feature and requirement from day one in our shear-ram design is that it sweeps the entire bore of the BOP while centering the pipe. We don’t have any issues with the pipe being on the outside. Even with significant side-loading of the pipe in the BOP, we can draw it into the center.”

NOV also looked at the control system. “New regulations are such that redundancy of the controls must always be in place. This has resulted in more frequent stack pulls, which carries an enormous cost. Our optional solution is a patented subsea retrievable pod system that we call RCX, whereby we can deploy, replace and retrieve either pod on the BOP while it is still on the wellhead. The hydraulic and electrical portions have been qualified. The retrievable part is at test phase,” he said.

Bigger BOPs and new regulations also are impacting the number of accumulator bottles required. With traditional bottles, there is need for as many as 35 bottles, each weighing 10,000 lb. However, NOV has existing patented depth-compensated bottle (DCB) technology for the accumulators that eliminates the need for so many bottles.

“Only a single precharge is needed for the bottles on the surface. As the stack goes deeper, depth compensation occurs automatically. Eight DCBs can do the same as roughly 35 160-gallon pistons at a fraction of the size and weight,” Cowan said.

Perhaps the biggest challenge has been dealing with evolving regulations from the U.S. Bureau of Safety and Environmental Enforcement (BSEE). “There have been a lot of changes by BSEE over the past few years, but things are finally mostly defined. BSEE requires testing and certification for all of

the 20K systems, whereby the operator, drilling contractor, independent third-party and the OEM must work together to produce the necessary documents for BSEE review and approval,” Cowan said.

“There are a number of reports, 1A through 1G, containing things like functional descriptions, technical capabilities, FMECA [failure mode, effects and criticality analysis], FEA [finite element analysis] work, material testing, validation of your equipment [and] testing validation, and the big one that BSEE is concerned about because of the weight of everything is load monitoring for wellhead fatigue,” he explained. “We are in the process of doing our qualifications and final testing now. All of this must be done before anything can go in the field. Without BSEE approval of the completion/production plan, you won’t get a permit to drill.”

By the end of this, NOV estimates they will have submitted well over 3,000 pages of documentation to meet the BSEE requirements.

The size of the BOP stack is a challenge that has several knock-on effects to the rest of the modular offshore drilling unit (MODU). “A six-ram 20K stack is going to be about 1.25 million pounds. A seven-ram 15,000-psi (15K) stack is just under 1 million pounds. That tells you a little bit of the difference between the 20K and the 15K stacks,” said Zack Stewart, NOV’s project sales manager. “When everybody thinks 20K, they just think of the BOPs, but it truly affects the entire rig. We previously built all the handling systems to be able to deploy and retrieve the BOP based on a 15K stack. The second you start talking about adding 300,000 pounds to 400,000 pounds, all the carriers have to get bigger and heavier. You have to upgrade or replace the whole BOP handling system.”

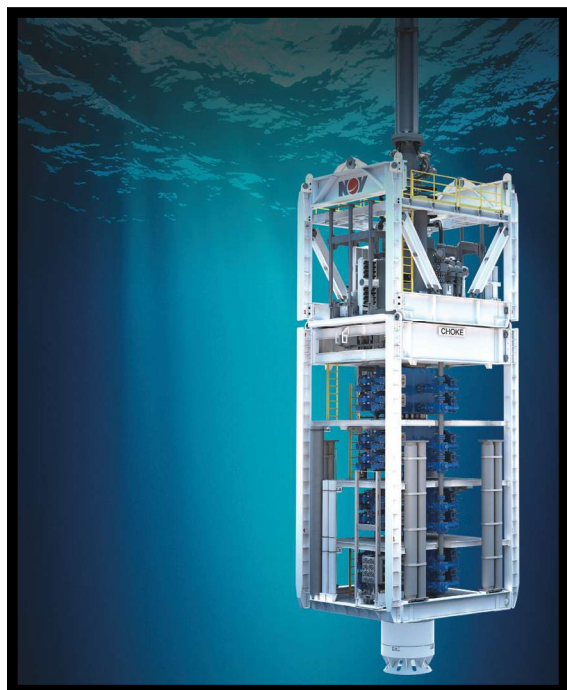
He added, “The 20K riser is bigger and heavier so all the riser handling systems have to be upgraded or replaced.”

The hook load for the hoisting system also increases significantly. “We are seeing well profiles where the operators are designing extremely long and heavy casing runs,” Stewart explained. “All of the rigs built during the boom cycle are completely out of hoisting capacity right now. They have been trying to do innovative things to be able to deploy more and more weight, but limits have been

reached and bigger, more capable capital equipment will have to be utilized.”

For example NOV's largest drawworks in operation today are rated for 1,400 tons. NOV is now developing a drawworks for 1,700 tons.

The biggest rigs built in the last cycle could haul 2.5 MMlb at the top drive elevators. Now the requirement is 3 MMlb. “All the hoisting equipment for that kind of load is being upgraded—new top drives, new crown-mounted compensators, new elevators, basically everything on the load path,” he said.



NOV's 20K BOP system is an 18¾-in., 20,000-psi stack with a connector, valves, choke and kill stabs, BOP mandrel and more. The BOP stack has six ram cavities (three double bodies) and one annular BOP. (Source: NOV)

“NOV is well-positioned to deliver everything the operators and drilling contractors need to meet the 20K challenge,” Cowan said.

Single tool for fluid management

Whether it is drillpipe or casing, the VERSAFLO casing and drillpipe flowback and circulation tool can be described as a seal element that forms a connection between the tubular in the elevators and the top drive, according to Weber with Frank's International. The tool allows the operator to take

returns or circulate through the top drive without the need for a different bypass. The flow avenue remains the same.

“It gives you a rapid way to form that hydraulic seal. It is a very easy system that has rotary shoulder or drillpipe connections on each end. The tool rigs up directly to the top drive in 15 minutes or less. Once it is made up, it can stay in place as you continue to operate in both casing and drillpipe configurations,” he said.

The lower portion of the tool is the casing adaptor while the upper portion is for drillpipe. A black seal element—a packer—is on the lower portion. Depending on the casing string being run, it will be dressed with that seal element. The correct sizes of packers are sent to the rig for whatever casing size that is being run, along with the drillpipe portion of the upper mandrel.

The tool has a rated tensile strength of 2.5 MMlb and has been proof-tested in excess of 3 MMlb. The pressure rating is 5,000 psi and the torsional rating is 70,000 ft-lb. The casing module can handle casing from a 7-in. to 18⅝-in. outer diameter. The drillpipe module can seal a 3-in. to 5½-in. inside diameter (ID) drillpipe.

Several features were built into the tool to help expand its versatility. One is its hydraulic swivel. “While it is connected and you are extending the seal element and running your landing string on elevators, you can come straight down, rotate and screw into the connection so that you can reciprocate and rotate your pipe with the VERSAFLO in place,” he explained.

One of the VERSAFLO's innovations is the use of Wi-Fi to control the tool. “Our operator has his controls. He can stand next to the driller and be in constant communication. He is looking at the same camera that the driller is looking at. As the driller sets the elevator, our operator is then able to extend the tool and form the hydraulic seal,” Weber said. “The Wi-Fi control element allows the hydraulically operated piston to be functioned safely by increasing communication between the operator and driller.”

One of the main applications for the tool is in the deepwater environment. “There are tight tolerance wellbores, which have very small areas of

clearance between the casing you are running and the previously drilled section of the wellbore. Drilling fluid is forced back into the ID of the casing. In most cases, the casing is being landed at a setting depth below the mudline,” he said. “If you think of running an 18-in. casing with a huge ID and it necks down to a 3½-in. to 4-in. ID, all that mud has to be squeezed into that smaller ID, causing flowback at the rotary table on the surface. The VERSAFLO tool allows you to continue to run that string of pipe or land out your casing with the tubulars still in the elevators. Now you are receiving that flowback through the seal element on the tool.”

As the tool is used more widely, Frank’s International is finding other applications. “Once we commercialized the tool and started getting more experience, the applications became more apparent. Some of these applications included a 7-in. liner run for a major operator in the Asia-Pacific region and an expandable liner run where you have to circulate and pull in order to expand the liner,” he said.

The operator used it for drilling applications as well. “They were able to circulate out their drilling assembly and circulate out when tripping out of the hole. That allowed them to trip on elevators but maintain pumping and circulating as they pulled out of the hole,” Weber said. “One operator in Canada referred to it as their go-to tool for any pump-in or pump-out of the hole situation.”

The tool also has been used for washing out and jetting out the riser and BOP when finishing the well.

Frank’s International debuted the VERSAFLO tool on its initial commercial runs in mid- to late 2017. The company had in excess of 75 jobs in 2018. The next version of the tool, called the Modular VERSAFLO tool, will expand the applications of the tool and allow the company to capture more of the jackup and land market.

Automated riser system saves time, improves safety

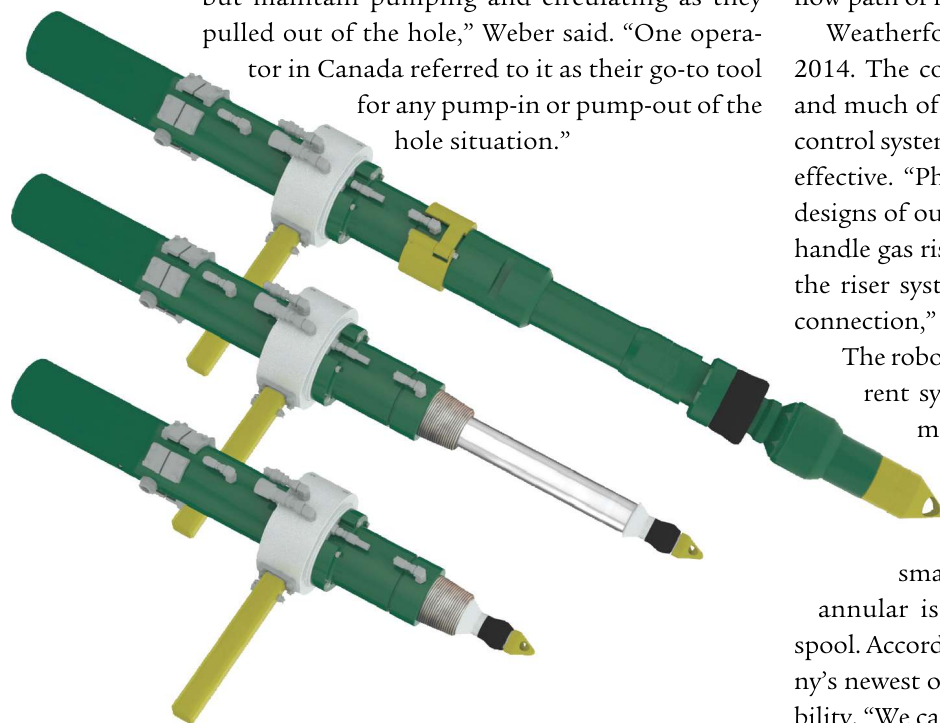
The new generation of automated riser system is Industry 4.0.

“This is the top of the line in control systems, hardware, software and PLCs [programmable logic controllers] to bring artificial intelligence, condition-based maintenance, additional sensors and speed of operation,” Weatherford’s Spinler said. “In that critical system is also a control system in the background with intelligence to help automate the processes. You have improvements in two levels. One is the control system itself, what it interfaces with and what it helps them do and what it is able to calculate, again taking into consideration the entire flow path of mud and the conditions in the well.”

Weatherford has done 7,600 MPD jobs since 2014. The company has taken all the experience and much of that information and put it into the control system to make the process easier and more effective. “Physically, we improved the hardware designs of our manifolds to have more capacity to handle gas riser events and, of course, automating the riser system by adding robotics and a single connection,” Spinler said.

The robotics make the system safer. In the current system, personnel have to go over the moonpool to connect the MPD in all conditions. Essentially, the entire process can be done without personnel. The system consists of a smart, below-tension-ring marine riser, annular isolation device and hands-free flow spool. According to Spinler, the RCD is the company’s newest one and has monitor and sensor capability. “We can predict failure and reduce potential

The VERSAFLO casing and drillpipe flowback and circulation tool is shown in progressive configurations to accommodate casing (top) and drillpipe (middle and bottom). (Source: Frank’s International)



impact by giving advanced notice to operators,” he said.

The real benefit of an MPD is in response to losses or influx. In current drilling operations, it takes minutes to understand what is happening. By that time, they are getting 15 bbl of influx, which they then have to manage through well control with the BOP, he said.

“With the new system, we are reacting in seconds. We have been able to detect and respond to gallons of an influx, less than a barrel. Because of the response to control the pressure, you can continue to operate and flow that out through the system without having to use the reactor,” he explained.

The new platform is being launched at the Offshore Technology Conference in May in Houston.

Weatherford also has released a new generation of rotary steerable systems (RSS) called Magnus. It was officially launched and began being used in the field in 2018. The company is developing larger tool sizes for the larger hole sizes needed for offshore applications, according to John Clegg, director of research, development and engineering for Weatherford’s Drilling and Evaluation segment.

“We developed our new system to match both the economic and applications requirements of the current RSS market,” he said. “It is a push-the-bit tool that moves the bit sideways. It has three steering pads to deflect the bit. Each of these has its own



Weatherford’s Magnus RSS features fully independent control of three steering pads to selectively push the bit sideways. (Source: Weatherford)

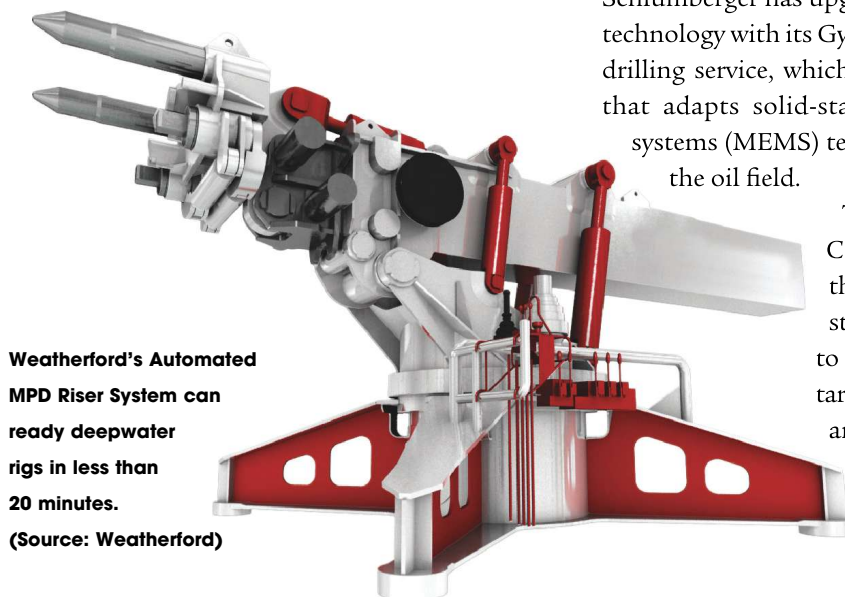
controller and actuation system, and each one is completely independent of the other two. It gives us some redundancy. If one of them fails, the other two can be able to give protection.”

Clegg added, “It also allows us much more precise control of the direction of the well and wellbore quality. In addition, it was very important to us to develop the technology that would allow Magnus to operate at the high rotary speeds and torques that will accompany the new generation of downhole motors.”

Gyro-while-drilling tool saves rig time

Schlumberger has upgraded its gyro-while-drilling technology with its GyroSphere MEMS gyro-while-drilling service, which incorporates a gyro sensor that adapts solid-state microelectromechanical systems (MEMS) technology for gyro surveys in the oil field.

The technology works off the Coriolis effect, which means the gyro sensor uses a vibrating structure (6-mm silicon plate) to determine the rate of planetary rotation. From that rate and an accelerometer, the sensor pinpoints its inclination, azimuth and the toolface orientation. The MEMS gyro sensor is rotated when



Weatherford’s Automated MPD Riser System can ready deepwater rigs in less than 20 minutes. (Source: Weatherford)

stationary through a predefined pattern to accurately measure its orientation, run quality control and self-calibrate.

The GyroSphere service is a simple gyro-while-drilling system to deploy. It comes in its own collar and can be placed anywhere in the bottomhole assembly (BHA). Furthermore, MWD engineers can run the service, and gyro surveys are published in real time through the surface system for use by the directional driller and customer. When an operator pulls out of hole, it can take additional surveys at that time, if required.

The solid-state MEMS technology differs from traditional rotating mass gyro-while-drilling tools, which are more complex and less rugged and efficient. Being intrinsically rugged, the MEMS technology can survive the drilling process without damage or loss of accuracy. It also has low power consumption.

The GyroSphere service is carried in a drill collar and can be placed anywhere in the BHA. It communicates with a MWD system.

Since the MEMS technology is solid state, it can survive shock and vibration levels that are similar to an MWD tool in the BHA. The tool has passive shock isolation and is housed within a barrel in a drill collar, which isolates it from the mud column.

The Schlumberger system requires no time to spin up compared to conventional rotating mass gyro-while-drilling tools, which ultimately saves time for operators. The tool can take a survey in two minutes, which fits into the time needed for a connection. This allows the service to take a survey without impacting rig time.

Overall, gyro-surveying efficiency and reliability are improved while the ellipse of uncertainty is reduced by up to 45%, which enables drilling smaller targets. By reducing the ellipse of uncertainty, the GyroSphere service is able to improve the precision placement of those smaller targets.

The technology is also beneficial in extended-reach drilling (ERD). For example, the service was



The new GyroSphere MEMS gyro-while-drilling service increases drilling survey efficiency and reliability with new MEM technology.

(Source: Schlumberger)

successfully used in a 7,010-m (23,000-ft) section of a well in East Asia, where the gyro surveys were taken at every connection with no additional rig time. The operator needed to perform a gyro survey program to total depth in the 12¼-in. section to pinpoint the target reservoir. When combined with the MWD surveys, the gyro surveys provided a 40% increase in accuracy compared to other surveying systems while saving 28 hours in rig time.

The use of the GyroSphere service for ERD operations is a key differentiator. The time spent static with pumps off after connection in ERD wells can result in stuck pipe, and the GyroSphere service enables operators to avoid these occurrences.

With the ability to combine these surveys with MWD, operators have a zero rig time surveying system capable of accuracies in excess of any other wellbore surveying system. **ESP**

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Production at BP's U.K. North Sea Clair Ridge development started up in November 2018. (Source: BP)

Platforms Enter a New Cycle

By John Sheehan, Contributing Editor

Both the fixed platform and floating production markets are picking up again after serious efforts by operators and contractors to cut costs.

The fixed platform and floating production systems markets are continuing to recover slowly after several years in the doldrums, following the oil price crash in 2014.

These signs of a renaissance are highlighted by the FPSO sector where there were nine awards in 2018, on par with the nine ordered in 2017, indicating a continued pickup from the dark days of 2016 when not a single order was placed.

The upturn comes as operators and contractors have teamed up to drive down prices with a focus on cost efficiencies and a move to more standardization of equipment.

The cost savings achieved have put the offshore sector in a good position for growth if the lower price base can be maintained to keep the industry in line with competitor producing sectors such as onshore.

Floater solutions remain key to accessing new reserves in areas such as offshore Brazil and Mexico as well as in the Lower Tertiary play in the Gulf of Mexico (GoM). Southeast Asia/China and East and West Africa are also major growth areas for floating production systems.

Fixed platforms remain the weapon of choice for closer-to-shore, easier-to-reach reserves, which can be tapped with more conventional methods.

FPSO	Country	FPSO Owner	Field Operator	Water Depth (m)	Order Date
Area 1 FPSO	Mexico	Modec	ENI	32	2018 Oct
Carioca MV30 FPSO	Brazil	Modec	Petrobras	2200	2017 Oct
Fast4Ward FPSO #2	TBD	SBM	TBD	TBD	2018 Nov**
Guanabara MV31 FPSO	Brazil	Modec	Petrobras	2100	2017 Nov
Hai Yang Shi You 119 FPSO	China	CNOOC	CNOOC	400	2018 May
Helang FPSO	Malaysia	Yinson	JX Nippon	90	2018 Apr
Johan Castberg FPSO	Norway	Equinor	Equinor	370	2017 Dec
Kaombo Sul FPSO	Angola	Total	Total	1600	2014 Apr
Liza #2 FPSO	Guyana	SBM	ExxonMobil	1690-1730	2018 July*
Liza Destiny FPSO	Guyana	SBM	ExxonMobil	1525	2017 June
P 68 FPSO	Brazil	Petrobras	Petrobras	1500	2010 Nov
P 70 FPSO	Brazil	Petrobras	Petrobras	1500	2010 Nov
P 71 FPSO	Brazil	Petrobras	Petrobras	1500	2017 Dec
Penguins FPSO	UK	Shell	Shell	160	2018 Jan
Petrojarl Varg FPSO	UK	Teekay	Alpha Petroleum	167	2018 Oct
Tanin/Karish FPSO	Israel	Energiean	Energiean	1700	2018 Mar
Tortue FPSO	Mauritania/Senegal	BP	BP/Kosmos	200	2018 Dec*
*FEED contract designed to morph into an EPC contract ** Speculative FPSO hull					

FPSO market upturn

Floater analysts International Maritime Associates said in a February report that the nine FPSOs ordered in 2018 are to be deployed in water depths ranging from 32 m (105 ft) with the Area 1 FPSO offshore Mexico to 1,700 m (5,578 ft) with the *Tanin/Karish* FPSO offshore Israel.

Six of the orders utilize new purpose-built hulls. Three are conversions or modifications of existing FPSOs.

Two of the 2018 contracts—an FPSO for use by Exxon Mobil offshore Guyana and an FPSO to be deployed by BP on an LNG project offshore Mauritania/Senegal—are FEED contracts structured to morph into engineering, procurement and construction (EPC) contracts, according to International Maritime Associates.

In its fourth-quarter 2018 Floating Production Systems Report (released in September 2018), Energy Maritime Associates reviewed the market for floating production systems, including FPSOs, floating LNGs (FLNG), floating storage regasification units, tension-leg platforms, spars, semisubmersibles, floating storage offloading units and

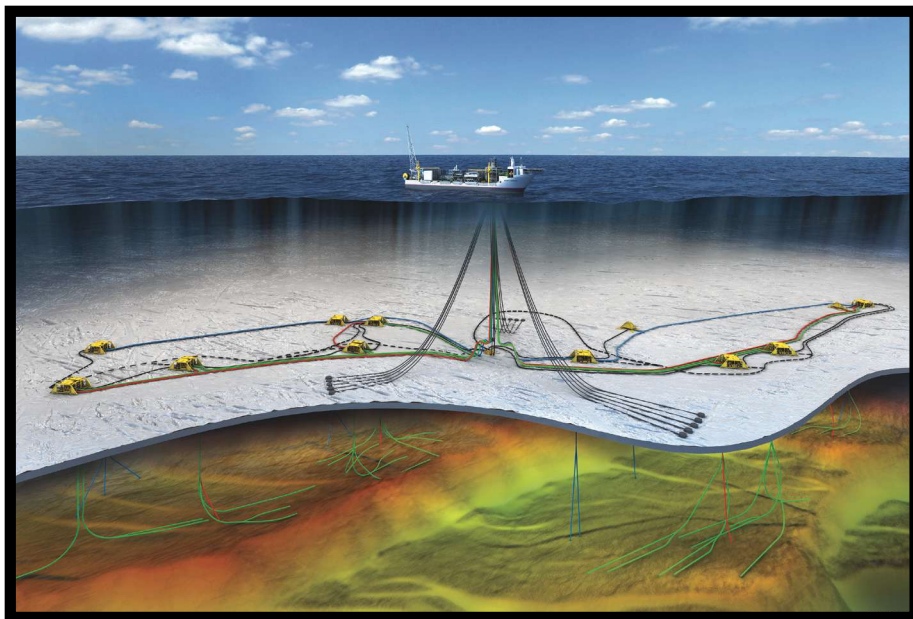
mobile offshore production units. Energy Maritime Associates identified 31 projects most likely to be sanctioned in the next 12 months.

“Oil prices have rebounded over 100% from their lowest levels, while offshore costs have hardly moved. As a result, many offshore developments are now very competitive, if not more attractive than onshore shale fields, with breakevens as low as \$30/bbl,” said David Boggs, Energy Maritime Associates’ managing director, in the report. “We see this as the start of a new cycle for the industry with reset pricing and a growing oil price similar to the period from 2004 to 2005. If oil prices remain stable, there is a tremendous opportunity for new floating production projects over at least the next two years. While there have been substantial industry reductions and consolidation, there is still sufficient industry capacity, particularly in the subsea and drilling sectors through 2020.”

Cost efficiencies

A prime example of cost-cutting initiatives having a positive effect on development plans can be seen with the approval by the Norwegian Parliament of

There were more than 15 FPSOs currently on order as of January. (Source: IMA/World Energy Reports Database)



The Johan Castberg Field offshore Norway, the largest subsea field currently under development, features 30 wells and will be developed with an FPSO+ solution. (Source: Equinor)

the plan for development and operation of Equinor's Johan Castberg Field in the Barents Sea.

