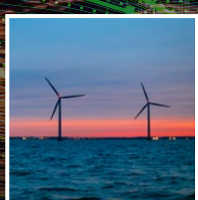
HARTENERGY NOVEMBER 2020

E&P plus

WILL BIG DATA SHAPE RECOVERY?

Companies are rethinking data analytics to navigate uncertainties

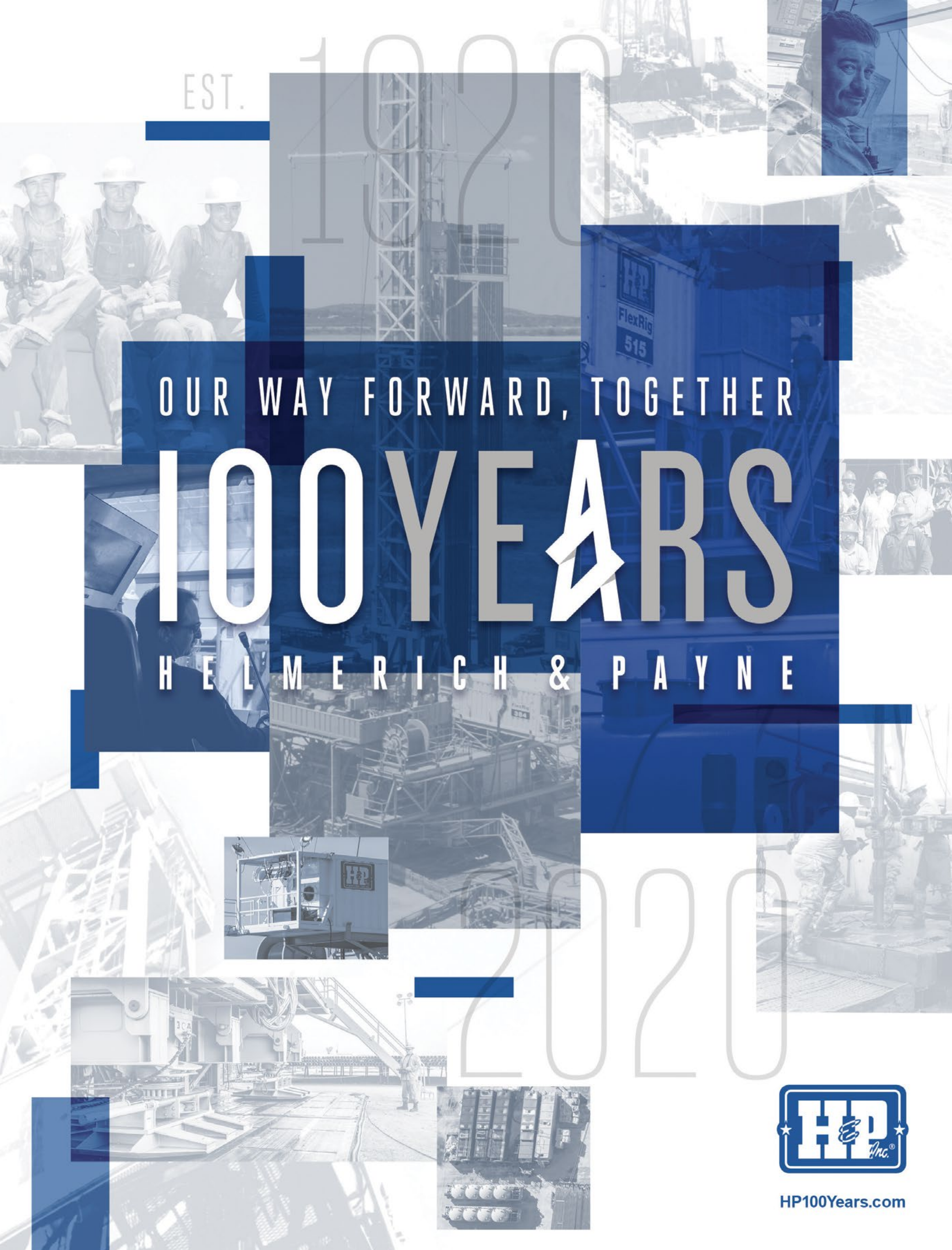
Q&A with Hinda Gharbi



Energy Transition

Operator Spotlight: Haynesville E&P

Regional Report: Southeast Asia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A Hart Energy Publication

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COVER STORY: DATA ANALYTICS

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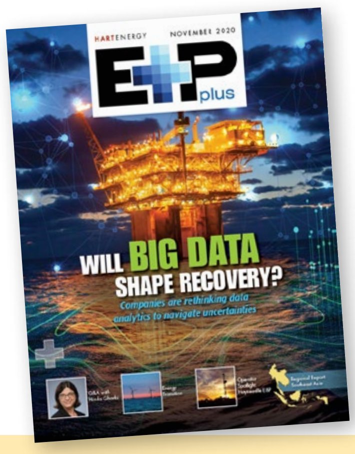

About The Cover: As the oil and gas industry struggles to recover from a historic downturn, energy companies are revisiting data analytics for resilience and recovery. (Background cover photo courtesy of Marc Morrison/marcmorrison.com; Cover design by Melissa Ritchie; Bottom images from left to right courtesy of Schlumberger, korsart/Shutterstock.com; Goodrich Petroleum; and Shutterstock.com)

Coming Next Month: The December cover story will focus on the major U.S. shale plays with a theme of "the good, the bad and the future." The Executive Q&A will feature an exclusive video interview with Scott Dale, executive director with Halliburton Labs. This issue will also highlight coverage of ADIPEC 2020 Virtual. The Regional Report will cover the Caribbean Sea. As always, E&P Plus will include its exploration, drilling, completions, production and offshore features in every issue. While you're waiting for your next copy of E&P Plus, be sure to visit HartEnergy.com for the latest news, industry updates and unique industry analysis.

E&P Plus (ISSN 1527-4063) (PM40036185) is published monthly by Hart Energy Publishing, LP, 1616 S. Voss Road, Suite 1000, Houston, Texas 77057. Advertising rates furnished upon request. All subscriber inquiries should be addressed to E&P Plus, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442, Fax: 713-840-1449; custserv@hartenergy.com.

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Experts 'cautiously optimistic' about Africa oil, gas exploration

By Velda Addison, Group Senior Editor

More licensing rounds and ending lengthy regulatory delays could lead to more exploration investment for Africa's oil and gas sector, experts said during a recent panel moderated by the African Energy Chamber.

U.S. Energy Development CEO shares insight on shale pursuits

By Velda Addison, Group Senior Editor

The private independent is actively pursuing partnerships and funding development drilling in U.S. shale plays as market conditions improve. "We look at over 300 deals on an annual basis, and this year's been no exception," Jordan Jayson, CEO of U.S. Energy Development Corp., told Hart Energy.

Experts: China replaces Middle East as top US energy challenge

By Joseph Markman, Senior Editor

China's oil and gas import market, and its growing antagonism, will be issues to grapple with for years, experts said during a KPMG webinar.

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HART ENERGY VIDEOS

By Jessica Morales, Director of Video Content

Kongsberg Digital president discusses digital twin, Shell partnership

Hege Skryseth, president of Kongsberg Digital, sat down with Hart Energy's Emily Patsy and Mary Holcomb to discuss leveraging digital technologies in the oil and gas industry plus the company's latest partnership with Shell.

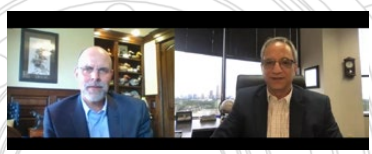
Oil & Gas Asset Clearinghouse CEO Cody Davis discusses A&D outlook, live auction

Cody Davis, CEO of Oil & Gas Asset Clearinghouse, recently joined Hart Energy's Jessica Morales to discuss A&D activity and also provided a preview of this year's first live oil and gas asset auction.

SEG Session Chair Bill Abriel on the business of geophysics

Bill Abriel, the BAG session chair and former SEG president, recently joined Hart Energy's Faiza Rizvi to discuss the first-ever all-virtual SEG Annual Meeting plus the importance of geophysics in the changing business climate of the oil and gas services sector.

Range Resources SVP talks being a leader among us shale producers on ESG



K. Scott Roy, senior vice president of Range Resources, recently joined Hart Energy's Len Vermillion to discuss the U.S. shale producer's net-zero ambitions and its outlook on natural gas in the energy transition.

Texas-based Jasper Ventures provides look ahead

Brent Jasper, president of Jasper Ventures, recently joined Hart Energy's Jessica Morales to discuss how his family-owned business has weathered multiple oil and gas downturns while still serving the midstream business for nearly 30 years.

As I See It

(Source: Elnur/Shutterstock.com)

The urgent need for CCUS

With financial resources dwindling, companies must prioritize GHG-reduction efforts.

Among the multitude of technologies and methods designed to reduce greenhouse-gas (GHG) emissions, carbon capture, utilization and storage (CCUS) is emerging as the one the oil and gas industry is putting its collective weight behind.

Major oil companies like Occidental Petroleum, Shell and Equinor have implemented CCUS technologies to different degrees. The Oil and Gas Climate Initiative (OGCI), which counts bp, Chevron, Repsol, Total and Exxon Mobil among its members, launched its KickStarter program in 2019, which facilitates large-scale commercial investment in CCUS. The OGCI holds a $1 billion-plus investment fund for CCUS projects.

The synergies between CCUS and oil and gas production are plentiful. Carbon is a major component of ESG efforts, and capturing carbon can be relatively inexpensive. In fact, putting an emphasis on carbon capture isn't just environmentally friendly; it might be imperative.

In the company's October newsletter, Ryder Scott said, "The financial health of the oil and gas industry may depend on it."

The analyst noted that more than 3,000 organizations and asset managers have signed up for the Principles for Responsible Investing initiative.

Speaking at the Ryder Scott Reserves Conference in mid-September, Logan Burt, managing director with Morgan Stanley Energy Partners, said, "Those asset owners and managers control more than $100 trillion of capital globally."

Those funds are essentially off limits to companies not making substantial efforts to reduce their carbon and methane emissions. But the industry seems to be taking CCUS seriously. According to Ryder Scott, there are 30 new CCUS projects underway that could double capacity over the next 10 years.

Not only does CCUS make sense from the perspective of increasing access to funding, it also increases recovery. According to Occidental, primary recovery methods and waterflooding can recover about 45% of oil in place. EOR, supported by CO_2 injection, could recover an additional 15%. Producers in the U.S. have implemented more than 130 EOR programs using CO_2, according to Ryder Scott.

Already, there are lessons to be learned in CCUS. Earlier this year, NRG mothballed its coal-fired Petra Nova carbon capture and storage project near Houston after failing to perform as initially predicted, but also as a result of low oil prices during the pandemic. Petra Nova has the capability to capture up to 1.4 $MtCO_2$ annual for use in EOR.

To be successful, CCUS must be adopted at scale. And to do that, the incentives must be there, and many countries do not incentivize carbon capture. Through its 45Q tax credit, the U.S. Department of Energy provides companies a credit for $50 per metric ton of CO_2 sequestered and $35 for projects that capture carbon and use it for EOR.

However, panelists at the recent Ryder Scott Reserves Conference generally agreed the credit was not enough to widely incentivize projects throughout the industry.

Achieving climate goals and carbon neutrality will likely play increasingly important roles in the oil and gas industry over the next several years, if not decades. But for CCUS technologies to truly make a difference, they must be widely adopted, prove their success and receive the support of the industry, both operationally and financially. +

Brian Walzel
Senior Editor
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Putting an emphasis on carbon capture isn't just environmentally friendly; it might be imperative.

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Guest Column

Energy transition requires solutions from the oil & gas industry

(Source: Syda Productions/ Shutterstock.com)

Achieving further success toward a lower carbon future will continue to require major investments of time, money and ingenuity.

The world's next energy transformation is underway, and transitioning to a lower carbon future will require ingenuity from all sectors of the energy industry. While renewable energy will continue to move us toward these goals, much of the innovation required will come from the oil and gas (O&G) industry, with its history of scaling technological solutions to meet the world's energy demand.

The transition is not about replacing one form of energy with another; it is about the entire energy ecosystem collaborating to power the world in the cleanest, most efficient and affordable ways possible. This is a transition all Americans can get behind, from oilfield workers in West Texas to solar installation technicians in California.

The O&G industry comprises engineers, data scientists, geologists, parents, grandparents, men, women and people of all races and backgrounds who care about the environment and want the best for future generations. Excluding this expertise wastes a major driver of energy industry solutions. We can provide the energy the world needs now, while making it cleaner and safer by using technology to reduce emissions and improve efficiency.

As we transition to lower carbon energy, we must be smart and realistic. According to the International Energy Agency, a billion people lack access to electricity, and global energy needs will increase 25% by 2040. Scale and expertise matter, and hydrocarbon products that provide access to affordable and reliable electricity must remain part of the fuel mix for the foreseeable future.

Together, we have reduced emissions while making energy production and consumption cleaner and more efficient than ever. The shift to natural gas for electricity generation cut CO_2 emissions by 2.8 billion metric tons from 2005 to 2018, according to the Energy Information Administration. From 2005 to 2017, U.S. electricity generation increased 4% while related CO_2 emissions fell 27%. Approximately 61% of that reduction was from switching to natural gas.

Further success toward a lower carbon future will require major investments of time, money and ingenuity. Although the industry is struggling because of COVID-19, we're developing next-generation technologies alongside renewable energy firms to deliver a decarbonized future.

National Oilwell Varco is developing equipment for one of the world's largest offshore wind turbine installation vessels. Oceaneering is using O&G ROV technology to monitor offshore wind facilities. Baker Hughes and Schlumberger are working to achieve net zero carbon. Halliburton recently created a renewable energy incubator.

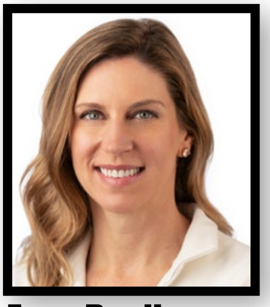
Danos is using virtual reality to bring the offshore to its workers. Along with being a driver of U.S. offshore wind, Equinor is outfitting O&G platforms with wind turbines and reducing greenhouse-gas emissions associated with the electrification of platforms.

Onshore O&G producers have implemented new technologies in aerial, satellite and ground-based monitoring of methane emissions from production facilities. One example is Project Astra, a collaborative effort in the Permian that identifies methane leaks as they happen. Onshore companies are deploying mobile sensors at their production facilities to feed emissions data into a leak-detection network.

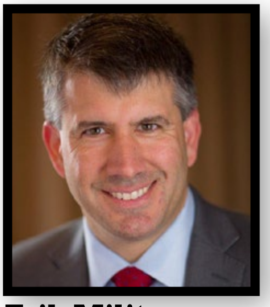
Through technology and innovation, the O&G sector has continually met challenges, increased efficiency and reduced emissions. Excluding the O&G workforce from collaboration delays the goal of a decarbonized energy supply. We know how to scale projects and deliver technology that reduces energy poverty and provides the power people need. We are partners on the path to developing technologies that will transition our energy economy to a cleaner future.

Authors:

Leslie Beyer
President, Petroleum Equipment & Services Association



Anne Bradbury
CEO, American Exploration and Production Council



Erik Milito
President, National Ocean Industries Association

Video

Q&A

In this exclusive video clip for Hart Energy, Schlumberger's Hinda Gharbi details the dynamics of the path forward for the oil and gas industry.

Schlumberger's Hinda Gharbi believes shifting industry trends have only accelerated this year

Efficiency, responsiveness, innovation and digitalization are among the factors that will shape the future of the oil and gas.

Len Vermillion, Editorial Director

Even before the COVID-19 pandemic hit, Hinda Gharbi, executive vice president of service and equipment with Schlumberger, said the company was already focused on changing industry dynamics. Priorities were being shifted within the industry, and operators and service companies alike had begun to shift their long-term plans.

"With the current pandemic, we believe these trends have only accelerated," she said in an exclusive video interview for E&P Plus.

So what shifts are needed? Gharbi points to several factors that will shape the dynamics of the industry going forward. In particular, she discussed operation efficiencies, capital deployment and overall responsiveness to the changing imperatives.

"We must innovate and transform to address the customer challenges," she said of Schlumberger's path forward in a new normal.

In this interview, she also discussed the industry's history and future of innovation, differentiating yourself from others, digitalization, creating value and more. +

(Source: Schlumberger)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Goodrich Petroleum president and COO details company's plans

Confidence in gas prices and low service costs solidify the Haynesville E&P's 2021 operations.

Brian Walzel, Senior Editor

While the oil and gas industry might be hard-pressed to find many bright spots in 2020, the recovery of natural gas prices, and subsequently the role of gas producers, can be one of them. Among those that are riding the natural gas wave is Goodrich Petroleum. Goodrich, primarily focused on the Haynesville Shale, produces 138,000 Mcfe/d largely from its approximate 24,000 net Haynesville acres. Historically low service costs and stable Henry Hub price points are allowing Goodrich to set its goals on top-tier growth and the potential for free cash flow in 2021.

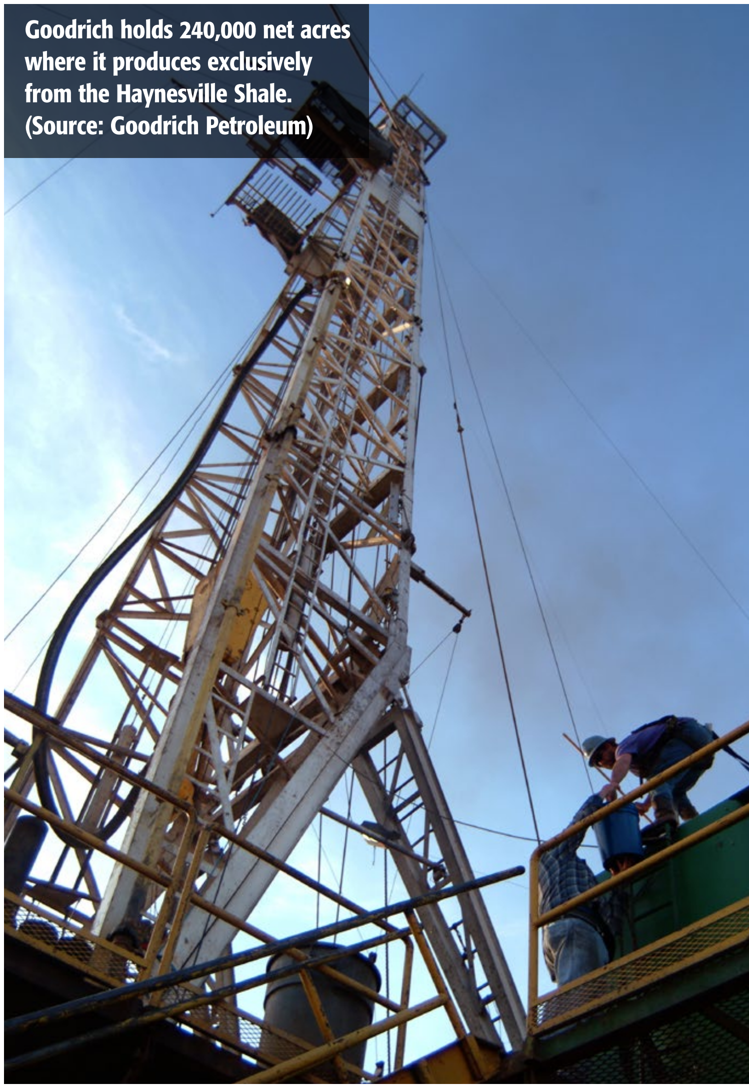
Goodrich President and COO Robert Turnham recently provided an exclusive interview with E&P Plus where he discussed in more detail the company's plans for the remainder of the year and into 2021. He also touched on the company's well completion strategy and how to position itself amid volatile times in the oil and gas industry.

E&P Plus: What is Goodrich's plan for the coming year in terms of spending?

Turnham: Gas prices have moved up dramatically, and so I think it's likely that we'll actually spend more money in 2021 than we spend in 2020. The margins are actually as good as we've ever seen in that basin, through a combination of better gas prices and much lower service costs. Based on what we're seeing in the field, I think it's likely that we spend more. We'll continue to grow at a double-digit rate and generate a significant free cash flow that we'll likely use to pay down debt initially and then ultimately start paying dividends at some point in the future.

E&P Plus: How might Goodrich deploy that capital next year?

Turnham: We're not really an acquisition company. We're really organic growth through the drill bit. All of our acreage is held by production, for the most part, in North Louisiana. We're now drilling very predictable development wells, tying into existing facilities and selling that gas at a very good net back to Henry Hub. So it's really just a matter of how much capital we want to spend that still yields a very good free cash flow yield. And then that will itself drive the growth in volumes. We won't be setting out to grow for growth sakes. It's really how much money [and] what are the economics associated with the wells? How much money do we want to spend that generates a very good free cash flow yield on the capital that we spend?



Goodrich holds 240,000 net acres where it produces exclusively from the Haynesville Shale. (Source: Goodrich Petroleum)

And so, whereas we spent $100 million last year drilling wells, we'll spend about half of that in 2020. But we'll be surging our production here in the fourth quarter. So as we enter 2021, we'll be at very high rates of production and likely ramp up our activities as we head into 2021, and then sustain that growth throughout the year.

E&P Plus: What is your approach to your DUC inventory for the rest of this year and into next?

Turnham: We had at one time two rigs running. Then we kept one rig running but did not complete a series of wells just due to low prices. And we also have received extremely competitive frac bids that we, frankly, had not seen since the play has gone through the renaissance. We have prepared those DUCs to be fracked as we head into the fourth quarter, where we see the significant improvement in gas prices. So even though the third quarter will be down production volumes versus the second quarter, and the fourth quarter will be up significantly, we'll pick the rig, if not two rigs, back up in January or perhaps late December so that we're well into our program as we enter 2021. Then our plan would be to not create DUCs. It would just be completion in a normal time frame because gas prices obviously for next year are much higher.

E&P Plus: How do you evaluate completion designs in the current pricing environment?

Turnham: At a time where service costs are higher, you tend to look at how to cut corners. In this case, with prices being so low—and at the peak, we were probably spending more than a $100,000 per stage—we're now less than $30,000 per stage. So we've gone the other direction. We have tightened our interval spacing to 100, maybe at most 125 feet per stage. And instead of just banking all of the savings from the reduction, we're actually adding some stages, still seeing significant savings and well costs, but making better wells. If you look at our well performance versus our type curves and versus the industry, you'll see that we're probably as productive, if not the No. 1 productive company, per foot of lateral drilled. And it's because we think we've gotten the sweet spot on how best to complete these wells.

E&P Plus: How do you approach your planning and activity for this type of environment—when it looks good now but considering how volatile things can be?

Turnham: So let's talk about volatility and the necessity to hedge a portion of your volumes. We really believe in 40% to 70% of your projected volumes, locking in a price that gives you the insurance policy to go ahead and spend the money necessary to drill the number of wells that you want to drill. And you can't get out ahead of yourself with long-term drilling contracts because of the volatility that you just described. Another scenario can happen. You can see better pricing or attractive prices, and therefore rig activity gets higher. Service costs start to creep up, which we would not be surprised to see. Usually anytime you see rates of return like you see on our [investor presentation] slides, that just cant last for very long, because guys are either going to put rigs to work or service costs are going to go up, such that you have good rates of return, but not exceptional rates of return.

Another thing that's different now is just availability of capital and what investors are wanting to see. They're not wanting to see you outspend. They want to see free cash flow, return of capital to shareholders either through dividends or pay down debt, such that the commodity prices do stay at favorable levels.

In addition to that, you have commercial banks that are becoming more conservative, [and] debt covenants are getting more conservative. So I think you throw all of that in a pot, and I think you have a recipe for better pricing [and] lower service costs. ✚

"Gas prices have moved up dramatically, and so I think it's likely that we'll actually spend more money in 2021 than we spend in 2020."

—Robert Turnham, Goodrich Petroleum

Goodrich Petroleum has grown its gas production from 70,000 Mcfe/d in 2018 to 140,000 Mcfe/d this year. (Source: Goodrich Petroleum)

SPONSORED CONTENT

Fundamental chemistry and methodology proves successful in preventing polymer induced agglomerations — ("GOO")

K. MacEwen, **K. Hoeman** and **J. Dawson**, Innospec Inc. Oilfield Services

For years, operators in iron-rich mineral basins, such as Woodford/Cana, Delaware and portions of the Eagleford have struggled with a rubbery-like substance adhering to surface treating equipment, accompanied with lost production. As a chemical company and a solutions provider, Innospec's Oilfield Services Stimulation R&T group, with their knowledge and experience of FR chemistry, wanted to not only treat the issue, but to fundamentally understand the cause of the issue. The solution came about only by surmounting some major scientific obstacles–obstacles tackled by many, but all without long-term successful resolution of the issue.

In the fracturing industry, it is common to use synthetic friction reducers (FRs) to overcome the high friction pressures associated with pumping large water volumes at high rates. The physical form of the FR is either invert emulsion, suspension or dry powder. However, regardless of the FR form, the chemistry of the polymer is critical. The chemistry of most common frac FRs is either anionic or cationic polyacrylamide co-polymers (see Scheme 1).

These polymers are very high molecular weight, so even at the dilute concentrations used for friction reduction they still allow, under proper conditions, the formation of undesirable "goo" responsible for impaired fluid flow and production. Although an important part of the "goo," the polymer itself must be subjected to downhole environmental conditions to cause the issue. Furthermore, the chemistry of the friction reducer polymer is a major factor in the formation of the "goo" and is highly dependent on the carboxylate content of the polymer.

