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Shell Drives Down Deepwater Costs Through Collaboration, Digitalization

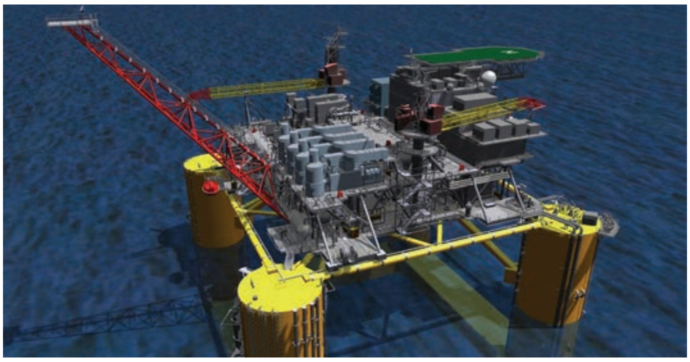
As Shell embarks on a journey toward an energy transition, the company is working to keep costs low while embracing digitalization and collaboration.

Continued improvement through upcycles is needed for future success, according to the company.

Despite some recent divestments in Norway and the U.K., where the North Sea is the heartland of Shell's operations, the company still has interests in 50 fields, 30 production platforms, two FPSOs and 30 subsea installations.

"We have had some tough years, but I'm pleased to say that there are new FIDs [final investment decisions] here," said Andrew Brown, upstream director for Shell.

Among the FIDs was the go-ahead to construct an FPSO, the first new manned installation for Shell in the northern North Sea in almost 30 years. The Penguins Field currently processes oil and gas using four existing drill centers tied back to the Brent Charlie platform. Redevelopment of the field, required when Brent Charlie ceases production, will see an additional eight wells drilled. The wells will be tied back to the new FPSO vessel, and natural gas will be exported through the tie-in of existing subsea facilities and additional pipeline infrastructure.



Vito will be Shell's 11th deepwater host in the Gulf of Mexico. The Vito development is owned by Shell Offshore Inc. (63.11% operator) and Statoil USA E&P Inc. (36.89%). (Source: Shell)

The industry is entering an upcycle. Brown said it has been relatively straightforward to improve during the downcycle, but the new scenario presents different challenges.

Continuous improvement

"We are taking out operating costs," he said. "We are taking 45% out of the development costs on our new projects. What we did in the North Sea is part of our Fit for the Future program. However, our challenge is to improve through the upcycle. I think only that will give us the resilience to allow us to succeed in the cycles that will follow."

Brown highlighted three deepwater projects in the U.S. Gulf of Mexico—Appomattox, Kaikias and Vito.

"We have managed to build the six hubs we have in the Gulf of Mexico by working in an integrated fashion from exploration through to operations," he said. "We are drilling and have been completing one well a week in the last three months. This sees a resurgence in this deepwater environment. Our projects there are not only below $40 a barrel; we are now down at $30 breakeven."

Steps to lower costs

The Appomattox development will initially produce from the Appomattox and Vicksburg fields. First oil is expected

WHAT'S INSIDE

by the end of the decade with average peak production estimated to reach about 175,000 boe/d.

For this project, "we have taken 30% out of the cost since FID. We built the hull cheaper, we built the topsides cheaper, [and] we put the subsea infrastructure in place cheaper. But quite significantly, we drilled cheaper. We've taken two-thirds out of the cost of the deepwater wells on Appomattox."

In addition to the cost reductions, Shell has reduced the cycle time from discovery to production. At the Kaikias development, which was brought online in second-quarter 2018, startup was achieved four years after discovery.

"Working with TechnicFMC, we redesigned the subsea installation and again took 30% out the cost of the project from FID to startup," Brown said.

Another cost saving has come from reducing the scope of deepwater projects with what Shell calls competitive scoping. Brown used the Vito development as an example.

"Anything that did not deliver a return in two years, we took it out of the scope of the project," he said, adding costs for Vito fell 70% from what was expected in 2014. "We achieved this through the partnership with our supply chain. I think that partnership is the core of what we're going to make sure we do in the future."

Driven by data

Growth in collaboration is one part of the drive for increased efficiency. But digitalization is equally important. "I fundamentally think digitalization will transform the way we optimize and make more efficient our operations," Brown continued.

For digitalization, data are king. Shell's portfolio has more than 100 petabytes of data, which is equivalent to more than 3 billion books.

However, "we have not used the data most sensibly," Brown said.

An effort is underway to change that.

"Working with our colleagues, we are creating a subsea, subsurface data universe that will help us understand more about the subsurface but also to optimize the surface facilities. We have 7,000 pieces of equipment connected to our smart connect," Brown said. "This will start to transform the way we look at and manage our assets and ensure that we keep our costs down."

At the Nyhamna facility in Norway, Shell has developed a digital twin that allows the company to better understand the facility and test operations and maintenance plans, he said.

But the process is not without challenges.

"This whole visualized journey is exciting, but it is going to challenge leadership. It is going to challenge us to use data in a very different way and challenge us to develop data scientists and the youth that can make this happen," Brown said. "If we can do that, well we can take this business to the next level of performance. It is not good enough for us to survive into transition. We are going to have to thrive through the energy transition."

— Mark Venables

DEVELOPMENT

BW Offshore Achieves First Oil Offshore Gabon

BW Offshore said Sept. 17 that it has produced first oil from the *BW Adolo* FPSO on the Tortue Field, 18 months after the initial investment was made in the Dussafu license offshore Gabon.

"We have achieved first oil from the Dussafu license within budget and on schedule," said BW Offshore CEO Carl K. Arnet. "The execution of the Dussafu project confirms the attractiveness of our model by combining proven resources, a resourceful organization and access to production assets to achieve short time to oil."

The *BW Adolo* arrived in Gabon in late July, and hookup of mooring systems and installation of risers and umbilicals were completed in September. The project was safely completed without any harm to people or the environment.

The FPSO is installed on the Tortue Field, one of five proven discoveries in the Dussafu license. The *BW Adolo* is a converted very large crude carrier with a production capacity of 40,000 bbl/d. The vessel has undergone an increased life extension scope enabling an extended production profile on the back of positive reserve developments.

The *BW Adolo* FPSO is installed on the Tortue Field offshore Gabon. (Source: BW Offshore)

"Our first priority now is to complete startup activities and stabilize production on *BW Adolo*. We will at the same time work toward the final investment decision on Tortue Phase 2, which will unlock additional production volumes, and continue the appraisal program of the recently announced discovery at Ruche NE as well as to confirm additional resources and strengthen the commerciality of the Dussafu license," Arnet said.

—Reuters

Equinor Looks To Floating Wind To Power Snorre, Gullfaks Platforms

The Snorre and Gullfaks fields, located in the Tampen area of the northern North Sea, were selected for the project after extensive evaluation. An illustration of the floating wind farm is shown. (Source: Equinor)

When Equinor announced at ONS 2018 that it was exploring the possibilities of supplying two of its oil and gas platforms with power from floating offshore wind, it marked an important step in the evolution of reducing the carbon footprint of producing hydrocarbons. The forecast is that it would result in a reduction of CO_2 emissions of more than 200,000 tonnes per year, equivalent to the emissions from 100,000 cars.

