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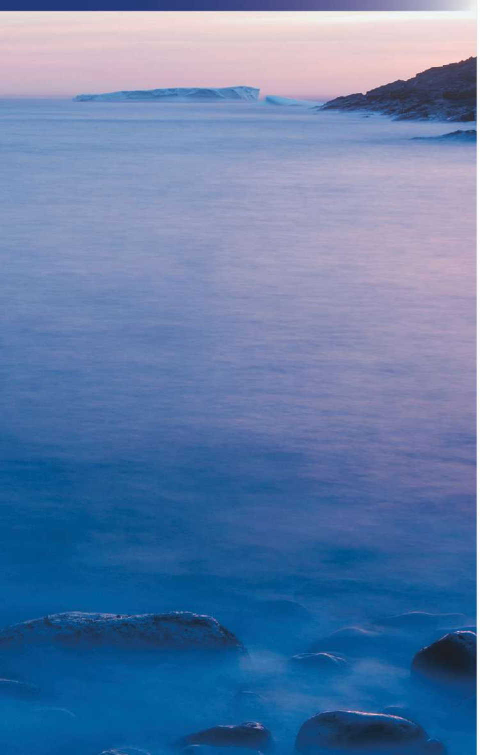
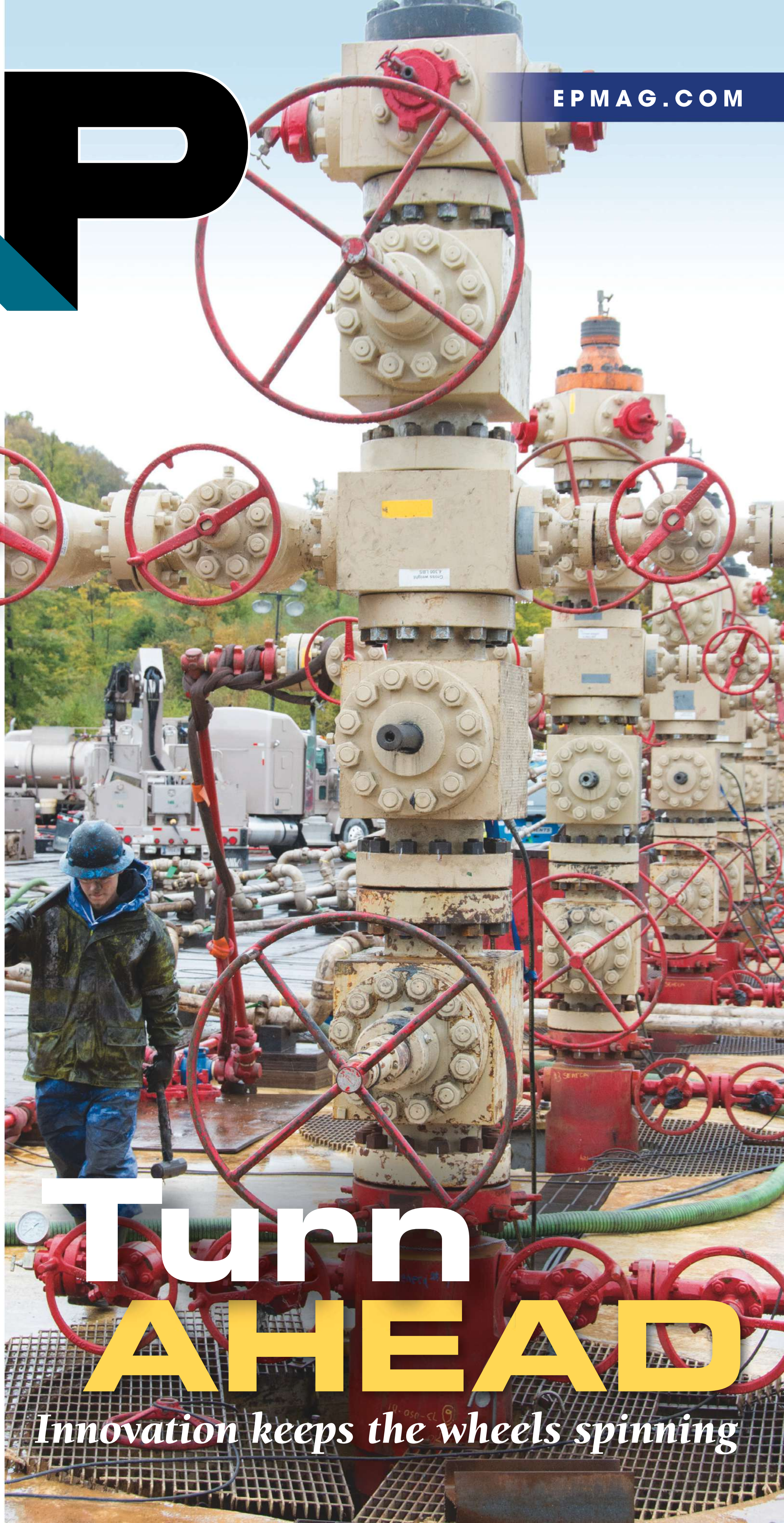
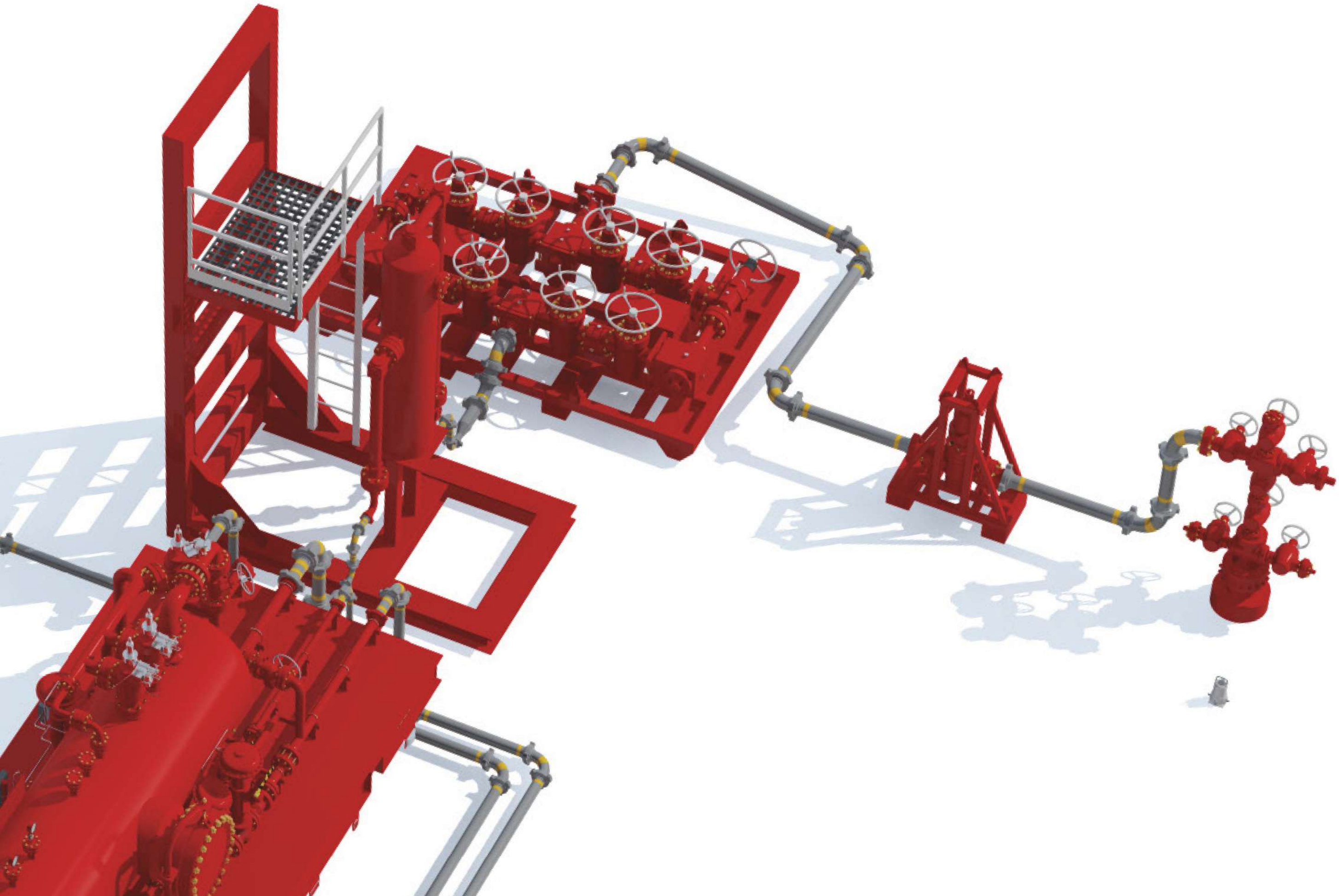




Turn AHEAD

Innovation keeps the wheels spinning



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A HART ENERGY PUBLICATION
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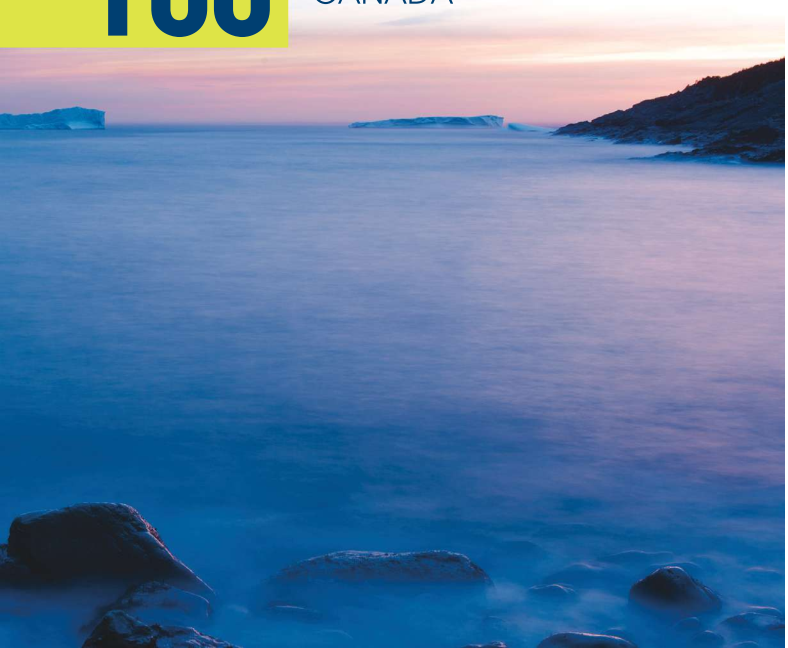


2017 MEA AWARD CATEGORIES

Onshore Rigs: pad drilling, mud pumps, power generators, top drives, rig equipment, BOPs, pipe handling and automation

Intelligent Systems and Components: digital oilfield, smart and real-time control and monitoring systems, remote operations, automation, intelligent agents, "big data" solutions, and networks & software

IOR/EOR/Remediation: advances in all IOR/EOR and remediation methods, reservoir monitoring and modeling, stimulation, workovers, chemicals, CO_2, environmental advances, and containment and response systems

Artificial Lift: ESP systems, PCP systems, Rod lift systems, gas lift systems, jet pump, hydraulic pump systems, plunger lift systems, capillary injection systems, and well site automation

Water Management: brine, frack water, produced water, flocculation, reverse osmosis, recycling, ultrafiltration, oxidation, storage, wastewater, metal removal and biocides

Subsea Systems: Christmas trees, BOPs, tiebacks, manifolds, processing (separation, compression and boosting), SSIVs (subsea isolation valves), SURF (subsea umbilicals, risers and flowlines), pipelines, power supply and controls, ROVs/AUVs, IRM (inspection, repairs and maintenance), intervention, flow assurance, and metering and monitoring

Floating Systems and Rigs: floating production and topsides systems and designs (FPSO, FLNG, GTL, FSO, TLP, spar, semi-submersible, hybrids), drilling units (rigs, drillships, hybrids), turrets, loading and offloading, mooring and positioning, people and cargo transfer, and safety and evacuation

Marine Construction & Decommissioning: vessels and systems, pipelay and flowlines, platforms, subsea construction, marine transportation and installation, heavy lift, hook-up and commissioning, structure removal, intervention and workovers

Exploration: potential fields, geochemistry, seismic acquisition (land and marine), processing algorithms and software, reservoir characterization, interpretation software, and hardware

Formation Evaluation: wireline logging, core analysis, cuttings analysis and well testing hardware and software

HSE: hardware, software, and methodologies related to health, safety and the environment

Drillbits: natural diamond, impregnated, PDC, bi-center, milled tooth, hybrid, insert and hammer

Drilling Fluids/Stimulation: chemicals, drilling mud, additives, flow enhancers and green systems

Drilling Systems: LWD/MWD, motors, coring, tool joints, fishing tools, drillpipe, whipstocks, subs, packers and rotary steerable systems

Hydraulic Fracturing/pressure pumping: matrix acidizing, proppants and chemicals

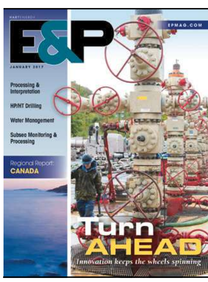
Non-fracturing completions: modeling/simulation software, completion hardware and completion effectiveness monitoring (microseismic, tracers, etc.)

E&P

SUBMIT TODAY
Entry Deadline is January 31!

DEPARTMENTS AND COMMENTARY

COMING NEXT MONTH The February issue of ***E&P*** will focus on innovation through industry collaboration. Other features will include rock physics, drilling fluids and oilfield chemicals, artificial lift, and marine construction and heavy lift. The unconventional report will focus on the Bakken. This issue also will feature a safety gear showcase. As always, while you're waiting for your next copy of ***E&P***, be sure to visit ***EPMag.com*** for the latest news, industry updates and unique industry analysis.



ABOUT THE COVER A zipper fracture on Seneca Resources' Clermont Rich Valley Pad C08-G in Cameron County, Pa., is featured on the cover. Left, Newfoundland and Labrador remains one of the world's few underexplored provinces, but new seismic data are piquing interest in the area. *(Cover image by Glenn Kulbako, courtesy of* Oil and Gas Investor*; left image courtesy of ggw,* shutterstock.com*; cover design by Felicia Hammons)*

E&P (ISSN 1527-4063) (PM40036185) is published monthly by Hart Energy Publishing, LP, 1616 S. Voss Road, Suite 1000, Houston, Texas 77057. Periodicals postage paid at Houston, TX, and additional mailing offices. Subscription rates: 1 year (12 issues), US $149; 2 years (24 issues), US $279. Single copies are US $18 (prepayment required). Advertising rates furnished upon request. **POSTMASTER: Send address changes to E&P, PO Box 5020, Brentwood, TN 37024.** Address all non-subscriber correspondence to E&P, 1616 S. Voss Road, Suite 1000, Houston, Texas 77057; Telephone: 713-260-6442. All subscriber inquiries should be addressed to E&P, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442 Fax: 713-840-1449; custserv@hartenergy.com.

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ACTIVITY HIGHLIGHTS

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Noble completes five Niobrara wells at East Pony prospect

IHS Markit reported that Noble Energy Inc. completed five horizontal Niobrara wells at its Denver-Julesburg Basin-East Pony prospect in Weld County, Colo.

New appraisal testing adds 28.3 Bcm of gas-in-place in Baltim South Field

According to Eni, results from an appraisal well in Egypt's Baltim South Field at #2X Baltim South West has added about 28.3 Bcm (1 Tcf) of gas in place.

Two Bakken/Three Forks discoveries announced

QEP Resources Inc. has completed two horizontal Bakken/Three Forks producers from a common drillpad on the Fort Berthold Indian Reservation in Section 28-148n-92w of Dunn County, N.D.

AVAILABLE ONLY ONLINE

Mexico's deepwater round exceeds expectations

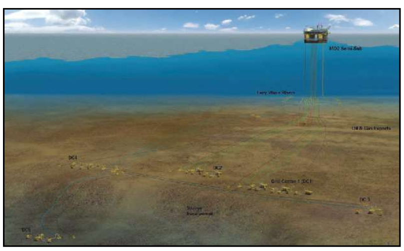
By Velda Addison, Senior Editor, Digital News Group

Eight of 10 blocks were awarded during Mexico's first deepwater round. Mexico expects to hold three more oil and gas auctions before year-end 2018.

Baker Hughes' frack fleet deal pays pennies on the dollar

By Emily Patsy, Hart Energy

Baker Hughes retains a minority stake in the new company, but analysts are skeptical the transaction was a fair bargain.



BP ponies up $9 billion to unleash Mad Dog phase 2

By Velda Addison, Senior Editor, Digital News Group

Plans include a new floating production platform that will be moored about 9.6 km (6 miles) southwest of the existing Mad Dog Platform.

OPEC just made a deal: now what?

By Jeff Quigley, Stratas Advisors

The OPEC deal could change the landscape of the oil market for the foreseeable future, but the specifics have yet to be determined.

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Industry on self-help road to recovery

The E&P sector enters 2017 on a cautious road to recovery, and the drillbit will lead the way.

The industry has long known it could not wait for a Christmas miracle. Its proactive players are getting on with what they do best—finding reserves—but they are finally doing it differently.

Andrew Latham, head of global exploration research at Wood Mackenzie, summarized this approach as simply "drilling fewer but better wells." Speaking at the Petex event in London, he said, "It is absolutely our view that exploration economics as an industry were broken, and they were broken even when the Brent price was above $100/bbl. But it's also our view that the industry can reset those economics and get back to delivering a profit."

But interestingly, Latham chose to back conventional exploration as a "massive contributor" going forward. Looking at oil supply from conventional finds made since 2000, he said production is higher from these than from tight oil finds made over the same period. "We're already getting 10 MMbbl/d from conventional discoveries since 2000. Our view is that looking at those already in the process of development or likely to be sanctioned very soon, we'll be getting around 20 MMbbl/d from this exploration success by the middle of the next decade.

"It's already double the scale of the tight oil industry."

Rather than volume, economics have been the problem. The industry suffered a "miserable decline in returns," he admitted, not so much due to lower oil prices but because of high costs and increased complexity. More than half the discovered volumes of the last decade "have gone nowhere."

The industry is acting, slashing global exploration spend from $100 billion per year three years ago to $40 billion. There has not been a huge drop in conventional wells drilled by majors, but there has been a drop in spending. "The majors are today spending the same per exploration well that they were in 2009. That's tremendous progress we're seeing, and we'll see other companies get the cost of exploration vastly lower," he said.

This focus on value also means prospects are chosen that have a greater chance of being monetized within a shorter time frame, including new plays and frontiers.

The strongest operators are backing themselves to find more resources, using the downturn to acquire exploration portfolios at lower cost. "We're already seeing evidence that these things are working out. This is an industry that can recover," Latham concluded.

This self-help therapy is producing a sharper industry in 2017. The volumes found might overall be smaller, but they will be inherently more profitable. E&P

Crowdfunding: new sources of capital for independents

New business model enables investors to buy shares of projects, not just stocks.

David Taylor, Crudefunders LLC

In the business world significant news does not always appear in headlines, yet it makes a profound impact. The oil and gas industry embodies a prime example. Even though extraordinary technological advancements have occurred in E&P and operating efficiency over the last few years, another key development has actually flown under the radar. Simultaneous with the technology explosion is the global revolution in the financial industry, also enabled by technology and aptly named Financial Technology or FINTECH.

Comprising several different components such as mobile payments, money transfers, consumer loans, asset management and capital acquisition, one component of the FINTECH revolution is particularly advantageous to the oil and gas industry: access to capital. Recent changes by the U.S. Securities and Exchange Commission (SEC) in May 2016 created an entirely new addition to the capital stack. This action opened the door to new sources of capital directly applicable to independents and small operators in the oil and gas industry never before available. The phenomenon, equity-based crowdfunding, represents one of the biggest changes in SEC regulations in more than 80 years, and the oil and gas industry is just now waking up to the possibilities for new growth capital.

How the game is played

The SEC passed new rules, along with amendments to existing rules, on Oct. 30, 2015, that were destined to have a profound impact on the future of the U.S. capital markets. These rules had previously been under consideration and deliberation by Congress for four-plus years under "Title III of the JOBS Act," also known as Regulation Crowdfunding. That is the operative term for oil and gas executives. These new rules and amendments were intended to permit companies to offer and sell securities through crowdfunding to a much wider definition of investors than previously possible.

The basic idea behind crowdfunding is to raise money through relatively small contributions from a large number of people, combining the best of microfinance and crowdsourcing. These new Regulation Crowdfunding rules had two primary purposes: 1) to assist in the capitalization of startup and emerging growth companies, thereby creating jobs and stimulating the economy; and 2) to provide investment opportunities, with appropriate protections, for a new class of unaccredited investors. These rules officially took effect May 16, 2016, for technology companies via web-based portals, which had met all of the SEC criteria for offering investments under these rules.

Because equity-based crowdfunding is breaking new ground in the U.S. and the oil and gas industry, industry independents might understandably have apprehensions. Statistics abroad are considerably more reassuring. While equity-based crowdfunding is relatively new in the U.S., it was a $34 billion global business in 2015, ($17.2 billion in the U.S. alone) and was projected by many analysts to surpass venture capital by year-end 2016. It also is projected to grow by as much as 20% per annum worldwide over the next few years. Bluntly speaking, equity-based crowdfunding is a major development that, for no valid reason, has gone relatively unnoticed by most of the U.S. population and the oil and gas industry.

Ironically, Regulation Crowdfunding was not originally imagined by its primary author and sponsor, Rep. Patrick McHenry (R-North Carolina), a member of the House Financial Services Committee, as an effective financial tool for the oil and gas industry. Rather, his stated purpose was "to foster relationships between investors and entrepreneurs," specifically "to permit crowdfunding issuances that offer an equity stake [securities] to investors." This includes any industry where capital is required and jobs can be created.

How Regulation Crowdfunding benefits operators

Of all of the industries where equity-crowdfunding is being introduced, the oil and gas industry, specifically the E&P sector, is uniquely and perhaps even ideally suited. The caveat is that operators need to separate their thinking about "rewards-based crowdfunding,"

Crowdfunding enables investors to support specific projects, not just purchase stock. (Source: Crudefunding LLC)

typically to raise money to build a prototype or create public awareness, from "equity-crowdfunding," with its multiple features and benefits to fund a potentially viable company. For the independent oil and gas company, Regulation Crowdfunding provides:

- Access to new, never-before-available capital from a new investor class—the "crowd." This crowd is largely composed of unaccredited investors; however, the numbers are huge;
- Relatively low cost of capital compared to other options;
- Maximum flexibility in project planning with a combination of capital sources that include the crowd with other capital sources;
- Perpetual funding from the crowd for entire oil and gas field development where success begets success and crowd participation momentum builds with achievement of expected results;
- National and (with SEC and anti-money laundering banking compliance) international exposure to operators' projects and development programs; and
- Crowd investor communication and management as one aggregated group through web-based portals.

