Venture Capital Finds a Deepwater Niche

BY DARREN BARBEE

Deepwater oil and gas, with a daunting reputation as a high-risk, high-cost industry, makes it a seemingly improbable marketplace for a fledgling startup with a mere $150,000 budget.

Yet large, integrated companies are changing the way they see smaller, more nimble companies that can, in something of a paradox, research and test technology and theories that global companies cannot afford, executives said Monday, May 6, at an OTC panel discussion on venture capital’s role in driving offshore innovation.

Panelist Ram Shenoy, chairman of WellDiver, said his company has spent as little $10,000 designing and developing frac balls that contain instruments to measure downhole pressure and temperature. The small company’s ability to adapt has resulted in eight products and 18 patents on onshore and offshore technologies with capex of just $150,000.

“This shows how entrepreneurs might be able to find a niche and a high-value application in what superficially appears to be a high technical risk, high financial risk market,” Shenoy said.

Kemal Anbarci, Chevron Corp’s vice president of natural gas production, LNG trading and infrastructure, said larger corporations, service companies and now startups are innovating.

Addressing Shenoy, he said he doubted “larger corporations have the risk tolerance to be able to deliver a technology you’re talking about for tens of thousands of dollars,” Anbarci said. “It would cost us that much just to discuss it.”

Haliburton Co. has its own track record for going far and wide to find the technology it needs. Several years ago, Haliburton famously bought a valuable piece of its own.”

LNG Market Saving the Day

BY EMILY PATSY

Since the U.S. first started exporting LNG from the Lower 48 in 2016, American LNG has become an unstoppable force.

“Frankly, I’ve never been more bullish about the future of LNG,” said Renee Pirrong, manager of research and policy data.

The U.S. emerges as a natural gas-producing juggernaut, “ said Pirrong. “It would cost us that much just to discuss it.”

Halliburton Co. has its own track record for going far and wide to find the technology it needs. Several years ago, Haliburton famously bought a valuable piece of

Guyana: Forging a Path Forward

BY BLAKE WRIGHT

Guyana is faced with important policy decisions against its green growth ambitions. It cannot recede from its energy sector even as it increases its green ambitions. It cannot recede from its energy sector even as it increases its green ambitions.

The country’s own Guyana 2030 initiative seeks to drive economic development and socio-cultural issues.

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Haliburton Co. has its own track record for going far and wide to find the technology it needs. Several years ago, Haliburton famously bought a valuable piece of its own.”

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TechnipFMC’s Subsea 2.0™ In-Line Compact Robotic Manifold received an OTC Spotlight on New Technology Award. With reduced size, weight and manufacturing costs, the compact manifold reduces size, weight and manufacturing cost. It incorporates a robotic arm for valve actuation, can be installed using the same vessel laying the flowline, and increases flexibility over the life of the field.

Award-winning technology

TechnipFMC is honored to receive an OTC Spotlight on New Technology Award for the Subsea 2.0™ In-Line Compact Robotic Manifold, recognizing its innovative, value-driven design. The compact manifold reduces size, weight and manufacturing cost. It incorporates a robotic arm for valve actuation, can be installed using the same vessel laying the flowline, and increases flexibility over the life of the field.

Gaining traction

An increasing number of operating companies worldwide have incorporated Subsea 2.0™ products into their projects, including Shell for its project Kaikias in the Gulf of Mexico, which achieved first oil one year early and under budget. Through innovative technologies and improved efficiencies, clients realize the benefits of simpler, leaner and smarter subsea fields.
Registration was busy on Monday, May 6, as more than 60,000 attendees made their way to NRG Park for the first day of OTC 2019. Attendees packed many of the Monday and Tuesday technical sessions to learn about innovative technologies and industry trends.
With interest high in oil and gas opportunities offshore Brazil, the country known for its deep water and huge presalt reserves is preparing for another set of auctions this year.

The main one, according to Marcio Felix, secretary of Brazil’s ministry of mines and energy, is expected to be the auction for acreage in the Transfer of Rights area. Scheduled for Oct. 28, the auction will offer production-sharing contracts for the Atapu, Búzios, Itapu and Sépia fields, which together are believed to hold up to 15 Bboe.

“I am confident the Transfer of Rights bidding round shall be a turning point in Brazil’s offshore history,” Felix said, noting it will take place a day before OTC Brasil. Minimum profit oil ranges from 19.82% for Itapu to 27.65% for Sépia, with fixed signature bonuses ranging from $448 million for Itapu to about $17 billion for Búzios.

The auction for surplus hydrocarbon resources comes after more than five years of discussion, which resulted in an agreement between the Brazilian government and state-run Petrobras concerning the area. At issue was a contract, signed in 2010 by Petrobras, in which the government exchanged exploratory rights over the presalt area for Petrobras equity.

Oil price changes through the years impacted contract revisions when the Transfer of Rights fields became commercially viable. News of the two agreeing to a revised contract, which granted Petrobras $9.058 billion, came in April, paving the way for the October auction.

Potential investors also have an opportunity to bid on blocks during the 16th bid round, scheduled for Oct. 10. During this round, taking place under the concession model, 36 blocks spanning 29,912 sq km (11,549 sq miles) will be offered. Areas include the Pernambuco-Paraíba, Jacuípe, Camamu-Almada, Campos and Santos basins. The auction is a huge investment opportunity that has already attracted investors worldwide given some of the blocks’ proximity near the presalt polygon or near recent oil discoveries, Felix said.

The sixth production-sharing presalt round will take place Nov. 7 when bids for the Aram, Bumerangue, Cruzeiro do Sul, Sudoeste de Sagitário and Norte de Brava will be taken. Minimum profit oil ranges from 22.87% to 36.98%. Petrobras has right of first refusal and operatorship (30% working interest) in the Aram, Sudoeste de Sagitário and Norte de Brava blocks.

"I’m 100% sure, and I say that on behalf of Minister [Bento] Albuquerque, that the bidding rounds to be held in Brazil in the second semester shall be a breakthrough in the world’s oil industry," Felix said.

Felix gave the speech for Albuquerque, who could not attend OTC but delivered a video message to attendees from what he called the oil and gas capital of the world, Rio de Janeiro.

“The giant oil volumes of those fields will attract all the participation of the major companies in those rounds,” Felix said, adding this means job generation for Brazil.

This comes as Brazil works to overhaul its natural gas sector, aiming to use gas—including associated gas from presalt fields—to use.

“We have before us an unprecedented opportunity to promote a revolution in the gas sector,” Felix said, comparing it to the transformation made by shale gas in the U.S.

The so-called “New Gas Market” is based on pillars that include fostering competition, integration of gas supplies to electricity and industry network, and regulatory harmonization between federal and state governments. The expected results, according to the presentation, include “mone tizing natural gas from presalt, Sergipe Alagoas and other basins, attracting midstream investments, making energy affordable by promoting natural gas fueled power plants and fostering industry.”

Investors have plenty of opportunities to take part in strengthening Brazil’s energy sector.
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- Reduce NPT
- Cut days off multi-well frac
- ZERO man hours in the red zone
Chevron Touts Strategies to Successful Partnerships

BY BRIAN WALZEL

With offshore operations in the U.S. Gulf of Mexico, Western Australia, West Africa and the North Sea, Chevron relies heavily on its vast array of partners to produce and deliver oil and gas around the globe. Among the company’s most successful deepwater partnerships is its Gorgon Project in Western Australia, a joint venture with the Australian subsidiaries of ExxonMobil, Shell, Osaka Gas, Tokyo Gas and JERA. Gorgon is one of the largest LNG projects, producing 73.6 MMcfd (2.6 Bcf/d), according to Chevron.