The field will be developed with an FPSO+ production vessel with additional subsea solutions. Compared with the original solution, Equinor said costs were halved from about \$11.7 billion to \$5.85 billion.

With first oil scheduled for 2022, the field has a production horizon of 30 years. Recoverable resources are estimated at 450 MMboe to 650 MMboe.

The field development consists of a production vessel and a comprehensive subsea system, including 30 wells distributed on 10 templates and two satellite structures. Globally, this is the largest subsea field under development.

"The project is on schedule, and gradually, we will see the results of the construction work. Many yards and companies across the country will be busy with Johan Castberg deliveries in the years to come," said Knut Gjertsen, project director for Johan Castberg.

Equinor said the project, which initially had a breakeven price above \$80/bbl, was not sustainable when the oil price collapsed in 2014. A new concept and new solutions were found by working with suppliers and partners to ensure the development is profitable at an oil price below \$35/bbl.

Project awards

Other project awards in 2018 included Shell's U.K. North Sea Penguins Field where an FPSO will take the place of the decommissioned Brent Charlie platform in the nearby Brent Field. As part of the redevelopment process, a further eight wells will be drilled and tied back to the FPSO vessel. Oil will be transported via tanker to refineries, and gas will be transported via the Far North Liquids and Associated Gas System pipeline to the St. Fergus gas terminal in northeast Scotland, according to the company.

Highlighting cost efficiencies, Shell said the redevelopment is an attractive opportunity with a competitive forward-looking breakeven price below \$40/bbl. Once fully functional, average peak production is expected to be about 45,000 boe/d.

Another FPSO project in the North Sea to reach a final investment decision (FID) in 2018 is Alpha Petroleum's Cheviot development. The *Petrojarl Varg* FPSO will be deployed to the field. First oil production is targeted for the second quarter of 2021 at an expected rate of at least 30,000 bbl/d.

Offshore Israel, Energean's Karish and Tanin development project remains on track to deliver first gas into the Israeli domestic market in the first quarter of 2021.

Left, Shell's Penguins Field will be tapped with a newbuild Sevan SSP cylindrical FPSO. (Source: Sevan SSP)



Senegal first

Meanwhile, MODEC was awarded a contract by Woodside Energy, operator of the SNE Field development, for an FPSO on Senegalese waters offshore West Africa. MODEC will perform FEED for the FPSO and, subject to an FID on the project this year, will be responsible for the supply, charter and operations of the FPSO. The SNE deepwater oil field is expected to be Senegal's first offshore oil development. The field is located within the Sangomar Deep Offshore permit area, approximately 100 km (62 miles) south of Dakar. The FPSO will be designed to produce about 100,000 bbl/d of crude oil, with the first oil production targeted in 2022 and will be moored in a water depth of about 800 m (2,625 ft).

Brazil FPSO orders

International Maritime Associates said Brazil is expected to account for 30% to 35% of the projected FPSO orders over the next five years as Petrobras ramps up activities.

This figure reflects a large number of deepwater projects in the planning queue in Brazil, the expected rebound of Petrobras over the next few years and the future role of international oil companies in Brazil deepwater exploration and development, according to the International Maritime Associates.

The FPSOs ordered for Brazil will generally be large capacity units based on purpose-built or converted very large crude carrier hulls.

In November 2018 Petrobras started production of oil and natural gas in the Búzios 2 area in the presalt of the Santos Basin with the *P-75* FPSO, the second unit installed in the Búzios Field. With a daily capacity to process up to 150,000 bbl of oil and compress up to 6 MMcm (212 MMcf) of natural gas, *P-75* will produce through 10 producing wells, also using seven injection wells.

P-75 was one of six FPSOs to start production in 2018 offshore Brazil. Others included the FPSO *Cidade Campos dos Goytacazes* in the Tartaruga Verde Field, the *P-67* and *P-69* in the Lula Field and the *P-74* and *P-76* in the Búzios Field.

Farther out, first oil is expected from the ultradeepwater Mero Field in 2021 and will involve the use of the *Guanabara MV31* FPSO, which is capable of processing 180,000 bbl/d of crude oil.

In addition, the Libra oil field is one of the most significant oil and gas discoveries in recent years. Situated about 177 km (110 miles) off the coast of Rio de Janeiro, the field could hold as many as 12 Bbbl of oil. The FPSO *Pionero de Libra* is operating the field as an early production system.

Standardized solutions

Standardization of equipment also is helping play a key role in the bounce back of the offshore sector. SBM Offshore is at the forefront of this revolution with its homogenized *Fast4Ward* FPSO. The design consists of a newbuild with a generic double hull capable of accommodating an internal or external turret mooring system or spread mooring and standardized modules. The vessel will have a production capacity of 100,000 bbl/d to 250,000 bbl/d of oil and up to 2 MMbbl of storage.

In July 2018, SBM Offshore announced that it had been awarded contracts for Exxon Mobil's second *Liza* FPSO, based on its *Fast4Ward* program, for the *Liza* development located in the Stabroek Block offshore Guyana.

Following FEED and subject to requisite government approvals, project sanction and an authorization to proceed with the next phase, SBM Offshore will construct, install and then lease and operate the FPSO for a period of up to two years, after which the FPSO ownership and operation will transfer to Esso Exploration and Production Guyana Ltd. The FPSO will be spread moored in a water depth of about 1,600 m (5,250 ft).

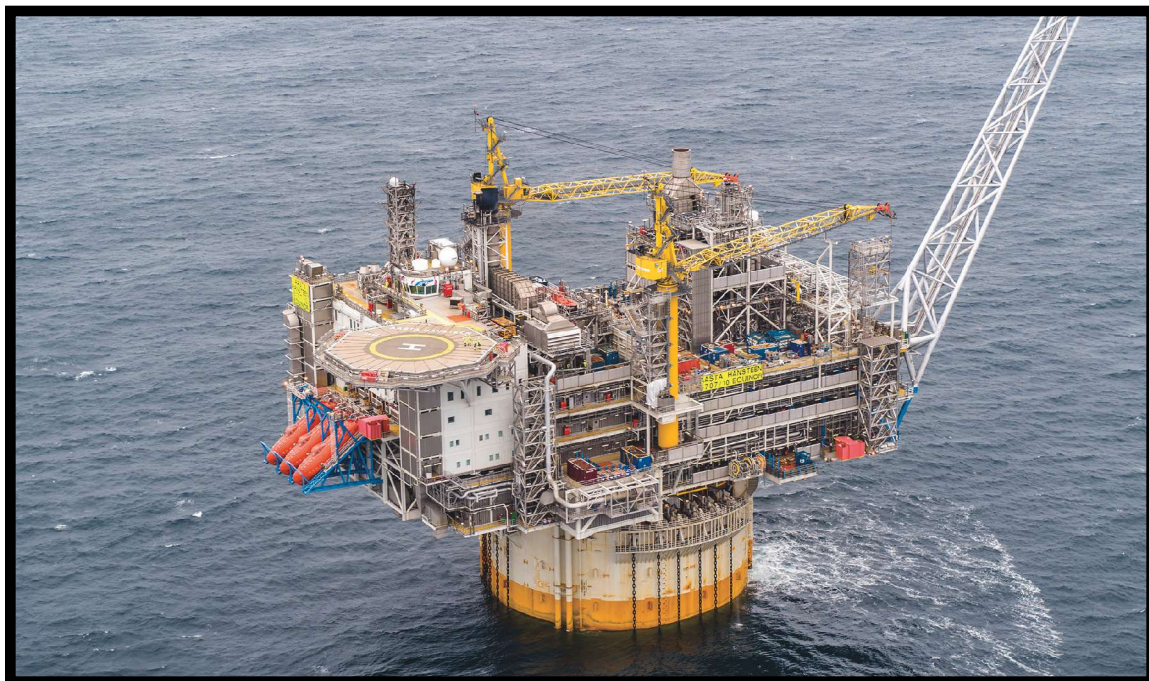
In a March 2018 press release, SBM said, "Fast4Ward optimizes an FPSO design, creating standard specifications and enhancing reliability, bringing costs down further. It accelerates delivery by up to 12 months and improves quality and productivity on a de-risked, more reliable plan with a higher degree of safety."

Aasta Hansteen onstream

The floater market is not the preserve of FPSOs, however, and there also have been some bright spots for other parts of the sector as well.

Equinor and its partners kicked off production from the Aasta Hansteen gas field in the Norwegian

Production at Equinor's Aasta Hansteen spar platform began in December 2018. (Photo by Roar Lindefjeld and Bo B. Randulff, courtesy of Equinor)



Sea in December 2018 with the largest spar platform in the world.

Aasta Hansteen is located 299 km (186 miles) west of Sandnessjøen, far from other fields and in an area with harsh weather conditions. The field development concept consists of a floating platform with a vertical cylindrical substructure moored to the seabed. Some 339 m (1,112 ft) tall, the platform weighs 70,000 tonnes. When the platform was towed to the field in April, it was the biggest tow on the Norwegian Continental Shelf (NCS) since Troll A in 1995.

Gas is produced from seven wells in three subsea templates. At water depths of 1,300 m (4,265 ft), this is the deepest ever installation of subsea equipment on the NCS.

Both Aasta Hansteen and the 483-km (300-mile) long pipeline from the field to Nyhamna can accommodate discoveries. The first one, Snefrid North, is already under development and will come onstream toward the end of the year. The recoverable resources at Aasta Hansteen, including Snefrid North, are estimated at 54 Bcm (1.9 Tcf) of gas and 353 MMboe of condensate.

FLNG resurgence

As the demand for reliable gas supplies grows, the FLNG market also is moving into a new wave of

developments. Westwood Global Energy Group's analysis of sanctioned and upcoming projects sees global FLNG capex projected to total \$52.8 billion over the 2019-2024 period.

As LNG exports take a foothold in the U.S., investment in floating liquefaction facilities in North America will play a pivotal role in global FLNG expenditure over the forecast, accounting for 45% of expenditure, the analyst said.

Golar LNG's *Hilli Episeyo* project offshore Cameroon came onstream in 2018. Built by Keppel in Singapore, the *Hilli Episeyo* is the world's first converted FLNG vessel. Launched in July 2017, the *Hilli Episeyo* was converted from an LNG carrier built in the mid-1970s and moved from Singapore to Cameroon in October 2017.

Golar also will be supplying its *Gimi* vessel to BP for Phase 1 of the Greater Tortue Ahmeyim project located at a nearshore hub on the Mauritania and Senegal maritime border. The Greater Tortue Ahmeyim project will produce gas from an ultradeepwater subsea system and mid-water FPSO vessel, which will process the gas, removing heavier hydrocarbon components. Expected to commence production in 2022, *Gimi* is designed to produce an average of about 2.5 million tonnes per annum of LNG. Total gas resources in the

field are estimated to be about 424 Bcm (15 Tcf) of gas.

Fixed platforms

For offshore projects that are closer to shore and perhaps less complex, traditional fixed platforms are still a cost-effective solution for operators.

BP's Clair Ridge project in the U.K. North Sea shows that there are exciting opportunities to develop resources with fixed platforms, even in harsh conditions. The multibillion-pound investment by BP and partners started up in November 2018 and is designed to continue producing until 2050.

Clair Ridge is the second phase of development of the Clair Field, 76 km (47 miles) west of Shetland. The field, which was discovered in 1977, holds an estimated 7 Bboe of hydrocarbons.

Two new, bridge-linked platforms and oil and gas export pipelines have been constructed as part of the Clair Ridge project. The project has been designed to recover an estimated 640 MMbbl with production expected to ramp up to a peak plateau level of 120,000 bbl/d of oil.

Clair Ridge is the first offshore deployment of BP's EOR technology, LoSal, which has the potential to increase oil recovery from reservoirs by using reduced salinity water in water injection. This is expected to result in up to an additional 40 MMbbl being cost-effectively recovered over the lifetime of the development.

In addition to the platforms, the Clair Ridge project also included new pipeline infrastructure with the installation of a 5.5-km (3.4-mile), 22-in. oil export pipeline tying into the Clair Phase 1 export pipeline. Oil from Clair is exported to the Sullom Voe Terminal on Shetland. A new 14.5-km (9-mile) long, 6-in. gas export pipeline tying Clair Ridge into the West of Shetland Pipeline (WOSP) also was installed as part of the project. The WOSP transports gas from west of Shetland to the Sullom Voe Terminal.

Clair Ridge also features an advanced drill rig that will deliver a drilling program over several years. There are 36 well slots, two of which are being used for the tieback of predrilled wells. The drilling program, which is likely to last more than 10 years,

includes drilling and completing development wells from the remaining 34 well slots.

Leviathan thinks big

In milder climes offshore Israel, Noble Energy's Leviathan project is now about 75% complete. The company has completed the installation of all infield gathering lines, subsea trees and fabrication of the jacket structure. The jacket has been installed. All four production wells have been completed, and flow tests have confirmed the deliverability of more than 8.4 MMcm/d (300 MMcfe/d) per well. Construction of the platform continues, and the project remains on schedule for startup by the end of the year. The Leviathan platform will have an initial deck weight of 22,000 tons. Processed gas will connect to the Israel Natural Gas Lines Ltd. onshore transportation grid in the northern part of the country and to regional markets via onshore export pipelines.

Minimal design

Unmanned, remotely operated platforms are another route operators are taking to cut costs.

The Oseberg Vestflanken 2 Field came onstream via a stripped down, unmanned platform. Remotely operated from the Oseberg Field center, the new Oseberg H platform is the first unmanned platform on the NCS. Recoverable resources are 110 MMbbl, and the project was delivered far below budget. The project was delivered at \$760 million, more than 20% lower than the cost estimate of the plan for development and operation, according to the company. The breakeven price was reduced from \$34/bbl to below \$20/bbl, further strengthening a development that is already highly profitable.

Maintenance campaigns are to be carried out once or twice per year on the platform. The alternative to an unmanned wellhead platform would have been subsea wells. According to news reports, the new concept provides a competitive alternative in developing smaller discoveries.

The 11 wells on Oseberg Vestflanken 2 will be drilled by the Askepott jackup rig owned by the Oseberg license. Nine wells will be drilled through the Oseberg H platform and two through an existing subsea template. Pipelines and subsea equipment also have been installed. **ESP**

Subsea Sector Recovery Underway

By **John Sheehan**, Contributing Editor

An increase in field development sanctions and subsea tiebacks as well as better project economics are helping bring the subsea sector back to life.

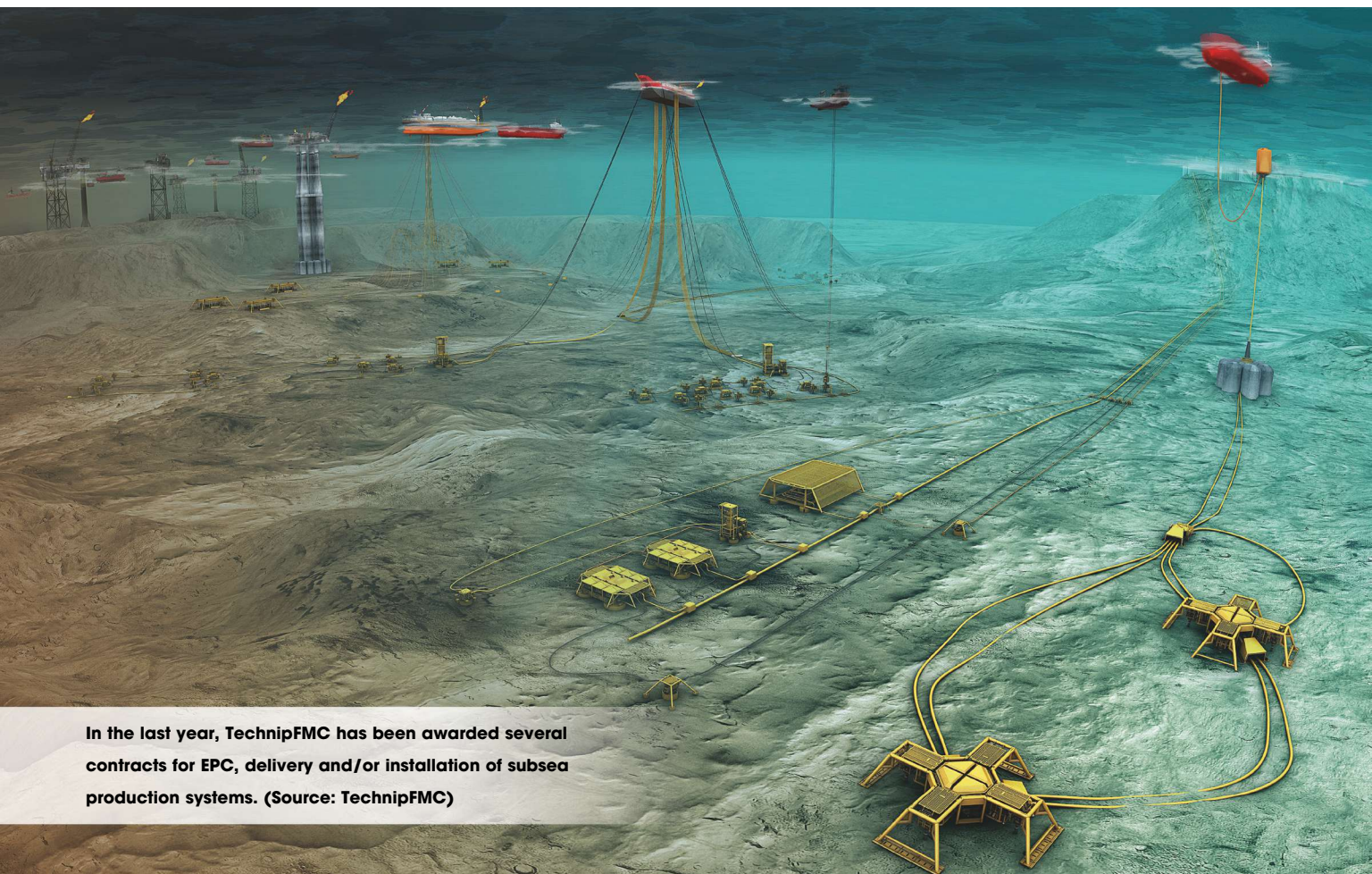
It has been a hard grind for subsea market players in the past few years, but signs of a let-up are on the horizon.

Four years since the oil price collapse of 2014, the subsea market is beginning to spark back into life as operators sanction new developments around the world, supported by improvements in project economics and increased cash flows.

Better collaboration between operators and contractors has seen subsea field architecture simplified, leading to further opportunities for growth.

Research by Rystad Energy suggests that the subsea market will be a top performing oilfield service segment in the years to come. The analyst expects the subsea market to outpace other market segments from 2018 to 2023 with 10% yearly

In the last year, TechnipFMC has been awarded several contracts for EPC, delivery and/or installation of subsea production systems. (Source: TechnipFMC)



growth, compared to 6% for the oilfield service markets in total.

The market for subsea equipment (e.g., the procurement of subsea wellheads, subsea trees, manifolds and control modules) is expected to lead growth with as much as 12% year-on-year increases.

The market for subsea umbilicals, risers and flowlines (SURF), including their procurement and installation, follows close behind subsea equipment with an expected 11% yearly growth, Rystad Energy said.

This growth will be supported by a new wave of subsea developments over the coming years, which will have subsea trees at their core.

After activity levels fell to only 240 subsea trees installed globally in 2017, Rystad Energy forecasts that more than 350 subsea trees will be installed per year by 2021. The market for subsea trees is expected to grow by 8% per year from 2017 to 2023. The U.K. and Norway will drive the growth through 2021, after which South America will take the lead. Global demand for oilfield services is projected to hit \$642 billion in 2019, of which the subsea market will account for 4%.

Of the projects that E&P companies are expected to commit to over the next four years in Norway and the U.K., Rystad Energy expects 53% of the offshore greenfield E&P expenditure to be for subsea tieback projects. This is a significant increase from 30% in the 2010 to 2018 period.

Norway leads the way

Equinor and its partners have decided to invest about \$165 million in a Vigdis subsea boosting station, expected to come online in the first quarter of 2021. OneSubsea has been awarded the engineering, procurement and construction (EPC) contract for the supply of the industry's first all-electric actuated subsea boosting system. Vigdis has been producing oil through the Snorre Field for more than 20 years.

Field production will be boosted by almost 11 MMbbl of oil. The boosting station will be connected to the pipeline to enhance the capacity between Vigdis and Snorre A, and it will help bring the wellstream from the subsea field up to the platform.

The scope of the contract includes a pump station with a manifold foundation and protective structure as well as a pump module, topside equipment, umbilical and all-electric controls with electric actuation. Work began in Bergen, Norway, in December 2018, and the first delivery is scheduled for February 2020.

Snorre expansion

Equinor also is championing its Snorre Expansion Project, and in early 2018 TechnipFMC was awarded an EPC contract for the scheme, covering the delivery of subsea production systems including six subsea templates and subsea production equipment.

TechnipFMC also claimed a contract from Equinor for the Johan Sverdrup Phase 2 development, located in the Norwegian sector of the North Sea at a water depth of 120 m (394 ft). The contract covers the delivery and installation of the subsea production system including integrated template structures, manifolds, tie-in and controls equipment.

TechnipFMC CEO Doug Pferdehirt highlighted ongoing efficiencies in the company's operations. In the company's third-quarter 2018 results report, he said, "We also successfully delivered two additional iEPCI [integrated engineering, procurement, construction and installation] projects in the third quarter—Trestakk and Visund Nord—both with Equinor on the Norwegian Continental Shelf. On Trestakk, our first awarded iEPCI project, we successfully delivered a fully commissioned subsea system utilizing only a single season of marine operations.

"Visund Nord was delivered in just 21 months from concept selection to first production; this was a new fast-track record for Equinor. An important factor in the success of these projects was the strong collaboration with our partner, Equinor, and the integrated capabilities of TechnipFMC."

TechnipFMC was recently awarded an iEPCI contract from Lundin Norway for the Luno II and Rolvsnes development, located in the North Sea at a water depth of 110 m (361 ft). The contract covers the delivery and installation of subsea equipment including umbilicals, rigid flowlines, flexible jumpers and subsea production systems.

In the U.K. sector, OneSubsea was awarded an EPCI and commissioning contract for a subsea multiphase boosting system by TAQA for the Otter Field.

OneSubsea and its Subsea Integration Alliance (SIA) partner, Subsea 7, will supply and install a subsea multiphase boosting system, including topside and subsea controls, as well as associated life-of-field services. The project will result in a 30.5-km (19-mile) subsea tieback to the TAQA-operated North Cormorant platform. This will be the longest subsea multiphase boosting tieback in the U.K. North Sea.

Meanwhile, Aker Solutions has been awarded a master contract to support the delivery of a subsea compression system for the Chevron Australia-operated Jansz-Lo Field offshore Australia. The first service order under the master contract will be for FEED of a subsea compression station that will boost the recovery of gas from the field. The FEED scope will also cover an unmanned power and control floater as well as overall field system engineering services. The field control station will distribute onshore power to the subsea compression station.

Composite pipe

Advances in thermoplastic composite pipe (TCP) solutions also are helping to cut costs for subsea installations.

Airborne Oil and Gas' TCP jumper is breaking through in deepwater applications around the world and is now expanding into West Africa following successful projects in the North Sea, Gulf of Mexico (GoM) and Asia. The disruptive technology provides considerable benefits in the application of a well jumper, where the flexible TCP jumper can be cost-effectively transported and installed subsea. The jumper is flexible, enabling installation without the need for metrology. This allows it to be prepared up front and installed directly after installation of the adjacent subsea components, such as manifolds, thereby reducing time to first oil. The jumper concept offers opportunities to prepare longer length on reel and cutting down to size in-country to deploy multiple jumpers in support of larger field layout.

Meanwhile, Magma Global, another manufacturer of TCP, has teamed up with TechnipFMC to collaborate on the development of the core element of its hybrid flexible pipe solution.

It will be used to address the challenges of the Libra Field in the Santos Basin presalt area offshore Brazil and other major deepwater projects. Brazil's Libra Field, operated by Libra Oil & Gas, is a deepwater presalt environment and considered to be one of the most challenging projects for the industry. The new hybrid flexible pipe incorporating Magma's m-pipe will deliver robust risers and flowlines with increased performance while offering significant overall reductions in the product installed cost. This will be achieved by combining the chemical resistance and fatigue performance of Magma's high-end carbon fiber PEEK TCP with the stability and strength of flexible steel armor.

Subsea tree technology

The subsea tree sector also has seen further moves by the main hardware manufacturers to streamline their offerings and reduce costs.

Baker Hughes, a GE company (BHGE), released its Aptara TOTEX-lite subsea system, a suite of new lightweight, modular technologies designed for the full life of field. The Aptara TOTEX-lite subsea system includes the lightweight compact tree, modular compact manifold, composite flexible risers, standardized fatigue-resistant wellhead system, modular compact pump and subsea connection systems.

The Aptara Lightweight Compact Tree system has a significantly reduced footprint compared with traditional deepwater subsea trees, which means 50% less weight and the potential to reduce Totex (capex + opex) by more than 50%.

