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### COMING NEXT MONTH

The December edition of *E&P* will be our special 2019 unconventional yearbook issue. Chapters will include an overview, key players, technology, logistics, environmental concerns and economics. As always, while you’re waiting for your next copy of *E&P*, be sure to visit [EPmag.com](http://EPmag.com) for the latest news, industry updates and unique industry analysis.
Chesapeake reports results from three Haynesville producers in Caspiana Field
Chesapeake Operating Inc. completed three horizontal Haynesville Shale wells from a pad in the Caspiana Field. The pad is in Section 28-15n-15w in Caddo Parish, La. IHS Markit reported that #1-Alt Johnson 28&33-15-15HC flowed about 954 Bcm/d (34 MMcf/d) of gas from fracture-treated perforations at 3,693 m to 5,976 m (12,116 ft to 19,605 ft).

Appraisal well in Tortue Field encounters 30-m (98-ft) hydrocarbon-bearing reservoir
Panoro Energy ASA completed appraisal well DTM-3 in offshore Gabon’s Tortue Field in the Dussafu License. The well was designed to appraise the western flank of Tortue Field in an attempt to extend hydrocarbon resources within Gamba and Dentale.

First extended-reach producer completed in the Frontier Formation of North Park Basin
The first extended-reach horizontal producer in the Frontier Formation of Colorado’s North Park Basin was completed by SandRidge Exploration and Production. The Castle 0780 6-17H20 well is in Section 9-7n-80w of Jackson County, Colo.

Could US shale operators dig up more cash?
By Velda Addison, Senior Editor, Digital News Group
U.S. shale operators have become more efficient, but there is still room for improvement, an energy consulting firm said.

Expert offers climate strategies for oil-producing countries
By Velda Addison, Senior Editor, Digital News Group
A global push to reduce emissions has set the world on a path toward less carbon intense forms of energy, but oil-producing countries can pursue various strategies.

New natural gas world emerges
By Alexa West, Assistant Editor
Tom Petrie with Petrie Partners discussed the emerging role of the U.S. in the world natural gas market at DUG Eagle Ford.

Real-time ‘meat thermometer’ monitoring cooks better wells
By Steve Toon, Editor-in-Chief, Oil and Gas Investor
At DUG Eagle Ford, MicroSeismic’s CEO Peter Duncan revealed the unprecedented impact microseismic technology is having on well monitoring.
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Shaped Cutter Technology
Brave new world, indeed

Ensuring the wildcatter spirit lives on in the next generation requires an ‘all of the above’ approach.

The year was 1843 when English mathematician and writer Augusta Ada King, Countess of Lovelace, aka Ada Lovelace, imagined the modern day, general-purpose computer that could be programmed to follow instructions. While the design of this computer or “analytical engine” was the brainchild of Charles Babbage, it was her code that would have made it possible to calculate the seventh Bernoulli number if the engine had been built. Disagreements between Babbage, his financiers and his chief engineer ensured the engine never made it off the drawing board. Lovelace, however, believed that the engine—once built—could go beyond calculating numbers to understand symbols and more.

“This insight would become the core concept of the digital age,” Walter Isaacson wrote in his book “The Innovators.” “Any piece of content, data or information—music, text, pictures, numbers, symbols, sounds, video—could be expressed in digital form and manipulated by machines.”

What would Lovelace, the woman considered to be the world’s first computer programmer, think of today’s Siri or Alexa? Would she pitch a fit over the Fitbit counting her every step or toss the ubiquitous iPhone out the window from the table of every boardroom and family dinner?

Yes, 175 years later, Babbage’s analytical engine has morphed into a palm-sized digital assistant capable of taking dictation while providing directions to the nearest coffee house offering free Wi-Fi with its lattes, all powered by highly advanced computer programs rooted deep in fertile soil of Lovelace’s code.

What would early day wildcatters think of today’s oil and gas industry, with its gussied up christmas trees bristling with every conceivable sensor communicating its status wirelessly to an operations center hundreds of miles away? Or of the fully automated drilling rig capable of doping, loading and connecting its own drillpipe?

The world has changed mightily in the 159 years since Col. Edwin Drake drilled the oil well that ushered in the first of many booms. To survive future busts, today’s businesses are harnessing the power of digital and all that it encompasses.

Sara Ortwein, president of XTO Energy, explained it best during her Chairperson’s Luncheon keynote at the 2018 SPE Annual Technical Conference and Exhibition, stating, “Companies that win will take modern technologies beyond mere computing capabilities to create an entire digital ecosystem, one that encompasses a digital culture and digitally savvy employees. So, are you ready to be a part of that transformation? I know I am. It’s a brave new world, and I can’t wait to see what it brings.”
Finding ‘spare’ change
Digital tools provide new life for aging offshore assets.

Martin Grant, SNC-Lavalin

The rising digital tide in the oil and gas industry is lifting many boats. Perhaps one of the most important, complex and yet least glamorous beneficiaries of this digital advance is the growing fleet of aging offshore assets. For these existing facilities, digital techniques are providing managers and engineers with increasingly economical and effective tools for maximizing capital efficiency and lowering operating costs.

In a mature industry where most operators face an increasing number of aging assets in their portfolio, creating greater capital efficiency is a priority. The overarching question is, “What can be done to keep the facility running safely as long as needed while spending as little as possible?”

The need for answers is critical. When the facility has reached the end of its life, the reservoir may become a stranded asset and its productive life is over. While there is ultimately a time for decommissioning, maximizing reservoir recovery often depends on extending facility life for as long as it is needed.

Engineering and digital tools
Many things affect this calculation of capital efficiency, cost and return on investment. However, much of it comes back to basic engineering principles regarding fatigue, corrosion and other causes of failure. Managing the asset to keep it running efficiently and effectively is a process of understanding how the failures occur and how to detect and prevent them.

For these aging assets, the opportunity presented by the digital revolution is the ability to merge huge volumes of data with experience-based engineering wisdom. Digital tools are the enablers in this complementary union.

Digital tools take many forms. In some applications, they immerse engineering teams in 3-D virtual realities; other applications launch intricately crafted algorithms to search through massive databases for trends and anomalies. Each tool is the product of a growing ability to understand and apply intelligence and visualization to data.

As with any other tool, using digital tools begins with defining the task; it is up to digital technology to justify its inclusion in any plan. This process quickly becomes a discussion about how operational wisdom supported by digital techniques helps an operator move forward.

Managing the spares inventory
Merging digital techniques with experience-based wisdom yields practical, innovative solutions. A good example is the challenge of managing the spare parts inventory, or “spares,” for complex facilities. Every oil and gas installation has a spares to hedge against downtime caused by procurement delays.

After years of high energy prices, operators might be holding up to 50% more spares than required; a large operator might now hold more than $3 billion worth of spares. The art in managing this inventory is working out what parts to hold to keep operational risks within acceptable levels. It can go one of two ways: if too little is spent, then the things needed are missing, or spend money on things that are not used. In practice, operators often get it wrong in both areas. Ultimately, it can be very expensive as the cost of parts, maintenance and storage adds up.

The inventory and operational data for analysis already exist but in unwieldy volumes. Conventionally, examining slow-moving inventory enables a judgment on whether the right spares are in the warehouse. This effort is limited by the challenge of aligning an opera-
tional rationale with the many thousands of individual components that make up an offshore installation.

However, the enormous amount of data is well suited to a digitally enabled solution. Data analytics provides a way to reduce waste by cleansing inventory data of unsuitable spares and by stocking the correct spares in the required condition.

The digital tool, in this case, involves using sophisticated algorithms to search through the data and spot trends, patterns and anomalies. The resulting analysis provides experts with a powerful way to investigate and rationalize the spares holding. When used to inform future analyses, the data also contribute to a predictive capability.

The results of the spares management process are typically pretty significant. An inventory optimization program for one operator identified potential savings of $179 million from a $214 million operational spares inventory in one basin alone. That included opex savings from less warehouse storage and lower labor costs and reduced capex spending on the unnecessary stock.

The $179 million revealed by the statistical analysis was realized through $79 million of unsuitable spares and $100 million of excess stock. To date, the client has confirmed savings of more than $50 million.

The potential $79 million savings in unsuitable spares involved identifying incorrect data, such as spares, without equipment asset tags and parts for decommissioned equipment. Rationalizing the spares inventory for low-criticality equipment identified nearly $17 million in potential savings.

Excess stock savings was determined using statistical analysis to identify maximum and minimum stock levels based on the acceptable risk of a stock outage, spares lead times and consumption rates. Reducing excess stock realized an abundance of both large and small savings. For example, 110 membranes for an inert gas package were held in stock at a value of $360,000, when, in fact, the maximum recommended quantity was 64 membranes—a savings of $200,000. Slow-moving stock held longer than five years, such as thousands of spares.
of O-rings and circuit breakers, accounted for an impressive $30 million in potential savings.

**Brownfield visualization through a digital twin**

Another type of digital tool enhances the engineering and delivery of brownfield projects through engineering visualization. A virtual 3-D representation of the structure is particularly important to aging assets, where maintenance and modifications take place in an existing facility. However, the asset’s age means many of these structures do not have a digital twin, and if they do, it is out of date or unsuitable.

For these existing facilities, digital scanning, digital twinning and immersive visualization technologies are key to both capturing and understanding the data. Digital scanning uses laser technology to produce an accurate record of the current facility. With new technology, the scanning process might only take a couple of days. Once captured, the data are used to create a 3-D version or digital twin. The linked data provide a visual asset information model that supports virtual and augmented realities.

With existing assets, where modifications are constrained by the structure, a digital twin provides engineers with a powerful tool for virtual planning and implementing construction and modification. In a virtual environment, the ongoing design is informed by a virtual reality construction. Allowing engineers to explore design options digitally by virtually walking around the installation enhances the construction effort and minimizes facility downtime. The 3-D model also facilitates training for the planned modification, improving safety and performance. All this takes place onshore, further reducing costs and improving safety.

For one offshore oil and gas normally unmanned installation (NUI), a brownfield digital twin was produced to enable remote assessment and simulation of constructability and installation in preparation for major works. This significantly reduced the manning requirements, which are in the order of about $20,000 per trip in logistics alone.

**Left, the spares management process identifies savings at multiple levels using analytics generated by using algorithms to search through the huge volumes of data to spot trends, patterns and anomalies. (Source: SNC-Lavalin)**

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**Have a story idea for Industry Pulse? This feature looks at big-picture trends that are likely to affect the upstream oil and gas industry. Submit story ideas to Group Managing Editor Jo Ann Davy at jdavy@hartenergy.com.**
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Sweet success in the Eagle Ford

With a premium position in what it believes to be the sweetest of the Eagle Ford’s sweet spots, ConocoPhillips has found the winning combination with science, experimentation and optimal well placement.

For ConocoPhillips, the Eagle Ford is the company’s first horizontal shale play in its history, holding approximately 210,000 net acres primarily in DeWitt, Karnes and Live Oak counties. The shale play has “some areas with extremely good rock with extremely good reservoir quality, areas where you can get the production that has a cost supply down in the $20 per barrel range,” Leveille said.

“Our primary mission as an oil and gas operator is to acquire acreage in those areas with the very best rock,” he said. “We did a fairly good job of doing this in that our 200,000 acres are located mostly in the best part of the Karnes and DeWitt county sweet spots.”

The good position, paired with ConocoPhillips’ “relentless focus on lowering cost of supply,” led the company to secure the top spot among Eagle Ford operators. For ConocoPhillips, it is $25/bbl as compared to the $30/bbl-plus cost of supply for other area operators, according to Leveille’s presentation.

Along with an optimal pace of development, four technologies have been key to the company’s success in keeping the costs of supply low for its fields. The company’s “Drilling Execution Efficiency Platform” and the use of digital acoustic sensing to optimize completions are two of the four. The remaining two go far in demonstrating the scientific and experimental approaches that are delivering returns for the company.

Understanding the Eagle Ford’s hydraulic fracturing characteristics is key. ConocoPhillips drilled and fractured a development well and then acquired a core from that fractured reservoir to accomplish this, according to Leveille. The company acquired core imaging logs from several wells, and from a review of all, a new picture emerged.

“We were able to ascertain what hydraulic fractures actually look like, and it turns out they look almost nothing like what the mathematical models that predict fracture geometries suggest they should look like,” he said. “With this information, we were able to rapidly evolve our completion time.”

Understanding the vertical draining within an Eagle Ford well through geochemical sampling of the oil also is key.

“You’d like to know how high your fractures are reaching so that you can understand how many layers of wells you should put into the reservoir,” he said. “This criteria...
allows us to understand the drainage from the reservoir over time very precisely and then optimize placement of wells into that reservoir.”

By understanding and using all of these key technologies, the company has consistently improved upon its well completion designs that are, in turn, delivering increases in per well output and recovery, he noted. For example, in 2012 the company’s Vintage 1 design pumped 3.8 MMlb of proppant downhole at 750 lb/ft with a 21-m (70-ft) cluster spacing, which evolved into the Vintage 4 design in 2017 with significantly more proppant used.

The impact of these adjustments is visible through the enormous improvements in production rates for the company. “If you went back to 2012, in about three years’ time, you’d produce around a third of a million barrels of oil equivalent,” Leveille said. “Today, in less than a year we’re producing that same volume, and the ultimate recovery from these wells has also gone up significantly. We’re working on a Vintage 5 completion right now, which we think has the possibility of giving us another uplift from where we are.”

Understanding the complexity in the geology of the Eagle Ford is yet another key in unlocking the full potential of the resource play. For example, understanding how the organic matter concentration changes within the reservoir and where the best rocks are located factor greatly into the optimization of the well placement and in the optimization of production, he said.

“We’ve been able to determine with a high degree of accuracy the vertical drainage, and from that, we were able to understand how many wells are needed in the different areas,” Leveille said.

Assisting in the development of that understanding is the company’s approach to data analytics and how it is applying it to understand complex problems in ways that were difficult to do in the past. “At ConocoPhillips, we see data analytics as a tool that every one of our employees is going to use to be more productive,” he said. “We do not see this as something that is necessarily replacing humans; it supplements a human’s capabilities as they can get more work done in a much shorter period.”

“For example, if you went back just a few years, it took us over 20 days to go from spud to spud on a well in the Eagle Ford. Today it is now around 12 days, and a huge part of that improvement is the use of data analytics to understand how to optimize every single operation involved in the drilling of an Eagle Ford well.”

The company is using data analytics in essentially all of its operations around the world, Leveille noted, adding that in all of those operating areas—from Alaska, the North Sea or in the Asia-Pacific—the use of data analytics is having as big of an impact as it is in unconventional reservoirs.

“Ours is an industry drilling tens of thousands of wells per year,” he said. “From those wells, we’re extracting enormous amounts of data that can then be analyzed. Those data, along with modern analytics tools, are enabling us to gain insights that would be very difficult to gain with the tools of the past. So today is a very exciting time.”

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About those frack hits

The debate continues over well interference as the industry moves toward full field development.

Richard Mason, Chief Technical Director

The best thing to be said about frack hits is the phenomenon provides an interpretive framework for everyone and every scenario.

Attent enough meetings, read enough papers and it is apparent that frack hits have no long-term effect on production; have a negative production impact and cannibalize reserves, creating uneven reservoir drainage; or, counter-intuitively, produce a positive production outcome.

It is evident the industry remains in the dark about the issue. It is hard to find two accounts from the same basin that even agree on the percentage of frack hits as the industry moves to infill drilling—let alone how best to approach the issue.

Some operators claim success avoiding the phenomenon via preloading and represuring while others argue such impacts are illusory and amount to robbing Peter to pay Paul. There is agreement on the causes, which include slickwater-associated greater proppant loading, tighter spacing (both between laterals and between stages in a single lateral), higher fluid volumes and an emphasis on near-term production maximization, or net present value.

The frack hit debate continued at this year’s SPE Annual Technical Conference and Exhibition in Dallas. E&P companies have experimented with a variety of approaches over the last half decade ranging from fracture and flow, small parent well preloads, higher rate water parent well preloads and refractures.

Consultant Ali Daneshy argued for a more precise definition of well interference to incorporate same well or intrawell versus offset or interwell interferences. One redistributes production between stages and generates patchy reservoir production while the other reroutes production between wells.

Substituting the term “well interference” for “frack hits” or “well bashing” opens the phenomenon to characterization that has definable attributes and therefore becomes eligible for engineered solutions. Attributes can range from simple pressure increases in offset wells to fluid and/or proppant communication to, in extreme cases, damaged downhole completion or production equipment.

In the Eagle Ford, one defense mechanism is spacing with well interference more common in laterals less than 122 m (400 ft) apart. That said, well interference, in one instance, was observed as far away as 610 m (2,000 ft). Go figure.

And that is exactly what the industry is doing. Techniques include far field diversion, which is achieved by multimodal particulate diversion in a pill comprising mixed sized proppant. The pill controls fracture length at the extreme and confines the stimulation field. The pill is pumped before increasing proppant and fluid volumes. Large particles build bridging near the fracture tip while medium- and small-sized proppant pack the tip to create a mechanically strong, low permeability barrier, creating a pressure dip on the far side. Far field diversion pills reduced frack hits in the Eagle Ford Shale from 64% on 233 stages in 11 wells to 16%, according to a team from Schlumberger.

Daneshy suggested shortening fracture length by reducing fluid volume and increasing spacing, employing cemented liners for better well control, and drilling and cementing adjacent laterals before stimulation via zipper fracture or simultaneous operations and placing wells on production.

BHP Billiton preloads the parent well and pursues a parallel development infill program, spending less upfront capital and generating payout more quickly in the Eagle Ford’s Karnes Trough and in the Permian Basin. Parent wells experienced a 25% increase in production over time versus control wells after infill fractures in parallel completion versus a 40% production decline in parent wells using other methods.

The irony? BHP Billiton is selling its U.S. acreage.
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During its long and storied past, the U.S. Gulf of Mexico (GoM) has more than once been referred to as “the Dead Sea.” Explorers looked for riches, exploited those riches and then moved on, assuming there was nothing left to find.

Time and technology have proven them wrong, of course. But the latest fantastic finds (e.g., Jack/St. Malo, etc.) have been in ultradeep waters and will cost billions of dollars to produce. Granted, there are riches to be found on the Mexico side of the border, recently opened after the energy reform in 2013. But those will take years to develop.

Exxon Mobil, for instance, is looking into selling many of its assets, according to a recent Reuters article. It and many of its counterparts are looking to divest their GoM assets in favor of more underexplored offshore areas as well as the North American shale plays, the article stated.

According to Reuters, Exxon Mobil is considering selling assets in the GoM that produce about 50,000 bbl/d, and it has stakes in assets that produce more than 200,000 bbl/d and 21 MMcm/d (730 MMcf/d).

Ten years ago I would have said this is all cyclical. The GoM comes and goes. For a while it’s the hot territory, and then its luster fades as companies discover troves of oil offshore West Africa or rediscover new regions of the North Sea. Then it thunders back to prominence.

But the Shale Gale has changed that mindset, as have new discoveries in previously unattainable offshore provinces. Take Guyana, for instance. Exxon Mobil recently announced its ninth discovery there. Maria Cortez, Latin American upstream senior research manager for Wood Mackenzie, recently said in a press release, “Guyana is set to create the greatest value of any offshore basin since the downturn. Exxon Mobil’s latest discovery, Hammerhead, is another play-opener and adds to more than 4 Bboe of reserves through an exploration program with a success rate that now stands at 82%.”

The company still has 18 prospects on the Stabroek Block, Cortez noted, and this has created a leasing trend in the region. She noted, however, that it is not without its issues. “This is high-risk exploration, and there are development challenges that range from building the required infrastructure to ensuring good natural resource governance,” she said. Additionally, the government will need to develop the institutional and regulatory framework to manage the emerging sector as well as set up a sovereign wealth fund.

Guyana was an exploration risk for Exxon Mobil, to be sure. At last year’s European Association of Geoscientists and Engineers conference, Erik Oswald, vice president of exploration for that company, noted that a good story could have gotten derailed by a bad well. The company was chasing two prospects at the time, and luckily it drilled the Liza prospect first. The second prospect, Skipjack, turned out to be dry, and if the company had drilled that one first, it probably would have abandoned the region.

So what about stalwart provinces like the GoM and the North Sea? Chevron is selling its North Sea holdings off of the British coast, according to Reuters, and Exxon Mobil has sold 29 leases or stakes in leases to other companies in the GoM since 2014.

Is the GoM a dead sea again? Time will tell. But I think there will be a resurgence.
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- Real-time interactive ability
- Rich preprocessing functions
I will admit to being a little bit puzzled and more than intrigued upon hearing the news over the summer that Diamond Offshore Drilling had launched its Blockchain Drilling Service. Until that point in time, blockchain had, in my mind, equaled cryptocurrency trading, and that conjured up visions of a person decked out in their jammies and fuzzy bunny slippers sitting behind their laptop screen mining for bitcoins while dreaming of their bit-riches.

Was Diamond Offshore adding bit mining to its portfolio of services, I pondered. The answer is no, but what the company did do by embracing digital technologies was add the ability for its clients to reduce their total cost of ownership.

So what is blockchain, and how does it apply to making hole?

Matt Higginson of McKinsey & Co. in a Digital McKinsey podcast described blockchain as a database or “distributed ledger” shared across a number of network participants, and at any moment in time, each member of that network simultaneously holds an identical copy of that blockchain database on their computer.