On Monday afternoon, May 6, president of Chevron’s Project Resources Co. Joe Gregory discussed strategies to enable successful partnerships and collaborations. He identified three critical elements to initiate a partnership and project—the people on the project, strong relationships among the team and trust among its members. Gregory stressed the importance of leaders of a partnership setting the foundation of a strong culture of learning and safety.

“When we do that, when we’re about to work with our counterparts and we can establish that [culture], it’s a powerful place to be,” he said. “When leaders make the workforce feel safe and empowered and valued, we’re going to get much more out of our team. We’re going to learn a lot from our workers, so we have to understand the challenges. Often we don’t listen enough.”

Gregory explained how failing to properly implement proper strategies at the outset of a partnership can often lead to underwhelming project results. He cited a recent survey by UBS Upstream of 58 offshore projects that found only 10% delivered on cost, schedule and the project’s attainment objectives. Additionally, 31% were not delivered on schedule.

“We have to find a way to bring some operational science and a different level of focus to the work,” Gregory said. He said companies typically focus on what they want to build, when they want it to be done and who are going to work with rather than the end result.

“But sometimes we don’t put enough focus on exactly how the work is going to be done,” Gregory said. “We need to spend more time together to partnership, focused more on how we’re going to get the work done along with other key parts.”

He added that for offshore to remain competitive with lower-cost developments, it needed to achieve predictable execution of projects and more competitive development classes.

“We as a company, we’re after anywhere from $15/bbl to $20/bbl in development costs,” he said. Gregory explained how Chevron often looks at project development with its partners from a production aspect.

“No only production of barrels, but the production of work,” he said. “[We look at] everything from engineering to procurement to construction activity to the fabrication activity.”

Gregory said Chevron believes projects can be analyzed from a production system from engineering through delivery.

“If we look at a system and not try to optimize every part, but optimize the whole as we work together, it’s going to yield significant benefits for all of us,” he said. Gregory addressed how economic challenges can arise by building up working capital in pre-existing contracts, which he said ultimately do not benefit investment in the project. He said if companies accumulate a significant amount of pre-productive capital in a long-cycle project, it potentially takes money out of other projects such as new wells.

“So, by optimizing our cash flow and making better decisions together, it’s going to create more opportunities for all of us,” he said. “Maybe not in the offshore, maybe in other parts of our business, but it will create opportunity and it is going to create value.”

Industry News

Schlumberger Service Provides Data Ahead of Bit

Schlumberger has introduced the IriSphere look-ahead-while-drilling service at OTC. The new service provides the industry’s first application of electromagnetic (EM) technology for detecting formation features ahead of the drill bit in oil and gas wells.

The service uses EM-based resistivity measurements more than 30 m (100 ft) ahead of the drill bit, which are then compared to a prepared model that incorporates offset and other data to reveal a pattern.

OTC Video Coverage


NCS Primed for Another Half-century

■ The Johan Sverdrup Field symbolizes how innovation and efficiencies govern forward thinking in the Norwegian Continental Shelf.

BY JOSEPH MARKMAN

How much confidence is there in the long-term viability of the Norwegian Continental Shelf (NCS)? Enough that when the 50-year-old OTC celebrates its 100th anniversary in 2069, the giant Johan Sverdrup Field is still expected to be producing.

“In many ways you can say that Johan Sverdrup is marking the beginning of the next 50 years on the Norwegian Continental Shelf,” said Anders Opedal, executive vice president of technology, projects and drilling for Equinor, operator of the giant platform that is on schedule to begin producing later this year.

The NCS, the subject of an OTC lunch panel on Monday, May 6, is estimated to hold up to 12.4 Bbl of undiscovered oil, two-thirds of which is located in the Barents Sea.

Johan Sverdrup, 155 km (96 miles) west of Stavanger, Norway, is estimated to contain about 2.7 Bboe.

“The Norwegian Continental Shelf has a lot of potential,” Opedal said. “At the same, the future of the NCS will be quite different. The resources are much more dispersed, more difficult to reach and produce.”

Norway’s oil and gas production will peak in 2023, said Bente Nyland, director general of the Norwegian Petroleum Directorate. At that point, natural gas will account for about half of production. Twenty projects are now under construction, representing an annual investment of about 140 billion Norwegian kroner, or US$15 billion, in 2019.

“Following the recent downturn in the industry, we now see a better investment climate,” Nyland said. “Exploration is picking up. We have received 13 new development plans. The industry has done good work on cost control and efficiency. This has led to a considerable reduction in exploration development and operating costs.”

Cost-cutting also is reflected in the new contracts being approved, she said. Even with significantly lower oil prices, the projects can still be brought to completion.

Development of the Johan Sverdrup Field is expected to cost about 80 billion kroner (US$10 billion). “Johan Sverdrup has in many ways served as an engine for improvement for Equinor,” Opedal said. Early-stage work was conducted during the downturn so developing efficiencies was imperative.

The project had to be a driver for simplification and standardization of smarter solutions across the whole company,” he said. “As a result, we have been able to achieve cost reduction approaching 40%.”

Construction of the massive Johan Sverdrup platform has become a laboratory for the partners developing the field, requiring them to find new and smarter ways to work through technology development. During a four-hour stretch on March 19, the Pioneering Spirit vessel performed the 26,000-mt processing platform lift, an offshore record. Moving two final platform topsides, a bridge and a flare stack were all completed during a 72-hour period in March.

Pioneering Spirit vessel performs the 26,000-mt processing platform lift.

The IriSphere service multifrequency transmitters and multireceiver bottomhole assembly provide continuous resistivity that detects formation features far ahead of the drillbit.

(See INDUSTRY NEWS continued on page 8)
XACT’s size and weight are just a fraction of conventional flowmeter systems. (Source: XSENS)

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While the Department of Energy (DOE) does not have the benefit of unlimited research dollars, deputy assistant secretary Shawn Bennett said the federal agency will be strategic as it continues to aggressively pursue partnerships with oil and gas leaders to improve technology in the industry.

Speaking during an early morning session at OTC on Tuesday, May 7, Bennett offered encouragement and support to the offshore industry in this time of fossil fuel uncertainty. He said the DOE is behind the offshore industry and its viable research projects.

“We know that industry invests in research that creates competitive advantage, but we also have some research questions the industry will not pursue at all,” Bennett said during the “DOE Oil and Gas: Addressing Technology and Market Challenges” session.

“These are the research question challenges that we are looking for and that is very important. We want to see what questions are out there that need to be answered for the industry as a whole, work on those and what we can fit into our niche,” he said.

“We tend to focus our research on increasing ultimate recovery, operational efficiency in a safe and sustainable manner as our contribution to meeting the president’s goal."

Bennett pointed to the gas-hydrate program and last month’s announcement of funding for advanced subsea systems technology as proof that the department is behind offshore research. The subsea systems technology will improve efficiency along with improving the capabilities for advance oil recovery and offshore wells. The DOE will provide up to $15 million toward the project.

Bennett said the project will be executed in two phases. Phase 1 consists of the group concept, validation of tools, technologies and processes in a laboratory or field analogue setting. Then Phase 2 will move the project forward with a full-scale prototype demonstration that is expected to persuade the stakeholders to continue developing the technology and commercialization of the project.

“That’s what is very important when I talk about partnership because we invest early in R&D,” Bennett said. “We want to get it to the point where industry can commercialize it and move forward and have a lasting impact on the world.”