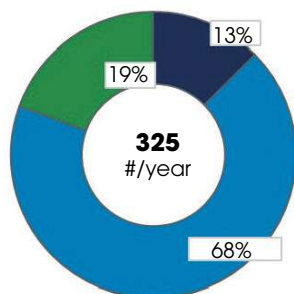
The Aptara tree also allows operators to evolve the tree system to suit changing reservoir conditions. Its unique industry-first design involves a flow path and caps for the tree that integrate functionality, such as high-integrity pipeline protection, or add boosting capability to reduce overall development costs or increase reservoir recovery.

"In recent years, our industry has made good progress in lowering the cost of subsea projects to the point where they have become more com-

SUBSEA TREE AND SURF INSTALLATIONS, 2000-2018 vs. 2019-2023

Subsea tree installation 2000-2018

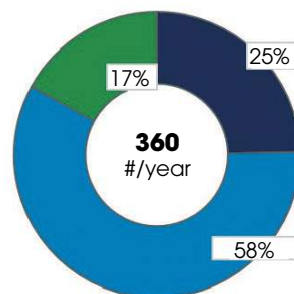
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Subsea tree installation 2019-2023

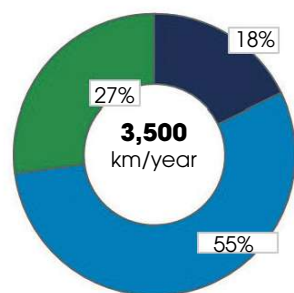
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SURF line installation 2000-2018

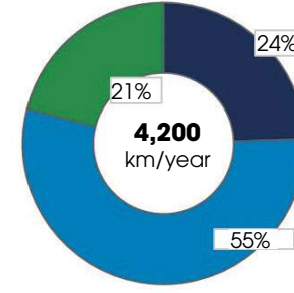
Kilometers



■ Ultradeep water ■ Deep water ■ Shelf

SURF line installation 2019-2023

Kilometers



■ Ultradeep water ■ Deep water ■ Shelf

The subsea market will be a top performing oilfield service segment in the years to come, according to Rystad Energy. (Source: Rystad Energy SubseaCube)

petitive with onshore developments,” said Neil Saunders, president and CEO of BHGE’s Oilfield Equipment business, in a press release. “While the gap has narrowed, we are taking that to the next level with Subsea Connect, making long-lasting, sustainable change and driving value from concept to commissioning and over the full life of the field.”

Smart subsea operations

There are also a whole host of smaller companies providing technology for smarter subsea operations. Norway’s Seabed Separation has released a dual pipe separator (DPS) technology that makes oil separation more efficient. By removing and treating water locally, all transport from the well or field is for oil and gas only.

This will reduce costs and increase revenues by enabling increased oil recovery and accelerated production. This business effect will be especially significant in subsea, where the DPS opens up for new production tie-ins on existing infrastructure.

Seabed Separation has received support from Lundin, Wintershall and Aker BP as well as public funding to commercialize the concept. A full-scale pilot was successfully tested at Equinor’s Porsgrunn test facility near Oslo in 2017 using fluids from the operator’s Troll Field.

Springing into action

Total also has been maintaining its reputation for offshore innovation. The operator is aiming to make significant savings in various areas, including water injection, thanks to the SPRINGS (Subsea PRocessing and INjection Gear for Seawater) project, the first-ever subsea sulfate removal and treated seawater injection unit that has been successfully tested by a deepsea pilot.

By removing a surface-based high-pressure water injection line, this solution will lower the development costs for satellite reserves that are more than 50 km (31 miles) away from an FPSO by more than 20%. Reducing development costs for fields located far from existing production locations

requires the intensification of subsea processing. Total partnered with Saipem and Veolia to meet the challenge.

The SPRINGS subsea unit is designed to operate in up to 3,000-m (9,843-ft) water depths, treat and inject up to 60,000 bbl/d of seawater filtered to one-thousandth of a micron.

Subsea power grid

In another industry breakthrough, Siemens has successfully concluded the first phase of its subsea power grid shallow-water test in Trondheim, Norway.

Siemens, in collaboration with industry partners Chevron, Equinor, Exxon Mobil and Eni Norge, is in the final stages of a program to develop a barrier-breaking system that will become the world's first subsea power grid designed for distribution of medium voltage power using pressure compensated technology.

"There will be more subsea compressors, pumps, processing plants and, in the future, entire production facilities placed on the seabed, all of which require power," said Frode Tobiassen, head of subsea at Siemens, in a press release. "This development is what we are preparing for with the subsea power grid."

The underwater power grid consists of a subsea transformer, subsea switchgear, subsea variable speed drive, subsea wet-mate connectors, and a highly reliable remote control and monitoring system that includes cloud-based user dashboards and data analytics.

Further integration

Following the downturn in 2014, a period of rationalization of subsea companies took place, and there were several tie-ups between major companies. This trend toward greater cooperation has continued, and Schlumberger and Subsea 7 are looking to form a joint venture (JV) that builds on the success of the SIA, which was established in 2015.

The SIA combines the subsurface expertise, subsea production systems and subsea processing systems of OneSubsea with the SURF systems capabilities of Subsea 7.

The proposed JV will create a unique life-of-field offering that includes autonomous subsea technology, digitally enabled remote surveillance and production monitoring, and inspection, maintenance and repair services.

BP and Aker BP also have entered into a pact to explore ways of developing pioneering new technologies together. The companies expect to invest in technological advancements, including developments in digital twins, advanced seismic techniques and processing, and subsea and robot technology.

Aker BP was formed in 2016 through the combination of Det norske oljeselskap and BP's Norwegian E&P business.

BP and Enpro Subsea announced the execution of a global frame agreement aimed at provid-

ing an enhanced subsea architecture and smart standardization using Enpro's flow access module (FAM) technology.

Enpro Subsea supplied the FAM technology to BP on the Kepler K3 project in the GoM, enabling project-specific technologies to be added to BP's standard subsea trees and manifolds to support BP in achieving

sanction to first oil in less than 12 months.

On the Kepler K3 project, BP used FAM technology to install multiphase metering, water cut metering and sand detection at the christmas tree end of a 3-km (2-mile) single spur tieback in addition to hydrate remediation and flow assurance hydraulic intervention module adjacent to the manifold. This removed the costs, risk and schedule associated with modifying standard hardware or adopting the dual flowloop alternative.

Following the success of the Kepler K3 project, Enpro and BP are now collaborating on follow-up FAM projects, including BP's Ariel 6, which is due to be installed later this year. **ESP**

Better collaboration between operators and contractors has seen subsea field architecture simplified, leading to further opportunities for growth.

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Evolving ROVs

By **Velda Addison**, Senior Editor, Digital News Group

Upgrades to work class and observation class ROVs propel sector forward.

As technology continues to transform the oil and gas industry, work class ROVs are taking up temporary residence on the seafloor as observation class vehicles aim to improve functionality.

Powered electrically or hydraulically, the ROVs are taking on tasks such as cleaning structures, inspecting equipment, carrying out surveys and supporting some drilling efforts—all while cutting costs and saving time for offshore operations. But the role of these tethered underwater vehicles is becoming more sophisticated as developers work to equip them with electric multifunction manipulators and other improved functions, enabling the devices to carry out more tasks.

“The end game is getting vehicles that can swim around subsea autonomously,” said Todd Newell, vice president of technology for Oceaneering International Inc., the engineering and technology company behind the battery-powered electric ROV (E-ROV). It also includes untethered operations and longer range capabilities.

The industry isn’t quite there yet. But headway is being made.

During a session at the recent Underwater Intervention 2019 conference, Newell spoke about key steps in the evolution of Oceaneering’s E-ROV, the concept for which he said was created by partner Equinor.

Oceaneering announced in August 2018 that one of its subsidiaries entered a contract with Equinor to provide a resident, battery-powered E-ROV to support subsea inspection, maintenance and repair activities on the Norwegian Continental Shelf in water depths up to 1,000 m (3,281 ft).

“This technology also deploys machine vision learning and augmented reality techniques, and

allows for efficiencies and versatility that lead to real-time control of the ROV and its tooling,” according to the press release.

The first-generation vehicle is moving beyond its original missions of carrying out remote operations utilizing subsea power stations. Amid continued steps to improve equipment reliability, the next generation E-ROV includes auto tooling, microbots, longer extensions, life-of-field applications and additional supervisory control, he explained.

“The technology inside E-ROV is actually building blocks for a lot of the future subsea robots,” Newell said. Key to its value proposition is an ability to be quickly deployed off a vessel to carry out tasks and be picked up by other vessels nearby to perform additional tasks, if needed. He compared the vessels as acting like taxicabs or Ubers for the E-ROV.

The solution is ideal for shallow-water regions where there is good field density, he said.

“It’s a really nice way of getting approximately 50 to 100 service vessel days out of annual service vessel budgets. That’s not a trivial amount of money for a solution that’s utilizing a lot of existing technology,” he added.

Volatile commodity prices combined with a drive for great efficiency have solidified technology’s place at the forefront of many oil and gas companies’ agendas to help bring down costs and improve operations. ROVs combined with automation also could transform how offshore operations are carried out. Such technologies are freeing up humans, who take on tasks, such as inspecting hulls, to perform other crucial tasks as innovation continues.

The next generation

Oceaneering's current E-ROV system is remotely operated using the company's Remote Piloting and Automated Control Technology (RPACT). As explained by the company, the system can perform typical tasks such as inspection, valve operation, torque tool operation and manipulator-related actions. It communicates to the onshore mission support center via a 4G mobile broadband system, allowing the transfer of real-time data and control.

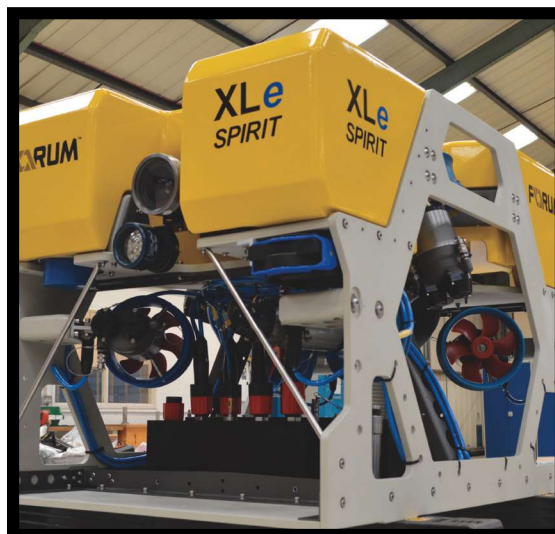
Its battery system has about 500-kW hours of energy, equivalent to about six weeks, Newell said. And the ROV can be recharged either subsea or on deck. The average ROV mission is about 30 hours. The ROV's main tasks have included a valve operation, a general observation operation on a leak and a cutting transport operation, Newell said.

The Freedom ROV can be either remotely piloted via tether or operated autonomously and tetherless using battery power, Oceaneering said. The ROV uses RPACT as well as Compass supervisory control software.

"The software provides full vehicle control—autonomy, payload and sensor control, top-side mission planning and situation awareness," Oceaneering said on its website. "The purpose-built Compass software provides key vehicle piloting improvements, including an unprecedented level of awareness in crowded subsea fields. The Freedom ROV can be programmed to make piloting decisions without the need for human pilot control, such as avoiding obstacles or responding to changing plans."

"Once we get E-ROV to where it has three months subsea duration, that's a nice time window for this to become a drilling support tool," Newell said. "There are supervisory controls built into this E-ROV already. There will be additional supervisory controls as well."

The company also has plans to take the technology into deeper water. However, Newell admits that could be a bit more challenging when it comes to communications using a 4G buoy or a satellite communications system. But that challenge, he said, could be remedied by using a power and communications cable from a drilling rig.



Forum Energy Technologies said its XLe Spirit E-ROV is capable of performing observation and inspection work as well as maintenance and repair work with its optional electric or hydraulic five-function manipulator arm. (Source: Forum Energy Technologies)

Also, the system will eventually move to electric tool manipulators, which also pose some challenges. In addition to having higher maintenance costs, lots of lift capability is lost with the switch to electric from hydraulic, Newell said.

Moving forward

Forum Energy Technologies also is advancing its large fleet of ROVs, having released the XLe Spirit earlier this year. XLe Spirit is the company's first observation class ROV to utilize its Integrated Control Engine (ICE). The technology aims to bring the ROV greater functionality that is typically found in larger work class vehicles.

John Herbert, business development manager for Forum Energy Technologies, discussed during the conference the company's new fully E-ROV product line, which includes the XLe Spirit. The ROVs aim to address concerns regarding loss of containment (LOC) and commonality of ROV system spares while lowering costs.

"As cameras, sonars, pipe trackers, gyros ... all decrease in size, it's becoming more practical for smaller observation class vehicles to enter the same realm and space as a traditional hydraulic work class cousin," Herbert said. "This brings operational advantages, such as reduction in LOC on a project, by introducing electric vehicles."

Other advantages include having smaller footprints and faster, less labor-intensive mobilization, Herbert said. **ESP**

Advanced Flowmetering

By **Gavin Munro**, GM Flow Measurement Services Ltd.

Two separate but overlapping flow ranges produced within a single metering device provide enhanced turndown ratios.

During a typical well test, flow rates are varied to assess reservoir size and performance. Many fixed and portable test separators utilize a dual chamber orifice fitting for performing the gas flow measurement, but these can be subjected to less than ideal use practices.

Experienced operators must perform the 30-minute plate changing process every time the flow rate changes significantly. This can result in five to eight gas release events during the testing of a typical exploration well. Some users have expressed safety concerns regarding exposure to flammable and possibly poisonous H₂S gas.

To maintain as small a footprint as possible, the space in which the orifice plate meters are installed is also generally very restricted. This can lead to the equipment incorporating several out-of-plane, 90-degree elbows at a distance of eight to 10 times of the pipe diameter (D), upstream of the meter. Essentially, going beyond the requirements set out in the ISO-5167-2 standard.

Most installations try to overcome this issue with a 19-tube bundle flow straightener, generally located five to six pipe diameters, upstream of the orifice plate. However, as ISO-5167-2 recommends these to be placed 13.5 D to 14.5 D upstream, it is highly likely that increased uncertainty is being introduced, especially at low beta (β) ratios. Alternatively, some users have deployed two parallel flowlines, containing meters, valves and instruments, adding to the capital cost, road (or crane) weight and maintenance costs.

Smarter flow measurement

Field operational constraints and functional concerns prompted the development of Adjusta-Cone, a modifiable cone flowmeter by GM Flow Mea-

surement Services Ltd. Applying conventional differential pressure (DP) cone meters as the base technology, a moveable cylindrical sliding sleeve is located within the bore of the meter housing and moves about a fixed position cone.

The sliding sleeve produces two separate but overlapping flow ranges, contained within a single meter body, giving an enhanced turndown ratio. It also boasts reduced installation space—up to 60% less footprint than that of a dual chamber orifice fitting—as well as weight benefits, compared to other meters.

The cone meter automatically self-adjusts to allow fluctuations of flow. In the low range, the sleeve partially covers the cone, and the β ratio is calculated between the cone outside diameter (OD) and sleeve inside diameter (ID). In the high range, the cone is uncovered, and the β ratio is calculated between the meter ID and the cone OD. The large and small β ratios produce one larger operating envelope, from the partial merging of the two individual envelopes.

However, the intelligent measuring tool has two different β ratios and corresponding coefficients of discharge, which are analyzed by the close-coupled flow computer. Aligned with the customer's choice of applicable standards, the technology computes every second the gas density, compressibility, expansibility, mass and volume flow rate.

Robust technology

Two flowmeters, a 6 in. (0.75 and 0.5 β) and 4 in. (0.7 and 0.45 β), were built and calibrated at the National Engineering Flow Laboratory (NEL) with dry nitrogen gas, flowing at 10 and 62 Bar (g) (Figure 1). A series of coefficients of discharge and corresponding Reynolds numbers were obtained.

At NEL, calibration was undertaken with the sliding sleeve in both the low and high ranges, and typical mass flow rates used for the 4-in. meter are shown in Table 1.

Upon completion of the dry gas calibration, the meter was wet gas tested using N₂ and a kerosene substitute to provide an over-reading datum for wet gas operation. Those data were compiled for a Lockhart-Martinelli parameter ranging from 0 to 0.25 and a gas Froude number ranging from 0.4 to 5.2. Selected dry gas results are shown in Figure 1.

The turndown ratio of the adjustable cone meter was demonstrated as 54.5:1 by mass flow rate (limited by the test facility). The example shows that an average uncertainty 0.49% applies over the calibrated operating range and the average repeatability of points is +/- 0.02%.

Field testing

In 2016 the 6-in. prototype meter was field trialed in the U.K. North Sea. It was installed in two offshore wells downstream of the separator pressure control valve during well testing operations.

The customer's orifice meter reading, running at 300 psi, was compared to that of the adjustable cone installed downstream of the pressure control valve and running at only 3 psi to 5 psi, which proved to be somewhat inconclusive.

Flow rates from the well tests were significantly lower than expected, so the adjustable cone was also found to be oversized. Readings from the adjustable cone were consistently higher than the orifice readings, largely due to oversizing, low pressure and the presence of moisture in the gas. The results proved that the meter was durable under oilfield conditions and that the sleeve would operate as desired.

Trials are ongoing on the 4-in. production model in the Middle East. Unlike the North Sea trial, in 2018 the meter was installed upstream of the pressure control valve so a direct comparison could be made with the customer's orifice plate readings.

The adjustable cone meter did not require a shift from the high range for all tests, while upward of 15 hazardous and time-consuming orifice plate changes were required as the flow rates were adjusted, exposing the operators to hazardous gas releases each time.

β Ratio	Pressure Bar (g)	Min Δp (mBar)	Max Δp (mBar)	Min q_m Kg/sec	Max q_m Kg/Sec
0.45	10	24	500	0.22 ²	1.01
0.7	10	24	850 ¹	0.86	4.96
0.7	61	24	850 ¹	2.04	12.00 ²
0.45	61	24	500	0.52	2.41

¹ Field use would limit the differential pressure limit to 500 mBar. ² Limits of the test facility

The adjustable cone meter provided a greater than 55:1 turndown ratio (in one range), which is comparable to expectations for the device. It also showed excellent agreement with the customer's flow data at consistently better than 0.5% of the orifice plate reading.

Gas metering of the future

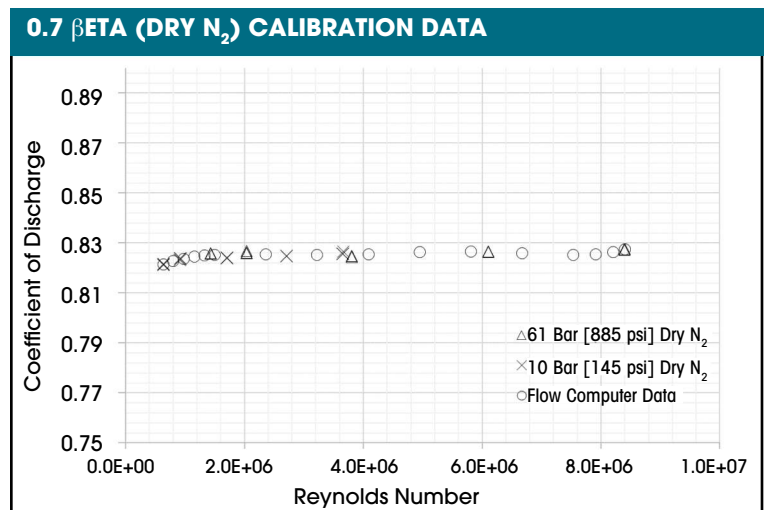
Further analysis is underway by GM Flow to fully understand the wet gas effect on different sizes of adjustable cone meters. The company is undertaking additional flow laboratory validation and characterization tests using finite element analysis and computational fluid dynamics to gain deeper insight into the mechanical, hydraulic and physical aspects of the device.

Various adjustable meter designs also are being investigated. This includes the application of advanced materials and manufacturing techniques and the use of artificial intelligence and machine learning software. Real-time remote access and control and wet gas applications also are being explored. **ESP**

References available.

TABLE 1. Data from the dry nitrogen calibration of the meter are shown. (Source: GM Flow Measurement Services Ltd.)

FIGURE 1. The sliding sleeve was calibrated in the low and high ranges, with typical mass flow rates used for the 4-in. meter shown below. (Source: GM Flow Measurement Services Ltd.)



Composites Gain Ground

By **Matt Green** and **Eri Vokshi**, ClockSpring|NRI

Composite solutions are delivering rapid, reliable riser repairs.

Composite repair systems are continuously improving. Technology advances are enabling the introduction of more composite products to the market, and more installations are improving industry understanding of the range of applications for composite systems. The growing number of installations is contributing to increased confidence in composites for both emergency and long-term repairs. These repairs generally can be carried out without negatively impacting operations, encouraging more potential users to take a closer look.

Taking the leap

In some cases, offshore companies have chosen a composite solution as a last resort.

For an operator offshore Thailand, a composite repair was made to avoid a traditional solution that could not be carried out without seriously impacting project economics. The asset owner had discovered wall loss on a 32-in. riser, but cutting the riser and replacing the pipe would have required production to be shut in, resulting in a loss of approximately

\$125,000/hr, or more than \$3 million per day. Replacement also would have required the logistics of sourcing the pipe and a vessel to transport it to the rig as well as engaging qualified welders to carry out the work, a process that could have taken months.

Instead, the riser was evaluated to determine the extent of the corrosion so a composite solution could be designed. Experts examined the pipe details, noting that the riser had lost significant wall thickness at an area where the riser transitioned through a concrete floor on the rig and was on a long radius elbow joint. The decision was made to use a unique pre-impregnated, bi-directional composite system that would reinforce the riser. This wet-applied system ensures the proper fiber-to-resin content ratios that are essential for reliable performance on transmission and distribution pipelines, oil and gas risers, process piping and is appropriate for complex geometries such as elbows, tees, flanges and girth welds.

Installing the composite repair

To promote adhesion, the technicians cleaned the riser with power tools to remove rust, paint and other foreign particles. The pitting and corrosion defects on the pipe were filled with two-part, high-compression strength epoxy putty. Using filler to address defects before applying the composite has two purposes: it restores the pipe to its original geometric shape and helps in transferring the load from the riser to the composite system.

Once the filler was applied, technicians coated the riser with the high-compression strength two-part Kevlar reinforced epoxy. Like the filler, the epoxy has two functions. It arrests corrosion and promotes the bond between the riser and the composite wrap, and it provides a load transfer medium

Technicians applied a composite repair to a long radius elbow joint over a length of about 3 m (10 ft) on a riser where it transitioned through the concrete floor of the rig. (Source: ClockSpring|NRI)



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engineered to cycle and work under extreme pressure strain and aggressive pressure cycling. Finally, the line was wrapped with a high-strength, fiberglass composite wrap to provide structural integrity to the repair. The materials were applied over a length of about 3 m (10 ft) to restore the riser to its original design pressure of 1,580 psi.

By using this high-quality composite repair system, the riser was repaired in less than 36 hours. A full hydrostatic pressure test of the cured repair at 1,700 psi (117 bar) for 4 hours provided confidence that the riser could be returned to service. It was restored to full operation later that afternoon, and production resumed, eventually reaching full capacity of 17.8 MMcm/d (630 MMcf/d).

Testing reliability over time

The riser had been in service for five years when the decision was made to remove the repaired segment. The intent was to perform inspections and tests to gain a better understanding of how the composite had withstood five years of wear. It is important to note that there were no issues with the performance of the repair during this time.

Part of the process involved a full review of the product testing and compliance information to verify the long-term values used in the original design. This review, coupled with the full site inspection and product tests of the original repair, would serve as proof of the composite repair's effectiveness for long-term use. The results would be used in the development of subsequent composite system designs.

As the contractor removed the composite repair system on location, adhesion testing and coupon inspections were made on the original repair system. These tests showed that the composite repair not only functioned as expected, but that there was no noticeable degradation of the adhesion of the system, which meant the composite would have continued to function as designed had the riser remained in service. Full inspection of the pipe wall thickness also revealed that the riser had experienced no further corrosion, which proved the composite also functioned successfully as a corrosion coating.

These test results, combined with the performance of the repair during five years of field service,

established the composite repair as a viable option for the owner, which not only reinstalled the composite repair on the original section of the riser but installed similarly designed composite repairs on other areas of the same pipe. These sections also will serve as test/inspection points to provide further field testing of the composite system.

Testing during product development

Composites materials used in structural strengthening are multicomponent systems that include a reinforcing fiber (glass, carbon, aramid, etc.), a saturating resin, a primer polymer and a filler compound. Understanding the role of each component (on both microscopic and macroscopic scales) in the system and its performance behavior is critical to ensuring a design that is based on limit state analysis. Thorough material performance analysis requires an understanding not only of the molecular behavior of the material but also an understanding of how that translates into a macroscopic performance.

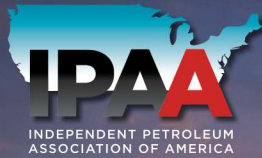
Usually, microscopic and macroscopic studies constitute different fields of research. Most R&D groups do not pursue them concurrently. However, when a technical team understands the connection between them and explores the two fields together, the knowledge of the materials is more complete, and there is much greater confidence in the products that are designed. This is a costly process, but R&D is vital to designing composite repairs that perform under exacting conditions on critical components.