If approved, the project will mark the first time an offshore wind farm is directly connected to oil and gas platforms.

"A lot of hard work remains. We must further mature the concept and reduce cost, have a regulatory framework in place and get sufficient financial support from Enova before a potential FID [final investment decision] next year," said Pål Eitrheim, Equinor's executive vice president for New Energy Solutions.

"This is an innovative project that demonstrates what we want to achieve on the NCS [Norwegian Continental Shelf], while at the same time it may pave the way for technology development and new industrial opportunities for Norway, Equinor and Norwegian supplier industry within profitable renewable energy."

The project is part of Equinor's quest to reduce the carbon footprint of its oil and gas production. Earlier this year the company said the giant Johan Sverdup Field will be powered from the onshore grid.

The Snorre and Gullfaks fields, located in the Tampen area of the northern North Sea, were selected for the project after extensive work to evaluate which oil and gas installations on the NCS were suitable for power supply from a floating offshore windfarm.

"We have assessed the CO_2 reduction potential as well as cost and technical feasibility," Eitrheim added. "Power cables from the wind farm will be connected to Snorre A and Gullfaks A. Both will distribute power further to the other installations on the field. The existing gas turbines will then work as backup power."

The plan is to install 11 8-MW Hywind turbines, Equinor's floating offshore wind concept. The 8-MW turbines will have a combined capacity of 88 MW and are estimated to meet about 35% of the annual power demand of the Snorre A and B and Gullfaks A, B and C platforms. In periods of higher wind speed this percentage will be significantly higher.

The floating wind turbine design features a single floating cylindrical spar buoy that is moored to the seabed by three cables or chains that have 60-tonne weights hanging from the midpoint of each cable to provide additional tension. The construction is ballasted so the turbine floats in an upright position. The arrangement allows the turbines to be placed in deep water, something that would have not been possible with traditional offshore turbines that are secured to the seabed. Each turbine is controlled onboard, so the pitch of the blades can be altered to dampen the motion of the tower and maximize production.

Eitrheim explained that the task of reducing the use of gas turbines by supplying platforms with power from floating offshore wind was a challenging and innovative project.

"The Hywind Tampen project is contributing to further developing floating offshore wind technology, reducing costs and making the solutions more competitive," he added.

The expected capital and development expenditures for the project are about $590 million, but the aim is to reduce that over the lifetime of the project. Investment of $67 million for the project will come from the industry's NOx fund, the Norwegian fund that supports efforts to reduce nitrogen oxide (NOx) emissions.

In addition, Norwegian authorities have, through their offshore wind strategy and Enova, offered financial support for innovative offshore wind projects associated with the oil and gas industry. The Snorre and Gullfaks partners have applied for support from Enova's program for full-scale innovative energy and climate measures to realize the project.

Equinor's partners at Gullfaks include Petoro and OMV, while it is joined at Snorre by Petoro, Exxon Mobil, Idemitsu Petroleum, DEA Norge and Point Resources. The seven Snorre and Gullfaks partners in the Tampen area in the North Sea will mature the project toward a possible investment decision in 2019.

"This is still a groundbreaking and challenging project that requires optimization of the technical solutions and further cost reductions before the partners can make a potential investment decision," said Olav-Bernt Haga, Equinor's project director.

—Mark Venables

DEVELOPMENT BRIEFS

Zennor Acquires Interest In UK North Sea

Zennor Petroleum Ltd. said Sept. 17 that its wholly owned subsidiary, Zennor North Sea Ltd., has entered a sale and purchase agreement with Mitsui E&P UK Ltd. (MEPUK) for its interests in U.K. Continental Shelf licenses P.213, Block 16/26a, Area B and P.345 Block 16/27b Area B, which represent an 8.97% working interest in the Britannia Field.

Completion of the transaction is subject to customary regulatory and partner consents.

The acquisition of the Britannia Field interest is strategic for Zennor given its 100% operated working interest in the nearby Finlaggan Field, a planned subsea tieback to the Britannia platform. Zennor is drilling two wells as part of the Finlaggan Field development.

The effective date for the transaction, which doubles Zennor's net production to about 5,000 boe/d, is Jan. 1, 2018. As part of the transaction agreement, MEPUK will retain the majority of the decommissioning liability up to an agreed cap with Zennor being responsible for the balance.

Aker BP CEO Predicts Fast Johan Sverdrup Ramp-up From Start

Aker BP, a partner in Norway's giant Johan Sverdrup oil field, expects a fast ramp-up of production when the initial development phase ends in late 2019, the company's CEO said Sept. 13.

"I think it will be done in a few months, because the production per well is so high," Karl Johnny Hersvik told Reuters on the sidelines of an energy conference.

Johan Sverdrup Phase 1 will have capacity to produce 440,000 boe/d, while Phase 2, which is starting production in 2022, is expected to further boost output to 660,000 boe/d.

Sweden's Lundin Petroleum, another partner in the Equinor-operated development, on Sept. 12 said it expected the field to start producing before November next year.

Equinor has said it expects the field to start in late 2019 but has not provided an estimate for when Phase 1 could reach full capacity.

Norway's Okea Mulls Four Options For Grevling Discovery

Norwegian oil firm Okea is looking at four options to develop its North Sea Grevling oil discovery, which in turn could impact on the company's valuation in a deal with Thai investor Bangchak Corp. PCL (BCP), Okea said.

BCP has agreed to invest $112.25 million in Okea to partly finance the company's $537.8 million acquisition of Royal Dutch Shell's stakes in the Draugen and Gjoea fields.

The various development options for Grevling included a standalone FPSO as well as a subsea tie-in to an existing platform. Okea also said it is considering installing a jackup rig with a floating storage and offloading facility, or a wellhead platform, and that its aim is for a per-barrel breakeven price below $35 to $40 when production starts in 2020-2022.

Redeployment of a leased FPSO could allow it to bring the field onstream in 2020, but this also would be the most expensive option, the presentation showed.

Okea has a 55% stake in Grevling after selling 15% to U.K.'s Chrysaor in March, while Norway's state-owned Petoro has 30%. Chrysaor has an option to increase its stake to 35% in the discovery estimated to hold 16 MMboe to 51 MMboe.

Okea also said Repsol's Yme Field redevelopment project, where it holds a 15% stake, was on track to start production in first-quarter 2020. Yme's recoverable proven and probable reserves are estimated at about 66 MMbbl of oil, based on a 10-year field lifetime, but the long-term ambition will be to produce 90 MMbbl of oil, the presentation said.

Hurricane Completes Lancaster EPS Subsea Installation

U.K.-based Hurricane Energy has finished installing the subsea umbilical, risers and flowlines for the Lancaster Field's early production system (EPS), the company said in a news release.

Having wrapped up the offshore installation program, the company plans to start a protective rock dumping program in October.