Bennett said the DOE is striving to make its research highly relevant to the needs of the industry and that is a priority for the agency.

“We don’t drill wells, but we want to make sure the security of the nation is supported by DOE’s science and technology capabilities,” he said. “We cost share our research with [the] industry and value all of our public and private partnerships. You can actually see this through a lot of the field labs that are currently onshore.”

The agency aims to support the oil and gas industry and its research projects.

BY TERRANCE HARRIS

Shawn Bennett

true downrange representation of the formation while drilling. This enables operators to make proactive decisions rather than reacting to measurements at or behind the bit while drilling wells. More than 25 field trials were conducted with the IriSphere service in Asia, Australia, Latin America and Europe. These trials included successfully detecting reservoirs and salt boundaries, identifying thin layers and avoiding drilling hazards, such as high-pressure formations that can lead to wellbore stability issues.

Offshore Western Australia, one customer used the IriSphere service in an unexplored part of a field to detect the reservoir 19 m (62 ft) ahead of the bit while drilling and determine reservoir thickness to be 25 m (82 ft). This avoided the need to drill a pilot hole, and subsequent coring operations were optimized based on data acquired while looking ahead of the drillbit.

Equinor Technology Ventures, Saudi Aramco Energy Ventures Invest in BaaS Company

Data Gumbo Corp., a Houston-based technology company that has developed a Blockchain-as-a-Service (BaaS) platform to streamline smart contracts management for industrial customers, has completed a $6 mil-

See INDUSTRY NEWS continued on page 20
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A host of successive natural gas discoveries in the Eastern Mediterranean offshore Israel have ignited economic growth and strengthened international ties with its neighboring countries. This was the focus of OTC’s “Around the World Series: Israel” panel discussion on the opening day of the conference, Monday, May 6. The panel centered on development of the energy market in Israel and its emergence as a major natural gas exporter.

“In 2009 Israel’s economy and international structure transformed overnight when Noble Energy discovered gas in the Tamar Field holding around 11 Tcf [311.5 Bcm] of natural gas,” said Gilad Katz, consul general of Israel to the Southwest U.S., in his opening remarks at the session. “In 2010 Noble Energy once again discovered another huge gas field called Leviathan, holding around 22 Tcf [623 Bcm] of natural gas. Those discoveries, together with recent trends in the energy market, have not only given Israel energy independence but have also made her a natural gas exporter.”

Katz added that the major gas discoveries have improved Israel’s relations with Egypt, Jordan, Greece and Cyprus, and despite political obstacles, several geopolitical formations have brightened the prospects of an energy hub in the Eastern Mediterranean. He also spoke about the EastMed gas pipeline intergovernmental agreement signed in the presence of U.S. Secretary of State Mike Pompeo, which will build a 1,200-m (3,937-ft) long pipeline to transport 10 Bcm (0.35 Tcf) of natural gas from Israel’s offshore fields to mainland Greece through Cyprus to the energy hungry markets of the EU. He added that last week the U.S. Department of Energy, Israel’s Ministry of Energy and the Israel Innovation Authority announced a $16 million call for proposals of the U.S.-Israel Center of Excellence in Energy, Engineering and Water Technology.

“Ten years ago, Israel did not have natural resources, and following offshore gas discoveries within a short span of time, we have emerged as an energy independent nation,” said panel speaker Shay Luvshis, Israel’s consul for energy and economic affairs to the U.S. He added that Israel has been ranked second for transforming dependence from fossil fuels to natural gas. By the end of 2030, the government aims to be powered by natural gas for around 80% of the country’s energy needs, with renewable energy filling the rest.

“Israel’s energy market is using advanced technologies and innovation like Internet of Things, Big Data and analytics, and robotics and unmanned equipment systems,” said panelist Vanessa Scrobie, energy business development director of Energy and Economic Mission for the government of Israel. She highlighted examples of companies that utilize technologies in energy operations such as those allowing experts in the control room to communicate visual instructions and real-time data with field technicians.

“First gas sales of the Leviathan project are scheduled to begin at the end of 2019,” said panelist Wesley Johnson, Noble Energy’s Leviathan asset manager. “Late last year, we successfully completed the drilling, completion and flow testing of all four production wells, which will flow around 1.2 Bcf [33.9 MMcm] per day.”

He added that the project 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. He said Noble Energy has already launched the jacket for the Leviathan drilling platform offshore and most of the gas will be exported to Jordan and Egypt.

Natural Gas Finds Transform Israel’s Energy Market

BY FAIZA RIZVI

Following major offshore gas discoveries, Israel aims to become an energy exporting hub.
The abundance of benefits from the Libra Field, located in the Santos Basin ultradeep water offshore Brazil, has been at the hands of a challenging production scenario.

“We have to deliver some solutions to overcome the challenges,” Petrobras’ general manager Paulo Rovina said. “In this type of project, making money is very important when you’re producing oil.”

Libra’s de-risking strategy has played a vital role in changing conventional reservoir appraisal thus optimizing full field development, Rovina said during the OTC session “Libra EWT Project” on Monday, May 6.

The extended well test (EWT) program, set in place by the Libra Consortium made up of Shell, Total, CNOOC Ltd., China’s state-owned CNPC and led by Petrobras (operator), unveiled the field’s uncertainties while simultaneously providing an extensive technological legacy to the offshore oil and gas industry.

“With a project of this magnitude, you need a very solid development plan. We had to learn from the reservoirs to minimize the uncertainties,” Rovina said.

Plans for the Libra Field include an exploratory phase furthering the acquisition of data through 2021, followed by the production development of four Mero fields from 2021 to 2048. The main reason for this strategy is to reduce the uncertainties on a fast track, on time to address the best actions to tackle the risks for the full field development. This reduction helps avoid capital exposure and will allow the transfer of knowledge from one project to another, according to Petrobras.

“The production-sharing contract for the Libra Field is for 35 years so we must optimize the recovery,” he said.

The program allowed for many firsts in terms of technology deployment. In particular, this project was the first use of an 8-in. production line in lazy-wave configuration contributing to the largest oil production rate of 58,000 boe through a single offshore well.

Another important first achieved was the flexible lines pre-laying with buoyancy modules in ultradeep waters. This operation allowed 43 days anticipation in production, compared to a scenario without pre-laid lines.

Additionally, the campaign consisted of moving the FPSO Pioneiro de Libra to different wells in the field and the use of “intensive” intelligent completions to acquire reservoir information from Libra.

The completion technology features independent pressure and temperature sensors in each zone, allowing real-time monitoring during production and gas injection.

“By analyzing the data from remote sensors, we are de-risking the reservoirs, and we are learning something every day,” he added.

The FPSO, equipped with the world’s largest vertical load support capacity equivalent to four Boeing 747s, employed robust swivel equipment that allows it to rotate around the turret. The swivel supports the highest gas injection pressure in the industry, according to a simulation presented by Rovina.

According to Petrobras, all of the innovative technologies applied in the Libra EWT Project will constitute a legacy for the oil and gas industry. The Libra Consortium said in a statement that it expects to continue to invest in robust planning, qualification and innovation to achieve production outcomes consistent with the potential of the field.

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Libra EWT Project Unlocks Powerful Technology

The Libra de-risking strategy has optimized both profits and technological innovation.

BY MARY HOLCOMB

Luggage Check

Need to check a bag during OTC?

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LNG

(continued from page 1)

Last year, the U.S. produced about 83 Bcf/d of natural gas, which is up 11% on the year. Pirrong said Tellurian sees production growth continuing into the future, driving export growth.