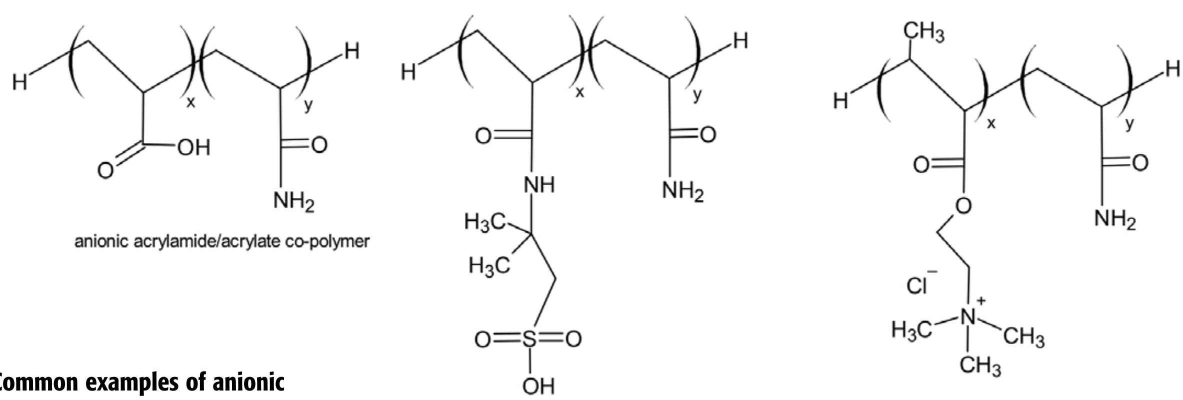
Carboxylic acids are weak acids and partially dissociate in solution to form the negatively charged carboxylate anion (see Equation 1).

$$(1)\quad RCOOH(aq) \leftrightarrow RCOO^{-}(aq) + H^{+}(aq)$$

The pendent carboxylate, like all weak acids, possesses an acid dissociation constant, or pKa, and this value is a gauge of the acid strength. The definition of pKa is given in Equation 2

$$(2)\quad pK_a = -\log\ K_a$$

where Ka is the acid dissociation constant. The lower the pKa value, the stronger the acid or a larger percentage of the acid concentration is dissociated in water. The pKa of acrylic acid, a monomer in the acrylamide (AcAm) acrylate (AA) co-polymer, is 4.25. This means at pH 4.25, half the concentration of acid is dissociated and in the other half, the acid is protonated and having a neutral charge. Generally, any acid, such as HCl, with a pKa less than zero is completely dissociated and is considered a "strong" acid. For comparison of acrylic acid to other acids, see the following chart.



anionic acrylamide/acrylate co-polymer

anionic acrylamide/ATBS co-polymer

cationic acrylamide/MaDAM quat

Scheme 1: Common examples of anionic and cationic co-polymer friction reducers

Acrylic acid, being a weak acid, and in its anionic form referred to as a carboxylate, produces charge repulsion between other carboxylate groups attached to the polymer that, in turn, acts to expand the volume of polymer when added to water. It's this polymer chain expansion, of the high molecular weight polyacrylamide polymer, that provides the friction reducer with its efficiency and effectiveness in slick-water fracturing. In normal frac water with the pH ranging from 6.0 to 8.5, the dissociated form of acrylic acid (acrylate) is highly dominant, assuring high anionic character of the polymer for maximum chain expansion needed for friction reduction.

In the polymerization of acrylamide and sodium acrylate to produce the FR, the anionic acrylate monomer is randomly distributed along the polymer chain. Because the percentage of acrylate groups is typically about 30% (by mole), it is highly probable small blocks of acrylate exist within the polymer chain. These blocks resemble small islands of scale inhibitor moieties within the polymer chain and can interact with polyvalent ions in the water.

Comparison of acrylic acid to other acids

Acid	pKa
Formic	3.75
Acetic	4.80
Benzoic	4.20
Phosphoric*	2.16, 7.21, 12.32
Boric acid	9.2

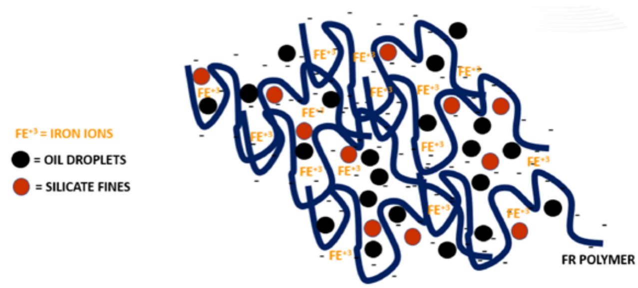
**Phosphoric acid, having three acidic protons, also has three pKa (pKa_1, pKa_2, pKa_3) values.*

Multivalent Ion Impact on FR Agglomeration

In waters containing divalent and multivalent ion species (Ca^{+2}, Mg^{+2}, $Fe^{+2,+3}$, Al^{+3}, etc.), there will be associations that form between the anionic acrylate ligands and the metal ion. For the purposes and remainder of this article, we will focus on the interactions between polymer FRs and iron, as this is related to the agglomeration.

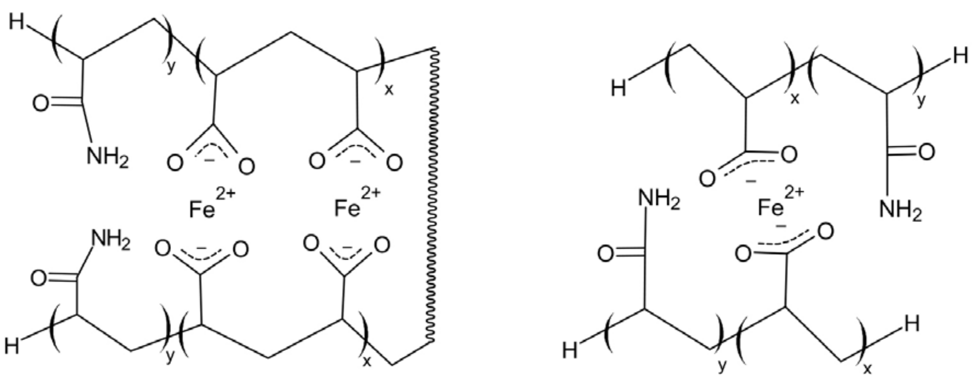
In the case of $Fe^{+2,+3}$, for example, these ion associations can generate intra- (within the same polymer chain) and inter- (two or more polymer chains) molecular crosslink junctions in the AcAm/AA FR co-polymer (see Scheme 2).

Couple the crosslinking, between iron and the weak acid component of the acrylate/acrylamide copolymer, with the known flocculation characteristics of these ultra-high molecular weight (15 – 18 x 10^6 Da) FR polymers, and you have unleashed the potential formation of an agglomeration nightmare. These same FR polymers are used in water treatment as flocculation aids to reduce total suspended solids (TSS). This agglomeration down-hole is "goo," and can be comprised of a mixture of FR, metal ions (such as iron), formation fines, clay, oil etc., as shown in the drawing below.



"GOO"

So, if you have high iron (>20ppm) content in your connate or frac fluid brines with the potential to generate Fe^{+3} ions, and you are using a co-polymer of AcAm/AA, you have a high probability of generating a "goo" nightmare. Now, you may be thinking that if the AcAm/AA co-polymer has a cause/effect issue with iron-laden waters, you should merely use a cationic FR. This choice will give you positive returns initially, but because of a weak link between the cationic group and the polymer chain, the cationic groups will eventually hydrolyze, causing the cationic group to split off the polymer chain as a molecule similar to the KCl substitute chemical, choline chloride (see Scheme 3). The hydrolysis not

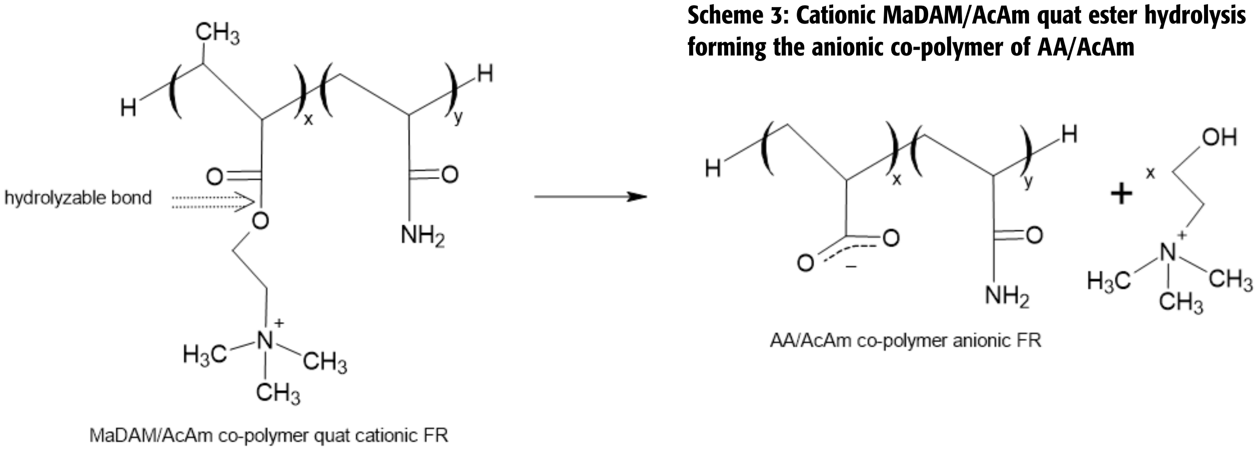


intramolecular - same polymer chain

intermolecular - different polymer chains

Scheme 2: Intra- and intermolecular interaction with Fe^{+2} and an acrylamide/acrylate co-polymer

Scheme 3: Cationic MaDAM/AcAm quat ester hydrolysis forming the anionic co-polymer of AA/AcAm



only reduces the cationic character of the polymer, it also produces the identical carboxylate groups occurring in the acrylamide-sodium acrylate co-polymer, AcAm/AA, described above.

Changing to a cationic FR is normally not the right, long-term choice to prevent the formation of "goo" damage. If you are in iron-laden waters, the chemistry of the FR is critical and should be chosen with careful consideration of the environment the FR will be exposed.

So now that we know what not to use, what type of FR do we use? Well, there are various less efficient FRs such as guar gum or guar derivatives, but the loadings needed are slightly higher and they tend to produce proppant pack and formation damage, regardless of the water chemistry. In addition, they tend to be good food sources for bacteria.

Fortunately, there is now a proven solution, HiRate MAXX -3200G that provides effective, efficient friction reduction at low concentrations and is completely immune to water chemistry– both immediately after treatment as well as long-term.

In field trials, last year in the Woodford Cana field, a high-iron prone formation in Oklahoma, Innospec's ground-breaking HiRate MAXX-3200G friction reducer was pumped at 0.3 gpt and was able to place 3.5 ppga 40/70 sand, as per treatment design. In fact, when experimenting with the loading during the early sand sub-stages, the minimum effective concentration in this formation and frac design was 0.15 gpt. Flow back samples collected after HiRate MAXX-3200G treatment were monitored for six months without any presence of "goo" and the operator has reported no "goo" related issues for 18 months up to the publication of this article. Afterward, multiple wells were treated in the same area HiRate MAXX 3200G –without the generation of any "goo."

Innospec's patent pending polymer is also anionic, but rather than relying on weak acid carboxylates, the new HiRate MAXX-3200G relies on a strong acid pendent group having very little affinity for cations in the water chemistry, especially iron. This inability to react with iron short circuits the goo formation while the polymer also provides effective and efficient friction reduction, allowing for low loadings of polymer in slick-water treatments. The friction reduction efficiency is based on the polymer's anionicity due to the strong acid pendent group to assure a high degree of charge repulsion between anionic groups, maximizing polymer chain expansion in any water, regardless of TDS. This same polymer is used in slick-water treatments using produced water exceeding 200,000 ppm TDS.

For Innospec Oilfield Services, "*chemistry matters*" is more than a tagline. It is the guiding principle that drives our business partnerships. We are not just a chemical provider, we are a chemical company, providing affordable, fit-for-purpose solutions. In this case, our unique approach to our client's agglomeration issues helped to determine that prevention by polymer selection is critical. Innospec's HiRate MAXX 3200G was specifically designed to short circuit the polymer-iron interactions to prevent the "goo" seed from ever forming, therby preventing future production and surface facility issues. +

WILL BIG DATA SHAPE RECOVERY?

*Check out the **TECH TRENDS** section in this issue to learn more about the latest data analytics technologies and services.*


(Background photo courtesy of Marc Morrison/marcmorrison.com; illustration design by Melissa Ritchie)

In the midst of a historic disruption with remote operations becoming the new normal, oil and gas companies are rethinking Big Data analytics to navigate the uncertainties of the industry's post-pandemic future.

***Faiza Rizvi**, Associate Editor*

Around this time last year, oil and gas executives were contemplating how Big Data analytics could become a source of significant competitive advantage for their companies. As the industry made slow, yet steady progress toward digital transformation, corporate discussions centered on how machine learning (ML), artificial intelligence (AI) and automation could save the upstream sector billions of dollars.

Fast forward to today, the industry is knee-deep in one of the worst downturns in history. The demand destruction has caused massive well shut-ins, historic layoffs and, consequently, remote operations have become the new normal. The executives are now discussing survival strategies using advanced digital solutions and are revisiting the use of historical data for resilience and recovery.

A recent study by McKinsey & Co. stated, "It is uncertain when the current perfect storm impacting oil and gas operators will pass…What is certain, however, is that only innovative operators with superior operating models will come out of this crisis prepared to cope with volatility and to sustain future growth."

Even though the upstream industry had begun embracing advanced analytics and AI for increased efficiency over the past few years, the pandemic-induced need for remote operations has created a sense of urgency among companies to tap deeper into the value of data. Between the short-term uncertainty of the pandemic and the long-term uncertainty of oil demand and prices, it's not surprising that data analytics—widely known for its optimization capabilities and predictive prowess—has become an essential tool for upstream companies to navigate the downturn.

'Core of the new normal'

"Data analytics is the core of the new normal and will definitely drive the next level of operational efficiency," Sunil Pandita, vice president and general manager with Honeywell Connected Industrial, told E&P Plus. "In fact, we call it pushing the technical limits of operation. The cost of the barrel has to be pushed down to historic low levels by increasing automation, reducing unplanned downtime and optimizing asset efficiency, which requires sophisticated data analytics. To make the best possible decisions in the short term while protecting the long-term interest in oil and gas assets, I think data analytics is a value-driver."

Pandita went on to explain how the pandemic has revealed that even if companies can't deploy people directly, as they did in the past, they can still maintain business continuity by switching operations to remote technologies to capture data, develop insights, implement autonomous operations and execute specific workflows where human intervention is required.

"Basically, the pandemic has triggered a shift from remote monitoring to increased remote operations," Pandita said. "Data analytics has changed the view of how and where remote operations can be applied. With the advent of data analytics, process simulation and advanced process control, we are now able to build a digital twin to monitor

The recent collaboration between Honeywell and Halliburton will leverage Halliburton Landmark's E&P cloud applications and Honeywell's Forge industrial analytics software solution to enable producers to make more informed and data-driven decisions. (Source: Honeywell)

upstream facilities. Data analytics has allowed implementing exception-based rules to detect anomalies and perform activities such as inspections. Similarly, field operations have become more intelligent with assistance for workers available remotely."

Other experts expressed a similar sentiment.

"I think the pandemic has definitely changed the needs of data management and governance in the upstream sector," said Gerardo Mijares, global director of production and reservoir management with Halliburton Landmark. "Every activity or process of a field operator has components of people and technology. Today, we are seeing a transformation in the people component. In order for us to continue executing operations with the same level of efficiency—or even better, we have to improve processes and technologies to compensate for human interaction, which is not there anymore. Data management is critical for both [service companies] and operators to achieve higher efficiency."

Seismic shift

Dan Brennan, vice president of Baker-HughesC3.ai with Baker Hughes suggested industry leaders double down on investments in technologies related to data analytics, adding that new technologies will be necessary to survive for some upstream players.

"We're six to eight months into the challenges that were brought on by the pandemic…and we're starting to

"With the challenges brought on by the pandemic and the downturn, we are going to see about five years' worth of transformative activity over the next 18 to 24 months."

—Dan Brennan, Baker Hughes

see some seismic shifts in terms of the mindset that the role of digital technologies can play in the upstream sector," he said. "We have definitely seen an uptick in the willingness and the desire to understand how cloud [computing] and AI can help support remote operations in the upstream sector."

Brennan added the industry is still in an early phase of witnessing what could be a "seismic shift" that the role of data analytics will play in the operations of the upstream sector.

"We are a highly innovative and resilient industry," he said. "With the challenges brought on by the pandemic and the downturn, we are going to see about five years' worth of transformative activity over the next 18 to 24 months."

Brennan also pointed out that the pandemic and the subsequent challenges have created a significant opportunity for the upstream industry in the area of digital transformation.

"There is so much opportunity that remains in the upstream sector to apply AI, machine learning and these types of technologies to improve efficiencies and get more production out of the existing assets in the portfolio," he said. "It's also an opportunity for the sector to truly lean into changing trends in the labor market. Companies should upscale jobs like petrophysicists, petroleum engineers and really develop career paths like those of data scientists.

"The opportunity is there not just for operators, but for everyone who has evolved within the supply chain of the upstream sector to be more open in terms of how we are sharing data, to be more open to embracing new ways of working [and] to be more open to embracing technologies like ML and AI to improve decision-making."

BakerHughesC3.ai, which is a joint venture that brings together the full-stream portfolio of Baker Hughes with C3.ai's AI software capabilities, is leveraging massive amounts of data

"For us to continue executing operations with the same level of efficiency—or even better, we have to improve processes and technologies to compensate for the human interaction, which is not there anymore."

—Gerardo Mijares, Halliburton Landmark

collected by Baker Hughes over the past decade.

"Specifically over the past three to five months, we have been working hand in hand with our drilling services team to apply the BHC3 technology to improve the productivity and outcomes that they can deliver to their clients," Brennan said.

Responding to business dynamics

In the current market environment, data analytics has become critical because when operations are carried out remotely, getting access to multiple systems to make decisions can be challenging, according to Gino Hernandez, global digital business leader of industrial automation and energy industries with ABB.

"You need processes that are driven analytically," he said. "In addition, you need disconnected business systems communicating and being driven analytically, so the systems themselves are responding to business dynamics. An example would be your ERP [enterprise resource planning] system communicating with production automation systems to check capacity for additional production to take an order and then executing the order. With ABB's Genix platform, we can help customers do just these types of things. We are taking reactive businesses to outcome-driven businesses."

Genix is a scalable, smart analytics and AI-driven platform and suite that makes data utilization easier by bringing together data with domain knowledge, technology and digital capability.

Hernandez said that in the current uncertain environment, it is human nature to immediately go to business instinct.

"Although instincts are important in business, data help you understand if what you are hearing and seeing lines up with your business," he said. "The data bring everything into perspective. You must have good systems in place that help you visualize the data in a way that is meaningful to you."

Moving away from the old digital culture

In a recent report, Deloitte noted that even though advanced digital solutions, including data analytics, cloud computing and ML, have played a key role in bringing higher efficiency and productivity to the traditionally complex operations of the industry, many companies are still struggling to establish a starting point for their digital transformation or breaking away from their old digital culture of "this is how we work."

While the pandemic has brought a greater sense of urgency in accelerating digitalization efforts to unlock new operational gains, it has also given "a new mandate-cum-challenge to put people at the core and prioritize their health and safety," the report stated.

Given that capital is the most constrained resource today, how should an oil and gas company plan its digital transformation in the current environment?

Deloitte suggests implementing a digital road map powered by human-machine collaboration, the first step of which is mechanizing operations and transmitting data to a unified

Schlumberger and IBM discuss recent collaboration

In this exclusive video interview with Hart Energy's Faiza Rizvi and Len Vermillion, executives from Schlumberger and IBM discussed a recent collaboration between both companies to accelerate digital transformation across the oil and gas industry. The joint initiative will increase global access to Schlumberger's E&P cloud-based environment DELFI and cognitive applications by leveraging IBM's hybrid cloud technology.

Even though DELFI offers access to several public clouds, almost half of oil and gas companies are unable to easily access these cloud platforms due to constraints around data sovereignty, reach of public clouds and architectural choices. The collaboration allows for workload portability, orchestration and management across multiple infrastructure environments allowing the DELFI environment to be available across a variety of infrastructure choices.

"We are working together to build a joint Open Subsurface Data Universe [OSDU] offering, which is an open-source collaboration to build a common data environment for the industry," explained Trygve Randen, global director of digital subsurface solutions with Schlumberger. "Today there are a lot of efforts to bring OSDU to public cloud. With this collaboration, we are aiming to offer OSDU with a full set of hybrid deployment options…and a common data environment that every operator in any kind of jurisdiction will be able to implement."

Manish Chawla, global managing director of energy and natural resources with IBM, said the joint offering is a great "entry point" for companies with large datasets looking for a flexible journey to the cloud that they can manage and control at their pace.

Randen added that in the process of gathering and processing data, it is important to liberate data from the silos and from the confines of different applications.

"We saw the opportunity to connect multiple data repositories into one platform. This will reduce the amount of duplication and have workflows that pan across multiple applications more easily. Also, one of the benefits of bringing the cloud concept is the availability of data all the time for all the workflows. With the cloud deployment, we want to ensure comprehensive access to data, which will give better insights and better decisions to avoid risk and optimize operations," he said. +

network. The next step is bringing together the data from on-field physical assets to off-field remote centers for real-time surveillance and optimization. By analyzing and augmenting the data using advanced analytics libraries and ML, companies can detect anomalies, intimate predictive maintenance alerts, overcome new challenges in inspection and maintenance activities, and reengineer the interplay of offshore and onshore teams.

Even though remote projects were being implemented well before 2020, the pandemic has accelerated the urgency to mitigate HSE exposure for both off- and on-field employees without disrupting operations. Employing cloud platforms to help experts working from home analyze and visualize operations, leveraging edge analytics to analyze the data at the place of data creation itself, and providing augmented wearables for the onsite workforce have become the bare minimums now, and these will likely become permanent fixtures in the post-pandemic world.

Challenges

According to Honeywell's Pandita, one of the biggest challenges in the area of data analytics has been the ability to get enough understanding of the assets and access to historical data insights while performing predictive analytics using asset performance management software.

"We approach this problem by building and utilizing out-of-the-box asset models based on an in-depth understanding of what brings critical equipment down, almost at a component level," he said. "This allows running intelligent analytics despite having insufficient data. Adopting a hybrid approach that combines first principle models such as thermodynamic models with data-driven models allows us to overcome this challenge of not having enough data to perform complicated operations like measuring asset performance."

Another challenge, Pandita noted, is that data from different parts of the value chain are trapped in different places, which need to be integrated to create value.

"Our approach involves awareness of end-to-end business processes, which now allow us to overcome the limitations of data silos," he said.

Halliburton's Mijares agreed that access to the right data quality is crucial.

"Availability of technology is broadening the area of data sources for our company," he said. "The boundaries of what used to be well-defined silos for management, engineering, operations, maintenance, business planning and so on are starting to blur because of better access to data with new technologies."

ABB's Hernandez pointed out that the biggest challenges that oil and gas companies face when adopting data management solutions is the inability to define a clear road map.

"Our customers are just struggling to know where to start," he said. "They have purchased point solutions and don't know how to bring it all together. At ABB, we like to help our customers take a step back and help them define where it is that they want to go and break the digital journey into steps driven by greatest business return. The first step in the journey is to leverage investments in the digital space. With ABB's approach, we encourage investments with our consulting and domain expertise and then apply our technology to bridge the gaps in technology."

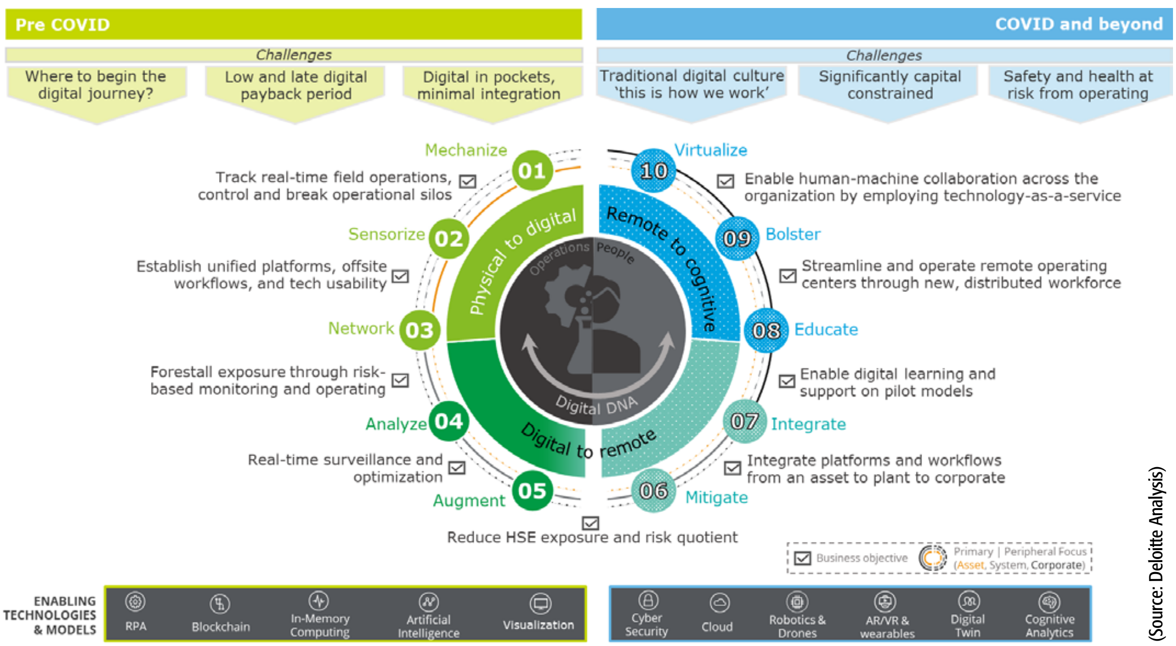
"Data analytics is the core of the new normal and will definitely drive the next level of operational efficiency."

–Sunil Pandita, Honeywell Connected Industrial

Pete Waldroop, CEO of W Energy Software, said the biggest challenge his company faces as a software provider is marrying raw data from 12 to 15 different systems and putting it all together to form meaningful and accurate datasets.