Unprecedented investor opportunity

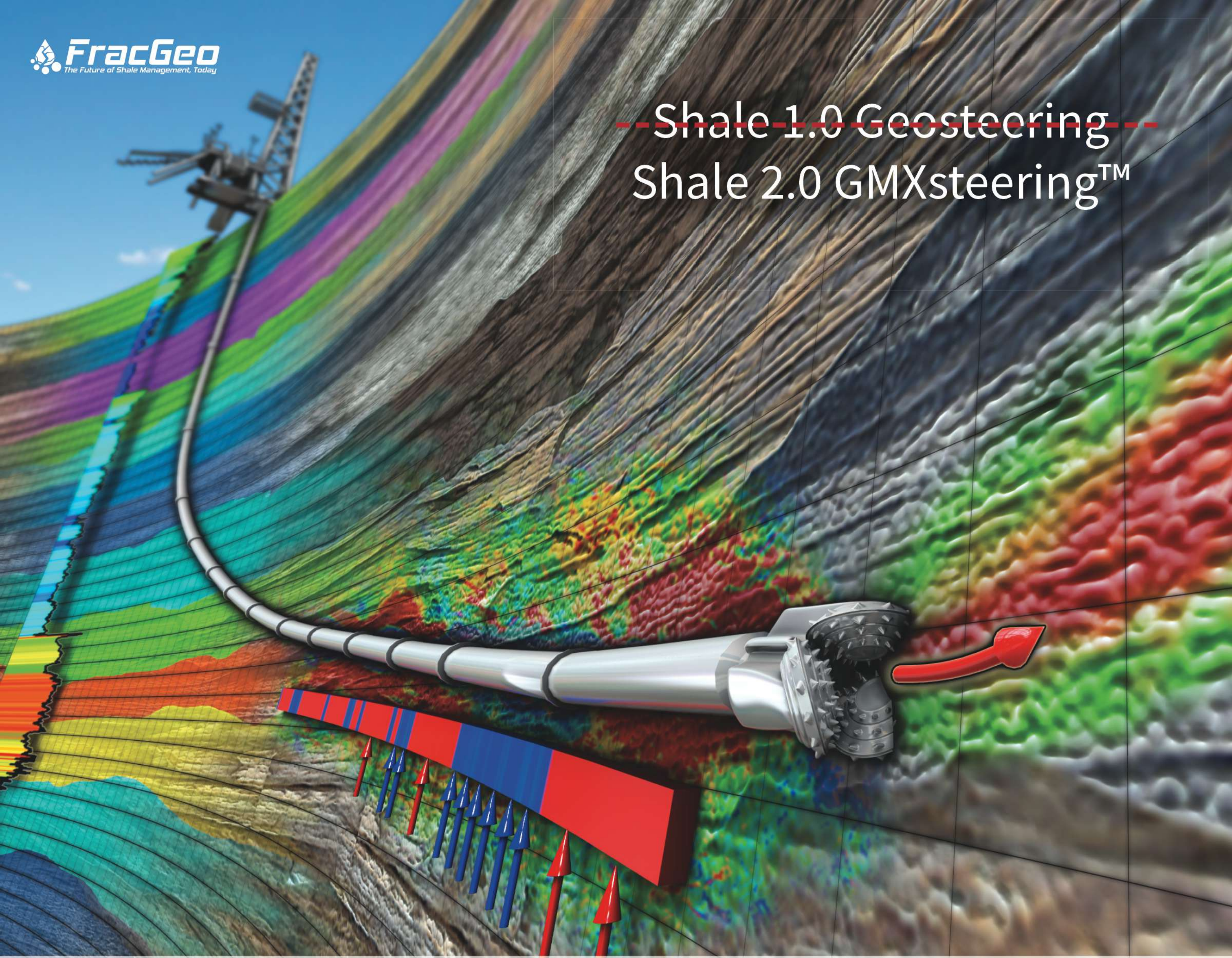
At the same time, benefits are not exclusively limited to operators since the individual investors become part of an investment opportunity that was previously beyond their reach. By virtue of SEC actions, the new crowd investor Regulation Crowdfunding through approved portals provides:

- An opportunity to invest directly in oil and gas projects, not merely public stock in oil and gas companies;
- An opportunity to invest in different levels of risk vs. reward and estimated return-on-investment profiles:
  - o De-risked completion-only projects where the investor gets a "free look" at the electric logs (and perhaps tests) prior to investing;
  - o Low-risk recompletion projects where production improvements are attainable from zones previously identified with openhole logs, cased-hole logs and/or offset production;
  - o Low- to medium-risk projects in proven fields with identified resources, extensive geology and infill wells in known formations; and
  - o Higher risk exploration where geology and reserves are less well known yet early indications are for excellent potential and high returns.
- Assuming project success, recurring revenues from working-interest ownership for years in the future;
- Generally higher returns on investment than other investment classes previously available to the crowd; and
- The opportunity to participate in an industry that has historically been closed to the general public.

Challenges and outlook

Of course, the brave new world of Regulation Crowdfunding is not without its challenges. In the original bipartisan bill (Title III of the JOBS Act) several restrictions were introduced to limit risk and exposure for unaccredited investors. Some of these also reduced the intended purpose of the original bill. As a result, McHenry acted swiftly and decisively by introducing H.R.4855 (aka Fix Crowdfunding Act) in mid-2016 to "fix" the original limitations and thereby increase the effectiveness of Regulation Crowdfunding for small business and the crowd investor. H.R.4855 passed the House side of the 114th Congress (2015/2016) by a vote of 394-4 in favor. It was sent to the Senate July 6, 2016, where it currently awaits action. This will likely be taken up and passed by the 115th Congress in 2017.

Despite the initial challenges in Regulation Crowdfunding, the future for the industry and its application for oil and gas is very promising. This optimism is not a surprise given so many upsides in terms of the benefits to operators and to the investors who are providing the valuable capital often unavailable to many small project sponsors, producers and operators in the past. E&P



Holy COWD*!

*Completion Optimization While Drilling (COWD™)

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GMXsteering™ in Live 3D Geomechanical models updated from real time GMX logs.

COWD™ products provide stage length and cluster density to achieve optimal fracing immediately after drilling is completed.

Register for FracGeo's open house and lunch on Thursday, January 26, 11:30 AM in The Woodlands for live demos of COWD during the SPE Hydraulic Fracturing Technology Conference.

www.FracGeo.com/register

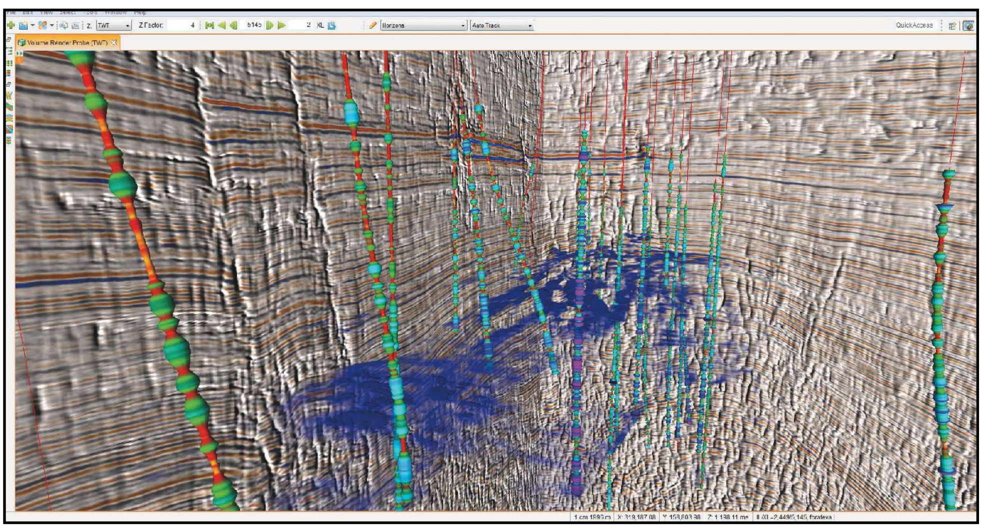
Cloud: the next big technology leap in E&P

It's no longer science fiction. Cloud computing is an everyday fact of life.

Will Childs, Oracle; and **Dave Butcher**, Landmark, a Halliburton business line

Everyone has been touched by cloud computing—it's pervasive; it's everywhere. It's impacting the way in which people work (and play) in ways that were hard to imagine five years ago. The latest statistics put public cloud spending at more than $70 billion, with a projected compounded annual growth rate at an astonishing 19%. This means that cloud spending will be more than $160 billion by 2020.

What is driving this incredible growth? Two words spring immediately to mind: innovation and disruption. Companies were initially looking to leverage the cloud to reduce the costs of maintaining expensive hardware and software assets in-house/on premise. Those early adopters quickly realized many other benefits. By using the cloud they could extend, enrich and innovate faster, and as a result they could reach new markets and disrupt their competitors in ways not previously imagined. This was especially prevalent in the software industry. Look at the rise of companies like Uber, Facebook, Netflix and AirBnb. All of these companies leveraged the cloud to disrupt and innovate at a pace of change not seen since the industrial revolution.



DecisionSpace 365 is offered in public and private clouds. (Source: Landmark)

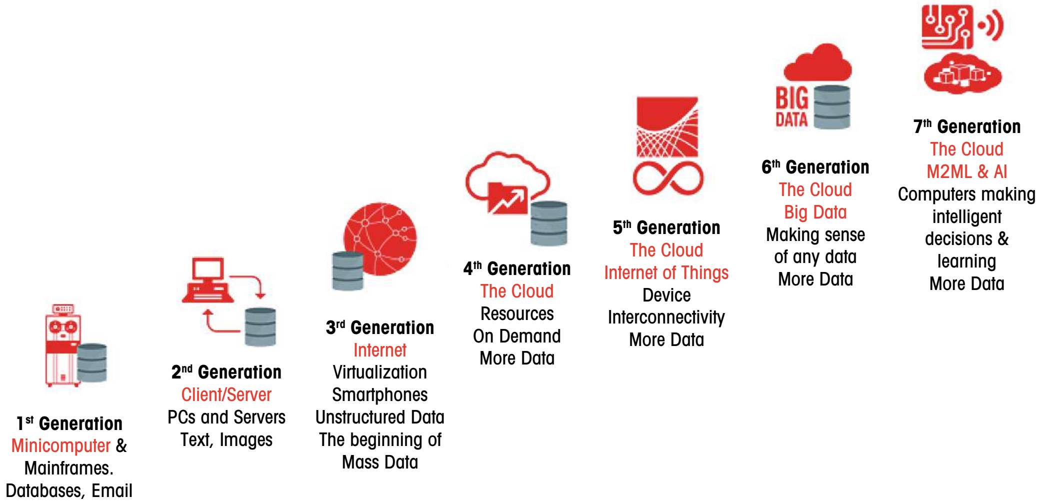
And the rapid pace of technology innovation continues. High-performance computing, the Internet of Things, Big Data, machine-to-machine learning and artificial intelligence have all accelerated as a result of general cloud availability. The cloud gives on-demand scale, security and access to advanced resources anywhere in the world. It's staggering to believe, but 90% of the world's data have been collected over the past couple of years. Why? How? Think cloud—it's the new medium where data are increasingly stored and processed.

What is a cloud?

The National Institute of Standards & Technology defines and describes cloud computing as "a model for enabling ubiquitous, convenient, on-demand network access to a shared pool of configurable computing resources such as networks, servers, storage, applications and services." Simply put, think of a cloud as a network of remote servers and software hosted on the Internet that can be used to store and process data and develop, deploy and run applications.

The cloud is rapidly evolving to becoming the *de facto* standard for how independent software vendors and enterprises develop, deploy and run their applications. Many, if not most, companies are looking at "cloud first" strategies. Industries previously off-limits to the cloud—healthcare, banking, insurance, government, etc.—are looking at the model as a way of helping them gain competitive advantage by developing new products and services while bringing them closer to their customers and partners.

In the healthcare industry the cloud is providing supercomputing processing power and scale to help scientists crunch genomic and biological data to gain new insight, resulting in accelerated development of targeted and personalized medicines. In the tourism industry the cloud is helping airlines consolidate disparate data sources from unrelated target sources. By using the cloud to process and analyze the data, new trends and insights are leading to new service offerings and routes to new markets. This concept of Big Data has only recently become accessible and a reality to the masses due in part to the availability of solutions in the cloud.



The evolution of computer technology will eventually lead to smarter machines. (Source: Oracle)

Data that previously took months or years to process and many millions of dollars in computer hardware/infrastructure investment can now be processed in days and hours and at a fraction of the expense, all at the click of a button.

Oil and gas in the cloud

The downturn has disrupted the industry, and the repressed price of a barrel of oil is forcing oil and gas companies to cut back on large capex. As a result, E&P companies are feeling the pinch. Landmark, a Halliburton business line, is one of those E&P companies looking to "navigate the cycle" with a view that the current downturn in business is likely to be the new "normal." As a result, Landmark is developing cloud technologies to help drive down costs, help speed up innovation and provide market differentiation through innovative development and deployment of on-demand software as a service to its customers.

Over the past 25 years Landmark has built a large portfolio of software applications that embody the science surrounding E&P. Its software has helped to change the way in which E&P processes and operations run by fully integrating the disparate workflows and data across the complete life cycle, helping operators increase production at lower cost. Landmark is leveraging the cloud to help develop and deploy the entire portfolio of software applications much more efficiently, and in return it is helping customers simplify the process of technology adoption and consumption. Customers will no longer need to plan for and procure expensive server infrastructure or software licenses. New software applications are deployed at the click of a button, and the latest functionality gets deployed in the cloud within minutes or hours vs. the traditional deployment life cycle of months. By leveraging the cloud, energy professionals are able to easily locate, obtain, visualize and utilize relevant data and information, helping them make informed and critical drilling decisions for the optimization of production at much lower costs.

Landmark in conjunction with the Oracle Cloud is actively developing and deploying the next generation of software as a service applications. DecisionSpace 365 will be offered in public and private clouds, giving users the flexibility of how, when and where they deploy their solutions, all in a fully managed and highly secured environment. Additionally, a thriving new community has emerged using the cloud as the medium in which to discover, learn, connect and collaborate.

The OpenEarth Community is being developed as a free, global and open community of scientists, engineers, software developers within oil and gas companies, service companies, software providers, data vendors and technology developers committed to producing an open and shared E&P cloud software platform. This is a great example of how the cloud can be used to collaborate and build new software, services and solutions in the digital age.

The cloud changes everything. It isn't a passing fad or trend; it's a new business, technological and operational paradigm that is impacting every industry and company. Embracing it has encouraging potential for new and exciting revenue opportunities, increased innovation and reduced costs of doing business during the downturn in the industry. E&P

Quantitative optimization for EOR/IOR

Operators can now leverage models uniting fundamental reservoir physics and data science for real-time quantitative optimization for EOR/IOR workflows.

Ian Hunt, Tachyus

Energy production requires a fundamental understanding of where resources are located, the extent or volumes of the hydrocarbons in place and how to exploit or extract them cost-effectively and safely. Operating companies have deployed significant capital over the last decade to collect massive quantities of real-time sensor data; however, particularly given current commodity prices, they are still seeking ways to modernize their analysis techniques and thus realize the return on investment from their data sources.

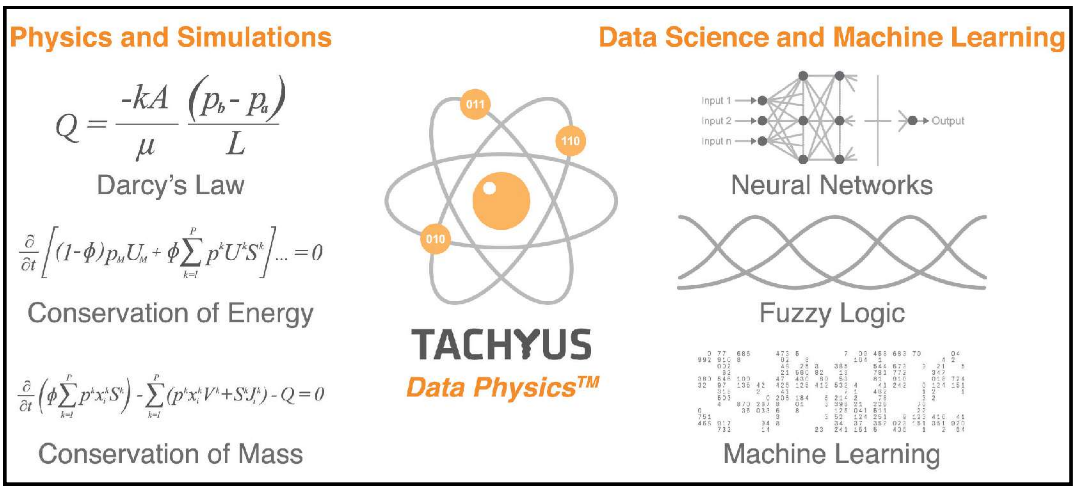


FIGURE 1. Tachyus has invented a patented technology called Data Physics that merges modern data science and the physics of reservoir simulation. (Source: Tachyus)

To accomplish this mission-critical objective, these organizations need a platform to rapidly integrate all field data, including cores, well logs, completion designs, real-time production data, maintenance records and financial constraints. Additionally, they require software capable of flexible descriptive analytics to visualize and contextualize this deluge of data.

However, such applications should not only integrate and visualize the different data sources but should also provide predictive analytics to allow the various engineers to quickly predict the production responses to stimulation, mechanical equipment failure, fieldwide forecasts for changing injection redistribution and capacity, infill drilling and other critical decisions.

Essentially, to transform data into dollars, an operating company needs a prescriptive analytics tool to explore the millions of possible what-if scenarios to identify the optimal operational and development plans.

Data Physics, a quantitative optimization framework, has been validated with eight operating companies across 14 EOR projects using data from more than 10,000 wells to enable operators to increase production by greater than 20% and/or reduce their operating expenses by more than 40%.

Decisions to optimize

As producers strive to efficiently manage capital in EOR projects, petrotechnical experts grapple with mission-critical decisions that determine the profitability of operations. In maturing reservoirs undergoing waterflooding, CO_2 flooding, chemical flooding or steamflooding, success hinges on a number of decisions with impacts on varying time frames.

- **Short term**
  1. Which wells to stimulate and when;
  2. What cyclic steam volumes to pump and how to establish prioritized schedules in steamfloods; and
  3. How to adjust injection pressures to achieve target injection volumes.
- **Medium term**
  1. Areal redistribution of injectant on a pattern-by-pattern basis;
  2. Vertical redistribution of injectant within multizoned reservoirs; and

3. How to adjust injection plans based on facilities constraints.

• **Long term**

1. When and how much to reduce/increase injection capacity;
2. Where to drill infill wells; and
3. How to design pattern shapes and sizes.

Limitations of existing physics-based modeling tools

For crucial decisions operators typically rely on semi-quantitative approaches such as decline curve analysis or simple analytical models. These methods are capable of using only a small portion of available data and function as rules of thumb, resulting in qualitatively optimized reservoir management decisions at best.

On the other extreme, major oil companies leverage sophisticated predictive modeling. Reservoir simulation is the most advanced technique available in that it is capable of integrating disparate data sources and predicting over long time horizons.

While reservoir simulation is an excellent tool for field studies and long-term planning, certain limitations prevent operators from leveraging simulation for day-to-day decision-making. These limitations include:

1. Reliance on geomodeling workflows that require months to years of manual setup;
2. Hours/days required to run a single scenario due to computational complexity;
3. Impracticality of obtaining optimal solutions given a limited set of scenarios; and
4. Sequential data integration that results in inconsistencies and failure to honor all the data.

In essence, reservoir simulation enables operators to precisely model the physics of a small number of scenarios; however, it is not designed to produce thousands or millions of scenarios and to automatically update those scenarios based on real-time data. Even for operators with the world's most sophisticated simulations, there is a need for faster models to achieve prescriptive analytics and leverage real-time data.

Limitations of existing data-driven modeling tools

Purely data-driven models lie on the opposite end of the spectrum compared to physics-based reservoir simulation. While simulation models require months to set up and days to run, machine learning models can be built in days and run across a full field in real time to rapidly explore thousands of scenarios and identify optimal solutions. Although such models offer a significant speed advantage and enable predictive analytics, in domains such as unconventionals where the reservoir physics are relatively more difficult to model, the absence of underlying physics prevents machine learning's use for quantitative optimization. The most notable challenges to quantitative optimization based on data-driven approaches include:

1. Models only accurately predicting already-measured responses in the reservoir;
2. Susceptibility to significant prediction errors due to data quality issues;
3. Inability to predict drilling responses given the absence of data at new locations; and
4. Poor predictability over longer time horizons and changing reservoir conditions.

Physics-based reservoir simulation and data-driven machine learning offer complementary strengths. An ideal predictive model would combine the speed and flexibility of machine learning with the predictive accuracy of reservoir simulation so that operators could integrate data in real time to quantitatively optimize key reservoir decisions continuously.

Merging physics, data

Data Physics merges modern data science and the physics of reservoir simulation. Like machine-learn-

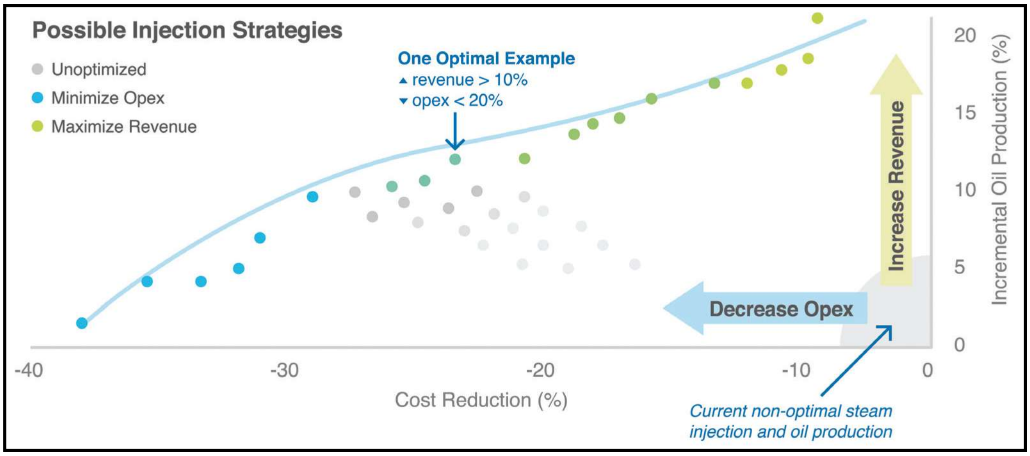


FIGURE 2. This chart shows the benefits of a prescriptive analytical model. The Pareto front describes the optimal solutions, allowing engineers to make operational decisions that have the most significant financial impact for any specific input constraint. (Source: Tachyus)

ing models, Data Physics models require only days to set up and can be run in real time. Additionally, because the models include all the same physics as a reservoir simulation, they offer excellent long-term predictive capacity even when historical data are sparse or missing.

Data Physics models integrate production data and well log data in a single assimilation step, unlike traditional sequential reservoir simulation workflows.

Data assimilation is automatic and leverages sophisticated algorithms, requiring minimal human intervention. These models directly incorporate raw data such as log responses without the need for manual interpretation. Data Physics models can therefore be rapidly built and continuously updated while assimilating various forms of data without inconsistencies.

Closed-loop optimization

After fitting historical data and validating predictive capacity, Data Physics models can be used to quantitatively optimize any future performance indicator such as short-term cash flow, net present value or ultimate recovery. Closed-loop optimization becomes possible due to the speed of Data Physics models.

Full steamflood optimization, for example, consists of a combination of pattern design, areal steam redistribution, vertical steam redistribution, selection of total steam capacity and infill drilling location selection. Focusing solely on steam capacity optimization, Figure 2 shows sample optimized and nonoptimized injection scenarios. The operator is not yet maximizing production or minimizing injection.

Depending on the operator’s priorities and risk tolerance, there are several optimal solutions. For example, steam injection can decrease almost 40% while maintaining oil production, or oil production can increase 20% while maintaining injection.

By harnessing the power of data with sophisticated modeling tools like Data Physics, producers are realizing quantifiable improvements in recovery. E&P

Keeping the industry relevant

Devon's president and CEO is convinced the industry will never stop innovating.

Rhonda Duey, Executive Editor

As the keynote speaker at the Society of Exploration Geophysicists annual meeting, Devon Energy President and CEO Dave Hager had his work cut out for him. Downturns are never kind to the exploration side of the business, and Hager's task was to give a talk that was edifying and entertaining. He did not disappoint.