Tellurian anticipates the U.S. will see about 20 Bcf/d of excess gas or incremental gas production occurring by 2025. "And all of this gas will need a home," Pirrong said.

Most of the production growth in the U.S. is coming from a handful of shale basins. In particular, Pirrong noted the surge of natural gas production in the Permian Basin, calling it "truly remarkable."

"It’s a hot topic for a reason," she said.

Oil producers like Chevron Corp., who also participated on the panel with Tellurian, have seen an increase in gas production. The problem, however, is a lack of infrastructure available in the basin to absorb all of the gas and transport it to market. As a result, roughly half a billion cubic foot a day of gas is flared in the Permian Basin every day, Pirrong said.

"Now to put that into an LNG perspective, that’s equivalent to about 4 million tonnes of LNG, which is equivalent to Thailand’s entire LNG demand this past year in 2018," she said.

In some instances, some producers in the Permian Basin have had to delay production as natural gas prices in the basin traded in negative territory. For example, Apache Corp. said April 23 it temporarily halted production at its Alpine High assets in late March.

"We need to develop the new infrastructure, both pipeline and LNG terminals to get that gas to market," Pirrong said. "And we really see the LNG market as sort of saving the day. There’s really no better place to put it than in the LNG market, which we see growing at about 11% so far this year."

Ultimately, by the end of 2019, she said Tellurian expects there to be about another 30 million to 40 million tonnes of LNG absorbed into global markets.

"Suffice to say we expect there is a requirement for at least 100 million tonnes of incremental LNG capacity built around the world to meet the growing demand by 2025," she said. "And we actually think that number could be much, much higher."

At the same time, Pirrong said the market is undergoing a rapid shift to commoditization. Long-term contracts will lose their dominance in the next five years as the product is increasingly recognized for what it is—a commodity. Replacing those contracts will be a system of commodity markets akin to crude oil, with prices fluctuating based on the supply and demand of a given day.

"That really challenges the existing business models that we’ve seen in the LNG industry," Pirrong said. "And it forces LNG developers to adapt to those changing market conditions."

In order to compete as the market transitions, Pirrong said Tellurian has been integrating up the value chain to deliver low-cost natural gas.

As a result, Tellurian is looking to acquire 15 Tcf of natural gas resources in the Haynesville, which Pirrong called a low-cost basin. "In addition to our back door in southwest Louisiana," she said.

Pirrong added Tellurian is also working to build pipeline infrastructure to reach into the Permian Basin to access that low-cost natural gas, which has been trading at negative prices this year. "Which is just bonkers to think about," she said.
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The Richards Bay Industrial Development Zone – Special Economic Zone (RBIDZ - SEZ) is a purpose-built, secure industrial estate on the North-Eastern coast of KwaZulu Natal, tied to the international deep-water port of Richards Bay.

It is tailored for manufacturing of goods and production of services to boost beneficiation, investment, economic growth and the development of skills and employement. The RBIDZ, is a Special Economic Zone (SEZ), that aims to encourage international competitiveness through world-class infrastructure as well as tax, VAT and duty free incentives to qualifying companies.

South Africa as a country is taking a turnabout on issues relating to energy and the diversification of its energy base and this structure is supported by its strong role as the continent’s leading power player with more than 45,000 MW of installed capacity and several new projects under development. Remarkable, there are prospects in the projects in the nearshore, midstream, downstream and power segments.

RBIDZ BRIEF OVERVIEW

The RBIDZ focuses on the following sectors: Metals Beneficiation (Aluminium, Iron Ore & Titanium), Marine Industry Development (Ship Building & Repair, Oil Refinery, Oil & Gas), Renewable Energy (Solar, Fuel Cells, Biomass), ICT (Telecom, Parties, Innovation Hub) and Agro-processing.

The RBIDZ Special Economic Zone has been identified and announced as the host of 2000MW Gas-to-Power plant to be developed in the country. In response to this development, the KwaZulu-Natal Province is in the process of registering gas opportunities in the province, and the RBIDZ has taken lead in the process. The identified 66 hectares of land has been set aside for the O&G Hub and a further 600-5200 hectares of land is proposed for the O&G Refinery in this SEZ.

THE RICHARDS BAY INDUSTRIAL DEVELOPMENT ZONE HAS THE WORLD-CLASS INFRASTRUCTURE READY TO TAKE ON BUSINESS.

BIG DECISIONS CALL FOR INFRASTRUCTURE DEVELOPMENT THAT COMPLEMENTS THE ACTION

INVEST IN RICHARDS BAY INDUSTRIAL DEVELOPMENT ZONE TODAY

Richards Bay Industrial Development Zone Company (SOC) Ltd
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Source: RBIDZ
Composites Enable Repairs Without Shutting in Production

By Judy Murray

When offshore assets need repair, the first thought normally is not a composite solution, but according to ClockSpring|NRI Regional Sales Manager Leah Tetreault, maybe it should be.

In a press conference on Tuesday, May 7, Tetreault and colleague Matt Green, vice president of Technical Services, discussed the evolution of composite solutions, including testing used to qualify composites for use in the oil and gas industry. Years of research—some managed by the Gas Research Institute and others funded by Pipeline Research Council International Inc. and the Pipeline and Hazardous Materials Safety Administration—subjected materials to a range of environments and applications and found them suitable for long-term repairs.

Tetreault explained that composites were developed specifically to contend with corrosion and have been used to address a range of offshore defects with positive results both above and below the water. These types of solutions have been installed around the world for more than 20 years, she said.

Tetreault gave as an example a project in Cook Inlet, Alaska, where prefabricated multilayered composite split sleeves made of high-strength, corrosion-resistant fiberglass were installed on 20-girth weld joints on a 10-in. gas pipeline. The owner needed a solution that would not require the pipeline to be moved and that could be installed with little clearance because of the location of other nearby lines. This installation was complicated by the fact that there was zero underwater visibility 30 m (100 ft) below the surface, and work could only take place during slack tides in the summer months. A composite repair tackled all the boxes.

Because a single diver had to make the repair, the technical team developed an innovative installation tool, building a frame that allowed the diver to take sleeves prepared on the deck of a barge to depth and position them on the damaged lines. "This frame concept has now been used in other offshore installations," Tetreault said.

The split sleeve solution is one of many that are used offshore. Tetreault explained, noting that different types of defects and operating conditions require different composite repair solutions.

According to Green, some projects span dry and wet areas. On a platform offshore Malaysia, a line running from the topsides to the seafloor had experienced considerable metal loss and multiple dents that required repair. While a team of technicians cleaned the line on the deck and used a pre-impregnated, bi-directional fiberglass composite to repair, divers addressed the dents in the underwater line with a similar solution. Both repairs were completed without shutting in production, he said.

Green shared the details of another repair offshore California, where a composite repaired riser damage caused by impact from a supply boat. Using rope access, a repair crew cleaned the riser, filled the dent with a high-compression-strength liquid epoxy and coated the repair length with a different epoxy to promote adhesion of the fiberglass composite. "The two-part epoxy stops future corrosion in the offshore environment," he explained.

This solution was carried out in less than 2 hours, restoring the line to safety without any loss of production. He said if traditional systems had been used, the repair would have been very expensive, noting, "A shut-down could have cost more than $120,000 a day."

Because of the designed-in safety of the products and the application methods used, they often can be installed without interrupting operations. This is a frequently overlooked "plus" in favor of composite solutions, Tetreault said, noting that an additional benefit is their versatility.