Speaking at the 2018 IADC Advanced Rig Technology Conference & Exhibition, William Fox, chief product officer for Data Gumbo Corp., explained that blockchain enables all parties in a transaction to have one version of the truth in the distributed ledger. Sitting on top of those ledgers are “smart contracts” that automatically execute the terms of a contract without human intervention, Fox noted.

“Automating execution of contracts eliminates accounting expenses, time delays, inaccuracies, legal fees, mistrust and disputes. At the same time, it increases audibility and profitability,” he said in his presentation. “It aligns incentives of all participants within the drilling industry toward a common goal.”

One example he hears quite often is how long it can take to see payment of a field ticket for services. “So the work is performed, but it takes the guy seven or eight days to input the paper ticket into the system that will be scanned and emailed to somebody for checking,” he said. “Then it goes into an ERP [enterprise resource planning] system where there is an authorization order and multiple sign-offs before the ticket is ever approved for payment.”

Blockchains and smart contracts can help speed up that process as certain aspects of the payment process can be automated if all parties to the contract agree.

“When a transaction is placed on a blockchain system, it’s fully transparent and fully auditable,” he said. “Our approach is that if there’s going to be a payment that is triggered by a field ticket, everything that backs that transaction up to trigger a payment goes on the blockchain so that all parties retain a copy that doesn’t get lost in the shuffle.”

Data Gumbo and Diamond Offshore developed the Blockchain Drilling Service. The scalable cloud-based service consists of five modules to drive efficiencies and eliminate waste, including supply chain and logistics management, well planning, spend monitoring, tracking of real-time bottlenecks and a performance tracking system that monitors operational key performance indicators, according to a press release.

According to a press release, the platform will be used in the procurement stage through the construction, completion and production phases. Tracking, planning and optimizing the well(s) through each phase provides the ability to reduce spend, eliminate waste, improve processes and better align all parties needed to deliver a well successfully. The service will be implemented fleetwide on Diamond Offshore drilling rigs, creating the industry’s first Blockchain Ready Rig fleet.
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Evaluating the future of the artificial lift market

Companies are taking innovative approaches to traditional systems.

Oil and gas wells needed artificial lift long before the market crashed in 2014 and still needed them afterward. Like other sectors of the industry though, the artificial lift market took a hit. A report issued this year by Westwood Energy stated that worldwide expenditures for artificial lift fell from nearly $16 billion in 2014 to about $9 billion in 2016—a 43% drop.

However, similar to others, the artificial lift market has rebounded and is expected to grow.

Westwood reports $1 billion in growth from the low of 2016 to this year and predicts 6% market growth through 2020 for artificial lift demand.

A report issued last year by McKinsey Energy Insights claimed at the time the challenge for the artificial lift market was the commoditization of its products.

“No recent technological advances have created differentiation within the market for the most popular lift methods,” wrote Dimitar Kostadinov and Brandon Stackhouse in an August 2017 McKinsey report. “This has encouraged operators to select equipment and services based primarily on price, prompting service companies to focus on developing low-cost offerings and placing sustained pricing pressure on the market.”

Oil and gas companies have been keen to such a challenge. At the recent Society of Petroleum Engineers Artificial Lift Conference and Exhibition in The Woodlands, Texas, several companies, either through technical papers or product exhibitions, provided examples of advances in artificial lift systems and operations.

Among those was an evaluation by Occidental Petroleum on a tailpipe system designed to optimize artificial lift performance in horizontal wells (SPE-190938 paper). The report, written by Chris Humphreys, et al., focused on a trial project that evaluated the performance of two tailpipe systems that could be applied to sucker rod pumps and ESPs to reduce the flowing bottomhole pressure without having to land pumps past the kickoff point and reduce the frequency and magnitude of slugging behavior at the pump.

Meanwhile, companies like Ambyint and Oasis Petroleum extolled the virtues of adopting digitalization in artificial lift operations. Novomet and Baker Hughes, a GE company, shared the work their companies have been conducting with permanent magnet motors.

Additionally, Raptor Lift Solutions featured a hydraulic lift system with built-in variable speed drives and remote monitoring capabilities. According to the company, the system allows the operator to pump two wells independently at two different production rates with one power unit. Maintenance can be performed on one well while the other continues to pump.

AppSmiths Technology featured its WellTracer gas-lifted well diagnostic and surveillance tool, which helps locate the primary point of gas injection. The system works by creating a snapshot of the well performance by introducing small amounts of CO₂ into the injection line, then measured that CO₂ concentration at the wellhead.

Although service markets like directional drilling and pressure pumping are more sensitive to market conditions than artificial lift, the proliferation of wells drilled during the industry rebound is creating a future base market for lift services. If companies continue to look for ways to evolve their tools and oil prices allow confidence in continued production, the artificial lift industry should remain robust. ESP
new oil
Refining Big Data for even greater value
With a number of successful projects under its collective belt, the oil and gas industry is proving Big Data is more than just a buzzword.
(Source: Makhnach_S/Shutterstock.com; Design by Felicia Hammons)

Technology has long been a key driver in the success of the oil and gas industry. Digitalization—the use of digital technologies to change a business model and provide new revenue and value-producing opportunities—is driving the industry to a whole new level. In these post-downturn times, everybody is keeping a close eye on the bottom line and adopting solutions that help keep costs low without compromising workplace safety. The promise that data analytics, machine learning, artificial intelligence (AI) and more can provide these sought-after solutions is growing.

However, as is the case with most raw materials, value often increases with improvement. Raw data, like crude oil, also must be refined for its real value to shine brightly.
This data refinement process is one that the oil and gas industry has come to embrace in recent years. Aided by advances in high-performance computing, networking, storage, machine learning and more, operators and service companies alike are installing the infrastructure and writing the algorithms necessary to mine and refine the data into actionable steps.

Big Data is beginning to deliver big results, but is it doing so fast enough?

“The industry has seized the opportunity, but the pace at which it’s been able to pull that opportunity forward and leverage it has not been at the right pace,” said Darryl Willis, vice president of oil, gas and energy for Google Cloud, in an exclusive interview with E&P. “We have to pick up the pace of transformation and change. Everyone is using the right buzzwords—artificial intelligence, machine learning, digitalization—but truly leveraging it is taking too long.”

By some estimates, just 5% of the data collected by the industry are used, but that percentage is set to increase significantly as oil and gas companies continue their digital transformation. Gartner reported in its “2018 CIO Agenda: Oil and Gas Industry Insights” that 54% of oil and gas companies are undergoing digitalization efforts. According to IDC Energy’s study “IDC FutureScape: Worldwide Oil and Gas 2018 Predictions,” 25% of major operators are invested in asset performance management while 75% of oil and gas companies have at least one digital transformation initiative in full operation.

“Data have always been the new oil, literally. Mining large seismic surveys and predicting new pay zones from historical well logs have always played a key role,” said Ramoj Paruchuri, studio director of Accenture’s Innovation Hub, in an exclusive interview with E&P. “What has transformed in recent times is the information that is getting collected from newer types of sensors and devices to assist operations from drilling and completions to production and in managing surface networks.”

According to Paruchuri, oil and gas companies are accustomed to having a longer-term view on their investments, reflected in how digital projects are evaluated.

“Innovation applicability and digital business case studies cannot be assessed just using traditional metrics and should also include such tools as usage and satisfaction index and time-to-decision and outcome impact indicators,” he said.

“It is understandable that commodity price swings significantly impact the margins, so having a measured cost take-out strategy is critical. We recommend [that] companies use digital and artificial intelligence beyond cost-cutting to improve in asset and worker productivity that impacts top line growth,” Paruchuri added. “Successful oil and gas companies who have adopted this have continued to see an uptick in growth by 5% to 8% year over year.”

As the industry continues to undergo a digital transformation, there have been challenges faced, partnerships formed and solutions found. In exclusive interviews with E&P, operators and digital transformation experts share details on projects that have made an impact. Additional articles in this month’s cover feature examine the efforts underway on data collaboration and how Big Data—this century’s oil—is impacting all facets of the industry.

**Operating in the cloud**

It is only in the last decade or so that the idea of cloud computing captured the public’s attention, moving from concept to buzzword to broader acceptance, following a path similar to that of the internet. Moreover, like the internet’s precursor, ARPANET, cloud computing has been around since the 1960s. Andrew McAfee, co-director of the MIT Initiative on the Digital Economy at MIT’s Sloan School of Management, noted in a 2011 *Harvard Business Review* article that at that time the idea of shared storage space or processing complex algorithms using high-speed computers located on off-site premises garnered considerable skepticism among technology professionals attached to onsite computing systems. While all that is provided by a cloud network can be accomplished on premises, to do so would be “surprisingly difficult, expensive and time-consuming, especially if a company is trying to repurpose older legacy technology for the modern age,” he wrote.

Seven years later, remnants of that skepticism are quickly disappearing as the benefits of cloud computing solidify.

“With the onset of cloud operations, we now fully see the ability of our industry to innovate, not in years or even decades, but in weeks,” said Arno van den Haak, head of worldwide business development oil and gas at Amazon Web Services (AWS). “The beauty of the cloud is that it is a two-way door. It allows one not only to innovate fast, but to fail fast, to learn, to iterate and to drive to completion very quickly and with minimal expense.”

An operator using this “innovate fast, fail fast” approach is, according to van den Haak, Australia’s Woodside Energy. The company has fully embraced cloud computing capabilities in its daily operations.

Shaun Gregory, executive vice president and CTO for Woodside, recently shared details of its first Big Data prototype with attendees to Halliburton’s Landmark...
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Innovation Forum & Expo. “Woodside’s innovation philosophy is structured around identifying the problem. The business needs to get value quickly, so the way to do that is to solve the problem,” he said.

“Problem first, then think big. Don’t try for an incremental change, get a prototype going on a small basis because that lets the engineers and scientists push the boundaries while striving for change. Then get it into the business quickly. If the technology is not scaled into the business, then you are not returning value to that investment. Think big, prototype small and scale fast.”

For Woodside, the team chose to start with the problem of how to increase revenue at its Pluto LNG Park. The onshore facility processes gas from the offshore Pluto and Xena gas fields in Western Australia. Gas is piped through a 180-km (112-mile) trunk line to a single onshore LNG-processing train. The $10 billion facility came equipped with 200,000 sensors used to measure various attributes like temperatures and pressures.

“We had an incident occur at the plant called ‘foaming.’ Basically, overpour your beer, and it foams over. That’s an issue in the plant because the ‘beer glass’ is four stories tall, and you can’t see it,” Gregory said. “On this particular column where we had the foaming issue that took the plant down, there were about 10,000 sensors on it.”

Early detection and prevention of foaming in the acid gas removal unit—a critical part of the production process—became the company’s first prototype using Big Data generated by those sensors.

“In the incident to report, an engineer pointed out that about 3 hours into what took about 8 hours for this incident to happen, a specific action was not taken,” he said. “The incident cost Woodside $300 million in lost revenue that could have been prevented had an action occurred hours before to stop the foaming.”

By connecting the sensors to the AWS cloud platform and using AWS’ Big Data technologies along with IBM’s Watson analytics platform, the company was able to crunch its more than 30 years of operational data along with the sensor data to develop an algorithm to identify the point in time to prevent foaming.

“Six weeks later, not only could we find it, we found it four days—not five hours—out,” he said. “It scaled perfectly. AWS accepted all these new data and did not skip a beat.”

Gregory said data streaming in from 10,000 sensors was not something that anyone could “digest in the past,” adding that the cloud, Internet of Things (IoT) and data analytics enabled the company to tackle bigger problems than what it previously would have contemplated.

That operator gained significant insights into its operations through its willingness to think big, prototype small and scale fast, van den Haak noted.

“It is a great example of working on a real business problem, prototyping and seeing the business impact of it extremely fast. The new insights that they gained helped make it possible to scale locally and globally,” he said. “Having those insights was transformational for Woodside.”

**Leveraging transformation**

With an acreage position that spans an area the size of New England, Hess’ Bakken operations are expansive. As North Dakota’s second largest producer, keeping production flowing for the company is critical. The company leveraged digital technologies to drive reliability, productivity and efficiency safely. Through its use of exception-based surveillance (EBS), actual issues affecting well operations in the field are identified. The company has spent the last few years developing this type of system to identify its sick wells from the healthy ones.

“Traditional oil and gas production surveillance was service technicians driving around and checking wells that made squeaks and leaks and looking for wells where the pumps were not going up and...
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“You're in a place with 1,600 wells, 600 pads and facilities spread out over a space the size of New England with more wells being added. Driving around and checking is not a good kind of health care plan.”

Starting in 2015 the company has been developing the necessary infrastructure to make EBS a viable option—Wi-Fi, fiber optics, sensors and more—and connected to remote operations centers to gather and store operational data.

“Our reliability operators receive signals from the wells indicating there is an issue and that attention is needed to resolve it. We have various steps along the way that ensure the signals are processed correctly. All of this work has been integrated with our Lean approach to manufacturing that we’ve been implementing,” he said.

Currently, the company receives 10 production signals to monitor the health of the wells, including oil in water level, gearbox loading and number of pump cycles, among others.

“We’re adding new signals all the time,” Turner said. “It is just like the medical industry; we’re adding more opportunities for EBS on our wells, our facilities, our treaters and all of our equipment throughout North Dakota. We use EBS offshore, too, but it makes a big impact in the onshore shale space.”

For example, EBS is used to detect tubing leaks created as the result of rod wear. The company’s MRI subsurface team identified triggers to detect these leaks. Previously, several manual steps performed at the well site were needed to identify the leak. Now, real-time data automatically flag the reliability operator to the potential leak in advance, Turner noted.

“For every signal, we catch in this process versus the traditional troubleshooting process, we reduce the troubleshooting time by three days and save up to 216 boe/d of deferred production just on tubing leaks alone,” he added.

Turner went on to note that the implementation of EBS across the Bakken has helped restore production more quickly and economically with remediation now occurring 75% faster than three years ago—capturing millions of dollars each year in what would be otherwise potentially lost production.

These data, along with drilling and completion data, production info, rod pump parameters and more, are collected and analyzed to find common well clusters and build regression models to find
problems versus waiting for the failure to occur proactively, he added. These signals also provide insights that are leading to the construction of better wells.

“One of the big areas we are working on right now is well tortuosity. You hear a lot about how low cost a well was to drill, but if it was drilled with an unacceptable angle, then there is a well defect present,” Turner said. “Our production signals have shown that the wells with the highest angles of tortuosity are the ones that have the most failures. It is still a work in progress as we’re looking at not just the wells that failed but also those that have had long lives.”

Through its use of EBS, the digital transformation has become embedded into the company’s culture of operational excellence driven by its adoption of the Lean manufacturing philosophy. Ownership throughout the organization is key to its success.

“It is a cultural transformation in that it is not just engineers generating signals and sending personnel out into the field to execute. Ours is a culture of continuous improvement, built at every level of the organization,” he said.

“You need a combination of strong leaders and people that understand why it is being done a certain way and why it is important. These wells are going to be here for a long time. Half the cost of an unconventional well is in the operating; the other half is in the capital. Pay attention to the operational side, not just the drilling side.”

**Partnering for success**

Schlumberger, like Hess, also has adopted the same spirit of creating and enabling a culture of continuous improvement through the use of digital technologies.

“Embracing new technologies generates a lot of excitement within Schlumberger. We have a natural bent in that direction, an almost genetic bias toward wanting to discover the next new technology,” said Gavin Rennick, president of Software Integrated Solutions for Schlumberger.

“From a leadership standpoint, it is critical to see that this is supported from the top and enabled from the bottom. For us, the most personal way of doing that is through training our employees, giving every employee access to the tools and capabilities to create or participate in working groups.”

For an industry built on data, sorting out good quality data from low-quality data has long been a difficult and time-consuming challenge, but Rennick believes the company has found a way to make that process far more efficient.

“It is important to understand that all data can be valuable and, when utilized, patterns within the data that do not seem intuitive can be realized,” he said.

“Having an ecosystem that supports all of the tools to handle the volume of data

**DELFI enables users to take advantage of E&P domain science and knowledge using the latest digital technologies to unlock the value of data. (Source: Schlumberger)**
“With a forecasted 31 billion connected devices just in the next few years, the global market for the Internet of Things and analytics is expected to disrupt every business process that we fully know today. Organizations will reinvent their production and supply chains to be intrinsically smart with self-learning analytics at the edge and in the cloud to maximize business value. As the industry becomes more connected, operating under persistent threats and sophisticated cyberattacks will be a new norm. Blockchain technology, which is a distributed and cryptographically protected ledger system, and security platforms based on blockchain will influence how oil and gas companies embrace cyber resiliency.”

“While many people do not think of our industry as a tech industry, we should never forget that advances in technology have unlocked vast new supplies of oil and natural gas from shale, transforming the global energy landscape in the blink of an eye. I expect that the pace and power of technology in our industry will continue to change exponentially, enabling economic progress and delivering incredible prosperity.”

“I believe over the next five years that some of the medium and smaller companies will probably start to use a lot more of their data. I hope that some of the larger companies will be fast followers as well. We need to be pushing somewhere between 50% and 100% utilization of the data that we have at our disposal. I’m expecting to see exponential growth in the utilization of data. Moreover, I do believe that companies that, ultimately, use their data will be those that win, and companies that don’t use their data will lose.”

“We will look back and be amazed at how far we’ve come. When you walk into an operations center or office of any company in the industry, you will take for granted access to a vast amount of information that’s not just raw data—it’s data that have been put in context, interpreted and delivered in meaningful ways to enable the business. The same could be said about machine learning. By then scientists and engineers will be used to having AI and analytics tools as part of their daily work, just like email and chat are available today. The rate of change and the absorption of digital technology in oil and gas across the next five years is going to be exponential, and that’s great news.”

“We are at the start of our business, similar to where the car industry was in the 1900s when there were over 4,000 registered cars in the U.S. Last year that number was close to 270 million cars. I’m not predicting that it will take us another 118 years to reach the same amount of customers and penetration, as we’ve seen with the car, but I do believe it is an analogy that holds. A big trend we’re seeing is the ongoing migration of entire data centers that are saving quite a bit of money. More companies are making the bold move to go all in because of the benefits and the transformation that they see underway in other industries.”

“With a forecasted 31 billion connected devices just in the next few years, the global market for the Internet of Things and analytics is expected to disrupt every business process that we fully know today. Organizations will reinvent their production and supply chains to be intrinsically smart with self-learning analytics at the edge and in the cloud to maximize business value. As the industry becomes more connected, operating under persistent threats and sophisticated cyberattacks will be a new norm. Blockchain technology, which is a distributed and cryptographically protected ledger system, and security platforms based on blockchain will influence how oil and gas companies embrace cyber resiliency.”

also is essential. Working with Google enables us to do both. Their technology stack is built to handle Big Data.”

That partnership with Google Cloud was formally announced in 2017 with the release of Schlumberger’s DELFI cognitive E&P environment.

“The amazing thing about the DELFI environment is that it allows our customers to combine their data and petrotechnical expertise with new digital technologies such as AI and analytics tools, and is customized to E&P based on our knowledge of the domain science,” he said. “Our customers can automate and orchestrate processes in a customized and intelligent way, from a sophisticated interpretation of a piece of data down to the basics of evaluating its quality,” he said. “Many of those elements are key services and technologies built into the data ecosystem that is provided within the DELFI environment, and as the environment is open, they are also able to create their own.”

In the quest for lower cost and maximized efficiencies, operators are moving away from silos toward a system-
wide approach to development. The digital transformation is facilitating this move, making innovation and technology development more of a collaboration rather than a solitary pursuit.

According to the company, the DELFI cognitive E&P environment enables a new way of working for asset teams by providing technology for seamless integration between geophysics, geology, reservoir engineering, drilling and production domains. The environment leverages data analytics, machine learning, high-performance computing and enables collaboration across E&P teams. “We made the connection with Google early on, so we could work together to solve specific challenges the industry was facing,” Rennick said.

The companies first partnered on overcoming specific challenges around seismic, and from there it “blossomed into a much broader business relationship where we are now bringing products to market together. That is possible when you have a level of technical respect and a tremendous level of trust with the company with whom you’ve partnered. Those sorts of relationships are what you need in order to be successful in the world at large and certainly in this industry going forward,” he said.

The launch of the DELFI environment saw the deployment of an E&P data lake on the Google Cloud Platform that comprises more than 1,000 3-D seismic surveys, 5 million wells, 1 million well logs and 400 million production records from around the world, according to a Schlumberger press release. “Our partnership with Schlumberger is a multiyear collaboration with several areas of focus. One is a focus on Big Data and the E&P data lake,” Google Cloud’s Willis said. “Another huge component is the focus on high-performance computing and also on artificial intelligence, particularly on accelerating seismic interpretation and in 3-D modeling.”

The E&P data lake is based on Google’s BigQuery, Cloud Spanner and Cloud Datastore platforms with more than 100 million data items comprising more than 30 terabytes of data. The Schlumberger Petrel E&P software platform and INTERSECT high-resolution reservoir simulator is running on a Google Cloud Platform integrated into the DELFI environment.
Today’s decision makers in the E&P industry have entered uncharted territory, with access to more data than they have ever had before. As leaders at E&P companies seek to follow the lead of other industries and transform their organizations into data-driven enterprises, a key question still remains: How can new value be unlocked from the data the industry already has?

Finding data that support better decision-making

Trailblazers in the industry have embraced and operationalized digital technologies, and they are already enjoying the “first order” benefits of enterprise data management, real-time information flows, and improved knowledge management and communications—namely that the same patterns are now faster, cheaper and better.