"The challenge has always been there but is exacerbated due to the need for remote operations," he said. "It's easy to get confusing unmatched information, and it is time consuming to put it together. And when we are working with premise-only data, the challenge lies in accessing it remotely and working with it."

Waldroop continued, "Oil and gas has become a much lower margin industry business. What that means is it is extremely crucial to have highly accurate data for businesses to make faster decisions in real time. Because depressed margins are going to be such a key point for us moving forward, with producers struggling to make $5 per barrel, they will need to have access to data to know what their costs are, where the production is coming from and where it is going." +



(Source: Deloitte Analysis)

Executive Q&A: Equinor's chief data officer talks digital solutions

Torbjørn Folgerø, chief data officer with Equinor, agrees that the role of data analytics has become more critical for the upstream sector in the current environment. Equinor is known to generate huge quantities of data. In total, more than 30 petabytes are stored in the operator's data centers. Even before the downturn hit the industry, the company was in the process of leveraging its massive amount of data, which Folgerø believes is a good "starting point" to navigate the challenging market environment.

In this exclusive interview with E&P Plus, Folgerø shares his insights with Hart Energy's Faiza Rizvi.

E&P Plus: With remote operations becoming the new normal, in what way has the role of data analytics become more critical for the upstream sector?

Folgerø: We have a good starting point because we have collected massive amounts of data over the years. I think at the same time, if we look back three or four years, the industry was lagging in the digital solution space as compared to other industries. We had a lot of data locked down in old-fashioned software, but I think our industry has proven in the last few years that we are one of the industries that embrace digital the fastest.

We are becoming a more data-driven company. At Equinor, we believe that the next step of our improvement journey will be mainly digital. … The majority of our improvement initiatives quite heavily center on digital. So it's a big shift in our company, which is not just needed to drive well performance

Torbjørn Folgerø

but also for the safety of workers and carbon efficiency.

E&P Plus: How is Equinor using data analytics to solve the needs and challenges of production?

Folgerø: On the data foundation side, we think of data in three layers. The first is the infrastructure layer. We have a cloud-first strategy at Equinor. A few years back, we decided to create a cloud-based data platform in collaboration with Microsoft called Omnia. So, every day we're making quality data available.

The next layer on which we are working heavily is the data architecture. We are feeding data from our legacy systems into Omnia, and then we are creating a future-oriented data architecture by using machine learning and AI. … Once we have the cloud-based infrastructure and data in place, we can then visualize and analyze the data in any way we want.

In parallel, we have a road map of six digital programs, which are powered by business initiatives to leverage data. A big area is production optimization, which is a huge value driver. We are also moving all global offshore industrial data into Omnia, which helps fuel Equinor's integrated operations center in Bergen, Norway, where almost 100 people are working to gather all these data as well as developing new machine learning applications for data analytics. We are seeing quite a significant impact on improving production using this approach.

We have also launched a subsurface data platform, making subsurface data available in Omnia. … This is used to explore new oil and gas reservoirs and to improve the recovery rates and lifetime of existing reservoirs. We are also using data analytics heavily to support our offshore wind sector.

Overall, we are seeing significant cash flow improvements due to digital and a promising impact that makes us confident and makes us want to accelerate even faster in the digital space.

E&P Plus: What are some of the biggest challenges that you have faced in the area of big data analytics during the recent months?

Folgerø: There are two main sets of challenges: One is on the human side and the other is on the technology side.

The human side is probably the most important one. If we are investing heavily in technology, we should also invest heavily in the competence and development of employees. When Equinor set up a digital center, we also set up a digital academy where our employees have already completed over 150,000 training periods. Upscaling the workforce is important so they understand the technology and trust [digital] solutions.

On the technology side, like I said, it is all about data, and we have a lot of historical data since 1972 in varying levels of quality. So we realized that we need to lift the quality of the data, which is a big challenge and a lot of hard work.

E&P Plus: How important is it right now to truly understand what data are telling you in the current environment?

Folgerø: I believe it is crucial. To be a leading energy company, we need to be a winner in the digital space. In the oil and gas sector of Equinor, we need to be safer, more carbon-efficient and more competitive. The main enabler for us to drive our improvement now is in the digital space, which we can't accomplish if we don't utilize our data in a structural manner. So at Equinor, we are working on developing ways of working built on leveraging our data. … And we're also using data to collaborate with our suppliers in more efficient ways.

E&P Plus: What are some areas of opportunity in the process of actually gathering and processing data?

Folgerø: That's a good question. We have invested in sensors for many years, but we are also seeing that data are coming from new sources. ... So, the first thing is that we need to expand our ways of collecting data—continue using sensors but welcoming new ways of data collection like robots and drones.

Secondly, we need to move the data locked up in old software into a more structured and machine-readable dataset. So that's one area that we are working heavily on, using natural language processing and other technologies to make our data more readable and easy to analyze.

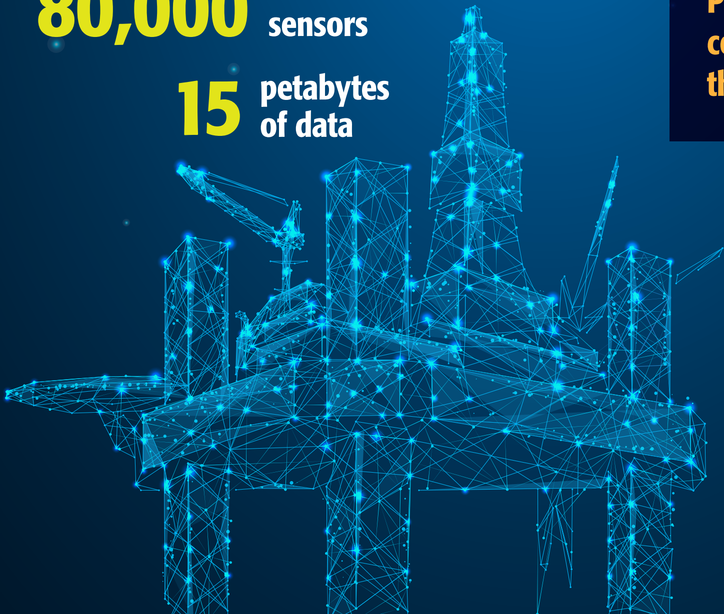
Finally, we are using machine learning-generated data to try to fill in the gaps in the datasets. It's quite novel, but we are still working in that area. +

By the Numbers

Big Data in oil and gas

80,000 sensors

15 petabytes of data



Production data from Equinor's Volve Field consisted of approximately **40,000 files**, with the entire dataset consisting of **4,206 gigabytes**.

A rig schedule is reworked as much as **75% of the time** due to a lack of proper data integration.

Big Data analytics could lead to production improvements by **6% to 8%**.

Modern offshore drilling platforms have about **80,000 sensors**, which generate **15 petabytes of data** during the life of the asset.

What is Big Data?

Data sizes are typically measured in petabytes, equal to 1,024 terabytes or exabytes, equal to 1,024 petabytes.

Advanced analytics can yield returns up to **30 to 50 times** of the investment within a few months of implementation.

43% of oil and gas executives surveyed identified the increasing availability of Big Data analytics as one of the top three trends that will positively impact their company's business growth in the next three years.

The value of the global oil and gas market with Big Data could reach nearly **$11 billion** by 2026.

(Source: Bain & Co., McKinsey & Co., EY, Market Reports, IEEE; data compiled by Brian Walzel; design by Melissa Ritchie)

Wind energy investment and activity are picking up offshore the U.S. (Source: korsart/ Shutterstock.com)

Challenges facing budding US offshore wind sector

Policy and permitting, the environment and metocean conditions, and infrastructure were among the topics discussed at the virtual OTC event as companies aim to advance projects.

Velda Addison, Group Senior Editor

With more than 2,000 GW of technical wind resource potential, the winds over open waters off the U.S. are capable of producing about twice the generating capacity of all U.S. electric power plants combined, according to the Department of Energy.

However, tapping part of that will require overcoming challenges—seen as opportunities by offshore wind energy players—for the budding U.S. offshore wind sector. During the recently held Offshore Technology Conference (OTC) virtual event, executives and regulators involved in offshore wind discussed projects underway and what is needed to bring such projects to fruition as the world moves toward cleaner forms of energy.

Challenges faced include policy and permitting, the environment and metocean conditions, and infrastructure.

The U.S. only has one offshore wind farm—Block Island offshore Rhode Island. However, that is expected to change.

"We have completed eight lease sales. We have 16 active all offshore leases that have been issued," Brian Krevor, environmental protection specialist with the Bureau of Ocean Energy Management (BOEM), said during the OTC Live virtual event. "We've approved eight site assessment plans, one general activities plan and we currently have 10 construction operation plans up for review right now."

He added that six more are expected within the next 12 months, and leasing for five areas are being considered.

"So, you can see that there's a lot going on right now for leasing," Krevor said. "And we currently have steel in the water for the Virginia research lease, which was two turbines off of Virginia."

New York is among the states advancing offshore wind projects as part of an effort to achieve 100% carbon-free electricity by 2040.

"Offshore wind plays a very key part in our advancing that goal," said Greg Lampman, program manager with the New York State Energy Research and Development Authority. "Our legislative mandated goal in New York State is 9,000 megawatts [MW] by 2035. This is enough to power about 6 million homes. And if you're thinking about a 12-MW turbine, that's about 750 turbines installed in the space by 2035."

Challenges, opportunities

Being a new industry in the U.S. is seen as both a challenge and opportunity, according to Ruth Mullins Perry, a marine science, regulatory and policy specialist with Shell Upstream.

"It's different from oil and gas in the sense that oil and gas leasing and the development of oil and gas resources typically involve a couple exploratory drillships or production assets," Perry said. "But when we talk about commercial or utility-scale wind farms, we're talking about

10 to 100 turbines in the water, and the spacing of those, the orientation of those, matters from a technical perspective. But it also matters from an environmental perspective based on where those are constructed."

Unlike the oil and gas industry, offshore wind in the U.S. does not have decades of coexistence with other industries operating offshore.

However, structures are less complex than oil and gas infrastructure, lacking subsea equipment and dynamic positioning and don't require significant personnel, according to Perry.

"Because they're pretty simple, these kinds of platforms offer up an opportunity where we can do more on autonomous environmental monitoring. We can put sensors on turbines. We can put sensors under the water," Perry said. "We can do quite a bit of data collection using these structures. And the scientific community is really thinking about understanding the impacts of climate change and other challenges and constraints on the ocean."

A challenging part of operating off the Atlantic coast is its sensitive habits and species, including endangered ones.

The environment itself also poses challenges, she noted, pointing out that offshore wind farm developers must account for the presence of nor'easters, derechos and hurricanes.

Major components of offshore wind farms are massive, and installation can pose another challenge, according to Danielle Jensen, integration manager with Shell's Mayflower joint development offshore Massachusetts. She described monopile-type foundations fixed to the seafloor at a water depth of about 60 m.

"We're going to drive that monopile into the seafloor, about 40 meters for stability. And then it's going to stick out above the water," Jensen said, noting the total monopile is about 330 ft. Then the turbine goes on top.

Offshore the U.S., Shell is involved in two joint venture wind developments—Mayflower and Atlantic Shores offshore New Jersey. Atlantic Shores is capable of generating 2.5 GW of power, while Mayflower is designed to generate 1.6 GW of power—enough for more than 680,000 U.S. homes, the company said.

Holding 50% stakes in each, Shell is working with France-based EDF Renewables for Atlantic Shores and Portugal-based EDP Renewables for Mayflower.

"We're excited to see this build in the U.S., and we're excited to translate a lot of our information, knowledge and experience from operating in the oil and gas side into offshore wind in the U.S.," Perry said.

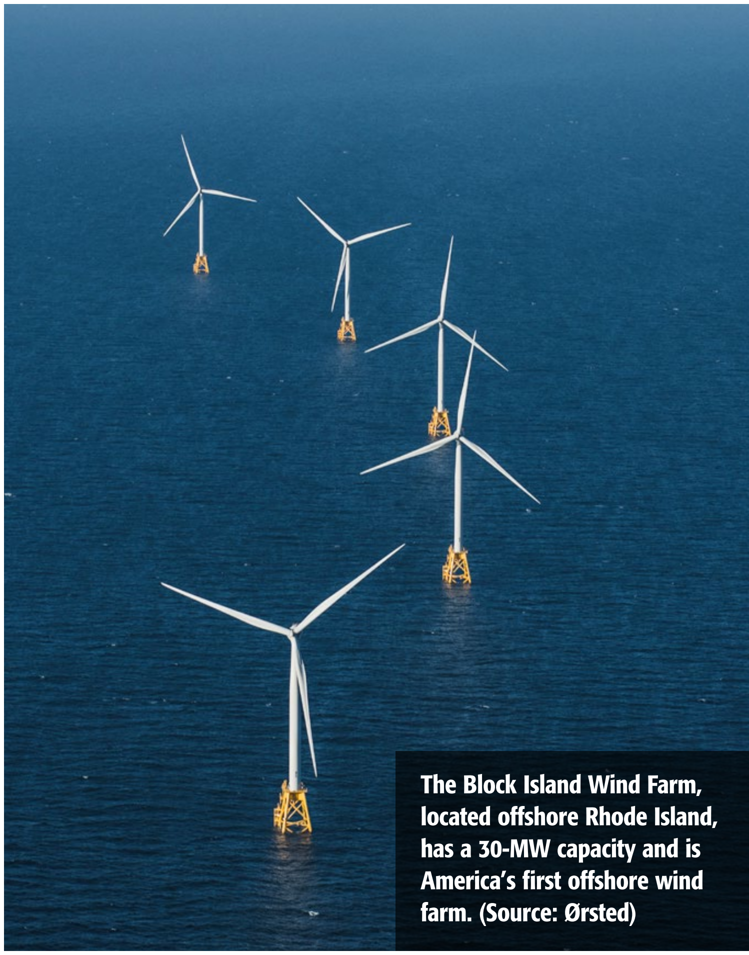
Regulatory hurdles

Regulations are perhaps one of the biggest obstacles the industry faces.

Projects must go through state and federal regulations with tons of work required before reaching the installation and construction phase.

"These projects are what we like to call permitting or development heavy, meaning there's a front end of multiple development phase years before you get into capex, opex and such," Perry said. "And so, during that time, there's upward of three to five years of site assessment to support project engineering and design."

The 800-MW Vineyard Wind knows about regulatory challenges. The $2.8 billion project was pushed off schedule when BOEM decided to carry out additional studies on the overall impact of wind projects planned offshore. The two-phase Vineyard Wind, which is owned by Copenhagen Infrastructure Partners and Avangrid Renewables, was initially set for completion in 2021-2022. Plans are now for operations to begin in 2023.



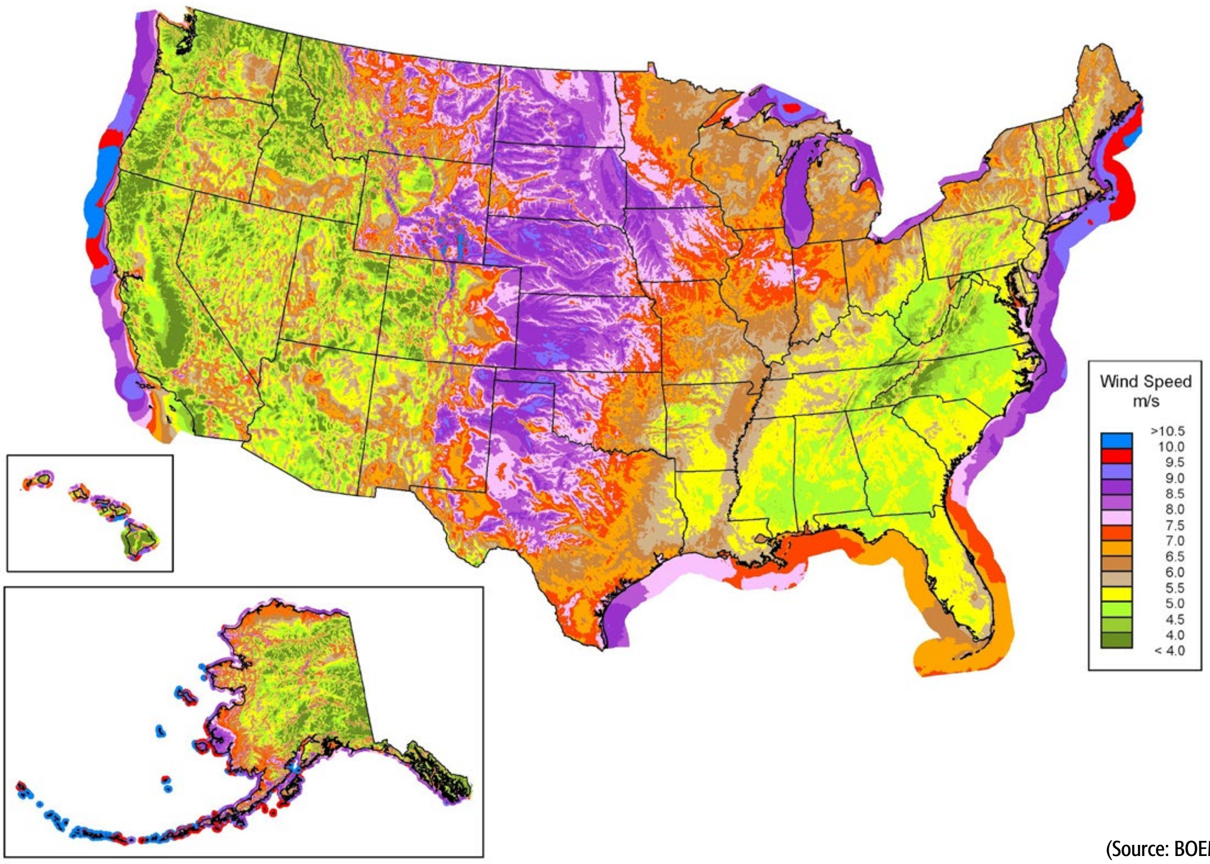
The Block Island Wind Farm, located offshore Rhode Island, has a 30-MW capacity and is America's first offshore wind farm. (Source: Ørsted)

Vineyard Wind submitted its construction and operations plan in 2017. Its status is currently listed as under review by BOEM.

"Vineyard Wind had a delay last year where they went from a draft environmental impact statement to a supplemental impact statement, and that was tied very much to the big interest and the big growth in the industry," said Rachel Pachter, chief development officer with Vineyard Wind, which is also developing the Park City Wind Project that will supply power to Connecticut.

"Regulatory certainty is a challenge that we face," Pachter said of the industry. "If you know what it's going to take to get through your regulatory process, you can make a lot more commitments and you know when it's going to happen. But that's not just true for us as developers; that's also true for the supply chain. And the electrical grid is a big one for us."

US Land-based and Offshore Annual Average Wind Speed at 100 m



(Source: BOEM)

Grids, which were not planned for power from offshore, tend to have weaker links farther away from main cities, she said.

"It's been slower getting this industry off the ground here in the U.S. The good news on that front is that there's a lot to learn from how it's been done," Pachter said. "So there are significant numbers of lessons learned that we take advantage of, particularly on the construction operations side. We're seeing a massive growth in the available technology."

Floating wind technology

The offshore wind industry is learning from the oil and gas industry when it comes to navigating supply chains, successfully co-existing with other maritime industries and perfecting the hub-and-spoke approach and offshore technologies.

This comes as the offshore wind industry also advances floating wind technology. Floating wind production has taken off in places such as Asia and Europe, which leads the world in floating offshore energy, mainly from shallow waters.

Principle Power is among the companies making technology available. The company's WindFloat floating wind turbine foundation enables wind turbines to be located in water depths greater than 40 m, according to its website.

"We're tracking about 30 gigawatts of projects globally that are under development," though many are still in the early phase, said Aaron Smith, chief commercial officer with Principal Power Inc.

Smith said the company sees potential for the industry to grow in the longer term. Citing the Carbon Trust joint industry project, Smith said more than 10 GW of floating capacity could be installed from 2030 and 70 GW delivered by 2040.

"That's up from about 100 gigawatts installed today," he said. "So, I think that gives a bit of a sense of the potential of the industry if we can do it well. I think speed and scale of this is really premised on having good and conducive political and regulatory factors that enable the industry to expand because unlike land-based renewables, offshore wind will always be subject to national governments, federal permitting agencies and these sorts of things, and so timelines tend to be complex." ✚

Editor's note: *An interactive animation depicting how a wind turbine works is available at energy.gov/eere/wind/animation-how-wind-turbine-works.*

The Gulf of Guinea province offshore West Africa, where an oil and gas drilling platform is shown, includes the Ivory Coast, Tano, Central, Saltpond, Keta and Benin basins and the Dahomey Embayment. (Source: Jan Ziegler/Shutterstock.com)

Eyeing exploration opportunity in Ghana

The West African country is depending on seismic data to gain more knowledge on basins and attract investors.

(Source: Comdas/Shutterstock.com)

Velda Addison, Group Senior Editor

The waters offshore Ghana have already given rise to the giant Jubilee oil field, where Kosmos Energy detected an overlooked Upper Cretaceous structural-stratigraphic play concept in the Tano Basin.

The 2007 discovery opened the door to a new hydrocarbon province, putting the West African country on the map. More oil and gas finds followed, including the TEN fields along with the Sankofa, Gye and Nyame fields. Companies such as Exxon Mobil Corp. have since joined a list of explorers that includes Kosmos Energy, Tullow Oil and Eni SpA.

"It took a while for companies to see that and convince themselves that the deepwater [offshore Ghana] has potential," said Michael Aryeetey, exploration and appraisal manager with the Ghana National Petroleum Corp. (GNPC), referring to activity following Jubilee.

Among the latest discoveries is Springfield E&P Ltd.'s 2019 Afina discovery in West Cape Three Points Block 2, where undiscovered resource potential was put at more than an estimated 3 Bbbl of oil and gas based on multiple leads and prospects in proven reservoirs.

None of those would have been possible without seismic acquisition and interpretation, and the future may hold more opportunity as areas are derisked.

With licensing rounds possibly on the horizon and more than a half dozen companies slated to acquire seismic data, there is potential for exploration activity to ramp up in Ghana, according to Aryeetey, who presented Oct. 12 during the Society of Exploration Geophysicists' (SEG) virtual SEG20 conference.

"Even in COVID times when most of operations have been suspended, we are expecting things will pick up next year," Aryeetey said, pointing out petroleum agreements with work obligations such as seismic acquisition and exploration drilling.

Optimism comes as the oil and gas industry continues to cope with the global coronavirus pandemic, lower energy demand, remote working conditions and shrinking budgets with projects in different parts of the world competing for limited capital.

Besides GNPC, companies such as Eni, Base Energy and Eco Atlantic, among others, are obligated to acquire 3D seismic across their licenses in Ghana, Aryeetey said. The state-run company has plans to acquire about 1,500 sq km of 3D over offshore Block 1 next year.

"Seismic companies should be looking at Ghana," he added. "It is expected that, once we complete our reconnaissance projects, the government will demarcate blocks in the Voltaian Basin and will advise international oil companies to come in and apply for blocks. So very soon there is a lot more that will be coming out for companies that are looking at Ghana."

Focusing onshore

Exploration across the some 103,600-sq-km Voltaian Basin onshore—the country's largest sedimentary basin—has not been as aggressive compared to offshore, Aryeetey said, but exploration activities date back to the 1960s. At the time, geological and geophysical data were acquired by a Russian geoscientist and a gravity survey was obtained by Romanian geoscientists as Ghana engaged in government-to-government exploration relationships.

Results revealed traces of oil and gas, which attracted Shell to the area to conduct an airborne magnetic survey and acquire seismic data after securing a five-year petroleum prospecting license. GNPC data show Shell drilled the Premuase well in 1977.

"Unfortunately, that well was not successful and the potential of the basin died at the time," Aryeetey said.

He later recalled that some water wells drilled in the basin encountered bitumen and gas.

Recent subsurface geochemical analysis indicates hydrocarbon has been generated in the basin, Aryeetey added. In the western part of the basin, "we are seeing seepages, but they are connected to the Tano Basin, which ascends offshore," he said.

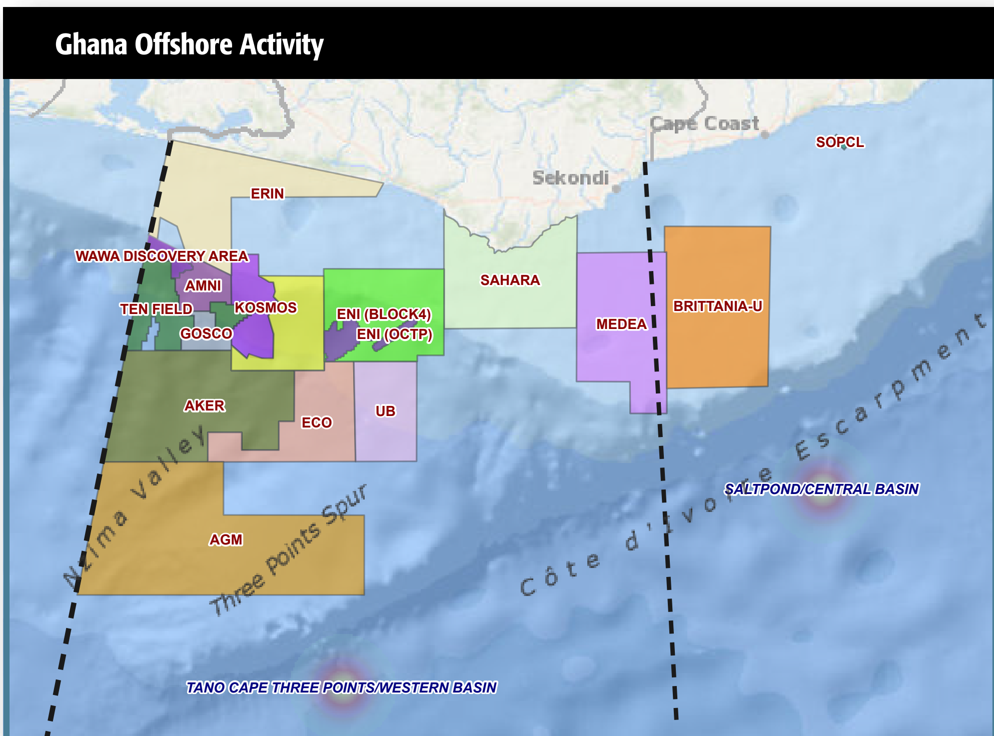
Geophysical data indicate conditions in the basin, which has Precambrian to Paleozoic-aged sediment, are favorable for commercial oil and gas potential, given the probability of stratigraphic and structural traps, according to a 2018 report released by the Oxford Institute for Energy Studies.