The performance of this composite system in the field is a testament to the R&D process, validating the design as well as the design process.

Efficacy and efficiency drive adoption

Composite technologies are changing the way corrosion repairs are carried out offshore. Developed specifically to contend with corrosion, composite technologies have been used to repair a range of offshore defects, producing results that prove their value in extending the service life of offshore rigs.

As companies in the offshore industry work to contain costs, more will begin using composite solutions that reduce risks and deliver reliable and durable repairs without compromising project economics. **ESP**



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Americas and Middle East Put Offshore Back on the Map

By **Aditya Ravi** and **Olga Kerimova**, Rystad Energy

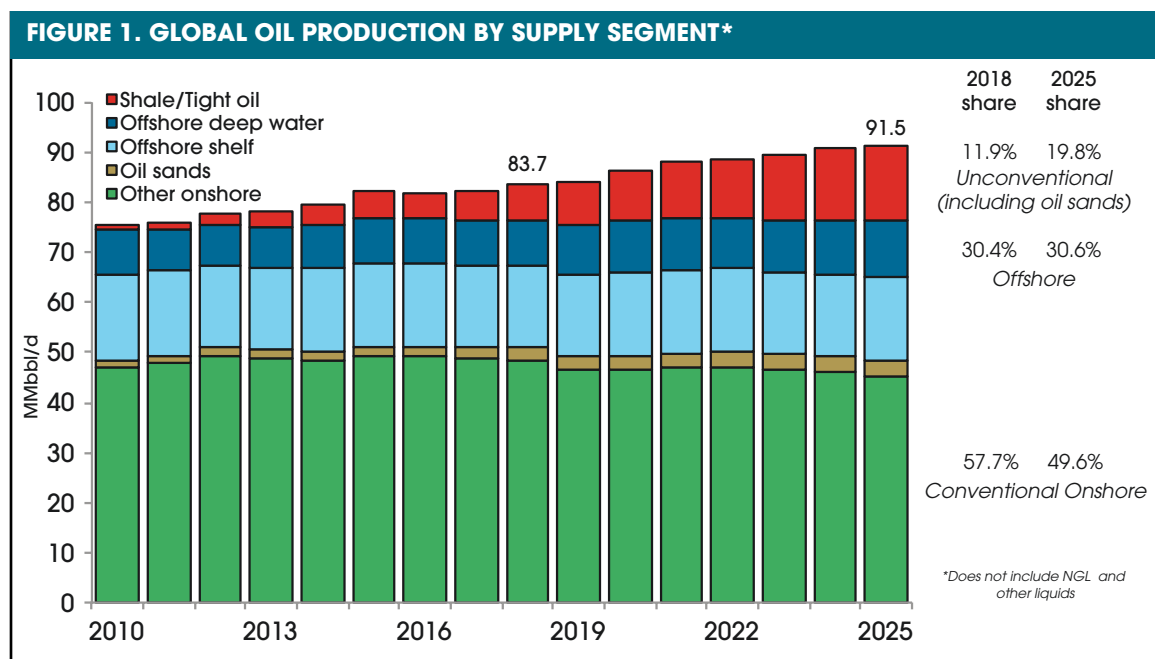
Offshore investment activity will see a gradual recovery next year with capex estimated to reach almost \$180 billion in 2025.

Since the beginning of this decade, the industry has seen an accelerated increase in the global oil supply as production has expanded at twice the rate on average in comparison to the previous decade. Oil output has grown more than 8 MMbbl/d in the last eight years from about 75.3 MMbbl/d in 2010 to 83.7 MMbbl/d in 2018 (Figure 1). Global oil production is set to grow further to about 91.4 MMbbl/d by 2025, as the ever-expanding shale production not only replaces the diminishing conventional oil produced onshore but also expands, catering to the growing global demand. In this high-growth environment, it is

noteworthy how the share of the offshore volumes in the overall oil supply has diminished from more than 35% in the 2000s to just over 30% in the 2010s. However, these levels are no longer expected to contract and are projected to remain relatively constant over the next few years. In absolute terms, Rystad Energy forecasts offshore oil production to expand from the current 25.4 MMbbl/d to about 28 MMbbl/d by 2025.

Global offshore sanctioning—new cycle expected

In the period 2010 to 2013, on average 9 Bbbl of offshore oil resources were sanctioned globally. After



(Source: UCube from Rystad Energy)

a trough of low sanctioning activity following the oil price collapse, a new surge in sanctioned resources is expected to be seen this year, with the Middle East and South America showing the most growth (Figure 2). Although somewhat lower sanctioning activity is anticipated next year, an average of 10.9 Bbbl/year in offshore oil resources is expected to be sanctioned over the next six years.

Among the key discoveries to be sanctioned this year is Phase 2 of the Liza Field offshore Guyana as well as large projects in Brazil in the Tupi and Marlim areas. Mero 2 is expected to be sanctioned in May with

bids to supply subsea trees for the FPSO already underway, and a tender for umbilicals, risers and flowlines is expected to be offered in April. Mero 3 and 4 are expected to be sanctioned next year. Atapu North is expected to reach a final investment decision (FID) by the end of the year, Buzios 5 in September this year and Itapu in the second half of the year (the tender process was delayed from the planned first quarter of 2019). The Marlim Revitalization project is due to be sanctioned in the second quarter of this year.

In the Middle East, expansion projects in Saudi Arabia dominate the FID landscape this year, with the expansion of the Zuluf Field to be approved by year-end, and Marjan and Berri expansions are expected to be sanctioned in the second quarter of this year.

The growth in sanctioned volumes post-2022 is expected to come both from the Americas and the Middle East, including the development of additional resources in the Safaniya Field in Saudi Arabia, Phase 2 of the Carcara Field offshore Brazil and Phase 2 of the Ayatsil-Tekel oil field offshore Mexico. Moreover, the development of Phase 2 of

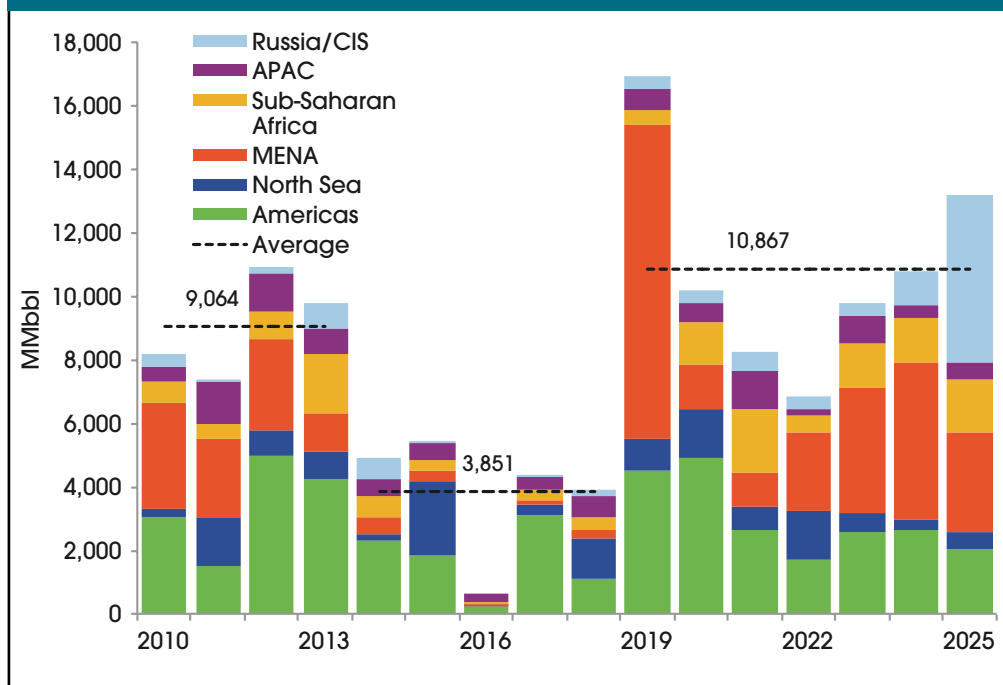
the Kashagan Field may add up to 5.5 Bbbl of sanctioned crude resources.

Americas poised for another wave of sanctioning

The Americas have been able to maintain a relatively stable oil supply from offshore sources over the past decade with production averaging about 6.45 MMbbl/d. The credit could largely be attributed to Brazil, as the nation has been able to compensate for the production decline from Mexico, where output has been falling steadily since 2004 (Figure 3). The gigantic presalt finds in Brazil have massively helped the Latin American nation take over as the leading offshore oil producer in the region.

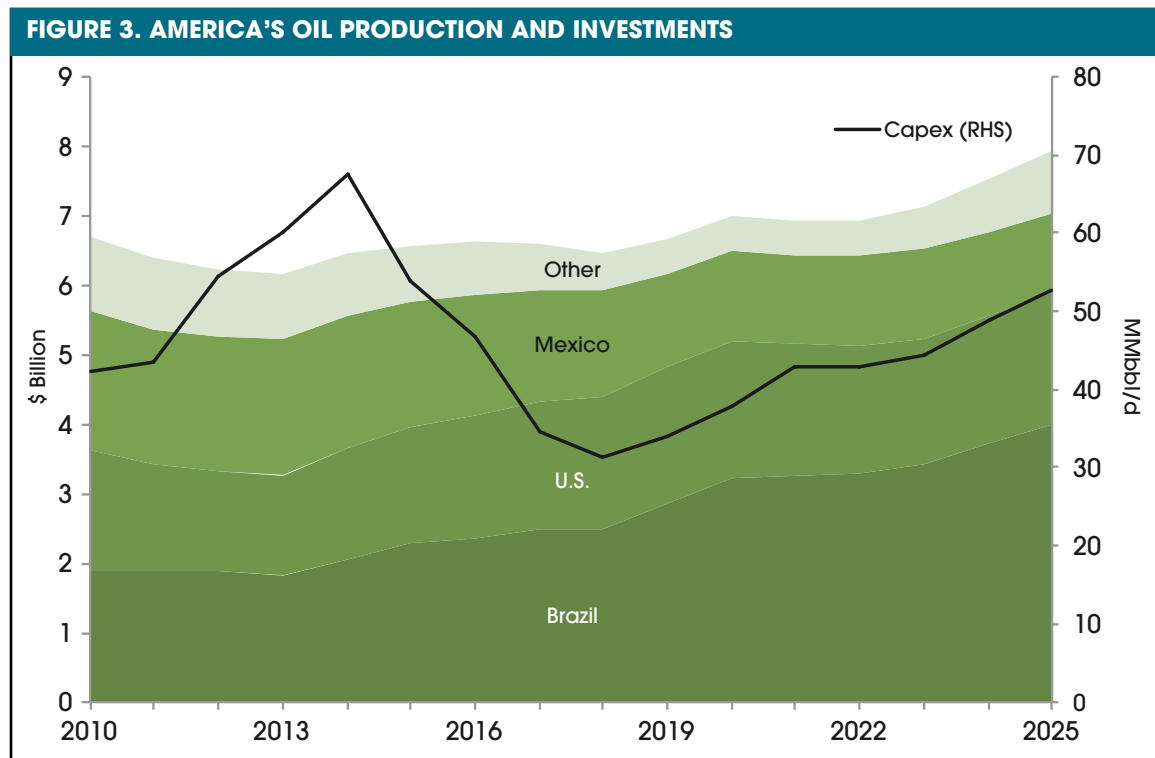
Elsewhere, a relatively stable oil price environment from 2010 to 2014 supported multiple field sanctioning on the U.S. side of the Gulf of Mexico (GoM), which led the region to follow in Brazil's footsteps. The two countries have been adding an average of 250,000 bbl/d year on year into the market over the past five years. This upward trend is expected to flatten out but just in the U.S. GoM. Brazil embarked upon its 10-year journey of doubling its 2-MMbbl/d offshore oil supply in 2014

FIGURE 2. GLOBAL OFFSHORE OIL SANCTIONED RESOURCES BY APPROVAL YEAR, SPLIT BY REGION



(Source: UCube from Rystad Energy)

(Source: UCube
from Rystad
Energy)



and has not even reached the halfway mark yet. The country is expected to add about 370,000 bbl/d in supply per year over the next two years. This would help the Americas region reach the 7-MMbbl/d mark and sustain it over the next four years until the next wave of presalt oil kicks in, further expanding the region's output to 8 MMbbl/d.

The 2010 to 2018 production levels were made possible by the massive investments by E&P operators during the oil price boom period. Capex was at an all-time high in the Americas from 2012 to 2014, peaking at about \$67 billion in 2014. As one would expect, Brazil and the U.S. GoM were the areas that attracted the highest spending. As E&P companies started contracting their spending budgets in the backdrop of the oil price collapse, since 2014, capex shrunk significantly, with investments in 2018 at less than half of what was spent five years ago. However, this trend is expected to be reversed as the industry stands at the cusp of the next potential investment wave. Over the next two to three years, the industry could see companies making FIDs on nearly 14 Bbbl of oil within the Americas. Brazil is touted to attract tremendous attention from the floater

specialists as it launches a barrage of tenders covering FPSO developments.

Some of the projects expected to gain the most traction would be the three additional units on Mero, two units on the Campos Basin Marlim project, where the operator intends to extend the life of field, a unit each on Parque das Baleia and Itapu, and a fifth unit on Búzios. In the U.S. GoM, Chevron is expected to lead efforts on the Anchor and Ballymore discoveries, while LLOG is expected to move ahead with its Mormont, Shenandoah and Khaleesi finds over the next few years. Mexico also is expected to make a return to the investment commitment scene, with Pemex expected to begin developing its multiple shallow-water finds, such as Esah, Cheek, Manik, Kinbe and Mulach. Fieldwood Energy, whose plan of development for its Pokoch-Ichalkil development was approved recently, is expected to make a FID soon. Elsewhere, Exxon Mobil is expected to commit larger capital to its Guyanese finds with Phase 2 on Liza followed by the Payara-Pacora fields. Combined, these factors will propel the spending in the region upward to more than \$45 billion per year on average over the next six years.

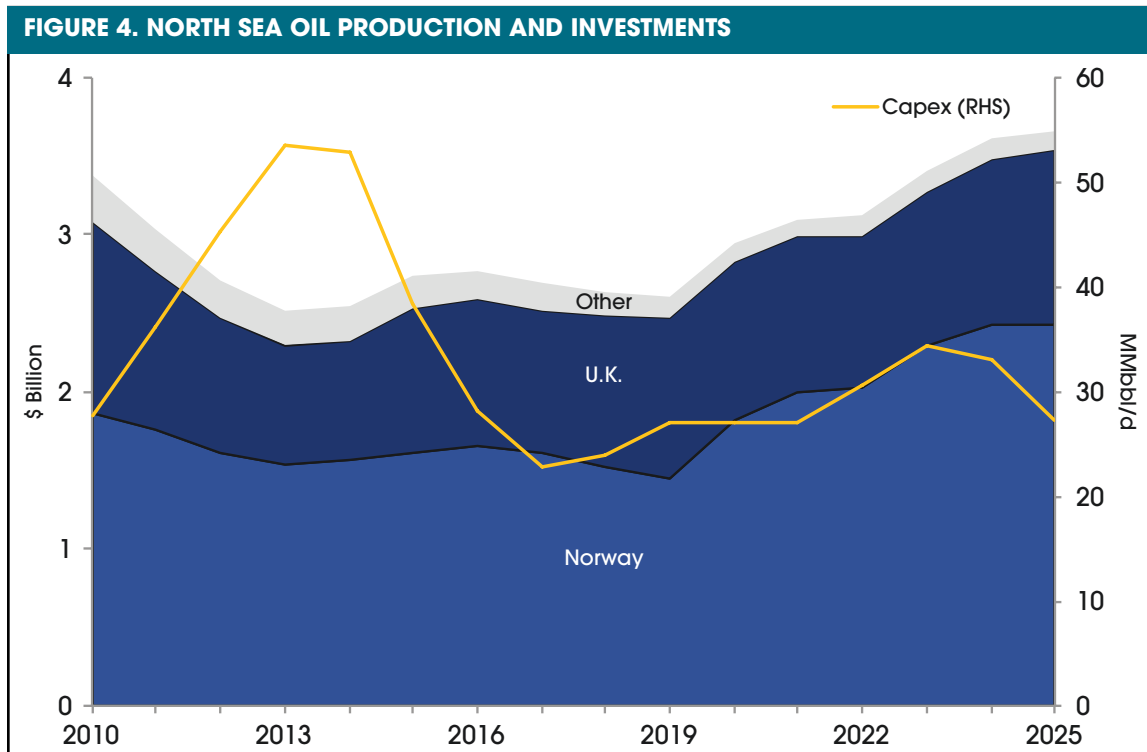
North Sea

As a result of the natural decline of mature fields, oil production from the North Sea declined historically from 3.4 MMbbl/d in 2010 to 2.5 MMbbl/d in 2014 (Figure 4). After a period of growth in 2015 to 2016, the decline was resumed, with this year's supply expected to fall to about 2.6 MMbbl/d. With Phase 1 of Norway's Johan Sverdrup project expected to start producing by the end of 2019 and Phase 2 in 2022, renewed production growth is expected next year, leading to about 3.6 MMbbl/d produced by 2025. From 2020, Johan Sverdrup is estimated to be the field with the most significant contribution to production growth, along with Johan Castberg and the expansion of the Snorre Field.

Investments in the region have declined steeply from the peak levels in 2013 to 2014 to a low of \$23 billion in 2017. The increase in spending before 2014 was primarily from mature fields in the Norwegian North Sea, such as Troll, Ekofisk, Eldfisk and Gullfaks, as well as the more recent Edvard Grieg and Jasmine discoveries. Key contributions to investments post-2017 are from the development of discovered resources, primarily Johan Sverdrup, as well as the Culzean Field, both

of which are expected to start producing by the end this year, and the Johan Castberg Field is scheduled to be online by year-end 2022. Post-2020, the Rosebank/Lochnagar and Lancaster projects in the U.K. North Sea, the Ormen Lange subsea compression project and the Grosbeak discovery (Gjøa area) in Norway, and the redevelopment of the Hejre Field in the Danish North Sea are expected to see increasing investments.

Hence, overall capex in the North Sea is expected to reach about \$27 billion this year, roughly half of the peak levels seen five years ago, and should grow to \$30 billion to \$35 billion over the next five years. Supported by the increasing investments, and largely driven by Norway, North Sea oil production is expected to enter a new growth phase next year and reach 3.6 MMbbl/d by 2025. Commercial development of the long-awaited Johan Sverdrup Field will play a key role in stable supply in the medium term. Both Norway and the U.K. hold significant discovered resources, and the timely development of these, as well as successful exploration performance in the future, will be crucial for the long-term production in the region.



(Source: UCube
from Rystad
Energy)

Middle East and North Africa

Offshore oil production in the Middle East and North Africa (MENA) region has increased from 6.8 MMbbl/d in 2010 to 7.8 MMbbl/d in 2018 (Figure 5). This year output is expected to increase by about 330,000 bbl/d to 8.1 MMbbl/d.

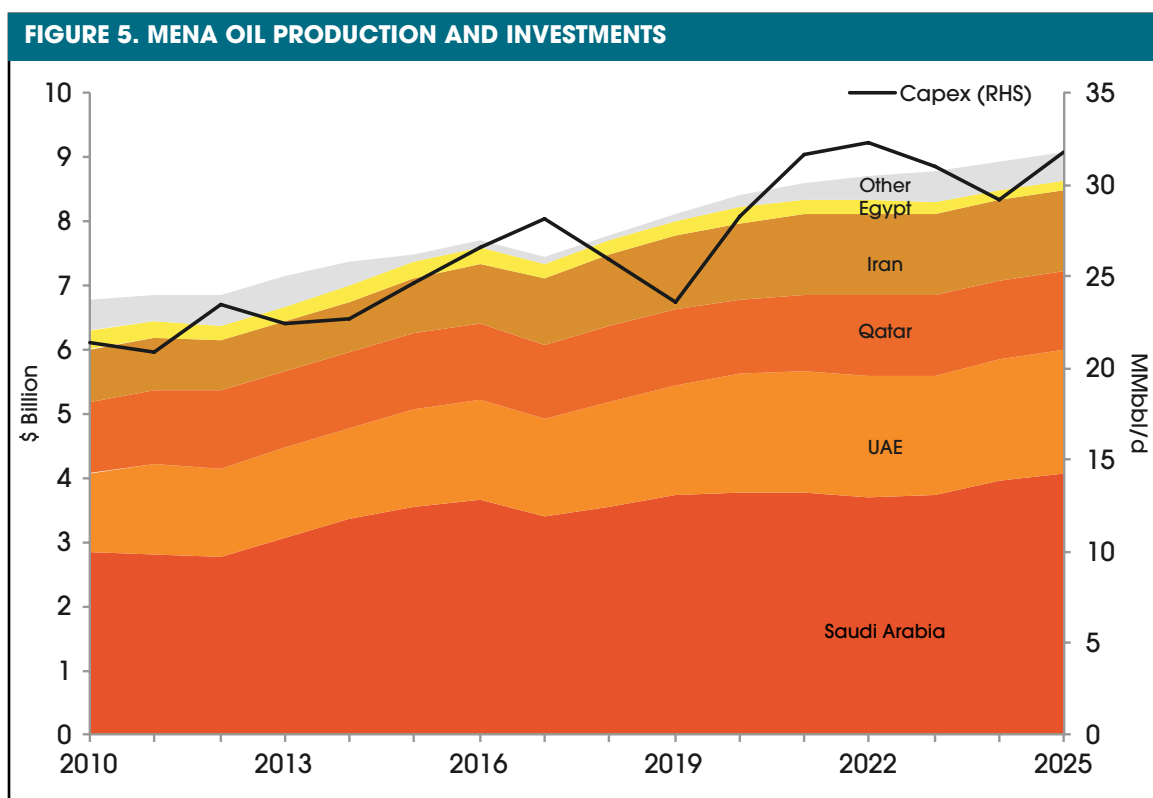
Saudi Arabia, the largest producer in the Arabian Gulf, is expected to keep oil supply rather flat year on year, in line with the OPEC+ cut agreement reinstated in December 2018. Rystad Energy estimates offshore oil production in the region to grow by about 180,000 bbl/d per year from 2019 to 2025, with the biggest contributions coming from the United Arab Emirates (UAE) and Iran. It is anticipated that Saudi Arabia will keep supply stable even after the OPEC agreement has expired to avoid an oversupplied market.

Offshore oil production in the MENA region is set to stand at about 9 MMbbl/d by 2025. Short-term growth is projected to come primarily from the development of the Satrah Al Razboot and Umm Lulu (Phase 2) fields in the UAE, which were put on production in September 2018, as well as Phase 2 of the Nasr

Field. In Iran, South Pars phases 13, 14 and 22-24 will be key for production growth going forward.

Spending levels have been increasing until 2017, reaching peak levels of about \$28 billion. Last year the capex was about \$26 billion, while 2019 spending is projected to stand at about \$24 billion. The region's offshore spending is expected to grow next year, averaging \$28 billion to \$32 billion over the next three years. During this time period, Saudi Arabia is expected to increase capital investments the most. Among unsanctioned fields, expansions of Marjan, Berri and Zuluf fields will see the largest capital contribution in the years to come, with all three projects expected to be sanctioned this year.

The UAE also is among the countries that are leading in terms of the capital investment increase in the medium term. A large part of the growth comes from new projects, including the Hail and Ghasha sour gas fields, and Phase 2 of the Upper Zakum expansion. In Qatar, the North Field expansion project (trains 8-11) is scheduled to be approved in 2019 to 2020 and will contribute to short-term growth in investments.



(Source: UCube from Rystad Energy)

Hence, the MENA region's offshore oil production is expected to grow over the next five years, with the highest short-term to medium-term growth projected in the UAE and Iran, while longer term growth is seen from the large projects in Saudi Arabia on track to be sanctioned later this year.