Hurricane added that the system is ready for the arrival of the *Aoka Mizu* FPSO. Sea trials are expected to start by the end of September, according to the release.

First oil is scheduled for first-half 2019.

Gazprom Neft Raises Reserves At Offshore Neptune Oil Field

Gazprom Neft, the oil arm of Russian gas giant Gazprom, said on Sept. 11 that a state subsoil commission has increased the oil reserves valuation of eastern offshore oil field Neptune to almost 416 million tonnes from the initial estimates.

Neptune, located near the Sakhalin Island in the Pacific Ocean, was Gazprom Neft's largest oil discovery last year. The company said reserves had been raised by 1.6 times the previous estimate.

Russian oil companies have increased oil development in the country's distant regions, such as East Siberia and the Far East, as traditional oil fields, located in Western Siberia, have become increasingly depleted.

"The Neptune Field has become one of the largest of Gazprom Neft's assets by reserve volumes," Alexander Dyukov, Gazprom Neft's head, said in a statement.

"The Far East will be a new strategically important region of our activity for many years ahead, which will allow our company to work more actively on the Asia-Pacific region's markets," he said.

Oceaneering Lands Subsea 7 Umbilical Contract For Shell's Vito

Oceaneering International Inc. has entered a contract with Subsea 7 to supply an electrohydraulic steel tube control umbilical and flying leads for Shell's deepwater Vito development in the Mississippi Canyon area of the U.S. Gulf of Mexico (GoM), according to a news release.

Product design and engineering are scheduled to begin in third-quarter 2018. Manufacturing is expected to start in 2019 at Oceaneering's facility in Panama City, Florida, the company said.

The contract work scope set to be finished in second-quarter 2020.

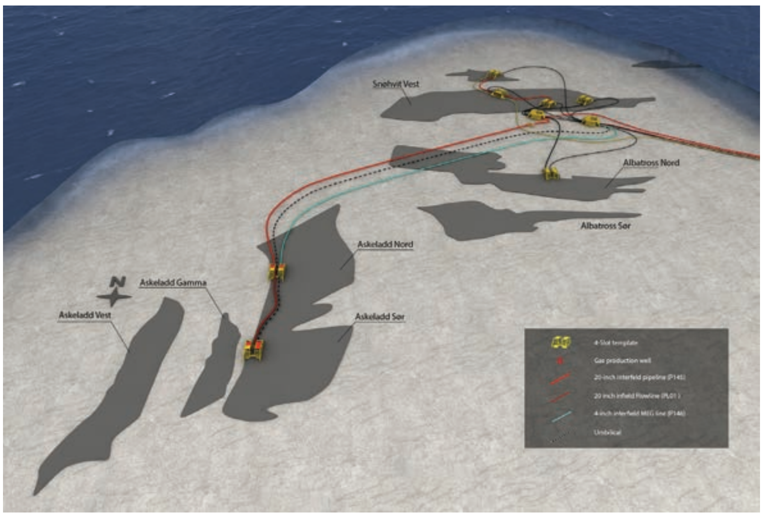
—Staff & Reuters Reports

EXPLORATION

Could Tide Turn For Barents Sea Exploration?

Depending on where explorers focus their drillbits, the challenges of exploring for and producing oil in the Barents Sea can be significant. Yet, these challenges are being tackled because more operators are seeing the basin's potential.

Exploration activity started in the Barents in the 1980s, said Neivan Boroujerdi, senior analyst Norway upstream oil and gas, for Wood Mackenzie. "But what was found, including Snøhvit, was gas, which saw companies 'take a breather' from the region," he said. "It wasn't until the Goliat oil field was discovered that companies really got started, which has led to the Johan Castberg development being sanctioned last year" with more projects already in the wings, including Wisting and Alta.



Equinor's Askeladd development is a subsea tieback to the Snøhvit Field in the Barents Sea. (Source: Equinor)

Although Barents Sea exploration activity dropped off during the downturn, it picked up again last year, with 17 wells drilled—a new record for exploration drilling in the Barents Sea, according to the Norwegian Petroleum Directorate (NPD). The biggest discovery in Norway in 2017 was Lundin's Filicudi well in the Barents Sea.

Neivan said the overall volumes discovered in the Barents Sea in 2017 were poor. "Last year's results gave us more questions than answers," he said. However, "the fundamentals remain in place."

Close to 5 Bboe have been discovered to date, half of which is gas. Wood Mackenzie thinks half of this is commercial or potentially commercial.

Light of hope

The NPD also sees potential here, stating that two-thirds of Norway's undiscovered resources are in the Barents Sea.

Large undiscovered resources suggest the potential for future spending in the region. Upstream investment in Norway in 2018 will be half that of 2014 when spending peaked, Neivan said, adding $15 billion per year is "a new normal."

"What's worrying, looking beyond 2023 and the start of the middle of the next decade, is that we are not getting visibility of new projects coming in to the pipeline."

Against this backdrop, the Barents Sea could be a light of hope. Spending in the Barents is projected to increase from just 5% this year to about 30% of the total by 2020s. Of the 10 Bbbl expected to be discovered offshore Norway between now and 2035, Wood Mackenzie believes nearly half of that will come from the Barents Sea, Neivan said.

"This tells us the Barents will be fundamental to the future of the Norwegian Continental Shelf," Neivan continued.

New projects are already well underway. In June 2018 Equinor's Johan Castberg development was approved. First oil on the floating production development, which will tap some 450 MMboe to 650 MMboe recoverable, is expected in 2022. Askeladd, a subsea tieback development into the existing Snøhvit facilities, was sanctioned earlier this year and is due onstream in 2020.

Challenges

However, the region is not the easiest workplace. Technical challenges include a harsh remote environment with limited logistics and difficult-to-drill shallow and complex reservoirs. Depending on the location in the Barents, sea ice and freezing conditions can be a major challenge, and in winter the area can be in darkness for long periods, which raises issues such as the ability to detect and track oil spills.

These issues can lead to marginal economics, Neivan said. However, this hasn't stopped companies from innovating.

In 2016 Austrian operator OMV, with the help of Schlumberger, delivered a horizontal well drilling record; the appraisal well on the Wisting Field landed out horizontally less than 270 m (886 ft) below the seabed. Companies also are collaborating to share resources in areas such as logistics, oil spill response and evacuation and emergency resources. Equinor and Eni, for example, are sharing a contract with Bristow Helicopters for crew transfer and search and rescue operations.

In short, companies are finding ways to operate in the area. Costs also have been falling, which has helped.

"We expect activity to remain pretty robust in the Barents over the next 18 months," Neivan said. "It's now 60% cheaper to drill in the Barents than it was in 2013 through lower rig rates but mainly through better rig performance. They're drilling more meters per day, and if you combine that with the exploration tax rebate [which companies receive offshore Norway], it's still an attractive place to explore, despite poor results to date."

Drilling plans

Equinor's drilling campaign for this year—comprising four operated exploration wells and one nonoperated well—has been set back due to delays accessing the rig that the company planned to use. However, the company said when it does start drilling in October, the 2018 activities will roll in to its 2019 plan. So far the firm has set out plans to drill on Korpfjell Deep and Gjøkåsen in the harsher eastern Barents and Intrepid Eagle, Skruis and Shenzhou in the western Barents Sea.