Composites are being used in new ways all the time, Green said, adding that studies have been done to investigate the viability of using ROVs to install composites at depths much greater than those achieved to date by divers. While there is no such capability at present, the value this capability would deliver is a strong driver for finding a way to make it work, he said.

Divers use a pre-impregnated, bidirectional fiberglass composite to repair a damaged line running from the topsides to the sea floor without shutting in production. (Source: ClockSpring|NRI)
Tight Oil versus Deep Water: More Similar Than You Think

Could the pendulum swing back to deep water?

What convergence will mean
The market wants cash generation, but tight oil is barely self-financing, even in the best quarters. Some firms are getting trapped—investors focused on dividends, not enough spare cash to scale up or acquire, and few alternatives in the portfolio. Other tight oil plays are available, but the investment proposition is not as strong.

Deep water offers more bang for your buck on a full-cycle basis but is still higher risk and probably not enough to derail the Permian juggernaut.

The trick will be balancing the best of both worlds, managing a portfolio with regular tranches of deepwater production, and tight oil on top acting as the growth engine. If one does not deliver, the other picks up the slack. With tight oil entry costs rising sharply every year, it may be prohibitively expensive to switch tracks now.

Longer term, according to Wood Mackenzie, U.S. independents need to think about life after U.S. tight oil. Many have abandoned deep water entirely, some unwisely. A faster deepwater investment cycle should make it an easier sell to the capital markets, but in most cases, investors have not warmed to the value of independents with diversified portfolios.

Ultimately, Wood Mackenzie believes it is a wiser choice to maintain deepwater exposure than to double-down on unconventional.

How tight oil went industrial
Operators drill and complete multiple wells across multiple formations simultaneously. Now the unconventional model starts to look a bit more conventional, as operators seek to maximize long-term recovery and value. However, the industrial strategy is still in its early days so the jury is out as to how effective and repeatable it will be.

"Old tight oil" involves drilling wells one by one, which restricts the cost savings offered by scale, and allows capital flexibility to respond to external circumstances, particularly oil price.

For "new tight oil," larger pads cost hundreds of millions of dollars and are more akin to offshore platforms in cost, size and complexity. Multiple rigs, shared infrastructure and economies of scale offer 10% to 20% cost savings, and scale means longer commitment and lead times, less short-cycle value extraction and more infrastructure and investment.

Faster, lighter... deeper?
The industry has seen average time from discovery to first production cut in half over the last four to five years, and final investment decision to first production has dropped by a third. This is due to lean, simpler projects and an increased role of phasing in behemoths such as Liza, Leviathan and Zohr.

By comparison, of about 60 Bboe (commercial) each in early stage projects, the Permian is double the capex/boe and roughly 25% less NPV10 than deep water.

"New deep water" involves tiebacks to existing infrastructure or standardized hubs (design one, build many); fast-track first stage of field development to achieve first oil/revenues quicker; smooth out initial capex requirements and de-risk the reservoir; hub-and-spoke model encourages future tieback opportunities; and subsequent phasing can be paced as required, offering more stop-go decision gates and capital flexibility.

What convergence will mean
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Could the pendulum swing back to deep water?
20K System to Deliver Ultrahigh-pressure Reservoir Access

Final development and qualification of a complete 20K system to be completed this year.

The next frontier and challenge in the offshore drilling market is ultrahigh-pressure well control, often referred to as 20K. In 2011 National Oilwell Varco (NOV) began developing a 20K BOP, but market volatility and the recent downturn slowed the development process. However, in 2018 renewed interest from operators provided the necessary incentives for completing its development. Operators will soon be able to drill ultrahigh-pressure assets.

When it comes to drilling a 20K well, it is not simply about the BOP and is more than just a pressure control system challenge. The size, complexity and depth of these wells means that not only are the BOPs affected, but also the entire subsea system, subsea handling equipment and the load path of the vessel. When designing technologies for 20K, it is about the complete rig package, which is something that NOV is accustomed to since the company has experience with designing and building everything from the crown to subsea. Higher hook loads required that NOV develop the biggest top drive and drawworks ever made, the TDX-1500 and AHD-1750 respectively, in addition to modifications in motion compensation, BOP handling and riser handling systems.

The development of a complete 20K system has been a long and well-thought-out road. It is important to look at the challenges the industry is facing with a new set of eyes rather than trying to build upon something that already exists when approaching new-frontiers such as accessing ultra-high-pressure reservoirs. In 2011 NOV started designing the 20K BOP with a blank sheet of paper and years of experience. The new system is an 18¾-in., 20,000-psi stack with connector, valves, choke and kill stabs, BOP mandrel and more. The BOP stack has six ram cavities and one annular BOP. It is equipped with two LFS (low-force shear) rams that are fitted in the upper cavities and with newly designed 4½-in. to 7½-in. Multi-Rams in the four lower cavities. NOV also designed a new 20K wellhead connector.

There was significant design that went into the development of the LFS shear ram. The LFS can puncture pipe rather than mash it by coming through the center then moving out as the rams close. NOV also took a close look at the control system since regulations require full-time redundancy in the controls, which has led to operators frequently performing costly system pulls. To provide a better, more cost-effective solution, a patented subsea retrievable pod system, RCX, was developed that can deploy, replace and retrieve either pod on the BOP while it is still on the wellhead. Regulations have also impacted the number of accumulator bottles required. If traditional piston-type bottles are used there is a need for as many as 25 160-gal bottles, each weighing 10,000 lb. In contrast, NOV's patented depth-compensated bottle (DCB) technology can provide the same working volume with only eight DCBs at a fraction of the size and weight. When using DCB technology only a single pre-charge is needed for the bottles on surface and, as the stack goes deeper, depth compensation occurs automatically.

One of the challenges that NOV faced throughout this process is managing the evolving regulations from the U.S. Bureau of Safety and Environmental Enforcement (BSEE). BSEE approval requires the operator, drilling contractor, independent third-party and the original equipment manufacturer to work together for testing and certification of the 20K systems. NOV is currently in the process of qualification and final testing.

NOV is perfectly positioned to deliver a holistic 20K system that is compliant with governmental regulations and gives operators and drilling contractors the right tools to meet the 20K challenge facing the industry.

The 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)
The OTC award-winning NovaLT16 continues to prove its power in the offshore market with a swift entrance and deployment in Asia’s growing market. With extended maintenance intervals and an excellent ratio between power output and footprint, the NovaLT16 by Baker Hughes, a GE company (BHGE), delivers key components required for offshore with recent deployments in Vietnam for Vietsovpetro and Malaysia for Yinson.

With a rated output power of 16.8 MW and a 7,800-rpm unit combined in a compact footprint, this turbine is suitable for offshore installations where space is usually tight. Its mechanical efficiency of up to 37.3% makes it extremely competitive among existing products in the 10 to 20 MW range.

The NovaLT16 boasts the longest maintenance intervals in the market for this power range with up to 35,000 hours mean time between maintenance, or more than four years in operation until the first overhaul, which is carried out by swapping the engine—an operation carried out in just 24 working hours. The actual engine swapping (sliding and mechanical connection) is done in 3 hours, with an additional 20 working hours for alignment and prestart checks (mainly wiring loop checks).

Entering the market in Asia

“The NovaLT16 turbine has been configured to ensure servicing activities can be completed quickly and efficiently, thereby reducing downtime, resulting in high levels of reliability, availability and efficiency, with reduced operating costs for the customer,” said Rod Christie, president and CEO of the Turbomachinery & Process Solutions business unit at BHGE.