Sub-Saharan Africa

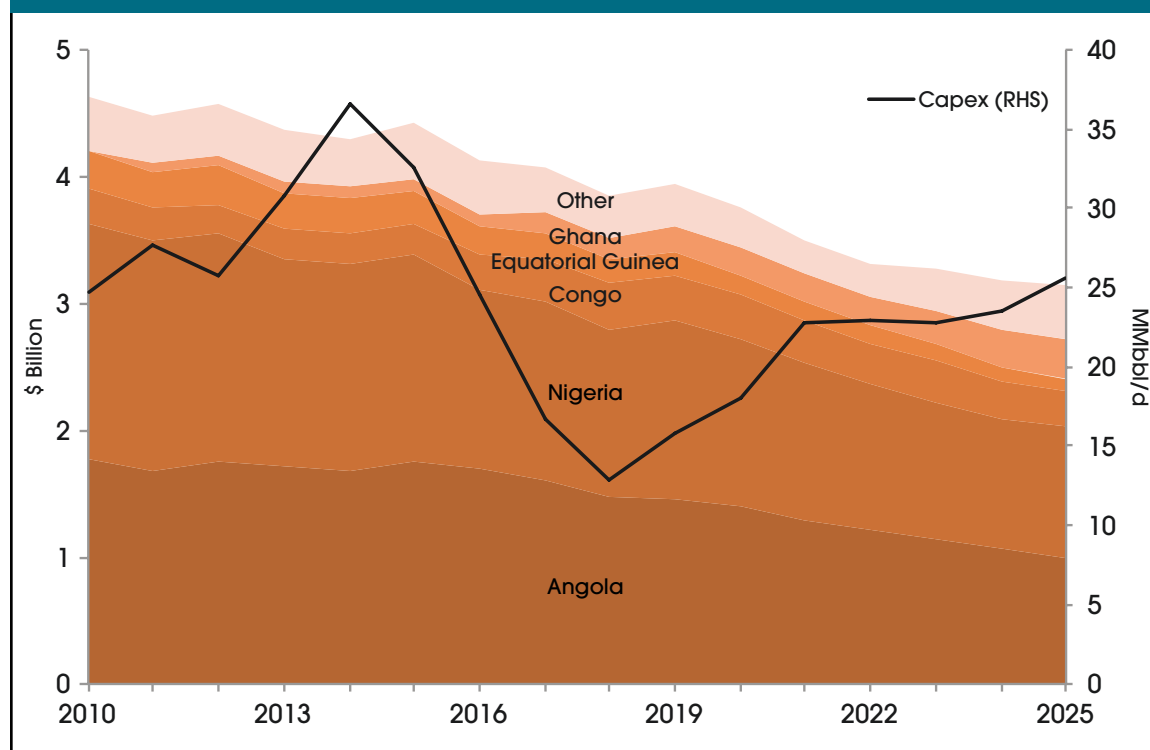
With more than half the production coming from maturing fields, Sub-Saharan offshore supply has been declining steadily since 2010. The region has seen its output decline to about 3.8 MMbbl/d in 2018 from the 4.5 MMbbl/d peak achieved in 2010 (Figure 6). Nigerian offshore output, averaging at 1.3 MMbbl/d in 2018, has declined the most, with production falling by about 525,000 bbl/d since 2010. Angola, currently the largest producer in the region, has seen its output fall by about 290,000 bbl/d during the same period, averaging 1.48 MMbbl/d in 2018. One should not expect a complete turnaround in this relatively mature region. Rystad Energy forecasts the production to continue falling by a further 800,000 bbl/d to a shade lower than 3

MMbbl/d by 2025. Investments in new projects are key for the region going forward, as more than 35% of the 2025 investments are expected to be in the currently nonproducing fields.

Offshore oil investments, which have been falling in the region since 2014, bottomed in 2018 at about \$13 billion. These numbers were rallying much above the \$25 billion mark, until an oversupplied market led to significant downsizing and capital discipline since 2014. However, Rystad Energy expects a reversal in the trend in the region, as the spending levels are expected to increase gradually over the short term, with slightly steeper growth expected over the medium term.

Nigerian projects, either delayed due to the uncertainly revolving around the Petroleum Industry Governance Bill (e.g., Bonga Southwest-Aparo and Owowo West) or delayed by legal action (e.g., Etan-Zabazaba) would act as key contributors to the higher spending levels and helping the country to keep the overall decline levels in check. In Angola the BP-led PAJ fields and Eni-led developments in Block 15/06 are some of the projects

FIGURE 6. SUB-SAHARAN AFRICA OIL PRODUCTION AND INVESTMENTS



(Source: UCube from Rystad Energy)

expected to be sanctioned over the next few years. Elsewhere, the Pecan development in Ghana and the recent finds of SNE in Senegal remain the drivers for raising the overall investment levels in the region. The projects mentioned above, along with a few others, would help raise investment levels to more than \$20 billion in the short term and close to \$25 billion in the medium term across the region.

Asia-Pacific

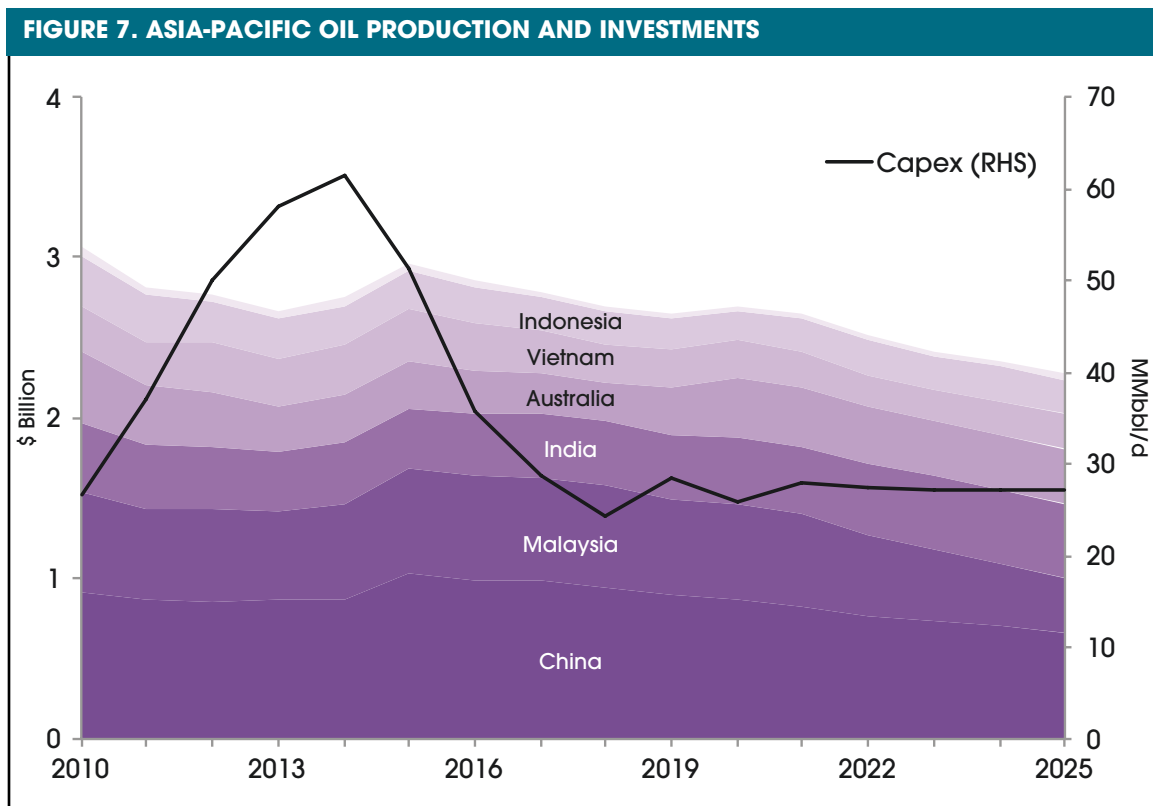
Another region where a significant amount of offshore oil supply comes from maturing fields is the Asia-Pacific, where Rystad Energy has seen the production decline from more than 3.5 MMbbl/d in 2010 to under 3 MMbbl/d in 2018. While the majority of the nations that make up the region have been able to sustain production, certain countries (namely Indonesia, Australia, Brunei and New Zealand) have seen their output fall dramatically.

One of the major factors for the offshore output falling is the lack of discovered volumes in the region. Over the past 10 years, total new volumes

found in the region's waters represent a meager 8% of the total discovered offshore oil resources globally. Additionally, only about a third of these discovered volumes have been able to get off the ground. This decline in production is expected to continue into the future, with production falling another 500,000 bbl/d over the next six to seven years, reaching about 2.5 MMbbl/d in 2025. However, this phase of decline is seen to be primarily dominated by China, Malaysia and Indonesia, whereas India and Australia are expected to revamp their supply.

One major reason nations like India and Australia are expecting to raise their production would be the high level of project sanctioning over the past few years. The 2018 sanctioning by ONGC on the R-Series and KG-DWN-98/2 (Northern Cluster) in India and the Ichthys and Prelude projects in Australia are helping to support production growth in these countries.

Offshore investments in the Asia-Pacific region have declined massively over the past five years, contracting by about 60% from the 2014



(Source: UCube from Rystad Energy)

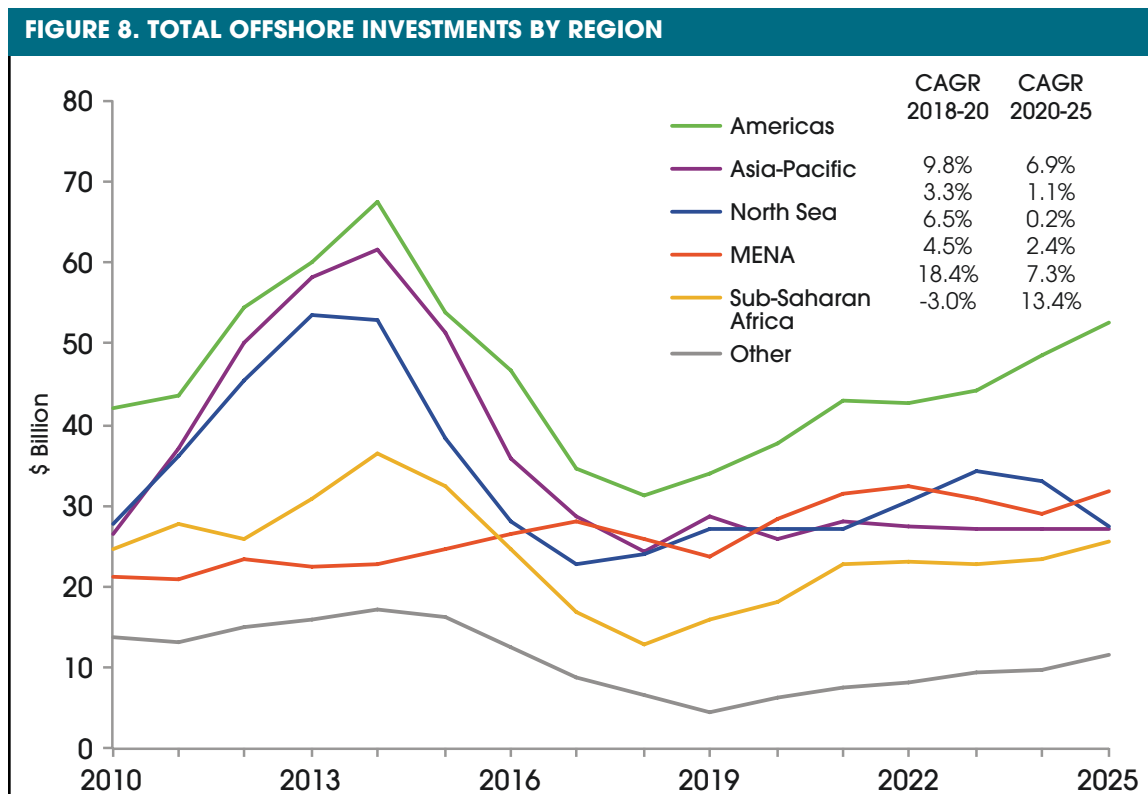
peak of \$60 billion (Figure 7). The 2018 investment levels are expected to be sustained over the short and medium term as E&P operators battle to find projects worth investing in within this mature region. Overall, about \$1.6 billion worth of oil resources are expected to be sanctioned over the next four years, driven by the CNOOC-operated Lufeng and Weizhou fields. Further contribution is expected from the shallow-water fields in India, led by a plethora of Indian E&P operators like ONGC, Vedanta and Hardy Oil & Gas. However, a lack of sizable investment options dictates an inevitable decline scenario in the region.

Conclusion

The honeymoon years of high offshore investment activity were followed by a period of more cautious activity and lower spending, culminating in 2018 when the offshore spending levels are estimated to have dropped to a low of about \$125 billion, a level not seen since 2007. However, a gradual recovery is expected already next year with capex estimated to reach almost \$180 billion in 2025.

Further analyzing the spending trends by region (Figure 8), this cyclical trend is evident for all geographies, to a greater or lesser extent, with a notable exception of the MENA region, where the spending levels have been fairly stable since 2010. The Americas are by far the largest region in terms of offshore investments, followed by Asia-Pacific, North Sea and MENA. North and South America are also the regions where we expect to see the highest growth in investments going forward, with Brazil and the U.S. GoM contributing the most.

The high growth in investments in South America and the GoM, the increasing spending in the North Sea and the consistently high spending levels in the Middle East are mirrored in the production contributions of these regions to the global offshore oil supply outlook. Hence, motivated by the significant sanctioning activity expected from these regions over the next five years, increasing volumes are expected to mitigate the decline from the regions dominated by the more mature production base, such as Sub-Saharan Africa and Asia-Pacific, keeping medium-term global offshore oil supply at about 27 MMbbl/d. **E&P**



(Source: UCube from Rystad Energy)

SPONSORED CONTENT

Things Go Better with Pipe

Growing pipeline network brings better prices, lower costs

Texas oil and gas producers can see the future now. As continued investment and hard work pay off with new and expanded pipeline capacity across the Lone Star State, many producers see stronger commodity prices as well as declining transportation expenses.

This good news is especially welcome in the Permian Basin. Pipeline bottlenecks there have cast shadows on what's otherwise one of the brightest spots in the industry today. Yet pipelines represent just part of the midstream universe. Gathering, treatment and storage can become pinch-points, too, as the U.S. resumes its historic role exporting crude oil and finished fuels to a still oil-hungry world.

And now that more (and bigger) ethane crackers and LNG technologies are creating a global market for American natural gas and its components, there are new choke points in these supply chains: Storage near ports and available liquefaction capacity across a growing fleet of LNG export plants.

Texas lies at the heart of it

Virtually all growth in U.S. oil and natural gas production for the next several years is expected to come from shale plays or unconventional wells – and the shale revolution began in Texas. Today the ports of Beaumont, Brownsville, Corpus Christi and Houston collectively export more crude oil and refined products than the rest of the country combined.

America's largest LNG export terminal is just across the state line – and other plants are coming at key points

2018 Event Metrics



along the Gulf Coast, some in Texas, some in Louisiana. This new global market connects with upstream supplies via Texas' midstream operations. The most extensive network of crude, natural gas and refined product pipelines in the U.S. wraps from South Texas to Beaumont with interconnects to the east and south into Mexico.

Lots of midstream action

All these factors and more will be examined and discussed within the program at Hart Energy's 2019 **MIDSTREAM Texas Conference and Exhibition**, June 5-6, 2019 at the Midland Country Horseshoe Pavilion in Midland, Texas.

Conference attendees at this annual event will hear nearly 20 speakers, from top executives with operating companies to economic experts, financiers and industry association leaders, as they analyze critical issues in today's midstream markets. Upstream supply, downstream demand, midstream bottlenecks (from gathering and treatment to pipelines, storage and LNG), as well as export terminals (onshore and offshore) will be fair game.

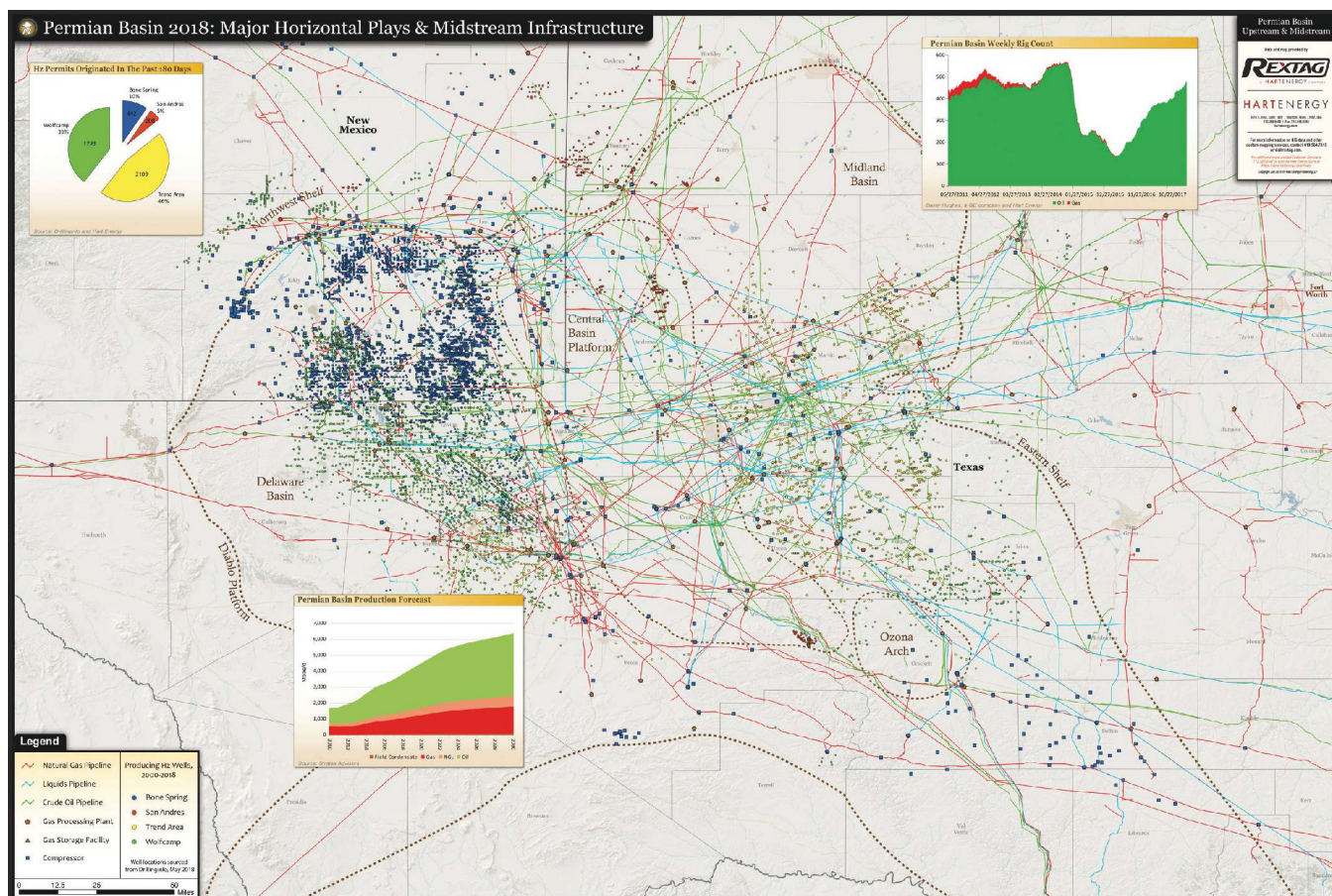
Solid knowledge transfer will occur

The MIDSTREAM Texas stage will host business, operations and technology leaders from organizations that are making huge investments.

The opening keynote address will come from Robert G. Phillips, chairman, president and CEO of Crestwood Equity Partners. The CEO of EagleClaw Midstream Ventures, a founding part-



The MIDSTREAM Texas Conference & Exhibition attracts hundreds of qualified midstream professionals from pipeline operators, E&P companies, gas processing facilities, transportation companies and other midstream-focused businesses.



ner and CEO of **Moda Midstream**, the president and CEO of **Lucid Energy Group**, and the president and CEO of **Vaquero Midstream** round-out the conference's C-suite presenters. The SVP - Corporate Development for **Enbridge**, the VP of Engineering & Operations for **EVX Midstream** and a dozen others complete the slate of esteemed speakers who will address the changing landscape for Texas' infrastructure.

Their organizations' assets and capabilities will play out-sized roles in what's coming for upstream producers, midstream operators and downstream users across the world. Beyond new or expanded pipes and growing storage terminals, a race is on to load VLCCs (very large crude carriers). Will it be dockside in Texas ports or from terminals offshore? Hear what's being said on-stage as well as among the hundreds of industry professionals in the session room and on the exhibit floor.

Fresh scrutiny on midstream assets

As this article goes to press, how midstream networks affect product quality is creating concern for the growth of U.S. exports. After South Korean refineries rejected two Eagle

Ford crude cargoes for oxygenate contamination, refiners may be re-thinking how to rebalance their crude slates.

Meanwhile, natural gas prices at the Waha hub have even occasionally shifted negative as producers outpace Mexican demand for piped gas, mostly for power generation. This squeeze seems destined to continue as new LNG capacity is being permitted, funded and built along the Texas coast.

No one knows what the future holds, but it's almost certain that more changes lie ahead. The best way to keep up is to be there. Register today at **MidstreamTexas.com**. **ESP**

CONFERENCE & EXHIBITION

MIDSTREAM
TEXAS

MidstreamTexas.com



2019 MERITORIOUS AWARDS FOR ENGINEERING INNOVATION

An expert panel of judges has selected the top 18 industry projects that open new and better avenues to the complicated process of finding and producing hydrocarbons around the world.

The *E&P* editors and staff proudly present the winners of the 2019 Special Meritorious Awards for Engineering Innovation, which recognize service and operating companies for excellence and achievement in every segment of the upstream petroleum industry. The pages that follow highlight 18 winners, picked by an independent team of judges.

The winning technologies represent a broad range of disciplines and address a number of challenges that pose roadblocks to efficient operations. Winners of each category are products that provided monumental changes in their sectors and represented techniques and technologies that are most likely to improve artificial lift, drillbits, drilling fluids/stimulation, drilling systems, exploration/geoscience, formation evaluation, HSE, hydraulic fracturing/pressure pumping, intelligent systems and components, IOR/EOR/remediation, marine construction and decommissioning, nonfracturing completions, onshore rigs, subsea systems and water management.

This year some of the brightest minds in the industry from service and operating companies entered excep-

tionally innovative products and technologies that have now been measured against the world's best to be distinguished as the most groundbreaking in concept, design and application.

The awards program recognizes new products and technologies designed by companies and people who understand the need for newer, better and constantly changing technological innovation to appease the energy-hungry world.

The panel of judges comprised experts in business, engineering and the sciences representing operating and consulting companies worldwide. Each judge was assigned a category that best utilized his or her area of expertise. Judges whose companies have a business interest were excluded from participation.

E&P would like to thank these distinguished judges for their efforts in selecting the winners in this year's competition.

As in past years, *E&P* will present the 2019 awards at the Offshore Technology Conference in Houston.