Couching his remarks as "an oil and gas story rather than a talk," Hager, a former geophysicist, said that, while he's more used to speaking to analysts and investors than technical people these days, he still thinks that getting the reservoir understanding down is as important as any efficiencies the industry might have gained through the recent downturn. "That's where geophysics really takes hold and is so important," he said. "Sometimes we tend to think that these unconventional plays don't rely quite as much on geophysics as they do on horizontal drilling and hydraulic fracturing. But I don't think that's the case."

Hager's main focus was on three major technical achievements that he's witnessed throughout his career—3-D seismic, deepwater development and unconventionals. "My career really intersected what I consider some of the interesting developments," he said. "And I think they really changed the entire oil and gas industry."

But he also said he expects "a fourth and a fifth" major technical advancement yet to come. "I'm not smart enough to figure out what it is, but there are people in this audience who are going to figure out what the next big thing is that will allow this industry to remain relevant for many years," he said. "If we'd continued to do things in the way we did them before any of these changes, we wouldn't be a business. But we're a vibrant business because of the continuous technical innovation we've seen."

Technical achievements

"Three-dimensional seismic really started to come into play in the 1980s, and it fundamentally changed the way we go about exploring for first conventional reservoirs and now for unconventional reservoirs," Hager said. "It has changed how we go about interpreting data. That along with the advent of the seismic interpretation workstation has led to an entire change in our business."

Dave Hager

Hager also was involved with the industry's move into deep water during his years with Oryx and Kerr-McGee. Here too geophysics played a role in lowering the risk, but Hager also remembers the excitement of implementing the first spars on some of the Kerr-McGee fields.

"It was a lot of fun during that time," he said. "If you think back on it, the onshore was dead, and everyone believed that the significant fields yet to be discovered were going to be offshore and particularly in deep water. It was exciting to be in that part of the business."

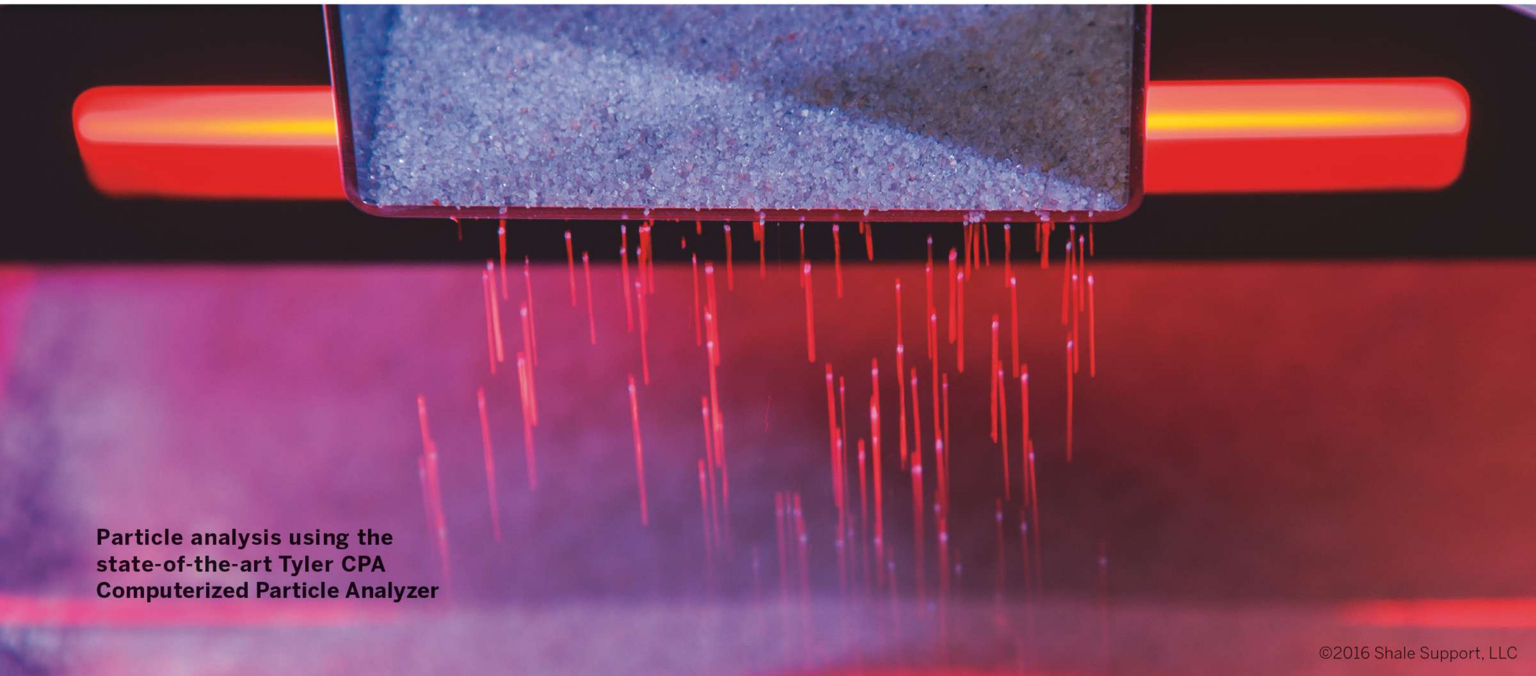
His third achievement, the ability to produce from source rocks, is particularly apropos since Devon bought Mitchell Energy shortly before the Blakley Estate D2H well was drilled. This well was the first to combine horizontal drilling with hydraulic fracturing, kicking off the Barnett Shale and ultimately the shale gale. Neither technology could have done it without the other, Hager said.

"As many of you know, hydraulic fracturing has been around since the '40s, and actually in one version or another horizontal drilling has been around since the '20s. It wasn't until Devon acquired Mitchell in 2002 that the idea came about combining horizontal drilling with hydraulic fracturing.

"Some of the guys I work with were involved in that first project. One of them, Tony Vaughn, who's now our chief operating officer, has a very interesting way of describing it. He was involved in the decision to drill the first horizontal wells with hydraulic fracturing. He says, 'You know, we were pretty confident that it was going to fail.'"

Hager added that the decision to go ahead with the well despite the expectation of failure shows the entrepreneurial spirit of the oil and gas industry. To indicate just how unaware the company was of the well's significance at the time, Hager showed a picture of the well.

"It was interesting to put this actual picture together," he said. "I guess we don't do as good a job as we should documenting history. Our lease operator had to take the sign from the entrance and stick it on top of the well so that we would have this picture."



Particle analysis using the state-of-the-art Tyler CPA Computerized Particle Analyzer

The Blakley Estate D2H well, about 45 minutes northwest of Dallas, marks the birthplace of the shale revolution. Drilled and completed for Devon Energy in 2002 and still producing today, it was the first well to combine horizontal drilling with hydraulic fracturing. (Photo by Colter Henderson, courtesy of Devon Energy)

Since the Barnett's success, he said, the shale boom expanded to other gas plays. Oil was a bit trickier. "From around 2004, and mainly in just pure shales, there was a real technical question: Will this work in the oil type plays?" he said. "Some other companies in the industry did a really good job proving that it will work in the oil plays, that even though the molecules are somewhat larger, they will move through this relatively impermeable rock, and it has expanded to the oil plays and then out of the shales.

"Now much of what we're drilling is not a classic shale-type reservoir but reservoirs that are very low in permeability. But with the benefit of horizontal drilling and hydraulic fracturing you can make economic accumulations out of them, so they might be a siltstone or a more limey type rock, but all of these now are working. The thing that is to me very encouraging about this also is that I feel we are still in early innings on this type of technology."

Geophysics in an independent setting

Hager showed several examples of how the company uses geophysics in its operations. In one example, a 4-D study of a steam-assisted gravity drainage project in Canada showed a change in the reservoir over time as it was heated by steam injection. Another example showed a comparison between two earth models. In the first model, the drillbit stayed within the modeled zone, and the well was a good producer. In the second example, the wellpath strayed significantly from the zone of interest.

"This is 3-D integrated generation of an earth model that allows us to predict the reservoir characteristics," he said.

Devon also is delving into predictive analytics through the use of control rooms to monitor drilling 24/7 as well as SCADA systems in producing fields that anticipate equipment failures before they occur.

Overall, Hager seemed upbeat about the ability of technology and innovation to keep the industry relevant. He closed with a quote: "We usually find oil in new places with old ideas. Sometimes we find oil in an old place with a new idea, but we seldom find much oil in an old place with an old idea. Sometimes in the past we've thought that we were running out of oil, but actually we were running out of ideas." What's interesting about this quote, he said, is that it was said by a professor at the University of Tulsa, Parke Dickey, in 1958.

"So we've been here before, and this industry has continued to innovate. I'm confident there are going to be more in the future, and I think geophysics is going to be right in the middle of all these innovations." E&P

Introducing a new controlled optimization process for multistage completions

A well-to-well program made possible by consistent frac placement and measured downhole pressures and temperatures

Controlling key variables enables true optimization

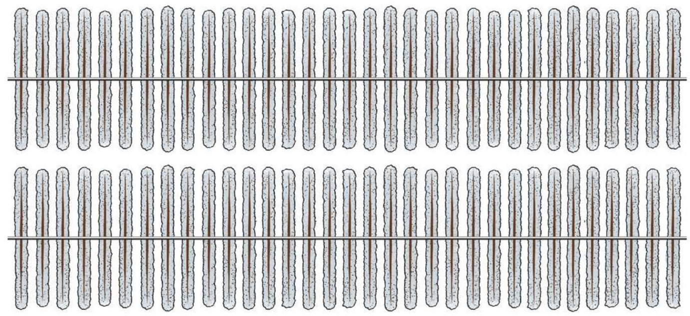
Plug-and-perf completions cannot be truly optimized, because the number of fracs, frac spacing, and propped volume are uncontrolled variables. The same is true for openhole packer/ball sleeve completions. Even if a completion is economically acceptable, there is no reliable, methodical way to improve the design, because frac placement is not repeatable from well to well.

With the Multistage Unlimited® pinpoint frac system, you know where fracs initiate and exactly how much proppant you put in each one. No matter what else you adjust—frac spacing, frac dimensions, proppant type and concentration, frac fluid, or injection rates—frac placement is predictable, verifiable, and repeatable, so you can clearly see the effects of your changes and adjust your design accordingly.

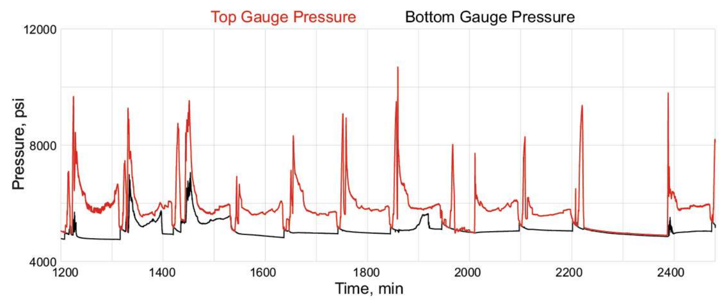
Recorded downhole data describes every frac

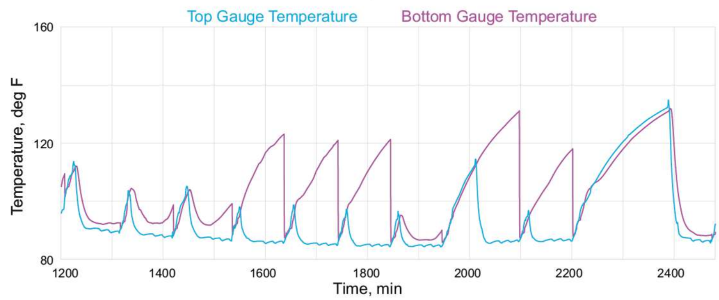
At every stage, the Multistage Unlimited frac-isolation system records pressures and temperatures at the frac zone and in the wellbore below (see charts at right). The data reveals the presence and type of any interzone communication (e.g., natural fractures or cement failure) and identifies the presence and source of near-wellbore restrictions. These stage-by-stage details provide critical insights operators are using to optimize frac design and frac spacing.

Consistent frac placement plus downhole data is your fastest route to truly optimized completions and field-development strategies. Learn more at ncsmultistage.com.



Predictable, verifiable, and repeatable frac spacing and propped volume facilitate formation-specific, well-to-well optimization across entire fields





Recorded pressure and temperature at and below the frac zone for ten stages. The data identifies any interstage communication and describes important frac and formation characteristics.

The Multistage Unlimited frac-isolation system is the world's leading coiled-tubing frac technology, with more than 137,000 stages completed.

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Bakken DUC roast

Bakken E&P companies turn their sights on reducing drilled but uncompleted wells backlog.

Richard Mason, Chief Technical Director

Canadian geese have started south, pheasant hunting season opened to mixed reviews and drilled but uncompleted wells (DUCs) are clearly in the crosshairs of E&P companies in North Dakota.

At long last the Bakken Shale shows signs of awakening as multiple Bakken E&P companies are moving forward with DUC reduction programs, with further expansion scheduled in early 2017, including one effort on behalf of a publicly held mid-cap to complete 60 inventoried wells.

Officially, the North Dakota Industrial Commission reported E&P companies completed 71 wells in September 2016, while the number of wells waiting on completion dropped by 27 to 861 to close out third-quarter 2016. Service providers report an average 7% decline in DUC inventory heading into the final month of 2016.

All good news. And it doesn't stop there. Well stimulation firms are reporting an increase in per-stage pricing, making the Bakken the third tight formation play to report price increases for well stimulation. As elsewhere, the price increase relates to greater proppant consumption as E&P companies boost stage count on tighter spacing and add increased proppant loading per stage. Pricing edged above $42,000 per stage, on track with increases reported during fourth-quarter 2016 in the Eagle Ford and Marcellus shales.

- **Bakken completions show significant boost in stages and proppant per stage.**
- **Well stimulation prices are rising as capacity tightens.**
- **2017 capex implies further reduction in DUC inventory.**

Outside of increased consumables, some well stimulation firms implemented a 10% increase for services based on a tightening market and longer waits for crews and equipment, while multiple Williston Basin well stimulation firms are actively signaling a post-Jan. 1 price increase across the board for pressure pumping services. Indeed, while the pace of well completion remains six stages daily on a 24-hr schedule, the actual number of days to complete a lateral increased to 12 as E&P companies face a shortage of readily available crews, with some well stimulation work remaining on extended daylight hours.

Like the airline industry, announcements of price increase and actual traction in the market are two separate events. Outside the Bakken well stimulation providers continue adding incremental crews nationwide in anticipation of increased demand in 2017 even as pressure pumping fleets rotate through regional markets in search of steady employment.

True to form, regional well stimulation capacity is rising in the Bakken. One E&P company added two well stimulation fleets in fourth-quarter 2016 focusing specifically on its DUC backlog, while a third fleet has entered the play, boosting the regional fleet count to 12. Regional hydraulic horsepower rose to 272,000. The amount of hydraulic horsepower applied per well rose to 27,000 hhp on the basis of modestly longer laterals, an increase in stage count per well and a large jump in the volume of proppant loading, which rose to 15 million pounds per lateral, up from 10.2 million pounds in third-quarter 2016, according to well stimulation firms. Proppant per stage rose 18% to 300,000 lb.

Service providers expect the DUC blowdown will lead to rising demand across all service lines in 2017, including drilling and workover. Well stimulation activity held steady despite the early November retrenchment in oil prices. Every rally in demand for oil service providers in 2016 has been cut short when commodity prices retreated, hence the importance of the OPEC meeting. That said, E&P companies appear committed to higher 2017 capital spending, which will benefit well stimulation early and the drilling sector later.

There were two changes in downhole trends in fourth-quarter 2016, including a jump in average stage count to 50 on an 11% decrease in stage spacing, while average proppant loading, as noted earlier, increased to 15 million pounds per lateral. E&P

Seismic industry in a world of pain

Reduced exploration budgets have seriously harmed the sector.

Speaking to the audience at PETEX in London last November, CGG CEO Dr. Jean-Georges Malcor painted a fairly dismal picture of the state of the seismic industry. This sector already was feeling the pinch when commodity prices went south in 2014. It has yet to recover.

Noting that E&P capex spending has dropped from $650 billion to $350 billion over the last 10 years, Malcor noted that a whopping $300 billion of that capex has evaporated in just the last three years. "We have had three years of continuous massive failing, and all regions have been affected," he said. "All of our clients have been reducing spending, although with [national oil companies] we see less reduction than the others."

He added that the seismic market has been reduced by 60% since 2012, "the last good year" for the industry. "Traditionally the seismic market would represent between 2% and 3% of the global E&P spending," he said. "Now it is clearly below 1% since all of our customers massively cut their E&P spending."

Meanwhile, since 2005 the marine seismic industry has launched 35 new seismic vessels, representing about a $7 billion investment. Not surprisingly, Malcor said, there is "a huge level of debt" represented by these vessels. "One can recover very little out of this massive investment today," he said.

The marine seismic industry is struggling as E&P companies continue to scale back on exploration. (Source: CGG)

Because the seismic industry already was in decline when the downturn hit, it hasn't had the chance to recover the return on this investment. And despite efforts to cut costs, he said, marine seismic prices have been collapsing. "It does not make sense to run a business where you have to pay to run your assets," he said.

It's not all doom and gloom. Malcor said the market will recover because the fundamentals are still there. Demand for marine seismic services has grown 1.5% to 2% per year, and reserves are dropping by about 5% per year.

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EPmag.com

"Our industry is going to face a massive squeeze at some point," he said. "The problem is, when? And what can we do to meet the demand?" He expressed doubts that merger and acquisition activity would be enough. "I think we will need to turn back to exploration," he said, adding that 60% of oil production in 2035 should come from new discoveries rather than existing fields. And cycle time will need to be cut.

"Time is becoming of the essence," he said. "The way we do exploration is very slow, but our ability to extract more from our existing wells is also extremely important."

Overall, Malcor told the audience, the seismic industry needs to reinvent the way it works with its customers and adopt more of a partnership model. "Today the whole business is too much about procurement," he said. "It's very difficult in the current circumstances to be in a position where we can value the technology and the innovation.

"I think we need to stand up as responsible people and engage with our customers. To say, OK, are we important in your business long term? Do you believe geoscience is an important part of your chain? If yes, we need to sit down, talk and reinvent the way we are working.

"We need to go through this difficult time the best we can, but let's make sure we are clever enough to work with our customers and our partners and our competitors to make sure the industry is not damaged too much at the end of this trough." E&P

Rhonda

Dueling basins: gas in Delaware Basin, oil in Permian Basin

During 2016 the Alpine High was opened up with 2.1 Tcm (75 Tcf) of gas, and the USGS estimated the Wolfcamp Shale has 20 Bbbl of oil—making the Permian Basin the best place to play.

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"The Wolfcamp now holds the largest estimated, continuous oil accumulation that the USGS [U.S. Geological Survey] has assessed in the United States to date." That's how the USGS described its estimate for the Wolfcamp Formation in the Midland Basin. The estimate is nearly three times larger than the 2013 USGS estimate for the Bakken-Three Forks resource assessment.

"Even in areas that have produced billions of barrels of oil, there is still the potential to find billions more," said Walter Guidroz, program coordinator for the USGS Energy Resources Program.

The Wolfcamp A, B, C and D have been opened up with horizontal drilling and hydraulic fracturing. More than 3,000 horizontal wells have been drilled and completed in the Midland Basin Wolfcamp.

Apache Corp.'s Alpine High Field is focused on the Woodford and Barnett formations. There are also some Wolfcamp zones in the field.

If you were an oil and gas company looking for a place to drill, you'd likely be willing to spend a half-billion dollars or so for a nice footprint in either basin. And there would be some financial institutions out there willing to back that play.

> If you were looking for a place to drill, you'd likely be willing to spend a half-billion dollars for a footprint in either basin.

The Baker Hughes rig count stayed the same at 218 rigs in the Permian Basin for the week ending Nov. 11, 2016. The 11 was rather a portent. After all, the Permian rig count was only 11 rigs fewer than the same week in 2015.

On Nov. 17, 2016, the price of oil was at $45.42, and the price of natural gas was $2.87. Which play would make the most money for operators today? That's the "$64,000 question," as the 1950s quiz show used to ask.

"Changes in technology and industry practices can have significant effects on what resources are technically recoverable," Guidroz said.

West Texas has been described as miles and miles of miles and miles. Operators are out in the undiscovered country—undiscovered resources are those that are estimated to exist based on geologic knowledge and theory. Continuous resources commonly require special technical drilling and recovery methods, according to USGS.

In its third-quarter 2016 report Nov. 3, Apache had expanded its acreage position by 13,000 acres to 320,000 net acres. John J. Christmann IV, Apache's CEO and president, said, "Our deliberate focus on strategic testing during the downturn not only yielded excellent results with our Alpine High discovery but also significantly improved our results in our Midland and Delaware basins focus areas. Our economic drilling inventory in the Permian Basin is more extensive today than at any time in the company's history, and we expect it will continue to grow as we further delineate our vast acreage position in the basin."

That is good news for the drilling industry. E&P

Scott

Eliminating double-money downtime

Partnership creates digital solution to reduce unplanned downtime of offshore operations.

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Growing up I spent a fair piece of time helping in the parts warehouse of my parents' small engine repair shop during the '80s oil boom. It was there that I heard variations of "if I'd only caught it sooner, then we could've fixed it before it broke" from customers.

It often was followed by its friend, "Time is money, and downtime is double-money." Downtime is not just profit lost but also the expense incurred getting the system running again. While preventing all downtime is not currently possible, advances in digital technologies are helping to make it a real possibility in the future.

GE Oil & Gas and BP announced a year ago their partnership to co-create a digital solution to reduce unplanned downtime in offshore operations. Less than a year later, on Nov. 15, 2016, the companies announced the startup of pilot testing of the Plant Operations Advisor (POA) on a BP production platform in the Gulf of Mexico.

"We've gone from a concept that was literally a gleam in our eyes when we first visited a little over a year ago to the starting up of the pilot test on our Atlantis platform [Nov. 11]," said Ahmed Hashmi, BP's head of Upstream Technology.

The POA is designed to improve the efficiency, reliability and safety of BP's oil and gas production operations. This initial deployment is a pilot test of the system and could—subject to its success—see deployment on other BP facilities around the world.

"Once the system is deployed across all of the planned facilities, we'll be tracking 20 million digital entities that are streaming live," said Binu Mathew, global head, Development and Product Management for GE Oil & Gas Digital. "Some of these will refresh quite frequently, every few minutes for example, and some less frequently. It is a very large volume of data."

The tool, built on GE's Predix operating system and through its utilization of GE's Asset Performance Management capabilities, rapidly integrates operational data from producing oil and gas facilities to deliver notifications and analytical reports to engineers so they can identify performance issues before they become significant, according to a press release.

"The control systems are meant to trip whenever something goes outside of its operating limit," Hashmi said. "We call these excursions. The Plant Operations Advisor will train itself as it witnesses these different excursions over time."

The POA provides simplified access to a variety of live data feeds and includes visualization capabilities including a real-time facility threat display. It also incorporates an extensive case management capability to support learnings from prior operational issues, the release stated.

The POA pilot is underway on BP's Atlantis platform in the Gulf of Mexico. Testing is set to run to the end of first-quarter 2017. (Source: BP)

"Our process engineers create a history of which component went out of its operating limit [and] what the conditions were that preceded it. The POA, through this training and the history, will give early warnings to the engineers, alerting them that a piece of equipment may be going out of range if X, Y and Z are not done to prevent it," Hashmi said. "Once we get into that zone, that's when we're truly reducing unplanned downtime… improving the reliability of the plant, and that's our objective here." E&P

Jennifer

Breaking open opportunities

The industry continues to push the boundaries of hydraulic fracturing technology.

Rhonda Duey, Executive Editor

During the heady "drill, baby, drill" days hydraulic fracturing was often just a brute-force technique to introduce enough permeability into shale plays to release the hydrocarbons. But operators quickly discovered that what worked well in one play didn't necessarily translate to another, and they continue to experiment with lateral lengths and proppant loads to optimize their completions.