However, few companies have the datasets they need to take the next step and reach “second order” benefits, where the data lead them to make new or different decisions that improve asset values and reduce HSE risk.

For analytics to deliver the kind of insights expected, companies need to ensure that the algorithms are processing as complete a dataset as possible. Ultimately, industry consortiums will prove to be the most effective way to develop the kind of robust datasets that can transform the industry by unlocking new ways of creating value and new modes of operation. Those companies that are open to pooling data and collaborating on solutions will find themselves collectively outcompeting their larger—but more insular—competitors.

THE VALUE OF DATA CONSORTIUMS
Completion Intensity Patterns by Operator (Illustrative Example)

In this case study example, a single operator alone would not be able to effectively predict well performance on untested completion strategies without trading data with an operator that already has tested strategies. (Source: Wood Mackenzie)
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Need for E&P consortiums
Every objection there is to an E&P data consortium—like a company’s data are too valuable, competitive or complex—has been heard, but there is a growing recognition that things need to be done differently. “Big Tech” has proved that data equal power, and E&P companies are eager to see the kind of impressive results that other industries already have achieved. Executives and investors of E&P companies are looking for results and signs of a material return on investment for the business. Increasingly, the industry is learning of new and growing key performance indicators (often financial) placed on the people who were originally asked to experiment, innovate and educate the business.

As more and more E&P companies turn to Big Tech for help, they are also coming to terms with the fact that there is not a magic technology that can deliver these kinds of results. If introducing new analytical tools was all it took to improve performance, then a marked difference between companies using Big Data solutions and those that are not would be seen. Instead, subject matter experts are complaining that they are spending almost all of their time wrangling data or worrying that they cannot trust the datasets. There is no question that—when deployed correctly—data and analytics have great potential, and that machine learning, artificial intelligence and other technologies will deliver new value, but this can only happen if that value can be found in the data that have been analyzed.

Uncovering new value through more integrated datasets
Finding new value from data requires bringing together disparate, cross-functional datasets and using the algorithms (appropriately) to find patterns across domains, the kinds of patterns the human brain is not capable of identifying when working within its functional silos. Most companies have likely already brought all the company data together in a shared environment.

However, the more data types, granularity and value—add done to internal data, the more the analytics is limited to only being able to learn from activities that an individual company operates. The algorithm can only learn from what it is shown, so unless external data are brought into the mix, the analysis done will not extrapolate well.

Companies that look to publicly available data will find data that are so severely limited in completeness, accuracy, granularity and timeliness that, while they provide the ability to analyze a much broader population of observations, they do not yield the answers to the more detailed questions. Publicly available data also cannot be combined with robust, high-quality internal datasets, because the underlying data required to correctly and consistently engineer the important features are not available externally.

This is what motivates operators to trade data, but it is hard enough to manage and prepare internal data into tidy, analytics-ready datasets, let alone wrangle datasets provided by multiple other operators.

Moreover, herein lies the rationale for an industry data exchange or data consortium. Other verticals have discovered the value and power of industry data consortiums, as Wood Mackenzie has grown to appreciate through its parent company, Verisk Analytics, which serves insurance and financial services, two of the most digitally evolved industries.

For insurance companies, pooling data—centrally managed and prepared by a data analytics group—has allowed them to conduct actuarial science on practically the whole population being insured, not just their slice of the market. In consumer finance, banks have been able to analyze their profitability and potential default losses from those they extend credit to, even when they are but one of many credit cards in any given wallet. In both cases, insurers and banks have contributed their data to one data analytics company, a far more effective and economical way to consistently prepare and protect data than multilateral, self-organized data trades.

With that central, analytics-ready dataset, companies can get straight into the analysis to find and optimize the value in their portfolios. Over time, having all of these data in one place leads to new ways of adding value that is only possible with that combined dataset, such as fraud detection and cross-industry predictive analytics.

Decades ago, companies in the insurance and consumer finance industries were at that same point of frustration that E&P companies are at today with data and analytics. The difference is that today insurers and consumer finance companies are enjoying the return on investment they have gained from analyzing data in industry consortiums and finding new ways of generating business value.

The E&P industry could easily do so as well. Instead of trying to develop cutting-edge technologies or introduce new processes, E&P companies should work to embrace the idea of industry data consortiums to develop the kind of robust, cross-company dataset the industry has the means to analyze and support business decisions adequately.
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The new Cambrian data explosion

The oil and gas industry is evolving to manage the pace of change.

Indy Chakrabarti, Emerson

The oil and gas industry has had Big Data capabilities for decades now. Since about 2014, however, things have changed across multiple areas, simultaneously. The industry has gone through one of its most severe downturns, creating the need for increased productivity. At the same time, data volume and variety have continued their expansionary pace, coinciding with the takeoff of technologies from outside oil and gas, including the introduction of the cloud, Big Data management and a new generation of advanced machine learning (ML).

This rapid rate of change has seen the industry evolve into new technologies and business models at a breathtaking pace. These next-generation technologies are beginning their transition from conceptualization and the prototype phase into real commercial solutions. Along the way, operators are discovering what works and common pitfalls.

Emerging data lakes

Among the new wave of technologies, the most fundamental is perhaps the least glamorous—data management, a challenge the industry has worked to resolve for decades. The recent introduction of data lakes, a new approach to better manage disparate data sources and volumes, might finally move the industry ahead of the problem.

James Dixon, CTO at Pentaho, a Hitachi Group company, coined the term “data lake,” and he contrasts it to a data warehouse, saying the latter is more like a packaged bottle of water, “cleansed, packaged and structured for easy consumption.”

A data lake, on the other hand, is water in its natural state, with users being able to sample just what they need when they need it. A traditional data warehouse approach calls for laboriously scrubbing, filtering and transforming all the data as they come. It requires knowing the business processes involved and results in a rigid and limiting structure. A data lake keeps all the data and only transforms them upon request. This flexibility makes it perfect for data scientists to glean new insights. It is for this reason that many major operators are building out their own data lakes.

Enabling AI

The data lake also is the key enabling technology to unlock the power of modern artificial intelligence (AI). The success of the new generation of such capabilities rests on the ability to access massive volumes of training data. For the most part, the algorithms the industry is using today in ML existed decades ago. However, the new types of algorithms discussed under the rubric of deep learning can tune themselves by learning from trial and error.

For example, a convolutional neural network can identify trends at near human or better rates; ML requires 100,000 or more samples to learn from, for each narrow use case defined, demonstrating the value of a data lake as the source from which AI can learn because all the data and all data types remain available for inspection.

The industry is still in the early days of applying ML in oil and gas. That said, there are already some emerging classes of applications that lend themselves to early success. Organizations would like to apply ML to automate many routine human tasks, such as better understanding the reservoir, analyzing the performance of...
their equipment, locating all their data and providing virtual assistance using tools like Amazon’s Alexa.

**Failure prediction**

Among these use cases, perhaps the most success has been demonstrated in the prediction of equipment failure. Many vendors and operators are demonstrating early detection of failure signatures for the pump, motor or artificial lift failure. Perhaps one reason for success in these areas is that there is a relatively constrained set of characteristics to monitor and lots of historical data to train on. In many cases, vibration, temperature and power consumption variations on equipment, trended over time, are enabling the detection of failure conditions in advance of them occurring.

Though predictive equipment failure lends itself to AI, operators are generally not going to replace the equipment before it fails, limiting the value to helping companies be prepared in advance and reduce downtime.

**Reservoir characterization**

A larger value proposition for AI is reservoir characterization. Finding more oil more rapidly has perhaps the highest return on investment in the industry. Here, seismic data, well log records, core data and other sources are all being combined to unlock new insights.

For example, Emerson’s Democratic Neural Network Association’s (DNNA) ML methodology identifies hydrocarbon-bearing facies using seismic and well log inputs up to 90% of the time on

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training data. Rather than a geologist, geophysicist and petrophysicist working together to make sense of huge amounts of reservoir data, the DNNA ML, once trained, can be dispatched to detect these deposits. To be clear, the need to have well-qualified personnel does not disappear. The ML is great at identifying possible target rich zones, but it still requires knowledgeable users to root out false positives and select the best drilling target. Additionally, the AI has to be trained separately for each new reservoir.

Despite those constraints, applying ML for reservoir prediction is proving to be a powerful tool. Training the AI for new areas, where there is good data management, is not difficult. There is significant value in freeing up user time to focus on evaluating the AI predictions rather than having to start from scratch.

End-user assistance
Perhaps less successful so far has been the use of AI for end user assistance. It is one thing for a virtual assistance tool to turn off a light—a very binary decision—but another for it to understand the operational context and navigate complex workflow steps, stay within appropriate safeguards and take action merely by a simple user request. The current generation of narrow AI remains more fit for precise tasks rather than as all-purpose assistance tools.

There is a key exception. It is conceivable that a junior operator, perhaps wearing an augmented reality headset, could be given simple AI guidance (e.g., meter reading to inspect) to enable lower-cost field workers to perform more complicated operations. It is a new and promising application under industry evaluation but is at an earlier stage of deployment than the other approaches to ML covered earlier.

Migrating to the cloud
The cloud is an enabling technology advancing the adoption of superior data management and ML. With the rapid migration to public cloud providers like Amazon Web Services and Microsoft Azure, organizations tap into prebuilt systems optimized for both data lakes and AI, enabling direct access to Alexa or Cortana, and the applications created enable ease of access to all data as they come to reside in the single, cross-connected repository of the cloud.

There is, indeed, considerable technological change happening all at once, but oil and gas professionals know the importance of change. There is, indeed, considerable technological change happening all at once, but oil and gas professionals, perhaps more than anyone else, know the importance of change. The Cambrian explosion helped usher in a new era of flora and fauna. However, that change took 25 million years to occur. Get ready. This time the industry is going to have to evolve a whole lot faster or face extinction.
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Strategically locking up land is an art form oil and gas companies have focused on for nearly 100 years. But the vanguard of the shale revolution—and the data and intelligence the industry has—means today’s landmen are competing over less and less available acreage, making it even more important to streamline the land acquisition process, secure the right leases and make complex decisions quickly.

Although the competition is fierce, opportunities to adopt the next generation of technology to secure a competitive advantage are there for the taking. The average landman might spend 80% of their time on research and only 20% on higher value activities such as analysis and negotiations. Land professionals who leverage the latest and greatest innovations flip that ratio and spend a majority of their time being strategic to outpace their competition.

There are five distinct technology breakthroughs that are clearly transforming how landmen conduct title research, find open acreage and evaluate leasing opportunities so they can beat their competition in the modern land grab era.

**Work smarter, not harder**

The potential value that companies can derive from Big Data is old news, but realizing that value still eludes many organizations. The volume, variety and velocity of oil and gas data have required land departments to invest a huge amount of resources into simply managing all that information. In other words, managing the data is often more important than the data alone. In addition, the complexity of integrating these disparate datasets has proven difficult for many
companies to overcome, leading to disjointed workflows and inefficiencies.

All this has led many land departments to seek expert guidance on the analysis of making Big Data into tangible insights, and many look to outside resources as technology partners for this important work. The integration of leasing data with rigs, permits, production, engineering and geology data into a single platform adds context to land research that has never been available at this level. With a holistic view into potential assets, landmen are now able to screen deals faster and prioritize the most promising prospects.

Map-based title research
Although maps are an indispensable tool for land professionals, running title on an area of land continues to be an exercise that requires hours of chaining title instruments using grantor/grantee relationships. By using the various tract descriptions in an instrument, and then tying them to the corresponding abstract/section, land professionals can bring title research into a new paradigm, one that will allow landmen to build a custom area of interest on a map and see all the associated instruments for that area. An added benefit of taking the real property records under research and integrating them into a data-rich, map-based platform is that landmen are now able to recreate the oil and gas environment during the life of the instrument under their review. The speed and accuracy intrinsic in this approach will condense weeks of research into hours.

Optical character recognition
Through the advancement in optical character recognition technology, users are able to decipher a text layer from a PDF image of an instrument with a high degree of accuracy. In some cases, it is possible to reconstruct severely damaged records, unreadable to the human eye. Artificial intelligence (AI) can be leveraged by building regular expressions to identify key words and phrases that can help decipher the various clauses contained within a lease. As more users interact with these datasets and make corrections and additions, machine learning is activated to help the process become more accurate and expand its understanding of the lease document, the clauses and how other datasets impact them.

Leave no tract unturned
Finding open acreage is not always as simple as finding a vacant 2-D section of land when a user introduces the complexities of Pugh clauses and depth restrictions. Traditional research can easily leave opportunities on the table as the user looks over prospects that seem unavailable when they simply are not available at certain depths. The solution professionals are turning to is 3-D subsurface queries. This approach allows filtering through the complexities of deep rights in stacked plays faster and makes it less likely to overlook valuable assets.

Integrated platforms
At present day, the workflow for every land department is highly fragmented as they are spread across a variety of platforms coupled together by loosely integrated outputs. This has resulted not only in the growing frustration of the team, but in the number of personnel required to move the data from one platform to the next. With each dataset that can be integrated into one unified platform, the amount of frustration and wasted resources is diminished. More and more land departments are looking to implement complete end-to-end solutions within one unified integrated platform to improve their capabilities and reduce resource drain.

Finally, as a new generation of landmen are ushered in, there is no doubt they will embrace technology, data and AI to more efficiently do their jobs. Why? Because they will have to. It is not as if expectations will be lowered, and, in reality, they’ll have to produce more with less manpower.

Two years ago baby boomers accounted for 19% of the oil and gas workforce, and that figure is expected to plunge to 7% by 2025, according to an Accenture Strategy analysis. That could mean a shortage of at least 10,000 petrotechnical professionals—possibly as many as 40,000—in eight years. All signs are pointing to a changing of the guard for employees of oil and gas. To think they will rely on paper maps and in-person courthouse searches would be a catastrophic assumption to make.

How land departments prepare for this shift matters, and one clear solution is through embracing data and AI to ensure companies are outmaneuvering the competition.  

With a holistic view into potential assets, landmen are able to screen deals faster and prioritize the most promising prospects.
Savings await companies ready to embrace digitalization

Application-specific software supports well design, engineering teams and their processes.

Bolstered by an upstream-friendly oil and gas market, E&P activity is on the rise. However, operators that focus on production alone might miss the best chance to substantially increase their margins in an industry that seems eternally volatile. According to several industry experts, that chance comes in the form of recently available well planning software that can substantially reduce the lead time required to create a high-quality well plan.

The idea that well planning is beneficial is certainly not new, nor are the tasks associated with it. However, performing these tasks effectively and efficiently has proven challenging for most operators, largely because the act of planning a well is a collaborative effort, involving the collection of disparate data from various groups and synthesizing it into one overarching program. Operators usually follow their well design processes, but common to each operator is the fact that wells are not designed wholly in series, but rather have many parallel sections, with sets of decision gates and countless data interdependencies.

Generally, the challenges that slow efforts to complete a well plan are related to the same key factors: the inability to increase security and compliance according to a company’s procedures and best practices; data inconsistencies; difficulties surrounding the integration of systems from other companies and collaboration among specialists in multidisciplinary teams; the need to enter the same data multiple times; and the inability to enable data analytics.

Well planning

Intelie, a subsidiary of global communications technology provider RigNet Inc., has developed an integrated well design platform that enables operators to manage, integrate and automate well planning data and has proven to substantially reduce well planning time associated with drilling and completion operations.

“It is astonishing to see how the introduction of data analytics has increased well planning efficiency while...
helping operators to conduct safer and more productive operations,” said Intelie CEO and RigNet vice president Lelio Souza. “I think this kind of technological innovation and the impact it’s having is exciting to watch and especially to be part of because it is helping to shape the future of our industry.”

First used to develop and build a well planning platform for Petrobras in 2012, the technology has since been used to optimize planning on hundreds of wells, supporting thousands of users. One operator saw the platform as a promising way to reduce well planning time through the development of an integrated suite of web applications that would support well design and planning with a focus on offshore wells. The resulting integrated suite reduced the operator’s well planning time by 50%.

“The suite condenses all our efforts in safety, the management process and best engineering practices for well design,” said the operator’s lead engineer on the project. “It also substantially reduced the time for the elaboration of a well plan, increased the security and compliance regarding the company’s best practices, and served as a repository for customized reports on well projects to national regulatory agencies.”

**How it works**

Much like a navigation program that can determine an optimal driving route by considering various dynamic and static datapoints, the platform uses a data-adaptive approach to well planning. Because the performance of the individual tasks of a well design process is not in a vacuum, the various
inputs/outputs from one application affect the inputs/outputs of applications upstream and downstream of the well being designed.

Platform designers addressed this condition by creating a platform that could facilitate the integration and analysis of data input/output from each component of the planning process, synthesize it and perform automated system-integrity and overall-conformity checks between the interdependent components.

The platform takes unstructured data processes, decision trees, data integration protocols and automates them while permitting users to collaborate on well planning and design. Any changes to an individual planning component that may affect other areas are flagged, notifying the appropriate parties. Defining and automating workflows, mapping data interdependencies within the workflows and creating a system of data governance were also keys to building an efficient planning platform.

The development of an integrated planning platform allows processes to be standardized. Operators are then able to embed their methods of well design into the software platform, ensuring that all their company-specific requirements are met. Key to the effectiveness and longevity of this type of platform is a neutral data repository. Allowing data to be free of any singular data protocol ensures the data produced and ingested by these applications remains constant, despite individual application revision, replacement or being put into competition with one another. Data remain mapped, regarding the overall workflow process and interdependencies. Beyond reducing overall well planning time, the integrated platform enables operators to enforce and ensure data governance.

Beyond road maps and static plans, the platform also can be designed with a condition-based execution well planning tool that can effectuate guidance for operational executions. The tool does this by directing a set of smart agents that are synthesized from the well plan and run on real-time analytics software while the well is drilled. In practice, a smart agent could be directed to monitor drilling. So when a drillbit is approaching the planned total depth or is drilling deeper than permitted, the smart agent could issue an alert, notifying the user that the planned depth limitations or lease line (block line) limitations have been reached. Intelie also provides a real-time aggregation, analytics, visualization platforms and advanced data solutions using various artificial intelligence and machine learning methods.
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Preventing fluid loss in troublesome zones

A low-density, direct-emulsion fluid delivered wellbore stability in the Delaware Basin.

Overlying much of the hydrocarbon-rich Delaware Basin is a thick evaporite sequence that poses a significant challenge for wellbore integrity. Conventional water- and brine-based drilling fluids promote severe wellbore washout and require high dump and dilution rates due to salt leaching when drilling through the evaporites. Lost fluid circulation below the evaporite formation due to a reduced fracture gradient is an additional drilling hazard (Figure 1).

Poor borehole quality impacts cementing operations as hole enlargement makes cementing the intermediate section more costly due to increased annular volume, especially where regulations require cementing to surface as proof of satisfactory zonal isolation. Multiple stages often are pumped to achieve this.

Many operators attempt to minimize borehole enlargement by drilling salt sections with a saturated brine fluid. After drilling the salt section two options remain: 1) set casing to isolate the salt and minimize the risk of excessive overbalance in the loss zones below, or 2) drill ahead and try to control mud density with dilution.

In the first option, the capital cost for a salt casing string is about $150,000 per well. At least one day is required to run and cement casing, plus the cost of the cement job must be factored into the decision. This added salt string also can restrict the final borehole diameter in the pay zone.

For the second option, drilling ahead and beyond the exposed salt leads to a compromise between washout and lost circulation risk. The drilling fluid must be diluted and the salt content reduced below saturation to stay under 10 ppg and avoid lost circulation. However, the unsaturated fluid will then continually dissolve salt from the wellbore, and the resulting density increase must be corrected by dump and dilution. The waste volumes generated by this approach sharply increase haul-off and disposal costs as well as add to already congested roadways.

Once the intermediate interval has been drilled and cased, most operators displace to a nonaqueous fluid (NAF) to drill the curve and lateral sections. Although the displacement takes 4 to 8 hours of rig time, and the cost per barrel for NAF is comparatively high, the drilling performance outcomes make it the preferred choice. These systems deliver reliable wellbore stability, good lubricity and fast ROP. If properly managed with efficient solids control equipment, a NAF can be reused on subsequent wells.

Despite the challenges and expense of coping with salt and losses in the intermediate section, the combination of using a brine-based fluid and displacing to a NAF has been widely implemented among Permian Basin operators. Any alternative fluid system would need to be suitable to drill both the intermediate and lateral sections, stabilize salt (and eliminate the salt casing string), produce a near-gauge borehole, offer sustained low density without excessive dilution and clean up easily for reuse on additional wells.

Drilling strategy change

A new low-solids, brine-based drilling fluid was first implemented in the Delaware Basin in May 2017. The formulation addressed known drilling issues by tightly combining the brine-based fluid with low-density oil to form a stable direct emulsion. The increased oil content (10% to 50%) lowered density, allowing the fluid to

Preventing fluid loss in troublesome zones

A low-density, direct-emulsion fluid delivered wellbore stability in the Delaware Basin.
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remain fully salt-saturated to suppress salt washout while preventing lost circulation in weak zones.

Since its introduction, the direct-emulsion fluid has been used on more than 60 wells, with an average savings of $200,000 per well. The fluid also was used to successfully drill eight lateral sections and enabled a better cement bond compared to those drilled with a NAF.