However, there are risks.

"The Voltaian Basin's sedimentary neo-Proterozoic rocks have similarities to hydrocarbon-producing areas in North Africa such as Morocco, Algeria, and Libya," the report stated. "Exploration in the basin is perceived to carry high risk, due to the probable geological history of the subsurface. Located in the southern part of the basin, Volta Lake—one of the world's largest constructed lakes—further adds to the complexity of acquiring seismic data in the area."

At only 2,538 line km, the basin has relatively low seismic data coverage, according to GNPC.

Michael Aryeetey, exploration and appraisal manager with the GNPC, speaks during a Q&A session Oct. 12 at the SEG20 virtual conference. (Source: SEG20 virtual conference)



(Source: Ghana Petroleum Commission)

Seeking seismic

Ghana has made progress in increasing seismic coverage, reaching nearly 80,000 line km of 2D seismic and more than 30,000 sq km of 3D seismic, Aryeetey said. Strategies have included awarding larger blocks to independent oil companies, enabling them to acquire extensive seismic data as part of their required work programs.

More data are needed because what has been acquired so far is not extensive enough, according to Aryeetey.

"3D will come, but we need a lot more 2D to fill into what we acquired right now," he said.

This includes the 36,000-sq-km Accra-Keta Basin, where the last 3D was acquired in 2006. Ghana's petroleum commission is looking to engage companies interested in acquiring such data, he said.

As for attracting investors overall, Ghana is depending on its political stability, fiscal regime and flexible contract terms.

"We allow investors to select areas they want to invest," Aryeetey said. "We have an open system where you can look at an area and go to the ministry and apply, and we'll do a lot of direct negotiations. It's not just licensing rounds."

Ghana continues to draw interest following its inaugural licensing round in 2018 to 2019.

In August 2020, Ghana opened 11 blocks in the Keta Basin and one block in the offshore Tano Basin for direct negotiations. Several companies have submitted expressions of interest, Aryeetey said.

Unlike the Tano Basin, a prolific deepwater basin in the transform margin of West Africa, the Keta Basin has not seen much exploration activity. Water depths of up to about 4,000 m are similar to Tano, he explained, but only about 200 wells have been drilled in Tano compared to about 16 in Keta.

"The few wells that have been drilled in deep water have shown tremendous promise," with high-quality reservoir, Aryeetey said. "What we have not been able to prove is a charge system. Therefore, we need to acquire the latest 3D seismic and do a lot of basin analysis to understand the geology of the basin. We believe, in Ghana, that it has a lot of potential and could even [have] bigger fields than we've seen in the Tano Basin. We expect in the future a lot more blocks will be put out there for investors." +

(Source: Shutterstock.com/Hart Energy)

Energy transition: threading the regulatory needle

The oil and gas industry needs to position itself strategically to attract investments while working to achieve low-carbon goals.

Michael Blankenship, **Eric Johnson** and **Stephanie Sebor**, Winston & Strawn

The oil and gas industry, particularly the E&P and oilfield services subsectors, have faced significant headwinds over the last few years, most recently with the simultaneous demand destruction resulting from COVID-19 and supply shock from the Saudi Arabia-led price war. These recent events, combined with capital flight out of the industry and demands for capital discipline by remaining investors, have accelerated the push by company stakeholders, regulators and others for energy transition initiatives.

But the energy transition journey will take decades. The industry, as a whole, needs to strategically position itself to remain profitable in oil and gas while concurrently evolving over time to meet the demands of a lower-carbon future. Oil and gas will retain a significant role in the global energy mix, particularly for developing nations. However, in

Michael Blankenship

Eric Johnson

Stephanie Sebor

the U.S. and Europe, alternative energy sources will expand and take capital—both financial and human—with them.

To successfully navigate this long-term evolution, the industry needs to focus on three key areas, simultaneously emphasizing both the present and the future.

Conflicting frameworks

From a regulatory perspective, the oil and gas industry finds itself facing conflicting frameworks, interests and objectives as it pursues its energy transition initiatives. Local and state regulatory regimes are becoming more restrictive while federal regulations are currently relaxing. Although the Joe Biden administration could quickly alter the landscape. Within the broader energy industry, traditional oil and gas and alternative energy, historically adversarial, are now looking to come together to push regulatory agendas, but it will be some time before the industry can truly establish the necessary "big tent."

For the energy industry to move forward effectively and efficiently, everyone is going to have to come together.

Even within oil and gas, many companies and subsectors are moving in different directions, pursuing their own best strategies and timetables for energy transition. To ensure the smoothest and most just transition, the oil and gas industry needs to exhibit an extraordinary amount of cooperation and forward thinking in its regulatory efforts as it threads the needle between the present and the future.

An excellent example of these conflicting regulatory frameworks, interests and objectives is the recent rollback of the President Barack Obama-era methane emission regulations. Environmental regulations applicable to the oil and gas industry have been subject to many amendments during the President Donald Trump administration, which has solicited a wide range of responses from the oil and gas industry and interested stakeholders. The reactions to the most recent changes to the air emissions standards in the New Source Performance Standards (NSPS) for the oil and gas industry have been particularly divisive, with some members of the E&P industry praising the changes and others expressing disappointment in the regulations as undermining decarbonization efforts.

On Aug. 13, 2020, the EPA issued two final rules relaxing methane gas emissions requirements applicable to various segments of the oil and gas industry.

The first of these rules, known as the policy amendments to the NSPS regulations, removes the NSPS requirements for the transmission and storage segment of the oil and gas industry altogether, including rescinding both volatile organic compound (VOC) and methane emissions standards for transmission and storage sources.

This final rule concludes that the oil and natural gas production source category only includes the production and processing segments of the industry. Because the EPA did not find that emissions from the transportation and storage segment cause or significantly contribute to air pollution that may be reasonably anticipated to endanger public health or welfare, the EPA improperly regulated emissions from the transportation and storage segment.

In addition, the EPA also rescinded the methane emission standards for the production and processing segment of the oil and gas industry, although VOC standards applicable to the production and processing segment remain in effect.

The second rule, known as the technical amendments, addresses the EPA's reconsideration of four aspects of the NSPS regulations: fugitive emissions requirements, wellsite pneumatic pump standards, requirements for certification of closed vent systems by a certified engineer and the application process for the use of an alternative means of emissions limitation. In addition, the technical amendments include other efforts to streamline implementation of the NSPS regulations as they relate to well completion, onshore natural gas processing plants, storage vessels, and record-keeping and reporting requirements. Paired

Three Key Focus Areas to Navigate the Evolution	
1. Continued Investment in New Technology	**For existing operations:** efficiency gains and decarbonization
	For the future: alternative energy, including wind, solar, hydrogen and nuclear
2. Robust Sustainability Disclosure and Messaging	**For existing operations:** effectively communicate successes in decarbonization and the benefits of the modern world afforded by oil and gas
	For the future: transparent disclosure around sustainability targets, progress toward those goals and alternative energy developments
3. Navigating the Energy Regulatory Landscape	**For existing operations:** continued lobbying efforts at all levels for regulatory regimes that allow the industry to economically produce sufficient volumes of oil and gas to enable a just and smooth energy transition in an environmentally responsible way
	For the future: a more inclusive and collaborative lobbying approach with alternative energy companies and trade associations

with the policy amendments, oil and gas companies are no longer required to monitor and repair methane leaks from production and processing operations.

While the API praised the rulemaking as "consistent with the requirements of the Clean Air Act," others, such as bp, criticized the rule.

"bp believes methane should be directly regulated by the EPA" and that "the best way to tackle [climate change] is through direct federal regulation, ensuring that everyone in the industry is doing everything they can to eliminate methane leaks," the company said.

bp's statement comes after its February 2020 pledge to zero-out its carbon emissions by 2050, with Shell also announcing its intention to be a net-zero carbon emissions business by 2050. Shell called the rulemaking "frustrating and disappointing" and has previously urged the Trump administration to directly regulate methane emissions from existing onshore oil and gas assets. Many players within the industry, for strategic, reputational, marketing and other reasons, did not see eye to eye on the rollback of the methane emission regulations.

And, unsurprisingly, the regulatory rollback has set off a flurry of litigation, with states, municipalities and environmental groups challenging the new federal rule in several cases filed on Sept. 14, 2020. Environmental groups also filed a motion for an emergency stay of the rule during the pendency of the litigation, which was granted by the District Court.

Moving forward

The varied reactions to the methane emission regulatory rollback are not surprising. And Winston & Strawn expects, in the short term, more conflict on regulatory issues rather than common ground. But for the energy industry to move forward effectively and efficiently, everyone is going to have to come together, both in support of traditional oil and gas and our lower-carbon future. Threading the regulatory needle will be a key to industry success. +

Editor's note: *This article was written in late September.*

Advancing hydrogen in the energy mix

Baker Hughes successfully tests and distributes hydrogen-blended gas turbine.

***Brian Walzel**, Senior Editor*

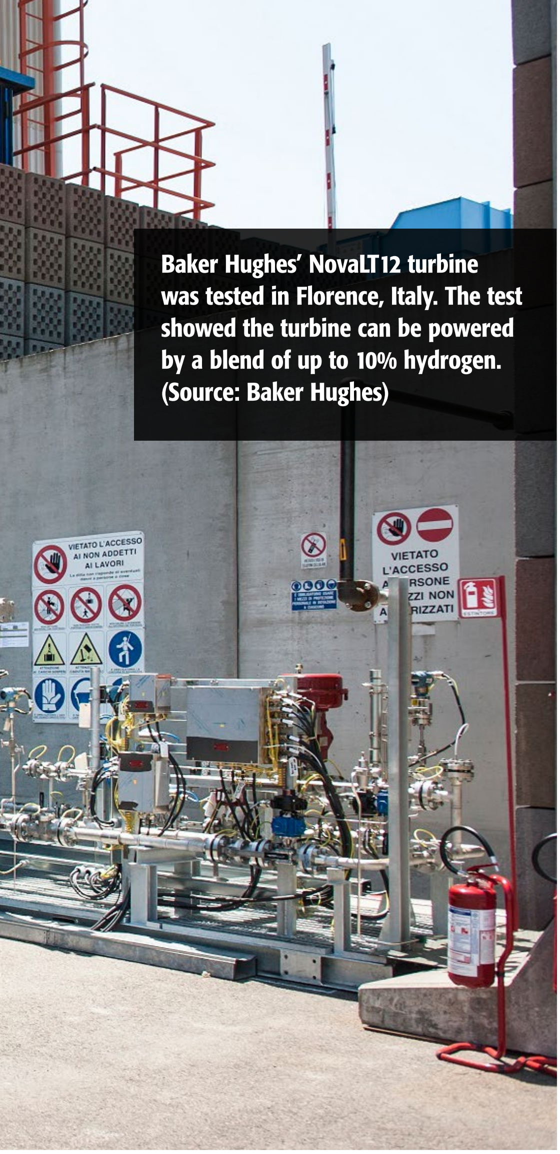
Transitioning to a carbon-neutral industry—as has been the stated goal of supermajors and global service providers alike—is an ambitious task and one that will require a mix of efficient fuels and the innovative technologies to produce those fuels.

Although the use of hydrogen as an alternative fuel to oil and natural gas is nothing new, its application is gaining in popularity as the world seeks new fuel sources. Of the multitude of hydrogen technologies that are either being tested or adopted around the world, Baker Hughes recently announced the successful test and application of the world's first hydrogen blend turbine for gas networks.

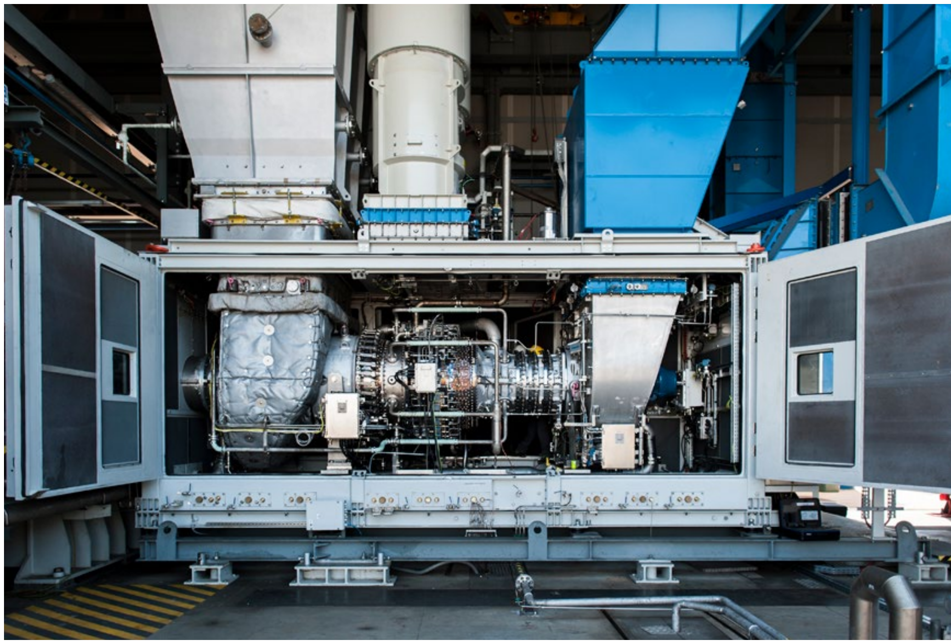
Baker Hughes' NovaLT12 turbine is powered by a blend of up to 10% hydrogen. The turbine will be installed by next year at Snam's gas compressor station in Istrana, Italy.

"The completion of this test represents an important step in defining the energy of the future," said Baker Hughes Chairman and CEO Lorenzo Simonelli.

According to Baker Hughes, its NovaLT turbine is capable of burning methane gas and hydrogen blends from as little as 5% to as much as 100% hydrogen. The company reports that by blending 10% hydrogen into the total annual gas capacity trans-



Baker Hughes' NovaLT12 turbine was tested in Florence, Italy. The test showed the turbine can be powered by a blend of up to 10% hydrogen. (Source: Baker Hughes)



The NovaLT12 turbine is capable of burning up to 100% hydrogen. (Source: Baker Hughes)

ported by Snam, it is estimated that 7 Bcm of hydrogen could be introduced into the network annually, an amount equivalent to the annual gas consumption of 3 million families and represents a reduction of 5 MMtons of CO_2 emissions.

Luca Maria Rossi, CTO, turbomachinery and process solutions with Baker Hughes, called hydrogen "one of the most promising fuels." But he acknowledged that for it to be seen as a truly green source of energy, hydrogen itself would need to be produced out of green energy.

Hydrogen is produced most commonly from fossil fuels, primarily natural gas. According to the International Energy Agency (IEA), natural gas accounts for about three-quarters of the annual global dedicated hydrogen production of about 70 MMtonnes.

"The name of the game in hydrogen is for it to be integrated into production with renewables," Rossi said. "Hydrogen can be used as a fuel for gas turbines but also for cars or for heating a house. It's a completely clean energy."

Transportation

Hydrogen as a fuel for cars is likely far off due to the lack of refueling stations, but there are efforts being made to speed up the transition. According to the IEA, there are eight countries with policies supporting various levels of hydrogen incentives in transportation. In addition, the IEA reports that there are about 50 global targets, mandates and policy incentives in place today that support hydrogen technologies, most of which are in transportation.

Baker Hughes is not new to hydrogen technology. The company developed its first hydrogen compressor in 1962 and, as Rossi explained, has worked to develop different hydrogen technologies throughout the entire supply chain. In 2008, Baker Hughes built the world's first turbine to run on 100% hydrogen. Today it has more than 1,000 units of hydrogen compressors installed across multiple applications, with about 70 projects worldwide using gas turbine technology to burn a variety of fuel mixtures with hydrogen content ranging from 5% to 100%.

"This is not just a laboratory," Rossi said. "We have actually sold these products, and these machines are going into the field and producing energy. This gives us an incredible advantage in terms of experience and learning what we can do with this fuel."

One of the ways in which hydrogen can be produced with less of an environmental impact is through electrolysis. Electrolysis uses electricity to split water into hydrogen and oxygen, a reaction that takes place in an electrolyzer.

According to the U.S. Energy Department, electrolyzers can range in size from appliance-sized equipment that is suited for small-scale distributed hydrogen production to large-scale, central production facilities that could be tied directly to renewable or other non-greenhouse-gas emitting forms of electricity. +

Kongberg's virtual collaboration services ensure customers get the data-driven insight and expertise they need, where and when it is needed. (Source: Kongsberg Digital)

The time to digitalize is now

It can be an opportunity to reevaluate how a company spends its time and what is influencing its productivity as a business.

***Stig Woelstad-Knudsen**, Kongsberg Digital*

As Kongsberg Digital has interacted with customers in the past six months since the pandemic lockdown, the feedback circles around two main points:

1. Operators would have been better equipped to handle their operations if they had been more digitally mature; and
2. Workers have embraced digital technology as they experience the benefits directly.

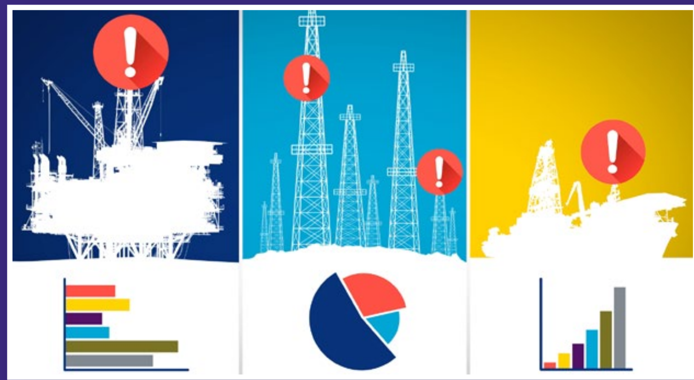
In that sense, 2020 has shown the world's industries that the time is ripe to start digitalizing.

At the beginning of 2020, most industrial players knew that digitalization would impact business sometime down the line. They had been presented with futurist scenarios of end-to-end interconnectedness and complete insight, and yet they had heard of many digitalization projects that failed. It was reasonable to question not if but when digitalization would make its great dent in the operation of traditional industries (i.e., when the technology was mature enough or when the organization could handle the change that comes with starting to digitalize).

Then a pandemic hit, and the world was forced to stay at home and conduct their work remotely. People's everyday lives were flipped upside down, and workers needed to find and learn how to use the solutions that allowed them to do their work efficiently, interacting with people and the digital world.

Digital solutions

The problem does not seem to be that organizations cannot handle the change in workflows that come with digitalization, as long as workers are given sufficient time to learn. Rather, people are quite apt at picking up new tools when they see the benefits clearly. Does the challenge, then, lie in the technology? Is it mature enough?



Standardize and centralize data delivery and facilitate a collaborative decision environment improving performance while reducing HSE and financial risk. In this short video clip, learn more about SiteCom real-time data aggregation and visualization for all phases of well construction. (Source: Kongsberg Digital)

The short answer is yes, but that does not mean that the futurist scenarios of end-to-end interconnectedness and autonomous operations with absolute insight is on the table just yet. Rome was not built in a day.

Industrial players should not wonder so much when the huge transformation will hit but rather ask themselves, do I believe digitalization will affect my industry? Is my business prepared for the change that will come? How am I reaping the benefits of digital solutions available today?

Digital solutions have already yielded opportunities at all levels in the oil and gas industry, notable in the offshore operations where cost is higher. The collection, contextualization and sharing of data in common user systems does not only enable the companies to break down the traditional silos between different expert groups. As more data are shared with other trusted vendors, it is possible to unlock new value with large contextualized datasets, giving teams an improved foundation for decision-making in real time and a spur for innovating for even more value. With the advent of COVID-19, digitalization has emerged with an even broader purpose, enabling employees to remain productive at home. Kongsberg Digital 's focus is to continue to shape technologies that enrich multidisciplinary teams and provide insight as well as elevate worker productivity through seamlessly replication of the office or rig work environment to their home.

Kongsberg Digital's SiteCom platform for real-time data aggregation and storage was launched almost two decades ago as the new independent approach to standardization of real-time data in the well operations domain industry based on the WITSML standard for data exchange.

SiteCom provides secure long-term data storage and is reliable with 99.9% uptime. It offers vendor neutrality, fast data transfer from the rig with minimum latency, and high scalability in terms of rigs, sensors and high-frequency data. It also offers global mnemonic sensor name translation to minimize configuration and support analytics and hosting of algorithms to do real-time and historic data analysis. Additionally, the platform is backed up by a global network of support professionals available 24/7.

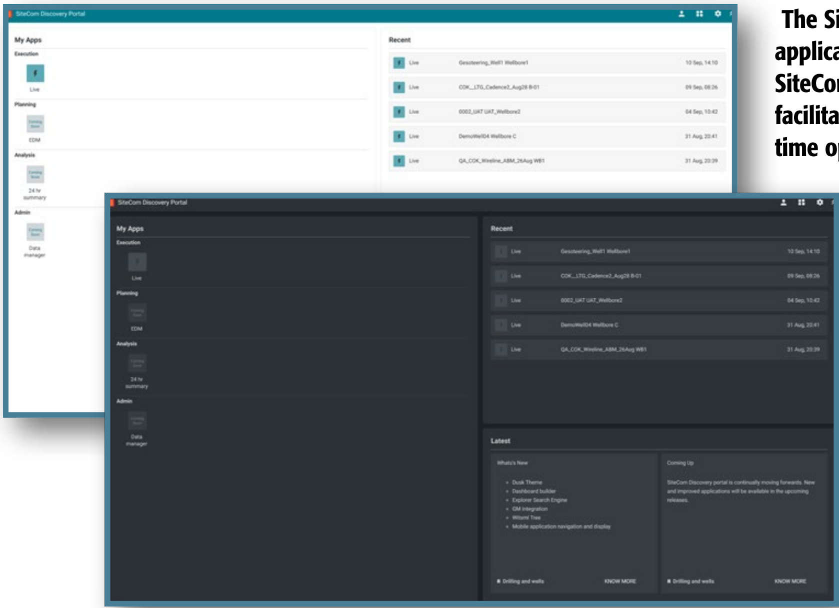
Offshore drilling

Offshore drilling was Kongsberg's primary market when launching SiteCom. The high costs associated with offshore drilling operations makes optimal decision-making in real time even more important, and the collaboration between rig operator and oil company is crucial in making this happen. The challenging conditions in harsh environments with restricted physical accessibility combined with technical challenges like satellite connections with low bandwidth shapes the requirements for the stability and reliability of the real-time service.

Offshore wells are frequently deep and complex, requiring access to the most experienced personnel to ensure safe and efficient well construction. Such people are in high demand, and the introduction of remote operations has allowed higher utilization of their skills, allowing a single person to support multiple operations from a remote real-time operations center or even their office desk.

Applications

Uncertainty has become the new normal in today's world. This uncertainty encompasses all aspects of operations from economic feasibility to the operational problems that will crop up and demand innovative solutions. To accommodate this dynamic market, Kongsberg has pivoted to develop compact discrete applications. When paired with the internal agile development cycles, the company can deliver continuously to customers with software that addresses their current need. This approach centers on a multi-application philosophy where individual apps are rapidly developed within a two- to four-month cycle. Regular customer interaction "tech wave meetings" enable the validation of the medium-term road map, early feedback from the end user community and an introduction of new functionality. This also serves as an additional opportunity for customers to influence Kongsberg



The SiteCom Discovery Portal is the host of the new applications from Kongsberg Digital and partners on the SiteCom ecosystem. Lightweight intuitive applications facilitate remote working in lieu of an office-based real-time operations center. (Source: Kongsberg Digital)

Digital's direction and priorities by pitching new ideas and concepts.

Each application is independent and unique in its purpose and function. Kongsberg Digital's applications are tailored to a specific task or workflow, adapted to a user group's terminology and intuitive with minimal to no training required. The applications offer platform independence; it must work anywhere on any device on any platform (PC, Mac, tablet or mobile). Immediate data is available with a focus on reducing duplicate input entry. The technology is independent from SiteCom core and other application updates, reducing the update overhead for our clients

The SiteCom Discovery Portal and Live application were delivered on time and numerous new applications are in progress. Early adopters committed to the same strategy and are accelerating specific applications to meet their end user needs.

The Subsurface Action Review is a subsurface reporting application for operational events and observations. Its aim is to reduce the time it takes the operation geology community to collate, edit and present their findings on an ongoing basis to well stakeholders. After action, reviews from a given hole section and offset analysis are also supported. The efficiency enables the geologists to concentrate on supporting the rig, while not losing their valuable insights along the way.

A secondary example is that cross-referencing the plan during execution of a well operation is crucial to determine if the well is progressing according to the plan and identifying disfunctions. Historically this process has been cumbersome, and an unnecessary time sink due to the lack of open communication between independent data systems. This has resulted in inaccuracies and hand keying identical inputs multiple times.

To streamline this administrative task, Kongsberg Digital has developed an application allowing engineers to link files from external systems to SiteCom. In using the application, updates to the plan will be automatically synchronized across when the plan is amended with, for example, the as-drilled trajectory and section total depth. This also can be used to ingest time summary reporting data to contextualize historical data.

Uncertainty also extends to the size of operations and capex/opex. With little to no warning, a singular event (e.g., a virus) can shred the outlook for the year and its budget. All the SiteCom related products can be hosted and scaled on a monthly subscription basis in terms of both rig and user count depending on the application, which allows customers flexibility to survive the volatility of today's market. The value of not paying for a solution until it is required can be the difference between a month in the black and a month in the red.