An entry form for the 2020 Special Meritorious Awards for Engineering Innovation competition is available at HartEnergy.com/mea. The deadline for entries is Jan. 31, 2020. **ESP**

2019 MEA JUDGES

Ben Bloys
Chevron

Mike Forrest
Consultant

**Richard "Dick"
Ghiselin, P.E.**
Qittitut Consulting LLC

David Johnston
Differential Seismic LLC

Peter Lovie
*Peter M. Lovie,
P.E. LLC*

Richard Mason
Hart Energy

Nelson Oliveros
*Integrated Energy
Services, Petrofac*

Bill Pike
KeyLogic

Eve Sprunt
Consultant

John Thorogood
Drilling GC

Scott Weeden
Consultant



ARTIFICIAL LIFT WINNER

AccessESP | RIGLESS WIRELINE RETRIEVABLE ESP

AccessESP's wireline retrievable electric submersible pump (ESP) system reduces the impact of deferred production and rig cost. A permanent magnet motor and a side pocket wet connect system were integrated to allow slickline/wireline ESP retrieval on a live well. The design also allows fullbore access to the lower completion when the ESP is retrieved. The goal is to integrate these technologies into a simplified rigless conveyance system that reduces HSE exposure and risks, reduces opex and offers cost-effective production optimization. Traditionally, when an ESP performance deteriorates or fails, or when an operator needs to access the lower completion for well repair or remediation, the only option is to pull the entire tubing string to surface, sometimes in remote or offshore operations with intervention costs ranging from \$3 million to \$15 million. There is often an opportunity cost associated with production downtime or well damage from kill fluid. HSE risks are associated with heavy workover operations. Many of these costs and risks can be eliminated when using wireline retrievable



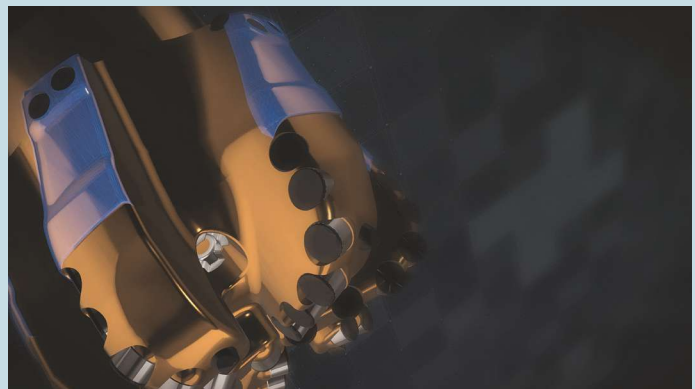
AccessESP's wireline retrievable ESP helps reduce HSE exposure and risks while providing cost-effective production optimization. (Source: AccessESP)

ESP. AccessESP systems mitigate these challenges, providing an alternative for well completion and ESP conveyance that allows ESPs to be changed out without a rig, on a live well and with reduced surface equipment. ■

DRILLBITS WINNER

BAKER HUGHES, A GE COMPANY | DYNAMUS PDC DRILLBIT WITH ANTIWALK TECHNOLOGY

Downhole forces can cause inclination and azimuth deviations in the lateral sections of horizontal wells. When an adjustable kickoff motor assembly fails to track straight, rotation must be stopped to execute a slide and correct trajectory. Trajectory corrections slow drilling and cause tortuosity and undulations along the well path. The Dynamus drillbit technology from Baker Hughes, a GE company (BHGE), incorporates design elements such as StayTrue shaped inserts for enhanced stability, wear-resistant Optimus cutters for extended life, a SweepBlade layout for ROP performance and a new matrix material body with high-torque shank. Each of these components plays a vital role in drilling smoother, straighter and longer laterals in less time and at less cost. In addition, Dynamus bits feature an AntiWalk gauge pad configuration that regulates side-cutting response using lateral depth-of-cut control. The engineered gauge pad optimizes tracking to hold azimuth and inclination with reduced dogleg severity under random lower-level lateral forces, yet it does not



The AntiWalk gauge pad engages the borehole wall at very low tilt angles to prevent trajectory deviations and resist lateral movement. (Source: BHGE)

hamper lateral aggressiveness while steering or building curve. The AntiWalk configuration essentially enables that bit's side-cutting response to adjust to changes in the outside lateral forces acting on the bit for consistently smooth, on-target drilling with less tortuosity. ■



DRILLBITS WINNER

ULTERRA | SPLITBLADE PDC BIT

Poor cuttings evacuation from the toolface of the drillbit has long been known to limit ROP. When traditional drillbit designs leave cuttings trapped on the toolface, collecting around the cutters and junk slots, drilling energy is wasted, toolface control is compromised and the bit can be damaged as result of rising temperatures. Ulterra's SplitBlade PDC drillbit design was developed to address the problem of poor cuttings evacuation. With its unique split blade geometry and double-barrel hydraulics, SplitBlade has enabled operators to achieve dramatically improved ROP, durability and directional control. The drillbit's primary blades separate past the cone, creating large-volume flow channels for cuttings evacuation. Vectored nozzles create a double-barrel hydraulics effect, dra-



matically boosting the maximum cuttings dispersal rate. This design channels more fluid directly onto the cutters, continually sweeping the junk slots and causing cuttings to be cleared from the cone up to seven times faster than conventional PDC drillbits. This improved cleaning allows the bit face to engage and fracture rock unimpeded, increasing ROP. The hydraulics of SplitBlade keep cutters cleaner, lowering residual heat, reducing thermal damage and increasing bit performance and longevity. ■

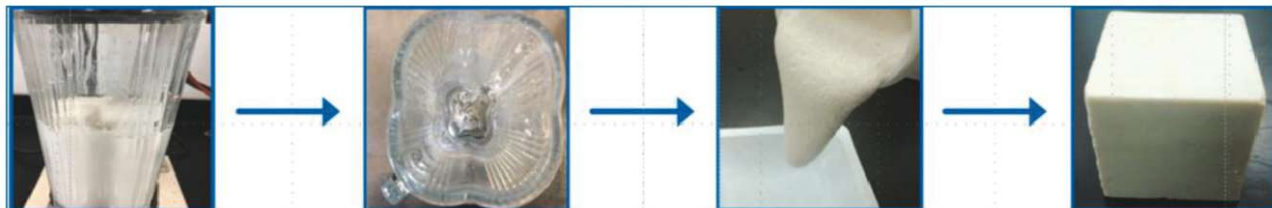
In the Midland Basin, operators using the SplitBlade PDC bit have reported an average 22% increase in ROP, a 26% increase in footage and improved dull condition in all cases. (Source: Ulterra)

DRILLING FLUIDS/STIMULATION WINNER

BAKER HUGHES, A GE COMPANY | MAX-LOCK LOST CIRCULATION MATERIAL

Drilling fluid losses to the formation are often an expensive and all-too-frequent problem for oil and gas operators, leading to nonproductive rig time, additional well costs and heightened operational and HSE risks. By one estimate, the industry spends \$2 billion annually to mitigate fluid losses, including pumping lost circulation materials (LCMs) such as calcium carbonate, cellulosic plant fibers and cross-link polymers. MAX-LOCK from Baker Hughes, a GE company (BHGE), is a step-change system for one of the industry's oldest and costliest challenges. The magnesia-based LCM is a phase-transformation technology that exhibits thixotropic behavior during pumping

and spotting. Once in place, the LCM will solidify into an acid soluble plug, which can be remediated later if needed. The thixotropic shear thinning fluid is easily mixed on site and pumped through the drillpipe. As MAX-LOCK enters formation voids and fractures, its viscoelastic properties thicken as its flow rate diminishes, building a gel structure that enables the LCM to effectively bridge the loss zone. Upon curing, it hardens into a high-compressive strength, nonporous plug that solidifies thief zones to enable drilling to resume. It is customizable so setting times can be formulated to match temperature, density and other application-specific variables. ■



MAX-LOCK LCM is shear thinning, does not settle after mixing, becomes crosslinked with temperature and sets to a solid plug after 2 hours of curing. (Source: BHGE)



DRILLING FLUIDS/STIMULATION WINNER

M-I SWACO, A SCHLUMBERGER COMPANY | MEGADRIVE EMULSIFIER PACKAGE

When standard invert-emulsion systems are reused multiple times, low-gravity solids buildup can cause progressive gel strengths. As the cost of base oil continues to increase, the required dilution results in higher overall cost per barrel of nonaqueous fluids. Most oil-based systems are reliably and thermally stable, but many typically exhibit elevated, and sometimes severe, progressive gel strengths as drilling progresses. In recognition of this problematic trend in elevated gel-strength oil-based fluid applications, M-I SWACO, a Schlumberger company, has developed the MEGADRIVE emulsifier package. This new drilling fluid system delivers the durable and temperature-stable invert-emulsion fluid operators have requested, without the associated elevated



The MEGADRIVE emulsifier package eliminates the costly drawbacks of elevated gels in invert-emulsion drilling. (Source: Schlumberger)

gel strengths. In addition, this fluid withstands high-solids loading, enables lower HP/HT filtrate values and delivers high tolerance to seawater and cement contamination. The MEGADRIVE package uses the MEGADRIVE P primary high-performance emulsifier as well as MEGADRIVE S secondary high-performance emulsifier and coating agent to synergistically provide good emulsion stability with low filtrate. This MEGADRIVE package

is designed to improve overall drilling performance of oil-based muds, potentially saving operators hundreds of thousands of dollars per pad. ■

DRILLING SYSTEMS WINNER

AFGLOBAL | ACTIVE CONTROL DEVICE (ACD)

AFGlobal's Active Control Device (ACD) for deepwater managed pressure drilling (MPD) seals and diverts annular wellbore returns using a nonrotating technology enabled by an actively pressurized sealing element. According to AFGlobal, the ACD system is the industry's first active, nonrotating sealing device for MPD operations. MPD methods are broadly used to address many offshore operational and safety challenges. Sealing and diverting annular returns are critical to these operations. The ACD replaces the decades-old rotating control device (RCD) technology with a design that eliminates major sources of wear, maintenance and risk. In doing so, it improves economics and the application of MPD. Active control of the primary sealing mechanism independent of wellbore pressure contrasts with conventional RCD sealing mechanisms based on an interference fit. The active



Testing of the ACD system was done at AFGlobal's purpose-built, full-scale test rig facility that simulates offshore drilling conditions by enabling simultaneous rotation and reciprocation with dynamic movement of the drillpipe mandrel. (Source: AFGlobal)

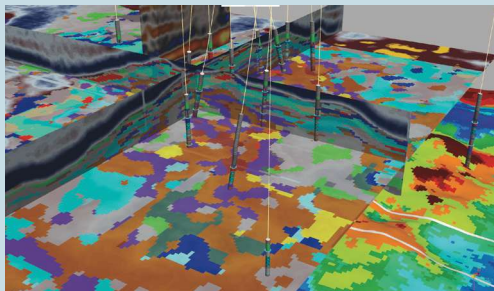
control ensures sealing integrity over the element's full life cycle and enables monitoring and condition-based maintenance that improves efficiency and safety. The ACD transforms how deepwater MPD operations seal and divert annular flow. Its advanced design and new capabilities to monitor and control greatly reduce wear, maintenance and risk in this critical task.

The ACD system has been designed so that catastrophic failure of the elements will not occur. The condition-based monitoring system included with the unit allows the operator to fully understand seal state with an estimated percentage of seal life remaining. ■



EXPLORATION/GEOSCIENCE WINNER

EMERSON | ROCK TYPE CLASSIFICATION WITH MACHINE LEARNING



Machine learning and rock-type classification use seismic data and facies logs to predict facies volumes and their probability of occurrence to improve reservoir characterization.

(Source: Emerson)

Emerson E&P has developed a supervised machine learning approach called Democratic Neural Network Association (DNNA). The method reconciles multiple datasets to predict facies away from the wellbore. It employs an ensemble of many neural networks running in parallel that simultaneously learn from the multiresolution wellbore and seismic data using different strategies and associations. This architecture minimizes the possibility of biasing. It includes a secondary training stage where seismic data are introduced away from the wellbore and voted on for training set inclusion to stabilize network training while preventing overlearning. The outcome of this process is a probabilistic facies model description of the reservoir. It predicts the most probable facies distribution and associated maximum probability as well as the probability relative to each facies. This results in less guesswork when quantifying uncertainty in rock type distribution. Results are interactively generated in a 2-D and 3-D environment for in-depth anal-

ysis and are reservoir simulation ready. The outcome is critical for reservoir geologists and engineers to better understand reservoir behavior. Once considered nice-to-have technologies, the sheer volume of well and seismic data that need to be analyzed has made machine learning an effective approach for transformation and analysis of subsurface data. Automated machine learning produces outputs in minutes or hours rather than months or years. DNNA provides a practical approach to invert directly for the desired model facies resolution and heterogeneity, including fluid overprint. The method has been demonstrated to predict lithozones in both conventional and unconventional reservoirs. ■

FORMATION EVALUATION WINNER

SCHLUMBERGER | CONCERT WELL TESTING LIVE PERFORMANCE

Concert well testing live performance from Schlumberger improves operational efficiency, optimizes HSE for both personnel and environment, and obtains high-quality data from surface and downhole to prove reservoir potential while empowering operators to achieve actionable test results. The Concert ecosystem digitally and autonomously acquires data from downhole tools, surface sensors and video, and it seamlessly makes data available with analytical capabilities to all testing team members and the operator wherever they designate so they can perform the well test as one team. The access and collaboration afforded by digital integration revolutionizes wellsite efficiency, informs timely decision-making, improves fluid-handling safety and mitigates environmental impact. Sensors and cameras are deployed



Concert well testing live performance equips wellsite personnel for real-time data access and communication with all team members and the operator sharing the same views and capabilities.
(Source: Schlumberger)

across all surface test operations for data acquisition, monitoring and analysis via rugged tablets and wearable technology. Robust software drives web dashboards and video displays to tablets and wherever operators specify, with everyone viewing the same data, diagnostics and analysis. Concurrent analysis and advanced diagnostics refine the scope of work and predict operational events or raise an alarm when needed. Test efficiency and HSE

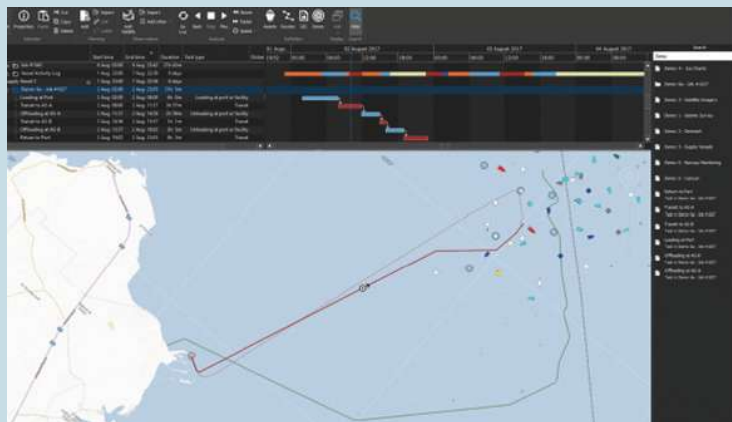
improvements come from automated data acquisition eliminating exposure to manual sampling and monitoring. The integrated video cameras continuously monitor burner combustion to enable 24/7 surveillance for fall-out, emissions and deluge water curtain without physically stationing personnel in visual monitoring proximity that subjects them to extreme heat radiation. ■



HSE WINNER

ION GEOPHYSICAL | MARLIN SMARTER MANAGEMENT OF MARINE OPERATIONS

Marlin ensures safety while reducing operational downtime in congested offshore theaters by giving all parties working in proximity full situational awareness of the planned activities of every other asset in the area. Marlin is the only commercially available marine intelligence platform that combines temporal project planning with 3-D situational awareness, analyzing and predicting operations using multiple real-time information sources like AIS, GIS and MetOcean data. Planned operations are combined with this live positioning data to flag potential conflicts based on operational objectives and HSE policies. This continuous assessment of operations reduces risks to safety and cost management, minimizing vessel and crew downtime due to scheduling conflicts. Gantt charts provide clear temporal visualization of operations in the area, with visual maps providing a real-time view of actual asset activities. All data are recorded over the course of a program so that operators can play



Marlin can be applied in a variety of marine applications, including SIMOPS, emergency response, geophysical operations, integrated activity planning, offshore logistics, and supply vessels and integrated asset logistics. (Source: ION Geophysical)

back operations at a later date to investigate incidents or identify opportunities to improve SIMOPS performance in the future. ■

HYDRAULIC FRACTURING/PRESSURE PUMPING WINNER
AFGLOBAL | DURASTIM PUMP

The DuraStim hydraulic fracturing pump developed by AFGlobal offers far-reaching gains in frac pump performance and the execution of hydraulic fracturing treatments. Its advantages for high-pressure, continuous duty operation extend to offshore pumping applications. According to AFGlobal, the DuraStim pump is the industry's first fully automated, long stroke, low frequency variable displacement pump. Developed for extreme duty on multiwell completions, the 6,000-hp pump comprises six individual pump units integrated by a computerized control, synchronization and automation system that varies pump rate hydraulically. A constant speed, zero emission 6,600-volt AC motor and six hydraulic rotary pumps drive the system. Electric and turbine drives are optimized by the constant speed operation, resulting in significant gains in fuel efficiency, reduced emissions and noise. Fluid-end stress, a key source of wear with conventional pumps, is greatly reduced by the new pump's 48-in. stroke and a low cyclic rate of 20 cycles per minute or less compared to 200 cycles per minute with conventional pumps. The pump triples the horsepower produced from the same footprint

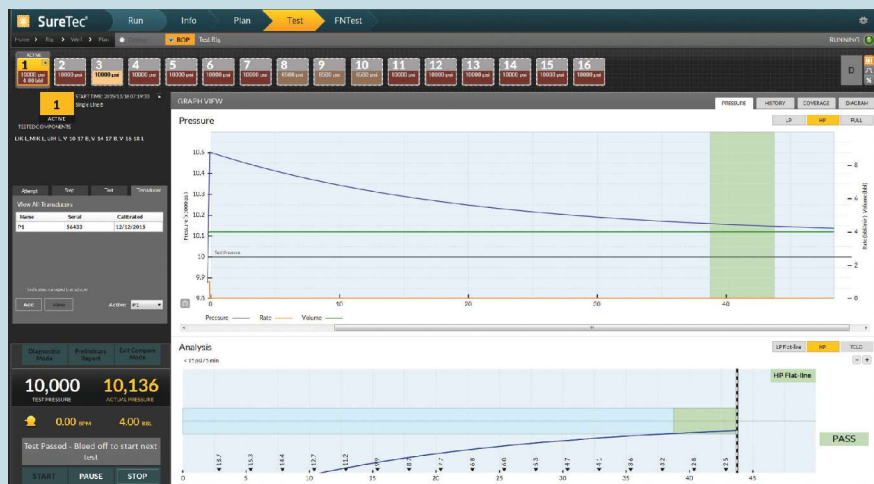


AFGlobal's DuraStim hydraulic fracturing pump is designed for multiwell completions and helps reduce frac spread complexity. (Source: AFGlobal)

as conventional pumps, significantly reducing frac spread complexity and improving wellsite logistics and safety. Cloud-enabled predictive maintenance and built-in diagnostics enhance continuous duty operation. ■



INTELLIGENT SYSTEMS AND COMPONENTS WINNER IPT GLOBAL LLC | SURETEC



The real-time validation of a subsea pressure test is provided in SureTec. (Source: IPT Global LLC)

required pressure tests throughout the life cycle of a well. IPT Global focuses on addressing the pressure testing workflow with a single integrated software platform designed to be the principal system of record for all pressure testing in upstream operations. SureTec provides real-time analysis of pressure, rate and volume data with preconfigured criteria so that tests can be objectively passed or failed. The tools were

IPT Global LLC created SureTec, a software suite specifically designed to address the challenges commonly experienced in digital pressure testing. The software was created as a fit-for-purpose digital alternative to properly design, plan, test, report and archive the results of all

designed to be intuitive and allow the user to quickly create easy-to-edit complex schematics. The planning tool was designed with industry requirements in mind and contains several safeguards that inform the user of incomplete test plans, missing testing requirements and safety concerns. ■

IOR/EOR/REMEDIATION WINNER BAKER HUGHES, A GE COMPANY | FATHOM XT SUBSEA226 BLACK OIL FOAMER

As subsea fields age and wells follow their natural decline curve, they begin to exhibit liquid loading, leading to fluid slugging in the flowlines connecting wells to production facilities. While common, these issues have historically been difficult to mitigate without expensive system upgrades and deferred production. The FATHOM XT SUBSEA226 black oil foamer is an economical alternative to combatting liquid loading and fluid slugging problems, enhancing the value of subsea assets. The FATHOM XT SUBSEA226 foamer effectively reduces liquid loading in deepwater subsea wells, minimizes fluid slugging in subsea flowlines and maximizes oil and gas production. The advanced chemistry foams 25 to 40 American Petroleum Institute gravity crude oil containing up to 60% water to



Applications of the new black oil foamer in the deepwater Gulf of Mexico have created millions of dollars in value for operators by reducing downtime and increasing production, according to the company. (Source: BHGE)

increase well run times, maximize production rates and reduce opex in high-cost deepwater environments. Baker Hughes, a GE company (BHGE), developed the new foamer by its FATHOM XT qualification procedures to validate reliability, deliverability and system compatibility under demanding deepwater conditions. The SUBSEA226 foamer can be added directly to the well without

dilution either on a batch basis or continuous basis, depending on the severity of liquid loading and the ultimate treatment objectives. ■



MARINE CONSTRUCTION AND DECOMMISSIONING WINNER

WEATHERFORD | MECHANICAL OUTSIDE-LATCH SINGLE-TRIP (M.O.S.T.) PLUS TOOL SYSTEM

Weatherford reinvented its subsea wellhead retrieval system by capitalizing on new technologies and redesigning components to increase cutting efficiencies. The M.O.S.T. (mechanical outside-latch single-trip) Plus tool includes a newly designed tension-cut mandrel, nonrotating flexible stabilizer (NRFS), large-diameter cutter and high-angle knives. The tool uses an advanced system that can reduce rig time by cutting and retrieving multiple cemented or uncemented strings in a single trip. The system uses custom cutting mechanism options to facilitate the most efficient cutting and recovery of subsea wellheads. These options include tension cutting with a top drive, compression cutting with a marine swivel or top drive rotary, compression cutting with a mud motor, and tension cutting with a mud motor. The M.O.S.T. Plus system confirms the cut without the need for tripping and easily latches and releases to inspect the cutting knives. It causes no damage to the internal wellhead seal-



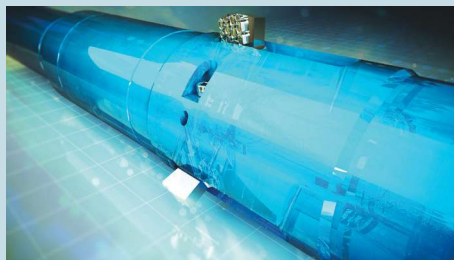
The tension-cut mandrel, NRFS, large-diameter cutter and high-angle knives in the M.O.S.T. Plus tool help minimize opex. (Source: Weatherford)

ing profile. The external latch mechanism helps to prevent swarf buildup by allowing more flow area in the high-pressure wellhead, which enables the cuttings to exit. The latch and unlatch also can be visually confirmed using an ROV on the seafloor. External latching also provides superior lateral support for the wellhead assembly to eliminate any lateral whipping that might impede cutting. The newly designed tension-cut mandrel enables the recovery of wellheads even where the ocean floor is at an incline. It recovers top-heavy wellheads or wellheads that protrude above the mud line, which can cause the wellhead to list and the partially cut-section to close in on the knives before the cut is fully severed. The tension-cut method can eliminate an additional run during wellhead cutting and retrieval. ■

MARINE CONSTRUCTION AND DECOMMISSIONING WINNER

BAKER HUGHES, A GE COMPANY | PERSEUS PUMP-THROUGH CUTTER

Baker Hughes, a GE company (BHGE), has developed its Perseus pump-through cutter. The internal hydraulic tubular cutter is designed to cut a single string of casing as part of a plug-and-abandonment campaign, slot recovery, well intervention and other cut-and-pull operations. The tool is dressed with BHGE's METAL MUNCHER advanced milling technology tungsten-carbide knives to cut or mill even the toughest steels. With an ability to increase mill life and penetration rates by as much as 1,000%, the carbide knives give the tool durable cutting and swarf control, while enabling more volume to be milled out in one run. Perseus is hydraulically operated and features on-demand knife activation to cut a single string of casing. When running above a mill or drill-bit, the cutter remains dormant and retracted, a unique internal design that enables 100% flow through and maintains pressure integrity below the tool. This feature allows multiple operations to be performed during the same trip,

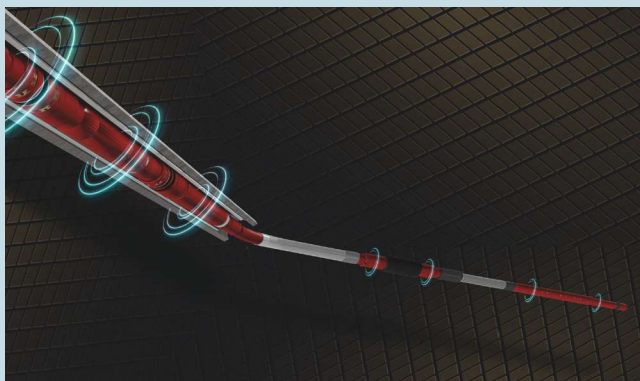


Perseus is designed to reduce well abandonment costs and safety risks. (Source: BHGE)

including dressing a cement plug, removing scale, underreaming or milling short window sections. The cutting sequence is initiated by dropping a ball from the surface, and the three knives are activated by the flow of drilling or workover fluid through a ball catcher. When the ball lands in the catcher, the necessary pressure differential is established to activate a mandrel that moves the knives into the cutting position. The continued movement of the mandrel forces the knives to pivot around the knife pins. After a successful casing cut, the knives become fully extended and the mandrel strokes clear of the ball catcher. The fluid then flows more freely through this separation, reducing the pressure differential and signaling to the operator that the casing is fully cut. The cut casing section can then be retrieved via traditional spearing methods. ■



NONFRACTURING COMPLETIONS WINNER WEATHERFORD | TR1P SINGLE-TRIP COMPLETION SYSTEM



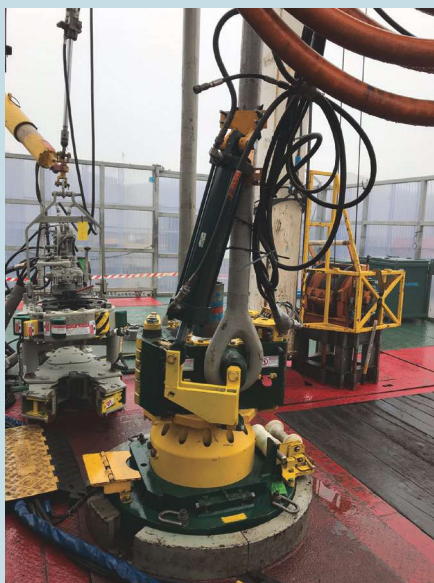
Now operators can control multiple RFID tools in a single string and selectively target and actuate individual tools as needed. (Source: Weatherford)

Performing multiple operations in less time and with fewer personnel and equipment requirements sets the stage for dramatic, tangible benefits in deep water. The Weatherford TR1P single-trip completion system is a remotely activated system that enables installing

both the upper and lower completion in one trip. This capability simplifies operations and reduces completion installations times by 40% to 60%, which reduces well costs by up to 25%. The TR1P system combines radio-frequency identification (RFID) technology and advanced completions tools into one system. The result is 100% interventionless operation without control lines, wash pipe, wireline, coiled tubing, wet connects and workover rigs. Before the TR1P system, many operational risks—involving well fluids management, well control, problems getting to the bottom, circulation problems and hydrocarbon influx—hampered single-trip operations to install both upper and lower completions. RFID integration provides true multicycle tool functionality throughout the completion string, which enables operators to set and test selective completion components, manage well control parameters, circulate the well from toe to heel and remotely bring the well online. RFID technology also gives operators a way to activate downhole tools without the usual mechanical limitations. ■