The cost benefits are derived from numerous improvements in efficiency:

- Caliper logs confirmed a gauge wellbore, resulting in reduced cement volumes and pumping schedules in multiple wells;
- Low densities helped prevent lost circulation, allowing deeper casing points and eliminating a casing string;
- Using a single fluid for all intervals saved 4 to 8 hours of displacement time per well;
- Enhanced ROPs (on par with NAF performance) significantly reduced time to total depth;
- Effective prevention of salt dissolution eliminated dilution and lowered water disposal costs by 70%; and
- Observation of salt cuttings on the shakers for the first time provided evidence of wellbore stability and formation integrity (Figure 2).

**Fluid design criteria**

This system is a direct emulsion, where the base brine is tightly emulsified with up to 50% diesel (7 ppg). The saturated brine phase of the fluid helps minimize washout, and the diesel phase delivers excellent density control without generating dilution waste volumes. By contrast, most NAF systems have an oil content exceeding 55%.

Formulation of the direct-emulsion system with produced water, an otherwise useless byproduct of oil production, keeps costs low. A barrel of produced water can be acquired for less than a $1/bbl, as opposed to trucking in a barrel of commercial brine (up to $27/bbl). Few other products are required, and the system is easy to mix on the fly at the rig site.

One critical element to the success of the fluid is a tight and lasting emulsion. Figure 3 shows a mud sample 2½ months after initial mixing, and the emulsion remained strong. As a further advantage, the system can be purposely de-emulsified so the diesel can be used in another drilling fluid as needed.

The formulation was tested extensively and optimized to ensure the new system would function well in a large-scale operation with high volumes and fast drilling rates. Compatibility testing was performed to prevent destabilization due to exposure to wellbore fluids and to confirm the fluid would not damage tool components.

The final formulation, as implemented in the field, was a salt-saturated, diesel-emulsion fluid with a density range of 8.6 ppg to 9.8 ppg. Rheological properties were relatively low. Equivalent circulating density and surge/swab pressures have been minimal.

**Removing efficiency barriers**

The direct-emulsion fluid actively demonstrates significant improvements in borehole quality, along with a dramatic reduction in lost circulation events and fluid waste volumes. The new fluid has proven durable enough for continual reuse, like a NAF system. It can be used to drill all wells on a pad and then be moved to the next location.

Since its first application more than one year ago, the fluid has consistently prevented leaching of the evaporitic salt layers, maintained near-gauge borehole conditions and removed the need for continuous fluid dilution and dumping. It has facilitated rapid and easy adjustment of low fluid densities, enabling successful drilling of formations with very low fracture gradients. 

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**FIGURE 2.** Salt cuttings are visible on the shaker screen, indicating the integrity of salt formations throughout drilling operations. *(Source: Halliburton)*

**FIGURE 3.** A saturated-salt, direct-emulsion sample was stable 2½ months after mixing. *(Source: Halliburton)*

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Optimizing well productivity through numerical modeling

Cloud-based reservoir modeling and simulations enabled an operator in the Wolfcamp Shale to improve well completion design.

Piyush Pankaj, Schlumberger

Optimizing horizontal wells is one of the major contributing factors to a successful economic recovery of unconventional reservoirs. That is why operators continue to seek new solutions for improving various completion parameters that directly impact well productivity. By conducting completion design pilot tests, operators can determine the most appropriate number of fracturing stages, cluster spacing, fracture design and other critical parameters affecting completion performance. However, such tests can be both cost- and time-prohibitive and might not provide much-needed answers.

One way to reduce costs and speed up completions is through numerical modeling of completion designs via cloud-based computing. The most valuable benefit of this method is that decision makers can study and understand a large number of variable samples rapidly and direct their field operations based on the assessment of numerous what-if scenarios—all of it accomplished in real time. This has a direct impact on production enhancement as numerical modeling simulations enable more accurate mapping of reservoir heterogeneity, more precise characterization of reservoir quality and a more defined process of selecting and placing effective completions in the wellbore.

As seen in a recent Wolfcamp Shale case study, hundreds of modeling simulations are required to understand trends in hydraulic fracture geometry and productivity when developing the most suitable completion design plan for an unconventional asset. This is only practical when an automated workflow is powered through cloud-based parallel simulations that thread the hydraulic fracture design, unstructured gridding and numerical simulation for production response.

Integrated earth modeling

In the Midland Basin of the Wolfcamp Shale, cloud computing techniques played a crucial role in optimizing well completion and spacing design of a multiwell pad. As a first step, creation and calibration of a 3-D earth model on the Petrel E&P software platform took place representing the asset’s geological, geomechanical and petrophysical properties. After these properties and the reservoir’s discrete natural fracture network were defined, cloud-based computing was used to perform a multivariate analysis to optimize the well completion design and well spacing. The following completion parameters were used:

- Proppant loading: 1,000 lbm/ft to 5,000 lbm/ft;
- Cluster spacing: 6 m to 38 m (20 ft to 125 ft);
- Number of clusters per stage: 3 to 7; and
- Horizontal well spacing: 91 m to 305 m (300 ft to 1,000 ft).

Additionally, petrotechnical experts used the Kinetix Shale reservoir-centric stimulation-to-production software to understand fracture geometries for zipper and nonzipper stimulation sequences and the effects of existing well production on reservoir geomechanical properties and infill well productivity. Several critical indicators of production and hydraulic fracture geometry parameters were evaluated, such as total and propped surface area; height, length and width of the fractures; and net pressure in the fracture.

Simulation engines

By using the numerical modeling approach, more than 500 cloud-based complex simulations of hydraulic fractures, as well as unstructured gridding of hydraulic fractures with fine-resolution numerical and finite-element geomechanical simulations, were performed to determine

1. An optimal well landing solution by using a full 3-D hydraulic fracture simulation model and complex fracture models in the Kinetix Shale software;
2. Simulated values to match with field measurements, such as treatment pressure history, microseismic data and production history. They provided calibration points for hydraulic fracture geometry and productive reservoir volume representation;
3. Future well performance for all completion sensitivity cases. Cloud-based simulations using the INTERSECT high-resolution reservoir simulator were implemented to predict this performance; and
4. Parent-child well relationship and the effect of stimulation timing on child wells. These parameters were established by using the VISAGE finite-element geomechanics simulator to predict reservoir geomechanical property changes over time. Achieving these results through conventional computing workflows—such as manual, single simulation at a time—would have taken months to years. Instead, the numerical, cloud-performed methodology delivered the results within a week.

**Proppant loading and perforation clusters**

Production increases with stimulation treatment size—but up to a certain level. Cloud-based simulations of the 3-D earth model have shown the total generated fracture surface area improves when increasing volume of proppants, with the propped surface area plateauing at about 3,000 lbm/ft. This has enabled a faster and more accurate economic analysis of the resulting production to determine the optimal proppant loading.

**FIGURE 1.** The Wolfcamp study indicated that smaller proppant loading at tighter cluster spacing results in slightly higher production compared with wider spacing and larger proppant loading. (Source: Schlumberger)
Optimizing cluster spacing when completing a well is another technical challenge in this region. The cloud computing simulations using Kinetix Shale software were analyzed showing that as the cluster spacing is reduced, more near-wellbore complexity and interaction with the natural fractures result in increased productive surface area. The analysis also demonstrated that as the clusters per stage increase, the fracture length drops because the fluid volume per cluster falls. However, the resulting surface area, fracture height, fracture conductivity and fracture width do not change significantly. Hence, the number of clusters per stage has less effect on well productivity as compared with proppant loading and cluster spacing. In other words, modeling demonstrated that the operator can improve production and overall project economics by reducing cluster spacing instead of increasing proppant loading (Figure 1).

Impact of zipper fracturing
Operators use the zipper fracturing technique to improve operational efficiency while stimulating multiple wellbores. In the Wolfcamp case study, the fracture geometry impact of a zipper fracture case was compared to a nonzipper sequential stimulation case on a four-well pad, finding that the interwell stress shadow effect is minimal until the volume reaches 2,400 lbm/ft.

Well spacing
In a multiwell pad, tighter well spacing usually results in fractures competing for the same rock volume; therefore, production interference is commonly observed. Here, however, marginal to no production interference occurs at 200-m (660-ft) well spacing over a two-year cumulative production. Nevertheless, production interference increases to approximately 8% at 135-m (440-ft) well spacing and 18% with 100-m (330-ft) well spacing.

Also, another finding from this case study is that treatment design can affect the well spacing decision—the larger the treatment, the farther the well spacing should be to mitigate production interference.

Parent-child wells
It is a known fact that existing well production induces a time-dependent geomechanical property change that shapes the nearby infill wells’ fracture propagation, fracturing hits and well productivity. Close well spacing between existing and infill or parent-child wells tends to result in a greater number of fracturing hits. This spacing sensitivity generated through cloud spacing analysis of a parent-child system for the Wolfcamp asset indicated that at a spacing of 135 m and closer, the probability of a fracture hit is significantly higher than for a system at 200-m (660-ft) spacing (Figure 2).

Bottom line
By applying the cloud-based reservoir modeling and simulations, the operator was able to place more wells per section, increased productivity per well by more than 40% and improved the net asset value by more than 50%. As exemplified in this case study, time and cost savings can be achieved through a cloud-based sensitivity study for operators who strive for optimized completion design. Booking reserves, economic evaluations and field trials can be completed with optimal assurance and in a short time frame. E&P

Editor’s Note: This article has been adapted from the URTEC-2876482 and SPE-191442-MS papers, both 2018.
Freemyer Industrial Pressure is moving into the future with a new generation of control systems and electric driven equipment options, while providing Engineered Hydraulic Fracturing, Well Stimulation, and Cementing Equipment Solutions throughout the World for the Oil & Gas Industry.
Vital gas safety improvements secured through wireless technology

A wireless hydrocarbon gas detector gives brownfield asset operators the opportunity to make significant improvements to personnel protection.

Achieving continuous improvement in safety onboard aging brownfield assets is a significant challenge. Reducing the potential impact on operations by upgrading legacy equipment, such as fixed gas detection systems—central to people and plant safety and security—has been a key driver for developers bringing forward a new generation of technologies.

Wireless systems will play a crucial role in mitigating the shortcomings of legacy cabled gas detection systems, as operations extend far beyond the design life of platforms in mature fields.

GS01, the wireless hydrocarbon gas detector developed by Dräger Safety’s GasSecure division, gives brownfield asset operators the opportunity to make significant improvements to personnel protection coverage while avoiding potential production shutdown disruption issues associated with working on aging wired systems.

The GS01 is an infrared gas transmitter for detection of flammable hydrocarbon gases and vapors in the oil and gas industry. Intrinsically safe and safety integrity level (SIL) certified, the transmitter provides completely wireless signal transmission and operates with a safe battery pack.

Cost efficiencies run as high as an 80% saving on the potential cost of tearing down an outdated system and replacing it. That number combines the savings made from the procurement, engineering, destruct and construct costs associated with the replacement of a wired system.

Where wired system intervention requires an operational shutdown of the asset, the associated costs for production operations are even higher. Those costs are a crucial consideration for asset owners, operators and managers working to eliminate shortcomings in legacy fixed gas systems as platforms and vessels enter a new phase of their operated life.

The GS01 system is capable of expansion without significant intervention. The lightweight device requires two 8-mm bolts for mounting and no cabling, allowing gaps found in platform gas detection coverage to be easily filled again without major remedial works being required.

Site installation work, as well as the volume of planning required before installation, is significantly reduced as devices can be preconfigured and are entirely battery operated.

Each GS01 detector draws less than 5 milliwatts of power, meaning that depending on ambient conditions in the installation area, each device can run for up to two years without requiring replacement batteries. The intrinsically safe design allows battery packs to be replaced in a hazard area.

Installation in demanding conditions

Safety-related measuring points on platforms, FPSOs and other vessels are numerous and in some cases extremely difficult—if not impossible—to monitor using wired gas detection systems prevalent on such assets. This issue introduces coverage gaps.

GS01 wireless transmitters require no conduits or cable, which simplifies installation. In open space it has the capability to send data to an access point up to 500 m (1,640 ft) away, while the GS01-EA variant with extended antenna can be installed inside structures where signal transmission is normally impossible due to shielding.

For temporary applications (e.g., during maintenance work or exploratory drilling), GS01 can be integrated into existing safety systems. In technically complex installations, such as on the rotating tower of an FPSO, transmitter installation can be carried out simply and effectively.
Harsh environment deployment success
The system has been successfully deployed offshore Norway for a major national oil company and is in use on one platform in a field development, which first entered service about 30 years ago.

A network of 20 wireless gas detectors was installed in three fire areas affected by weather exposure, with one gateway (radio access point) per area.

Given the platform’s age, many add-ons have been integrated into its structures over time. Therefore, there are many obstructions, from heavy steel decks to machinery that would test the detectors’ radio communication systems.

The GS01 system’s gateways communicate to one ABB fire and gas node presenting the alarms and failure status to operators in the central control room.

At the point of installation, it was estimated that the project would expend 5% to 10% of the installation time required for a conventional wired detection system.

Additional tests showed that radio signal coverage was extensive. One gateway could cover most of the platform despite several detectors having been placed in challenging locations.

Ten of the GS01 detectors were installed shoulder-to-shoulder with the platform’s legacy wired gas detector to compare response times, and tests showed it was essentially equal for both detectors; however, the digital design of the GS01 gas detector gives a quicker reading on the correct level of gas.

Operational stability delivers assurance
Wireless gas detection systems are able to offer at least the same level of safety performance as traditional, wired systems housed in 4-20 mA cabling. This means that, without compromise to safety, they also can secure cost efficiencies in terms of removing the necessity for FEED, materials, man-hours and downtime required to install and commission a wired system.

Wireless surveys can be quickly and easily carried out to prove connectivity. The system can be built, configured and commissioned onshore, facilitating an onsite installation time of days rather than weeks, and can be achieved while the plant is still running.

Infrared sensor technology in GS01 uses proprietary micro-electromechanical systems (MEMs) optical filters. MEMs offer long-term stability and eliminate the need for recalibration of the detector, which directly reduces associated system maintenance costs. MEMs operate at three different wavelengths and include heated optics to prevent condensation in the sensor.

Cybersecurity through innovation
Concerns centered on cybersecurity resilience in vital utilities led to the expedient creation of a new regulation in the U.K. in the form of the Networks and Information Systems Directive. Emerging wireless technologies need to fulfill its requirements if assets in oil and gas are to be capable of being safely and securely operated.

GS01 eradicates the weaknesses presented by aged wireless technology. The SIL2-capable device uses the ISA100.11a standard for its wireless communication, which provides additional assurance compared to other systems, such as WirelessHART.

A clear benefit of the object-based standard is the possible embedding of foreign protocols, including the SIL3-certified safety protocol PROFIsafe. In combination with GasSecure’s SafeWireless communication concept for fast and secure transfer of measurement data, this enables easy integration of the GS01 into safety instrumented systems delivering a fully SIL2-capable signal chain. Furthermore, the open ISA100.11a standard supports easy integration of other field devices into the wireless network.

Even in a non-SIL system, the device remains constantly visible on the system, providing optical and power diagnostics without negatively impacting the unit’s battery life.
Shale oil resources have become a key contributor to oil production in North America. Due to the micro-permeability of these reservoirs and rapid depletion of pore pressure proximal to the fractures and wellbore, the oil production for most wells declines sharply after a short period of production and the hydrocarbon recovery from these wells is low, typically 3% to 12% of original oil in place.

The development of effective EOR techniques is necessary to produce the significant amount of the remaining oil. Conventional secondary recovery processes, such as water injection, are ineffective in unconventional reservoirs because of the low injectivity and poor sweep efficiency in these formations. Consequently, the injection of gas, with a much lower viscosity, has received most of the attention. Several operating companies have performed pilot studies for EOR from shale oils using CO₂ or produced gas injection. For instance, EOG Resources disclosed oil recovery improvement of 30% to 70% from the Eagle Ford Shale wells by injecting natural gas using huff-and-puff techniques.

Gas huff and puff refers to the cyclic process by which gas is injected into a reservoir to achieve miscibility with the oil. The mixture is then produced from the same well after a period of soaking (well shut-in) time. One single gas huff-and-puff cycle consists of three stages: injection, soaking and production.

The effectiveness of the gas EOR process in shale oils is dictated, at its foundation, by the diffusion process on the nanoscale, where gas molecules travel through the matrix pore structure to combine with the oil. Advection at this scale is very difficult, as the movements of the gas and oil molecules are primarily dictated by the diffusion process.

Diffusion is temperature-dependent and driven by concentration and pressure gradients along the path traveled. As the gas moves into the matrix pore structure, it combines with the oil through miscibility or solubility. The mixture has lower viscosity and swells, pushing the oil from the pore space to the adjacent microfracture or macrofracture, and draining to the wellbore.

Diffusion physics also drives the movement of the oil/solvent mixture through the matrix pore throats based on the oil/solvent solution concentration gradient. In the huff-and-puff process, the soak time allows the diffusion process to permeate gas deeper into the matrix and the oil/solvent solution from the matrix. Reducing the wellbore pressure during production increases the swelling of the oil and enhances the back-production effectiveness.

**Advanced completion flow control for gas EOR in shale oil reservoirs**

The autonomous inflow control device (AICD) is an active flow control tool that provides an additional restriction to unwanted fluids, such as water or gas, and creates the additional restriction without any connection to or remote actuation from the surface and without any intervention by the operator. When used in a horizontal well, segmented into multiple compartments, an AICD completion prevents excessive production of gas after breakthrough occurs in one or more compartments. Tendeka has employed more than 25,000 AICD FloSure rate-controlled production (RCP) valves in more than 135 wells worldwide.

The effective distribution of the injected gas in long horizontal wells and the ability to keep the gas in the reservoir to maintain energy can greatly affect the recovery efficiency that can be achieved with EOR. Advanced completions utilizing appropriately designed inflow control devices (ICDs) and AICDs can enhance the performance of these huff-and-puff gas EOR schemes.

The completion is composed of an internal liner that subdivides the wellbore into multiple segments using swell packers. Each packer is positioned to compartmentalize either individual fractures or clusters of fractures.

Within each segment of the liner, the number and size of the ICDs and AICDs are determined to control both gas injection and oil and gas production at prescribed rates under the expected operating conditions. ICDs are used in each compartment to balance the distribution of gas injection along the length of the well.
bore by appropriate sizing of the nozzle in the ICD, combined with a check-valve mechanism allowing flow in only the injection direction. AICDs in each compartment restrict the early back-production of gas. The FloSure RCP-type AICD also has check-valve properties allowing flow in only the production direction.

The well is initially produced to generate oil production and deplete pressure in the reservoir proximal to the wellbore and fractures. Once the production and pressure have declined, production is stopped, and gas is injected into the wellbore. Gas is injected in all segments of the completion simultaneously by flowing down the main well conduit, into the internal liner and out each segment through the ICDs. Injection is continued until either a certain amount of gas is injected into the formation or pressure conditions are created that preclude continued injection (Figure 1).

The well is then shut in for a period to allow the gas to diffuse into the oil in the pore spaces of the formation and for the oil/solvent solution to diffuse back into the microfracture labyrinth.

After a predetermined soak period, the well is placed on production. Gas and oil are produced from the reservoir rock into the microfractures and induced fractures before flowing into the wellbore. With a conventional completion, injected gas flowing back during the production phase of the huff-and-puff cycle is preferentially produced because of the favorable mobility of the gas. However, in an advanced completion, produced fluids pass into the production conduit through the AICDs (Figure 2).

The AICD provides greater flow restriction to gas than to oil, and as such, compartments containing fractures dominated by the oil phase are produced with a minimum restriction, while compartments containing fractures dominated by produced gas are subjected to a very high-pressure drop. This maintains high pressures in those zones where the gas has not had enough time to effectively react with the interstitial oil while maximizing oil production from high oil phase zones. In this manner, excess gas is retained in the reservoir to further diffuse and react with the oil, and to maintain reservoir energy and pressure to improve oil recovery. With the AICDs added to the completion, the length of the soak period can be shortened, and the effectiveness of the gas injected can be improved.

The cycle of injection and production is repeated multiple times to maximize the recovery of liquid hydrocarbons from the reservoir.

The implementation of advanced completions in EOR applications has been studied by reservoir and well performance simulation. The study has demonstrated how advanced completion technology can be used to balance the distribution of gas injection along the length of the wellbore. It can, therefore, help control the early back-production of gas in a huff-and-puff gas EOR process for unconventional oil recovery.

**Have a story idea for Operator Solutions?** This feature highlights technologies and techniques that are helping upstream operators overcome their challenges. Submit your story ideas to Group Managing Editor Jo Ann Davy at jdavy@hartenergy.com.
Flow assurance problems can cause significant financial penalties due to lost production and the cost to fix them as well as representing serious HSE risks. If potential flow assurance issues are not detected early and left unmitigated, they can lead to pipeline blockages, catastrophic failures, loss of containment and shutdown. As the oil and gas industry accesses deeper waters and increases reliance on long subsea tiebacks and pipelines to processing facilities, the potential for flow assurance issues increases.

Flow assurance issues include corrosion, erosion, vibration-induced stress, liquid slugging, emulsions and the formation of different chemical deposits in pipelines including wax, hydrates, asphaltenes, naphthenates, paraffin and scales. Optimized chemical dosing is an essential strategy, along with other methods, to ensure effective flow assurance.

Chemical dosing will vary over the lifetime of a well, with the choice of chemicals changing according to the produced fluids and production rates, to ensure production optimization, asset integrity and low flow assurance risks. Therefore, it is essential to make sure the chemical balance is accurate. For example, under-injection of chemicals for scale or paraffin control can result in reduced production and hence lower profits due to the uncontrolled buildup of deposits in pipes. Ultimately, these deposits can potentially block the pipe completely leading to lost production, but even if this point is not reached, production might be halted to remove the coatings.