Case study

When COVID-19 first struck the oil and gas industry, organizations were collectively scrambling to get a global workforce situated in home office settings while maintaining an acceptable level of productivity. Utilizing Kongsberg's SiteCom suite, a large international oil company was able to safely move its real-time operations center to an isolated staff house within less than 24 hours without any interruptions to its service. It continued running for more than four months. They also were able to expand their user access level to ensure all home base employees had concurrent access to their real-time feed and historical well database. With a remarkable level of global disruption and transition, employees were still able to maintain their productivity levels with ease.

Conclusion

In these uncertain times, there are risks and opportunities. It can be an opportunity to reevaluate how a company spends its time and what is influencing its productivity as a business. It begs the question, what should a company be doing with its data and what can that data do for the company? ✚

Patterson-UTI Drilling's comprehensive fleet of pad-capable rigs like APEX-XK 256 features advanced walking systems combined with performance automation technology to enhance operations. (Source: Patterson-UTI Drilling Company LLC)

Collaboration leads to improved BHA performance

Extended-reach laterals in the Delaware Basin require robust technological innovation.

***Marcus Howell**, Patterson-UTI; **Jordan Ellington**, Matador Resources; and **Eric Sonne**, Taurex Drill Bits*

In the evolving pursuit of consistent performance drilling, slim-hole curve-lateral intervals in New Mexico's Delaware Basin present unique challenges for optimization through both drill bit design and motor performance. The engineering partnership of Matador Resources Co. allowed Patterson-UTI Drilling, MS Directional and Taurex Drill Bits to work jointly to solve these challenges.

Challenge

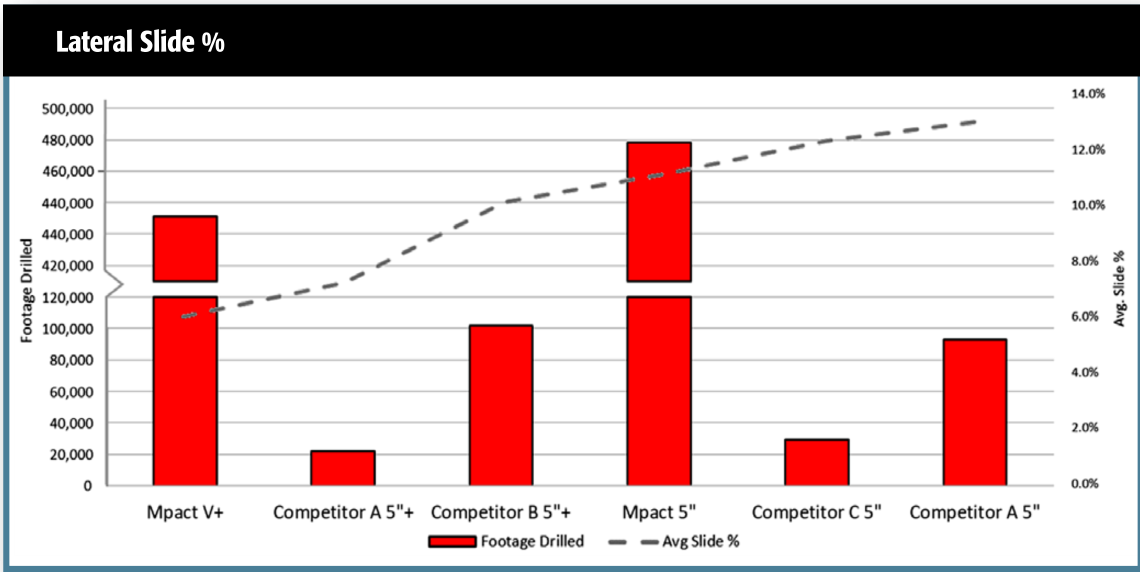
The need to reduce drilling and completion cycle times along with improving capital efficiency is a consistent theme in the upstream E&P sector.

Polycrystalline diamond compact (PDC) cutter technology has rapidly improved in terms of performance and reliability over the past few years, highlighting some of the reliability concerns in slim-hole tools.

While rotary steerable tools have been a solution for different parts of the Permian Basin, the technology has proved to have its own limitations, which can be cost prohibitive.

The high hydrostatic and lithostatic pressures encountered while drilling deep Delaware Basin targets often decrease buildup rates in the curve and reduce penetration rates in the lateral. Additionally, the interbedded nature of these strata, consisting of sandstones, shales and carbonates, creates a challenging drilling environment.

For a bottomhole assembly (BHA) to drill through this target without premature drill bit or tool failure, it must be able to withstand excessive shocks and vibrations, high-torque events



MS Directional's engineering team developed the Mpact V+ 5⅝-inch lower end motor for companies that need maximum drilling performance for 6¾-inch hole applications. (Source: MS Directional)

as well as provide directional control while drilling varying rock types.

In addition to these challenges, tortuosity and frictional forces complicate BHA behavior. Unfortunately, isolated optimization strategies to mitigate these challenges can often be contra-dictory by nature.

A collaborative approach to parameter management, directional control, tool reliability and penetration rate is imperative for improved BHA performance. Ultimately, the operators of today require equipment and downhole tools that can endure harsh drilling environments, particularly in extended-reach, slim-hole lateral applications for reduced overall lateral footage costs.

Technology solution

MS Directional's MPact motor division has introduced the V+ (5⅝-inch) high performance lower end specifically designed for 6¾-inch hole size. In doing so, it optimized every design feature for maximum benefit. This resulted in a performance drilling motor that exceeds other options available on the market.

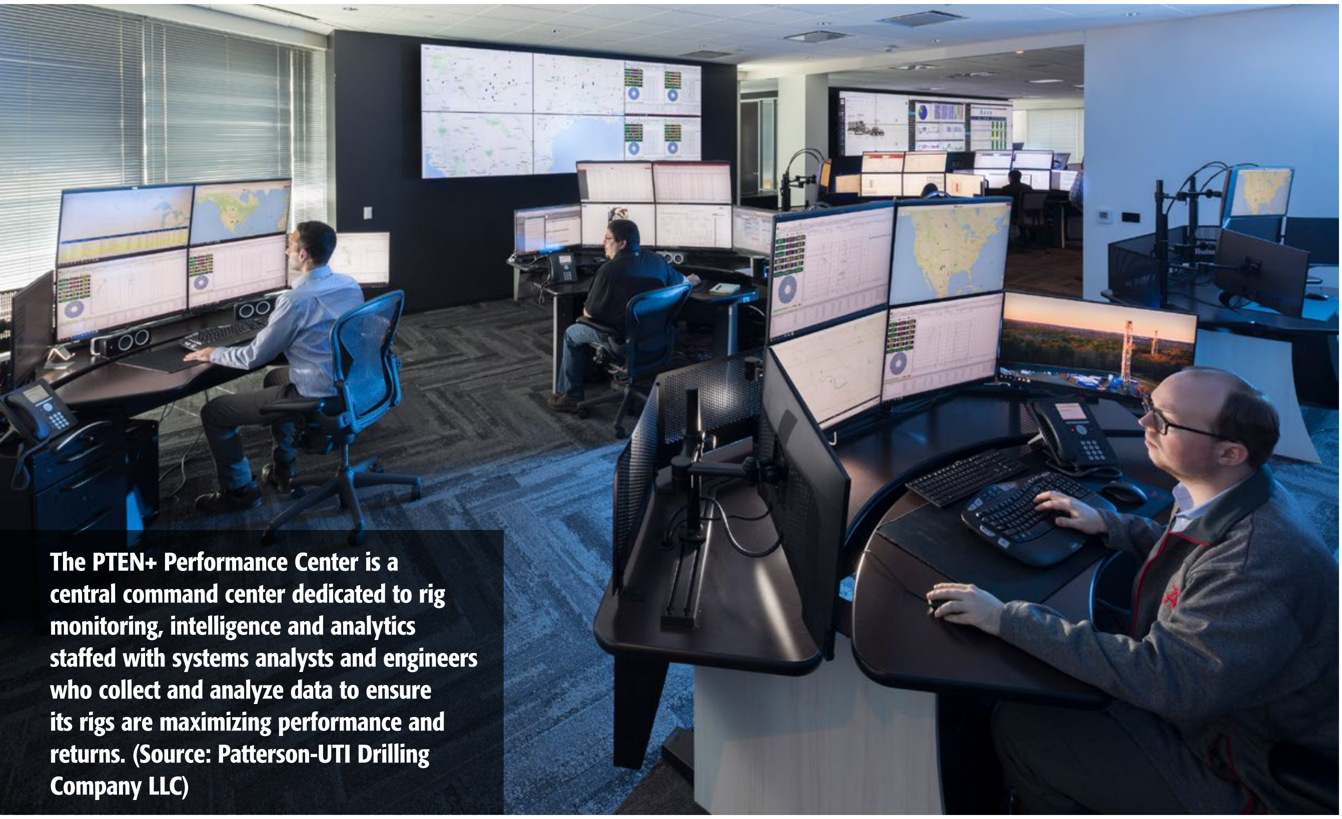
The V+ utilizes Mpact's enlarged two-piece transmission design with a torque capacity of 12,500-plus ft-lb. The Mpact V+ has provided a direct benefit to operators yielding up to 50% reduction in lateral slide and 20% increase in total ROP on average.

Equally crucial is appropriate PDC cutter selection. The deep Delaware Basin lithology rapidly leads to several forms of premature cutter failure. This application demands PDC cutters with high axial and torsional impact toughness without sacrificing thermal and abrasion resistance.

Taurex's rapid cutter development and robust cutter selection procedures have led to unrivaled durability in this application. Taurex's recent design optimization strategies have centered on precise wear measurements and sophisticated data analytics performed after every drill bit run. These careful measurements are performed in house at Taurex's Automated Metrology Laboratory, which quantifies drill bit wear data autonomously with unparalleled accuracy. Evaluation of wear data has allowed the identification of underlying relationships between drill bit wear, drilling parameters, cutters and design characteristics to drive scientific recommendations. The superior accuracy and reliability of drill bit wear analysis accelerates the speed of learning for superior optimization strategies, maximizing drill bit performance faster than ever before.

Result

Matador Resources Co. utilizes its real-time operating center, MaxCom, to monitor its operations and drilling performance 24 hours per day, 365 days per year. The MaxCom team, consisting of engineers and geologists, utilizes data analytics and real-time data to optimize drilling performance and target the best rock in each reservoir. This interdisciplinary teams approach enables a data-driven decision process while maintaining flexibility in their engineering design. The MaxCom and drilling engineering teams have worked together to tailor their well design based on well and tool performance data. As a result of the well engineering, along with the aforementioned improvements in tool technology and reliability, Matador has had eight-plus runs with this particular BHA design delivering an average footage drilled of 9,914 ft per run



The PTEN+ Performance Center is a central command center dedicated to rig monitoring, intelligence and analytics staffed with systems analysts and engineers who collect and analyze data to ensure its rigs are maximizing performance and returns. (Source: Patterson-UTI Drilling Company LLC)

at more than 73 ft/hr. Additionally, this performance has been replicated across various horizons and asset areas within the basin.

Matador's longest run to date with this assembly drilled 12,052 ft in 173.5 drilling hours for an average ROP of 69.5 ft/hr. Independent of the on-bottom performance increase of this assembly, this run could save between 24 and 40 hours, pending hole conditions faced in various parts of the basin. At an assumed rig spread rate of $2,500 per hour, this has the potential to save between $60,000 and $100,000 to the well's drilling costs. These savings exclude other tangible savings related to a new BHA, such as a new bit, motor, MWD and agitators.

Tools to improve drilling efficiencies

Additionally, Patterson-UTI's APEX-XK 1500 is designed for safe, fast-moving and fit-for-purpose drilling. From mobility to drilling, the rig's operations improve value by increasing the time a bit is on bottom, reducing nonproductive time and rig move cycle time. The APEX-XK 1500 is equipped with the latest in AC drilling technology, which allows the driller to set strict drilling parameters, enhancing the ability to deliver superior drilling rates in the toughest drilling conditions.

Through the PTEN+ performance center, these technologies are extended to 24/7 real-time monitoring, communication and automation. Additionally, the rig is equipped with a high-torque top drive, racking capacity of 25,610 ft of 5 inches for extended laterals and three mud pumps with 7,500-psi fluid ends.

Furthermore, MS Directional's most recent MPower fleet Mercury MWD enhancements have provided the latest data compression rates all while improving mean-time-between-failure hours in excess of 3,000. Technology in conjunction with its Remote Optimization Center provides ongoing support with best practices for drilling excellence.

In addition, Taurex's drill bit design software, BitLogic, can accurately model forces exerted on individual PDC cutters. This complex rock-bit interaction capability provides Taurex with the ability to predict behavior of the bit in different strength formations and mitigates cutter damage while achieving superior penetration rates. BitLogic's analytical capabilities coupled with the empirical data collection ability of Taurex's Automated Metrology Laboratory have resulted in unparalleled speed of learning, which has translated into unprecedented drill bit performance. +

Acknowledgement: *The authors of this article would like to thank those involved with the Delaware project: the Matador Resources Co. drilling team, Patterson-UTI operations and marketing personnel, Derek Koller and Bret Barre with MS Directional as well as Casey Kitagawa, Dustin Lyles, Dustin Marrs and Michael Chai with Taurex Drill Bits.*

Boosting SWD well and producer performance

The propellant-boosted enhanced perforation achieved more than 2.5 times the flow rate through the core test sample. (Source: Enhanced Energetics)

Propellant-boosted perforating optimizes performance in SWD and producing wells.

***JD Schmidt**, Enhanced Energetics*

Propellant-boosted perforating has proven to affordably increase completion and recompletion performance in a wide variety of saltwater disposal (SWD) wells and producers. Advances in integrating propellants with traditional shaped-charge perforating technology have enabled perforating and stimulation operations to be performed in one trip at lower cost than traditional two-step, shoot-and-treat methods. The critical success factor is the adoption of a progressively burning, solid propellant designed to increase penetration, eliminate clogged perforations and overcome near-wellbore damage from compaction caused by traditional shaped-charge perforators.

Boosting SWD injectivity

E&P companies invest millions of dollars to safely dispose of produced water in wells they own and operate or in third-party, off-lease wells. With SWD costs in some areas reaching half of a well's operating costs, operators in the Permian, Illinois and other basins are adopting the propellant-enhanced perforating technique to improve injectivity index and lower operating expenses.

Standard perforating gun systems enhanced with propellant boosters create multiple 10-ft or longer radial fractures that remove skin to enhance the injectivity index. After the shaped charge fires and penetrates the casing, the slower progressively burning propellant breaks down the formation to lower treating pressures, reduce acid volume and improve rates.

For a Delaware Basin operator, Enhanced Energetics applied propellant-boosted perforating technology during the initial completion of an SWD well. Step tests proved propellant boosters improved perf injection efficiency when compared to traditional perforating, and the volume of acid required for stimulation was reduced. The step test achieved an injection rate of 28 bbl/min at 1,866 psi. This result indicated the SWD well had about 35,000 bbl of daily capacity at a permitted pressure of 1,500 psi.

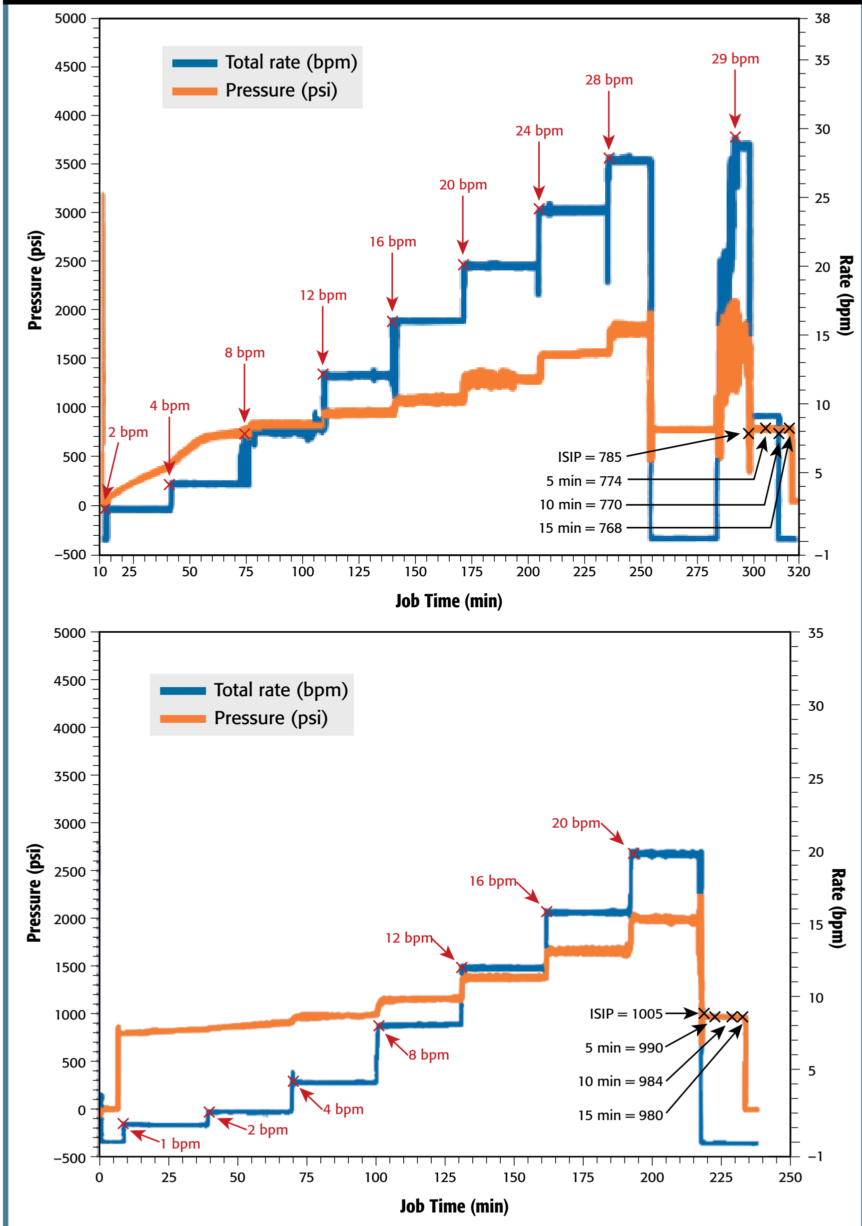
Compared to offset wells, this 71% increase in injection volume was achieved at the same pressure. Compared to status quo offset SWD well completions, the propellant-enhanced SWD required 50% less acid, rig time decreased by an average of five days, and the lower pressure needed to achieve permitted rates reduced the horizontal pump size and associated power consumption.

Boosting conventional and unconventional production

Enhancing perforations in conventional and unconventional wells with propellant boosters has delivered step changes in completion performance. In vertical and horizontal wells, propellant boosters with shaped charges extend the technical limit of conventional perforating performance by breaking down every perforation tunnel in advance of treatment operations. Fractures created in perforation tunnels bypass skin to enhance productivity and lower treating pressures. More than 6,000 wells have been completed with propellants worldwide in carbonates, sandstones and naturally fractured reservoirs.

In 2019 an operator in the San Andres dolomite formation in the Permian Basin recompleted two wells initially completed with conventional perforations and acid treatment. The propellant-boosted perforating gun overcame formation damage and improved the performance of the subsequent acid stimulation. A 5,000-gal acid job was run after each Kraken perforating job. For several months, one well doubled production and the second well more than tripled production with the propellant-boosted stimulation method.

Step-rate tests



Step-rate tests in a new well completion (top) with propellant-boosted perforating versus an offset well (bottom) with traditional perforating prove propellants drive higher injection volume. (Source: Enhanced Energetics)

Operators and wireline service companies are viewing propellant boosters as a standard completion method to reduce risk and lower the total cost of operations.

Recent work in unconventional wells with plug-and-perf completions showed promising results that have not yet been released by operators. Large datasets are being analyzed to compare results with and without propellant-boosted perforating. The metrics impacted include higher pumping rate, minimizing time to achieve rate and complete each stage, lowering the chance of screenouts, and increasing prop volume.

Tests confirm effectiveness

An API Recommended Practices 19B, Section 4 Test at Halliburton's Jet Research Center evaluated perforation flow performance with conventional and propellant-boosted perforating guns.

The difference in flow performance between a perforation with no propellant boosters and a perforation with boosters was dramatic. The propellant-boosted enhanced perforation achieved more than 2.5 times the flow rate through the core test sample with a 50% reduction in pressure compared to the shaped charge alone.

In the two perforating tests with a shaped charge assisted by propellant boosters, propellant ignition occurred immediately after the explosion of the shaped charge. The burning of the propellant boosters generated high-pressure gas inside the gun and exited out into the perforation tunnel. This process creates a dynamic-overbalance event that enhances the perforation and creates fractures past the compacted rock (skin) produced by conventional shaped charges, thereby improving access to the formation.

Overcoming inertia to adopt propellants

Operators and wireline service companies that study actual well performance results and API test data are viewing propellant boosters as a standard completion method to reduce risk and lower the total cost of operations.

When completion engineers consider the following four factors they become more willing to adopt propellants:

1. Propellant boosters are safe to handle and transport;
2. They are compatible with deep-penetrating, big-hole and equal-hole entry charges;
3. Tools are assembled and verified away from the well site to lower operations risk; and
4. Gun systems enhanced with propellant boosters can be conveyed and fired by all standard methods and with customized shot densities and phasings. ✚

Progressively burning Kraken propellant boosters generate high-pressure gas in the perforation tunnels, which creates fractures that improve well connectivity. (Source: Enhanced Energetics)

Unconventional rod pumping

Complete, predictable, end-to-end sucker rod control allows successful rod pumping in challenging unconventional and deviated modern wells.

***Jonathan Martin**, Black Mamba Rod Lift*

Bending moments at traditional legacy guides leads to sucker rod failure. (Source: Black Mamba Rod Lift)

Technological advancements to produce hydrocarbon fluids from the reservoir to the surface has generally been most prevalent in directional drilling. As wells come online, their IP is typically supported by electric submersible pumps or gas-lift technologies, which are relatively unaffected by wellbore geometry. As production rates decline, wells are converted to reciprocating rod lift, understood as the most economical form of producing fluids. Modern, unconventional, directional deviated and horizontal wells bring challenges to industry. The drilling department's decision-making most often does not have the flexibility to consider lifelong production complications due to wellbore path and design. High deviation, doglegs or changes in direction lead to an increase in failure frequency when on reciprocating rod lift. It is imperative for sucker rod pumping to remain economical and reliable in modern wellbores.

A new manufacturing process led by product design has been commercialized for sucker rod pumping. Material science is paramount to the utilization of this new technology. Black Mamba Rod Lift's sucker rod stabilizer is marketed as end-to-end sucker rod control for well operators. The Black Mamba, an overmolded helical centralizer, is available for use with traditional steel sucker rods and is rapidly finding its way through the marketplace.

Traditional deviated vertical wells feature doglegs and troublesome geometry farther down the wellbore. These areas are commonly addressed with consumable plastic 4-fin sucker rod guides or centralizers. The guides and centralizers prevent steel-on-steel wear between the rodstring and production tubing.

Deep unconventional horizontal wells are drilled efficiently by using multiwell pads; this drilling practice causes significant deviation, translating to high side loads when designing for reciprocating rod lift applications. The axial load on the rodstring is greater farther up the rodstring (rod weight plus fluid load). When the rodstring makes contact with the tubing, this axial load is transferred by way of side forces causing rod-on-tubing wear. High side loads lead to holes-in-tubing and sucker rod parts, failures commonly observed throughout industry.

Producing sand issues

Fracking is utilized to increase the hydrocarbon inflow to the producing well. Sand is used and pumped into the formation in an effort to crack and hold the Earth open on a microscopic scale, allowing and providing an increase in

(Source: BalLi8Tic/Shutterstock.com)

Black Mamba provides complete, predictable rod control and protection. (Source: Black Mamba Rod Lift)

the fluid flow to the wellbore. A side effect of this technological advancement is the introduction of sand with the hydrocarbon fluids, which must be produced. Producing sand causes its own issues in reciprocating rod lift. The sand acts as an abrasive to the downhole pump, sometimes seizing the pump, as it can find its way between the downhole pump plunger and barrel.

In this case, operators may opt for a "high-clearance" pump, which allows the solids to pass and be produced. With increased clearances, downhole pump efficiency is reduced. To counter this, operators will set the surface pumping unit to operate at an increased rate. An increase in acceleration and velocity of the rodstring then exacerbates all potential issues of compression, side load and tagging, which leads to an increase in failure rates as the system is cycling more often at higher velocity and with higher kinetic energy in a given amount of time.

Other issues

Other reciprocating rod lift issues exist that can lead to premature sucker rod failure. Pump tagging (fully stroking the pump-in) sends significant compressive stress and loads through the rodstring at every pumping cycle. Other nature-induced complications in the rod lift system that negatively affect the sucker rodstring include fluid pounding, gas pounding, slug flow and intermittent stuck pumps, among others. Instances of compression are impossible to avoid and undeniably present within the system.

In all instances of the above, sucker rod flex, compression and/or buckling cause drastic increases in stress along the sucker rod, sometimes far greater than peak tensile stresses predictive software computes during the upstroke when fluid is lifted.

Compression can cause buckling or instability in the sucker rodstring, creating high stresses found at rigid areas along the sucker rod body. These high stresses create micro-fractures in the surface of the steel rod that propagate and lead to a guaranteed eventual rod part.

For a slick, unguided sucker rod, bending moments and micro-fractures occur at the transition point from the forged upset down to the primary sucker rod body diameter. For guided sucker rods, bending moments and common rod failure locations occur at the edges of sucker rod guides where the rod is held rigid and centered in the tubing.

A drastic increase in sucker rod life can occur if these instances of compression are controlled and accommodated. Compression is not necessarily problematic when sucker rod instability is alleviated, preventing the bending moments and high-tensile stresses during compression instances.

Specs of the centralizer

The Black Mamba provides constant centralization and reinforcement of the sucker rod over an extended length. The plastic centralizer features a single-fin design, helically wrapping around the sucker rod up to 36 inches in length.