Others also are drilling in the Barents. In the western Barents Sea, DEA is planning to drill at Gråspett, Spirit Energy is planning to drill the Scarecrow prospect and Lundin at Setter Pointer. In the eastern Barents, Aker BP is planning drilling on the Stangnestind prospect at the Fedynsky High.

Most are targeting oil, as it is an easier commodity to store and ship. But there is also gas, a commodity that Norway supplies in vast amounts to Europe.

Wood Mackenzie assessed what would be a commercial-sized discovery, using license PL 961 as an example. It found that a minimum economic field size would need to be 99 Bcm (3.5 Tcf), using a semisubmersible to produce the gas and a pipeline to shore to export it, "and that's an optimistic best case," Neivan said.

If up to 198 Bcm (7 Tcf) of neighboring resources could feed the infrastructure, it would make it a worthwhile prize, he said.

Yet companies are not being incentivized to go for gas, he added. And "given long lead times in Barents [on average 15 years], the time is right to have that discussion now."

Ways to get gas out of the Barents Sea already are being discussed.

According to Andreas Wulff, communication manager for ENI Norge, Gassco performed a study in 2014 on the possibility of extending the gas pipeline system from the Norwegian Sea to Barents Sea. At the time, the conclusion was that it was too expensive. But the idea is being studied again, and the work so far shows there's been a 40% to 50% cost reduction for the work, Wulff said, speaking at ONS in August in Stavanger.

"The world has changed in a positive direction for a gas pipeline to the Barents Sea," he said. Earlier this year, Gassco said it was making an infrastructure plan for the region.

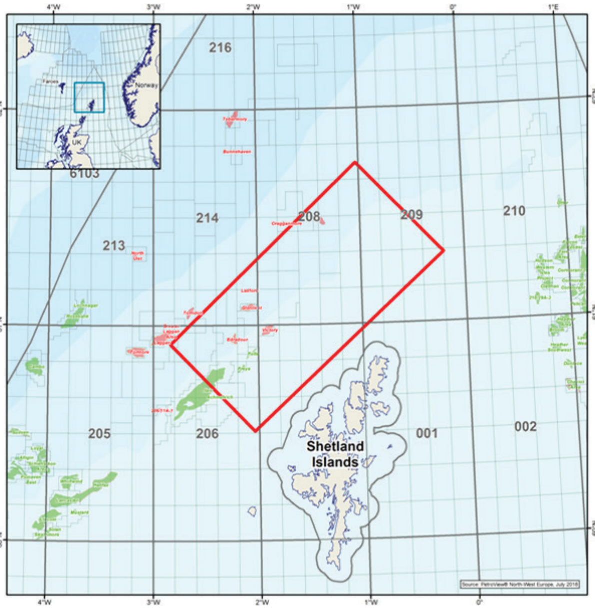
—Elaine Maslin

EXPLORATION BRIEFS

CGG Starts Survey In West Shetland Basin

CGG has begun acquisition of a high-density, rich-azimuth, towed-streamer multiclient survey that spans 3,600 sq km (1,390 sq miles) in the U.K. West Shetland Basin, the company said in a news release.

The survey focuses on an underexplored area northwest of the Shetland Isles over the northern part of the Rona Ridge.



CGG is using advanced de-blending and full-waveform inversion velocity modeling as part of the survey focused on an area northwest of the Shetland Isles. (Source: CGG)

"Until now, oil and gas companies interested in the exploration potential of this part of the West Shetland Basin have lacked high-quality seismic data," CGG CEO Sophie Zurquiyah said in the release. "We expect our new rich-azimuth images to reveal an unprecedented level of detail in this exciting frontier area."

By undershooting the volcanic intrusions and shallow unconformities present in the area, CGG aims to image multiple targets from shallow Tertiary and Cretaceous plays to complex fractured Devono-Carboniferous reservoirs. The project will include use of the *Oceanic Vega* and *Geo Caribbean* vessels along with CGG's broadband imaging technology, including advanced de-blending and full-waveform inversion velocity modeling, according to the release.

The company said a fast-track prestack depth migration dataset will be available in first-quarter 2019, while the final data will be available in mid-2019.

Egypt Signs $1 Billion Exploration Deal With Shell, Petronas

Egypt has signed a deepwater oil and gas exploration deal with Royal Dutch Shell and Malaysia's Petronas worth about $1 billion for eight wells in the country's West Nile Delta, the petroleum ministry said.

The country also signed a second $10 million deal with Rockhopper, Kuwait Energy and Canada's Dover Corp. for exploration in the Western Desert, a ministry statement said.

Egypt aims to be a regional hub for the trade of LNG after a string of major discoveries in recent years including Zohr, which holds an estimated 850 Bcm (30 Tcf) of gas.

TGS Preps For Multibeam, Seep Project In MSGBC Basin

TGS plans to begin multibeam acquisition for its first regional offshore MSGBC SeaSeep project in the Northwest Africa Atlantic Margin in fourth-quarter 2018, according to a news release.

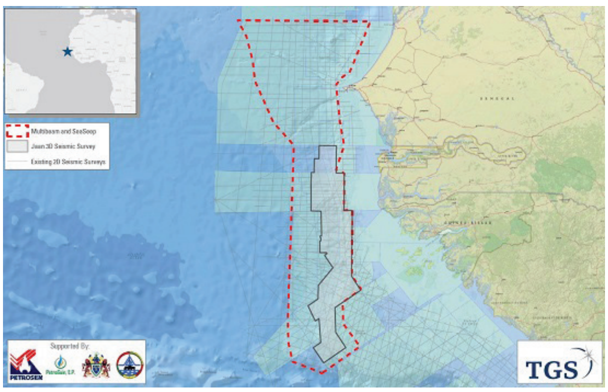
Covering about 113,500 sq km (43,822 sq miles), the MSGBC Basin program will incorporate about 230 cores from the seabed based on multibeam backscatter anomalies, the company said. The coring and geochemistry stage will follow acquisition of the multibeam.

Final results for the project, which is supported by industry funding, are expected in second-quarter 2019.

TGS also is gearing up for a 3-D multiclient project called Jaan in the southern part of the basin. The company will use modern triple-source broadband acquisition technology and the *BGP Prospector* seismic vessel to gather data from northern Senegal through The Gambia and the AGC zone, into Guinea-Bissau and down to the Guinea transform fault, TGS said in a separate news release.

The project will cover 11,135 sq km (4,299 sq miles) of new acquisition complemented by the reprocessing and full prestack merging of existing multiclient 3-D. Once complete, the final depth migrated volume will be more than 28,300 sq km (10,926 sq miles) and will completely capture the prospective paleo-shelf edge trend from the shallow to the deep.