While under-injection might save on operational costs, it can ultimately result in reduced production, increased maintenance costs and greater risks to assets. For example, under-injection of corrosion inhibitors might result in halted production to evaluate pipeline integrity and replace affected components.

On the other hand, while over-injection of chemical additives increases operational costs, it can reduce production downtime but also can lead to issues with the effectiveness of downstream processing. Some upstream processing facilities can recover these chemicals for reinjection to reduce costs and issues for downstream processing. Operators are focused on increasing production while reducing operational costs, but must balance the effectiveness and investment in a challenging economic environment. For example, the cost of chemical injection to mitigate flow assurance issues can exceed $2/bbl of produced oil.

The development of appropriate chemical treatment programs requires samples of the production fluid. However, the collection of samples at the platform means the sample will be at different conditions as compared to subsea pipelines, adding additional measurement uncertainty from the laboratory analysis of the sample and subse-
quent extrapolation to subsea conditions. Other disadvantages of this type of sampling are that some chemical components might have already been deposited in subsea pipelines and therefore are not detected in topside samples, creating a major flow assurance risk.

The lack of real-time data regarding fluid composition to develop intelligent feedback systems for controlled chemical injection is a major barrier to the development of cost-effective flow assurance strategies. Instead, there is a heavy reliance on taking physical samples of the produced fluids and sending these for composition analysis. This expensive and lengthy process to obtain fluid composition is not regularly performed, despite the industry recognizing that flow conditions can change very quickly. It can take several weeks from the collection of a sample to the provision of usable data before operators allow decisions on flow assurance and chemical injections, by which time flow conditions will likely have changed.

To reduce capital costs, fluid sampling infrastructures are commonly no longer included within new field developments, but this has reduced the margins for error and increased flow assurance risks. Consequently, there is a reliance on over-injecting chemicals to eliminate any potential issues.

Chemical treatment programs to mitigate flow assurance issues might be developed that could require continuous injection; this is common for upstream production, or intermittent injection depending on requirements and flow composition. For flow assurance risks, such as hydrate control, high volumes of chemicals (e.g., methanol or glycol) might need to be injected. In the case of methanol injection, this can be up to 40% by volume of the liquid present; then this exacerbates other flow assurance issues with multiphase flows such as slugging.

Future of chemical injection

There have been some pilot investigations by research organizations into the development of new sensor technology and models that can be used successfully to indicate when flow assurance issues might occur in real time and determine accurate chemical dosing.

Research has shown in one field that, for the most part, there was no need to inject any hydrate inhibitor chemicals as the flow conditions and fluid composition were outside the hydrate formation envelope. This substantially reduced operating costs. Previously, inhibitors were continuously injected based on the worst-case operating scenario. One estimate suggests that with improved chemical management, a potential reduction in monoethylene glycol could save about UK £1 million per year for a typical single gas well.

Fluid sampling techniques need to be developed that allow online analysis in real time using robust technologies capable of operation in the field reliably and with little maintenance. Those will need to be accurate and repeatable for all flow compositions, velocities and flow patterns. Methods also will need to be established to provide a real-time breakdown of the hydrocarbon composition of multiphase flows to establish optimal chemical dosing requirements and determine the amount of water present.

Sensors will need to be developed and evaluated, or techniques using correlations linked to other sensor measurements could be developed to detect and measure the quantities of residual-dosing chemicals in different parts of a pipeline. Flow assurance models could potentially be optimized, based on the real-time data from inline sensors in long subsea pipelines and risers, and in other remote, inaccessible locations.

If new sensors were developed that can determine the hydrocarbon composition and concentration of added inhibitor chemical species in real time, this would offer a major innovation in flow assurance management, reducing measurement and modeling errors. Information on the flow conditions, such as temperature, pressure, hydrocarbon composition and water content, could be used to establish safe operating envelopes, within which no chemicals would be required. The same strategy could be applied to inhibitor chemicals for wax and scaling.

Flow assurance intervention costs could be substantially reduced by the availability of real-time data that will make it possible to rapidly identify and mitigate issues, including equipment failures and production shutdowns, and to reduce the cost and volume of chemicals required. The development of sensors and sampling to collect real-time data, combined with a more advanced fundamental understanding of physical chemistry, will deliver a significant improvement in the optimization of chemical injection programs and launch a new era in cost-effective flow assurance management strategies. Crucially, by using online analysis, this should all be possible in a way that does not increase operational risk.  

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Accelerating hydrocarbon discovery in New Zealand’s offshore frontier

A multiclient program offers new insights into the Pegasus Basin.

The commitment to use advanced technology, seismic data and geophysical expertise was the backbone of a recent acquisition, processing and interpretation of a large multiclient program in the underexplored Pegasus Basin offshore New Zealand.

Between 2014 and 2016 WesternGeco conducted 2-D and 3-D seismic programs across the East Coast of the North Island and into the basin, adding to one of the largest in the industry’s multiclient libraries.

The seismic acquisition and processing technologies used in the program yielded a complete reinterpretation of stratigraphic and structural features. This provides E&P companies with a new high-quality dataset with which to explore this highly prospective region (Figure 1).

Geological setting and prospectivity

More than 300 known onshore oil and gas seeps occur in the eastern part of New Zealand’s North Island, indicating at least one active petroleum system. Although more than 40 wells have been drilled onshore, only two have been drilled offshore, making this region vastly underexplored.

The eastern margin of the North Island is part of the forearc of the Hikurangi subduction zone, which accommodates oblique convergence between the Australian and Pacific plates. Associated Miocene-Recent compression along the margin has created a northeast-southwest trending fold and thrust belt, with a series of elongated growth structures and adjacent inverted sub-basins with fill that is variable and diachronous.

Primary plays in the region involve fault-bounded anticlines and stratigraphic pinchouts against structural highs. An extensive gas hydrate system also indicates additional potential for gas accumulations trapped beneath the gas hydrate layer.

Both offshore wells drilled to date targeted structural highs adjacent to the Titihaoa sub-basin. In 1994 the Titihaoa-1 well targeted one of the many fault-bounded hanging-wall anticlinal closures along the margin and encountered thinly bedded reservoir-quality Miocene turbiditic sandstones. In 2004 Tawatawa-1, which was drilled 35 km (22 miles) north-east of Titihaoa-1, intersected Miocene thinly bedded siltstones and shales.

The two offshore wells did not find commercial reservoirs, but they did encounter elevated gas readings, suggesting the presence of hydrocarbon charge in the basin.

A key target is Neogene clastic reservoir quality rocks, which are present onshore and are suspected also to be offshore. Identifying their presence and extent in the offshore environment is under investigation, and knowledge of the geological setting is crucial to further exploration efforts.

New acquisition and interpretation

The 2-D survey acquired in 2014 provided a much-needed regional perspective and allowed the mapping of major structures. However, a 3-D survey was required to deliver more accurate imaging and posi-
tioning in structurally complex areas such as steeply dipping intervals and overhangs.

Understanding the geological challenges was critical as the correct high-end model-building technologies and workflows were applied to completely image the region. Several workflows were used to derive a detailed tilted transverse isotropy (TTI) model, including multiparameter common image point picking, premigration azimuth preservation, steering filters and joint parameter updates.

Multiparameter common image point picking was performed to ensure that complex residual moveout of small-scale velocity anomalies were detected and fed into the tomographic input. Premigration azimuth preservation was used to incorporate ray tracing in the correct azimuth, particularly in acquisition turn areas to confirm the convergence of the velocity updates. A TTI model was selected so that the migration considered the slow and fast velocity direction as well as the dip and azimuth of the complex structures to generate the most accurately positioned depth image.

These technologies used 3-D Kirchhoff prestack depth migration to create a high-quality image of the complex subsurface. As a result, better input data with a more accurate earth model and robust migration algorithms delivered a more accurate final image for interpretation and quantitative analysis (Figure 2).

The 3-D uplift

Figure 2 (bottom) shows the latest uplift in imaging achieved throughout the entire depth section of the 3-D survey. A bottom simulating reflector can be seen marking the base of the gas hydrate stability zone in both the 2-D and 3-D data. Nevertheless, with the 3-D dataset, stratigraphic events near the bottom simulating reflector are clearly trackable through the high-amplitude band. This detail enables shallow intervals to be interpreted with increased confidence and the gas hydrate play to be assessed in further detail.

The high-resolution imaging within the trench-slope basins in the 3-D dataset also offers a more comprehensive insight of sedimentary fill within. Sedimentary units and unconformities can be traced and correlated across individual sub-basins, giving an improved visualization of the interplay of sedimentation and the structural evolution along the margin. Crisper imaging shows finer detail within mass transport complexes, with individual and stacked systems now evident. Faults and folds can be seen within mass transport complexes that act as paleo-flow indicators, assisting in the study of sedimentary fill within individual sub-basins.

Given the areal extent of the survey, scanning through the 3-D volume highlights the evolving degree of deformation along the margin. Starting inboard, the margin is represented by a highly deformed reactivation zone with up to 5-km-thick (3-mile) trench-slope sub-basins composed of syn-subduction sediments. Progressing outward, the mid portion is dominated by a series of imbricated thrust faults and folds with asymmetrical sub-basins forming on the back limb of the folds. The outboard of the imbricated zone is represented by a relatively non-deformed outer portion consisting of long wavelength frontal folds underlain by propagating thrusts.

Even though major structures are visible in the 2-D data, the limitations of 2-D imaging mean that there is little understanding of the deeper portions and the relationship between structures. With the 3-D dataset and the rich low-frequency content, there is a significant improvement in event continuity at depth. As a result, improved interpretability of deeper previously undefined structural elements enables more accurate structural models to be built and the evolution of the margin to be investigated.

The 3-D seismic acquisition and processing technologies give a considerable imaging uplift over the 2-D data and create a platform on which to image and map the structural and stratigraphic elements in detail across the Pegasus Basin. As a result, E&P companies can conduct more thorough investigations of the subsurface, helping to unlock the full potential of this region.
The shale boom transformed the onshore drilling rig fleet as rigs capable of drilling horizontal unconventional wells typical of major North American basins differentiated from their peers and, consequently, more sought after. The downturn demanded new efficiencies, driving a massive shift in well orientation that would ultimately make onshore unconventional wells the most economical and profitable drilling option. To drill and complete these wells, however, required better wellbore placement and hydraulic fracturing technologies. It required rigs with more power and speed that could drive the heavier strings necessary in more complex well construction as laterals got longer and formations more challenging. The industry demanded land rig advances that were ideal for use in this new oil field.

As oil prices recovered, and the market steadily gained momentum, the rigs that were coming back online the fastest were alternating current (AC) and “super spec” rigs, which are rigs with massive improvements in load capacities, drilling equipment with 1,500 hp or more and the ability to quickly move between well sites in pad drilling applications. Precision and control are also major concerns with super spec rigs, as stability is critical if wells are to be drilled without deviating from their planned trajectory through the oil-producing sweet spot. Lithologically complex formations with multilayered rocks of varying resistances have made wellbore placement and maintenance even more critical, positioning the rigs that are equipped to drill challenging extended-reach wells ahead of the competition.

Beyond power and speed upgrades, reducing footprint is a desire for drilling contractors, with modular equipment that can more easily be situated in various places on a drill floor becoming more widely used. Modularity allows the drilling contractor to customize the rig’s layout in a way that benefits the operator while optimizing equipment placement also ultimately lowers maintenance intensity. Additionally, rigs with automation capabilities built into the drilling control system provide further benefit to both the contractor and operator. As a result of the advent of these well-equipped super spec rigs in North American land drilling, mechanical rigs have generally not returned to service. Similarly, silicon controlled rectifier-powered (SCR) rigs have largely remained idle unless AC rigs were unavailable. In many cases, drilling contractors are looking to convert SCR rigs into AC rigs to improve performance and make them more competitive in the marketplace.

**New purpose-built land rig**

Much of the demand for super spec land rigs has come from the Permian Basin, which has experienced a renaissance of sorts over the past several years, as well as other high-activity areas in North America and the Middle East. Beyond the previously discussed benefits of these rig types in North America, the Middle East benefits from additional changes to rig design, including
being able to handle higher temperatures and having wheeled moving systems suitable for desert applications. Across regions, part of the appeal of a super spec rig is that it has efficiencies that make drilling economical where it otherwise might not have been, and even the simplest of changes can have an impact. For example, having a top drive that runs up and down the mast rails instead of using a torque tube means the top drive can travel within the mast during rig moves, making rigup and rigdown simpler and faster.

National Oilwell Varco (NOV), as a manufacturer of rigs and equipment, understands market dynamics in the land drilling arena. The need for higher horsepower, larger hookload capacities, increased setback capacity and pad drilling capabilities were the primary drivers as the company builds on years of design and engineering efforts to develop a new rig. NOV announced its new Ideal 2000, a purpose-built land rig, not one upgraded from its original 1,500-hp configuration. The design of the rig allows operators to have configurable options.

An optional stand transfer vehicle can be included in the fingerboard, while pipehandling can be mechanized. The design of the drawworks enables its configuration to needed horsepower capacities. The rig’s design also is ready for the addition of a third mud pump and can accommodate up to four generator sets. A third mud pump not only provides an additional 7,500 psi of fluid circulating capacity for deeper wells but also makes the system more redundant—streamlining maintenance when the other two pumps are running or providing a backup in a case of failure in one of the other pumps. The added generator set accommodates the power needed by the third mud pump and provides added redundancy in case another engine goes down. The auxiliary generator provides power as requirements increase, with the fourth generator set giving the power system more flexibility to accommodate those requirements.

Walking rigs not only benefit drilling contractors but also help to improve oil field economics, boosting efficiency and driving the output of the newer units higher. Typically, rig movement has required rigging up and rigging down, meaning that even the simplest of moves could be a nightmare because of time lost disassembling and reassembling the rig. Earlier rig models have not been ideal for walking applications for a variety of reasons, with the drawworks’ placement on the ground and the hydraulic power unit and cabling setup being the primary issues. The Ideal 2000 rig design has an integrated walking system, allowing the rig—with a full setback—to move to an adjacent well. Placement of the drawworks on the drill floor, along with a dedicated local equipment room for the top drive and drawworks, reduces cabling. The hydraulic power unit, BOP control unit, drill line spooler, and choke and kill manifold are cantilevered off the substructure to travel with the rig.

**Automation upgradable**

If the drilling contractor is interested in drilling automation, then the NOVOS-enabled rig equipment ensures less downtime for an upgrade. NOVOS, NOV’s process automation platform, is deployed within the Amphion or Cyberbase control system to automate repetitive processes, taking the burden away from the driller and standardizing performance at the rig and fleet levels. Also, the platform hosts a selection of drilling performance applications that address various drilling dysfunctions, allowing the operator to improve performance through better understanding of what’s going on in the well. Having the automation platform presents a benefit to all participants in the process; drilling contractors can further differentiate their fleet, and operators have access to critical performance-improving tools and software. Applications also can be custom developed, an endeavor already pursued by several oil and gas companies, universities and other interested parties.
Industries from every corner of the world have embraced the digital transformation and have begun to adopt the new technologies available to them. The oil and gas industry is no different; new technology is continuing to dramatically change the way the industry successfully operates. As the oil and gas industry quickly changes, organizations are challenged to adapt to these changes and adopt new technology. One area that has become a focal point for this transition is the maintenance of pump equipment.

Before adapting to new technologies even enters the equation, the oil and gas industry is facing a shortage when it comes to experience with pump maintenance. The industry continues to lose the expertise required to properly care for and maintain equipment. Veterans of the industry have developed an innate ability that allows them to listen acutely for the sounds of a problem associated with the equipment, a skill that their businesses so heavily depend on. As experts leave the field for one reason or another, new faces take over the reins of responsibility for maintenance. Unfortunately, those new hires often lack the proper experience and expertise to care for pumps; as a result, equipment ends up being misused and abused.

**Supplementing field experience**

When the signs of required maintenance are missed and equipment ends up being mistreated, the consequences are severe. The overall life expectancy of equipment can be lowered drastically, reducing the value of an investment. As damaged equipment goes through lengthy repairs, the downtime impacts a business. Not only is the business paying for an expensive and likely avoidable repair, but it is also unable to stay up and running, keeping its operation from profitability. With the increasing deficit of experts, oil and gas businesses must change the way they do maintenance by adopting new ways to monitor information and manage equipment.

Although organizations are challenged to address the lack of expertise in the field, they are also met with a shifting environment where new technology is playing a central role in the way maintenance is conducted. Twenty years ago, there was no automation and very limited electronics being used by pumps and other equipment. Even five years ago, pumps were providing much less information than they are able to currently. Today’s equipment is smarter, with enough computing power to record incredible amounts of data and provide a completely different level of monitoring and insight, including access to second-by-second changes.

**Adopting new technologies**

Adjusting to the new technologies associated with pump equipment can be challenging, but when that technology is leveraged to the fullest extent, it can provide immeasurable benefits to organizations. Not only does today’s technology allow data to be collected to fill the void left by those with the expertise to understand the proper way to care for pumps, those data provide new insights that allow workers to do an even better job of understanding their equipment and how to maintain it, ensuring organizations get the most use possible out of their equipment.

The roller bearings of a QEM 3000 pump are inspected for wear following more than 3,000 hours of use. (Source: Weir Oil & Gas)
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Businesses in the oil and gas industry need ongoing maintenance programs and repair options to solve their challenges and ensure equipment performs safely, reliably and efficiently. They need to minimize the downtime and extend the life of their equipment. To meet the requirements of the industry, modern solutions must leverage Industrial Internet of Things (IIoT) technology and Big Data analytics to connect and monitor all equipment for maintenance in a one-stop shop that is easy to understand and respond to. As more data become available, a solution is needed that prevents data overload by turning information into intelligent insights on trends, issues and predictions to keep pump equipment operating as effectively as possible.

Cloud computing system

One example of a system providing these services is Weir’s IIoT platform, Synertrex. The platform harnesses the latest cloud computing technology to transform productivity, foresee risk and enhance performance. Data are gleaned from products and transformed into powerful insights that can help identify problems before they occur, reduce downtime and optimize equipment performance across an entire circuit. Tools such as this are able to leverage the most innovative technology available to accurately monitor equipment for maintenance issues that are arising or could arise in the future, preventing problems such as the failure of critical components. This translates into protecting a business’s bottom line.

In addition to the insights an IIoT platform can provide, organizations need an aftermarket solution that does more than provide repairs. A modern solution must help customers eliminate nonproductive time, improve safety and lower long-term costs. Weir Edge services does this by looking at all equipment and trends to see if current needs are being met and responding quickly to keep uptime at a maximum. The system provides root cause analysis and product life extension strategies in addition to traditional pressure pumping equipment and repairs, maintenance programs, planning and implementation, and onsite training and education.

Today’s organizations also need a modern solution capable of efficiently, accurately and reliably managing inventory by utilizing technology to cut down on the man-hours traditionally required for this task. For example, Weir’s SPM RFID technology and mobile application allow organizations to access detailed inspection information of their assets in real time from anywhere in the world all at a fraction of the time it previously took to capture, maintain and share this information.

These levels of precision and convenience are requirements in the current industry environment.

A new paradigm shift

Ultimately, the oil and gas industry’s growing shortage of pump maintenance expertise, coupled with the rise in innovative technology being applied to equipment, results in a paradigm shift. To compensate for the dearth in employee expertise, the industry is changing its approach to pump monitoring and maintenance, increasingly relying on technology to provide the information and insights needed to accurately care for valuable equipment and improve upon the process in which maintenance is conducted.

Organizations need solutions that use IIoT and Big Data technology to provide a full view of maintenance plans, equipment utilization and real-time monitoring data to properly care for their pump equipment. Current solutions are capable of turning mass quantities of data into quick, actionable insights, decreasing downtime of equipment and offering predictive maintenance. All of this results in increasing the efficiency of equipment in a cost-effective manner and increasing the speed, uptime and safety of a business and its valued equipment.

Although the oil and gas industry might be facing challenges as its environment changes and experts are no longer readily available, if organizations adapt to these changes and adopt new technologies, they can run smarter maintenance operations than ever before, extending the life and uptime of their pump equipment.
Smart pressure pumping technology provides better performance

The industry has a new standard in pressure pumping performance. AFGlobal is the leading manufacturer of pressure pumping technologies providing fully integrated and customized solutions. Our advanced AMI cloud-based control and data management allows for better real-time decisions. And the precision-engineered DuraStim™ Gen II frac pump, rated for 6000 hp, provides continuous duty and operational efficiency. That’s industry-leading innovation—all designed to reduce downtime, lower operating costs and optimize operational efficiency.

afglobalcorp.com/NRG
The most recent downturn in oil prices presented some of the darkest times for oilfield equipment manufacturers and their pressure pumping customers. Tens of thousands of machine shop, manufacturing and oilfield service workers were furloughed. The downturn did not discriminate against executives, middle managers or critical hands-on workers. Now that the dust has settled, there was a new message to those who survived—innovate or die.

It is the mantra that E&P operators, supporting service contractors, equipment manufacturers and even the suppliers of raw materials have come to embrace. Desperate times called for desperate measures, and no group was immune to the immense pressure to cut costs, lead times and process cycle times.