This month *E&P* takes a look at a company that has done just that in the Utica. Using its "Generation 3" completion scheme, Eclipse Resources is enjoying phenomenal success after first testing the strategy on its record-setting Purple Hayes well.

Logging-while-tripping technology aids operators who want to do engineered fractures by gathering log data while the pipe is being pulled out of the hole. This saves time and money and provides immediate formation evaluation information.

Other articles look at a new biosurfactant technology as well as the importance of proppant sand quality.

In this lower-for-longer environment, it's likely that continued advances in hydraulic fracturing will lead to greater efficiencies and—the holy grail—increased production. E&P

Recipe for success

One company's 'super-lateral' approach is paying significant dividends.

Rhonda Duey, Executive Editor

Finding the right recipe for a fracturing job is critical in shale plays. In the Utica Shale, Eclipse Resources is writing a whole new cookbook.

At a time when many companies are deferring well completions to a later date, Eclipse is so happy with its "Generation 3" completion design that it turned 11 gross wells to sales during third-quarter 2016 and, according to its third-quarter results, is "very encouraged with the initial results of the wells as compared to the company's previous completion designs."

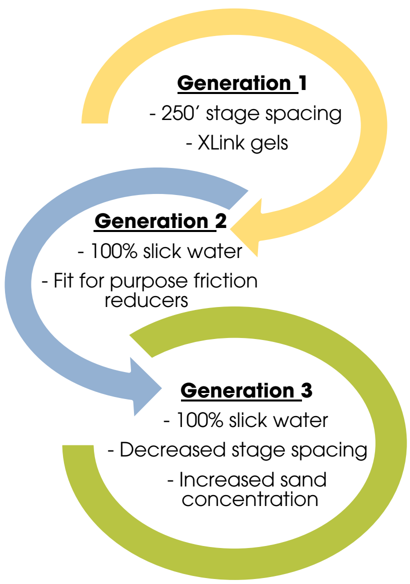
Perhaps more telling is the fact that while completing wells for Eclipse, its Halliburton fracturing crew set a Halliburton record for the most stages completed in a month by a single crew in the northeastern region, then broke its own record the following month. Eclipse also helped the Halliburton crew set a record for the total amount of proppant pumped in a month by a single crew in the northeastern region. The crew pumped more than 82 million pounds of proppant in October 2016.

The reason for the feeding frenzy is the record-breaking Purple Hayes 1H well in Guernsey County, Ohio. The 5,640-m (18,500-ft) lateral is the longest ever drilled in the U.S., and the 124 fracture stages were completed at a rate of 5.3 stages per day. Dubbed the "Super-Lateral Program," this type of drilling and completion design has become the standard for Eclipse in its Utica acreage.

Back to basics

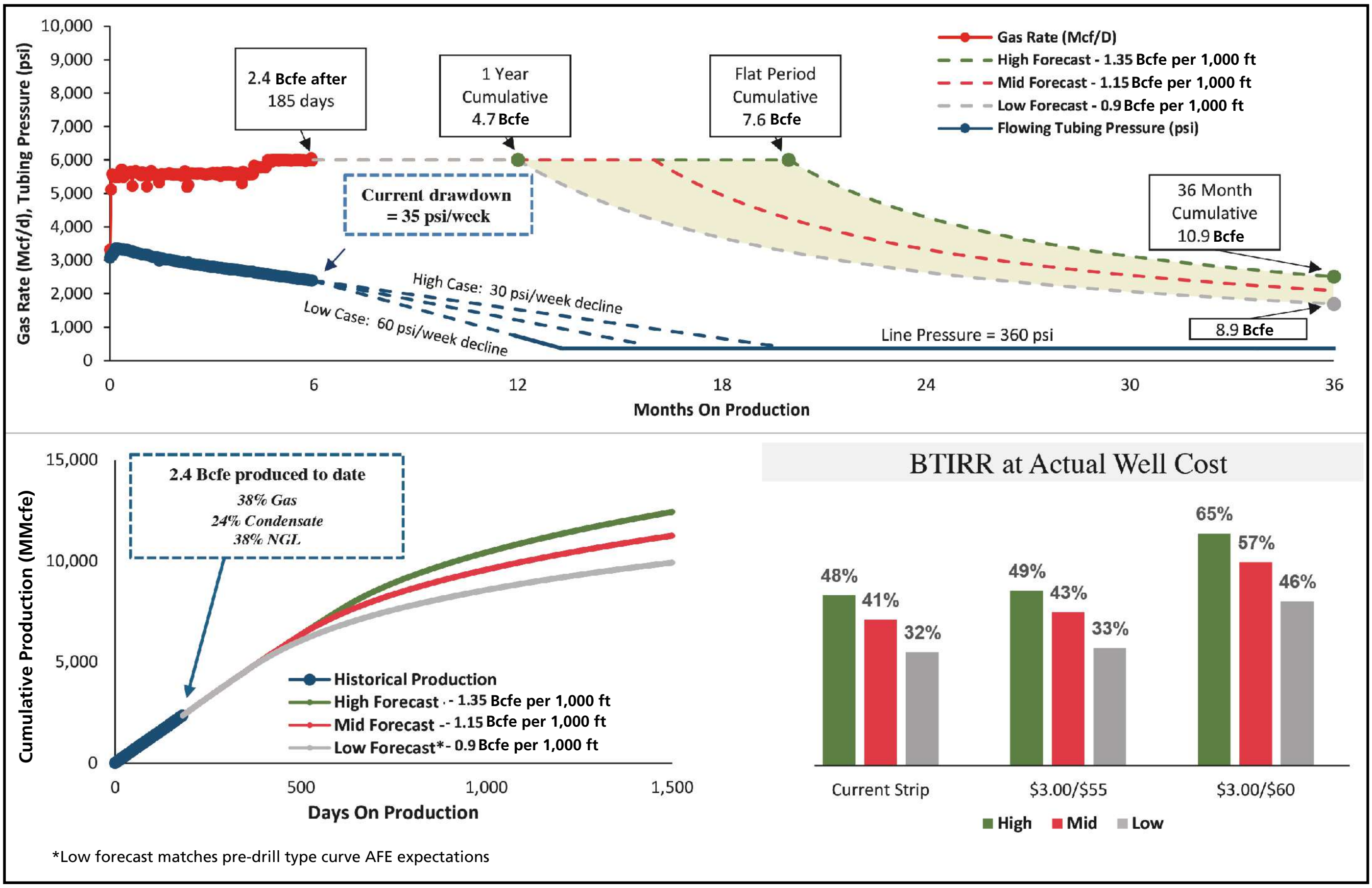
Speaking at Hart Energy's 2016 DUG East conference, Oleg Tolmachev, Eclipse's senior vice president of drilling and completions, told the audience that the company took a systematic, process-driven approach to execute this well construction project. The process involved multiple well planning iterations and torque and drag modeling as well as a tight range of mud parameters, bit selection, cement design, wireline drag models, fracture design and drill-out methods.

"Super laterals allow us to dramatically lower F&D [finding and development] cost, which is crucial in today's low commodity price environment," he said. In an interview with *E&P*, Eclipse President and CEO Benjamin W. Hulburt went into more detail.



	Completions Date	Location	Stage Spacing Range (ft)	Sand Loading Range (lbs/ft)	Slick Water
2014 Pads	2014	Wet/Dry	175 – 315	1,261 – 2,393	60%
Pad A	Q4 2015	Dry	223 – 230	1,358 – 1,472	100%
Pad B	Q1 2016	Wet	150	1,400	100%
Pad C	**Q2 2016**	**Wet**	**149 - 150**	**1,800 - 2,000**	**100%**
Pad D	**Q3 2016**	**Wet**	**110 - 151**	**2,000 - 2,400**	**100%**
Pad E	**Q3 2016**	**Wet**	**110 - 150**	**2,400 - 3,000**	**100%**
Pad F	**Q3 2016**	**Wet**	**150**	**2,400 - 2,600**	**100%**
Pad G	**Q4 2016**	**Dry**	**150 - 200**	**2,600 - 3,000**	**100%**
Pad H	**Q4 2016**	**Wet**	**150**	**2,600**	**100%**

Eclipse continues to experiment with higher intensity completions while maintaining a flat cost structure. (Source: Eclipse Resources)



Given the well results over the first 185 days, Eclipse believes the Purple Hayes well is trending toward its mid- to high forecast as production continues to remain flat and pressure drawdowns continue on current trends. (Source: Eclipse Resources)

"Essentially you are spreading out the fixed-cost portion of the wells, which is the pad cost in the vertical portion of the well. You are spreading that out over a greater amount of productive lateral."

The problem in the past, he said, was that the farther out the lateral is drilled, the less recovery per foot was achieved. "What we are trying to prove is that in this reservoir with our completion design we will not get significantly different recovery by going longer," he said. "That's what we feel pretty strongly we've proven, at least to ourselves."

Indeed. As of Nov. 3, 2016, the Purple Hayes No. 1H well had produced a cumulative amount of 67.9 MMcm (2.4 Bcfe) during its 185 days of production while encountering much smaller pressure declines than expected. It's expected to outperform Eclipse's legacy "type well" reserve expectations by 28% to 50%.

Going after the DUCs

Like many companies, Eclipse has a portfolio of drilled but uncompleted (DUC) wells in its asset base. Unlike some companies, it drilled these wells with every intention of eventually completing them and bringing them onstream. In most cases, higher prices would be the lure to complete the DUCs. But Eclipse has other reasons as well.

"We are really glad we drilled them as DUCs," Hulburt said. "If we had fracked them two years ago when we drilled them, we would not have used this new frack design." The company completed 12 DUCs in third-quarter 2016 using its new Generation 3 completion design, he added, while staying within budget.

Lessons learned?

Eclipse has benefitted from the addition of some savvy Appalachian drillers from other companies. Hulburt said this type of experience certainly helps when drilling the vertical portion of these wells. "They know what zones tend to be a problem on the way down," he said.

The completion design, on the other hand, can't be compared to experience in, say, the Marcellus Shale.

"I don't know how transferrable that is," he said. "But certainly having the regional service contracts and relationships helps a lot."

Hulburt added that operators in other parts of the country are interested in learning more about this completion design. "We have gotten a lot of inbound calls," he said. "It has definitely been a pretty fantastic project for us. We obviously don't want to just tell all of our competitors how we did it, but we've definitely had calls from all over the country [from] different operators in different shales."

Though Hulburt wasn't aware of any other companies that are trying something similar, he said the trend overall is to go with longer laterals. It's the other costs that have to be factored in.

"In the Permian your pad costs are probably $150,000," he said. "Where we are, building a pad is $2 million, sometimes $3 million. At some point it's probably easier and cheaper for operators in the Permian to just build another pad. You definitely add a level of risk going out this long."

Having dry gas helps. Unlike other gassy plays like the Eagle Ford, where operators moved into the liquids portion of the play when natural gas prices tanked, dry gas is still the preferred target. "Even at $2.50 gas prices, the wells are still very economical if you are in the core area," Hulburt said. "The dry gas portion is pretty much where all of the drilling rigs are in the Utica now."

Overall, Hulburt is bullish on the industry going forward, enough so that the company has finished out its 2017 gas hedging program, which now covers about 80% of its expected production. "I think the fundamentals have been improving throughout the year," he said. "We certainly are not out of the woods yet. But I think we definitely feel a lot better than we did six or eight months ago."

Companies to form North American land pressure pumping company

Baker Hughes Inc., CSL Capital Management and West Street Energy Partners (WSEP), a fund managed by the Merchant Banking Division of Goldman Sachs, announced an agreement to create a pure-play North American land pressure pumping company, according to a Nov. 29, 2016, press release.

Under the terms of the agreement, Baker Hughes will contribute its North American land cementing and hydraulic fracturing businesses, which comprise assets in the U.S. and Canada. This includes personnel, expertise, technology and infrastructure. Upon closing, CSL Capital Management will contribute its Allied Energy Services platform, which provides hydraulic fracturing and cementing services on land in North America. Further, CSL Capital Management and WSEP will together contribute $325 million in cash to the new company, of which $175 million will be used to strengthen its balance sheet and position it for growth while the remaining $150 million will go to Baker Hughes. CSL Capital Management and WSEP together will own 53.3% of the new company, and Baker Hughes will retain a 46.7% ownership stake. The new company will operate under the BJ Services brand and will be headquartered in Tomball, Texas.

Warren Zemlak, current president and CEO of Allied Energy Services and former long-time senior executive with both Schlumberger and Sanjel, will serve as CEO of BJ Services. "The combined company will have 1.9 million hydraulic horsepower and more than 240 cementers, among other assets, and an owned-facility footprint throughout North America to serve our customers in all basins," he said. ■

Engineering better completions with LWT

Logging-while-tripping formation evaluation helps enhance production through engineered completion designs.

Billy Anthony, GR Energy Services, and **Ricardo Quintero**, Cordax Evaluation Technologies Inc.

Affordable and fast openhole-quality logging data can be acquired by logging while tripping (LWT) pipe to enhance hydraulic fracturing operations through engineered completion designs. With cost-efficient LWT resistivity, density, neutron and spectral gamma ray logs, perforating and fracturing programs might be designed based on formation properties to optimize cluster placement and stage spacing. The acquisition of memory logs through LWT collars during normal trip-out eliminates the need for vertical pilot holes to evaluate pay zones and allows the completion to be optimized for toe-to-heel heterogeneity.

LWT operations

With more than 650 successful runs worldwide, LWT is a proven formation evaluation technique that allows wireline-quality openhole logs to be acquired immediately after drilling has been completed while the drilling assembly is tripped to surface. LWT measurements are obtained with standard openhole API-calibrated logging devices and meet all requirements for porosity and resistivity measurements. The battery-operated memory-based tools are lightweight with a small outer diameter, allowing simple deployment within specialized LWT drill collars.

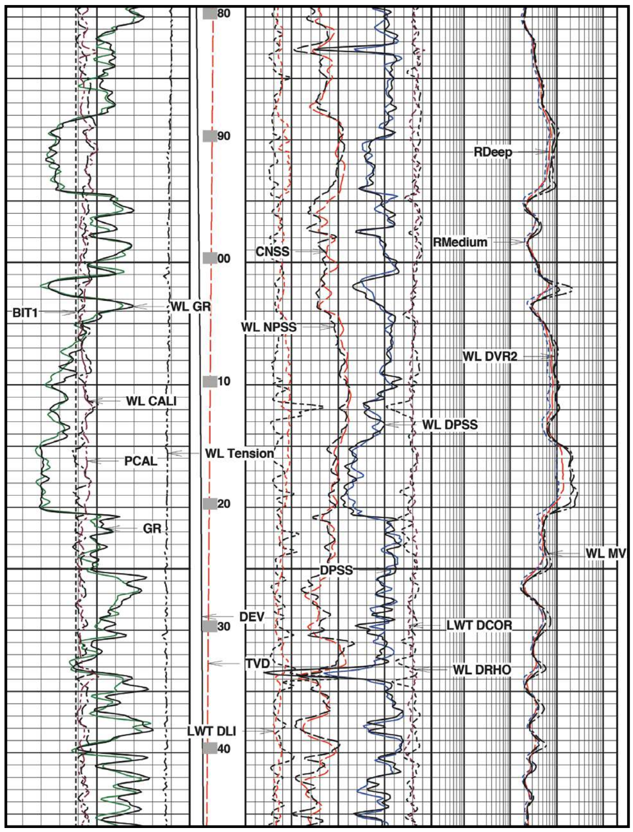
The LWT collar, which is inserted into the drillstring on the last bit trip or on the planned reamer run, does not require any change in drilling plans or extra rig time to change to a specialized bottomhole assembly (BHA). LWT tools are deployed (pumped down) at the well total depth (TD) stage and log untethered during the normal pipe trip-out. Virtually no additional rig time is needed.

During the operation the logging tools reside at all times inside the drillpipe and can be fished, eliminating the risk of damaging or losing the tools and radioactive sources in the hole. While deploying the tools and measuring, the operator has full well control.

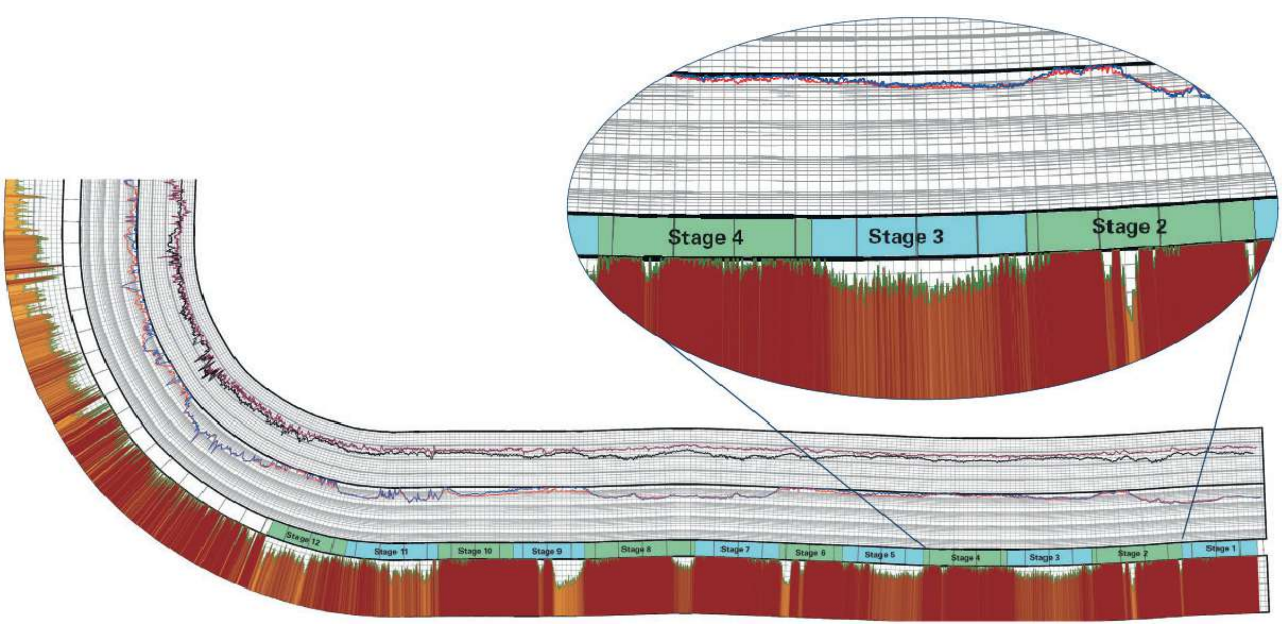
Unlike MWD and LWD tools, LWT tools are not a permanent part of the BHA but instead are deployed and retrieved from the drillstring only when log data are required. Operators get the benefit of significant cost savings in openhole data acquisition because

- There is virtually no additional rig time to acquire logs;
- Lost-in-hole charges are 10 times to 30 times lower than wireline or LWD; and
- There is no risk of tool sticking.

The LWT collars are positioned as close to TD as possible. After reaching TD with the LWT collars in the BHA, the tools are deployed in the drillpipe and pumped down. Once landed, the rig pumps a mud pill, if required, and



This comparison overlay of LWT and conventional wireline data acquired in the same well shows an excellent match. (Source: GR Energy Services and Cordax Evaluation Technologies Inc.)



LWT data can be analyzed to take the guesswork out of stage length and perforation cluster placement decisions to improve the effectiveness of hydraulic fracture operations. (Source: GR Energy Services and Cordax Evaluation Technologies Inc.)

trips out at logging speed. The rig can circulate, rotate or reciprocate pipe with the tools landed in the collar. LWT tools have achieved greater than 98.5% uptime to date, and no tools have been lost in hole.

Applications

Reduction of risk, rig time savings, depth and well-to-well correlation, and acquisition of formation evaluation data in poor hole conditions are potential benefits in any onshore or offshore well. In unconventional wells, the primary application is enhancing production through engineered completion designs. The traditional approach to perforating placement in horizontal wells with geometrically spaced perforating clusters and stages does not take into account toe-to-heel heterogeneity and often results in a number of perforation clusters that do not contribute to well performance. Production logging data have shown that as much as 40% of perforations might not adequately accept treating fluid, resulting in nonoptimized stimulation of the targeted reservoir.

LWT data are used to optimize completions by precisely positioning stages and perforation clusters along the wellbore that target rock with similar geomechanical and producibility properties. A proprietary ZoneGrader program integrates and analyzes LWT formation evaluation and drilling data (weight on bit, rpm, ROP, torque, MWD/gamma ray and mud logging data). This unique answer product grades the formation along the wellbore based on geomechanical and producibility formation characteristics. Geomechanical rock properties include stress, brittleness and lithology. Producibility properties include lithology, total organic carbon, porosity, permeability and saturation. With the wellbore graded by geomechanical and producibility properties, the number and position of stages can be determined and perforation clusters precisely placed.

After selecting the ideal stage spacing and perforation cluster placement, the shaped charge and gun system design can be optimized to ensure higher payback hydraulic fracturing operations. By using the advanced shaped charge designs and perforating rock with similar properties within the stage, more even proppant distribution can be achieved across all perforation clusters, which leads to enhanced production. In addition, formation breakdown can be improved and the chance of screenout decreased by placing perforations in consistent rock.

The benefits of an engineered completion design based on LWT data can be validated after flowback by deploying a special cable into the well with fiber-optic monitoring sensors. This approach is being used to record distributed temperature (DTS) and acoustic (DAS) surveys to detect and monitor the contribution of each perforation cluster. Unlike traditional production logs, the entire wellbore can be simultaneously surveyed in real time, and the results of the DTS and DAS profiles are used to optimize future stimulation programs and to consider the potential benefits of refracturing programs. E&P

Engineered biofluids control clay, fines

Nano-sized surfactant improves fracturing success.

Ashoka V.R. Madduri, Charles R. Landis and **William W. Aud**, HPPE LLC

Biochemical engineering is a new technology that is being introduced and applied in many different disciplines. Across an array of industries these biochemically engineered products offer superior and unique performance at less cost and are environmentally preferred. Akin to the conversion of the vacuum tube to the silicon chip, the new generation of engineered biofluids (EBF) is superior to the first generation of biopolymers because they provide biochemically engineered solutions on the molecular level. These EBFs use selectively grown polymers combined with precise molecular substitution to fit the specific use. This new capability provides many industries, including the petroleum business, a new class of superior, low-cost solutions for the first time.

Biotechnology in the oil field

Biopolymer technology is not new to the petroleum business. For example, two popular products, guar and xanthan gum, are biopolymers. What is unique with this new EBF technology is that it is possible to design a product on a molecular level that is more chemically specific for the desired task.

Biopolymers are grown to provide different shapes and molecular exchange characteristics to optimize base-level features for a wide range of industries. To give some perspective on EBF polymer types for the petroleum industry, their features can vary for friction reduction, coating of target surfaces such as clays, surfactant usage and particle size, hydrogen sulfide sequestration, dust control, cement workability, etc. The same polymer type can be developed to have different molecular interaction characteristics, providing significant versatility on the molecular substituent level. In the biochemical engineering design phase, molecular customization provides the ability to fine-tune the design via specific molecular substitution to fit each approach.

FIGURE 1. In this clay pack test filtrate comparison there is a significant amount of migrated fines with a leading clay control product. With the HPPE CS series, the effluent is clear. (Source: HPPE LLC)

A good example of this complete process is HPPE LLC's CS3315 clay control and fines stabilization product. The base polymer's molecular interaction design is optimized to be attracted to clays and then enhance the clay coating and fines stabilization process with its long-chain polymer structure. With molecular-level substitution reactions, select molecules are attached to the base biopolymer to provide advanced performance. The final product is the first to aggressively address both clay swelling and migration in one chemical. Because it is an EBF, it is superior in design, sustainable, environmentally compliant and less expensive.

These functionalized biopolymers are designed with several advantages. They are built with robust functionality in the molecular structure, providing for enhancement, evolution and simplification. They are stable within a range of typical pH, salinity and trace metal scenarios, and they have robust electron exchange characteristics.