When compression occurs, the rod is held co-axially in alignment with the production tubing. Bending moments are eliminated as the sucker rod can flex and move, yet the rod is still centralized when in the rodstring is operating as intended in tension. If compression exceeds the critical buckling load of The Black Mamba two per, three per or four guides per rod configuration, it is best to utilize Black Mamba Rod Lift's fully guided sucker rod molded as seven guides per rod. The engineering and reinforcement of the rod and centralizer assembly increases the sucker rod's critical buckling load (the peak compressive load before instability, e.g., buckling occurs) beyond what is possible in a rodstring design. Peak compressive load potential is mostly equal to the weight of the rodstring above the sucker rod in question.

Case study

This year multiple operators in the Permian Basin have installed The Black Mamba in modern horizontal wells of which rod pumping with prior practices and rod guides have been problematic. With this technology, sucker rodstring dynamics are ideal; complete axial compliance exists between the sucker rod and tubing. Optimizing the rod design and controlling the string from top to bottom provides minimal noise in load cell readings and downhole dynamometer card generation. Surface and downhole testing have validated the success of the seven per guided sucker rod, ideal for areas of known negative loading.

Operators can pump the curve with confidence, setting the downhole pump beyond the kickoff point allowing greater pump fillage and reduced pump-off time. Utilized as a replacement for traditional legacy sucker rod guides, The Black Mamba can be substituted for traditional guided sucker rods and eliminate the need for heavy sinker bars and costly stabilizer bars, providing superior sucker rodstring protection and control at a reduced cost. +

"With Black Mamba Rod Lift, operators and engineers know exactly what their rodstring is doing, every stroke."

–Jonathan Martin, President and COO with Black Mamba Rod Lift

(Source: Marc Morrison/marcmorrison.com)

Addressing obsolescence in control systems

Efforts to extend the life of oil and gas production assets may make it necessary to consider upgrading obsolete controls infrastructure.

***Ryan M. Primeaux**, W-Industries*

It is common for offshore oil and gas facility control systems to operate reliably for many years without major intervention. This is not surprising since reliability and availability are fundamental requirements in control system design. This high level of reliability is a desirable characteristic of these systems in the offshore environment since they support the oil and gas production processes and the essential self-supporting utilities and services of the asset.

However, a very robust control system that provides years of reliable service can bring about an associated lack of attention to the control system infrastructure that can lead to a hidden issue: unrecognized obsolescence. In this case, when an obsolete component finally does fail, it can be challenging to find replacement parts or repair services. It also can be difficult to find technicians with experience in older hardware or software platforms to service these systems. This may present a significant risk to production and unexpected interruptions in essential utilities and services.

While some organizations implement obsolescence management programs with proactive strategies for mitigating obsolescence, many others do not and only discover the magnitude of these risks when an issue, such as a failed component, arises. In some cases, the risks associated with these obsolete systems, along with facility life extensions and forecasted production levels over that time, can lead some operators to consider a complete control system overhaul to a modern, fully supported control system.

The risks associated with these obsolete systems can lead some operators to consider a complete control system overhaul to a modern, fully supported control system.

There are significant challenges with upgrading the control system of an actively operating offshore oil and gas production facility. Some of the common challenges are

- Lack of accurate and complete detailed documentation of the existing infrastructure;
- Maintaining essential utilities and services during installation and commissioning (e.g., power, water, emergency response systems, hull bilge, ballast controls and fire protection services);
- Minimizing production downtime associated with cutover and commissioning activities; and
- Design constraints due to limits on existing space, power, etc.

The approach

Understanding the complete scope of obsolescence and the resultant upgrade is a critical first step. Discovery activities are performed, which include a combination of reviewing existing system documentation and site surveys for verification and to close any information gaps. With these data, upgrade concepts are developed to address each area of obsolescence.

Some manufacturers offer hardware conversion systems to facilitate easier migration from some of their older hardware platforms to modern ones. These conversion systems keep all existing I/O wiring terminations intact, eliminating the need for time-consuming wiring verifications. However, there can be challenges with these conversion systems. Existing panels and cabinets may not have enough space to accommodate the increased space requirements of the conversion system hardware, making it necessary to develop alternative solutions. Hardware conversion systems are not available for all hardware platforms. In this case, I/O wiring terminations must be reestablished to the new hardware.

This might also be a good time to consider incorporating advanced technologies and features that may be advantageous to production efficiency. If the facility has significant remaining life expectancy and possible expansions, implementing newer object-based elements in the control system can provide a solid platform for simplified system maintenance and future expansion.

Detailed planning is required to ensure that the cutover and commissioning activities are completed as efficiently as possible to minimize the downtime associated with the upgrade. Individual work plans are developed for each panel or cabinet where work is required, and cutover tasks are divided into two categories: those that can be completed prior to a production shutdown and those that must be completed once production has been safely stopped.

All hardware components are staged and configured, and hardware tests are performed to verify appropriate functionality. The process control and safety system programming is installed on the staged hardware and a full software verification is completed to ensure compliance with all governing documentation.

Upgrading process control

W-Industries recently had the opportunity to execute an upgrade of the process control and safety systems on the Ram Powell tension-leg platform in the Gulf of Mexico. The facility had been recently purchased from Shell by Talos Energy and included an obsolete Allen Bradley PLC-5 based process control and safety system. The control system obsolescence issues were identified by Talos Energy prior to the acquisition of the asset, and the company made plans to proceed with the execution of an upgrade shortly after taking ownership.

Front-end engineering began with the analysis of all available information and a resulting survey of the facility to close all information gaps. Armed with this information, W-Industries developed two different upgrade concepts. The first concept was an upgrade "in-kind" option, which included upgrading to modern hardware and supported software and provided only the functionality included in the existing system. The second concept incorporated additional functionality and enhancements, such as redundancy in communications, software and hardware redundancy, additional controls via a central control room, onsite historian, and programming enhancements that take advantage of available features in the modern control system platform. When presented with these two options, Talos Energy considered the expected longevity of the asset and chose to take advantage of the upgrade opportunity to implement the additional functionality and enhancements, which should increase uptime and provide a more robust system to accommodate future expansion.

During detailed design, numerous challenges were encountered. An original equipment manufacturer conversion

W-Industries' new hardware is staged prior to shipment to the asset for installation. (Source: W-Industries)

system was used to migrate from the obsolete Allen Bradley 1771 series I/O to the modern 1756 ControlLogix platform. This system provides a significant benefit by allowing field wiring terminations to remain in place on existing swing arms, eliminating the risk of wiring errors and reducing cutover time. However, the larger space requirements of the conversion kits made modifications necessary to accommodate them in existing cabinets due to space limitations.

The existing control system also included several Allen Bradley 1791 series Block I/O modules throughout the facility. This type of I/O has no swing arm, which made it necessary to reestablish all I/O field wiring. The distributed nature of these modules and number of panels in which they were located presented a challenge in minimizing cutover time. To combat this, W-Industries designed centralized panels housing the new 1756 I/O. These panels were pre-installed with cabling installed between these panels and each panel with Block I/O. This reduced the cutover work scope to the removal of the wiring between 1791 I/O and the field terminal blocks in each panel and terminating the preinstalled wiring to the new centralized panels. This eliminated the need to physically remove old modules, install new modules and reestablish power and communications in each panel during the cutover.

Device level ring networks were designed for all I/O communications as a replacement of the existing data highway networks. Device level ring offers a huge performance improvement over Data Highway and also provides media redundancy.

Ethernet communications networks were designed in accordance with the ANSI/ISA 62443 standard, following all network segmentation and separation rules. As an enhancement to the existing system, the HMI system infrastructure was designed with redundancy to protect against hardware failures. The design features triple redundant hardware in which the load is distributed across all physical host machines under normal conditions, with each physical host capable of assuming 100% of the load if required.

Full hardware and software testing and verification was completed onshore prior to shipment. All hardware was staged and the complete system mockup was used to facilitate testing. This provided a high level of confidence that the system would perform as expected when installed on the facility.

In the end, the new facility control system was cutover and commissioned in conjunction with other work scope that required a production shut-in during a 14-day turnaround. This compressed time frame was made possible using design elements that allow work to be done prior to the facility shut-in, minimization of activity required during cutover, and detailed planning and work instructions for use by the installation personnel to streamline their activities.

In 14 days, the Ram Powell facility was upgraded from an obsolete process safety and control system that exposed Talos Energy to significant downtime risks to a control system with modern technologies and features that provide advanced diagnostic information aimed at increasing facility production uptime and will also make facility additions or expansions much easier in the future. +

(Source: Shutterstock.com)

Cloud-based safety platform enhances worker protection

A new digital technology delivers real-time notifications for improved worker safety and productivity.

Mary Holcomb, Associate Editor

The oil and gas industry's safety culture will always be an area worth improving, no matter the market or a company's financial standing. For many, an automated safety management solution is essential to meeting compliance requirements.

Honeywell has been at the forefront of developing applications that maintain compliance and recently added its cloud-based Safety Suite Real Time platform to its portfolio. The software application monitors workers' exposure to gas, weather and physiological conditions in real time, according to Chris Tipton, Honeywell's senior director of global services and connected safety.

The open platform provides a comprehensive view of safety data from multiple sites in real time, which enhances worker readiness while reducing incidents through early detection notifications. The insights from the technology help operators reduce compliance costs, streamline management tasks and capture data to review to prevent future incidents, Tipton said.

"Every customer is a little bit unique, but they all invest a significant amount of time in day-to-day management of safety products and instruments."

–Chris Tipton, Honeywell

"When we created Safety Suite, it was built upon our safety history and the evolving requirements of our customers," he said. "We created differentiating features and capabilities to help the safety managers know and report what safety compliance measures are being applied. Additionally, Safety Suite enables our customers to react immediately to situations if there is an incident and take action."

During a recent interview with E&P Plus, Tipton discussed the company's latest safety platform and shared his insights on measures critical to the continued protection of oil and gas workers.

E&P Plus: How does Safety Suite work, and what is the process for adopting and integrating the technology into a company's business model?

Tipton: Our Safety Suite solution has multiple applications that come together in an integrated platform. We provide a suite of different features, customizable views and tailored reports to help our customers manage their safety outcomes. We provide APIs that integrate the safety data into a company's overall safety management processes.

We want our customers to have a single dashboard right at their fingertips that provides real-time information and awareness related to their workers' safety and environment. Safety Suite is always monitoring the environment and assessing the threats that could impact a worker's safety. For example, our geofencing feature is very popular. Users can set a perimeter and notify supervisors if a worker is entering a restricted area without proper authorization, either via email or SMS text message.

The first step for adopting and integrating our solutions starts with assessing the company's safety goals and understanding where there could be opportunities for productivity.

E&P Plus: What sets the Safety Suite apart from similar products offered in the market?

Tipton: We have designed the product from the ground up, which allows it to easily scale from a small installation to a robust enterprise solution to meet the ever-changing needs of today's businesses. In addition, the same solution can either be made available as a cloud offering or deployed on-premise depending on a customer's preference.

The software has been built as an open extensible platform that allows customers the option to not only work with our products but extend the solution out with third-party data integration, which provides a complete solution that automates and monitors worker safety.

The user interface also sets the product apart. We designed it to be simple and intuitive based on many customer inputs in terms of how they use the tool.

E&P Plus: How does the system improve efficiencies for companies, and what kind of results can a user anticipate?

Tipton: Every customer is a little bit unique, but they all invest a significant amount of time in day-to-day management of safety products and instruments. We help automate these tasks to drive productivity, enabling our customers to focus on safety versus mundane administrative tasks.

Secondly, managing safety in real time drives instantaneous response and the ability to react. Users can feel comfortable in knowing that the instruments, the connectivity and the software that we provide will help keep the workers safe.

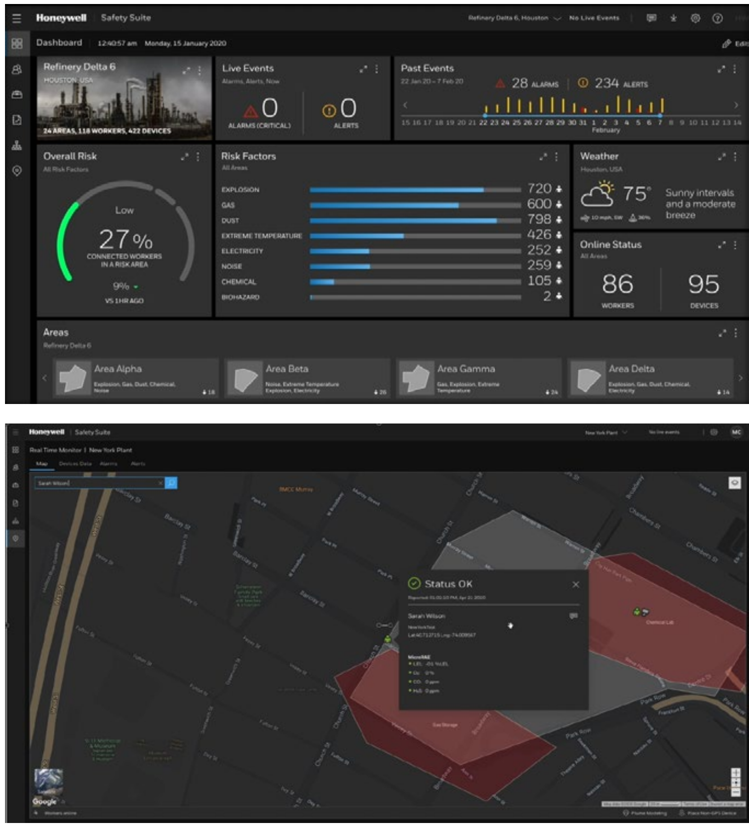
Lastly, using the data management and reporting capabilities of the Safety Suite, managers can assess incident reports and historical data to unearth opportunities for improving safety, productivity and compliance.

E&P Plus: Where do you see the most opportunity for this system?

Tipton: In the oil and gas [industry], upstream and downstream operations provide good opportunities. Our traditional upstream, midstream and downstream customers are very interested in managing their fleet of instruments, the associated reporting and ensuring the products and instruments are functioning properly.

We also allow customers to define geo-fences or areas around their plant to provide additional monitoring capabilities supporting their operational environments, which allows them to better visualize and monitor the activities at the plant.

Another area of interest is monitoring any leak through plume modeling. This capability allows the customer to model the leak based on weather conditions and preempt possible exposure paths. This is really helpful in working to ensure the workers and community is safe.



This dashboard view (top) and map view (bottom) display the Safety Suite Real Time software for industrial operations. (Source: Honeywell)

E&P Plus: Moving forward, does Honeywell have plans to build on the technology, possibly add applications or processes?

Tipton: Today, the platform utilizes instrument data and layers it with geolocation data. But when I think about the future, I look at all parts of the ecosystem facilitating connected safety.

For example, the PPE [personal protective equipment] that is worn is becoming smarter and digitalized. We already have made advances in hearing conservation that protects the worker in higher sound areas, and we're integrating that data into the platform. We have a lot of relationships with other safety equipment providers, and we're working with them to provide a central hub for safety, which I think is very exciting.

When we listen to our customers and understand a little bit more about the problems they would like to solve, we're able to take a very extensible and adaptive platform and expand it to meet their needs. I'm very bullish about advances in the industrial IoT [Internet of Things] as well as the application of artificial intelligence and advanced analytics to reshape the dynamics of managing worker safety. That's an area where we will see an explosive growth, and we can't really conceive all the different applications that will be available, but it'll be exciting to be a part of it. +

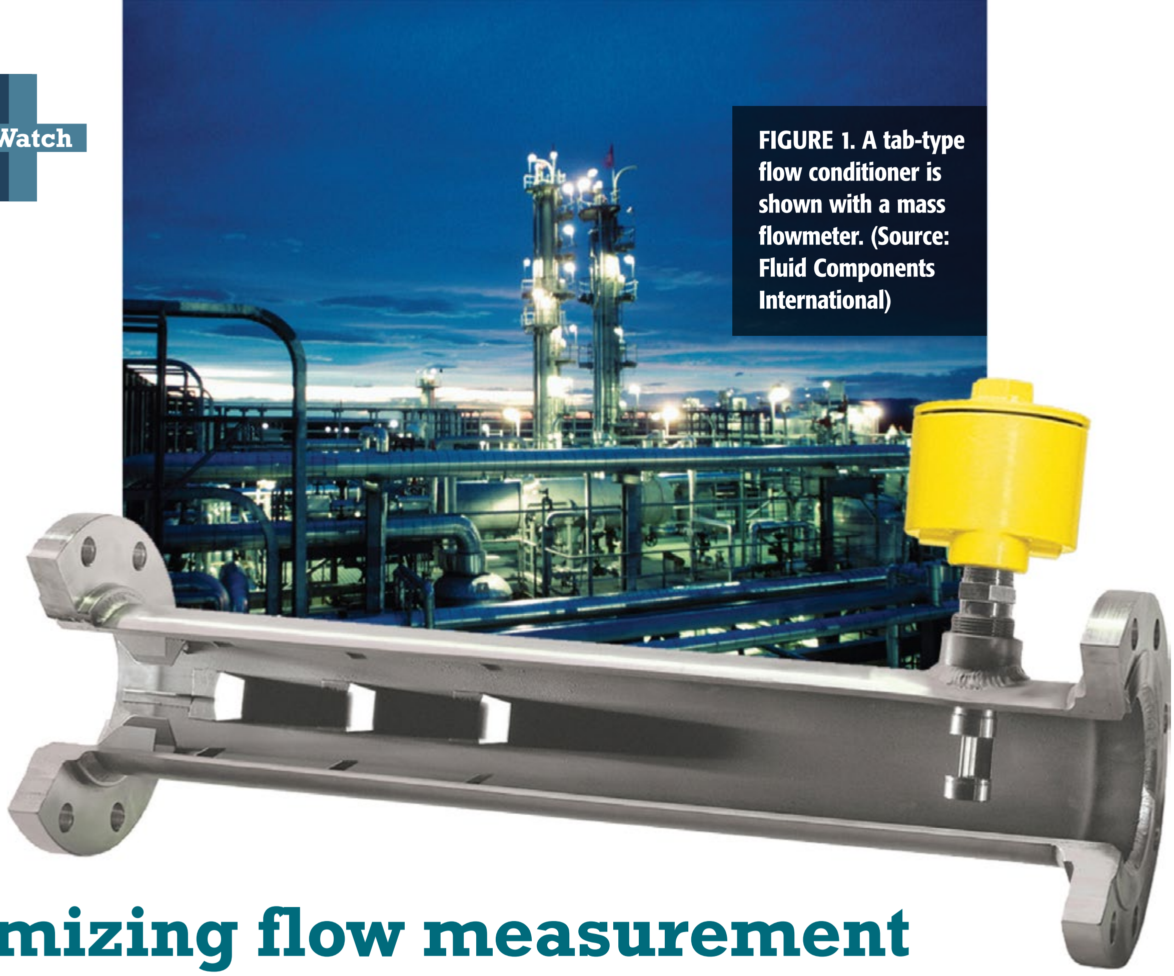


FIGURE 1. A tab-type flow conditioner is shown with a mass flowmeter. (Source: Fluid Components International)

Optimizing flow measurement accuracy to reduce costs

Smart flow conditioning projects pay for themselves.

Don Lundberg, Fluid Components International

Plant projects that optimize flow measurement accuracy can result in significant cost savings while offering quality improvements and even a competitive advantage. The accurate measurement of gases, steam, liquids and slurries is critically important in oil and gas production, pipelines, refineries and many other types of petrochemical plants.

Unfortunately, the measurement of flow is often an afterthought–especially in many plant expansions, equipment upgrades and retrofit projects. The selection and placement of flow switches and flowmeters requires careful advance thought. Choosing the wrong flow sensing technology for an application or placing the flow instrument in the wrong location too closely to pumps or valves can eliminate potential cost savings and it frequently results in unnecessary replacement or relocation projects.

Careful planning for new or upgrade flow instrumentation in a company's process, however, offers many advantages:

- Reduced initial instrument installation costs and faster startup;
- Lower energy costs to run burners, boilers, fans or ovens;
- More efficient consumption of process gases, such as chlorine or nitrogen;
- Lowering the consumption of process water and wastewater; and
- Less frequent plant maintenance and equipment replacement.

The problems

In a perfect world, every plant would have an instrumentation engineer on staff who is familiar with all the different flow technologies on the market, has experience applying them in multiple processes or industries, enough budget to buy the best equipment and a great maintenance team to do the installation.

The best and most effective ways to optimize the plant's flow instrumentation can be summed up with four broad guidelines:

1. Be sure to select the appropriate flow sensing technology for the process media;
2. Think ahead, in advance about the installation and maintenance requirements;
3. Don't forget to consider the impact of other equipment near flow instrumentation; and
4. Anticipate the need for a flow conditioner or flow straightener to ensure accuracy.

Technologies for flow measurement

The first consideration when choosing a flow sensing technology should always be the process media to be measured: air, gas, steam, liquid or slurries. There is no "one size fits all," meaning all flow sensing technologies perform best in one or two media, such as gas or liquids. For example, some sensor technologies will measure slurries—and some won't at all.

The industry's major flow sensing technologies available include coriolis (mass), differential pressure, electromagnetic, positive displacement, thermal (mass), turbine, ultrasonic, variable area and vortex shedding.

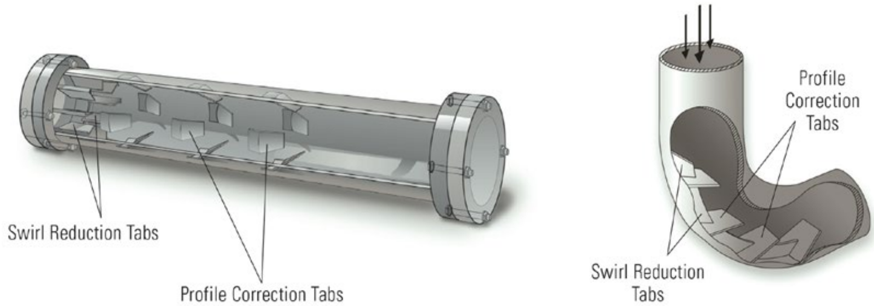


FIGURE 2. Pipe straight-run and elbow tab-type conditioners are displayed. (Source: Fluid Components International)

Potential installation problems

One of the most common issues when installing flow instruments, especially flowmeters, is an inadequate straight run upstream and downstream from the instrument. In advance of making any hard decisions about a particular flowmeter, consult the manufacturer's specification to determine the necessary straight pipe run. Failure to do so often results in a "do not pass go" situation and not achieving a "first-time right" solution.

Nearby piping elbows, expansions or reductions, and/or or spiral piping in close proximity to flow and other instrumentation often further exacerbates the problem of inadequate straight runs. High-density equipment layouts without enough space and poor piping layouts all work together to alter the process media's tangential, radial and axial velocity vectors. The final result is flow disturbances, including swirl, jetting and velocity profile distortions.

When flow disturbances are created in pipelines, there is a high probability of a significant impact on the performance of flowmeters, pumps and other equipment. For example, with flowmeters, the irregular flow of process material adversely affects the accuracy and repeatability of many of the most popular flow sensing technologies: differential pressure, turbine, magnetic, thermal, ultrasonic and vortex shedding. Depending on the flow sensing technology, the straight pipe run requirements for flowmeters varies from 10 to 20 or more diameters.

The answers

To reduce the impact of swirl and other flow disturbances in the pipe on flow measurement accuracy, one of the simplest and most effective solutions is the use of flow conditioners. With the addition of a flow conditioner in the process stream, it is often possible to increase the accuracy and/or repeatability of a flow instrument by 50% or more.

Thermal mass flowmeters with the addition of a flow conditioner, for example, can be optimized to perform at ±1% accuracy instead of their standard ±2% accuracy. That type of accuracy improvement can lead to large savings in controlling expensive natural gas fed burners for plant boilers over a year's period of time.

There are many different kinds of flow conditioner technologies:

- Perforated plates are often chosen for use in natural gas pipelines or other clean gases and liquid applications. They are simple to install and require no spool piece, but they can be prone to clogging in dirty gas.
- Tab-type conditioners perform well in clean or dirty gases and liquids because of the tapered design of their tabs. They provide excellent cross-mixing to remove swirl and correct velocity profiles with minimal pressure-drop.
- Honeycomb vane-type conditioners are frequently selected in HVAC or compressed air handling system applications where they provide air flow profile corrections. A wide variety of different designs and materials are available.
- Tube bundles and vanes have been used for decades. Tube bundles are effective at removing swirl but have the tendency to freeze the velocity profile; therefore, they are not as efficient at isolating and correcting flow distortion anomalies.

All of these technologies have their advantages and/or disadvantages, depending on the process and plant. Thinking about the process media, the plant's equipment, environmental or other regulations, and maintenance schedules, a company will be able to narrow the field to one or two best choices.

In general, that the more effective flow conditioners are at correcting flow profile distortions, the more pressure drop they can produce. When the goal is to lower power consumption or pumping costs or

FIGURE 3. Elbows, like those pictured, can be used at offshore oil pumping stations. (Source: Fluid Components International)

FIGURE 4. This elbow is shown with an insertion panel tab conditioner to pump connection. (Source: Fluid Components International)

FIGURE 5. Tab-type conditioners in straight-run, insertion panel and meter-run designs are depicted. (Source: Fluid Components International)

there is a need to speed product throughput, then the company will want to minimize head loss or pressure drop.

When considering the potential impact of pressure drop, for example, one of the flow conditioning technologies that has proven itself effective is the tab-type flow conditioner (Figure 1). In its standard straight tube configuration, the Vortab Flow Conditioner consists of pipe fitted with a short section of swirl reduction tabs combined with three arrays of profile conditioning tabs.

The combined effect of the tab-type conditioner's anti-swirl and profile conditioning tabs creates a repeatable, flat velocity profile at the outlet of the pipe. An elbow flow conditioner also can be configured with the same tab-type flow conditioning technology (Figure 2), where an elbow must be installed to route the piping to support the required equipment layout of the process.