In 2015 Kerr Pumps was drawn into the fluid end replacement market by several large pressure pumpers in search of longer lasting fluid ends that could withstand the high pressures needed to fracture shale. At that time, a global special metals producer was looking for a partner to experiment using an extremely tough aerospace stainless steel alloy for fluid end forgings. Super Stainless, a high-tensile, high-Charpy stainless steel, was introduced as an innovative metallurgy as compared to 4330 carbon steel and 17-4 PH stainless steel.

Through the downturn, the company continued development of new sealing technologies and fluid end designs that shifted wear to sacrificial consumable components rather than to the expensive fluid end. In 2017 the two-piece Frac 1 CONNECT fluid end was developed with a 30% to 40% lower price point than the legacy flange-style design.

New fluid end, valve seat designs

To dissipate the enormous cyclic stresses generated within fluid ends during high-pressure pumping, a departure from the legacy fluid end form factor was required. Most notable was the transition from threaded suction cover caps to a stud-and-nut design.

In pumps that use the threaded suction cover caps, a 4.5-in. plunger pumping at 12,000 psi delivers more than 287,000 lb of stress onto the threads of the caps. With the stud-and-nut design of the Frac 1 CONNECT fluid end, that stress is dispersed down to 35,875 lb across each of the eight studs and nuts (Figure 1).

If there is one Holy Grail in pressure pumping, it would be maintenance-free stages for the fluid ends. Valve seats are the lowest common denominator for...
routine fluid end maintenance. The company developed the Super Seat valve seat to address wear (Figure 2). The stainless steel construction of the valve seat includes tungsten carbide at the strike face to endure more than 200 hours of operation regardless of the proppant composition or the shale basin. Since January the company has monitored the field performance of thousands of Super Seats, with numerous reports of the seats lasting more than 400 hours with minimal signs of wear.

Developed to bridge the gap until a longer lasting, 200-plus-hour valve is introduced, the company has developed the Frac One X (F1X) fluid end design, which features a bolt-on threaded hammer nut to access the fluid end (Figure 3). The F1X provides the familiar threaded cover cap of the legacy-style fluid end with an added fail-safe protection. The major problem this design solves is seized cover caps from broken threads. Simply replace the bolt-on threaded hammer nut—in the field—and resume pumping. The F1X brings forward the new two-piece fluid end design for a more rigid connection with substantial stainless steel cost savings. Additionally, there are bolt-on cover caps to disperse the massive cyclic stress loads, while providing threaded connections for simpler swap out of valves and valve seats.
The future of methane management

Several opportunities exist to reduce GHG emissions in production operations.

According to the U.S. Environmental Protection Agency’s (EPA) “Inventory of U.S. Greenhouse Gas Emissions and Sinks” report, methane accounts for about 10% of U.S. greenhouse gas (GHG) emissions. Of this, one-quarter is from the natural gas industry. Expressed as a percent of natural gas production, this equates to 1.3% of production. While other studies have suggested much higher emission levels (some as high as 7.9%), the most recent and most comprehensive non-EPA study found emissions only slightly higher at 1.7% (the paper tabulates emissions for both oil and natural gas systems at 2.3% of gas production. ICF estimates that the natural gas portion equates to 1.7% of emissions).

ICF’s services for measurement and mitigation of methane emissions from the oil and gas industry have included work for the industry, regulators and nongovernmental organizations ranging from policy analysis and development to direct support for industry operations. Over the last five to 10 years, the company has seen an increasing focus on methane emissions from these industries for several reasons.

Among those is that the climate-forcing effect of methane is greater than that of CO₂. The global warming potential (GWP) describes the ratio of methane equivalent to 1 ton of CO₂ and can range from 34 to 86, depending on the timescale being considered. On the positive side, this means that reducing 1 ton of methane is equivalent to reducing 34 to 86 tons of CO₂. In addition, there are available methane-reduction technologies for most of the emission sources.

When methane emissions can be captured and sold, the value of the gas can offset the cost in some cases.

Tracking emissions

On the other hand, reducing methane emissions is complicated by the fact that the natural gas industry is actually several different industries with different types of emission sources and ownership and regulatory structures. The EPA inventory includes more than 100 different industry segment/emission source categories. Figure 1 shows the EPA estimate of emissions in the various industry segments. Gathering and boosting is the largest, followed closely by development and production, and then transmission and storage.

Methane emissions from oil and gas operations have declined significantly since the EPA started tracking them, decreasing from almost 200 MMtonCO₂e in 1990 to 164 MMtonCO₂e in 2016. (Editor’s note: According to the EPA, the unit CO₂e represents an amount of GHG whose atmospheric impact has been standardized to that of one unit mass of CO₂, based on the GWP of the gas.) Moreover, natural gas production has increased significantly during that same period, so emissions per unit of production have been declining continuously, falling by 45% from 9 kg CO₂e/Mcf in 1990 to 5 kg CO₂e/Mcf in 2016 (Figure 2).

![2016 GAS INDUSTRY METHANE EMISSIONS (MMtonCO₂e)](image)

**FIGURE 1.** Upstream segments are the largest contributors to methane emissions. (Source: EPA)
There are several reasons for this continuing decline. As equipment is replaced and new equipment comes online, the new equipment is typically cleaner and more efficient.

In addition, the industry has made significant voluntary reductions, including those made in cooperation with the U.S. EPA Natural Gas STAR program, which has reported more than 28 Bcm (1 Tcf) of methane reductions.

In recent years federal regulation (e.g., New Source Performance Standards) and state regulation (e.g., Colorado Regulation 7 and Pennsylvania GP-5) also have resulted in reductions.

Opportunities for reduction
Nevertheless, there are still opportunities for further reductions. In 2014 ICF completed a study that quantified the opportunities and costs for methane reductions in the natural gas industry. Since that time the quantification of baseline emissions technologies has improved, new regulations have changed the baseline, mitigation technology costs have declined and new technologies have been developed. Although the specific results of the study could bear updating, they are useful for an initial survey of current opportunities for reductions.

Some of the opportunities, while still cost-effective, are no longer as large because they have now been implemented at many facilities or are now required by regulation. For example:

- Emissions from well completion for hydraulic fracturing are regulated to a high degree of reduction;
- Many high bleed pneumatic devices have been replaced and low bleed pneumatics are now required for many applications;
- Instrument air is required in certain applications as a replacement for gas-powered equipment;
- Scheduled rod packing replacement is now required for reciprocating compressors in some applications; and
- Wet seal compressor emissions are lower than previously thought.

Management opportunities
Although many of these opportunities might be smaller than projected a few years ago, some of them still might be attractive. In addition, there are other opportunities that have changed less and present good possibilities. One is leak detection and repair programs and control of nonstandard emission events. Structured periodic inspection and leak detection programs are important to maintaining good equipment performance, identifying equipment problems that create emissions and avoiding intermittent malfunctions that can result in large emissions.

Another such opportunity might be better control of liquids unloading. Well venting to control liquids is a potentially large source of emissions. There are a variety of alternative measures depending on the age and other characteristics of a well, so there is no one solution, but lower emitting solutions exist and should be pursued. New approaches might be required for horizontal wells as they age.

A third opportunity could be replacement of pneumatic pumps. Electric pumps or instrument air can be highly cost-effective alternatives where electricity is available either from the grid or onsite gas- or solar-powered generators.

Vapor recovery from tanks is still an important option even though more tanks have been regulated in recent years. Although the emissions are small in the overall inventory, reduction of methane from the natural gas industries can be a cost-effective option.

Finally, flaring of stranded gas from oil wells could be an opportunity for implementation. Even as flaring is being reduced via improved infrastructure and due to regulation, there are still opportunities to reduce flaring through onsite gas use and/or capturing the gas via CNG or LNG.

References available.
Advancing CO$_2$ EOR as a form of carbon capture in the Permian

Additional EOR pilots have been initiated in the Delaware and Midland basins.

Richard Jackson, Occidental Petroleum

With more than 40 years of experience in the application and use of CO$_2$ EOR technology, Occidental Petroleum has injected more than 50 million metric tonnes of CO$_2$ annually to produce oil in the Permian Basin that would otherwise be left in reservoirs. The company’s global strategy includes active investments in CO$_2$ EOR and carbon capture, utilization and storage (CCUS) as well as other emissions-reducing technologies. Occidental believes these technologies offer meaningful tools to address greenhouse gas emissions and grow its business. In the Permian Basin, Occidental relies upon multiple CO$_2$ sources, both natural and anthropogenic, transported by dedicated pipelines, to ensure an adequate supply for the company’s 34 CO$_2$ EOR projects. This includes the Occidental-operated Bravo Dome Field in northeastern New Mexico and additional supplies from methane fields in the southwestern Permian Basin. Occidental’s Century Gas Plant in Pecos County, Texas, further expands the company’s EOR infrastructure in the Permian Basin by capturing CO$_2$ from the natural gas processing.

Occidental has received Environmental Protection Agency (EPA) approval for two monitoring, reporting and verification (MRV) plans for CO$_2$ EOR fields in its Permian Basin operations at the Denver Unit in Texas and Hobbs Unit in New Mexico. These plans, which were the first-ever approved by the EPA, provide a framework for quantifying the amount of CO$_2$ permanently sequestered in the geology of the reservoir.

The specifics of the MRV plans are best reflected in the EPA’s final decision letter for the Hobbs Field:

“The MRV plan identifies, describes and reviews potential pathways for surface leakage, including the likelihood, magnitude and timing of potential leakage,” the letter stated. “For example, in examining existing wellbores as a potential leakage pathway, Occidental identified active and inactive wells that are completed in or penetrate the Hobbs Field, summarizes regulatory requirements for the wells and describes operational practices for mitigating potential risks. As another example, Occidental examined the probability of leakage through subsurface features, such as faults and fractures, and determined that there were no faults or fractures that transect the San Andres Formation interval in the project area and provided several lines of evidence supporting this conclusion. Occidental determined that there are no leakage pathways at the Hobbs Field that are likely to result in significant loss of CO$_2$ to the atmosphere.”

The EPA confirmed in its findings that Occidental’s MRV plans had successfully assessed the reservoir’s storage...
capacity, identified and mitigated potential pathways of CO₂ leakage, and monitored and reported the amount of CO₂ sequestered throughout the process. The MRV plans demonstrate the safe and secure storage of CO₂ through EOR in a fully transparent manner.

During the first year of the plan, Occidental sequestered more than 3.1 million metric tonnes, as measured by the MRV plan. More than 25% of this sequestered amount came from captured anthropogenic sources, which is the equivalent of the emissions of more than 200,000 vehicles per year.

What’s next
Significant opportunities remain to gain additional recovery by expanding Occidental’s existing CO₂ projects into new portions of reservoirs that have only been waterflooded. The company’s EOR operations include a large inventory of future CO₂ projects, which could be developed over the next 20 years or accelerated, depending on market conditions.

Occidental also has implemented four different unconventional EOR pilots across the Midland and Delaware basins. The initial results are encouraging, and advancing this technology will allow Occidental to incorporate EOR into its future horizontal drilling development plans.

Meanwhile, Occidental is working with biofuel producer White Energy to evaluate the economic feasibility of a CCUS project. The study, which is expected to be completed early next year, will examine the cost of building a carbon capture facility. If deemed economically feasible, the project would capture CO₂ at White Energy’s ethanol facilities in Hereford and Plainview, Texas, and transport it to the Permian Basin for sequestration in Occidental’s EOR operations.

Climate and energy authorities, including the U.N. Intergovernmental Panel on Climate Change and the International Energy Agency (IEA), recognize the important role that CCUS must play if atmospheric carbon concentrations are to be limited to levels targeted in international climate accords. Based on research by the IEA, it has been shown that CCUS in the form of EOR, along with anthropogenic carbon CO₂, can provide a significant reduction in life-cycle per barrel CO₂ emissions compared to oil produced using non-EOR techniques.

The lower carbon future that global industries must work to achieve will depend on continued technical advancements in capture technology and the application of CO₂ EOR, which governmental policies, such as the recently passed FUTURE Act or 45Q, will provide. One opportunity for growing this technology would be to increase the reach of the current pipeline infrastructure system. Industries that emit CO₂, such as refineries, power generators, ethanol plants and cement plants, might not be located near a pipeline or a sequestration site like EOR or saline reservoirs. Locating a CO₂ pipeline, such as the proposed pipeline from Houston to the Permian Basin, along corridors where there are many capture opportunities provides synergies that, combined with 45Q, will help with the economic feasibility of both carbon capture and pipeline projects.
Putting AI and cloud technologies to work in the digital oil field

Systems enable predictive maintenance for ESPs.

Nico Jansen Van Rensberg, Siemens AG, Germany

Given that most oil and gas wells must go on artificial lift at some point during their production life cycles, and with electric submersible pumps (ESPs) being one of the most efficient ways of doing so, it is no surprise that most offshore wells use them to maximize output as much as possible.

But even though ESPs are designed, engineered and built for rugged reliability in the harsh conditions of corrosive seawater and extreme deepwater pressures, they can fail. And when they do, the costs to repair or replace them are extreme but usually dwarfed by the costs of lost production.

Actionable insights
Siemens developed a predictive maintenance solution called AI4ESP for remotely monitoring ESP performance by applying artificial intelligence (AI) technology. Compared to conventional approaches of ESP monitoring, AI-assisted monitoring can be transformational. That is because large amounts of data—many datapoints every second—can be processed with almost unlimited scalability. Taken together, all these data can provide a digital map of ESP operations, effectively creating smart pumps at the heart of a digital oil field. Because it is vendor-agnostic and standards-based, this concept provides coherent monitoring of all ESPs deployed in a field across multiple vendors’ equipment, eliminating the need to deal with difficult interface problems. It also can apply to all types of ESP applications, offshore or onshore. Although the system utilizes cloud-based technologies, the design of the solution is such that it also can be used with private clouds or on premise systems.

Successful field test
Recently, for an onshore E&P customer in Germany, Siemens conducted a successful test of a cloud-based, ESP monitoring solution that uses AI and Industrial Internet of Things (IIoT) connectivity. Siemens is planning a similar proof of concept for an offshore production platform with multiple ESPs.

Today an ESP’s sensing fabric draws from its automation and electrification systems, while its SCADA system logs data into historian databases, mostly used for troubleshooting or forensics. Although deviations can alert operators to performance issues, this now happens only after an event occurs—when a potential production impact may already be underway.

In contrast, the Siemens ESP predictive maintenance system brings together AI and cloud-based IIoT technology while ensuring sensitive production data remain highly secure. It uses an ESP’s streaming process data as fuel to build an ever-richer ESP operating profile in these three ways:

1. Anomaly detection: As ESP data stream 24/7 from the wellsite into a cloud-based database,
advanced analytics and AI algorithms seek variances from expected behaviors of various parameters. Deviations are flagged and alerts sent to operators before a performance event occurs. The graphical representation shows the different types of ESP data being processed. An anomaly in the data source as indicated can reveal a potential failure several days before the actual failure of the ESP mechanism.

2. Behavior labeling: As data keep streaming into the database that holds the ESP’s ever-more precise operating model, machine learning occurs as the pattern recognition and statistical algorithms get smarter over time. Here, the Siemens Artificial Lift Suite software and the cloud model’s advantages kick in. Operating data from ESPs worldwide can be aggregated and analyzed to label ESP behavior profiles specific to their applications and environments. These not only can flag behavior anomalies in one ESP but also alert operators of ESPs in similar applications and environments, delivering even more advanced notice of an emerging issue.

3. Predictive maintenance: Given the real-time feedback loop between an ESP and its cloud-based operating profile (i.e., its digital twin), ESP operators can deploy predictive maintenance models that use proactive condition monitoring to provide them with decision support about how to address impending issues. This can ensure greater ESP availability and uptime while saving spare parts and labor. Costly disruptions can be avoided.

AI’s potential is just starting, with many new applications expected in the future to help optimize asset utilization and lower production costs for greater profitability across the oil and gas industry. The ultimate goal of applying AI in the digital oil field is to improve decision support so ESP operators can know how to prevent production disruptions and use the intelligence from the advanced analytics to optimize reservoir production.
Marginal fields—friend or foe for operators?

A new modular system combines the advantages of a platform with the rig-run benefits of a subsea development.

Despite a modest increase in offshore E&P activity, many development prospects remain largely unattractive to the major industry players. Stranded hydrocarbon discoveries, aptly called “marginal fields,” are being largely ignored by bigger operators due simply to some discoveries’ limited scope, such as the size of the reserve, making the field economically infeasible. Decision-making for the development of marginal fields requires a thorough investigation of the economics of development costs and hydrocarbon recovery rates as well as an evaluation of the technical and geological conditions and risks. Other concerns, like limited or nonexistent pipeline infrastructure to get products to market, further complicate a hard-to-sell value proposition.

With operators routinely seeking efficiency gains and cost improvements to maximize their use of capex, it isn’t worth the economic investment to develop a field if the reservoir is small and/or the production potential is low. It is often the case that fields with marginal economics and low reserves will require some sort of unique solution, a novel concept that will remove development barriers in that scenario. Unfortunately, this reduces the attractiveness of marginal fields to large operators because of limited fieldwide applicability during a well development campaign. Yet that very same field could be, for a smaller and more agile operator, a chance to quickly implement an effective solution on a project with three or four producing wells. Such a solution could yield much greater benefits when produced on a shorter life cycle than typical larger developments, which stretch over significant time frames.

Case study

DeNovo Energy Ltd. is a new independent upstream company operating Block 1(a) in the Gulf of Paria offshore the west coast of Trinidad. The company set out to drill a three-well development campaign in the stranded Iguana Field using a jackup rig in shallow-water depths of approximately 27 m (88 ft). The field is undergoing fast-tracked development and is expected to yield 2 MMcm/d (80 MMcf/d) of gas that will be transported to the Port Lisas Industrial Estate for processing via a 45-km (28-mile) offshore and onshore pipeline.

The history of the Iguana Field dates back to the early 1980s, but the field remained undeveloped despite changing operators several times. DeNovo acquired the block in 2016 and benefited from a lean operating structure and in-depth knowledge of the region. Additionally, DeNovo’s size meant the economic impact to the company would be strong enough to merit an investment, even with lower production levels.

National Oilwell Varco (NOV) worked with Aquaterra Energy, a provider of global offshore engineering solutions, to deliver an application of its XLC-S connector on an Aquaterra Energy-developed offshore platform. The Aquaterra Energy concept, called Sea Swift, is a conductor-supported platform ideal for benign, shallow-water applications, such as the Gulf of Paria. In such applications, Sea Swift reduces maintenance and well capital costs by
utilizing dry trees and enabling access provision by crew boat or helicopter. The design of the solution facilitates quicker, more cost-effective installation, enabling all activities to be performed by a standard jackup rig without the need for additional installation vessels. This reduces upfront costs while also eliminating the need for traditional platform structures.

The benefits of rig-installable, conductor-supported platforms often outweigh those of traditional platforms and subsea trees for shallow-water development projects. Aquaterra Energy’s Sea Swift concept was the ideal solution for DeNovo’s challenge of developing the Iguana Field economically. It helped DeNovo reduce necessary capex while also simplifying and accelerating the path to first gas.

The unit, which included local power generation, manifolds and a control system, was completed end-to-end in 10 months and was the first of its kind to be installed in the country. The cost savings achieved were magnified by the use of a smaller fabrication yard that worked quickly and effectively. Furthermore, using the jackup for installation made it easier to manage the project and reduced any risks involved with transportation and installation.

NOV provided Aquaterra Energy with the XLC-S connector for the platform, which is a second-generation integral connector with the pin and box threads machined directly into the wall. In addition to having an optimized connector geometry, the XLC-S also has a true flush inside diameter and outside diameter.

The connector is ideal for conductor-supported platforms due to the enhanced structural strength and improved fatigue performance, while the external metal-to-metal seawater exclusion seal ensures that corrosion in the threads will not be an issue. XLC-S connectors typically make up via three low-torque, spin-up turns until the thread surfaces engage. The connectors can be made up with either power tongs or manual tongs at comparatively low makeup torque rates of 30,000 ft-lb to 60,000 ft-lb, depending on size. Comprehensive physical testing of XLC-S connectors and a significant amount of field data have validated the connectors’ performance, and they take up no more annular space than a pipe. Additionally, the design of the connector eliminates large diameter forgings and welding costs, which on this project was a critical driver of both reducing overall costs and helping Aquaterra to deliver the platform to DeNovo in such a short time frame.

Drilling has been completed for all the Iguana wells using the Well Services Rig 110, and first gas is expected by the end of the year.

**Friend or foe?**

For the smaller, more agile E&P companies, marginal fields should not be ruled out, despite some of the inherent risks such fields pose. The main challenges come from developing an innovative solution that will make the field profitable and implementing that solution on the actual project. As the price of fabricated steel has decreased, so have the cost differences between a conventional jacket and alternative options, such as a Sea Swift platform. Overall cost savings primarily come from using smaller and more agile fabrication yards and a jackup rig for installation, as demonstrated by DeNovo in this application. This also helps to ensure a simpler, more cost-effective project management process and reduces risk associated with the development itself.

These factors in today’s cost-constrained climate mean that a conductor-supported offshore platform solution is becoming a more financially viable option for fast and effective production in marginal shallow-water developments. As a working example, due to the reduced time to first gas and the cost benefits of using a jackup rig for installation, a Sea Swift platform installation can be up to 45% less expensive than a conventional jacket platform.

For DeNovo, the choice was clear. The modularity of Aquaterra Energy’s conductor-supported platform allowed DeNovo to bring together the advantages of a platform with the rig-run benefits of a subsea development, while NOV’s connector technologies provided improved structural integrity and fatigue performance as well as assisted Aquaterra Energy in delivering the platform quickly. This type of combined, integrated solution, showcased via DeNovo, is ideal for the economics of marginal field developments.
Innovative technologies for industry’s toughest challenges

Companies at ADIPEC 2018 will be showcasing new products and services designed to meet industry challenges.