Biopolymers for clay stabilization, fines control

Clay control and shale stabilization are important aspects in the optimization of petroleum reservoirs in the hydraulic fracturing process as well as any operation that subjects the formation to extraneous fluids. HPPE has released a biopolymer-based clay stabilizer product line to the hydraulic fracturing industry: ClayStabilizer (CS) CM3300, CM3315 and CM3330. These products are engineered biopolymers, more particularly high molecular-weight functionalized polysaccharide-based molecules that have been shown to be extremely effective at controlling clay swelling/stabilization and fines migration.

Surfactant	Interfacial Tension @ 1 gpt in Tap Water (dynes/cm)	Oil Breakthrough Times - Column 1 (min:sec)	Oil Recovery - Column 2
HPPE Biosurfactant	4.52	3:40	222%
Common Industry Surfactant	9.99	9:12	180%

FIGURE 2. This chart shows the comparison of HPPE's biosurfactant properties to a common industry surfactant. (Source: HPPE LLC)

FIGURE 3. The HPPE biosurfactant properties produce a stable solution of nano-scale droplets capable of reducing contact angles at liquid interfaces and providing film-forming geometries in the reservoir. (Source: HPPE LLC)

In all third-party independent clay control analysis laboratory testing on unconventional reservoir rocks, the CS series controls clay swelling and migration better than the commercially available clay control products. Consistently, it is superior in capillary suction test, roller oven and clay pack flow tests.

One item that is not typically documented is the nature of the filtrate effluent from a packed column flow test. This visual observation is a good way to determine a chemical's fines migration tendencies. Figure 1 is an image of the effluent following a typical clay pack flow test. The image shows significant amounts of migrated fines with a leading clay control product. With the HPPE CS series, the effluent is clear. It shows that the engineered biofluid is a tangibly superior fines migration control fluid. This is because it is specifically designed to achieve this task with its long-chained polymer and electron exchange attraction optimization. Considering the cloudiness of the other sample and small size of the clay pack flow test apparatus, a practical observation is that significant fines migration would be expected with the typical industry clay swelling control product. This is a typical observation with many applications in formations that contain both swelling and migrating clays when only the swelling mechanism is addressed.

Typical oilfield applications must pump two separate chemicals to aggressively address each problem, clay swelling and migration. This functionalized biopolymer is specifically designed to accomplish both tasks with one chemical. Additionally, because it is a liquid, it is dispersed throughout the reservoir and fracture system, providing the best approach to address migrating as well as swelling clays. For cost and logistical reasons it is common for operators to take approaches to arrest the clay swelling piece but not the migration component, which as observed can be significant. With HPPE's biochemically engineered clay control biopolymers, the need to pump two separate chemicals and the associated cost problem is eliminated.

Biosurfactants for the oil field

Surfactant use in the oil field is well-established for application in stimulation, completion and drilling fluids. A primary use is to reduce interaction issues associated with the fracturing and formation fluids in the reservoir and fracture system, thereby reducing formation damage and optimizing the hydrocarbon production. The HPPE surfactants consist of nanometer-sized surfactant droplets. This droplet size is a valuable new feature and yields a stable, small internal phase that lowers surface tension of liquid-liquid and liquid-mineral contact surfaces while permitting its access to the lowest permeability zones in unconventional reservoirs. Additionally, some testing indicates that the HPPE EBF surfactants reduce absorption depletion, which is a typical problem in reservoir completion applications.

Interfacial tension is the work required to increase the size of the interface between two adjacent immiscible phases. Lowering the interfacial tension with a surfactant increases the mobilization of oil from the formation to increase the total recovery of oil. HPPE biosurfactant interfacial tension is very competitive with common industry surfactants, while the breakthrough times and oil volumes recoveries are superior. These properties combined with of one of the smallest nano-emulsions in the market maximize reservoir contact and optimize the effectiveness of the application (Figure 2). These features produce a stable solution of nano-scale droplets capable of reducing contact angles at liquid interfaces and providing film-forming geometries in the reservoir (Figure 3). These biosurfactants deliver superior properties to the industry at typical concentrations of 0.5 to 2.0 gallons per thousand (gpt, for treatment rates of gallons of product per thousand gallons of makeup water). E&P

Quality control, logistics key to effective proppant

Particle analysis and real-time tracking are just two of many areas where new technologies are driving innovation in proppant efficiency and well productivity.

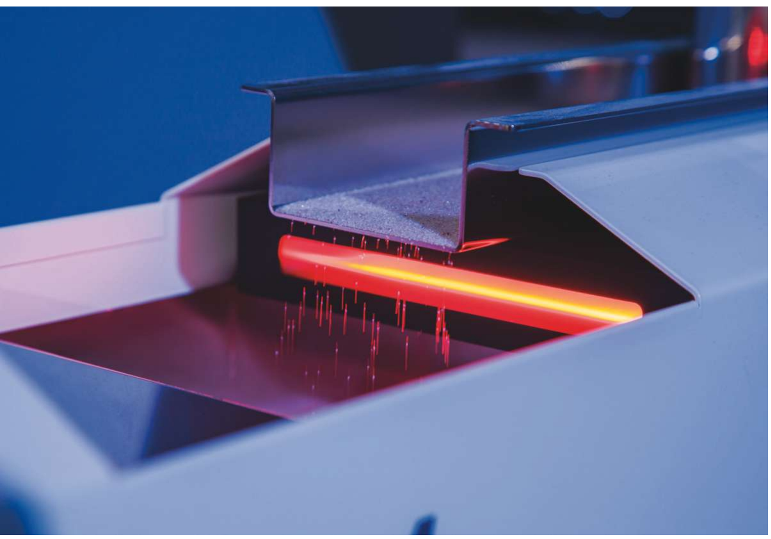
Paul DeVille, Shale Support

Even as the oil and gas industry begins to rebound, budget constraints push energy producers to keep rig counts low and completion schedules light. Operators need to maximize every completion program in hopes of achieving steady producing wells. Now more than ever, quality, accuracy and efficiency can make or break a well. There is little margin for error.

A key to the completion stage of an oil and gas well is hydraulic fracturing, which requires large quantities of sand (proppant) and water. With a depressed oil market, something as simple as fracture sand can have a significant impact on field development economics.

Proppant's role

There are various types of proppants used across the industry, from sand that is mined and then chemically treated to engineered products made from ceramics and other materials. Proppant solutions directly impact completion economics, treatment size and the well performance. Fracture sand is the most widely used option in the industry. An average shale well requires up to 5 million pounds of fracture sand during the completion phase depending on its location and formation characteristics. Energy producers spend about $300,000 on fracture sand per well.



Particle analyzers have the ability to quality-test a batch of sand within five minutes and can determine whether or not the sand meets or exceeds API and customer standards. (Source: Shale Support)

Without proper quality control (QC) and logistics management, proppant solutions can cause major problems for oil and gas operations. One mistake and an entire order of fracture sand is rendered useless.

To better understand this, it's important to look at fracture sand quality on a granular level. The physical aspects of the proppant are key: size, shape, weight and chemical application. Fracture sand does not go from the mine to downhole directly. Once mined, the sand is processed through a series of dryers, screeners and coatings to achieve optimum physical attributes for well performance.

Performance factors include conductivity throughout the life of the well, crush resistance and acid solubility. In addition, rock formations vary by basin and require different proppant solutions to enhance well performance.

Logistics are important as well. Once fracture sand is mined and processed, it is loaded into rail cars for transport to the basin, where it is stored in large silos before a truck delivers it to the well site. Strict QC standards must be maintained to prevent contamination during transport and while stored.

If proppant quality is compromised at any point, the product cannot be pumped down the well. The $300,000 loss is only the beginning for energy producers. They become entangled with the supplier of bad sand, often entering into legal disputes to recoup their initial investment. In addition, no fracture sand means no fracture, and well operations must shut down. The associated costs are considerable as many service companies and suppliers penalize operators for downtime. Energy producers are forced to identify a new vendor and procure another load of proppant on the fly. To top it off, they face the environmental challenge of responsibly disposing of 5 million pounds of tainted fracture sand, another costly outcome. Finally, the operator or drilling contractor runs the risk of a public relations

Rail Tags ensure QC is maintained throughout Shale Support's mining and logistical process, eliminating any risk of human error. (Source: Shale Support)

nightmare in communities where fracturing already is seen as an environmentally risky business.

On numerous occasions, Shale Support—a vertically integrated supplier of proppant—has been called in to provide fresh fracture sand following contamination by other suppliers. It strategically integrates quality and logistics to avoid downtime and excessive costs with a QC program.

QC is essential

As the industry enters a new era in efficiency, oilfield service companies and operators are looking to fracture sand providers to maintain quality, accuracy and efficiency. Proppant providers use traditional analysis methods approved and mandated by the International Organization for Standardization (ISO) to determine the quality of the proppant. These methods are time-consuming—a single test can take up to 30 minutes to complete—and the results often are subjective and vulnerable to human error. Traditional methods also lack necessary safeguards to ensure that the proppant arriving at the well site has not been contaminated during the logistics process.

Shale Support mines fracture sand from its properties in Picayune, Miss. With the latest QC technology, the company maximizes the effectiveness of wet mining and drying processes to ensure accuracy and performance of its product.

After fracture sand is treated, the company uses its particle analyzer to quality-test sand from each batch. With the particle analyzer, facility operators know within five minutes whether or not the sand meets American Petroleum Institute (API) and customer standards. Because of the efficiency and superiority in analyzing each sand particle, the particle analyzer provides customers the assurance that the sand they're ordering is the sand they'll receive. Additionally, the company maintains samples from every batch of sand ordered in case there are any concerns about quality once the sand leaves its facility.

Once proppant has been tested and is approved to send to a customer, Shale Support moves into its second phase of QC, the Rail Tag System. The particle analyzer uploads results into the system and assigns a unique code that will not allow a rail car to be built or unloaded out of spec. The system mitigates human error and maintains QC safeguards throughout the logistical process by scanning the unique code at various checkpoints throughout the transport process. The Rail Tag System allows real-time tracking of the product as it travels to the well site.

Once the proppant arrives to its delivery location, logistical teams confirm the Rail Tag hasn't been tampered with (if the seal is broken, there's the potential a load of sand has been contaminated) and that, once scanned, the details on the sand delivered match the original request.

Logistical efficiency

Shale Support transports its proppants via rail and road to all major U.S. shale plays. The company owns and operates terminals in the heart of the Eagle Ford Shale and Permian Basin. These facilities allow the company to store large quantities of proppant in locations that are strategically located near high amounts of hydraulic fracturing activity. It also means the company maintains control of the proppant from the mine to the well site. If there is a problem with the proppant, the operator and Shale Support can identify it immediately and know exactly when contamination occurred, offering its customers peace of mind.

While the onshore industry looks to 2017 with cautious optimism on production, the pressure to meet quick demands with quality and accuracy is ever-present. Reducing or eliminating the risk of downtime for any well is key to saving operators significant sums of money. Shale Support follows current ISO regulations and uses traditional analysis methods while preparing for industrywide acceptance of particle analyzer data. Embracing new technology and driving innovation to strategically integrate QC and logistics is vital to maintaining efficiency and well productivity. E&P

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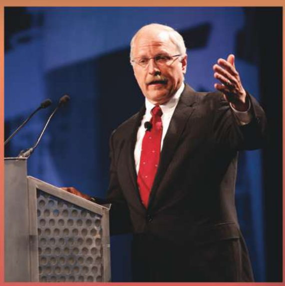

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Perforation hole size is a key gateway to the formation

New charges provide consistency.

Shaun Geerts and **James Kinsey**, Core Lab

Tough economic times continue to challenge improvements in perforating technology that can reduce costs and increase productivity. With the plug-and-perf "factory style" of wellsite operations, many of the perforating components are being commoditized. The desired result of perforating always has been to establish effective communication between the wellbore and the producing formation. Different reservoirs, basins and completion methods always have benefitted from specific perforation design. The development of new enhanced perforating systems geared specifically toward hole size consistency that improves cluster efficiency will provide customer value by reducing the cost of hydraulic fracturing while increasing stimulated reservoir volume.

Fracturing challenges

Perforating prior to a hydraulic fracturing treatment presents challenges not seen in other perforating scenarios. This type of perforating scenario relies heavily on the perforation hole size as the most critical component. Operators commonly specify a desired hole size from their service provider to complement their treatment design. It is a common misconception in the industry that the data presented correctly represent all of the hole sizes that will be achieved in the wellbore. Historically, that almost has never been the case. Most commonly, the number quoted for hole size is an average of data collected at different fluid clearances during the American Petroleum Institute (API) RP-19B Section 1 test (industry standard test for perforators). The deviation from maximum to minimum hole size can be drastic and could lead to increased perforation friction, increased tortuosity and reduced cluster efficiency.

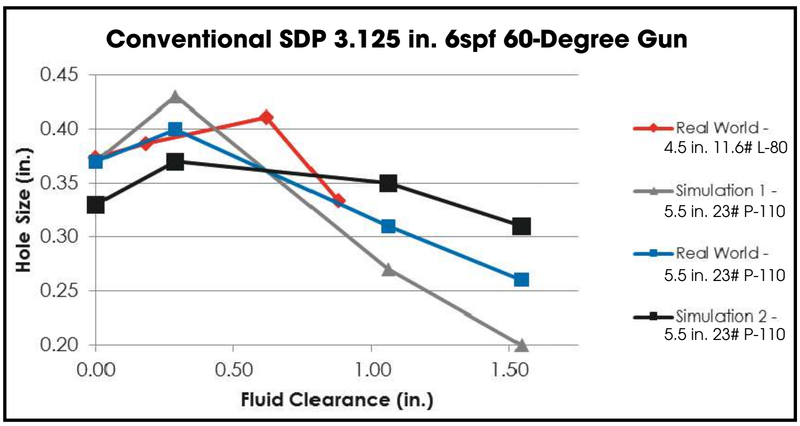


FIGURE 1. Perforation hole sizes vary based on casing and simulation type. (Source: Core Lab)

Casing variations

In addition to the variation in hole sizes being misrepresented as a single average number in hydraulic fracture treatment designs, the casing the data were collected in also might vary from the one used in a particular well. The perforating gun sizes most typically used in unconventional wells range from 2.75-in. to 3.375-in. diameter systems. The industry standard test allows these systems to be tested in 4.5-in. 11.6-lb L-80 casing. The effect of additional fluid clearance coupled with a higher grade of casing in a well cased with 5.5-in. 23-lb P-110 casing can be seen in Figure 1. The average hole size observed in the Section 1 test bears little resemblance to the actual minimum and maximum hole size when test-fired in the actual casing used downhole.

Realizing the API test data might not reflect actual downhole results, there have been other attempts to translate the API test data to downhole conditions using simulations. There are a number of computer simulations available, ranging from manufacturer- or service provider-specific programs to third-party software. These simulations use a variety of input data to generate an estimated performance output, but with no standard or control over the input data, how accurate is the output? Figure 1 shows the correlation between API Section 1 data and two different simulation software outputs: one more optimistic and one more pessimistic. Simulation programs also have one-size-fits-all assumptions for how casing grade affects hole size. They tend to make assumptions that higher yield casings will reduce the hole size.

However, Figure 1 shows this is not always the case. Again, with hole size being a critical element in the treatment design, these numbers do not represent actual downhole performance and might result in sub-optimal performance during the operation.

Quality control

A third and less realistic datapoint is a quality control (QC) shot. These data are typically acquired in a single shot in a flat mild steel plate at a single fluid clearance. During perforating charge design the hole size in that mild steel plate has been characterized and calibrated back to casing test data and is a valuable measurement for the charge manufacturer to ensure consistency during the manufacturing process. However, the measurement is not a realistic representation of downhole performance and was never meant to be. Figure 2 shows the variance between a QC test shot in flat plates, a QC test in actual casing coupons and API Section 1 data.

New methodology

As a result of these shortcomings in current test methods, a new and better method to estimate hole size is needed and has been developed to show the hole size expected downhole. It is not an earth-shattering development since the most elegant designs are often the simplest ones. The easiest way to know the hole size and its deviation from minimum to maximum in a particular casing is to shoot a full system test in that casing.

The industry has been focused on full system testing in a full API RP-19B Section 1 test, which is very expensive and would frankly not be possible for the myriad of casing sizes, weights and grades being used today, not to mention the various gun systems and charge types. But casing itself is reasonably inexpensive and can be test-fired very quickly. The engineers at Owen Oil Tools have done testing to confirm that the confinement of the casing in cement as in the API-19B Section 1 test yields virtually no difference to the data collected in casing alone for Deep Penetrator or Consistent Hole charges. Figure 3 shows data from a perforating charge that was fired in a Section 1 target and in the same casing unconfined with statistically no change.

Testing in the casing size, weight and grade that is being used in a particular well is the best method available to ensure the number quoted for hole size reflects reality. It also provides a more accurate range of hole sizes to be used in the completion design.

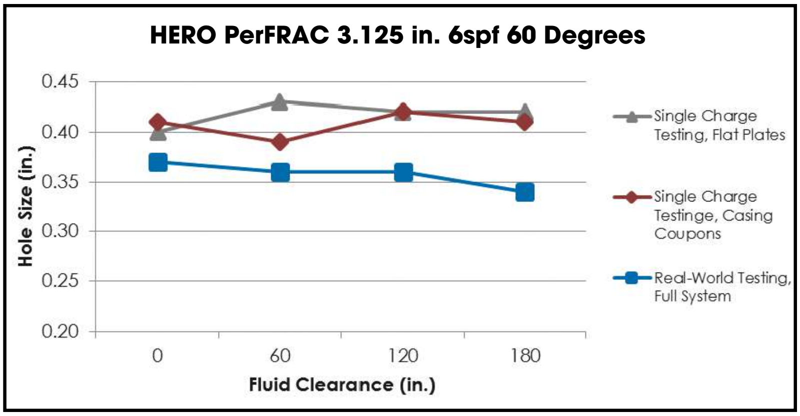


FIGURE 2. This figure shows the variance between a QC test shot in flat plates, a QC test in actual casing coupons and API Section 1 data. (Source: Core Lab)

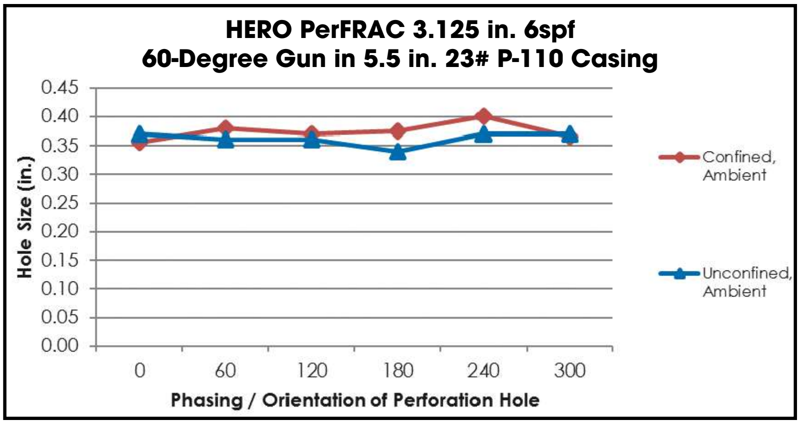


FIGURE 3. Consistent hole charges have been confirmed to have no degradation in hole size when subjected to hydrostatic conditions. (Source: Core Lab)

New charges

Recognizing that hole size is a critical component to hydraulic fracture treatment design, the engineers at Owen Oil Tools have released a new line of charges that provide an extremely consistent hole size. The HERO PerFRAC line of perforators has been specifically designed to provide a consistent hole size circumferentially around the wellbore, and that hole size has been verified by test-firing in many of the typical casings used in horizontal unconventional wells. These consistent hole charges also have been confirmed to have no degradation in hole size when subjected to hydrostatic conditions, as seen in Figure 3.

By understanding the limitations of existing test standards, the industry can begin to adapt and advance toward new methods to produce realistic hole size values for its customers in more beneficial formats by displaying the true range. As the technology seen in perforators continues to expand, it is imperative to remember that perforation hole size is more than just a number on a datasheet. E&P

Renewable wind blowing fair for offshore players

Companies are demonstrating that talk of applying their offshore expertise and experience to real-world renewables is more than just hot air.

Mark Thomas, Editor-in-Chief

The growing number of offshore companies seriously stepping up their interest and activities in the expanding renewable energy sector is no accident.

For many this process has been accelerated by the horrendous downturn that has decimated the upstream oil and gas sector, spelling out for the survivors in no uncertain terms that they need to diversify their offerings and targeted markets. It's not simply a PR gimmick to appease environmentally aware investors and the general public. In most cases it makes sound business sense, both for today and in the inevitable long-term future.

Statoil's pilot Hywind Demo steel spar floating wind turbine has been working offshore Norway in 220 m of water with no problems since 2009, supplying power directly to the Norwegian grid. (Source: Statoil)

A broad energy portfolio over the next several decades will be the answer to supplying the world's continuing growth for more fuels as no one sector is remotely able to meet the majority of that demand on its own.

Major operators like Eni and Statoil, for example, have long recognized the need to be involved in this sector. Eni is undoubtedly the upstream industry's star performer in terms of its conventional oil and gas success of the past two years or so, with major discoveries like its giant Zohr gas field offshore Egypt rapidly being fast-tracked toward production later this year.

Renewables focus

But Eni is not doing this at the expense of renewables. The company signed an agreement with GE in November 2016 to develop renewable energy projects and hybrid solutions with a focus on energy efficiency.

The companies intend to jointly identify and develop large-scale power generation projects from renewable energy sources, covering technologies within offshore and onshore wind generation, solar power, hybrid gas-renewable projects, electrification of new and existing assets, waste-to-energy projects, the "green" conversion of mature or decommissioned industrial assets, and the deployment of technologies developed by Eni's R&D department.

Eni, which has been operating in the renewable energy sector since 1980, said this deal is part of its ongoing strategy to develop renewable sources by leveraging the industrial and commercial synergies of its traditional activities.

Statoil's Hywind project

Statoil is following the same approach, particularly with regard to its offshore expertise. Its lead role in developing what will be the world's largest floating windfarm offshore Scotland, the Hywind project 25 km (15.5 miles) off the coast of Peterhead, should be operational by late 2017. The project will see five 6-MW turbines supplied by Siemens placed in 100 m (328 ft) of water in the U.K. North Sea generating electricity, following on from the successful trial of a single 2.3-MW floating turbine the operator has had up and running offshore Norway since 2009 in 220 m (722 ft) of water. Siemens also supplied that Hywind Demo turbine, with the 100-m deep draft floating cylindrical steel spar built by Technip.

The technology is relatively simple, with each of the new Hywind project's installations to be a similar spar buoy moored by three steel catenary cables to suction cup anchors. Hywind will use a ballasted catenary layout that adds 60-tonne weights hanging from the midpoint of each anchor cable to provide additional tension.

This is not a small-scale token gesture of a project—Statoil will invest about NOK 2 billion (US$233 million) in Hywind Scotland while also pointing out that it still remains essentially a pilot project that could be a forerunner to a much larger scale development depending on its performance and economic findings.

SBM's extensive floating production and mooring expertise has been brought to bear on its floating wind turbine design, now chosen by EDF-EN for a pilot project offshore France. (Source: SBM Offshore)

Supply chain experience

The importance of being able to dip into an experienced oil and gas supply chain to design, build and deliver this kind of project will be a key factor in the early success of such pioneering ventures. Offshore veteran Saipem, for example, has been contracted by Statoil to carry out the lift and mating operations for Hywind Scotland.

The vision of floating flotillas of turbines far from shore in water depths and strong winds beyond the reach of seabed-fixed turbines is an enticing one for offshore players, whether constructing, installing, maintaining or decommissioning them. It's a natural extension of what they have been doing for decades.

The market is relatively small at present, with offshore wind making up just 3% of all wind power, but most observers believe it can only continue growing, especially as countries such as Japan, China, the U.K. and U.S. are increasing their wind power ambitions.