Many hydrocarbon production, refining and pipeline distribution processes require different types of flow instruments that can benefit from the installation of tab-type flow conditioners.

At an offshore oil pumping station, for example, the process engineering team needed to add a pump to increase liquid capacity. Elbows feeding into the pump consisted of a 20-inch inlet and reduced down to a 12-inch section (Figure 3).

The engineer quickly determined there was no room for the pump's required straight run and no way to expand the platform to accommodate the pipe run. By inserting a tab-type elbow conditioner in the elbow itself, the engineer solved the space problem by ensuring a properly conditioned flow entering the pump at a large cost savings and freed real estate for other possible uses.

Similar situations exist in refineries or pipeline pumping stations where pumps and elbows must operate in crowded conditions while the simultaneous need for accurate gas or liquid flow measurement must be accommodated.

At another plant, the engineering team needed to add two identical 14-inch centrifugal pumps to feed water into its main boilers. The pump configuration required that the line size drops from 16 inches at the elbow to 14 inches at the pump inlet. These pumps are powered by 350-hp electric motors.

Upon installing the pumps, it was found that the indoor facility did not have adequate room for an upstream pipe run into the pumps. Note the close proximity of the building's wall in Figure 4. Installing a tab-type flow conditioner in the elbow compensated for the lack of the necessary pipe straight-run and provided an equally distributed flow profile entering the pumps.

Beyond accommodating elbows and pumps, tab-type flow conditioners are also available in other configurations, including straight-pipe runs, insertion panels and meter run configurations (Figure 5). No matter the equipment or instrumentation when space is a problem in maintaining adequate lengths of straight pipe, flow conditioners are a useful solution.

Conclusion

The first-time right selection of the proper flow instrument and its effective installation can be achieved by thorough advanced planning, including the consideration of the process media and installation location. Where appropriate, the addition of flow conditioners can optimize the performance of flow instruments and other equipment such as pumps and valves. +

Editor's note: *Don Lundberg is a senior engineer at Fluid Components International.*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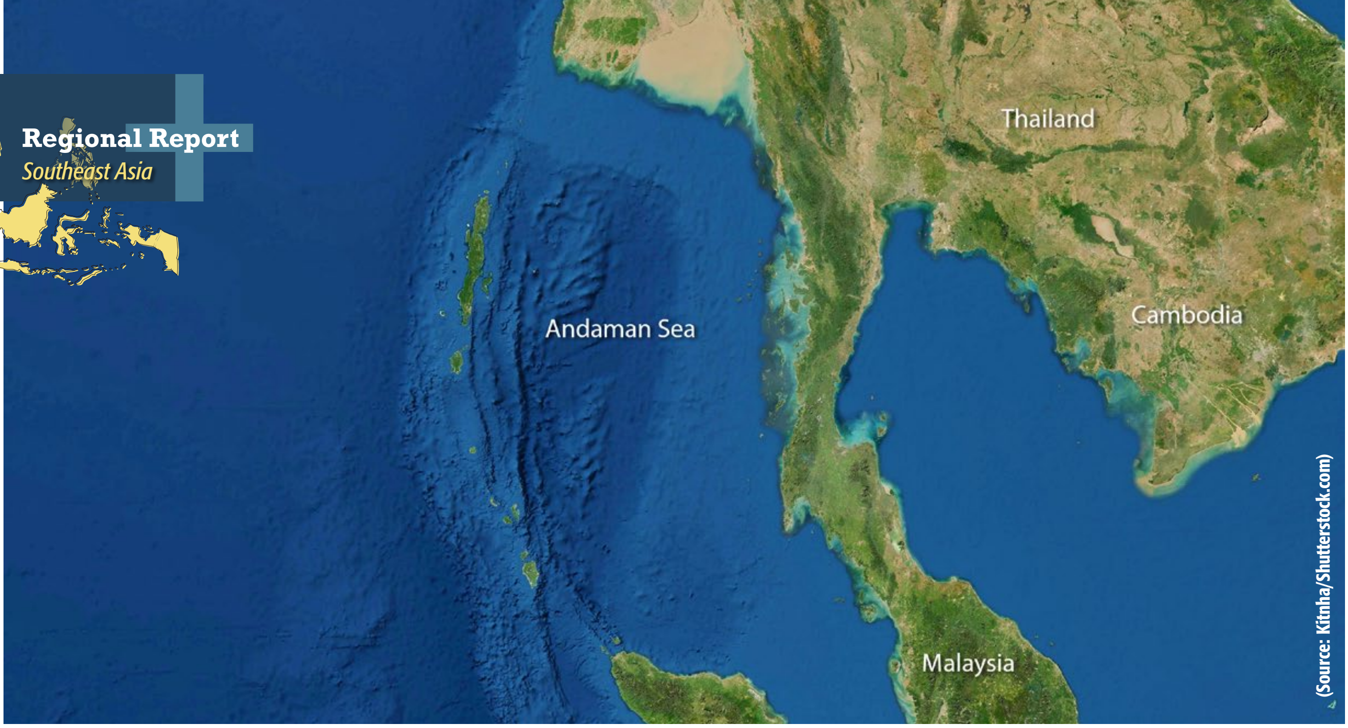


(Source: Kitnha/Shutterstock.com)

Wet gas prospect spurs resource development in Andaman Sea

Development for Southeast Asia looks promising with exploration programs planned for 2021 and 2022.

Larry Prado, Activity Editor

Following an extensive 3D seismic survey and the confirmation of a large wet gas prospect in the southern Andaman Sea, Premier Oil and other major companies are planning to explore the gas and condensate potential.

The recent discovery in the sea by Premier Oil is near a mothballed LNG train at the onshore Arun facility on the island of Sumatra, Indonesia, in the Andaman II Block.

The large wet gas prospect has an estimated prospective resource of approximately 6 Tcf of gas and 200 MMbbl of condensate in each of the Andaman blocks. Field development and exploratory drilling is planned in 2022 for both prospects. The Andaman II license is located in the underexplored but proven offshore North Sumatra Basin, and exploration drilling is planned in the Andaman II and South Andaman blocks.

The primary focus will be on two Andaman II prospects, Timpan and Sangar, which underpin a proposed field development. An FPSO vessel would receive the feedstock, and the gas would be piped to the onshore Arun facility, which is within 320 km to the south.

In early 2020, Mubadala Petroleum completed the farm-out of a 20% participating interest in each of the Andaman I and South Andaman gross split production-sharing contracts to Premier Oil. With participating interests in these three adjacent blocks, Mubadala is the largest net acreage holder in the area, securing the core of the underexplored but proven North Sumatra Basin offshore Aceh for future exploration.

According to a 2019 Premier Oil corporate presentation, its expanded position in the South Andaman Sea gas play has low upfront costs, but at that point, they had no well commitments.

CEO Tony Durrant said, "We have completed a 3D survey with encouraging initial results. The prospectivity on 2D seismic was confirmed with further upside identified. We are also planning a two-well program targeted for 2021 in Andaman II and South Andaman."

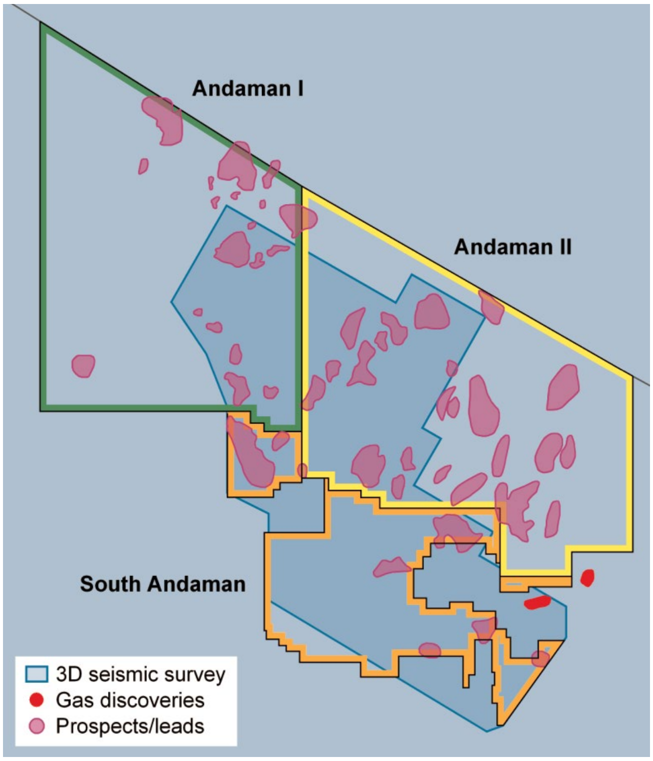
About the Andaman Sea

The original Andaman Sea oil and gas exploration began with surveying and mapping in 1959 by Oil and Natural Gas Corp. Ltd. (ONGC). Geophysical surveys in the offshore areas of the Andaman-Nicobar Basin were started by ONGC in 1977 with 24-fold common depth point seismic reflection in 1977.

Seismic surveying began in the 1990s east and south of the sea, and 2D and 3D surveying helped detail the Neogene prospects identified earlier and in mapping of additional prospects within the Pre-Neogene section.

According to GEO ExPro, the Andaman Sea Basin is still considered "frontier" for hydrocarbon exploration, as only 13 exploration wells have been drilled in the project area. A few wells were drilled in the 1980s, followed by a second phase of drilling from 1984 to 1987. All of the wells targeted the shallow-water part of the fore-arc basin, and most of them were close to the Andaman Islands. Of these wells, the first to be drilled (AN-01-1) discovered gas in Miocene Limestone, which flowed on-tes,t and another well (AN-32-1) encountered gas shows.

The Andaman Sea Basin extends approximately 1,250 km from Myanmar to Sumatra and was formed by the oblique converging plate boundaries of the Indian Oceanic and Southeast Asia tectonic plates, which was initiated in the early Cretaceous and has continued to the present day. The effects of the easterly subduction of the Indian Ocean Plate beneath the Southeast Asia



Premier Oil's 3D seismic surveys revealed gas discoveries and other prospects and leads in the Andaman Sea. (Source: Premier Oil)

plate created a classic island arc system with the formation of six discreet geotectonic units, which include (from west to east through the Andaman area) the foredeep (Andaman Trench), inner slope/accretionary prism, island arc/outer structural high, fore-arc basin, volcanic-arc and back-arc basin.

The arc system is interrupted in the Andaman-Nicobar area by a mid-Miocene to present day spreading center. This is opening in a north-north-west to south-south-east direction, and it comprises a series of segments separated by similarly trending transform faults.

The Timpan and Sangar clusters are large four-way, dip-closed structures with strong seismic amplitude change with offset responses, and flat spots shown in the Premier Oil survey conform to structure.

Other exploration

ONGC also is focusing on the unexplored deep waters of the Andaman Nicobar Basin, the Indian frontier zone that lies between hydrocarbon producing fields in south Myanmar and northwest Indonesia. The company will be targeting the Andaman Nicobar deep waters because of the potential for hydrocarbon reserves. Studies indicate the Andaman Nicobar Basin has potential to produce oil and gas like the adjoining basins in south Myanmar and southwest Indonesia, as the geological structures of the three are same.

According to ONGC, the Andaman Nicobar Basin, spread over an area of 47,000 sq km—including deep waters in southeastern part of Bay of Bengal—is part of the Island Arc System that extends from Myanmar in the north to Indonesia in the south. The giant Yadana and Yetagun gas fields in Myanmar are located on the north side of Andaman Basin, while Arun, Kuala Langsa and NSO in North Sumatra Basin (Indonesia) are in the south.

ONGC plans to launch a new exploration campaign to drill as many as 18 wells in six deepwater blocks in the Andaman Basin. The exploration program includes drilling three exploratory wells in each of the six blocks that are located in water depths between 9,170 ft and 11,221 ft on the east and west sides of Andaman and Nicobar islands.

ONGC has submitted a proposal to India's federal environment ministry to drill each of the 18 wells in six blocks to a depth about 19,685 ft.

The first four are located in water depths of 2,875 m to 2,980 m on the west of the Andaman Islands. The remaining two are in water depths of 2,320 m to 3,420 m.

The geophysical and 2D seismic surveys by ONGC in the deepwater blocks have shown the presence of hydrocarbons and the prospects for large hydrocarbon reserves, similar to the ones in the neighboring oil and gas fields in Myanmar and Indonesia.

Malaysia

Several major upstream and downstream oil and natural gas projects have been commissioned in Malaysia during the past few years as part of the country's strategy to enhance output from existing oil and natural gas fields.

In the offshore Malaysia portion in the Mottama Gulf, PTT Exploration and Production has found commercially proven gas reserves in Block M9 in the Zawtika prospect. According to the company, well 4-Zawtika successfully proved commercial hydrocarbon reserves with about 500 ft of net gas sands, more than the expected 134 ft.

Myanmar

The state-run Myanmar Oil and Gas Enterprise signed agreements for gas production with partners including MPRL E&P Co., Woodside Energy and Total.

The agreements cover production at offshore gas block A-6, which is west of the Ayeyarwady region and has good prospects for commercial production, according to MPRL E&P Co.

The Block A6 Region joint venture, which includes partners Total, Woodside Petroleum and MPRL E&P, will be Myanmar's first ultradeepwater natural gas field project. It is also the only new gas development to be started under the country's administration.

The field is estimated to contain 2 Tcf to 3 Tcf of gas, with a projected daily output of 400 MMscf, which is approximately 20% of Myanmar's existing daily output.

Although not expected to come onstream until 2024—an optimistic forecast according to some analysts—the project is expected to bolster national energy supplies and provide needed state revenues in a country known for having one of the lowest tax takes worldwide.✚

Editor's note: *This story was completed prior to Chrysaor's purchase of Premier Oil in early October.*

New data analytics technologies

With the upstream industry navigating challenges due to remote operations, low oil prices and demand destruction, these new technologies, trends and collaborations in the area of data analytics will help companies increase efficiency and optimize operations.

New data analytics platform offers subsurface data insights

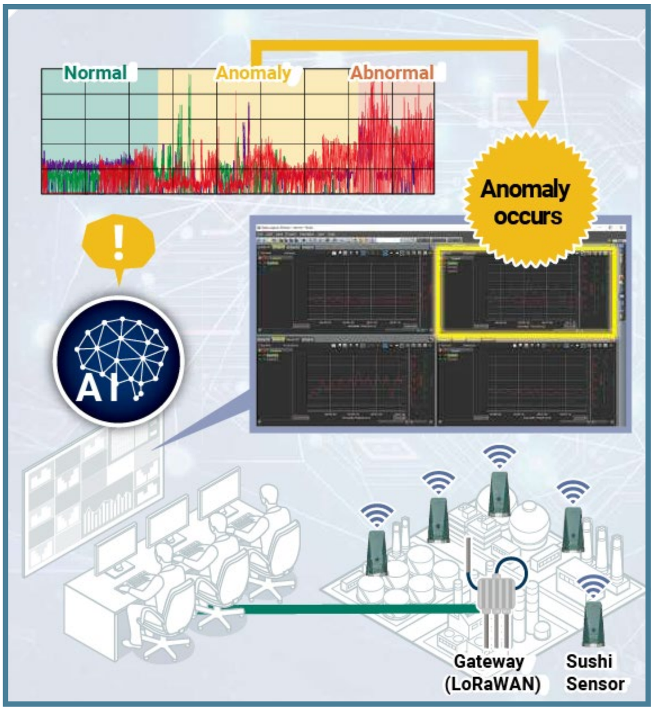
Katalyst Data Management has released its Katalyst 360 data analytics platform, which provides a 360-degree view of how subsurface data assets are being utilized within an organization. Katalyst 360 greatly expands the utility of Katalyst's data management solutions, giving oil and gas companies the ability to gain greater insight into their valuable subsurface data assets. The platform features analytics dashboards that are synchronized to an oil and gas company's subsurface data. The platform comes with ready-to-use dashboards that display multiple attributes such as project status, data completeness and process efficiency. Users also have the ability to easily create and customize their own dashboards for analytics specific to their needs. E&P companies can easily extend their understanding of their data and draw insights from the entirety of their subsurface data investment. The new analytics platform was built for Katalyst Data Management's iGlass multicloud database, which has more than 80 petabytes of subsurface data under management. Subsurface data managed by iGlass feeds the Katalyst 360 analytics environment, and plans are to further enrich the platform with oil and gas operational data, economic and production data as well as public data. The goal of Katalyst 360 is to enable oil and gas companies to use analytics to implement predictive and prescriptive actions.

Companies partner to transform HSE management using AI

Lloyd's Register has partnered with STC Global to use artificial intelligence (AI) to unlock insights from the vast amounts of incident data captured by HSE functions, which is left untapped. Leveraging complementary expertise, the partnership will be beneficial for HSE professionals by integrating natural language processing AI and root cause analysis technologies. As part of the development of its integrated digital HSE program for clients, Lloyd's Register will leverage its AI technology, LR SafetyScanner, that is built to ingest large amounts of data and then cluster them to provide HSE professionals with actionable insights across 24 hazard categories. Similarly, STC Global will apply COMET, a progressive tool in the field of incident investigation and root cause analysis. Some of the key benefits of combining the two technologies will include the ability to capture recurring systemic root causes and commonly occurring root cause clusters; map out hazard hot spots and emerging trends to focus improvement strategies and prevent incidents in the future; and create safer and more profitable work environments. The outputs from the partnership will help HSE professionals to better identify and understand the underlying causes of HSE trends, patterns, systemic problems and latent dangers. By developing a tool that provides a holistic, end-to-end view of past, present and potential incidents, HSE professionals will gain a comprehensive understanding of the key hazards associated with each incident in real time. Once deployed, HSE professionals will be able to gain deep insight into the where and why of safety issues, ensuring each can be addressed more efficiently and effectively.

Digital solution offers improved data-driven maintenance strategies

Yokogawa has released Sushi Sensor, an OpreX asset management and integrity wireless tool with advanced artificial intelligence (AI) analytics via GA10 software that make it ideal for Industrial Internet of Things (IIoT) plant asset management applications. The tool addresses a growing need for efficient and effective online collection of equipment data across industrial facilities via wireless sensors for early equipment failure detection. The Sushi Sensor combined with AI GA10 software transforms a reactive maintenance process to one that is proactive and condition-based. By leveraging wireless technology, the tool reduces costs and logistical challenges for early equipment failure detection



Yokogawa's Sushi Sensor is a wireless device for IIoT that automatically detects and notifies signs of abnormalities in equipment. (Source: Yokogawa)

to deliver enhanced plant safety, reliability and profitability. The Sushi Sensor, with long range wide area network (LoRaWAN) communication technology and advanced analytics from GA10 software, enables the digital transformation of rotating equipment asset management. Approved by testing and standards agency for operation in hazardous areas, the Sushi Sensor is a compact wireless device providing online vibration and surface temperature measurement in machines and process equipment. Via LoRaWAN, the Sushi Sensor efficiently communicates digitized measurements to Yokogawa's advanced AI analytics environment. The tool provides easy installation/setup, environmental resistance and monitoring versatility via on-premise servers or the cloud.

Companies partner to bring natural language processing to software

mCloud Technologies Corp. has entered into a partnership with Aiqudo Inc., leveraging Aiqudo's Q Actions Voice AI platform and Action Kit SDK to bring new voice-enabled interactions to the company's AssetCare solutions for Connected Workers. By combining AssetCare with Aiqudo's powerful Voice to Action platform, mobile field workers will be able to interact with AssetCare solutions through a custom digital assistant using natural language. In the field, industrial asset operators and field technicians will be able to communicate with experts, find documentation and pull up relevant asset data instantly and effortlessly. This will expedite the completion of asset inspections and operator rounds using hands-free, simple and intuitive natural commands via head-mounted smart glasses. Professionals will be able to call up information on demand with a single natural language request, eliminating the need to search using complex queries or special commands.

With Aiqudo nature language processing integrated on smart glasses, mobile field workers can call up information on demand from the mCloud AssetCare platform, expediting the completion of inspections and operator rounds at facilities. (Source: mCloud Technologies Corp.)

Remote subsea inspection technology overcomes challenges

Integrated technology and inspection company, MCS, has released a new system that allows an entire offshore inspection campaign to be delivered remotely. The Remote Inspection System (RIS) utilizes sophisticated data compression and transfer as well as 3D imagery and data capture to move all work completed from an offshore vessel inspection container onshore. The system overcomes travel restrictions and ensures safety of people by allowing work to be completed anywhere, including at home, with live video feeds and clear voice communication. The RIS overcomes potential challenges caused by the pandemic, saves money and allows inspection campaigns to be completed three times faster compared to a traditional offshore team. As the operation can be completed entirely onshore, it allows teams to work only during hours of operation, saving on mobilization and demobilization, transit and weather delays. RIS also offers complete flexibility. Once the system has been set up on a vessel, RIS can be used instantly by the request of the client, even on very short notice.

New tool uses data analytics for tracking measurement of liquids and natural gas

W Energy Software's new oil and gas measurement product line, which is under development and expected to be commercially available by year-end 2021, will track liquids and natural gas measurement data across the energy value chain. WE Measure will provide upstream and midstream companies with essential data management capabilities to monitor gas and liquid measurement data from the wellhead through production, storage, transportation, processing and points of sale. Additionally, the measurement tool will enable companies to warehouse field data in the cloud, validate measurement data, track product quality, and balance gas and liquid volumes. The tool will enable existing clients to integrate measurement data with their W Energy Software solutions and drive new operational and cost efficiencies. WE Measure will provide upstream and midstream companies with a secure data warehouse for centrally managing volume, energy and product quality measurement data in the cloud, integrating large numbers of SCADA data sources and streamlining meter data analysis. The tool also will provide processes and functionality to validate measurement data, provide volume balances, deliver clear audit trails and ensure compliance with energy industry, regulatory and accounting standards. +

Editor's note: *The copy herein is compiled from press releases and product announcements from service companies and does not reflect the opinions of Hart Energy. Submit your company's updates related to new technology products and services to* ***Faiza Rizvi*** *at* ***frizvi@hartenergy.com****.*

1 Alaska

bp recompleted a Prudhoe Bay Field well in Alaska that was originally drilled in 2014 at the #06-22B Prudhoe Bay Unit. The well is in Section 2-10n-14e in Umiat Meridian. It was tested flowing 288 bbl of oil, 27.513 MMcf of gas and 1,051 bbl of water per day with a flowing tubing pressure was 903 psi. Production is from a Ivishak Shale perforated zone at 10,465 ft to 10,870 ft.

2 New Mexico

Oxy USA Inc. completed a Purple Sage Field-Wolfcamp well in Eddy County, N.M., ocated in Section 17-24s-29e. The #037H Salt Flat CC 20-29 Federal Com produced at a daily flow rate of 5,202 bbl of oil, 11.096 cf of gas and 9,516 bbl of water. Drilled to 20,363 ft (9,990 ft true vertical), production is from acidized and fractured perforations at 10,209 ft to 20,185 ft. Tested on a 21/64-inch choke, the shut-in casing pressure was 1,421 psi.

3 North Dakota

Burlington Resources Oil & Gas completed a Middle Bakken well and a Middle Three Forks well at a Dunn County, N.D., drillpad. The pad is in Section 26-147n-97w in Little Knife Field. The #44-36TFH Franklin was drilled to 21,747 ft (11,393 ft true vertical). It initially flowed 230 bbl of 41°API oil, 276,000 cf and 5,717 bbl of water per day after 31-stage fracturing, and production is from Middle Three Forks perforations at 11,705 ft to 21,541 ft. Gauged on a 31/64-inch choke, the flowing tubing pressure was 1,715 psi. The #34-36MBH-2NH Franklin was drilled to 21,835 ft (11,305 ft true vertical) and produced 278 bbl of 30.5°API oil and 504,000 cf of gas per day from Middle Bakken at 11,705 ft to 21,625 ft. It was tested on a 30/64-inch choke with a flowing tubing pressure of 2,488 psi.

4 North Dakota

Two Howard County (RRC Dist. 8), Texas, Spraberry Field wells were announced by Birch Operations Inc. The wells were drilled from a pad in Section 18, Block 33, T&P RR CO Survey, A-1090. The #7LS Traveler 18-30 G was drilled to 18,358 ft (true vertical depth of 7,674 ft). It was tested flowing 533 bbl of 37°API oil, 376,000 cf of gas and 2,284 bbl of water daily from perforated Spraberry zone at 8,052 ft to 18,245 ft. The #7WA Traveler 18-30 G was drilled to 18,844 ft (8,016 ft true vertical). It produced 2,098 bbl of 36.8°API oil, 578,000 cf of gas and 260 bbl of water per day from a perforated Wolfcamp interval at 8,548 ft to 18,790 ft.

5 Texas

IHS Markit reported that Barron Petroleum completed a Val Verde Basin discovery in Val Verde County (RRC Dist. 1), Texas. Based on the results from two wells, the company estimates that the 13,000-acre project holds 417 Bcfe (74.2 MMboe) in oil and gas reserves. Developed with the use of a 3D seismic survey, Barron has identified 67 high-graded Strawn locations on the acre-age and could potentially develop Canyon

at 9,000 ft and Ellenburger at 16,000 ft. The first wildcat, #1 Sahota Carson 20BU, hit approximately 70 ft of gas-bearing Strawn pay. It was fracture-stimulated and flowed up to 5 MMcf/d of gas. It was drilled to 12,650 ft in Section 12, Block C15, R.A. Ashley Survey, A-2575. About one-half mile to the east-southeast in the same section, #3 Sahota Carson 19BU was drilled and cased to 12,890 ft. According to IHS Markit, the well is currently holding for data.

6 Louisiana

GEP Haynesville LLC completed another Haynesville Shale producer in the Bayou San Miguel Field portion of Sabine Parish, La. The #001-Alt Olympia Minerals 26-23HC is in Section 26-9n-12w. It was drilled to 21,088 ft (true vertical depth of 12,763 ft). It flowed 39.845 MMcf of gas and 464 bbl of water per day from a perforated zone at 12,894 ft to 20,875 ft. Tested on a 33/64-inch choke, the flowing casing pressure was 8,438 psi.