TGS is the operator and major investor in the project. Partners are PGS and GeoPartners, and the survey is supported by industry funding. Acquisition is scheduled to



Acquisition of CGG's multibeam and seep project along with the 3-D multiclient project called Jaan in the MSGBC Basin are set to start later this year. (Source: CGG) begin in early fourth-quarter 2018. TGS plans to use its Clari-Fi broadband technology to process data collected.

Total Acquires 25% In Orinduik Block Offshore Guyana

Total E&P Activités Pétrolières has exercised its option to acquire a 25% working interest in the Orinduik Block offshore Guyana from Eco Atlantic (Guyana) Inc., the company said.

The option exercise was received by Eco before delivery of the final 3-D seismic data due to be delivered to Total, which would have triggered a 120-day exercise window for the option.

Following the option exercise and subject to the receipt of all requisite regulatory approvals, including that of the government of Guyana, for the transfer of the 25% working interest to Total, the working interests in the Orinduik Block include Tullow (operator, 60%), Total (25%) and Eco Guyana (15%).

In accordance with the terms of the option, Total will pay the option exercise fee of $12.5 million to the company on receipt of all requisite approvals for the transfer of the 25% working interest. It is anticipated that the option exercise payment will provide adequate funding to meet Eco's share of the costs to drill at least two wells on the Orinduik Block as well as recover the costs of the now completed expanded 3-D seismic survey.

Earlier in September the company announced completion of a technical report on the Orinduik Block, produced by Gustavson Associates LLC, which reported gross P50 (best estimate) 2,913.3 MMboe and net (40%) 1,165.3 MMboe, identified across 10 leads on the Orinduik Block.

Norway Gets Bids From 38 Oil Firms In Licensing Round

A total of 38 oil companies have submitted bids for exploration acreage offshore Norway in a so-called predefined areas (APA) licensing round, according to the country's energy ministry.

Bidders include oil majors Shell, ConocoPhillips and Total as well as Norway's Equinor and Aker BP, Sweden's Lundin and Italy's Eni.

The total number of bidders was almost as high as the record 39 in the previous APA round in 2017.

When announcing the round in May, the government expanded the predefined areas near existing discoveries by 103 blocks in the Norwegian and the Barents Seas.

Norway's right-wing government wants oil companies to explore more on the Norwegian Continental Shelf, especially in the Arctic Barents Sea, which is estimated to hold more than half of undiscovered resources on the shelf.

—Staff & Reuters Reports

TECHNOLOGY

Meeting The Challenges Of Deepwater Pipeline Inspection

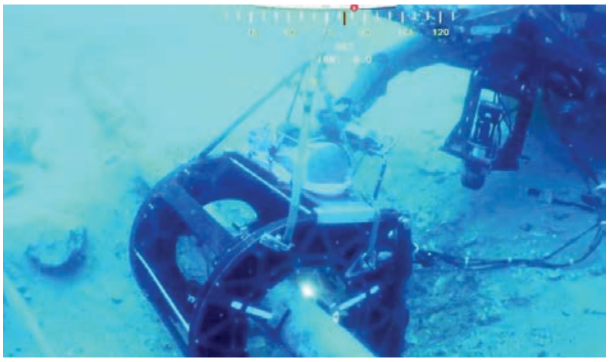
Moving tools into deepwater environments is a challenge. Even individual components rated for 3,000 m (10,000 ft) do not always perform as anticipated when they are connected in a system. Regardless, the tools are expected to work. So as companies develop inspection tools for deployment in deeper water, considerable effort is invested in eliminating impediments that could compromise performance.

Understanding restrictions

According to Mike Killeen, technical solutions lead for global subsea inspection at Oceaneering, "Everything in an inspection is some kind of compromise because no one technique can do everything."

In cases where an intelligent pig can be used to inspect a pipeline, things are fairly straightforward and cost-effective with regard to coverage per dollar spent. As long as the pig can transit the line, 100% of the line can be inspected.

The problem is that about 30% of the pipelines in operation today are not "piggable." Sometimes there is no way to launch and/or receive the pig, or the flow is too low. Where sections of pipe have been replaced, introducing a line with a different schedule, the change in diameter can prevent a pig from passing. When a line has never been pigged, and the internal condition is unknown, owners often are leery of deploying a pig that could encounter extensive wax buildup, sand deposits or asphaltines.



The Neptune ROV completed its deepest inspection to date in 2017 at 2,250 m water depth with equipment rated for 3,000-m buoyancy. (Source: Oceaneering)

Successfully launching tethered inspection tools depends on knowing the number of bends in the line and their radii, Killeen explained, because friction from the tether as it pulls tight around a bend could make it impossible to retrieve the tool in an emergency.

"If you can't get a pig inside a pipe, the other option is to inspect it externally," he said.

Inspection tool, limitations

When a pig is not the answer, sometimes external automated ultrasonic testing (AUT) is.

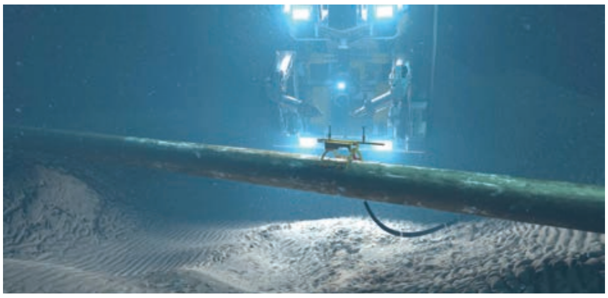
"Used by divers in shallow water since the early '90s, AUT delivers precise encoded measurements to plus or minus fractions of a millimeter of accuracy," Killeen said, "but it isn't always feasible."

Full corrosion mapping with an external UT tool requires 360-degree external access to the pipe, which requires dredging. The coating can be an issue depending on sound penetration, which in some situations means coatings must be removed.

"Even where UT can be used, it is not fast, and there are associated costs of the vessel and the ROV to be taken into account while you're gathering data," he said. Digital radiography is another option, but it does not provide sub-millimeter accuracy measurements.

"Unlike inspections that use a pig, external UT and radiography inspections do not cover 100% of the line due to the associated costs of doing so, but they yield sufficient data to assess a pipe's general condition."

Despite their inherent limitations, these technologies are providing deepwater inspection capabilities that were not available less than a decade ago.



The Sea Turtle uses electromagnetic acoustic transducers to assess the plate or pipe condition of structures, pipelines, jumpers, flowlines and risers. (Source: Oceaneering)

Evolving capabilities

The first ROV scanners were not intended to work at 3,000 m but to replace divers in much more shallow inspections, Killeen explained. When Oceaneering introduced its first Neptune UT tool, an ROV-deployed AUT scanner, the buoyancy rating was considerably less than 1,000 m (3,300 ft).

"We didn't need tremendous depth capability, because the water depth where we were doing mostly flexible riser inspections in the North Sea was at maximum 500 m [1,600 ft]," he said.

The depth of the ROV-deployed tooling changed when demand for flexible riser inspections began coming in from West Africa. "To work in West Africa, the equipment had to have greater depth capability," he said.