Production enhancing

In addition, wind is seen as something that can be reapplied back to the oil and gas sector. Companies such as DNV have flagged the possible efficiencies and production-enhancing benefits of placing wind turbines on new and existing field facilities.

A study released in early 2016 by the classification society calculated that in some cases a floating wind turbine instead of a gas turbine could economically provide power for water injection to boost oil production from depleting reservoirs without the need to shut down production and also would reduce fuel costs. DNV, along with study partners including ExxonMobil, estimated savings of about $3/bbl of oil using a 6-MW Hywind instead of traditional engines to power a pair of 2-MW water injection pumps into an offshore well. This would be economically viable, DNV said, at step-out distances of up to 30 km (18.6 miles).

Turbine power capacities also are continuing to rise, with those installed offshore in 2013 averaging 4 MW, while today's projects under development are in the 6 MW to 7 MW range. DNV said turbine size will increase over the coming decades, stating that some developers expect 10-MW offshore turbines to be commercially available in the early 2020s.

Familiar floaters

The various options for the substructures are all very familiar to offshore contractors, with the three main designs currently in play being spars, semisubmersible units and tension-leg platforms, all of course being much smaller scale than those used in offshore oil and gas production designs so far.

This is where companies such as Technip and SBM Offshore come in. The latter's field-proven floating production and mooring technologies are directly applicable, and this was recognized by France's EDF-EN for a government-backed offshore wind pilot project underway.

SBM was picked to potentially supply three floating wind systems to sit in 100 m of water off the coast of

Marseilles, France. Again, this is no sudden and reluctant entry into the renewables sector by an oil and gas player. The company's technology arm has been working for more than a decade on its offshore renewable energy offerings, mostly focused on floating wind power, wave and tidal energy, and ocean thermal energy conversion. As it points out in its renewables literature, "Half of the world's population lives within 60 km [37 miles] of the coastline, making it a natural match for energy supply and demand."

Lightweight solution

The work for EDF-EN came via its ongoing technical development collaboration with the French research and innovation organization IFPEN.

SBM's lightweight floating wind turbine solution features an inclined taut mooring arrangement that minimizes motions at the level of the nacelle. SBM said the inclined legs create a fixed point close to the nacelle location, minimizing the accelerations and motions of the nacelle to decrease the loading on the turbine and mast as well as helping to optimize power output. The inclined legs also reduce the tension in the mooring lines both in operational and extreme cases, the company added.

The floater and its mooring system have been successfully tested in a model basin at 1:40 scale, with the design compatible with horizontal-axis and vertical-axis wind turbines.

An optimized installation process would feature a wet tow to site with the wind turbine generator installed, meaning full quayside integration. The construction of the structure using smaller components also means that they can be built at different locations to optimize costs, schedule and local content requirements.

If the project receives the eventual final investment decision, SBM will deliver the modular floating systems and mooring components on a turnkey engineering, procurement, construction and installation basis. The project is in the pre-FEED stage.

Floating wind farms remain a solution still in their early stages, but much of the initial cynicism about their economics is fast disappearing thanks to encouraging early performances by various pilot projects off Norway, Italy and Portugal and—more latterly—offshore Japan. As costs continue to come down through natural design improvements and their competitiveness compared to onshore and fixed offshore installations grows, the wind looks to be blowing in the right direction for floating turbines. E&P

Drones in land seismic data acquisition operations

Technology has great potential to reduce HSE risks.

Rodney Lopez and **Jack Caldwell**,
Geospace Technologies

Unmanned aircraft systems (UAS), commonly known as drones, are being used in numerous applications. The number of drones being used and the number of applications to which their use is being applied is growing at a tremendous rate. Companies like Amazon-PrimeAir and DHL already have the ability to deliver packages to customers. A company called CyberHawk is an aerial inspection company that deploys its drones to perform visual inspections of high-value and high-risk offshore assets. U.S. Customs and Border Protection uses drones to evaluate activity that has triggered signals from geophones placed along the U.S. border.

In the U.S. the new small UAS Rule (Part 107), including all pilot and operating rules, came into effect Aug. 29, 2016. In the U.S. alone, as of mid-March 2016, the U.S. Federal Aviation Administration (FAA) had more than 408,000 registrations of drones that had a weight between 0.55 lb and 55 lb. The FAA is forecasting 2.5 million commercial (nonmodel) drones in the U.S. by year-end 2017. Drones are common enough these days that ready-to-fly drones are available off the shelf, and the price associated with these can start as low as about $500. The FAA also is forecasting that over the next few years the average price of lower end small drone units will be $2,500, and the average price for upper-end models of small drones will be $40,000. One of the obvious uncertainties in forecasting the drone market is related to the unknown nature of the evolution of federal regulations.

A drone-conveyed camera recorded this receiver station where the geophone is not properly planted. (Source: Geospace Technologies)

Drones in land seismic operations

Since the industry is continually on the lookout for ways to improve efficiency, decrease cost, improve the safety of operations and reduce the social and environmental impacts of its activities, it is obvious that applications of drone technology are being explored. Ron Bell, in a presentation to the Rocky Mountain Association of Geologists in July 2015 titled “How Drones Will Change Exploration Geoscience,” listed the advantages of drones for data collection: 1) low-altitude operation, 2) programmable flight path, 3) lower datapoint cost, 4) improved productivity, 5) higher definition, 6) greater sensitivity, 7) access to difficult and risky areas, 8) generation of more data, and 9) reduced risk to personnel and public safety.

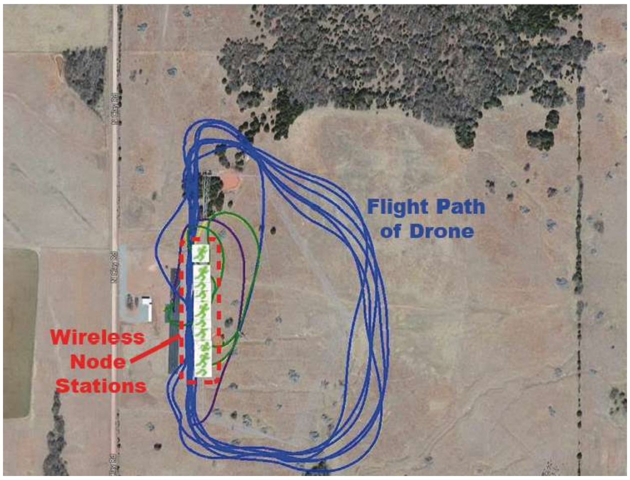
The benefits of having a bird’s-eye view in land seismic data acquisition operations are almost limitless. Seismic operations have always relied on “boots on the ground” information. Some of the major activities of a seismic operation include surveying, shot-hole drilling, acquisition-equipment layout, troubleshooting and moving/retrieving equipment. Each stage of the operation is critical to move on to the next. Information about the status of all of the activities associated with a seismic operation, including how the acquisition system is performing, is crucial for party chiefs and managers. The primary conveyers of this information are the members of the seismic crew.

The terrain, weather and infrastructure have large impacts on seismic operations. An elevated, time-varying video of these factors without endangering crew members is what a drone can easily provide today. With respect to video feedback, most drones come with cameras capable of recording up to 4K video quality. These cameras are usually mounted on a gimballed structure that facilitates recording high-quality images. As weather or ground conditions change, field activities can be modified for safety reasons as necessary. By being able to monitor on-the-ground conditions over large areas, crew members can be instructed to avoid high-water areas or guided to alternative routes. In the Amazon a small downpour can change the day-to-day waterways that the crew uses to service a live patch of receivers. In areas of steep and rugged topography rainfall can change the availability of what had been accessible trails or approaches. In desert terrains sand may shift, again causing access routes to change.

There are often sensitive areas (cultural, archeologic, environmental or regulatory) that require a custom approach for access or avoidance. Crew efficiency, in addition to safety, can be improved by the use of drones. Simple verification that a recording station was deployed properly or that a receiver or receiver string has actually been stomped into the ground can prevent having crew members traverse difficult terrain just for those purposes. It is anticipated that this technology will have an impact on making decisions about when to shut down and/or restart operations due to noise levels created by weather or other time-varying conditions. Because land acquisition often requires operations in less-than-perfect terrain and weather conditions, the use of video information provided by drones is almost unlimited, and this is with existing technology.

What's coming

Considering where the technology is undoubtedly headed, one can see additional uses for drones in land operations. In particular, many other types of information besides video can be provided in real time. Existing drone technology has centimeter accuracy with respect to position, so improved accuracy over what is generally available in seismic operations of specific land positions can be provided by its use. Information related to noise and other seismic-line status can be collected using drones. Geospace Technologies is developing a system that includes a Line Health Recorder with radio communication. This system can send a full receiver status scan (GPS health, battery health, memory remaining in the recording unit, geophone test results and root mean square noise levels) back to a base station in real time. The associated software has the ability to collect status from radio transceivers that are mounted in the field and/or on a helicopter, a mobile vehicle or a drone. Using video confirmation and status information can minimize the hazards of working in dangerous areas. For example, if projects like the 2014 Huacaya 3-D survey (750 sq km [290 sq miles], 27,000 live nodal stations) in Bolivia, where the mountainous terrain proved to be a logistical obstacle, would have had this technology available, hundreds of man-hours could have been saved. What took two mountaineers, one medic and one qualified LineViewer crew member to walk in 8 hours could have been done in less than half the time. Collecting line-status data, video confirmation and other information is going to become a necessity as seismic data collection evolves in the near future. The industry wants more information, higher resolution information and delivery of information faster.



Colored curves are the drone flight path. The status of 10 stations was checked by a drone. Since only nine station icons are shown, one station (the second from the top, where a small gap exists) is dead. (Source: Geospace Technologies)

It is a given that regulations will evolve rapidly and vary from country to country over the next few years. A seismic contractor that works globally will likely encounter different regulations as its crews work in one country or another. It is a reality today that some countries do not allow drones to be imported, which means that to implement drone technology into a seismic operation, the contractor has to build its own in country.

In the long run, the use of drones to aid in field acquisition of seismic data will happen. How fast the technology is adopted and to what ultimate extent depends on 1) how it reduces exposure to risk and hazards for the crew; 2) how much it reduces the required crew man-hours per survey; 3) its impact on the quality of the seismic data acquired; and 4) its social and environmental benefits. E&P

Double the value of P-source seismic data

A wealth of information is buried within traditional P-wave datasets.

Bob A. Hardage, Bureau of Economic Geology, University of Texas-Austin

In this time of economic stress across the oil patch, everyone is searching for techniques that can extract increased geological information from seismic data they already have or for methods that provide higher value seismic data across new prospects at the lowest possible cost. Seismic technology developed at the Bureau of Economic Geology provides options that allow these objectives to be realized for several types of land-based reservoir targets.

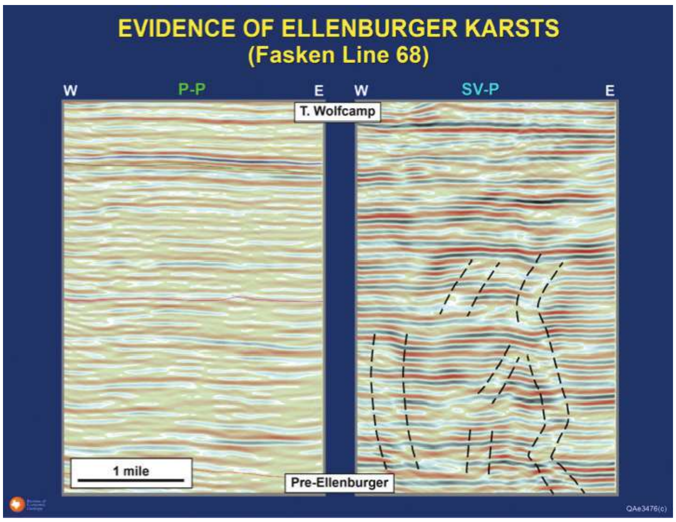


FIGURE 1. A P-P image and SV-P image were extracted from the same vertical-geophone data. The images are depth-registered. The target interval is the karst-prone Ellenburger carbonate. Seismic data were provided by Fasken Oil and Ranch Ltd. (Source: VertiShear)

Embedded images

The key concept that needs to be understood is that two separate independent seismic images are embedded in the responses of vertical geophones. However, only one of these images has been used for decades, this being the compressional (P-P) image. In this wavefield notation, the term P-P refers to data that involve a downgoing illuminating P wave and an upgoing reflected P wave.

The other long-overlooked image that also resides in vertical geophone data is the "SV-P" image. This image is produced by a downgoing illuminating vertical shear (SV) wave that converts to a reflected upgoing P wave at rock interfaces. This is an important point about P-P and SV-P data. Both wavefields involve an upgoing P mode, and P modes are recorded by vertical geophones. Thus, for decades seismic interpreters have used only 50% of the image information that resides in vertical geophone data. In tough economic times it is not wise use of exploration dollars to ignore half of the geological information that is available in P-source vertical-geophone data.

How SV-P data are created

Land-based P-wave sources are one of three types: vertical vibrators, buried explosives or vertical impacts. The seismic community has fallen into the trap of viewing these sources as generating only downgoing illuminating P wavefields. However, well-documented field tests show that all of these P sources generate more downgoing illuminating SV energy than downgoing illuminating P energy. These field test results can be obtained by requests directed to *vertishear.com*.

An inescapable dual illumination of deep geology occurs when seismic data are generated by traditional P sources. These sources will always illuminate geology with downgoing SV waves in addition to downgoing P waves, and both of these illuminating wavefields will create upgoing P reflections that are recorded by vertical geophones. Thus, SV-P data reside in any data that are generated by a P source and recorded by vertical geophones. These SV-P data can be used to make valuable images that show geological features not seen in P-P images.

Value proposition

The value of SV-P data is that they create an image of geology that is based on SV-to-P reflectivity, not on P-to-P reflectivity. The end result is that rock and fluid properties are revealed with SV-P data that are difficult and often impossible to extract from P-P data. Current industry practice is to create this SV information by acquiring P-SV data, which involves a P source and three-component (3-C) geophones, not vertical geophones. SV-P illumination of geology with vertical-geophone data is the mirror image of P-SV illumination with 3-C geophones. Both imaging options involve the same lengths of SV raypaths; hence, each image provides the same degree of SV sampling of rock properties. Because SV-P and P-SV reflection coefficients are essentially identical, SV-P and P-SV images should be identical if both datasets are properly recorded and processed. Specific examples of the value of SV-P data are:

- Improved fracture analysis of rock units because SV waves are far more sensitive to fractures than P-P data are;
- Improved fault analysis because SV waves detect subtle faults that are not seen with P-P data;
- Imaging Class 2 amplitude vs. offset reservoirs that are invisible on P-P data;
- Imaging through gas-invaded intervals to see geology that is blanked out in P-P images; and
- Access to the velocity ratio, which is the most important of all seismic attributes for mapping lithofacies.

Examples of SV-P images

Extensive searches indicate that only one example of an SV-P image exists in geophysical literature. However, the source used to make that image was a horizontal vibrator, not a P source. Efforts to locate any published example of an SV-P image created by a P source have failed to find a single example. The only examples of SV-P images produced with P sources appear to be those generated at the Bureau of Economic Geology.

The example shown in Figure 1 is a repeat of a graphic that appeared in the November 2016 issue of *E&P*. The P-P and SV-P images in this figure are depth-registered, and a horizontal line extending across both images is a depth-equivalent horizon. Both images span the Ellenburger carbonate in West Texas. The dashed corridors on the SV-P image enclose reflector sags and terminations associated with karst collapse. Equivalent features are absent or vague in the companion P-P image. This example not only illustrates the diverse nature of the two images that coexist in the same vertical-geophone data, but it also supports the principle that SV-P data are far more sensitive to fractures and subtle faults than are P-P data.

A second SV-P example is displayed in Figure 2. In this case, the SV-P image was made from vertical seismic profile (VSP) data. This image was constructed from the same VSP geophone responses from which the VSP P-P image (not shown) was constructed. Thus the concept that two separate and independent wavefields exist in surface-based vertical geophones also applies to VSP geophones that are

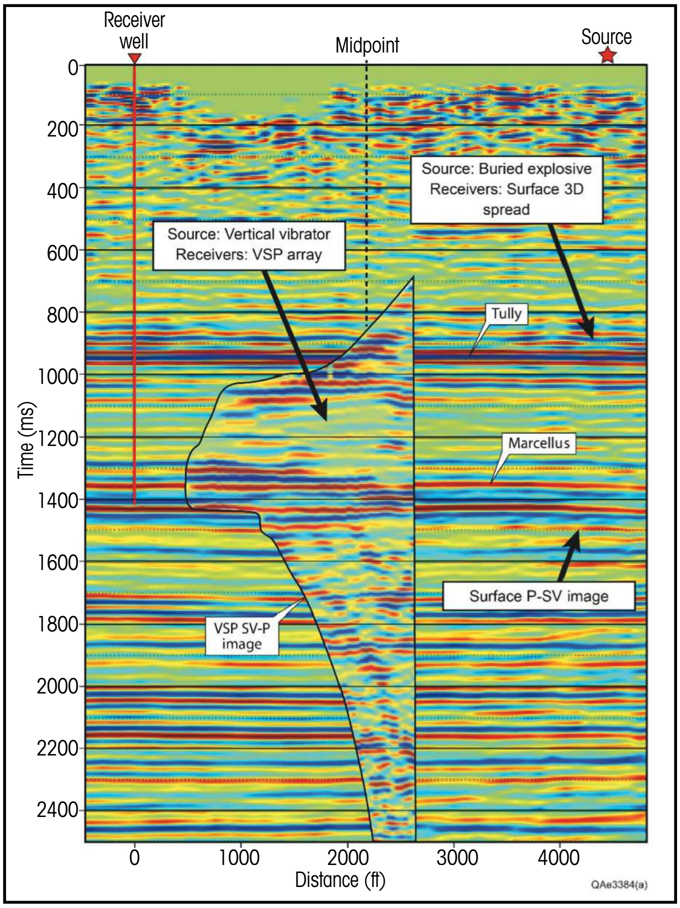


FIGURE 2. This image compares an SV-P image constructed from VSP data and a profile through a P-SV data volume created from surface-based 3-C geophones. Note the equivalence of the SV-P and P-SV images. (Source: Pennsylvania multicient surface data presented with permission from Geophysical Pursuit Inc. & Geokinetics Inc.)

oriented to capture upgoing P reflections. The VSP well that provided this SV-P image was inside an area where surface-based 3-C geophones allowed a P-SV image to be made. The agreement between the SV-P and P-SV images verifies the fundamental principle that SV-P and P-SV images are identical when the two wave modes illuminate the same data space.

It is sobering to realize that many thousands of square miles of SV-P data have been recorded and are lying dormant and untouched in libraries as legacy P-wave data. Anyone who has not utilized any type of shear-wave seismic reflection data in prospect evaluation can now do so at minimal cost by using these existing vertical-geophone data. The industry must not continue to ignore 50% of the seismic information that is acquired when seismic data are generated by a P source and recorded with vertical geophones. E&P

High-resolution color inversion displays

New processing technique offers a seismic view with remarkable detail.

Norman S. Neidell and **James Charuk**,
Neidell & Associates

Recent significant discoveries by Apache in the West Texas Delaware Basin and ExxonMobil offshore Guyana make clear that more effective seismic imaging of geology might help identify similar opportunities both in relatively new areas and those that might be considered "known" or of little potential. An alternative processing treatment for conventionally acquired 2-D and 3-D seismic survey data produces subsurface images scaled in approximate absolute velocities, representing a seismic view showing remarkable detail and approximating subsurface geology. Indicated velocity changes are made visible by this method and also track quite closely actual velocity variations observed from logging results. These results can be obtained in both conventional and unconventional objectives. In particular, new and previously unrecognized opportunities might be noted in frontiers and even in older areas.

HPR

Highest possible resolution (HPR) imaging, which follows from seismic holography, has been studied and written about by several prominent geoscientists. The final data presentation by this method is a full-wavefield composite inversion that also includes an estimated velocity trend function. It is entirely a seismic product since there is no propagating wavelet, and no subsurface information is used in the data treatment. Boundaries are described by those frequencies necessary to represent their character. That is, higher energy boundaries will show narrower (and necessarily lower) frequency content due to surface roughness and vertical gradation. Frequency content then also becomes a depositional energy measure, and

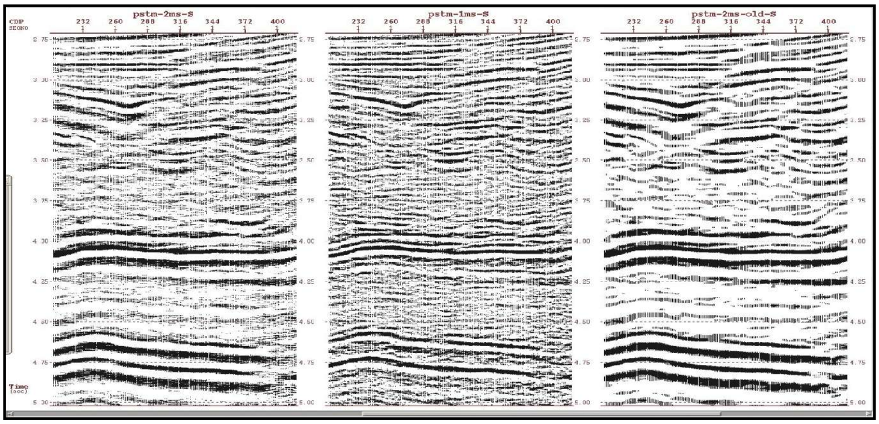


FIGURE 1. The flat event in the structures at the lower left is best defined by the 1-ms image in the center. (Source: Neidell & Associates)

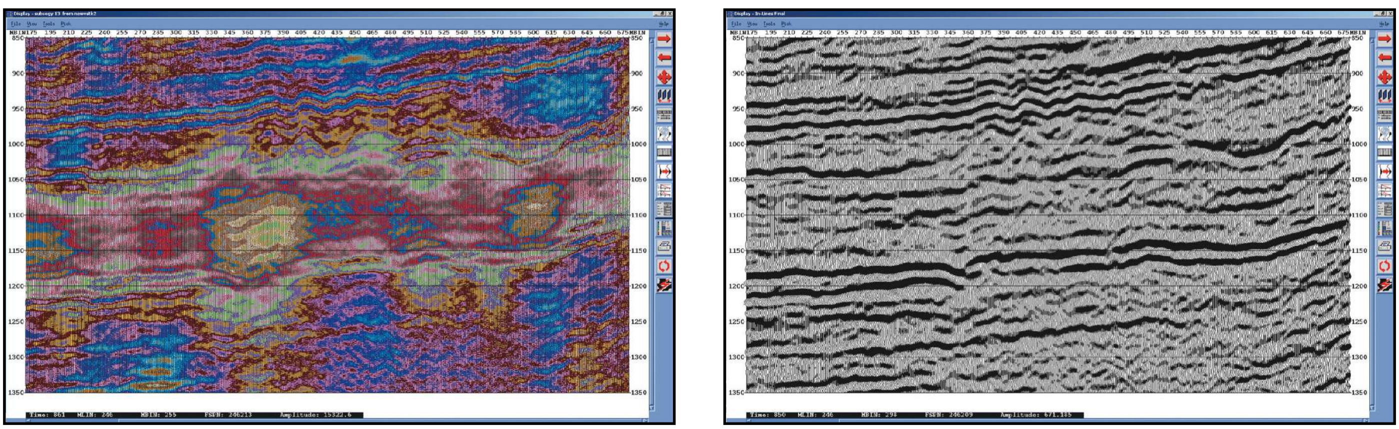


FIGURE 2. An unrecognized potential Strawn development lies below the basal carbonate in the Permian Basin. (Source: Neidell & Associates)