Vietnam continues to have significant levels of oil and gas developments with an increasing demand for power plants, refineries and petrochemical plants. For the Vietsovpetro project, the NovaLT16 provides an efficient solution with a strong emphasis on high availability and reliability, while reducing operating costs. It will be combined with the gas compression platform’s existing gas engine-driven reciprocating compressors to expand gas compression capacity at Block 09-1.

The NovaLT16 turbine is designed for both mechanical drive and power generation applications, and for this development, its mechanical drive capabilities are ideally suited to enhance the facility’s gas compression performance with 89% or higher compressor efficiency.

Developed and built in Florence, Italy, the order for Vietsovpetro was received in 2017 and shipped from Italy in September 2018, with completion at the Asian yard in March of this year. The commercial operation date is expected in May.

In January BHGE shipped two pre-assembled NovaLT16 driven compression train units to Yinson in Malaysia. The module was co-engineered with the customer for easy maintenance through modular engineer exchange with a total weight (dry) of 196 tons and a main skid rate of 166 tons.

R&D and testing

Known as a mainstay in the BHGE Nova Turbine family and developed in Florence, the NovaLT16 includes a two-stage high-pressure turbine featuring single crystal buckets to provide best available metallurgy for higher efficiency and availability. The additional two stages on the free power turbine are equipped with a variable geometry nozzle, which allows an unbeatable partial load efficiency, at 70% load gas turbine efficiency, it is just 10% lower than the maximum rated efficiency or full load, which is considered a best-in-class degradation.

BHGE relies on tested and proven components along with improvements in technologies and materials, thanks to R&D facilities at BHGE. The first NovaLT16 machine completed an endurance test of 8,000 hours in a dedicated power generation station connected to the public electric grid in the BHGE plant in Florence under the supervision of the engineering company Pöyry, which issued the certification.

CONTRIBUTED BY BAKER HUGHES, A GE COMPANY

Our company has been a long standing supplier of drive solutions for the growing oil and gas industry. Extreme operating conditions demand for high-quality, reliable products and services, in which we can provide due to our profound know-how.

Minimum quantity > 1
Max. crankshaft radius 170 mm
Machining length approx. max. 2,500 mm depending on design.
Depending on the position and diameter of the throw!

We would be pleased to offer an individual package!
**Amazon Vessel Readied for Modifications**

The vessel will use more automation and better control systems and robotics to keep the crew size down.

**CONTRIBUTED BY MCDERMOTT**

Mcdermott is getting closer to realizing its vision to develop a vessel into a world-class ultradeepwater J-Lay vessel.

The last few years have seen significant innovations in offshore rigs to downhole monitoring and solutions farther downstream, wireless technologies have had a significant impact on oil and gas operations—improving efficiencies, delivering savings and opening up areas previously considered inaccessible. Now wireless is making inroads into one of the last frontiers—the environmental conditions they operate in, and due to current monitoring limitations, the difficulties of accessing representative pressure and temperature data and anything more than a snapshot of flow contributions.

The result is expensive but sub-optimal well and reservoir management with a lack of information from the lower completion and reservoir sandface. This physical interface where the formation and the wellbore meet is an area considered off limits when it comes to sourcing accurate, multizone information. The lower completion has been considered too risky, costly and complex when it comes to online monitoring.

Now, a new downhole reservoir network solution that provides online monitoring from the lower completion will reverse this trend. In partnership with Metrol, a provider of battery-powered wireless well monitoring, Emerson offers the first wireless-enabled, integrated upper and lower completions downhole solution that communicates with instruments at the reservoir sandface via a new wireless interface.

The Roxar Matrix Downhole Wireless Interface combines the cabled permanent downhole gauges in the upper completion with the wireless sensors and controls along the reservoir sandface to provide a total well solution. IMCN builds on Emerson's years of experience in advanced permanent downhole monitoring and the capabilities of its existing Integrated Downhole Network.

IMCN was new to the vessel's systems, including an additional 5 MW of power and the design of the electrical system expansion, under the management of IHC.

The Amazon's first major pipe lay project after modifications will be on BP's Greater Tortue Ahmeyim natural gas project located offshore Mauritania and Senegal.

For more information, visit McDermott at booth 2263. A briefing on the Amazon conversion is scheduled each day at 2 p.m. in the company's exhibit.

**Making Communication Inroads Downhole**

A new downhole wireless network enables online monitoring of lower completions.

**CONTRIBUTED BY EMERSON AUTOMATION SERVICES**

From communications at the well pad to remote offshore rigs to downhole monitoring and solutions farther downstream, wireless technologies have had a significant impact on oil and gas operations—improving efficiencies, delivering savings and opening up areas previously considered inaccessible. Now wireless is making inroads into one of the last frontiers—the lower completion.

The last few years have seen significant innovations in well design and completion methods.

Yet, along with these innovations comes new challenges involving data collection and monitoring. These challenges include the length and deviations of such wells, the environmental conditions they operate in, and, due to current monitoring limitations, the difficulties of accessing representative pressure and temperature data and anything more than a snapshot of flow contributions.

The result is expensive but sub-optimal well and reservoir management with a lack of information from the reservoirsandface.
The first installation of a high-performance, low-consumption electrically heat traced flowline (EHTF) in the U.S. Gulf of Mexico (GoM) will be carried out later this year by Subsea Integration Alliance, a collaboration between Subsea 7 and OneSubsea, for the BP Manuel Project.

Developed by Subsea 7 in conjunction with manufacturer ITP, the EHTF is a thermally efficient flowline system based on a combination of high-performance Pipe-in-Pipe Isoflex insulation and low-power electric trace heating.

Unlike more power-hungry direct electric heating methods, EHTF minimizes topside power requirements and enables longer distance tiebacks.

"Together with the BP team, through the deployment of EHTF technology, we have produced an optimized solution that will enable us to reduce the total cost of the project while also accelerating the first oil target date to just 24 months from discovery," said Craig Broussard, Subsea 7’s vice president for the GoM.

The Manuel project award follows an earlier engineering, procurement, construction and installation contract to Subsea 7 in December 2017 for the design, manufacturing and installation of a 20-km (12-mile) EHTF system for the Aker BP Ørufjord Project in Norway.

"EHTF is a highly cost-effective technology, overcoming the challenges of longer distance tiebacks and greater water depths," said Thomas Sunde, Subsea 7’s vice president of strategy and technology. "It enables us to draw on our considerable experience in heated pipe technologies to design and install ‘neighborhood’ tie-ins or long single-line tiebacks to enhance our clients’ production performance. EHTF improves access to reserves by allowing for long tiebacks with no looping requirement and can enable the transport of well streams above hydrate appearance temperature via direct connections to onshore facilities."

CONTRIBUTED BY SUBSEA 7

First Installation of Electrically Heat Traced Flowline in the US GoM

An innovative combination of high-performance insulation and low-power heating enables longer distance tiebacks.

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NETL Presentations

Wednesday, May 8, 2019
Booth 1325

Embracing Uncertainty in the ML/ AI Era—The VGM Tool for Oil and Gas Decision Makers
Presented by Jennifer Bauer and Kelly Rose
Organization: National Energy Technology Laboratory (NETL)
10 a.m. – 11 a.m.

Corrosion Resistant Aluminum Components for Improved Cost and Performance of Ultradeepwater Offshore Oil Production
Presented by Glenn Grant
Organization: Pacific Northwest National Laboratory
11 a.m. – 12 p.m.

Employment Opportunities with NETL
Presented by Chuck Taylor
Organization: NETL
12 p.m. – 1 p.m.