7 Gulf of Mexico

In Mississippi Canyon Block 812, Shell Oil Co. completed a Middle Miocene discovery at #0K003S3B OCS G34460 ST03BP00. The well was drilled to 29,739 ft (true vertical depth of 23,343 ft). It flowed 12,478 bbl of 33.5°API oil and 25.725 MMcf of gas per day. Tested on a 36/64-inch coke, the flowing tubing pressure was 9,897 psi, and production is from a perforated zone between 29,218 ft and 29,345 ft.

8 Ohio

An Ascent Resources Utica Shale discovery was tested flowing 32.845 MMcf of gas and 139 bbl of water per day. The Belmont County, Ohio, well, #4H Bannock Unn BL was drilled in Section 6-8n-5w. The Harrisville Consolidated Field completion reached 21,877 ft (9,170 ft true vertical). It was acidized and fractured, and production is from a perforated zone between 9,232 ft and 21,767 ft.

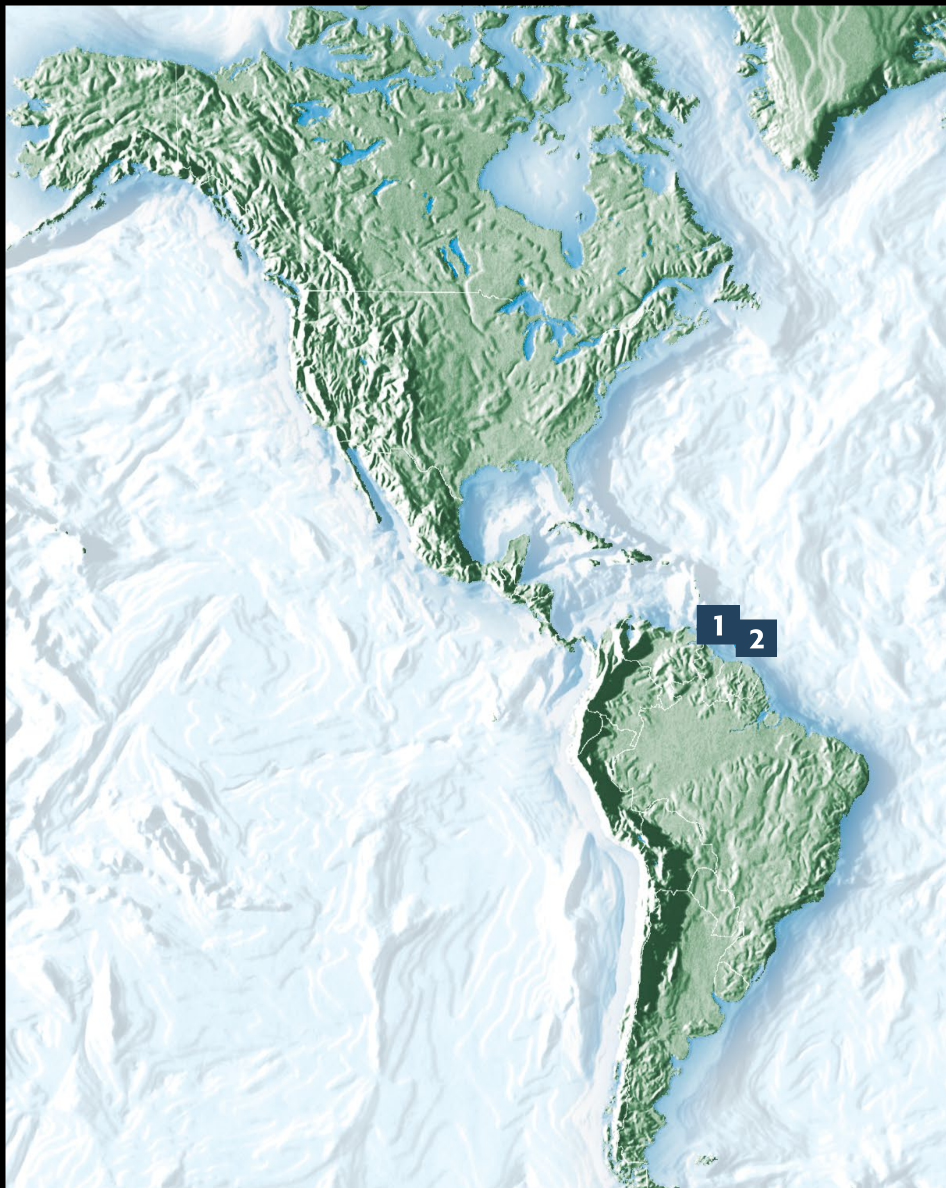
—By Larry Prado, Activity Editor

1 Trinidad

Touchstone Exploration has announced final production test results from the #1ST1-Cascadura well in Trinidad's Ortoire exploration block. Two sections were tested: an upper zone from 5,570 ft to 5,915 ft and a lower zone from 6,056 ft to 6,218 ft. The upper zone (Cruse and Herrera) had an absolute open flow rate of 390 MMcf/d of gas and averaged 5,472 boe/d (86% gas). The lower test (Herrera) flowed 92 MMcf/d with an average of 5,157 boe/d (87% gas). Both tests were limited by the capacity of surface test equipment.

2 Guyana

Exxon Mobil Corp. has mobilized a drillship to drill and perform an exploratory test in offshore Guyana's Kaieteur Block. The venture, #1-Tanager, is targeting prospective resources of 256.2 MMbbl of oil. Current estimates for the site range from 135.6 MMbbl to 451.6 MMbbl of oil. The planned depth is 8,000 m, targeting the stacked Maastrichtian to Turonian reservoir intervals in the southern part of the block. The #1-Tanager is the first well in a potential multiwell drilling campaign being operated by Exxon Mobil on the Kaieteur and Canje Blocks over the next six to 12 months. This campaign will evaluate high-impact, Upper Cretaceous prospects in the Liza play fairway with possible multiple stacked reservoir targets.



3 UK

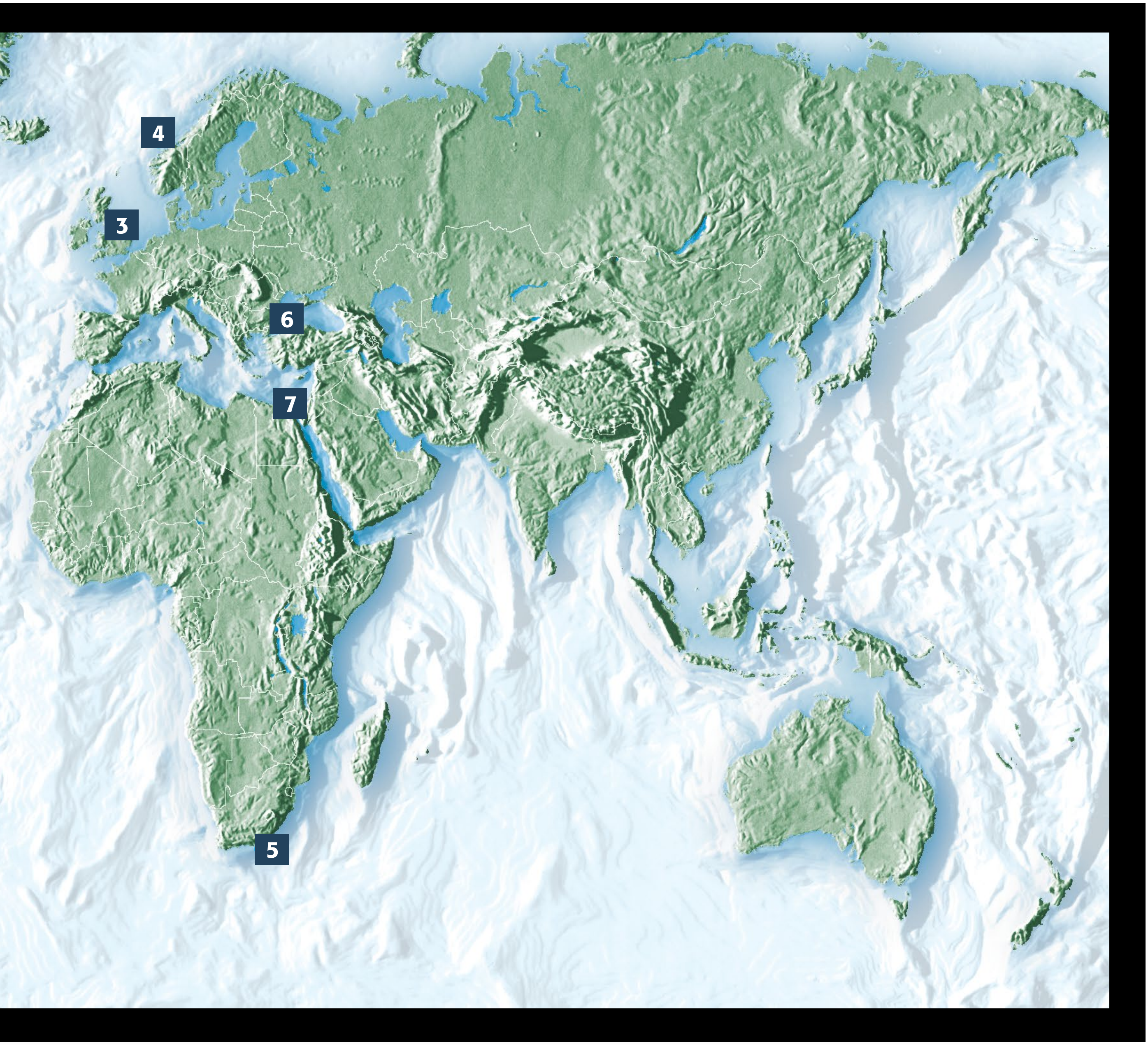
Reabold Resources has spud exploration well at the West Newton B site in East Yorkshire, U.K., in PEDL183. The test is a follow-up to the #2A-West Newton discovery well in 2019. Surface casing at the new site will be set to approximately 80 m into Cretaceous Chalk. The planned depth of the new venture is about 2,000 m. According to the company, West Newton covers 176,000 acres and could represent the largest U.K. onshore oilfield discovery in decades with a significant liquid and gas development opportunity with two hydrocarbon discoveries. The findings will establish productive capability and any future drilling operations.

4 Norway

Neptune Energy has received a drilling permit for wildcat well #6406/12-G-1 H in Norway's PL 586. The well will be drilled after a drillship completes the drilling of observation well #6406/12-H-4 in PL 586. The area in this license consists of part of Block 6406. This is the seventh exploration well to be drilled in this license, and it is about 36 km southwest of Njord Field.

5 South Africa

Total has spud the #1X-Luiperd exploration well in Block 11B/12B offshore South Africa following the Brulpadda discovery. The exploratory well will test the eastern area of the Paddavissie Fairway on Block 11B/12B to follow up on the Brulpadda discovery of gas condensate and light oil. A drillstem test also is planned. Block 11B/12B is located in the Outeniqua Basin and covers an area of about 19,000 sq km. The Paddavissie Fairway is in the southwest area of the block and includes the Brulpadda discovery, which confirmed the petroleum system. The Luiperd prospect is the second to be drilled in a series of five large submarine fan prospects with direct hydrocarbon indicators defined utilizing both 2D and 3D seismic



data. The #1X-Luiperd is being drilled in 1,795 m of water and has a planned depth of 3,550 m subsea. According to Total, the well will test the oil and gas potential in a mid-Cretaceous aged deep marine sequence where fan sandstone systems are developed within combined stratigraphic/structural closure.

6 Turkey

Turkish Petroleum Corp. announced a deepwater gas discovery in the Turkish sector of the Black Sea. Well data and geophysical testing indicate the estimated reserves are 11.3 Tcf of gas. The #1-Tuna was drilled in Sakarya Field in Block AR/TPO/KD/C26-C27-D26-D27. Area water depth is 2,115 m, and the well had a total depth of 4,525 m. It encountered more than 100 m of gas-bearing reservoir in Pliocene and Miocene sands. Turkish Petroleum plans to begin production and connecting the gas to the national grid by 2023.

7 Israel

Eni announced a new gas discovery in the Abu Madi West Development Lease in the waters of the Nile Delta offshore Egypt. The #1-Nidoco NW-1 exploratory well hit 100 m of gas-bearing sands with 50 m in the Pliocene sands of Kafr-El-Sheik and 50 m in the Messinian age sandstone of Abu Madi. Both zones had good petrophysical properties. This is the first time Abu Madi was encountered in Nooros Field, and it extends gas potential to the north of the field. The preliminary evaluation indicates that the Great Nooros Area gas in place is estimated to be more than 4 Tcf. Area water depth is 16 m.

—By Larry Prado, Activity Editor

For additional information on these projects and other global developments, visit the drilling activity database at hartenergy.com/activity-highlights.

PEOPLE

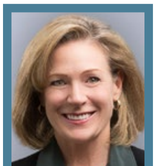
Iraq has appointed its oil minister, **Ishan Ismael**, to lead the Iraq National Oil Co.

TechnipFMC has named **Arnaud Pieton** president and CEO-elect of Technip Energies. **Jonathan Landes** has been appointed president of subsea. Additionally, **Margareth Øvrum** has been appointed to TechnipFMC's board of directors.

Petrofac has announced that its current group CEO, **Ayman Asfari**, will step down at the end of 2020 to focus on his health, family and charity. He will be succeeded by **Sami Iskander**, effective Jan. 1, 2021.

Ring Energy Inc. has named **Paul D. McKinney** CEO and chairman of the board of directors.

Mads Nipper has been appointed CEO and group president of Ørsted, effective Jan. 1, 2021. He will replace **Henrik Poulsen**, who has resigned from his position but will remain in office until Dec. 31, 2020. To support a smooth transition, Poulsen will serve as special adviser to Nipper until Jan. 31, 2021.


Cook


Kirk

Chrysaor has agreed to a reverse takeover of Premier Oil, the firms said Oct. 6, creating the British North Sea's largest oil and gas producer. The deal, which will see Premier's creditors paid $1.23 billion in cash, will fold one of the world's oldest independent producers into a private-equity-backed group. The combined group, which will have a new name, will be run by Harbour CEO **Linda Cook**, while Chrysaor CEO **Phil Kirk** will be head of its European business. Current Premier CEO **Tony Durrant** will not have a role in the group.

Pablo Flores, CEO of Ecuador's state-run oil company Petroecuador, has informed the board of directors of his intention to resign following the South American government's plan to merge Petroecuador with Petroamazonas, another state-owned oil company focusing on upstream crude E&P in the Amazon region.

Tachyus, a provider of data-driven production optimization software to the oil and gas industry, has selected former vice president of customer success, **Fernando Gutierrez,** as CEO.


Dealy


Shah


McDonald

Pioneer Natural Resources Co. has announced the promotions of **Richard ("Rich") P. Dealy** to president and COO and **Neal H. Shah** to senior vice president and CFO, which Pioneer said are part of the Permian Basin shale producer's goal to deliver long-term shareholder value. The changes, effective Jan. 1, 2021, also included the promotion of **Elizabeth ("Beth") A. McDonald** to senior vice president of Permian strategic planning and field development and marketing.

Ted Williams has joined EnCore Permian as partner and COO.

Bristow Group Inc. has appointed **Jennifer Whalen** CFO and senior vice president.

David Schorlemer, CFO of Basic Energy Services Inc., has resigned to pursue other interests. Following Schorlemer's resignation, the board has approved the appointment of **Adam Hurley** to serve as executive vice president, CFO, treasurer and secretary of the company.

Borr Drilling Ltd. has appointed **Christoph Bausch** as its new CFO, replacing **Francis Millet**.


Linden

Westwood Global Energy Group has appointed **David Linden** to the newly created role of head of energy transition. The announcement comes as the company commits to helping the energy industry successfully navigate decarbonization. Linden will be responsible for defining and implementing the company's energy transition offering for the oil and gas, power and renewables sectors.


Reid

J+S Subsea has welcomed **Phil Reid** as its first managing director and **Doug Sedge** to its board as a nonexecutive director.

Marwell, the wellbore and completion specialist, has announced two new senior appointments: **Øystein Eide** and **Petter Rommetvedt**. Joining from Aker BP, Eide will lead the drilling and well construction segment. Joining from Perigon AS, Rommetvedt will head up the completion segment.

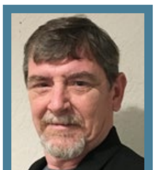

Bonetti

Sparrows Group has appointed **Chris Bonetti** to the newly created position of regional manager for Australia to drive the company's growth in the country. Bonetti will be responsible for furthering the company's diversification into the industrial market. He will also lead the business across the oil and gas and renewables markets in the region.

Gonce

Hill

Danos has added **Justin Gonce** to its business development team as executive account manager for shale operations. Gonce will focus on developing a growth plan for Danos' shale business across multiple service lines. He will support business development efforts in the Permian, Eagle Ford, Marcellus, Bakken and other shale basins across the U.S. Additionally, **Melanie Hill** has been appointed business development representative. She will support Gonce in his areas of focus developing Danos' shale regions.



Gault

Quality Companies has appointed **Iain Gault** business development manager. Based in Houston, Gault will serve to grow the client base in the deepwater and international arenas and introduce an expanded range of the company's services to the energy sector.

Neil Manfred has been named Airswift's IT director.

Mullins

ConocoPhillips has announced that its board of directors has elected **Eric Mullins** to serve as a board member. Mullins currently serves as co-CEO of Lime Rock Resources, a private-equity fund focused on acquiring and developing low-risk oil and gas properties.

Halliburton Labs has announced that its first advisory board members will be **Reginald DesRoches**, **John Grotzinger** and **Walter Isaacson**.

EOG Resources has appointed **Michael T. Kerr** to its board of directors.

COMPANIES

OMV has opened an Innovation & Technology Center in Gänserndorf in Lower Austria.

Siemens USA has launched an advanced microgrid research and demonstration laboratory at its U.S. Corporate Technology headquarters in Princeton, N.J. The living laboratory will validate the latest technologies to provide the market with a comprehensive blueprint of how microgrids can be flexibly operated in similar applications such as universities, office parks and industrial sites while reducing the adverse impacts of energy uncertainty.

Proserv Controls has formally unveiled two new facilities in Mussafah, Abu Dhabi, and Cumbernauld, near Glasgow, Scotland, as it seeks to expand its service support business.

Milestone Environmental Services LLC announced that the New Mexico Oil Conservation Division has approved the company's permit for an oilfield waste slurry injection facility near Jal in Lea County, N.M.

AqualisBraemar has opened its first office in Russia, based in Moscow, to further enhance the group's service offering in the Russian energy, marine and loss adjusting markets.

The Ion has announced Chevron as its first leased occupant. The Ion, formerly the Sears Building in midtown, will anchor the 16-acre Innovation District with the goal to become the epicenter for Houston's innovation ecosystem focusing on quality collaborations among entrepreneurs, incubators, accelerators, corporations and the academic community. It is scheduled to open in 2021.

Stress Engineering Services Inc. has launched its new Digital Solutions Group to reduce energy industry clients' costs and manage risks through digital technologies.

Bristow Group Inc. will rename its Aeróleo Division in Brazil to Bristow and remain focused on its support of the oil and gas industry and other vertical lift solutions.

Devon Energy and **WPX Energy** have entered into an agreement to combine in an all-stock merger of equals transaction. The combined company will be named Devon Energy. The transaction, which is expected to close in the first quarter of 2021, has been unanimously approved by the boards of directors of both companies.

Chevron Corp. completed its acquisition of **Noble Energy Inc**. on Oct. 5.

ConocoPhillips and **Concho Resources** announced on Oct. 19 that they have entered into a definitive agreement to combine companies in an all-stock transaction valued at $9.7 billion. The transaction is expected to close in first-quarter 2021.

NTS Group has acquired **Amega West Services** from **Carpenter Technology Corp**. Amega is a provider of manufacture, repair and rental of legacy and specialized drilling equipment used in offshore and land-based oil and gas extraction applications.

Weir Group Plc has agreed to sell its oil and gas division to U.S. heavy equipment maker **Caterpillar Inc.** for $405 million in cash, as the engineering company focuses on its mining business. The deal is expected to close by the end of the year, and Weir said it

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would help strengthen its balance sheet for future investments.

C-Innovation LLC, an a liate of **Edison Chouest Offshore** and its family of companies, has acquired the controlling interest in **Caltex Oil Tools**, a provider of equipment rentals, services and customized engineering capabilities to the offshore industry.

Abu Dhabi National Oil Co. has announced the launch of **AIQ**, its Artificial Intelligence (AI) joint venture company with **Group 42**, an AI and cloud computing company.

Quorum Software has acquired **Landdox**, an innovator in cloud-first land technology.

Rockwell Automation has acquired **Oylo**, a privately held industrial cybersecurity services provider based in Barcelona, Spain.

LR Energy has entered into a definitive agreement to sell its Energy business unit to **Inspirit Capital**, a London-based investment firm focused on building long-term value.

NTS Group has acquired **Amega West Services**, a provider of manufacture, repair and rental of legacy and specialized drilling equipment used in offshore and land-based oil and gas extraction applications, from **Carpenter Technology Corp.** +

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AD INDEX

A service provider's perspective on the energy transition

A willingness to step outside comfort zones will enable the OFS industry to make meaningful contributions to the energy transition.

Tanya Herwanger, TGS

According to the Energy Progress Report 2020, an annual report that tracks progress on Sustainable Development Goal 7 (SDG7) "Affordable and Clean Energy," 789 million people globally still lack access to electricity, and 2.8 billion people—over one-third of the global population—lack the means to cleanly and safely cook.

Additionally, the U.N. advises that lack of access to energy may hamper efforts to contain COVID-19 across many parts of the world because energy is critical to operating healthcare facilities, providing clean water and enabling communications during times of social distancing. The 2020 report shows some progress toward 2030 targets under SDG7 as well as significant work if society is to achieve universal access to affordable, reliable, sustainable and modern energy.

To date, even the most optimistic energy transition scenarios show that additional oil and gas E&P is required to effectively meet future demand and compensate for the ongoing decline in existing reserves. It is clear that oil and gas will continue to play a role in addressing the world's energy needs alongside renewable sources. Why is this relevant? It is relevant because if we are to reach the goal of universal access to clean energy, then our focus needs to be both to look for and develop renewable alternatives while also decarbonizing the E&P of fossil fuels.

For oilfield services (OFS) companies, particularly those that operate in the exploration phase of the oil and gas value chain, this is central to adapting to the energy transition and ensuring they find their place in this changing landscape.

Emissions reductions in seismic

A needed first step for the seismic industry is setting and implementing a strategy aimed at reducing carbon emissions associated with seismic operations. We would all greatly benefit from a holistic strategy and standard for analyzing the climate impact from seismic operations, as this will lead to better planning and better decision-making. This will, in turn, reduce associated carbon footprints.

Agreeing on a carbon strategy and defining a standard for seismic operations will require collaboration from all stakeholders: acquisition companies, equipment manufacturers, ancillary service providers and seismic data consumers like TGS and oil companies. To achieve this, we need buy-in from the industry and value chain to effectively absorb the increased investments that may be a byproduct of decarbonization within the industry. This latter point remains to be tested.

In TGS' 2019 Corporate Sustainability Report, the company reported carbon emissions from seismic operations on a project-by-project basis as well as by survey type (e.g., by separating 2D versus 3D versus ocean-bottom node versus multibeam and coring versus land acquisition and operations).

A more complete carbon analysis of seismic operations should include the ancillary activities related to, for example, crew changes as well as other elements like survey design, equipment age and technology. The inclusion of these factors is necessary to provide a more complete emissions analysis and to understand the carbon footprint. This will improve survey planning, benchmarking and decision-making. This is how we will ultimately drive change in our industry toward decarbonization.

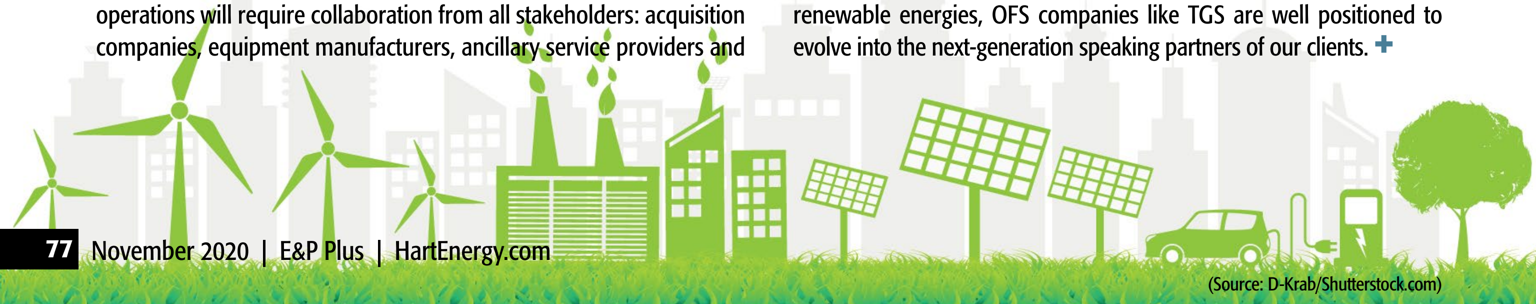
"Enhance, reuse, recycle"

"Repair, reuse, recycle" has long been used colloquially to define the circular economy. TGS has tweaked this to be "enhance, reuse, recycle." Businesses need to embrace this mentality and look for opportunities in all aspects of business in which to apply it sensibly.

We lose sight of the role the oil and gas industry can and will play in a low-carbon world and in providing clean energy access across the globe. If companies fail to enthuse existing and future employees, they will lose the talent, passion and energy needed to achieve the sustainable world we all want for ourselves and future generations.

Alongside efforts to decarbonize ongoing exploration activity, it is important to look for opportunities in renewable sources of energy.

A willingness to step outside comfort zones grounded by our strengths and experience will enable OFS companies to make meaningful contributions to the energy transition. By focusing both on what we can do directly to decarbonize E&P and looking for opportunities to support renewable energies, OFS companies like TGS are well positioned to evolve into the next-generation speaking partners of our clients. +



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