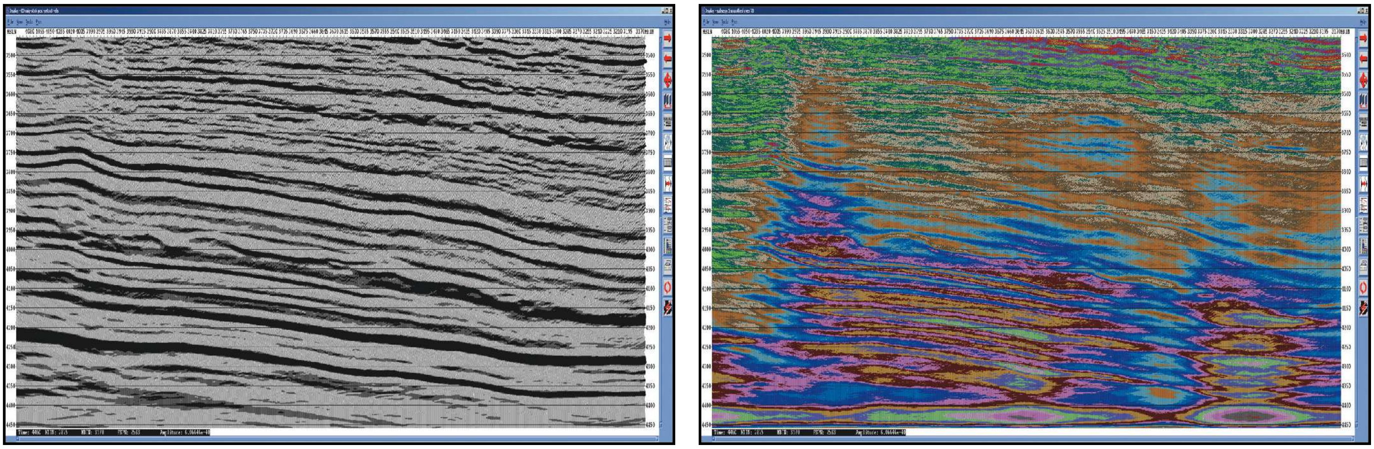


FIGURE 3. Where are the carbonates? The blues and maroon in the HPR data clearly define them. (Source: Neidell & Associates)

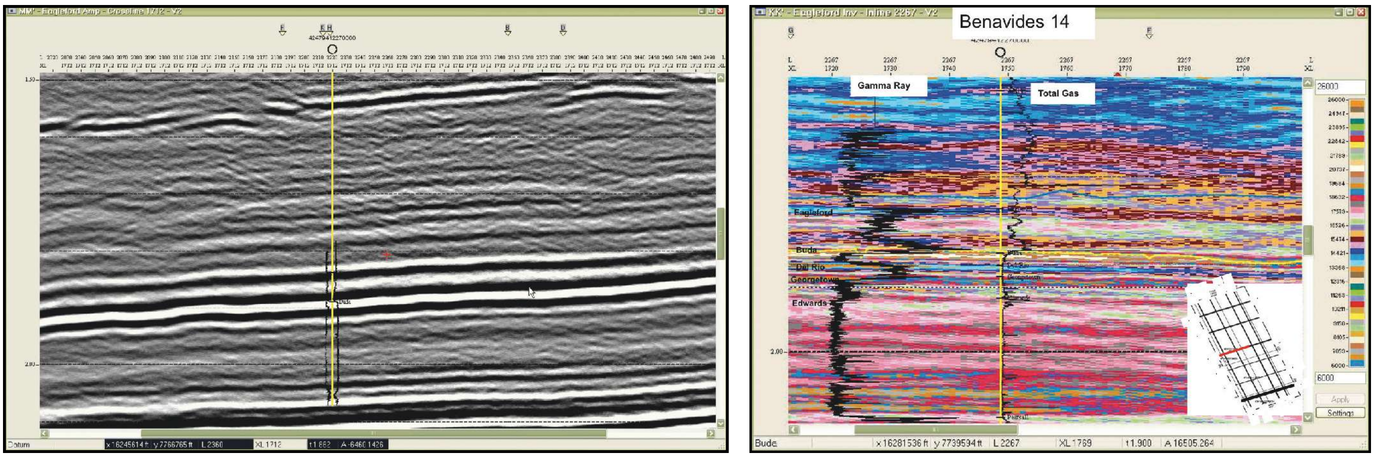


FIGURE 4. Note the carbonaceous middle member and its gamma ray signature in this Eagle Ford well. (Source: Neidell & Associates)

frequencies in the hundreds of Hertz become obtainable from standard (and existing) seismic survey data. Outputs typically have 16 times the sampling of standard presentations and are viewed with an extended visual dynamic range color display. Resolution is increased by factors approaching five, especially in the deeper section. Marine ghosting effects vanish, and interpretability of the geology is increased 25-fold to 30-fold.

Capturing information content

High-velocity (impedance) lithologies (especially carbonates and consolidated sands) have little seismic expression and often go unrecognized, even unsuspected. Thin and deeper consolidated clastics can be mapped and resolved adequately for other follow-on attribute studies to be applied. Fluid-bearing chimneys can be mapped in detail. Well ties show remarkable character matches. There are also indications that microstratigraphy requiring definition in the hundreds of Hertz becomes accessible for study. Changing the basic paradigms by which seismic field data are treated more fully captures the information content embodied and significantly enhances hydrocarbon E&P opportunities.

Figure 1 shows a comparison of processing alternatives for a short seismic profile using standard seismic displays. Both HPR images at the left and center have greater resolution than the standard 4-ms processing at the right. Only the 1-ms processing at the center has the resolution necessary to see the flat spots in the two structures at the left, one just below halfway down and the other deeper in the section below it.

Of course, the standard displays do not do justice to the full information content of the data. This requires a display having far greater visual dynamic range. One such display shows some Permian data using highly contrasting color steps of 122 m/sec (400 ft/sec). Figure 2 contrasts the composite inversion with the HPR data in traditional display format. The Cisco and Canyon structures (pinks

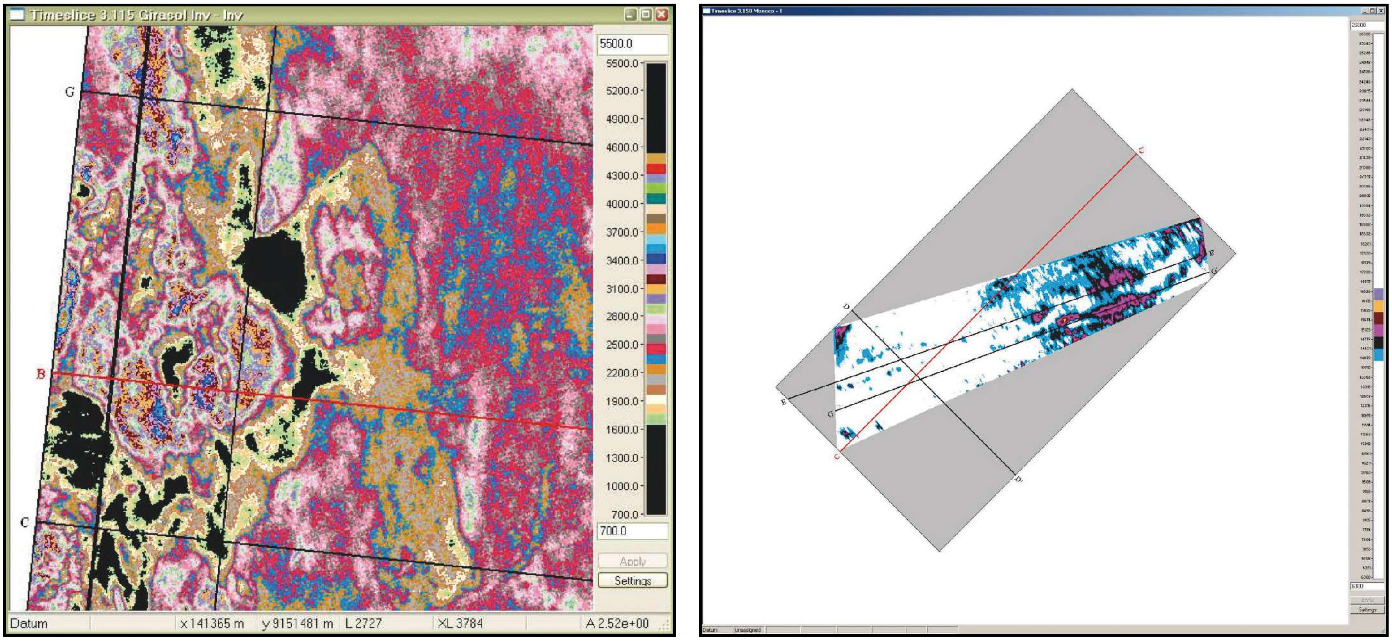


FIGURE 5. Time slices are shown for an Atlantic Oligocene turbidite reservoir (left) and Edwards Barrier Reef reservoir in McMullin County, Texas. Known and most likely hydrocarbons (as identified by velocity) are shown in black for both figures. (Source: Neidell & Associates)

and green) above the basal carbonate (blue and red) have produced more than 100 MMbbl of oil. A very similar velocity character is shown by the Strawn development below the basal reflector (pink and green again), and this has not been drilled. Conventional seismic displays offer little incentive to investigate such features, and nearby well control is very sparse.

On both sides of the Atlantic Ocean there are clastic opportunities overlying prospective carbonate developments. But viewing the HPR data in standard display, some may ask where the carbonates are (Figure 3). The velocity display even shows the consolidation effects on the carbonates as one moves deeper in the section, with the mustard color indicating even higher carbonate velocities.

The industry will always benefit from exceptional geological study and innovative thinking for finding and producing hydrocarbons.

What benefits does this technology offer in the unconventional setting? In Figure 4 the interval between two railroad tracks on the standard display is expanded to show three distinct members, an upper and lower shale bracketing a carbonaceous middle member. A corresponding gamma ray log helps validate the rock properties. Velocity variations within the middle member also are clearly seen. There is, of course, often a good correlation between production capability and velocities as seen, but both clays and calcites are involved.

Finding hydrocarbons is one matter, but producing them effectively is another matter. If it was possible to somehow associate a velocity value or range of values with the hydrocarbons, it would be possible to better define and appreciate the reservoir architecture. This would make development more effective and greatly reduce costs. Figure 5 shows a clastic offshore example and an onshore carbonate, where the most likely occurrences of hydrocarbons are shown in black. These both are from known production.

The industry will always benefit from exceptional geological study and innovative thinking for finding and producing hydrocarbons. Now the industry can add to these truly extraordinary seismic imaging to further enhance its abilities. Discoveries like those cited earlier might not be so infrequent if the industry combines insight and intellect with superior seismic imaging. E&P

References available.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Dual system to tackle HP/HT challenges

Handling HP/HT operations safely, economically and with environmental sensitivity calls for highly specialized equipment and technology to exploit future reserves.

Ben Cannell, Aquaterra Energy

Danish operator Maersk Oil, together with its project partners BP and JX Nippon, is developing one of the largest gas discoveries of recent years—the HP/HT Culzean Field on the U.K. Continental Shelf.

There are currently less than 100 HP/HT wells producing around the world, with Culzean to eventually feature six such production wells. Drilling of the first well was underway in September 2016.

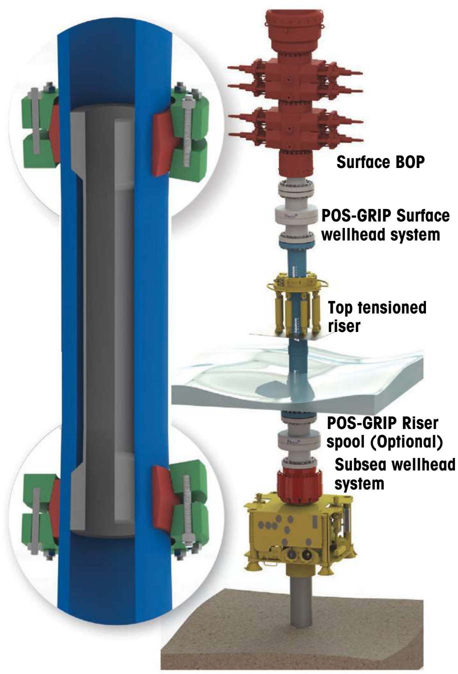
Faced with engineering complexity and cost challenges associated with such large independent jacket-based operations, there is a growing trend toward small- to medium-sized developments that can produce to an existing facility or dedicated floating facility.

This is especially important in regions that do not support HP/HT projects that would otherwise be uneconomic without government incentives, similar to that used on Culzean, which is due onstream in 2019.

In today's cost-constrained climate there is now an increasing move toward marrying complementary systems that can combine field-proven technologies to reduce cost and time-to-field implementation.

Changing mindset

Aquaterra Energy and Plexus Holdings have developed a lightweight dual-barrier HP/HT riser system that can be deployed by a jackup rig and is a viable and cost-efficient alternative to semisubmersible installation for HP/HT well operations. Though the dual-barrier system has not yet been deployed in the field, all of its component parts already are well-established.



The dual-barrier HP/HT riser system provides a means of accessing HP/HT wells with a subsea riser system deployed from a jackup rig. (Source: Aquaterra Energy)

The jackup-deployable system is suitable for water depths of up to 150 m (492 ft) and harnesses the attributes of the companies' respective subsea technologies by combining Aquaterra's HP/HT riser system and Plexus' POS-GRIP wellhead engineering technology. This enables an inner riser string to be installed inside a conventional high-pressure riser (HPR) to provide full 20,000-psi capability without compromising safety, integrity and operational performance.

Jackup advantages

Semisubmersible units have traditionally been used to perform drilling, completion, intervention and abandonment services on subsea wells.

However, in comparison to semisubmersible units, heavy-duty jackup drilling units rated for up to 150 m water depth can now undertake such activities at reduced cost and risk when the jackup-deployed HPR is used to span the gap between a dry surface BOP and a subsea tree.

As top-tensioned risers and lower jackup rig offsets impart lesser loads onto the wellhead and other subsea components, an additional benefit is the possibility for improved wellhead/low-pressure housing/subsea tree loading performance. This results in less fatigue damage, thereby extending the service life of equipment, increasing safety margins and improving operational envelopes.

Moreover, typical HPR systems are designed to withstand 50-year storm conditions under a well control situation. Unlike semisubmersible units, the use of a jackup rig removes the need to disconnect from the well in extreme weather conditions, eliminating unnecessary nonproductive time.

As new-generation jackups are now capable of operating in increasing water depths, the range of subsea wells that are a viable option for a jackup-deployed HPR also continues to increase. This alternative means of deployment has the potential to access about 60% of the total number of subsea wells worldwide.

Plexus' POS-GRIP surface exploration wellhead was being prepared to be run through the rotary table and installed on the riser during recent operations in the North Sea. (Source: Plexus Holdings)

It's a 'keeper'

The most significant benefit to the operator is the ability to convert exploration or appraisal wells into a "keeper" or production well. The U.K. government, in particular, has identified this as a key issue, and the jackup-deployable dual-barrier HP/HT riser system directly addresses this challenge.

As current mudline suspension hanger technology does not provide a means of safely suspending HP/HT wells, it is not possible to reenter or tie back exploration or appraisal wells to existing platform-based or FPSO infrastructure.

However, when combined with an HPR and a jackup, using a subsea wellhead allows such wells to be converted to a keeper, and the cost base during the exploration phase, compared to a semisubmersible unit, is considerably reduced. Deploying a dual-barrier riser in such wells allows them to be reentered or put into production, potentially saving an operator millions of dollars.

Dual-barrier capabilities

The challenge of expanding incumbent technologies into HP/HT environments is simply increasing the pressure and temperature rating of fullbore risers, which is outside current manufacturing limits.

According to research, at pressures of about 10,000 psi and elevated temperatures in excess of 121 C (250 F), the required material chemistry, available manufacturing techniques and capital cost of large-bore dynamic HP/HT steel pipe could become prohibitive. It also can increase the cost of HPRs by more than 400% from that of a standard 5,000-psi system. This, in turn, has limited the advance in HPR deployments to projects with lower temperatures and pressures due to the technical and commercial restrictions and the trend toward thicker walled riser joints.

This issue is of particular importance for a subsea HPR as the riser is exposed to tension, environmental loading via wave action and—during well control events—wellbore pressure. Systems subsequently have much heavier walls to withstand this combined loading, and typical subsea HPR codes, such as American Petroleum Institute RP 2RD and International Organization for Standardization (ISO) 13628-7, account for design and qualification at 1.5 times the working pressure of the riser.

The dual-bore system addresses this by using a standard outer HPR for lower pressure/temperature zones in the well. Once HP/HT zones are about to be encountered, a protected inner HP/HT riser string is run inside the outer HPR between the surface BOP and the subsea wellhead. This philosophy allows the inner riser string to have a thinner wall due to the protection provided by the outer string and its qualification to casing codes such as ISO 13679 CAL IV.

Incremental step forward

The joint system developed by Aquaterra and Plexus represents an incremental step forward in subsea capabilities as it facilitates safe and effective drilling operations in HP/HT conditions and provides a structurally sound pressure-retaining conduit between the subsea wellhead or tree and the rig's surface BOP.

Rather than increasing the pressure rating of the outer riser, POS-GRIP allows an inner riser string to be temporarily installed, allowing full HP/HT capability from the subsea wellhead all the way to the surface

BOP. The latter can then remain in place for the entire project once nippled up.

The pressure-retaining well control inner riser string will see a reduced environmental load, with the main riser supporting the majority of the bending. At surface the POS-GRIP surface housing allows the inner HP/HT riser string to be terminated inside. Subsea at the wellhead, the HP/HT riser string is connected to the POS-GRIP, creating an HP/HT conduit.

The dual-barrier HP/HT riser system eliminates the issues associated with surface wellhead developments that contain elastomeric seals, particularly those located between the mudline and surface. Due to the flexible placement of the POS-GRIP to surface and subsea systems (+/-4 in.), this negates challenges with setting the inner liner space out between two points.

Field-proven technology

Over the last 20 years POS-GRIP has been used on more than 300 wells drilled by jackup rigs, with full metal sealing capability and pressure ratings up to 20,000 psi at 190.5 C (375 F).

The dual-barrier HP/HT riser system is based on field-proven technology using all metal-to-metal gas-tight seals on both the external and internal riser strings. It is capable of withstanding environmental and operational conditions expected during the HPR service life and can be used in drilling, completion, intervention and abandonment modes.

Amid the ever-increasing industry focus upon HP/HT operations, this methodology represents an innovative and cost-effective alternative while maintaining safety, integrity and operational performance.

Aquaterra's engineers developed the first HPR systems deployed in the North Sea in the 1990s, which were typically used on lower pressure wells. With increased well pressure requirements of more than 5,000 psi and for those more than 10,000 psi, the dual-barrier HPR system can offer significant financial savings and safety benefits over single-barrier systems. E&P

Expanding the envelope

LWD at extreme temperatures and pressures requires advanced electronic components.

Tim Parker, Halliburton

The oil and gas exploration industry continually searches for untapped hydrocarbon reserves. Over time, the reserves that are easiest to access have been developed and consumed, requiring operators to extend their search for fresh reserves into areas that are more technically challenging. Such challenges can include complex geological structures, thin or poor-quality pay zones, tight rock or marginal pressure envelopes in which to drill. Many of these challenges can be addressed by development of specialized downhole tools designed to evaluate the rock formations and help position wellbores optimally within the reservoir. However, all such tools depend on electronics, and a challenge is to produce tools that are able to function at high temperatures.

Demand for high-temperature tools is increasing, as is the temperature at which they are required to operate. As the trend toward higher temperatures and pressures continues, it is necessary to define further categories to distinguish "ordinary" high-pressure or high-temperature wells from those requiring more advanced tools.

Halliburton's Quasar system is a new MWD and LWD (MWD/LWD) system capable of operating at temperatures up to 200 C (392 F) and 25,000 psi, placing it firmly in the ultra-HP/HT category (Figure 1).

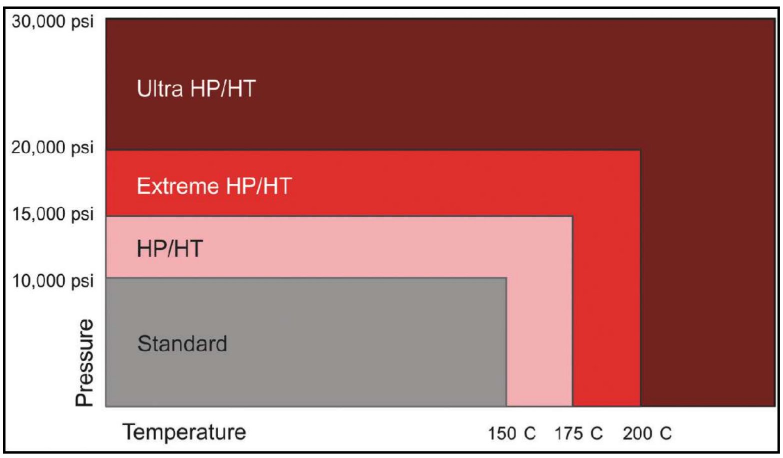


FIGURE 1. Halliburton's definitions of pressure and temperature ranges for downhole tools include various grades of HP/HT environments. (Source: Halliburton)

The key challenges in high-temperature environments revolve around the electronic components of the system and the need to ensure they work reliably, are not damaged by the operating environment and provide measurements equivalent in accuracy to those provided by conventional systems. Techniques such as flasking and the use of eutectic materials for sacrificial melting are widely used in the wireline industry. However, these techniques are not appropriate for the drilling environment because of the much longer run lengths. Instead, the development of the Quasar system used a variety of other techniques to build reliable electronics for a 200 C environment. These included simplification of circuit designs to minimize the number of components required, screening of components to identify those most capable of operating at high temperature, careful modeling of heat flow patterns to eliminate hot spots in the electronics and removal of potentially corrosive elements from the atmosphere inside the tools. Rigorous testing at every level of the tool build process helps ensure the system performs as intended across its entire operating range.

The new system is built around the Quasar Pulse tool (Figure 2), which is an integrated base-services collar that provides all of the basic functions necessary for any MWD/LWD service. These include telemetry, directional survey, natural gamma ray, drillstring dynamics and pressure-while-drilling modules as well as power regulation and data storage functions.

The system is expanded further by the addition of the Quasar Trio suite of formation-evaluation sensors (Figure 3), providing multispacing resistivity, azimuthal density and neutron-porosity measurements. Accurate evaluation of gas zones, which are common in high-temperature environments, is only possible if all three measurements are available. A great deal of care was taken to help ensure the performance of these sensors in terms of their measurement range and accuracy is at least as good as their lower temperature counterparts. The system is the first in the industry to offer such a comprehensive suite of measurements at 200 C, allowing operators to evaluate high-temperature reservoirs while drilling without the need for subsequent wireline runs.

Haynesville

An operator in the Haynesville Shale wanted to drill a horizontal well to 6,887 m (22,595 ft) measured depth with a total vertical section of 3,070 m (10,072 ft). The expected circulating temperature at this depth was 182 C to 188 C (360 F to 370 F); therefore, the well could not be drilled with industry-standard high-temperature tools, which are typically rated to only 175 C (347 F). This restriction had limited the length of laterals in similar wells to about 1,524 m (5,000 ft). The operator deployed the Quasar Pulse service and was able to deliver the well successfully with a lateral section of more than 3,050 m (10,000 ft), which was a record for the Haynesville Shale. The operator would previously have had to drill two complete wells to achieve the same lateral footage. The Quasar Pulse service saved the operator the significant cost and time associated with drilling another well.