The Abu Dhabi International Petroleum Exhibition & Conference (ADIPEC) is being held Nov. 12-15 in Abu Dhabi. ADIPEC is “a world-class business forum where oil and gas professionals convene to engage in dialogue, create partnerships, do business, and identify solutions and strategies that will shape the industry for the years ahead,” according to the conference website.

The event will feature about 2,200 exhibiting companies, 980 expert speakers, 161 conference sessions and more than 110,000 attendees.

The following is a sampling of some of the latest technologies that will be showcased at ADIPEC 2018.

Editor’s note: The copy herein is contributed from service companies and does not reflect the opinions of Hart Energy.

Platform provides 24/7 online access to API standards

At ADIPEC 2018 the American Petroleum Institute (API) will be showcasing API Compass, a platform that incorporates the latest technology to give companies organization-wide, 24/7 access to all API standards and specifications. API standards help ensure safety, compliance and interoperability. A subscription to API Compass offers powerful workflow tools, allowing users to annotate on the fly plus compare versions easily. An enhanced search feature allows users to find the information they need quickly and effectively. Clients also may get customized sets of standards and access both the HTML and PDF versions. The ability to share a standard, cite it, then link it back to the company intranet is a valuable feature. API’s clients also benefit from automated notifications of new and revised standards with the ability to access API standards remotely. API Compass is designed to deliver reliability and efficiency, saving organizations both time and money. api.org

System eliminates traditional process of shaking fluids from drilled solids

Cubility AS will be showcasing the latest evolution of its solids control solution, the MudCube, at ADIPEC 2018. The MudCube is a compact, lightweight solids control system that eliminates the traditional process of shaking...
The Fragmenting Gun System is designed to fragment or break up into small pieces upon detonation of the perforating charges. (Source: DynaEnergetics)

Fluids from drilled solids. The system uses a combination of high airflow and a rotating screen filtration system to improve separation efficiency, allowing more drilling fluid to be recycled and resulting in dryer cuttings and less waste. Building on these capabilities, the MudCube X comes with an enhanced modular design for easier integration into rig designs and fast installation and maintenance, ensuring immediate value and return on investment to Middle East operators and drilling contractors. The MudCube X also is engineered to allow local manufacturing and assembly in Gulf Cooperation Council countries, providing customized solutions that directly address Middle East needs. cudility.com

**Perforating gun system breaks up into small fragments upon detonation**

This year DynaEnergetics will be introducing the Fragmenting Gun System at ADIPEC 2018. This non-retrievable perforating gun system was designed in collaboration with Shell. It features encapsulated charges tested to 15,000 psi. The system is designed to fragment or break up into small pieces upon detonation of the perforating charges. The debris then settles to and remains on the bottom of the wellbore or sump. This new technology provides multiple benefits, from cost savings in drilling time to better production by utilizing charges with higher explosive loads. With no need for extra sump since the gun breaks into small pieces, the drilling time can be shortened by hours or days. Also, in thru-tubing applications where there are restrictions in the tubing, the system can be deployed without the worry of gun swell since the gun fragments upon detonation. dynaenergetics.com

**New rotary steerable system drills fast, increases reliability**

Halliburton Co. will be showcasing the iCruise intelligent rotary steerable system, a new technology that provides operators with automated drilling commands and real-time directional data to optimize decision-making to reduce rig time and save costs. The iCruise system provides some of the highest mechanical specifications available that deliver 400 rpm and up to 18 degrees/30 m (100 ft) dogleg capabilities to drill fast while delivering greater accuracy. In North America it helped an operator drill more than 1.6 km (1 mile) in a complex reservoir while geosteering through a 9-m (30-ft) productive zone and maintained the wellbore 100% in the reservoir. Additionally, the Prodigi AB service is a first-of-its-kind offering that introduces automation to hydraulic fracturing. By automating the breakdown process of a fracturing treatment, it helps deliver better well performance. The service uses algorithmic controls and is supported by a Halliburton completion adviser who tunes the system to optimize performance. Prodigi AB service improves overall efficiency, maximizes the performance of perforation clusters and mitigates the risk of screenout. It also provides consistent design execution, better distribution of fluid across the perforated interval and improved treatment pressures. halliburton.com

**Better way to design, manage projects**

Using project life-cycle management of projects more effectively is a key area in which McDermott has invested its digitalization efforts. The company is adapting this technology from the manufacturing sector and applying...
it to the capital project space. Instead of trying to manage an engineering, procurement, construction and installation project by sending emails with specifications and engineering drawings and using disconnected tools to execute engineering, McDermott’s approach has been the development of Gemini XD and the use of integrated engineering software. This is an advanced software platform that improves efficiency and productivity throughout the project life cycle. The platform enables McDermott to digitalize and standardize its processes, share information across the project team efficiently and drive down costs by shortening communication lines and bringing together engineering information into a single location. The key advantages are the ease of transparency and better collaboration on a project leading to digital project delivery. This enables working with the user in a digital fashion, cutting down on emails and the time it takes to close actions. The platform becomes the single source of truth not only for the project but also for post-handover operations. mcdermott.com

Right, the SAQR drillbit was designed specifically to meet the challenges of the Middle East market. (Source: NOV)

ION line of cutters, with unique-shaped geometries designed to improve ROP and drilling efficiency in harsh Middle East applications. In addition, superior depth-of-cut control components reduce risk of torsional oscillations. nov.com

Solutions for asset integrity challenges
Oceaneering provides comprehensive, field-proven solutions that enable better decision-making, focused spending and increased safety for all asset integrity challenges, including advanced and conventional nondestructive testing inspection technologies, integrity engineering services and inspection management. Oceaneering solves pipeline challenges safely and fast, providing the engineering and hardware required to address issues from minor defects to catastrophic failures. At ADIPEC 2018 the company will feature its Smart Flange Plus Connectors, which seal against the pipeline or riser to enable the safe completion of permanent subsea repairs, providing a robust, structural connection point. Avoid costly shutdowns and expensive hyperbaric welding with the Smart Tap Clamp for damaged or leaking pipelines, installable with or without a diver. The lightweight and portable Quantitative Short Range guided wave tool for identification of corrosion under pipe supports will be on display along with the permanently installed Wireless Ultrasonic System, which is battery-free, for condition monitoring. oceaneering.com

Mixing technology increases process flow momentum through annular restriction
At ADIPEC 2018 ProSep will have a technology focus on its proprietary Annular Injection Mixer (AIM). The AIM is a compact, in-line mixing technology that increases the process flow momentum through an annular restriction. The technology injects admixture—corrosion inhibitor, scale inhibitor, demulsifier, water, glycol, etc.—around the annular restriction to take advantage of the increased momentum, thus applying energy and shear forces to the complete fluid flow. A small stepped opening, along with a gradual return to initial pipe diameter, creates a dispersion force and intense mixing action that subsequently provides
enhanced mass transfer between the process fluid and admixtures. This typically results in almost 100% utilization of the admixture for mass transfer or thermal quenching. Recently, ProSep has developed the AIM technology through a series of joint testing programs, along with computational flow dynamic modeling, that demonstrated the mixer’s ability to provide about 100% mass transfer of water from natural gas into glycols (dehydration); create 100% heat transfer and quenching during wash water or caustic injection (corrosion prevention); and demonstrate 100% heat transfer and evaporation during admixture injection into a gas (thermal equilibrium). prosep.com

Well testing live performance system digitally integrates all process information
At ADIPEC 2018 Schlumberger will be introducing its Concert well testing live performance to bring real-time transparency, collaboration and accessibility to well testing, cleanup and production testing operations. This information-centric system digitally integrates all process information via ruggedized tablets, wearable technology, wireless sensors and video cameras. Efficiency, safety and the environmental footprint are improved while ultimately confirming both data quality and whether test objectives have been met. Concert performance’s in-line monitoring, data collection and analysis, quality control, real-time reporting and global communications capabilities have been extensively field tested in Kazakhstan, Saudi Arabia and Australia. Robust software drives web dashboards and video displays across the well testing team, remote operations center and customer offices. Interactivity gives all involved the same data, diagnostics and analysis. Data quality and usability are increased, and in turn, personnel exposure and the need for manual measurements are significantly reduced. slb.com

Chemical tracer and wireless technologies improve efficiency
RESMAN AS will be highlighting its chemical tracer and wireless technologies at ADIPEC 2018. The technology provides operators with zone-specific well production data and production trends for use in production optimization and continuous well performance evaluation, and it enables Middle East operators to monitor their reservoirs for up to 10 years without intervention risks and costs. With RESMAN, small amounts of chemical tracers are released continuously in different zones of the well. Through analyzing samples taken over a period of time (e.g., one sample every week), it is then possible to determine zone-specific production trends and water breakthrough events and to verify that the well has sufficient drawdown pressure. Consequently, the tracers add a zonal resolution to the well production data for targeted well performance assessment and operational decisions. To date, RESMAN’s technologies have been adopted by 52 oil operators worldwide in more than 485 production wells. resman.no

Increasing sand control reliability and maintaining injectivity
To address the challenge of sandface injection flow control, Tendeka has developed Cascade®; a new well screen, flow control completion system that utilizes intrinsic check-valves to prevent any backflow or cross-flow during shut-ins. Depending on well conditions, it also limits the damaging effects of water-hammer. As part of a three-year R&D program, a field trial was conducted with a major operator in the Gulf of Mexico (GoM) to improve performance on water injection wells, which had suffered severe loss of injectivity within a short period of
A Permian Basin saltwater disposal (SWD) well was used to test several aspects of functionality using multiple downhole memory gauges to record pressures at reservoir depth. The SWD well has been put on full-time water disposal duty for several months. Plans are in progress for the implementation of Cascade in an injector well on a deepwater GoM asset.

Water management solution lowers costs
Shale operations are dealing with higher water management costs and more environmental and operational risks than ever before, both of which are becoming an increasingly larger part of operators’ costs. Sourcing freshwater and increasing volumes of sand flowback and produced water, which are often trucked out and disposed, are the primary cause. Addressing these challenges in an environmentally responsible way frequently requires adding more services and personnel at each site. TETRA Technologies’ water management solution delivers innovative and differentiating offerings for produced water transfer, de-sanding and on-the-fly water treatment and recycling. By integrating and automating the company’s offerings, efficiency is maximized through job planning and crew optimization, helping reduce manpower for a typical fully integrated completion operation by more than 30%. The step change in efficiency is delivered through fully automated technology that provides greater transparency and quality control throughout the transfer, flowback and recycling of produced water—all while simultaneously improving environmental considerations.

Self-orientating tools aid completion string running
Varel’s Downhole Products will be showcasing a new family of completion string deployment technologies that provide simple, self-orienting solutions to common wellbore running problems. The LedgeRunner, Free-To-Rotate (FTR) and Lock-Rotate-Lock (LRL) guide shoe products aid the smooth running and installation of completion strings to total depth in challenging extended-reach and lateral wells. The tools improve the ability to reach total depth by self-orienting the string to run past problematic string rotation that can compromise completion-running operations in challenging extended-reach and lateral wells.
obstructions. LedgeRunner uses mechanical ratchet technology to navigate an eccentric nose past wellbore obstructions by applying minimum pickup and slack-off at the surface. FTR and LRL products use self-orientation of an eccentric nose without additional string intervention. varelintl.com

Automated connection integrity tool mitigates safety concerns
Weatherford has introduced Vero automated connection integrity, a new solution that goes beyond tubular running onshore and offshore. This world-first tool combines autonomous software and automated technology for the makeup and evaluation of casing and comple-

Right, Weatherford’s Vero solution applies artificial intelligence to mitigate safety concerns and build lasting well integrity, connection by connection. (Source: Weatherford)
tion connections. By applying intelligence to eliminate human errors or oversights, the technology enhances safety, increases efficiency and validates well integrity with absolute certainty. Automated makeup technology takes control during makeup and breakout. With smooth, computer-controlled precision, the technology delivers consistent results while eliminating the effect of human factors on the connection. Autonomous evaluation software serves as the brains during the process. The built-in software evaluates the makeup to the original equipment manufacturer criteria with unparalleled accuracy and consistency. weatherford.com

Program provides on-demand iron rental, asset management

Through its Weir Edge Services program, operators in Europe, the Middle East, Africa, Russia and the Caspian region can enjoy the ease and flexibility of on-demand iron rental, asset management and recertification of flow iron from all original equipment manufacturers. Weir offers 20,000 pieces of iron for immediate shipment to positively impact operators’ supply chains and asset management functions. Weir ships tested, certified equipment on demand, including pieces not normally stocked, to provide complete asset management and uninterrupted supply chain support. With Weir Edge, skilled engineers resolve any root cause of downtime, and equipment is returned to the field like new, backed by a guarantee. Weir’s RFID AMP technology underpins this new offering, providing service and recertification in any facility with its mobile recertification and pressure testing units. global.weir

Water-based fluid can be injected into the freeze zone

Wild Well Control Inc., a Superior Energy Services company, now provides a fluid for when liquid hydrocarbons are present. Wild Well’s newly developed FreezeLITE, a special water-based fluid, can be injected into the freeze zone. The fluid will displace hydrocarbon-based fluids and stay suspended in the freeze zone above the hydrocarbon-based fluid. FreezeLITE is designed to have low density so that it floats on the brine/methanol as well as any liquid hydrocarbon that might seep to the surface. Thus, a stable volume of easily freezeable liquid would remain in the freeze zone. This allows a freeze to be put into effect without having to remove the hydrocarbon-based fluids in the well, which saves thousands of dollars in terms of product and time. FreezeLITE is non-hazardous and safe for onshore and offshore applications. As an effective medium for nitrogen freezing operations, FreezeLITE allows operators to perform successful freezing operations under a variety of circumstances in challenging wells. wildwell.com

Weir’s RFID AMP technology, part of Weir Edge Services, underpins the company’s new iron recertification offering.
(Source: Weir Oil & Gas)

A 48-in. helical freeze offshore in the Middle East is shown.
(Source: Wild Well Control Inc.)
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Oil, gas production in the Rockies continues to climb

Laramie and Weld counties are seeing increasing permitting activity.

Brian Walzel, Associate Editor, Production Technologies

Following in the footsteps of their bigger brothers, most notably the Marcellus-Utica and Haynesville, the Niobrara and Denver-Julesburg (D-J) basins continue their climb to record production. However, unlike most other plays that saw substantial production declines post-2014, the Niobrara and D-J never saw their production levels dip below 113 MMcm/d (4 Bcf/d), according to the U.S. Energy Information Administration (EIA). In its September “Drilling Productivity Report,” the EIA reported the Niobrara Basin would reach record production in October with 144.4 MMcm/d (5.1 Bcf/d) of natural gas, up 1.4 MMcm/d (50 MMcf/d) over September production.

Although a predominantly gas-heavy play, the Niobrara’s oil production has seen exponential gains during the course of the market recovery. According to the EIA, oil production in the Niobrara also has reached record levels, with 620,000 bbl/d through October.

The Niobrara’s rig count bottomed out in 2016 when less than 20 rigs were in operation, but according to the EIA, that number has steadily rebounded with nearly 60 rigs in operation through August.

Permitting activity is also on the uptick, according to Drillinginfo. In an exclusive report provided to E&P, Drillinginfo reports that the number of permit filings in the D-J Basin has grown from just over 600 during the first quarter of the year to more than 800 in the third quarter. Since late 2015, the core areas of interest for developers have been northeast Weld County, Colo., and southern Laramie County, Wyo.

Some of the most recent top wells in the play have IPs of 1,800 boe/d or more. According to UGcenter.com, WPX Energy’s 701-4 HN1 Williams well saw an IP of 2,666 boe/d and Chesapeake Energy’s 6H Feller Unit NW well produced 1,859 boe/d.
The D-J Basin saw steady increases in natural gas production volumes between 2013 and 2016, although 2018 production date-to-date has dipped slightly. In addition, overall gas volumes are not as high as wells in gas-directed plays that often see up to 283 cu. m/d (10,000 cf/d), according to Drillinginfo. (Source: Drillinginfo)

Laramie County type curves have the highest IP rates for crude oil. The Weld County curve reflects a larger sample size, however, and has IP rates of about 265 bbl/d. (Source: Drillinginfo)
Advances in well-established technologies are playing a major role in production optimization and the generation of accurate well and reservoir data for decision-making support. One such example is chemical tracer system technology.

The underlying premise of chemical tracers is that they allow operators to monitor zone-specific inflow, identify inflow issues and perform targeted well intervention from qualitative and quantitative interpretations.

This is achieved through polymer rods containing chemical tracers installed during the manufacturing process of the completion in the different zones of the well. With the chemical tracers and the polymer matrix being stable and inert in a wide range of well conditions, the permanent tracers are contacted by target fluid and will selectively release upon fluid contact.

Although the initial development of inflow tracers was designed to provide qualitative information on the location of water breakthroughs in production wells, this evolved into the development of oil tracers for oil inflow monitoring with an interpretation based on the quantification of transient flow.

When the well is shut in, a cloud of tracers is built up in the individual well zones and then flushed out when the well is opened. By analyzing the arrival pattern of tracers on the surface and tracer concentration decay during the startup, it is possible to determine both qualitatively and quantitatively from where production is coming. This analytical approach has recently been verified to provide excellent results for a 25-km (16-mile) subsea tieback, where a clear and quantifiable plot of tracer arrival time, concentration and decay was achieved.

However, there is still much more that chemical tracers can do to support production optimization. RESMAN’s new intelligent tracer technology and the zone-specific well production data and production trend tracking it generates can play a role in production optimization and continuous well performance evaluation without the risks of intervention.

Adding zone-specific information

With RESMAN’s nonintervention, intelligent tracer technology, integrated with the completion equipment to monitor segments of the reservoir interval, small amounts of tracers are released continuously when contacted by the target fluid.

By analyzing samples taken from the well over a period (e.g., for two months with one sample taken every week), it is possible to correlate trends in zone-specific tracer concentration with trends and changes in production behavior for the well. This can be related, for example, to oil, water and gas production rates, water cuts, gas-oil ratios, bottomhole/tubing head pressure and temperature, and sand production.

Intelligent tracers, when correlated with global production data, provide information about changing production trends from each zone and add a zonal resolution to the well production data for targeted well performance assessment and operational decisions. For instance, if the water cut suddenly increases, an increase in tracer signal from one of the zones will indicate from which zone and at what time the
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increased water breakthrough occurred, and therefore also what zone to keep under observation and for potential remedial action (such as water shutoff operations).

Figure 1 illustrates how two independent water breakthrough events from one subsea well were detected through intelligent tracers. In this case, the operator adjusted the reservoir models and improved the management of the fieldwide waterflood program.

Sudden drops in oil tracer signals also can infer differential pressure depletion along the wellbore as well as identify targets for zone-specific stimulation to increase oil production from such zones. The tracers can determine if the different zones are producing after initial startup and assess if the well has been properly cleaned. They also can be instrumental in testing different well designs or longer well paths to determine the relative production from a lateral or extended toe in the well (based on the transient flow model).

Another important tool for production optimization is evaluating zone-specific well performance at different operational settings. Analyzing tracer profile changes during a multirate test, where changes of the well are intentionally induced by the operator, for example, can give important insight and decision support for production optimization at zonal resolution.

If the choke is reduced, the drawdown and production rate are reduced and, from tracer profiles, it will be possible to see if tracers from specific zones disappear. This would indicate that this zone requires higher drawdown and therefore provides information about differential pressure support distribution along the wellbore.

Conducting a controlled multirate test and correlating production changes with tracer signals will provide the operator with essential information about the operational modes of the well and can be used for production optimization and to support well operation decisions.

Integration with existing workflows
The concept of continuous monitoring where tracer signal trends are cross-correlated with general production data also is compatible with existing data workflows used for production optimization and reservoir surveillance.

In this way, the value can be extracted when tracer data are uploaded into the operator’s existing data-base system and software platforms. To this end, RESMAN has developed software to import the data into Petrel and Emerson’s Roxar RMS reservoir characterization software.

Industry applications
One operator wanted to determine the inflow contribution across the reservoir interval from each branch of a dual-lateral well without performing a coiled tubing intervention for a production log. RESMAN tracers, with uniquely identifiable signatures, were placed in three 1,524-m (5,000-ft) laterals.

In this case, inflow distribution results revealed that production along each lateral varied significantly with the toe of the upper lateral contributing 44% of production, while the entire lower lateral contributed 39%. Through the intelligent tracers, the operator avoided a high-risk intervention while gaining valuable insight into zonal inflow for improved completion design and well placements.

In a second example, an operator needed to identify the optimum stimulation strategy to maximize production in multistage fracturing wells. Intelligent tracers were again installed, this time in the 12 stages of a 2,438-m (8,000-ft) horizontal well, to measure inflow performance along the lateral.

Here, the inflow distribution for each stage revealed that the stages stimulated using mechanical diversion led to three times more production than those where dynamic diversion was used (Figure 2). Based on these findings, the operator deployed the optimum simulation method fieldwide and realized a dramatic improvement of 270,000 bbl of oil per well per year.