ONSHORE RIGS WINNER FRANK'S INTERNATIONAL | COLLAR LOAD SUPPORT SYSTEM FOR STANDS (CLS-S)

The Collar Load Support System for Stands (CLS-S) of tubing is a nonmarking tubular handling system that accommodates a wide range of pipe sizes. Unlike typical slip-type elevators and spiders, the CLS-S system allows the running of threaded and coupled stands of tubulars as well as single joints without causing damaging die penetration marks. In doing so, it eliminates the potential for corrosion cracking due to stress concentrations induced by conventional handling equipment. The risk of slip crush and iron transfer is minimized as the CLS-S system enables the tubular to be supported by the load face and not by penetration, avoiding the slippage issues prevalent on certain alloys with conventional inserts. Die and insert impressions,



The CLS-S System is the next step in Frank's CLS technology by removing the requirement of heavy load transfer sleeves to be manipulated around the rig floor. The smallest version of the system is set up for 27.5-in. rotaries that are typically found in the onshore market. (Source: Frank's International)

with or without iron transfer, may adversely affect the corrosion resistance and mechanical integrity of corrosion-resistant alloy (CRA) tubulars in conducive well environments. Although levels of susceptibility may vary, all CRA materials are susceptible to downhole corrosion mechanisms. Nonmarking technologies like the new CLS-S system are the preferred method in a safe and cost-effective approach to running stands of CRA tubulars. ■



SUBSEA SYSTEMS WINNER

ONESUBSEA, A SCHLUMBERGER COMPANY | MULTIPHASE COMPRESSION SYSTEM

OneSubsea, a Schlumberger company, has developed, qualified and put into operation a multiphase compressor technology enabling boosting of unprocessed well streams. This minimal footprint, contra-rotating compressor technology is a subsea compressor concept that works at any combination of gas and liquid (0% to 100% gas volume fraction). It is a robust, yet highly efficient machine tolerating transient process conditions, such as large liquid slugs and variable process pressure. Subsea compression is used to extend plateau production, accelerate production, optimize reservoir drainage and maximize ultimate recovery. The Schlumberger multiphase compressor leverages extensive OneSubsea subsea pump system experience. Subsea boosting has accumulated more than 3 million operating hours—equivalent to 350 years—and is recognized as an



The world's first subsea multiphase compression system, which adds an estimated 22 MMboe, is shown being prepared for deployment. (Source: Schlumberger)

important part of enhanced drainage strategies. Experience is being gained from a North Sea subsea gas field, where the robustness and versatility of the equipment have contributed to large value generation. The compressor has been used to kick off dead wells and enhance liquid recovery from the field. Its capability to handle large liquid loads (up to 100%) has been pivotal to unlocking this potential. The multiphase compressor system has operated with 100% regularity

since startup and has reached Technology Readiness Level 7. A major advantage of subsea compression over topside compression is that the compressor is located closer to the reservoir; hence, the power required for the same differential pressure is less and the potential drawdown of the reservoir is larger. Subsea compression stabilizes the flow and reduces flowline pressure loss. ■

WATER MANAGEMENT WINNER

SCHLUMBERGER | AQUAWATCHER SURFACE WATER SALINITY SENSOR

The AquaWatcher Surface water salinity sensor is the latest-generation microwave sensor technology applied to continuous in-line water conductivity measurement in wet gas and multiphase (water-continuous) flow that provides real-time data output of water salinity. The sensor provides a high-accuracy, high-resolution determination of salinity across the full range of gas volume fraction to enable the detection of water property changes and identify the origin of produced water. Automating salinity determination brings several benefits to operators. It eliminates conventional manual sampling that provides only snapshots of salinity conditions and potentially exposes field personnel to H_2S in the produced water. Not having to periodically deploy personnel also saves operating expenses. This mobile sensor can be installed as a standalone application upstream from the separator during well cleanup or flowback operations to monitor change in the water type for optimizing the duration of the well cleanup process. Standalone installations also are used to detect first water in extremely low concentrations. The Aqua-Watcher Surface sensor's reliable detection of water drop-

lets in the flow provides critical information for flow assurance purposes to help prevent hydrate formation and minimize the occurrence of scaling and corrosion that triggers the need to inject chemical inhibitors. **ESP**



The AquaWatcher Surface water salinity sensor is ending the manual sampling of produced water with its continuous, automated in-line salinity determination for wet gas and multiphase flow and seamless integration with the Vx Spectra surface multiphase flowmeter to improve flow-rate calculation while reducing overall operating cost. (Source: Schlumberger)

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Life Extension through Predictive Maintenance

A North Sea major looks to transform late-life asset operations with digital twins.

By **Andrew Young**, Akselos

Against the backdrop of uncertain energy prices—which are expected to be lower for longer—and aging assets attached to maturing hydrocarbon developments, the energy industry is adopting digital transformation strategies. By exploring new, disruptive technologies that challenge established operating models, assets will be able to operate well beyond their intended design life, safely and cost effectively.

In 2016 Shell challenged technology developer Akselos to deploy its next-generation structural simulation software to one of its late-life assets in the North Sea. The goal was to provide sufficient structural integrity and performance data to demonstrate compliance with current codes and standards as well as support a life extension of 20 years on a 50-year-old asset without an increase in inspection requirements.

A two-year joint industry project (JIP) ensued with the aim to transform asset structural integrity management by pairing a detailed 3-D, condition-based structural model with real-time sensors to create the first predictive digital twin of an entire asset in the industry. Danish engineering firm LIC Engineering was a key partner in the project.

Large-scale simulations

Now approaching the end of the two-year project, Shell and Akselos have successfully implemented a fast, accurate and cost-effective life extension technology and methodology. The new approach ultimately improves the performance of the platform by introducing unprecedented levels of accuracy, made possible by new technology developed at the Massachusetts Institute of Technology and the Swiss Federal Institute of Technology.

“We were in need of a new methodology,” said Emmanuel Fakas, Shell’s structural technical authority. “The traditional approach using existing simulation tools has served the industry well for decades, but there was a significant amount of time-consuming sub-modeling required, which resulted in, at times, overly conservative estimates. When we became aware of new technology that was capable of industrial scale simulations with absolute accuracy, we understood how powerful this could be.”

On a beam model example, conventional models using stress concentration factors estimated that each joint was in need of immediate repair or replacement. The Akselos sensor-enabled model showed that each of the joints had decades of safe operating life remaining, with many far surpassing Shell’s life-extension objective of 20 years.

“The software has the ability to mesh all joints, estimating the hot spot stresses accurately at the right locations,”

Fakas said. “It accounts for the chord flexibility explicitly and in a simple analysis. The traditional approach requires several separate analyses, which can really escalate the time involved based on the number of local joint models required.”

This new level of understanding and accuracy is the difference between a significant investment in maintenance (or even decommissioning) and safe life extension.

Eliminating uncertainty

Digital twins are not a new concept. But the numerical model that is traditionally used as a basis for the technology is



Digital twins create models to accurately identify hot spot stresses on offshore facilities.

(Source: Akselos)

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based on best estimates and does not eliminate uncertainty. The key to eliminating this uncertainty and achieving true accuracy is a simulation that is fast enough to integrate sensor data at the speed of a sensor feed.

The computational method behind the digital twin selected by Shell for this project is based on an algorithm called reduced basis finite element analysis (RB-FEA). It produces models 1,000 times faster than the industry standard numerical method, finite element analysis (FEA). Without this speed, true condition-based modeling of large assets would not be possible because of the time required to perform the calculations using conventional FEA software.

This speed allows the Akselos model to accurately identify hot spot stresses. These data are used to focus inspections on areas of risk rather than wasting time on inspecting areas that have no issues.

Benefit of sensors

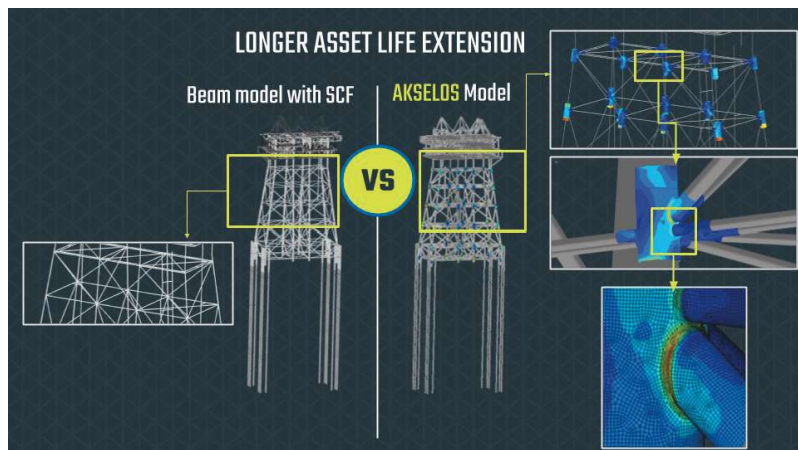
The speed also makes the technology compatible with operational sensor data and, as a result, the accurate simulation tool that aligns with Shell's vision for true condition-based monitoring of large assets.

Accelerometers and wave radar data are assimilated into the digital twin to provide a true picture of the loading conditions and resulting hot spot stresses. Engineering technology inputs, like wave and current loading condition, run and failure criteria are integrated into the digital twin. This is part of an integrated workflow interfacing with operational feeds such as sensor and inspection data. The outputs are then interpreted through a dashboard to understand current and future condition.

From laboratory to asset

Early in the two-year JIP, LIC Engineering mocked up a laboratory model to demonstrate the procedures of establishing a digital twin, using eight accelerometers and three displacement sensors. The laboratory model had the structural complexity of an offshore jacket foundation, and a digital twin was set up to demonstrate the high-fidelity structural analysis using the RB-FEA method.

This demonstrated the accuracy of RB-FEA, and a simulation of the real-life assets was modeled. The finite element model has 3.1 million FE degrees of freedom and was solved within a few seconds on a single computing core. While the solution time is comparable to a 1-D beam model, the full 3-D stress field was resolved in this model, which is of particular importance in complex structural components like the joints.



Digital twin systems quickly provide high-resolution analytics. (Source: Akselos)

Akselos and LIC Engineering developed a streamlined workflow based on real-life experience of offshore engineers. This industry knowledge was digitalized to enable much faster detailed analysis of offshore assets. The result was a single streamlined workflow in place of a process that used to require multiple software applications, and a complex workflow transition from holistic beam models to detailed 3-D joints. This new workflow fully integrates with wave loading and other preprocessing plug-ins as well as post-processing add-ons for fatigue and code checks.

Operational and added value

The physics-based digital twin, now fully operational for the North Sea asset, aims to provide understanding of the real structural life and health of the fixed platform. The results should enable the asset team to significantly improve the inspection strategy and introduce a next-generation methodology for asset integrity management.

With an improved risk-based inspection strategy, Shell expects to safely continue operating this particular asset up to 20 years. With successful results, the technology might be rolled out to other aging assets across Shell's upstream portfolio and across younger assets to lower opex through improved health analysis.

Shell and Akselos have pioneered accurate condition-based monitoring that could completely transform asset integrity management in mature basins like the North Sea and beyond. **ESP**

Have a story idea for Tech Watch? This feature highlights leading-edge technology that has the potential to eventually address real-life upstream challenges. Submit your story ideas to Group Managing Editor Jo Ann Davy at jdavy@hartenergy.com.

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Digital radiography provides cost savings

Oceaneering International Inc. has released a new digital radiography system for the oil and gas sector, the Trip Avoidance X-ray Inspection (TAXI) system, aimed at reducing the number of unplanned shutdowns, according to a press release. Typically, radiography uses gamma radiation emitting isotopes. This upsets nucleonic level control instrumentation on pressure vessels and equipment, causing trips that result in costly unplanned plant shutdowns and associated process safety risks. The TAXI system enables Oceaneering's technicians to digitally radiograph pressure piping and infrastructure associated on or around equipment fitted with nucleonic detectors. The work can be carried out while the plant is in service, using a specialized system that delivers pulsed X-rays. The field-proven process provides an optimal nondestructive testing solution to detect corrosion, pipe thinning and potential loss of integrity. It ensures continuous operations, significantly reducing the risk of loss of primary containment, associated safety risks and also maximizes plant uptime. The system complies with Ionizing Radiation Regulations 2017 and does not require plant nucleonics isolation. It can reduce deferred inspections, resulting in increased plant efficiency and also provides significant cost savings by eliminating unplanned process shutdowns caused by trips. In addition, it enables in-service inspection of normally inaccessible systems, such as small-bore piping. *oceaneering.com/TAXI*

Reclosable CT frac sleeves save 24 hours of rig time

An operator in West Texas using third-party frac sleeves to isolate and hydraulically fracture multiple stages in a single continuous operation was dissatisfied with the operating efficiency. According to a press release, Schlumberger was called in and deployed 37 reclosable CT frac sleeves with 1,481 m (4,860 ft) of casing in the lateral in 5 hours. All the frac stages were completed in 55 hours; the average time between opening one sleeve and the next was 16.4 minutes (excluding fracturing time). Use of Schlumberger's frac sleeves saved 24 hours of operating time—a 30% reduction—compared with the third-party provider. The operator was able to stay on budget and on schedule and chose Schlumberger frac sleeves for all comple-

tions planned in this field for the subsequent year. The sleeves also provide flexibility for rigless zonal shutoff later in the life of the well. *slb.com*

DAS system extends boundaries

Designed in partnership with Fotech Solutions, SigmaWave is the first integrated distributed acoustic sensing (DAS) system designed exclusively for borehole seismic applications and reinforces Sercel's advanced range of downhole seismic acquisition systems. SigmaWave is fully integrated with Sercel's existing downhole seismic tools and enables continuous, real-time seismic measurements along the entire length of a fiber-optic cable. Whether by retrievable or permanent deployment, it is now possible to visualize and monitor the well in real time and instantly generate SEG-Y files. With unique features such as user-selectable gauge length, the system acquires the highest quality seismic data. *sercel.com*



The SigmaWave integrated DAS system offers the borehole industry a complete seismic acquisition system that provides accurate data in a ready-to-use format for a wide range of applications. (Source: Sercel)

Well intervention for downhole data acquisition

Well-SENSE's FiberLine Intervention (FLI) system uses distributed fiber-optic sensing to deliver high-quality well data. The compact design can deliver data significantly faster and at around a tenth of the cost of conventional methods, according to a press release. The system places bare fiber-optic line along the length of the well using a weighted probe deployed from a launcher on the surface. The fiber acts as a distributed sensing



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device, monitoring temperature and acoustic changes along the length of the well. The company's new Active-FLI package has additional single-point electronic and optical sensors at the end of the probe, which means it can capture more data as it descends downhole, increasing production logging and flow measurement capabilities. According to the company, the system is currently the only technology of its kind on the market to combine both single point and distributed sensing and aims to provide a detailed image of the well throughout its life cycle. Costs are dramatically reduced compared to traditional intervention methods as the portable plug-and-play equipment is compact and lightweight with minimal footprint and manpower required, meaning projects can be completed rapidly with much less production downtime. The probe and fiber-optic line are designed to dissolve in the well, so no time nor expense is incurred for retrieval. The tool is most commonly used for completion, production and integrity applications, including cement assurance, gas-lift optimization, flow monitoring and leak detection. *well-sense.co.uk*

Offshore temporary water treatment solution

Water To Sea (WTS) has released its offshore system for the temporary treatment of flowback fluids, off-spec produced water and slop water for compliant overboard discharge, reuse or reinjection. The treatment technology is designed to surpass performance of traditional electrocoagulation and filtration media treatment alternatives, a press release stated. The heart of the WTS system is its Thincell technology, an electrochemical process inducing multitreatment reactions—electrolytic oxidation, emulsion destabilization, coagulation, flocculation and flotation—all in a single, pressurized chamber. Combined with other WTS processes and modular components, the compact system continuously treats up to 12,000 bbl/d of produced water for environmentally compliant discharge, reuse or reinjection. *watertosea.com*

Wellhead manager optimizes oil and gas operations worldwide

Remote workers can collaborate using mobile devices with ABB's versatile new cloud-based visualization system, ABB Ability wellhead manager, which supports smarter teamwork, enhanced efficiencies and lower costs for oil and gas operators of all sizes, according to a company press release. The new system, based on SCADA, allows both large operators and small startups to gather information about their onshore upstream asset. ABB Ability wellhead manager is cloud-based so

that operators can gain insights about their production assets anywhere in the world. Remote workers can connect in real time, supporting enhanced teamwork and productivity for optimal results. By providing immediate access to data, alarms and callout notifications, the technology also reduces downtime and risk. In this way, operators can proactively prevent issues, predict productivity and scale up or down as necessary. The system also supports better decision-making, with field production data digitally gathered and visualized using a progressive web application. It includes clear dashboards, insights and analytics. ABB Ability wellhead manager is a subscription service, so operators only pay for the service that they use, without having to make use of capital to purchase. *abb.com*

Corrosion solution for pipe end protection

Sometimes pipe ends are capped to protect against physical damage and intrusion of foreign objects during storage and shipping. Cortec's CorroLogic CorrPlug brings pipe caps to the next level by incorporating VpCI corrosion protection technology directly into the plastic cover, according to a company product announcement. CorroLogic CorrPlug pipe caps are heavy wall black polyethylene pipe caps containing vapor phase corrosion inhibitors. The pipe caps protect pipe threads, pipe ends and other tubular objects from corrosion, mechanical damage and contamination during transit, handling and storage. The caps are specially designed for easy installation and removal and offer protection all the way to the last pipe thread. This helps eliminate extra labor on pipe ends that might otherwise need to be cleaned off before being joined together. During humidity testing, pipe threads capped with CorroLogic CorrPlug pipe caps showed a significant advantage in corrosion protection compared to pipes capped with regular plastic containing no corrosion inhibitors. *cortecvci.com* **ESP**

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1 Alaminos Canyon Block 772

Shell Oil Co. is drilling a second Lower Tertiary test on the company's ultradeepwater Whale project. It is located in Alaminos Canyon Block 772 at 2 OCS G35153, and area water depth is 2,591 m (8,500 ft). A successful completion could confirm Shell's Whale discovery, which according to the company, is one of the largest Gulf of Mexico discoveries in the past decade—1 (BP) OCS G35153 hit more than 427 m (1,400 net ft) of oil-bearing pay. Total depth is 7,007 m (22,988 ft). To the north, adjacent Block 728 (OCS G31195) is also part of Shell's Whale project. The company has drilled two tests on the tract with few details available.

2 Green Canyon Block 282

A deepwater sidetrack well has been scheduled by Talos Energy LLC in the company's producing Boris Field. The 3SS (ST) OCS G16727 will be drilled in Green Canyon Block 282. Last reported depth was 4,070 m (13,354 ft). According to the permit for the sidetrack, the original hole will be kicked off at 3,194 m (10,478 ft). Water depth is 716 m (2,350 ft).

3 Ship Shoal Block 336

GulfSlope Energy Inc. is active at a bypass on the company's Tau prospect. The subsalt exploratory test, 1 (BP) OCS G36121, is being drilled by a jackup. The subsalt exploratory test is in the southwestern portion of Ship Shoal Block 336 (OCS G35244). The planned bottomhole location is to the south in Block 351. The permit indicates that the bypass would be kicked off from the original hole at 1,493 m (4,900 ft). According to the company, the exploratory test is targeting multiple Miocene sand levels trapped

against a well-defined, angled flank of the large salt structure.

4 Walker Ridge Block 595

Shell Oil Corp. has planned a side-track well for an exploratory test on the Stones Southwest prospect in the company's Stones Field. The 1 (ST) OCS G36088 will be in the western portion of Walker Ridge Block 595. According to the permit, the original hole will be kicked off at 6,839 m (22,437 ft). Work on the original hole began in July 2018. Water depth in the area is 2,987 m (9,800 ft). IHS Markit reported that Block 595 and neighboring Walker Ridge Block 594 (OCS G36087) to the west make up Shell's Stones Southwest prospect. The prospect's exploration plan indicates that as many as nine tests could be drilled from various surface locations on the tracts. Wells in the Stones Field yield crude at depths of about 8,077 m (26,500 ft) in the Lower Tertiary.

5 South Pelto Block 16

A shallow-water exploratory test has been spud by EnVen Energy on South Pelto Block 16 offshore Louisiana. The 1 OCS G35607 is being drilled in the northwestern portion of the block in 17 m (56 ft) of water. Navitas Petroleum originally acquired the lease in March 2018 at OCS Sale 235, and EnVen acquired a 50% stake in the lease in June 2018 and now serves as operator of the project. According to IHS Markit, several tests have been drilled on Block 16 under previous leases. The lone producer on the tract, Chevron's 1 (BP) OCS G01234, was online for about one year in the 1970s. The well is producing from Upper Miocene at 3,693 m to 3,699 m (12,118 ft to 12,136 ft) and recovery totaled 311,485 cu. m (111 MMcf) of gas, 7,090 bbl of condensate and

187,000 bbl of water and was a part of the South Timbalier Block 52 Field.

6 South Timbalier Block 311

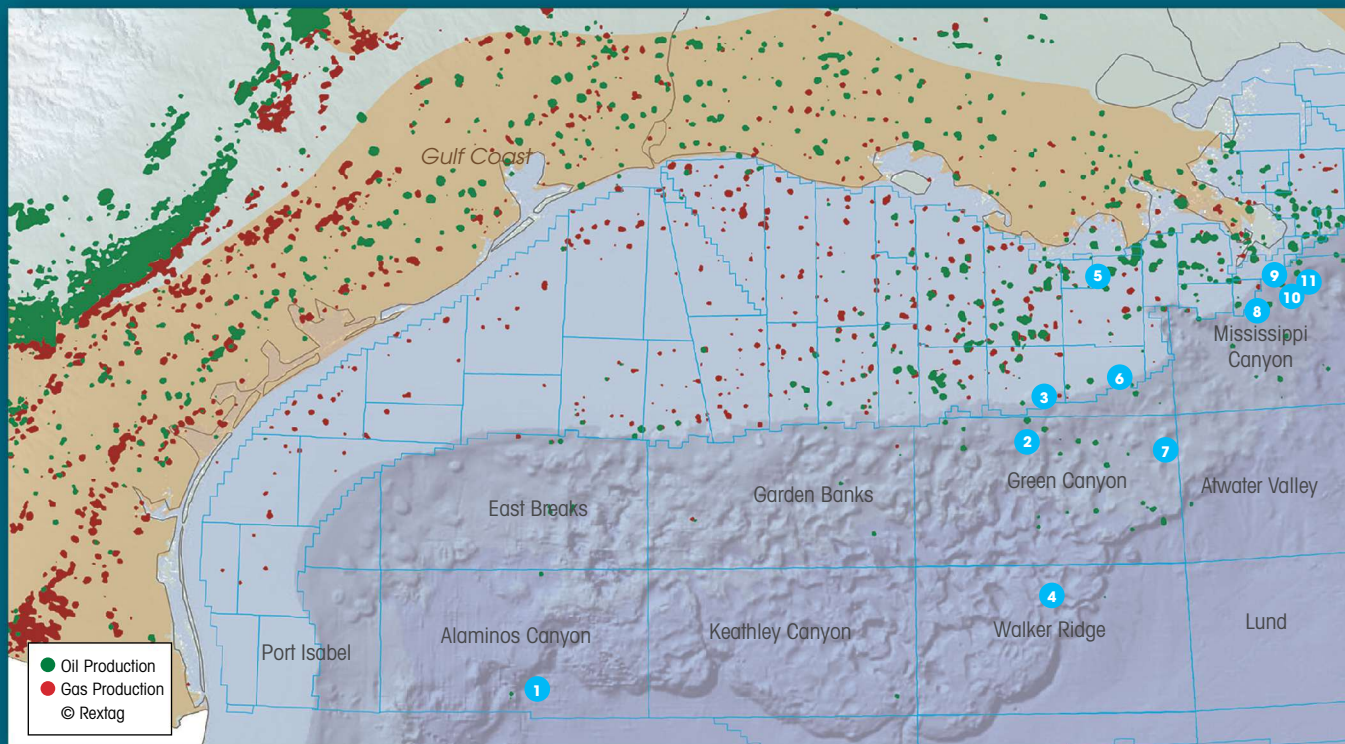
In the South Timbalier Block 311 Field, Walter Oil & Gas Corp. is drilling a third development test at 3-A OCS G24990 from the existing A platform in the northern portion of South Timbalier Block 311 (OCS G31418). According to the permit, the development venture will bottom to the south in Block 320. Water depth in the area is 119 m (392 ft). Nearby production is in Block 311 at the company's 1-A OCS G31418 lease, which was completed in mid-2018. The 6,003-m (19,694-ft) well has recovered 322.8 MMcm (11.4 Bcf) of gas and 1.4 MMbbl of condensate from Middle Miocene at 5,593 m to 5,608 m (18,350 ft to 18,400 ft).