Gas Hydrates
Presented by Gabby Intihar
Organization: DOE Office of Fossil Energy
1 p.m. – 2 p.m.

Subsurface Trend Analysis—Improved Prediction of Subsurface Properties for Geohazard & Resource Assessments
Presented by Kelly Rose
Organization: NETL
2 p.m. – 3 p.m.
In GoM, Massive Improvement in Efficiency Among Top Operators

Increase in region’s deepwater activity points to better days ahead for GoM.

BY JOACHIM MILLING GREGERSEN, RYSTAD ENERGY

Deepwater activity in the U.S. Gulf of Mexico (GoM) showed signs of growth in 2018, amid the buzz of shale mania. Most drilling life-cycle stages showed positive signs, from lease sales to drilling metrics. Shell was the main driver behind the turnaround, although several companies have shown a commitment to their communicated hub-and-spoke strategy. Drilling efficiency in 2014 to 2018 also increased as a result of better planned drilling campaigns.

In 2017 the number of spuds in water depths of more than 305 m (1,000 ft) dipped below 100. However, in 2018 this number rebounded to 130, which was a 31% year-on-year increase and the greatest year-on-year increase since 2012. Shell alone spudded an impressive 42 of these wellbores, followed by BP, Chevron and Anadarko.

In 2014 and the years to follow, the industry saw lower activity and a stringent focus on cost cutting, which resulted in more efficient drilling. Data from the Bureau of Ocean Energy Management (BOEM) suggest a clear trend in efficiency gains. By estimating the perceived drilling speed from spud to total depth (not to be confused with rate of penetration) in main wellbores, Rystad sees a massive improvement in efficiency among the top operators. The most efficient drilling programs are displayed by the most active operators, which show a relation between the number of wellbores drilled and the efficiency of drilling operations. The most efficient driller in 2018 was BP, closely followed by Anadarko, which both achieved perceived drilling speeds well above 183 m (600 ft) per day.

At the same time, the market for operators has consolidated. Only 15 operators are actively spudding wellbores at the present time, a 20-year low, excluding the outlier year of 2011. This is almost half of what was seen in the beginning of the millennium. With fewer operators, and efficiency gains due to increased drilling per operator, Rystad sees that overall drilling speed is also increasing. This has resulted in an efficiency increase of 65% as compared to 2014.

The disciplined style of efficient drilling, along with the hub-and-spoke strategy, has helped boost the popularity in lease sales among GoM operators. The March 2019 lease sales were double the total sales in August 2017 proving that operators are willing to increase activity and are confident in their ability to competitively exploit GoM resources.

Redefining the CT BOP Performance

A new design of blade structure and slip ram optimizes CT BOP comprehensive performance.

CONTRIBUTED BY THE JEREEH GROUP

The Gulf of Mexico oil spill in 2010 was a devastating disaster that caused 5.180 sq km (2,000 sq miles) of pollution and $20 billion in massive compensation. This was a warning to the well control equipment manufacturers about product safety, reliability and performance.

Coiled tubing (CT) BOPs are key for well control. They function as the last protection to prevent the uncontrolled flow of liquids and gases during operations by having the ability to shear the CT and seal the wellbore simultaneously in case of any issues during the operations. Activating the slips prevents CT from falling into the wellbore, while the shear ram cuts the tubing, ensuring the tubing stays in the BOPs until operations can be altered.

As job location and working conditions change all the time, Jereh R&D engineers found a way to improve the efficiencies of the BOP performance.

The force born by the shear blade changes in a complicated way, which is what engineers have studied and improved. At present, the shear stress is calculated based on material mechanics. However, people fail to take such factors as shear blade structure, blade clearance, shearing speed, friction and shearing section deformation into consideration. Therefore, material mechanics cannot reflect the nature of deformation during the shearing process.

To lower the shear force, Jereh engineers, through comprehensive analysis, calculation and verification, upgraded the full edge blade to an embedded structure to allow the CT to be sheered by using only 75% shear force.

Studying the material and heat-treating parameters of the 2-in. CT (CT110, 0.204 in.), for example, each blade is capable of shearing continuously 40 times, which greatly improves the shear ram performance.

The slip ram is as important as the shear ram, which serves to grab and hold the CT by latching shear teeth onto tubing hydraulically to prevent slippage. Since the CT will be damaged to a certain degree when the teeth are latched into the tubing, improving slip ram capability by minimizing the CT damage is another challenge to the engineers. The slip gripping angle, height, interval and heat treating affect the slip ram performance in different degrees. Through combined design calculation and verification, it is concluded that the obtuse-angled teeth can effectively hold the CT with minimum damage to CT and reduces stress concentration when heat treating to avoid tooth break. Again using the 2-in. CT (CT110, 0.204 in.) as an example, the carrying capacity of the slip ram after optimization is 70.2 tons.

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spectroscopy technology from a company in the food industry. “We innovate when the times are tough,” he said. “If you're a startup company looking for a new way of doing things, these are the good times.”

The benefit of working with artificial intelligence and machine learning are what the financial investor world calls “capital light,” he said. “If it’s capital light it can generally return more capital than what you put in and then some;” and at a fast pace, Sledzik said. “That, almost by definition, is an area all of us are focusing on, because it can bring more bang for your buck than maybe these capital heavy opportunities.”

Saudi Aramco is taking a long view on most of its investments. Its aims include driving future demand for hydrocarbons. Sledzik said his investments are designed to pay off for the company years into the future.

“They’re going to scale it right,” he said. “We hope Halliburton is in the position to buy the company to scale it right.”

Anbarci said people may look back on 2013 and 2014 as the “good old days,” but in many ways the pace of drilling wells prevented companies from driving down costs or increasing efficiencies. “We innovate when the times are tough,” he said. “If you’re a startup company looking for a new way of doing things, these are the good times.”

Halliburton also serves as an exit destination for companies sponsored by the venture capital arms of large corporations such as Chevron and Saudi Aramco. James Sledzik, managing director for Saudi Aramco Energy Ventures in the U.S., said with offshore projects relatively capital intensive, investors are more inclined to look outside the sector. “There’s a behavioral aspect that has to change with big companies interacting with little companies,” Pow- ers said. “We’re definitely going to have to think about, in this ecosystem, how we tread very lightly.”

That may mean less legal burdens and more obser- vation as opposed to ownership, he said. Powers noted that the company recently began funding a proof of concept around a smaller company’s founda- tional patent with little legal framework. “The inten- tion is to create a durable process” for interacting with small companies, he said. “It remains to be seen what happens.”

Halliburton continues to find ways to push itself, said Greg Powers, Halliburton’s vice president of global innovation. “My chairman asked me if we could possi- bly print 3-D parts downhole while they’re in the midst of breaking.” Powers said. “I think that’s a pretty good long aspirational goal.”

But giant companies such as Chevron and Hallibur- ton are trying out partnerships with smaller companies rather than simply absorbing them, as they might have done in the past.

Halliburton, which last year spent $525 million on R&D, also realizes “we cannot invent everything,” Pow- ers said. “To move the needle, we have to embrace this notion other people might be a significant portion of your inventing.”

In the past, a company Halliburton’s size could come across a small business with an import, founda- tional patent for a new technology. Halliburton, which employs about 30 patent liaisons, could “patent around your inventing.”

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The head of R&D at the company, Dr. Aneel Gill, will be presenting papers on the technology twice daily at booth 1339-A.