Most of the work continued to be in the North Sea, but global demand brought with it expectations for increased depth capability. In 2013 Oceaneering made the big step to 1,400 m (4,600 ft). Continuing to push the boundaries, the company completed its deepest inspection to date in 2017 at 2,250 m (6,400 ft) water depth with equipment rated for 3,000-m buoyancy.

Improving technology

Inspection efficiency evolved along with depth capabilities, Killeen said. "Moving from doing straight-up corrosion mapping with pulse-echo phased array has proved to be three to six times faster than conventional methods," he noted.

Escalating the ability to work at greater depths is one of Oceaneering's primary goals, he said, pointing to the company's subsea electromagnetic acoustic transducer tool as an example. "Over a span of six years, it went from being used in less than 100 m [330 ft] water depth to 1,300 m [4,250 ft]," he said.

Oceaneering takes time to consider the long-term prognosis for each tool, Killeen said. "Ideally, we want it to go to 3,000 m with every individual component rated for that depth. We want 100% spares. We have an ideal in mind for tool performance and then look at what has to be done from an engineering standpoint to get it there," he said.

For subsea AUT, this approach led to using hyperbaric testing to evaluate functionality at greater pressure levels that would be encountered at the deployed depth, beginning with ambient conditions and increasing depth incrementally to 3,000 m.

Set up in a hyperbaric chamber, the AUT tool moves a probe axially along a pipe for 20 in., then circumferentially around the pipe and then back 20 in. axially while engineers check to see if the depth has affected the mechanics.

"We look for things like whether it slowed down because the tolerances were tight because of the greater pressure," Killeen explained. "It's those little things that don't seem like they would introduce serious problems that can trip you up in the field."

The company also is taking specialist inspection techniques that are used topside and figuring out how to use them subsea.

"There is way more technology used onshore and topsides than subsea," Killeen said. "The challenge is figuring out what fits and where because you're going to spend so much to develop and test it and get it accepted that the capability has to be worthwhile and deliver something different."

The next frontier

The next advancement, according to Killeen, is likely to be in a different area altogether. "I think one of the big things that will come to the fore over the next few years will be permanently installed monitoring systems with resident ROVs," he said.

Because so much mobilization is required for an inspection, leaving the ROV *in situ* subsea for periodic redeployment could be advantageous—allowing the ROV to ping the area of interest occasionally and having experts evaluate the data. "I don't think this is a million miles away," he said.

Another advancement will be derived from a bigger toolbox. Having access to more offerings from a single source would make it easier to find the right solution more quickly, simplifying evaluation of the pros and cons. This is one of the reasons Oceaneering is partnering on techniques to deliver deepwater inspection solutions.

Guided wave inspections are an example, Killeen said, pointing to work Oceaneering is doing with an equipment manufacturer to deliver this service topside. Now the companies are working to deliver the same service subsea, providing a complete solution by bringing subsea AUT capability and proven guided wave equipment together.

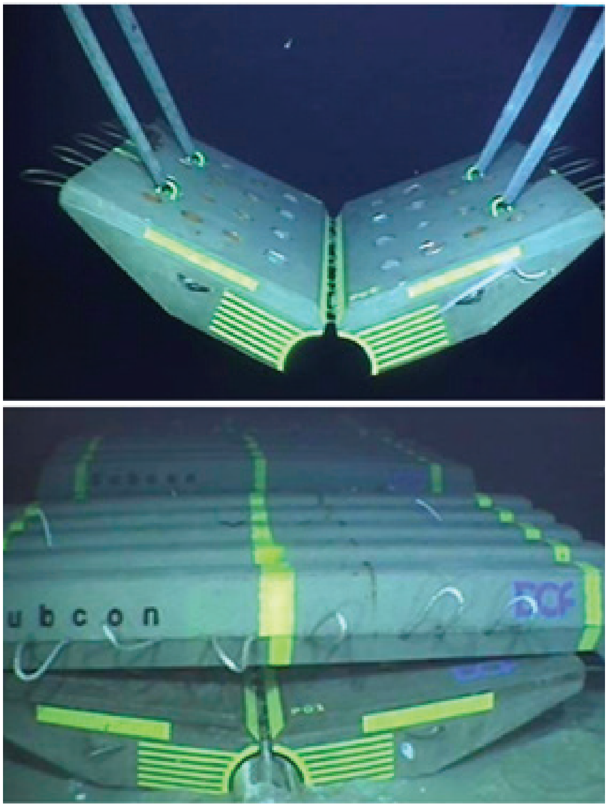
"Using new technologies and combinations of technologies in creative ways is what will move the industry forward," Killeen said.

—Judy Murray

TECHNOLOGY BRIEFS

Shell, Subcon Introduce Engineered Pipe Clamping Mattress

Subcon has released a new method to mitigate pipeline walking. Developed in cooperation with Shell Global Solutions (Shell), it is an engineered "pipe clamping mattress" (PCM).



Shell has a U.S. patent pending for the pipe clamping mattress. (Source: Subcon)

The technique was first developed on Shell's Malampaya project as an alternative to traditional rock dumping. The results led to a further 15 PCMs being deployed on the same field in first-quarter 2018.

"When rock dumping or concrete matts are deployed for walking mitigation, the vast majority of load is wasted because it is passed straight onto the seabed," Subcon CEO Matthew Allen said.

Addressing pipeline walking with PCMs also eliminates the need for fall-pipe vessel and competent rock, according to Subcon.

Future field developments may consider a wait-and-see philosophy for pipeline walking, eliminating suction pile fabrication and installation. As pipeline-walking is an uncommon and slow process, remediation can be achieved using post-installed PCMs, the company said.

Shell has a U.S. patent pending for the PCM and has released the PCM option to the market via a global licensing agreement with Subcon.

Schlumberger Offers New MEMS Gyro Surveying Service

Schlumberger has introduced the GyroSphere microelectromechanical system (MEMS) gyro-while-drilling service, responding to the needs of E&P companies for a faster gyro-surveying-while-drilling tool that increases drilling efficiency and reliability while reducing drilling risks.

As the first application of MEMS technology for gyro surveying while drilling in the oil field, the GyroSphere sensor performs gyro surveys faster than conventional systems and avoids the need for recalibration between runs, the company said. Solid-state technology enables the GyroSphere sensor to withstand the downhole shock and vibration that occur during drilling beyond the limits of current gyro technologies. Additionally, the GyroSphere service can reduce gyro survey uncertainty by up to 45%, providing more accurate access to smaller reservoir targets.

The GyroSphere service has been proven through extensive testing and field trials in the North Sea, Ecuador, Africa and Russia. In Russia the GyroSphere service enabled a customer to avoid wellbore collisions while accessing reservoirs from existing structures, eliminating drilling risks associated with deploying conventional gyro surveys, according to Schlumberger.