Have a story idea for Tech Watch? This feature highlights leading-edge technology that has the potential to eventually address real-life upstream challenges. Submit your story ideas to Group Managing Editor Jo Ann Davy at jdavy@hartenergy.com.
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Single-gas monitors detect standard, special gases
With the Pac 6000, 6500, 8000 and 8500, Dräger offers a new series of personal single-gas monitors, according to a press release. The monitors detect not only standard gases, such as carbon monoxide (CO), H₂S, sulfur dioxide and oxygen (Pac 6000 and 6500), but also special gases, such as ozone, phosgene and nitrogen dioxide (Pac 8000). In addition, the Pac 8500 is available with dual sensors for H₂S /CO or oxygen/CO, and a hydrogen-compensated CO sensor. This significantly reduces the influence of hydrogen on the indication of CO. Users can choose between 18 long-life sensors for the detection of up to 33 gases. The industrial battery used in the monitors enables a service life of two years without a battery change. Existing accessories also can be used with the new monitors. Additionally, the Pac series withstands harsh operating conditions. The sensors can be used in a temperature range of -40 °C to 55 °C (-40 F to 131 F). A replaceable membrane filter protects the sensor against foreign substances such as dust or liquids. draeger.com

Module plans, visualizes horizontal well surveys
geoLOGIC systems has released its geoSCOUT version 8.8 with new features added to enhance the user experience of this product, a press release stated. The new Well Profile Viewer module of version 8.8 allows users to plan and visualize horizontal well surveys in the context of formations, contours, downhole events, completions and logs. It helps users focus on the horizontal section of the wellbore, compare multiple surveys to choose the best option before drilling, pick formation tops, import grid files and create reference surveys to compare wellbores. geologic.com

New structurally optimized jacket design
Chet Morrison Contractors has formed a strategic partnership with iSIMS to launch the iJacket, a new optimized method in jacket and foundation design, according to a press release. The iJacket is more structurally optimized than the conventional true X-braced jacket design, supporting the same deck load, conductor/riser count, drilling deck, wind turbine or other payload as its conventional counterpart. The iJacket is engineered to provide significant cost savings and reduce material and labor requirements over traditional foundations and jackets by up to 30%. Modern 3-D engineering design and analytical tools allow engineers to design and arrange bracing in a configuration that offers further structural optimization, while still meeting or exceeding the industry design requirements for strength and fatigue performance. chetmorrison.com, intellisims.com

New technology projects get support from OGIC
The Oil & Gas Innovation Centre (OGIC) is supporting three new research projects centered on how digitalization can improve efficiency and provide cost savings to the oil and gas industry, according to a press release. Three companies have teamed up with Robert Gordon University’s (RGU) School of Computing Science and Digital Media to carry out research into the digital transformation of the oil field.

The first project entails DNV GL developing an interactive program extracting and processing information from images of piping and instrumentation diagrams and other types of engineering drawings. This will speed up the collection of data for use in several technical applications. Phase 1 of the project was completed with support from The Data Lab, with Phase 2 being primarily supported by the OGIC. Working with RGU, Phase 2 will build on the methods and algorithms developed by Phase 1.

The second project involves ComplyAnts working to develop an automated system to manage the compliance process. ComplyAnts selected RGU on the strength of its School of Computing Science and Digital Media research and delivery capabilities. RGU will utilize artificial intelligence to develop an automated system to manage the end-to-end compliance process pipeline. The project aims to deliver a fully functional prototype within one year.

The third project involves IDS working to develop a data-driven tool to predict task durations, associated risk and nonproductive time. This is Phase 2
of the project; Phase 1, which was supported by The Data Lab, saw the development of a natural language processing library that classifies engineering terms within a daily report. These are then mapped to allow benchmarking and data analysis. This will reduce the amount of time it takes engineers to work with offset data. ogic.co.uk

Cost-effective treatment for produced and flowback water
Water Standard and its produced water subsidiary, Monarch Separators, are strengthening their focus on the unconventional oil and gas industry with a recent upgrade to their H₂O Spectrum platform technology, according to a press release. This water treatment platform provides operators with a wide spectrum of affordable produced and flowback water treatment options from disposal to recycle and reuse, or treatment for safe surface discharge. Water Standard has added a low-cost alginate flocculant, coupled with Monarch Separators’ separation technologies to advance the H₂O Spectrum platform. Performance from testing a range of challenging inlet water qualities with turbidity up to 700 NTU has resulted in treated water for reuse and recycle with turbidity of less than 2-4 NTU, oil in water down to less than 2 mg/L and iron removal to less than 1 mg/L. For more extensive surface discharge treatment, the H₂O Spectrum platform boasts 100% BTEX and total organic carbon removal along with 99+% salinity reduction and the successful accomplishment of passing the Whole Effluent Toxicity tests required for safe surface discharge. waterstandard.com

Next-generation advanced oxidation process
OriginClear Inc. has completed development and testing of AOxPlus, a method to produce hydroxyl radicals in large quantities to treat highly contaminated wastewater, according to a company announcement. The highly reactive hydroxyl radical delivers more than twice the oxidation, or cleansing power, of chlorine without the toxic byproducts. Based on laboratory testing, OriginClear engineers estimate that the new AOxPlus can produce 10,000 times more hydroxyl radicals than the original AOx technology, delivering superior contaminant breakdown on the same footprint. To generate these new levels of hydroxyl, the OriginClear research team used a special air-breathing membrane in a new reactor, disintegrating hard-to-remove contaminants. AOxPlus does not require chemical injection or clear water (as with ultraviolet) and is cost-effective when compared with, for example, diamond electrodes. It can offer a more efficient treatment solution to sectors that produce highly contaminated wastewater. originclear.com

Applications safely cut costs, time and minimize environmental risk
Tendeka has released the MajiFrac Solution, a new portfolio of applications that aims to reduce water use and pumping time during completion operations in unconventional shale plays in the U.S., according to a company press release. The MajiFrac Solution is the combination of a wide range of high-performance technologies and products, which can be used either individually or collectively. It includes a specially blended thermally stable modified acid system; the company’s MajiFrac Composite Plug, which incorporates a pump down feature to minimize water bypass; and MajiFrac, a range of high-viscosity friction reducers. According to Elizabeth Cambre, Tendeka’s business development manager of production enhancement, “In one example, the MajiFrac Solution delivered savings of up to 50,000 barrels of water and reduced pump operating times by 200 hours. The sequence in which the MajiFrac technology is deployed enables optimized fluid distribution across the interval. This can lead to more contact area with the formation resulting in increased production.” The modified acid system, which can be prepared in produced water, boasts a combination of spotting a spearhead acid with plug and perforating guns. It is harmless to the skin and achieves ultralong-term corrosion protection compared to conventional acids, thereby reducing risk to personnel, the environment and eliminating the hazards of casing integrity. While maintaining the positive aspects of solubility and reactivity rates, it minimizes unsafe exposure levels and effluent rates as well as costly transport and storage. It already has been tested and approved by several major operators. tendeka.com

Please submit your company’s updates related to new technology products and services to Ariana Hurtado at ahurtado@hartenergy.com.
A Marathon Oil Corp. Upper Three Forks discovery initially flowed 5,694 bbl of oil, 192,555 cu. m (6.8 MMcf) of gas and 6,497 bbl of water per day. According to IHS Markit, the Bailey Field well, SunEd 24-11TFH, is in Section 14-146n-94w of Dunn County, N.D. It is producing from a lateral extending from 3,399 m (11,151 ft) northward to 6,497 m (21,315 ft), with a true vertical depth of 3,290 m (10,793 ft), and bottomed in Section 2-146n-94w. The venture was tested on a 1-in. choke after 43-stage fracturing between 3,414 m and 6,456 m (11,200 ft and 21,180 ft) with a flowing casing pressure of 1,800 psi.

Parex Resources announced an oil discovery at exploration well Andina-1 on the Capachos Block in Colombia’s Llanos Basin. The well encountered the primary Guadalupe Formation reservoir at 5,090 m (16,700 ft) and was drilled to 5,334 m (17,500 ft), with a true vertical depth of 3,290 m (10,793 ft), and bottomed in Section 2-146n-94w. The venture was tested on a 1-in. choke after 43-stage fracturing between 3,414 m and 6,456 m (11,200 ft and 21,180 ft) with a flowing casing pressure of 1,800 psi.

Another discovery was announced by Exxon Mobil Corp. in the offshore Guyana Stabroek Block. The Hammerhead-1 well encountered 60 m (197 ft) of high-quality, oil-bearing sandstone. The latest well is about 14 km (9 miles) south of the Liza-1 well and was drilled to 4,225 m (13,861.5 ft) and is in 1,150 m (3,773 ft) of water. According to the company, there is potential for additional production from undrilled targets, and the company plans additional exploration and appraisal drilling. A second exploration vessel will begin drilling at the Pluma prospect, which is about 27 km (17 miles) north of the discovery at the Turbot-1 well.

FAR Ltd. has selected its drillsite for the Samo-1 offshore exploration well in its operated Block A2 in the Atlantic. The prospect lies immediately to the south and along trend from the SNE oil field in Senegal in the highly prospective Mauritania-Senegal-Guinea-Bissau-Conakry Basin. Area water depth is 1,017 m (3,337 ft), and it will be the first well drilled offshore Gambia since the late 1970s. The Samo prospect has two main targets: an upper reservoir interval that contained liquid-rich gas at SNE and a lower reservoir interval that was oil-bearing at SNE. The two target reservoir intervals are assessed to have a combined prospective resource of 825 MMbbl of oil (best estimate, unrisked).

Lundin Petroleum AB completed appraisal well production testing at the 16/1-28S well in the Rolvsnes discovery in production license (PL) 338C on the Utsira High in the Norwegian North Sea. A horizontal well was drilled and tested flowing at a constrained production rate of 7,000 bbl/d of oil. The combined Rolvsnes and Goddo prospective area is estimated to contain gross potential resources of more than 250 MMboe. The appraisal well is about 3 km (2 miles) from the Edvard Grieg platform and is the third well on the Rolvsnes oil discovery. Additional testing is planned as well as an additional exploration well at the Goddo prospect in PL815.

Panoro Energy ASA has announced an oil discovery at the Ruche North East Marin-1 well in offshore Gabon’s Dussafu Marin production-sharing contract license. The well was drilled...
to identify additional oil resources in the presalt Gamba and Dentale in the greater Ruche area. It was drilled to 3,400 m (11,155 ft) in 115 m (377 ft) of water. Log evaluation, pressure data and fluid samples indicate that approximately 15 m (49 ft) of good quality oil pay was encountered in Gamba and 25 m (82 ft) in stacked reservoirs within Dentale. Additional testing is planned, including a sidetrack to appraise Dentale sands in an updip location and the lateral extent of the Gamba reservoir.

Egypt
Shell Oil Co. and the Petronas Carigali plan to drill an eight-well program in the West Nile Delta prospect in the Mediterranean Sea. The West Nile Delta Deep Marine Phase 9B program is set for completion in late 2019. The production anticipated by Shell is about 11.3 Bcm/d (400 MMcf/d) of gas, but Shell did not disclose the volume of gas to be produced from the first two wells to be drilled. The West Nile Delta Deep Marine development is part of Egypt’s drive to achieve gas self-sufficiency before year-end 2018 and stop the importation of LNG.

Cyprus
Exxon Mobil and Qatar Petroleum are expecting to receive permission from the government of Cyprus to return to their exploration operation in Block 10, despite warnings from Turkey that such activity infringes on the rights of the Turkish Republic of Northern Cyprus. According to the Cypriot newspaper Phileleftheros, the partners plan to drill the initial exploration well on the block this year at a site far from the disputed area. The first well, Delphini-1, will be followed by wells at the Antheia and Glafkos prospects.
Crescent Point Energy Corp. has elected Craig Bryksa as CEO and president. Robert (Bob) Heinemann has been appointed chairman of the company’s board of directors.

TransGlobe Energy Corp. CEO Ross Clarkson will retire Dec. 31, but will remain a nonexecutive director. Current president Randall (Randy) Neely will assume the role of CEO and president.

Zion Oil & Gas Inc. has named Dustin Guinn CEO.

Gary C. Hanna has been appointed interim CEO and president of Rosehill Resources Inc. and Rosehill Operating Co. LLC until the search to fill the role has been completed. Hanna succeeds J. A. (Alan) Townsend, who retired in April.

EQT Corp. has announced its senior management team upon completion of the company’s upstream and midstream business separation: Robert J. McNally, CEO and president; Jimmi Sue Smith, CFO and senior vice president; David Schlosser, executive vice president of E&P and innovation; Blue Jenkins, executive vice president of commercial, business development, IT and safety; Lew Gardner, general counsel and vice president of external affairs; Dave Smith, vice president of human resources; Blake McLean, vice president of strategic planning; and Pat Kane, vice president of investor relations.

Whiting Petroleum Corp. has named Tim Sulser chief corporate development and strategy officer.

Nine Energy Service Inc. has welcomed S. Brett Luz as chief accounting officer. Luz assumes the role following the retirement of Rich Woolston.

Gary A. Rinaldi will be retiring as CFO, COO and senior vice president of Sprague Resources LP and will remain with the company until Dec. 31 to assist with the transition of his responsibilities. David Long will assume the role of CFO on Jan. 1, 2019.

Gazprom VNIIGAZ has appointed Maxim Nedvetsky director general.

Pieridae Energy Ltd. has named Melanie Litoski CFO.

Anthony (Tony) Aulicino has joined CES Energy Solutions Corp. as CFO, succeeding Craig Nieboer who will remain with the company until a proper transition of duties and responsibilities has been completed.

Gulf Island Fabrication Inc. has welcomed Westley Stockton as CFO, executive vice president, treasurer and secretary.

Martin Smith has been appointed COO of Cyber Prism, a cybersecurity provider for the oil and gas sector.

Horizon North Logistics Inc. has promoted Joseph Kiss to president of modular solutions, and Mark Becker has joined the company as president of industrial services.

Blue Ridge Mountain Resources Inc. has appointed Michael Hodges senior vice president of finance. In addition, upon the successful completion of the company’s proposed merger with Eclipse Resources Corp., he will assume the role of CFO and executive vice president of Eclipse from Matthew DeNezza, who will remain with Eclipse and support the transition until the close of the merger.

Chris Newton has been appointed a nonexecutive director of Tap Oil Ltd.

Cabot Oil & Gas Corp. has elected Peter B. Delaney to its board of directors.

Neptune Energy has welcomed Gro Gunleiksrd Haatvedt (left) as vice president and group head of exploration. In addition, Amanda Chilcott (right) has been appointed group human resources director.

The American Petroleum Institute (API) has welcomed Debra M. Phillips as vice president of Global Industry Services (GIS). In addition, the GIS division has promoted Gao Jie as chief representative in China. The Market Development division has hired Brian George as senior policy adviser of market development as well as Amanda Eversole as COO and Ben Marter as director of communications. The State Petroleum Council division has named Jonathan Bargainer executive director of the Alabama Petroleum Council and Christopher McGowne associate director of the Colorado Petroleum Council.

Premier Oilfield Group has named Dr. Sau-Wai Wong vice president of technical software.

Enpro Subsea has named Francesco Santoro a senior adviser and strategic consultant in South America.

Airswift has promoted Albert Kahlow to regional director for the Middle East and Peter Denham to regional director for Europe.
Ashtead Technology has appointed Stephen Steele corporate development director.

Mark Cullens has joined OPITO as director of strategic development.

Apache Corp. has named Emily McClung vice president of community partnerships and employee engagement.

Lawrence B. Fisher and David Herskovits have been elected as independent directors of Viking Energy Group Inc.

Paul Smith has been named group managing director at UTEC Survey, an Acteon company.

Chariot Oil & Gas Ltd. has appointed Chris Zeal an independent nonexecutive director.

**COMPANIES**

Precision Drilling Corp. plans to buy Trinidad Drilling Ltd. in a deal valued at $796 million. The transaction is expected to close by the end of the year.

Eclipse Resources Corp. and Blue Ridge Mountain Resources Inc. have entered into a definitive merger agreement, which is expected to close in the fourth quarter. A name for the combined company has not been disclosed.

Kosmos Energy Ltd. has completed its acquisition of Deep Gulf Energy for about $1.23 billion in cash and stock.

HENDerson, a drilling rig and equipment provider, has acquired HP Piping Solutions.

Drillinginfo has acquired Oildex, an oil and gas financial automation software firm.

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Be a trailblazer

Removing key barriers enables faster technology adoption in the oil and gas industry.

The historical slow pace of technology adoption in the oil and gas industry is not a new issue by any means. Articles surrounding technology adoption tend to increase amid a commodity price downcycle. The current downcycle, from 2014 to present, is no different. There have been multiple passionate calls for lowering production costs per barrel via the use of various technologies in the past three to four years.

Some operators seem to have achieved tremendous efficiencies, with at least one major reporting a breakeven price of $30/bbl for a new offshore platform. It does give hope that there is a definite commitment to lower costs. At the same time, it is far less challenging for a large operator to achieve said efficiencies than for a small supplier.

From ProSep’s perspective, the challenges faced by smaller suppliers fall into three critical categories.

Serial No. 2

Operators want the best and latest technology but refuse to buy the first of its kind (Serial No. 1). In some situations, case studies are not enough; neither are operating units in different geographies. From an operator’s risk assessment perspective, it is understandable that with millions of dollars at stake, it would not be prudent to deploy something that does not have a track record. One solution would be to empower decision makers (technical, procurement and engineering) to granulize risk factors rather than use an age-old uniform corporatewide template and treat each technology on a case-by-case basis.

Commercial terms and conditions

It is no secret that large operators have teams of legal and commercial experts on staff to address all possible risk factors in contracts. Contracts, depending on dollar amount and scale of the project, can be complex and need the appropriate risk assessment and ring-fencing. Concurrently, when dealing with smaller suppliers, the scale and complexity are not large. Operators still tend to use one-size-fits-all commercial terms. This results in unnecessary delays in the project award time line and execution, increase in costs and, in some cases, failure to deploy an impactful technology. There are lots of smart individuals on hand at every company who are more than capable of executing this job.

Financial criteria

To be specific, most operators have boilerplate procurement criteria to qualify suppliers (e.g., approved vendor lists). Innovation tends to occur at smaller companies with limited financial history and strong balance sheets. Most times, it is hard to qualify financially to be on the approved vendor lists, and if suppliers qualify, they are asked to provide expensive and hard-to-secure financial instruments. It would be prudent to segment approved vendor lists documents by company size and use appropriate criteria to speed up technology deployment. Procurement teams also should be empowered to evaluate off-script risk mitigation measures including the transfer of ownership and periodic in-person audits. Furthermore, it would be beneficial to design and implement simpler financial instruments by pooling risks and lowering costs instead of letters of credit.

Advancement of humanity has witnessed significant step changes—historically when technology deployment occurred within a short time frame. Tremendous advancements in underlying infrastructure technologies, computing speed for one, have allowed us to improve technologies in various walks of life including oil and gas. Let’s all work together to remove the barriers and speed up the adoption.
The Ultimate Diverter: Now More “Ultimate.”

How to get maximum return on refrac operations

The most permanent, most cost-effective solution for refrac operations just got even better.

Enventure’s ESeal™ 3.0 RF (Refrac) Expandable Liner reliably creates a new wellbore with permanent isolation of existing perforations and internal pressure integrity – at higher pressures and greater temperatures than before.

In practice, this results in a faster payback on investment and extended production life of the reservoir.

- Expandable liner creates largest possible ID
- Maintains pressure integrity
- Single, one-time process
- More accurate, more predictable diversion

NEW in version 3.0:
- Stronger connections, higher pressures, greater temperatures
- Engineered analysis of the operating window

Cost-effective. Reliable. Permanent. Enventure’s ESeal RF Liner is the Ultimate Diverter.

Find out more at www.EnventureGT.com/refrac
Pinpoint fracturing delivers aggressive infill completions one frac at a time, with less risk of well bashing.

Multistage Unlimited® pinpoint fracturing delivers more SRV with far less risk of frac hits and well bashing during infill field development, compared with plug-and-perf. You put fracs where you want them, and you control how much sand you pump into each one, preventing “super clusters” that can hurt production from offset wells. With repeatable frac placement from well to well plus recorded downhole pressure/temperature data, you can truly optimize stage count and spacing in a given formation with just a few wells.

More stages per well
NCS pinpoint fracturing delivers more individual entry points with far higher frac efficiency than plug-and-perf. For example:

- 227 stages (Montney)
- 168 stages (Montney)
- 161 stages (STACK)
- 159 stages (STACK)
- 155 stages (Bakken)
- 147 stages (Permian)

More sand per well
More intensity means pumping more sand, and NCS Multistage pinpoint fracturing handles it:

- 18.2 million lb @1,870 lb/lateral ft (Montney)
- 17.5 million lb @2,190 lb/lateral ft (Montney)
- 15.0 million lb @1,711 lb/lateral ft (Duvernay)
- 14.2 million lb @1,973 lb/lateral ft (Permian)

Faster execution
NCS Multistage pinpoint completions are being executed faster than ever. Here’s why:

Higher rates. Technology and design advances have boosted Multistage Unlimited frac rates through the coiled tubing/casing annulus to nearly 80 bbl/min in 5.5-in. casing, far higher “per cluster” than plug-and-perf and more than enough to transport sand (>12 ppg) with slickwater.

Fewer coiled tubing trips. Almost 90% of NCS Multistage jobs are performed in a single coiled tubing trip. As many as 227 sleeves have been fracked without tripping out of the hole.

99+% sleeve success rate. More than 165,000 NCS sleeves have been installed, with the highest sleeve-shift success rate of any coiled-tubing completion system.

Learn more at ncsmultistage.com