Newpark Receives Shell Supplier Award
Royal Dutch Shell honored Newpark Fluids Systems with its 2018 Global Wells Services Award for suppliers with operational hours less than 100,000. The company was recognized for its HSE and leadership practices executed in Albania. Newpark assisted Shell with formations that are historically difficult to manage, provided waste management and water treatment including reverse osmosis. Newpark provided quality service both onsite and remotely with its technical field and office support in Albania as well as additional laboratory and technical support from Houston.

For more information, visit Newpark at booth 105.

Jumbo Wins Offshore Subsea Decommissioning Project in North Sea
Jumbo has been awarded an offshore decommissioning project in the North Sea by TAQA Energy BV that involves the removal, transportation and dis- posal of three subsea protection domes and piles.

The removal operation will take place in the offshore series of fields located in the P15 Block 35 km northwest of Hoek van Holland, Dutch North Sea, at a water depth of 26 m to 28 m (85 ft to 92 ft).

This project is part of the emergent North Sea decommissioning program, where much of the offshore oil and gas infrastructure is reaching the end of its productive life and must be safely removed and disposed.

See INDUSTRY NEWS continued on page 23

James Sledzik
Vericor’s gas turbine engines are now being used in trailer-mounted mobile configurations such as hydraulic fracturing. This utilization requires a low-speed, high-torque cyclical operating cycle that differs from the power generation cycle for which gas turbines are known to excel. It is therefore imperative for the original equipment manufacturer to fully understand how its engines perform when operated through this type of cycle.

Vericor’s legacy remote monitoring systems are typical of those used at power plants where the network infrastructure is housed within the facility where the engine is installed. The same type of system cannot be used in mobile applications due to the need for small form factor devices suitable for rugged environments.

Initially, the approach was to develop a solution based on well-known SCADA technology. As different SCADA solutions were investigated, it became readily apparent that SCADA has now evolved into the Industrial Internet of Things (IIoT).

The emergence of the IIoT has made technologies available to quickly develop and deploy a viable remote monitoring package. One of the primary characteristics of the IIoT is the use of cloud computing for data storage, analytics and visualization. Vericor has partnered with Microsoft to implement a cloud-based platform for remote monitoring services. Within the Microsoft Azure Cloud, data from the field are stored and served to a web browser interface or mobile app. Users interact with engine data through dashboards, trends and other visualizations. The cloud also hosts a digital twin of each engine that determines real-time performance. Predictive analytics is used with the performance trend to aid in the determination of maintenance intervals. An alert system pushes notifications out through SMS, email or a mobile app whenever certain critical faults are detected or if the digital twin identifies an abnormal trend in engine performance.

To collect data from the field, a network edge device is needed to extract data from the engine controller and relay it to the cloud. Vericor has partnered with LEC Inc. to provide the edge device and manage data transmission through its existing relationships with global cellular providers. Data are sent at 1-second intervals during an engine start sequence and at 6-second intervals while the engine is running at power. The edge device also retains up to seven years of historical data on an encrypted SD card.

Successful deployment in China

The IIoT-based remote monitoring system has been successfully deployed in a hydraulic fracturing trailer in China. The installation of the edge device took only a few hours with data arriving at the cloud within a few seconds of actual engine operation. The system continues to deliver operational data whenever the trailer is running. The immediacy and regularity of the data provide insight for Vericor to understand how its engine is being utilized in this application. Through the use of the digital twin, Vericor is able to proactively respond to performance trends and communicate that information to the customer.

Cybersecurity

Although the internet age has brought connectivity to an unparalleled scale, it has also brought serious cyber risks along with it. Cybersecurity needs to be considered throughout the development of any IIoT program. Exploits could result in asset downtime or damage to equipment. Therefore, the selection of IIoT technologies and partnerships must be well thought out. A thorough risk assessment of every possible exploit must be analyzed to develop a defense-in-depth strategy for cybersecurity. In Vericor’s remote monitoring system, the edge device and the cloud both incorporate multiple levels of cybersecurity protection. Even after development is completed, it remains necessary to stay abreast of industry standards and continually adapt best practices to mitigate these risks.

CONTRIBUTED BY VERICOR POWER SYSTEMS

Leveraging the IIoT for Remote Monitoring and Diagnostics

New technologies enable rapid deployment of remote monitoring capabilities.
future generations toward the creation of a national system of governance, values and ethics conducive to sustained “green” economic development and socio-cultural harmony. However, the plan was set in place prior to the country’s emergence as a world-class hydrocarbon basin.

Wendy Brown, International Oil & Gas Association environment director, will moderate the OTC panel discussion, which will explore how a country like Guyana can achieve its Sustainable Development Goals through strong collaboration between the oil and gas industry, national governments and nongovernmental organizations.

To assist with the challenges, the World Bank just last month allocated $20 million to help Guyana create the regulations and institutions needed to develop its rapidly growing oil and gas sector. The funding, in the form of an International Development Association credit, will enable the country to create checks and balances that lessen the environmental and social impacts of hydrocarbons production in the country.

Supermajor Exxon Mobil has already played a key role in the country’s unrivaled oil revolution and recognized that the way forward requires a judicious path to realize long-term democratic wealth creation while responsibly and sustainably protecting its environment. The operator will be the first to produce oil offshore Guyana when it turns the taps on its Liza Phase 1 development next year. Liza was discovered in 2015. Subsequent appraisal drilling revealed an initial discovery in excess of 1 Bboe. Phase 1 development envisions a 17-well project tied into an FPSO hub.

Panelist Erik Oswald, vice president, Americas, Exxon Mobil Exploration, stresses the importance of a safe, responsible and respectful approach to resource development in the region while forging and maintaining long-term, sustainable partnerships with resource owners that generate social and economic benefits for society.

“Realistically, it will be difficult for Guyana to avoid the resource curse,” Marcel added. “Oil revenues will disrupt its small economy and its political system. Safeguards are needed to mitigate those risks.”

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Our NovaLT™16 gas turbine delivers 16.8 MW shaft output power to maximize production and minimize risk for both onshore and offshore applications. Designed with a 35,000-hour mean time between maintenance, and a 24-hour turnaround for engine swap, the NovaLT16 sets a new standard for maximized availability, low maintenance, high fuel efficiency, and reduced emissions.

Learn more by visiting BHGE at booth #2827.

DAILY TECH TALKS
AT BHGE BOOTH #2827

Wednesday, May 8

9:30 am  Delivering Upstream and Enhanced Productivity Through Your Projects’ Life of Field with Subsea Connect
10:00 am Achieving Step-change Efficiency Improvements in Offshore Sand Control
10:30 am Leveraging Subsea Connect for a Radically New Approach to Planning Your Next Subsea Project
11:00 am Carbon Management—Securing the Sustainability of Oil and Gas in the Energy Transition
11:30 am Discover BHGE’s Innovative Commercial Models for Project Success
12:00 pm Improving Reliability Using Alfa Laval System-level Failures
1:00 pm Spotlight on New Technology Award Winner NovaLT16: Maximizing Production and Minimizing Offshore and Onshore Risk
2:00 pm Reduce Non-productive Time with the Intelligent Subsea Stethoscope
2:30 pm Drilling Through Narrow Hydraulic Windows: Without Losing Power or Restricting Performance
3:00 pm Explore Advanced Developments in Autonomous Subsea Pipeline Pre-commissioning
5:30 pm Improving Mature-well Recovery Rates with Fast, Effective Chemical Treatments
4:00 pm Using Data-driven Decision making & TOTEX Savings for Subsea Blowout Preventers
4:30 pm Learn How BHGE is Enhancing Offshore Power Generation Solutions

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