GyroSphere MEMS gyro-while-drilling service aims to increase drilling survey efficiency and reliability with new microelectromechanical technology. (Source: Schlumberger)

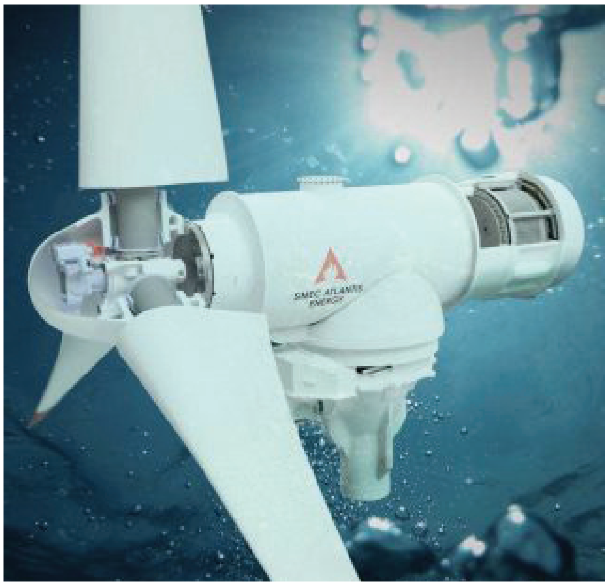
Simec Atlantis Energy Unveils Single Rotor Tidal Turbine, AR2000

The Turbine and Engineering Services Division of SIMEC Atlantis Energy (SAE) has unveiled the design for its new 2.0-MW tidal power turbine system.

This next-generation turbine will be capable of accommodating rotor diameters of between 20 m and 24 m (66 ft to 79 ft), site dependent, with a cut in speed of less than 1 m (3 ft) per second and a maximum of output of 2.0 MW at 3.05 m (10 ft) per second for a machine with a 20-m rotor diameter.

The AR2000 has been in development for over two years and builds on the successes and lessons learned from the AR1500 deployment and operation on the MeyGen project in Scotland, according to a news release. The machine will be available commercially in fourth-quarter 2019.

The turbine is offered as part of a complete rotor to grid tidal generation system, with an array architecture that allows multiple turbines to be connected in parallel, reducing the cost and impact of the subsea infrastructure.



The turbine is offered as part of a complete rotor to grid tidal generation system. (Source: SIMEC Atlantis)

The AR2000 will feature a new electromechanical pitch system, 360 degrees of yaw, upgraded onboard health monitoring and diagnostics systems and optimized critical system redundancy. The AR2000 will have a 25-year design life with quarter-life interventions for routine maintenance. The system utilizes a quick connect wet-mate system, designed for rapid and safe deployment on either a gravity base or mono pylon of up to eight turbines per day.

Atlantis is in discussions with governments, developers and site owners with respect to identifying potential locations for a manufacture, assembly, testing and commissioning facility.

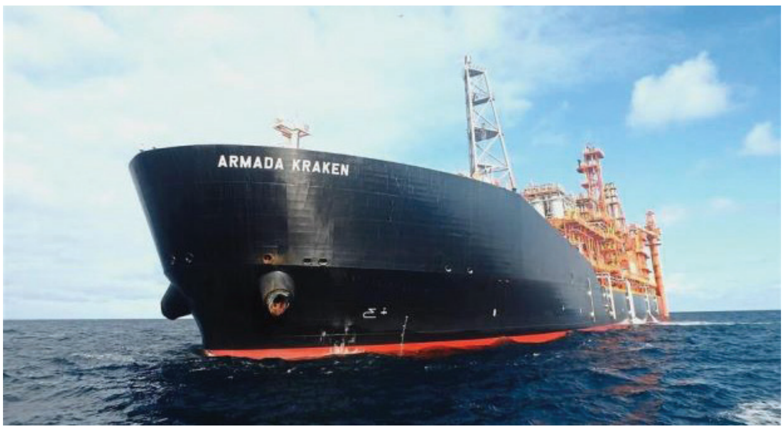
—Staff Reports

FLOATER BRIEFS

FPSO's Final Acceptance To Mitigate Default Risks On Loans

Malaysia-based Bumi Armada Berhad said Sept. 12 that it expects acceptance of its *Armada Kraken* FPSO to help mitigate the group's default risks on its related borrowings and improve earnings and cash flow visibility.

Lenders could have demanded full repayment if final acceptance was not achieved, said Kenanga Research, putting the company at risk of default on borrowings of $459 million.



The final acceptance of the *Armada Kraken* FPSO will lead to improved earnings visibility and cash flows, according to Kenanga Research. (Source: Bumi Armada Berhad)

Bumi Armada anticipates receiving full charter rates for the FPSO post-final acceptance by charterers EnQuest and Cairn, which will lead to improved earnings visibility and cash flows. Kenanga has bumped its fiscal year 2018-2019 by 12% after modeling in the higher chart rate assumption.

Earlier in September, Bumi Armada said the *Armada Kraken* FPSO had received final acceptance from the charterers EnQuest and Cairn, in accordance with the requirements set out in the original bareboat charter contract in December 2013, and supplemented by two amendment agreements.

Reliance Orders FPSO To Cease Production

Reliance Industries ordered the FPSO *Dhirubhai-1* to shut down production when its contract expires on Sept. 19.

Dhirubhai-1 is operated by Aker Floating Production AS. The 10-year contract with Reliance for the MA field offshore eastern India was set to expire on Sept. 19. Reliance gave its shutdown order on Sept. 17.

Reliance's purchase option on the FPSO remains valid until the contract expires.

—Staff Reports

VESSEL BRIEFS

Sonardyne, Guidance Marine Partner To Aid Navigation

Two maritime technology companies announced Sept. 11 that they are collaborating to develop a system that will help unmanned autonomous vessels navigate even when losing their connections to global navigation satellite systems.

Sonardyne International Ltd.'s underwater positioning systems and Guidance Marine Ltd.'s relative surface positioning systems will be integrated in a single solution called the AutoMINDER (Autonomous MarIne Navigation in Denied EnviRonments) project, which will create a common interface structure and allow the various sensors to be fed into one platform.

Sonarydne is contributing its SPRINT-Nav all-in-one subsea navigation instrument to the system. The device combines its Syrinx DVL SPRINT INS solution with a high-accuracy pressure sensor into an integrated unit. That integration allows highly accurate acoustic-aided positioning by integrating sensor data from the Doppler Velocity Log and/or other acoustic positioning inputs, the company said a news release.

The device is fed position data from Guidance Marine's vessel-mounted CyScan laser instrument, which takes range and bearing measurements from targets mounted on buildings or stationary surface structures in the ocean, to calculate the vessel's position and maintain positioning between targets.

CyScan already has shown its accuracy in sea trials earlier in the year. The instrument was mounted on Sonardyne's *Echo Explorer* survey vessel and was used to calculate the vessel's position during transit between Sonardyne's Plymouth Sea Trials and Training Center and the company's classroom facility in nearby Turnchapel, U.K. The result was a positional deviation of less than 0.5 m (1.6 ft) over a 1-km (0.6-mile) transit when compared with local, shore-based RTK Global Positioning System data.

Trials are scheduled for later this year and will incorporate water track velocity data using Sonardyne instruments. Guidance Marine also will deploy its recently launched SceneScan product, which maps surface features of structures, such as offshore oil platforms, processes the point cloud data and applies simultaneous localization and mapping techniques to provide relative position data.