7 Green Canyon Block 389

According to IHS Markit, LLOG Exploration Co. plans to expand the company's Khaleesi project in Green Canyon 389 in the Gulf of Mexico. The exploration plan indicates that two more tests could be drilled from offsetting surface locations in the southeastern portion of Green Canyon Block 389, bottoming to the south beneath previously undrilled Block 433 (OCS G35867). Area water depth is 1,097 m (3,600 ft). The Khaleesi discovery well, 1 (BP) OCS G35865, was drilled in 2017 in Block 389 and bottomed to the east beneath Block 390.

8 Mississippi Canyon Block 562

BP is drilling a second test in the company's producing Isabela Field in the northeastern portion of Mississippi Canyon Block 562 at 2 OCS G19966. Water depth in the area is 1,951 m (6,400 ft). The



development test is known as BP's Isabela 2 project. The company's Isabela Field discovery was made in 2007 from an offsetting surface location. The discovery well, 1 (BP) OCS G19966, was drilled to 5,898 m (19,350 ft). Production is from an Upper Miocene zone at 5,751 m to 5,779 m (18,868 ft to 18,960 ft). Since coming online in 2012, recovery from the well through mid-2018 is 14.2 MMbbl of crude and 334 MMcm (11.8 Bcf) of gas.

9 Viosca Knoll Block 823

A development test is planned by W&T Offshore Inc. to expand the company's Virgo Field. The 13-A 3 OCS G16549 will be drilled from the A platform in the western half of Viosca Knoll Block 823. It will bottom to the southwest in Viosca Knoll Block 822, and area water depth is 345 m (1,132 ft). The

company's 12-A OCS G35803 has been drilled and bottomed to the northwest in Viosca Knoll Block 779. The most recent field well was completed in April 2018 at 10-A (ST) OCS G16549, which bottomed beneath Block 823 in Miocene at 4,925 m to 4,981 m (16,158 ft to 16,343 ft). The sidetrack gas well was drilled to 5,111 m (16,770 ft), with 4,109 m (13,482 ft) true vertical depth. Recovery during the well's first three months online totals 7.9 MMcm (280 MMcf) of gas and 35,359 bbl of condensate.

10 Mississippi Canyon Block 257

LLOG Exploration has added a second deepwater test to the company's Red Zinger project drilling program in the Gulf of Mexico. The 2 OCS G35325 will be in Mississippi Canyon Block 257, and area water depth is 1,768 m (5,800 ft). The off-

setting Red Zinger discovery, 1 (ST) OCS G35325, was drilled in 2016 to 5,791 m (19,000 ft). The Miocene discovery is expected to be tied back to the Delta House floating production facility on Block 254.

11 Mississippi Canyon Block 82

Anadarko Petroleum Corp. is underway at a development test in the company's Horn Mountain Field (as of March 20). The 8 OCS G18194 is in Mississippi Canyon Block 82 (OCS G35313), and it is expected to bottom to the south in Block 126. Water depth in the area is 1,311 m (4,300 ft). In 2018 the company won exploration plan approval to drill as many as 16 tests from various surface locations on Block 81 (OCS G35312), Block 82 and Block 126. There has been no production to date from blocks 81 and 82.

1 Jamaica

A report for Tullow Oil from updated 3-D seismic data by ERC Equipoise Ltd. indicates that the offshore Jamaica Walton-Morant license gross, unrisks mean oil prospective resource is 229 MMboe, an increase of about 10 MMbbl. The survey covered 2,250 sq km (869 sq miles) of recent 3-D seismic data at the Colibri prospect to de-risk highly prospective Cretaceous and Tertiary-aged clastic and carbonate reservoir targets, including Colibri, that have been mapped by Tullow on 2-D seismic data.

2 Ireland

Europa Oil & Gas has identified a new prospect in offshore Block LO16/20 in the Slyne Basin that includes the company's Inishkea Prospect. The Inishkea Prospect is adjacent to the producing Corrib gas field in the Corrib Field petroleum lease area. According to a report, the Inishkea gross, mean, unrisks prospective gas resources are approximately 42.4 Bcm (1.5 Tcf). Site surveying is planned for mid-2019 and includes an exploratory well. Farm-in negotiations are being conducted for three of Europa's offshore Ireland licenses, including LO16/20 and its Inishkea Prospect.

3 UK

An offshore U.K. Colter Prospect appraisal well, 98/11a-6, was drilled by Corallian Energy Ltd., and it encountered a 9.4-m (30.8-ft) reservoir interval in the Sherwood Sandstone. The well is an appraisal of 98/11-3, which was originally completed in 1986 within the Colter Prospect. The 98/11a-6 well was drilled to 1,870 m (6,135 ft) on the southern side of the Colter Prospect bounding

fault, and it encountered oil and gas at the top of the reservoir. A petrophysical evaluation of LWD data has calculated a net pay of 3 m (10 ft), and similar indications of oil and gas were encountered in the 98/11-1 well within the Colter South fault terrace. Analysis of the new data indicates that the two wells may share a common oil-water contact in the downdip margin of the Colter South prospect. Corallian's most recent assessment of the Colter South Prospect prior to drilling appraisal had estimated a mean recoverable volume of 15 MMbbl. A sidetrack to 98/11a-6 is planned and will be drilled directionally to a Sherwood Sandstone target within the Colter prospect on the northern side of the bounding fault.

4 UK

Azinor Catalyst Ltd. has reported an oil discovery at its Agar-Plantain exploration well, 9/14a-17B, in the U.K. sector of the North Sea in Block 9/14a in license P1763. The well and associated sidetrack well delineated the eastern extent of the hydrocarbon discovery. The sidetrack well encountered a 20-m (66-ft) interval of high-quality, oil-bearing sands with no oil-water contact. The original discovery well in the block, 9/14a-15A, encountered a 10-m (33-ft) Eocene Agar zone in high-quality Eocene Frigg sands. Reservoir oil samples have now been recovered to surface, and further analysis will be required to define the recoverable resources. The current recoverable resource estimate is between 15 MMboe and 50 MMboe. The 9/14a-17B well is in the process of being plugged and abandoned.

5 Norway

Faroe Petroleum has announced the results of the Rungne exploration well 30/6-30 in the Norwegian

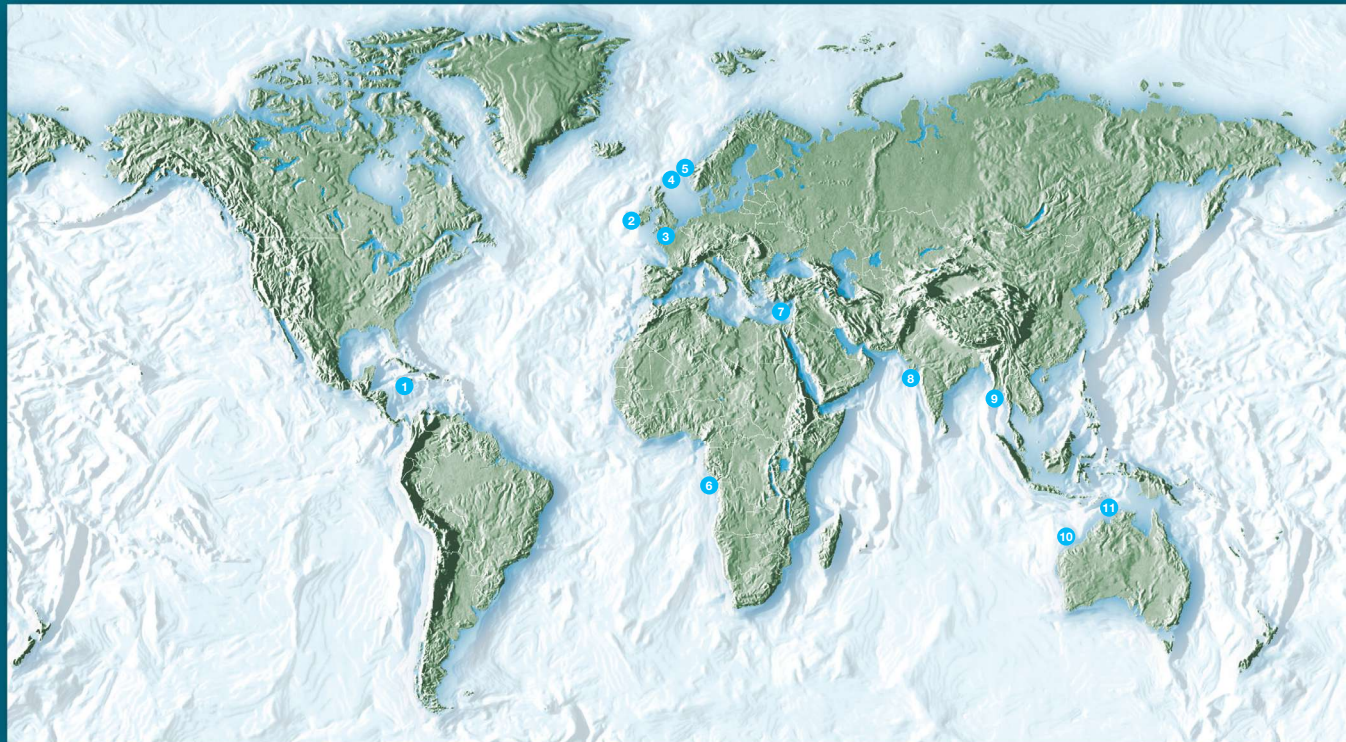
North Sea. The 3,469-m (11,381-ft) well hit a 56-m (184-ft) gross gas/condensate column in the interbedded Middle Jurassic Ness sandstones and 86 m (282 ft) of gross water-bearing reservoir in the primary Oseberg target. No hydrocarbon contact was encountered within Ness. According to the company, the preliminary gas and condensate recoverable volume range for the discovery in the Ness Formation is estimated to be 2.7 MMboe and 17 MMboe, and it is unlikely to be commercial in isolation.

6 Angola

Eni announced an oil discovery offshore Angola in Block 15/06 at the Agogo exploration prospect. The Agogo-1 NFW encountered a 203-m (666-ft) oil column with 120 m (394-ft) of net pay and 31-degree-gravity oil in subsalt diapirs in Lower Miocene sandstones. The IP capacity was about 20,000 bbl/d of oil. Based on current estimates, the find could hold 450 MMbbl to 650 MMbbl of oil. The well was drilled to 4,450 m (14,600 ft) and is in 1,636 m (5,367 ft) of water. The Agogo-1 NFW is the third commercial discovery on the block.

7 Cyprus

Exxon Mobil announced an offshore Cyprus gas discovery at the Glaucus-1 well, which is in Block 10. It hit a gas-bearing reservoir of about 133 m (436 ft) and was drilled to 4,200 m (13,780 ft) in 2,063 m (6,769 ft) of water. Preliminary interpretation of the well data indicates the discovery has an estimated in-place gas resource of 141.5 Bcm to 226.5 Bcm (5 Tcf to 8 Tcf). Additional analysis and testing are planned. The Glaucus-1 well was the second of a two-well drilling



program in Block 10. The first well, Delphyne-1, did not encounter commercial quantities of hydrocarbons.

8 India

Oil and Natural Gas Corp. has reported two offshore gas discoveries in the Arabian Sea. The GKS091NFA-1 well was drilled in Block GK-OSN-2009/1 in the Kutch offshore region. According to the company, result suggests the play could extend across a large area. Another well in the Western Offshore Basin, B-203-2, flowed 783 bbl of oil and 78,579 cu. m/d (2,775 MMcf/d) of gas from an interval within an early Oligocene Mukta Sandstone. A limestone interval in the Heera Formation also flowed oil and gas. The discovery confirmed a westward extension of the WO-4 plays in the downdip direction.

9 Myanmar

PTTEP Exploration & Production has found commercially proven gas reserves in Block M9 in the Zawtika Project offshore Myanmar's Mottama Gulf. According to the company, the Zawtika-24 well successfully proved commercial hydrocarbon reserves with 152 m (499 ft) of net gas sands, more than the expected 41 m (134.5 ft), with the latest discovery to prolong Zawtika's gas production.

10 Australia

Santos Ltd. will drill an offshore Australia exploration well, Roc South 1, in the WA-437-P Permit. The well will be drilled after the nearby Dorado-2 appraisal well is completed. According to the company, Roc South has a similar geological trap structure to Dorado, and Dorado is situated updip of the Roc structure. The

joint venture partners are Carnarvon Petroleum (20%) and Santos (80%).

11 Australia

PTTEP Exploration & Production announced a gas and condensate discovery at the Orchid-1 well, the first exploration well in Permit AC/P54 in the Timor Sea offshore Australia. The well was drilled to 2,925 m (9,596 ft) and encountered gas and condensate with a net pay thickness of approximately 34 m (111.5 ft). The discovery will be incorporated into development planning of the Cash-Maple Field, which contains an estimated resource of 99.1 Bcm (3.5 Tcf) of gas. **ESP**

For additional information on these projects and other global developments, visit the activity highlights database at

HARTENERGY.COM

PEOPLE

Arja Talakar has been appointed CEO of Siemens Oil & Gas.

Approach Resources Inc. appointed **Sergei Krylov** CEO. He succeeds **J. Ross Craft**, who has resigned as the company's chairman and CEO. Krylov also will retain his duties as CFO. In addition, **Jim Crain** has been appointed chairman of the board.

Archer Ltd. CEO **John Lechner** has resigned from his position. He will remain as a senior adviser to the Archer leadership team during the transition period until a new CEO is appointed.

Flotek Industries Inc.'s board has decided to separate the role of chairman and CEO. **John W. Chisholm** will remain as the president and CEO, and **David Nierenberg** was elected to serve as chairman of the board. Additionally, Flotek has appointed **Paul Hobby** to the board, Corporate Governance and Nominating Committee, and the Strategic Capital Committee.



Expro has promoted **Alistair Geddes** (left) to COO and **Keith Palmer** (right) to executive vice president of product lines.

Encana Corp. has named **Corey D. Code** executive vice president and CFO. **Sherri A. Brillon**, who has served as Encana's CFO since 2009, will be retiring at the end of May.

OPITO has appointed **Hart Victor** vice president of strategy for the Asia-Pacific region.

Robert Griffith, vice president of Nissan Chemical America Corp.'s Pasadena plant, has retired.

Ladislav Paszkiewicz has been appointed senior vice president of investor relations for Total and as a member of the Group Performance Management Committee, effective July 1. **Mike Sangster** will retake the role on an interim basis until then.



i-Tech 7, Subsea 7's life of field business unit, has selected **Simon Hird** as a new regional director to help strengthen and grow the company's life of field business in the Asia-Pacific region.



Eduard Dadov has been named director general of Gazprom Sotsinvest, and **Vyacheslav Tyurin** (left) has been appointed director general of Gazprom Invest.



WFS Technologies has appointed **Moray Melhuish** to the specially created post of commercial director.



Foster Marketing has named **Anna Scordos-Brooke** as its director of public relations.

Senex Energy Ltd. announced that **Andy Zhmurovsky** has resigned from the board.

Harvest Oil & Gas Corp. announced that **Colby Dunn** has resigned from his positions as chairman of the board of directors and as a member of the board. The board has appointed **Tim Caffisch** to serve as a member of the board and as a member of the Compensation Committee. The board also appointed **Steven J. Pully** to serve as chairman of the board.

Comet Ridge Ltd. has appointed **Martin Riley** nonexecutive director. Also, **Mike Dart** resigned from the

board due to a new full-time executive role.

COMPANIES

Chevron Corp. announced on April 12 its plans to acquire **Anadarko Petroleum Corp.** The transaction is expected to close in the second half of the year.

Southwest Research Institute will open a new facility offering cost-efficient standard corrosion testing for oil and gas clients. The facility, located on the Institute's San Antonio campus, will be used primarily to test the sulfide stress cracking resistance of carbon steel alloys for oil wells and offshore drilling applications.

BASF has founded the new company **BASF Digital Solutions S.L.** located in Madrid, Spain, to drive forward the digital transformation of the BASF group and develop IT solutions. BASF opened the new site for digitalization in February.

SIMMONS EDECO, a supplier of onshore drilling and workover services to the global oil and gas industry, has opened its second operations base in Mexico. The new facility in Villahermosa, Tabasco, features extensive operations, training and research facilities.

DEA Deutsche Erdoel AG has acquired **Sierra Oil & Gas**, enhancing its presence in Mexico.

Drillinginfo, an energy software-as-a-service and data analytics company, has acquired **Midland Map Co.**, a premier map provider in the Permian Basin.

4Subsea has acquired **Astori AS**, a provider of subsea control systems for well intervention operations. **ESP**



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Publisher

HENRY TINNE

Tel: 713-260-6478

htinne@hartenergy.com

Vice President of Sales

DARRIN WEST

Tel: 713-260-6449

dwest@hartenergy.com

Senior Marketing Manager

BILL MILLER

Tel: 713-260-1067

bmiller@hartenergy.com

Executive Director—Digital Media

DANNY FOSTER

Tel: 713-260-6437

dfoster@hartenergy.com

Sales Manager, Eastern Hemisphere

DAVID HOGGARTH

Tel: 44 (0) 7930 380782

Fax: 44 (0) 1276 482806

dhoggarth@hartenergy.com

United States/Canada/

Latin America

1616 S. Voss Road, Suite 1000

Houston, Texas 77057 USA

Tel: 713-260-6400

Toll Free: 800-874-2544

Fax: 713-627-2546

Advertising Coordinator

CAROL NUNEZ

Tel: 713-260-6408

cnunez@hartenergy.com

Subscription Services

E&P

1616 S. Voss Road, Suite 1000

Houston, Texas 77057

Tel: 713-260-6442

Fax: 713-840-1449

custserv@hartenergy.com

COMING NEXT MONTH The June issue of **E&P** will focus on completions. Other features will cover reservoir characterization, drillpipe, proppant logistics, surface systems and ROVs/AUVs. This issue also will include a perforating systems spotlight and technology showcase. The unconventional report will focus on the Marcellus-Utica, and the regional report will cover Southeast Asia. While you're waiting for your next copy of **E&P**, be sure to visit the newly launched **HartEnergy.com** for the latest news, industry updates and unique industry analysis.



ABOUT THE COVER Production at the Valhall oil field in the southern Norwegian North Sea started in 1982. In January 2017, the Valhall and Hod fields passed more than 1 Bboe produced, three times the volume expected at the opening of the field in 1982. (Cover photo courtesy of Aker BP; Left photos (from top to bottom) courtesy of nikkytok/Shutterstock.com, Husky Energy, Kjetil Eide/Equinor and suphakit73/Shutterstock.com; Left background image by Dudarev Mikhail, Shutterstock.com; Cover design by Felicia Hammons)

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Journey Toward Autonomous Operations

Digital technology has significantly optimized operations in oil and gas, from automated processes for plant startup through to simulators, remote operations, predictive maintenance and robotic inspection.

By Susan Peterson, ABB

The oil and gas sector has eyed the benefits of autonomous operation for many decades. The attraction is evident with this new way of working offering significant benefits to operators in terms of safety and operational efficiency. It also will reduce the cost of new installations by removing the living space for workers and support staff. What's more, ABB studies have shown that 80% of production downtime is preventable, and half of this is due to operator errors. These errors cost the petrochemical industry \$20 billion each year.

Until recently, the journey toward autonomous operations has been a slow one. The first tentative steps were taken in the late '80s by AMOCO on the Hod wellhead and stabilization platform for its Valhall Field. The thinking at the time was that it did not make sense to have any people on the wellhead platforms and, as they were close to the main facility, it was a perfect candidate. During the next decade, the concept advanced in Eni's Augustina and Barbara gas fields in Italy, which were both predominantly unmanned and remotely operated.

The next step along the autonomous pathway involved moving to an entirely unmanned operation. An excellent example of this is the remote satellite platforms supporting the two wellheads at the Peregrino Field. The facilities were more challenging and complex, as the operations included processing and electric heating—both of which demanded more power.

The progress of digital technologies has placed the reality of autonomous operations within reach. There have been examples of significant steps along the path, such as ABB's work on the Aasta Hansteen Field. The challenge was to make the first gas startup process as

quick and efficient as possible. For this, ABB needed to reduce a sequence of more than 1,000 manual interventions to as few as possible, saving about 40 days in the commissioning phase of the project.

In other industries, ABB is progressing toward autonomous operations. The marine sector is on the way to developing autonomous shipping and already has a strong remote monitoring proposition. Likewise, the mining sector already utilizes autonomous trucks and drilling, and it has projects in place to increase autonomy.

Then there is the automotive industry, with its much publicized quest for autonomous cars. The automotive industry has many similarities to the oil and gas sector.

It already has developed the technology for autonomous vehicles, and much technology is in use every day in road cars, such as blind-spot detection, lane departure warning and parking assistance. All that is required to make cars fully autonomous is for them all to be packed to work in harmony, safely and reliably.

There are already numerous examples where digital technology has significantly optimized operations in oil and gas, from automated processes for plant startup through to simulators, remote operations, predictive maintenance and robotic inspection. With a growing trend of remote operations and support from modern artificial intelligence platforms, digital progress is underway.

Across the sectors mentioned, there remains a common hurdle to overcome—legislation. At present, regulations have developed over the years based on manned operations, with a human presence required for many processes. With autonomous systems being installed to mirror conventional work on some new facilities, evidence that autonomous operations can be carried out safely is being accumulated. Once these data are presented to regulators, legislation will most likely ensue to support an age of autonomous operations. **ESP**

With a growing trend of remote operations and support from modern artificial intelligence platforms, digital progress is underway.



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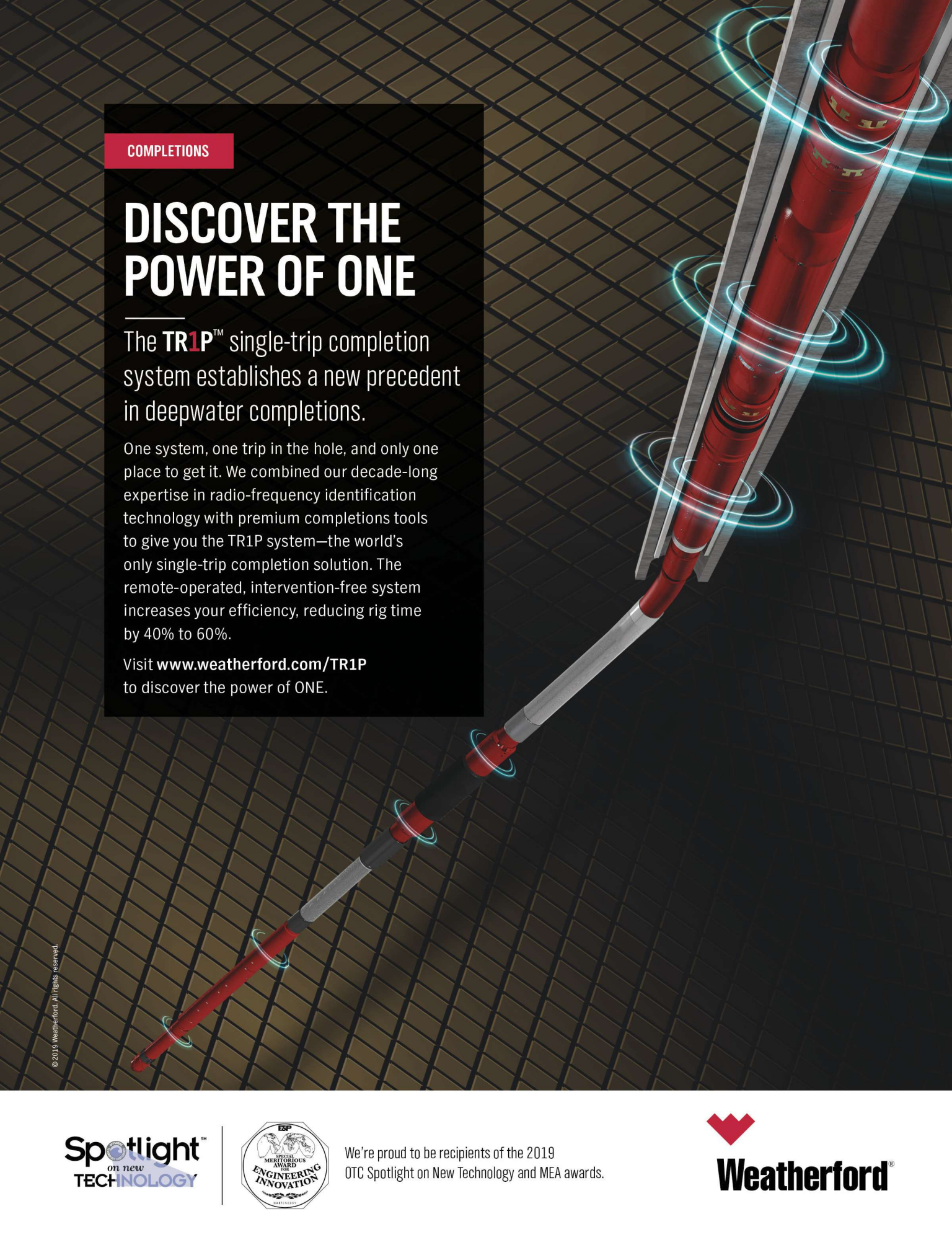
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