Forssea Robotics Receives Funds For Subsea Vehicle Qualifications

A swift cash infusion of $2.8 million will allow Paris-based Forssea Robotics to conduct sea trials for its Atoll vehicle in summer 2019, the company said on Sept. 14.

French venture capitalists Irdi-Soridec and a team of international energy investors supplied the funds for the startup, which developed an autonomous ROV that can be deployed from a light vessel. Atoll employs embedded control algorithms that allow it to perform its own approach and docking.

Atoll acts as a homing device that leads a subsea cable to infrastructure on the seabed at depths of up to 2,000 m (6,562 ft). The system reduces operating costs in certain subsea interventions, because it can be deployed from a very light vessel.

A screenshot from a video animation shows Forssea Robotics' Atoll vehicle. (Source: Forssea Robotics)

The funding enables Forssea Robotics to qualify the proprietary-designed vehicle and underwater vision systems, Gautier Dreyfus, co-founder and CEO at Forssea, said in a news release. "We will undertake several trial sessions in October 2018 in shallow water, whereas the full-depth equipment will be assembled early 2019 for deep-water trials mid-year. Working offshore is a real challenge, and this successful fundraising is an important milestone underpinning our ambition."

—***Staff Reports***

BUSINESS

Gas Reigns As Green Agenda Looms

Equinor is assessing the feasibility of using floating wind turbines to power its Snorre and Gullfaks facilities. Pictured is an illustration of the floating wind project. (Source: Equinor)

While demand for oil will peak in 2023, demand for gas will continue increasing through 2034 as the world becomes increasingly electrified, DNV GL said in a forecast of world energy supply and demand out to 2050.

As a result, global gas capital spending will grow from $960 billion in 2015 to a peak of $1.3 trillion in 2025, while operational spending will rise by 30% between 2015 and 2040, according to DNV GL's 2018 Energy Transition Outlook.

Other trends the outlook predicts include North America continuing to dominate unconventional gas production and seaborne gas trade from North America to China trebling by 2050.

Conventional onshore and offshore gas production is expected to decline from about 2030, while unconventional onshore gas is expected to rise to a peak in 2040, according to the outlook, leading to a growth in leaner and shorter lifespan gas developments.

"It's important for the oil and gas industry to work on efficiency and also competitiveness, and for gas to take over from oil it has to be cheaper," said Liz Hovem, CEO of DNV GL—Oil & Gas. "To be cheaper, it has to be produced in a cost-effective way."

But as focus grows on cleaner fuels, including biogases, the industry will not only have to work toward being cleaner and leaner, there will also be other changes, including the introduction of greener gases, such as biogas, syngas and hydrogen, into transmission and distribution systems, she said.

Work is starting in this space. Hovem cited a joint industry project that is assessing how equipment and infrastructure that is in place can cope with throughput of hydrogen, instead of natural gas. In Leeds, in the U.K., there's a project called H21 that is looking to convert natural gas infrastructure that takes gas to people's homes for heating to a hydrogen system. There's potential for that hydrogen to be produced from natural gas offshore and for it to be piped to shore for use as a fuel, Hovem said, stripping the carbon off it before it goes into the energy system.

Norwegian energy firm Equinor revealed it is doing research in this area at the European Gas Conference in Oslo earlier this year, she said. Engineering firm Jacobs has started a gas-to-hydrogen including carbon capture feasibility study for Equinor.

While hydrogen is a small part of the energy mix now, it could play a much larger role and faster than might be expected, just like wind and solar energy development grew faster than expected, she said.

The wider industry also is looking to other ways to "greenify" itself, including using offshore floating wind turbines to provide power for offshore oil and gas production facilities. Equinor announced during the ONS conference and exhibition in Stavanger in late August that it was assessing the feasibility of using 11 floating wind turbines to provide power to its Gullfaks and Snorre facilities. Earlier this year, Aker BP said its North of Alvheim and Askja-Krafla development will be "energy positive" and with "zero emissions," by having all-electric topside and subsea infrastructure, powered from shore as well as offshore wind turbines.

Even traditionally oil- and gas-focused conferences are getting the message—this year's ONS and Houston's Offshore Technology Conference had sessions on offshore wind. "It's a lot about hedging and being prepared and social acceptance," Hovem said.

Back to natural gas, Northeast Eurasia (including Russia), the Middle East and North Africa will account for most onshore conventional gas production in the lead up to 2050, while North America will continue to dominate unconventional gas production, the report said. In the offshore sector, the Middle East and North Africa will see the highest annual rate of new gas production capacity from now until at least 2050.

LNG capacity will increase as production rises, doubling by the late 2040s, according to DNV GL, as gas is shifted to demand centers. Seaborne gas trade is expected to treble from North America to China by 2050 and an increase in trade from Sub-Saharan Arica to India and Southeast Asia also is expected.

—Elaine Maslin

BUSINESS BRIEFS

EnQuest To Issue Discounted Shares To Buy Magnus Oil Field

U.K.-focused oil company EnQuest is offering new discounted shares to buy out the Magnus oil field and has borrowed money against 15% of its Kraken Field as it seeks to reduce its debt pile of almost $2 billion.

EnQuest, which owns a quarter of Magnus, launched a $138 million rights issue on Sept. 7 to help it to buy the rest of the 12,000-bbl/d North Sea field from BP, sending its share price tumbling by more than 13%.

If successful, the deal will bring 60 MMbbl of reserves—or an additional 30%—to EnQuest's portfolio and also increase its stakes in the Sullom Voe oil terminal, Ninian pipeline system and Northern Leg Gas pipeline, the company said.

The rights issue announcement came as EnQuest, which has a market value of about $590 million, reported a close to 50% jump in first-half post-tax profit to $43 million thanks to its Kraken Field boosting overall output.

EnQuest also said it had agreed to ring fence 15% of Kraken for Oz (Och-Ziff) Management in exchange for $175 million, to be paid back within five years.

First-half production of 31,000 bbl/d at Kraken was slightly below expectations, but it has since picked up to as much as 36,000 bbl/d. The company had been seeking to sell a 20% stake. The Kraken money will help EnQuest to pay back nearly $200 million of debt due next month, CEO Amjad Bseisu said.

N-Sea Kicks Off IRM Campaign In North Sea

N-Sea Offshore Ltd. is delivering subsea inspection, repair and maintenance (IRM) services in the Central and Northern North Sea for an oil and gas development and production company after landing a $39 million contract, according to a news release.

The three-year contract is utilizing N-Sea vessels and project crews for vessel-based and daughter craft diving combined with ROV operations, N-Sea said. The contract is all-inclusive and includes options for extensions.

Pre-engineering survey work for the project is already complete, the company said.

—Staff & Reuters Reports

N-Sea Offshore Ltd. is carrying out a subsea IRM job in the North Sea. (Source: N-Sea Offshore)

UPCOMING

The next issue of *Subsea Engineering News* will be distributed Oct. 4. Until then, visit *epmag.com*.

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