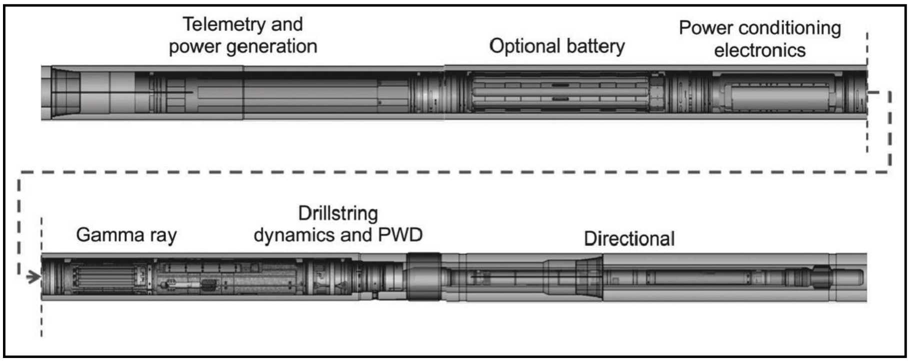


FIGURE 2. This schematic of the Quasar Pulse integrated base-services collar is shown split for clarity. (Source: Halliburton)

FIGURE 3. The Quasar Trio system is the first MWD/LWD system to offer comprehensive formation evaluation at 200 C. (Source: Halliburton)

Southeast Asia

An operator in Southeast Asia wanted to reduce costs and achieve logging objectives in a batch of high-temperature offshore wells in which the anticipated bottomhole static temperature was 195 C (383 F). The past drilling practice for similar wells was to drill until reaching the maximum temperature rating of the MWD/LWD tools and then pick up a “dumb iron” assembly to drill to total depth (TD). This method resulted in uncertainty in the borehole position and loss of formation logging data. Another common practice was to use temperature mitigation techniques such as reducing rotary speed and circulating to cool the tools, but this significantly increased the amount of rig time required to drill the reservoir section.

The operator ran the Quasar Pulse service on five wells from the platform. Across the five wells the operator reported that the Quasar Pulse service saved about $1 million and more than 100 hours of rig time. This was accomplished by reducing the number of wireline runs, eliminating trips for tools that had reached their operating temperature limit and not having to use time-consuming temperature mitigation practices to reach TD.

Another operator was developing a gas field in which multiple wells had a bottomhole temperature that exceeded 200 C. With conventional equipment it is only possible to drill these wells using extensive temperature-mitigation procedures, including time spent circulating to cool the tools below their operating limit of 175 C. Even then it is sometimes impossible to drill to final TD without exceeding the tool specifications. Therefore, the operator was forced to complete the section without MWD/LWD tools in the drilling assembly. Additional time then had to be spent acquiring essential formation evaluation data with wireline tools.

To reduce the overall time spent on drilling and evaluating the well, the operator chose to run the Quasar Trio MWD/LWD triple-combo system to acquire all of the necessary formation evaluation data while simultaneously avoiding the need for temperature-mitigation procedures. The result was a comprehensive set of formation-evaluation data that included gamma ray, multispacing resistivity, azimuthal density and neutron-porosity measurements as well as measurements of downhole pressure for well control and directional surveys for well placement. The tools were exposed to a maximum temperature of 197 C (387 F), making this the first MWD/LWD triple-combo run to operate successfully at this temperature. E&P

Acknowledgment

This article is based on the Society of Petroleum Engineers (SPE) paper 180592, “Taking the Heat: Logging While Drilling at Extreme Temperatures” by T. Parker and P. Cooper, presented on August 22-24, 2016, at the IADC/SPE Asia-Pacific Drilling Technology Conference and Exhibition in Singapore.

Guided wave radar delivers produced water savings

Automated tank gauging system makes real-time verification of storage tank volumes possible.

Jennifer Presley, Senior Editor, Production Technologies

Do you know Ol' Lonely? He's the dressed-in-blue repairman typically depicted waiting for something productive to do since his company's dependable appliances never need repair. Oil and gas producers in the Eagle Ford Shale and elsewhere are finding that through the services of a similarly encased-in-blue monitoring device, the money spent on produced water disposal can be put to something more productive due to decreased disposal expenses.

The device, a Rosemount 3308 wireless level transmitter, has helped operators realize significant savings and increased safety when the device is installed on storage tanks. Manufactured by Emerson Automation Solutions, the transmitter provides automated real-time readings of the oil and water levels and interfaces in the tank. In these cost-conscious times, these accurate and verifiable readings are providing greater clarity in operators' oil and produced water inventories.

Manual gauging

Determining how much product came out of the ground and where it went with a high degree of accuracy can be a difficult and hazardous exercise.

Manual tank gauging or "hand dipping" is the preferred method as it is viewed as a low-cost, effective solution to manage tank inventory and custody transfer measurements. The American Petroleum Institute (API) 18.1 standard governs the procedure for how these measurements are made. This method is highly dependent on variables like the weather and the accurate reading of the measuring tape by a worker.

"How much oil is in a specific tank? If the answer is sending a worker to the top of the tank to take a manual reading, how accurate and repeatable will that reading be? Will two individuals get the same reading? What if it's raining and the worker doesn't want to get wet? Is precision of +/- 1 in. considered good? How about +/- ½ in.?" asked Michael Machuca, director North America Upstream O&G Marketing for Emerson Automation Solutions. "For the size of tank typical at most well pads, ½ in. of oil represents a barrel."

An operator in the Eagle Ford Shale was disposing about 700,000 bbl of produced water per week at a cost $1.25/bbl, totaling $45.5 million per year in hauling and disposal costs, he said.

"They estimated a 4% to 6% inaccuracy per truck haul as they had no means to verify and were forced to rely on the trucking company's annotations. At a 5% error rate, this accounted for $2.2 million in avoidable expenses," Machuca said. "Another operator told us it estimated it was being overcharged eight to 10 barrels per load, which totaled about $1.3 million per year for it in excess saltwater disposal cost."

In addition to being subject to human error, manual gauging is a worker safety risk. In 2016 the National Institute for Occupational Safety and Health and the Occupational Safety and Health Administration issued a hazard alert (HA3843) on the health and safety risk for workers involved in manual tank gauging and sampling at oil and gas well sites.

Between 2010 and 2014 there were nine fatalities due to tank vapor exposure during the manual gauging and sampling of production and flowback tanks. According to the alert, working on or near the tanks is of particular concern because the tanks contain concentrated hydrocarbon gases and vapors that are under pressure. The opening of the thief hatch directly exposes the technician to the release of these pressurized gases and vapors, potentially leading to the creation of an oxygen-deficient environment. Exposure to this environment can potentially lead to immediate health effects, including loss of consciousness and death.

The first recommendation out of the 10 listed in the alert is to implement alternative tank gauging and sampling procedures that enable workers to monitor tank fluid levels and take samples without opening the tank hatch. In response, API 18.2 was issued. The standard allows for custody transfer of crude oil from lease tanks using alternative measurement methods that are more practical and economic for small lease tanks.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"While there has been an existing standard API 3.1B for automated tank gauging for custody transfer measurement, this standard was designed for large storage tanks with requirements that are not practical and are not economical for small lease tanks," Machuca said.

Alternative gauging

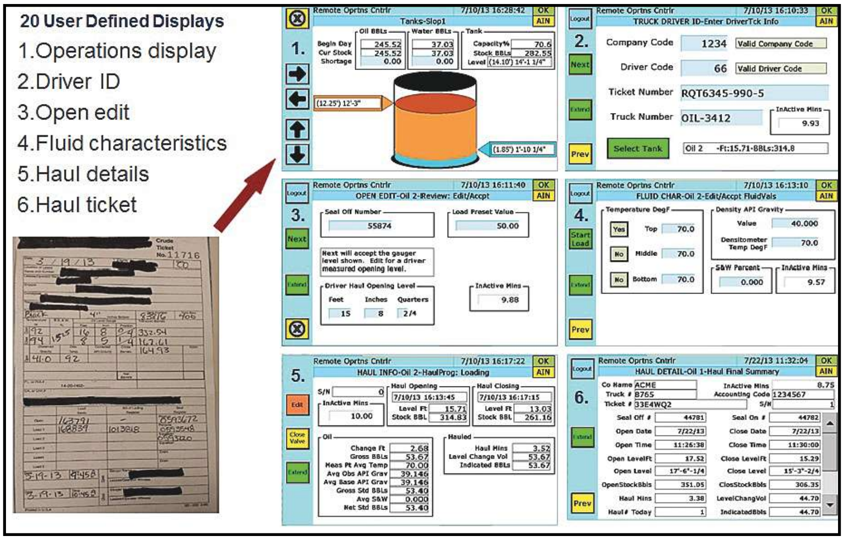
An acceptable solution by API 18.2 is the use of a guided wave radar to measure the volumes and interfaces in the production tanks.

"Guided wave radar is based on microwave technology. Microwaves are only affected by materials that reflect energy, which means that temperature variations, dust, pressure and viscosity do not affect accuracy," Machuca said. "The device sends a low-energy microwave pulse down a probe. When the pulse hits the media, a significant proportion of the energy is reflected back up the probe to the device. The level is directly proportional to the time-domain reflectometry.

Microwave pulses are sent out by a transmitter installed at the top of the tank. As the pulses travel through the oil (in brown) or water (in blue), the actual level measurement is taken as a function of the time taken from when the signal was emitted to the time at which the echo from the media (be it oil or water) is received. (Source: Emerson Automation Solutions)

"Because a proportion of the emitted pulse will continue down the probe, an interface also can be detected. This is especially useful to detect the presence of oil in the water tank. When microwaves hit the oil surface, some are reflected back, and some continue through the oil."

He continued, "The reflected microwaves provide the level reading, and the microwaves that continue through the oil will be reflected back on the water surface. These microwaves then provide the interface reading. With this reading the operator can schedule a technician to remove the oil from the water tank, ensuring it is not lost to the saltwater disposal facility."



Applications like Emerson's Tank Manager transitions the recording of haul details from a paper ticket to an automated real-time capture of data like tank levels, truck driver identification, fluid characteristics and information about the haul. (Source: Emerson Automation Solutions)

Guided wave radar devices have no moving parts and are virtually maintenance-free. The devices are available in a wired and a wireless model, with the wireless model powered by battery.

All instruments and diagnostics used by the automated gauging system can be brought into a central controller or remote terminal unit. Human-machine interfaces are used to automate haul transactions using either manual or automatic tank gauging.

Solutions for remote operations include flow computers and remote terminal unit platforms with flexible software applications and SCADA systems to monitor the process of fluid transportation. Operators using Emerson's Tank Manager application, traditionally used for oil hauling operations, are seeing the benefits for applying that same technology to saltwater disposal.

"After one operator estimated a reduction of $15 million worth of fiscal risk by formalizing and automating its metering of oil at its production tanks, it decided to extend the same process to manage its saltwater disposal and expect $1.3 million in savings on its disposal cost," Machuca said.

As a solution to its $2.2 million in avoidable expenses, the Eagle Ford Shale operator deployed 800 copies of the Tank Manager application. Internal results show a 5% reduction in error or inaccuracies, he said. Cost savings are estimated to be $2 million per year based on current drilling and production rates across 2,000 wells and with oil prices at or near $60/bbl. E&P

Meeting water needs

Complete package offers operators an integrated solution set to meet water management needs.

Kirk Trosclair, Fountain Quail Energy Services

Across all U.S. shale plays an average of 12 bbl of water is produced for every barrel of oil. In 2015 about 66 MMbbl/d of water flowed out of onshore U.S. oil and gas wells. By 2020 produced water volumes are expected to reach 92 MMbbl/d, according to the IHS "Future of Water in Unconventionals" study. Industry experts estimate that 2015 oilfield water management costs in the U.S. exceeded $37 billion.

Fountain Quail helps operators reduce their water management costs by integrating its systems into its onsite operations. This also helps the company focus on its core business and meet environmentally friendly objectives like reducing truck traffic and minimizing the use of freshwater. This is accomplished through the use of the company's proprietary solution set, which includes the chlorine-dioxide (ClO_2)-based MAVREX water treating system; the ROVER and NOMAD systems for recycling to clean brine or freshwater; and the MAG Tank solution for containment as well as sourcing solutions, above and below ground pipeline transfer, trucking, and Class II saltwater disposal wells.

Mobile water treatment options

The MAVREX system is a water treatment plant housed inside a trailer. The system can be used at several different points in the water management value chain.

The MAVREX system is a water treatment plant in a trailer that uses safe, advanced ClO_2 technology. (Source: Fountain Quail Energy Services)

ClO_2 is a selective disinfecting oxidizer for bacteria control that has been used in various industries in the U.S. for more than 70 years and for more than 20 years in the oil field. While it is both environmentally friendly and U.S. Environmental Protection Agency-approved, it is also extremely effective with a rapid bacteria kill rate and a lower dose rate (compared to traditional biocides), and it's effective across a broad range of bacteria, fungi, biofilms and viruses. It also is less corrosive than chlorine.

Using a patented method, the system monitors in real time the pretreatment and post-treatment water and self-adjusts the treatment dose as water conditions change. This is in contrast to other systems that rely on fixed-rate dosing and manual sampling with a large margin of error. By automatically adjusting dose rates to changing conditions, chemical usage is optimized, overdosing is prevented, treated water will be bacteria-free and overall costs will be lower.

Treatment and blending occur automatically in the trailer, making the system unique in the industry. There is no need for external trailers or manifolds. Only treated water with low levels of ClO_2 leaves the trailer, resulting in much safer operations.

An operator in the Permian Basin recently had a challenge in sourcing water for its high-volume fractures. To meet the demand, the operator resorted to sourcing water from a brackish aquifer, effluent from a local municipal wastewater treatment plant, fresh water from various sources and produced fluid from its own acreage. The treatment demand spectrum of these waters stretched across three orders of magnitude.

The system was used to blend these diverse waters, varying the treatment rates to match the ever-changing demand to achieve the desired water quality, minimizing overall cost and protecting the reservoir from the challenging surges of microbial demand by constantly monitoring, recirculating and treating the working tanks on location.

Treating and recycling

The MAVREX system can stand on its own or serve as a complement to the ROVER and NOMAD recycling systems which, respectively, treat and recycle produced fluids to clean brine for reuse during fracturing or to distilled freshwater for fracturing or surface discharge.

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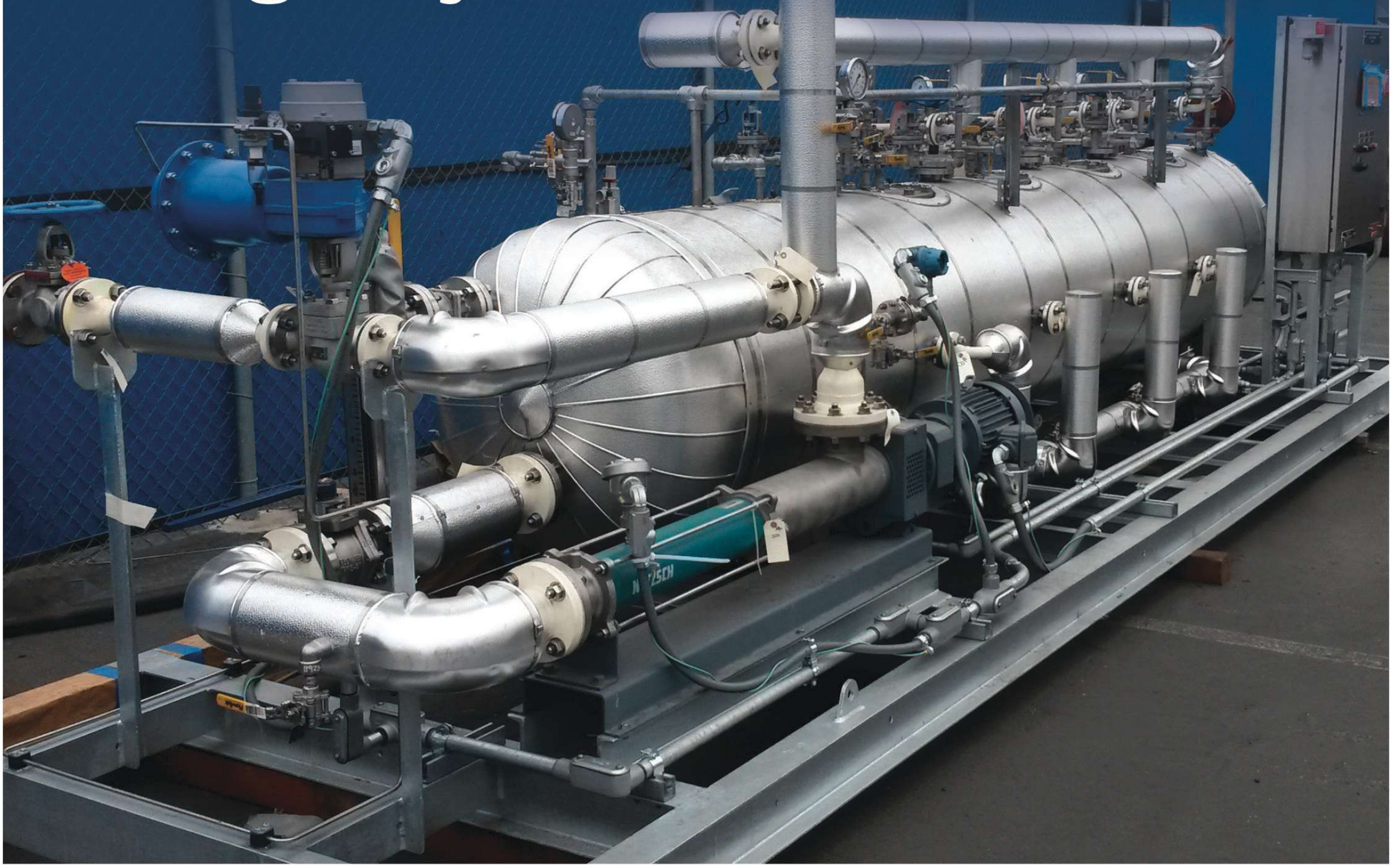


For example, Fountain Quail worked with a large E&P company in the Permian Basin that was having difficulty sourcing an adequate supply of water for hydraulic fracturing. Additionally, capacity at the customer's saltwater disposal well (SWD) was limited, complicating produced water disposal. The ROVER system was installed at the SWD pad and put the E&P company's wastewater to work. The company turned a liability into an asset and cut its water management costs by converting its wastewater into its water supply while it was developing wells in the region.

The old paradigm was recycling or disposal. The new approach integrates recycling and disposal to improve water economics. The beauty of this project was its simplicity. The customer aggregated produced water from three nearby SWDs that were connected by existing pipeline. A ROVER system was installed and used the SWD tanks as feed supply tanks. No pad was needed. Instead, the treatment system was located at the SWD pad and was tied into the existing three-phase power that fed the SWD pump. Because the ROVER used significantly less power than the injection pump, the customer saved on power costs while recycling. The company's infrastructure (gathering lines, gun barrel separator) continued to function as designed. No alteration to the gathering infrastructure was required. This "plug-and-play" integration model has been highly successful and has been replicated in other regions since this initial project.

The clean brine was used successfully for fracture supply on nearby wells. During a six-month period of operation at this location, ROVER recycled 1.2 MMbbl of produced water. The overall water management savings were estimated at 78% during the recycle program.

Modular containment solution

The MAG Tank is cost-competitive compared to traditional earthen impoundments and first-generation aboveground storage tanks. It is a modular aboveground containment tank with a flexible, customizable footprint; multiple capacities; and a solution that significantly reduces truck traffic compared to individual fracture tanks.

The tank's design features a modular approach with standardized panels. Containment capacities start at 10,000 bbl with designs that exceed 100,000 bbl. After site preparation, the tank is typically installed in one to two days, minimizing downtime, and it can be rapidly broken down, moved to another fracturing site and reassembled in a different configuration.

Recycling and disposal options

In the past operators viewed recycling and disposal as mutually exclusive paths for produced water management. Fountain Quail believes in integrating these paths. By integrating recycling at its disposal facilities, the company can create "water management hubs" for its customers.

Water sourced from an underground aquifer is transferred via aboveground pipeline to a MAG Tank in West Texas. (Source: Fountain Quail Energy Services)

For example, the produced water from a region flows to a water management hub that contains a SWD well in addition to a ROVER (clean brine clarification) and NOMAD (distillation) system. This allows producers flexibility based on their water needs.

If wells are being developed nearby with slickwater fractures, producers might opt to recycle enough clean brine (<10 nephelometric turbidity units, pH-neutral) from the hub using a ROVER to meet their demand. If 10# brine is needed, then a NOMAD evaporator system can be used to provide this product along with fresh (distilled) water. The amount of recycling depends on the water needs in the nearby region. The ROVER and NOMAD systems are "plug-and-play" platforms that can be relocated to where they are the most effective.

Waste is transformed into an asset instead of a liability. Producers will find in some regions that the lowest cost and most available fracture supply might be recycled water from a nearby water management hub. If recycled product is no longer required in a region, then the recycling systems can be removed and redeployed closer to the water demand.

The hub concept is all about giving producers optionality to manage their water in the most effective manner possible. It also gives Fountain Quail the ability to repurpose one producer's waste into a valuable product for other producers in the region. If produced water is trucked to a hub, the same truck can back-haul fracture supply water or 10# brine, thereby doubling the efficiency of the truck so it is not hauling empty in one direction. E&P

New flying lead technology emerges

Innovations in data transmission delivered cost savings to a major Gulf of Mexico field development project.

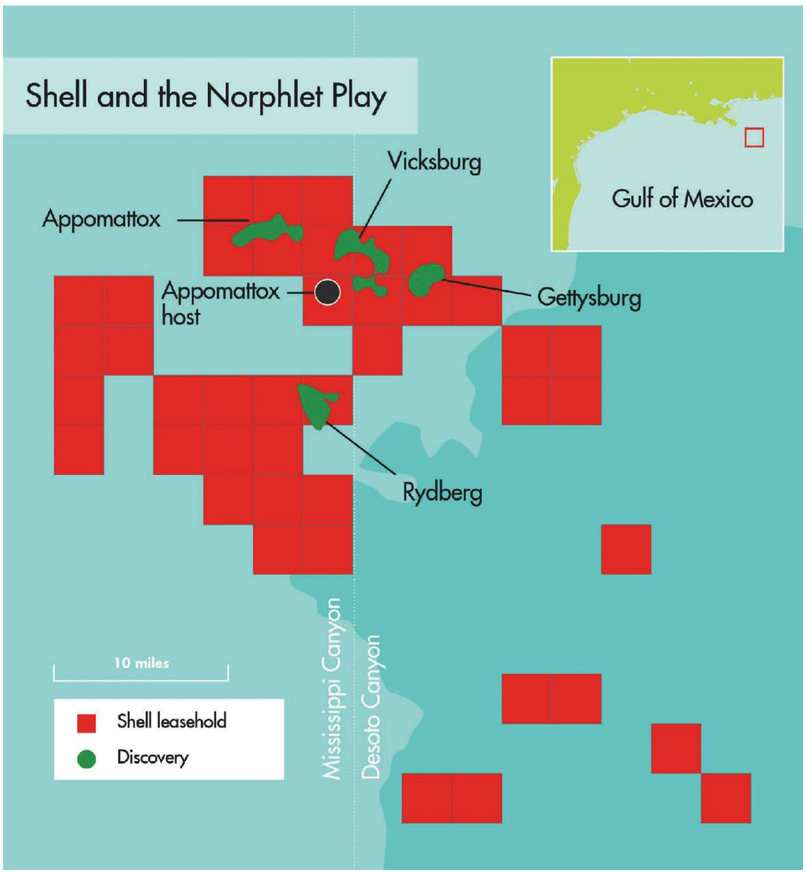
Velda Addison, Senior Editor, Digital News Group

Tough times for the oil and gas industry have led offshore operators to subsea technology to help cut costs as many lean toward standardization and simplified yet innovative concepts.

Use of new electrical optical flying lead technology is among the design changes helping trim costs for the Shell-operated Appomattox development in the U.S. Gulf of Mexico's Norphlet geologic trend. Unlike some of its fellow deepwater counterparts, Appomattox is progressing through the downturn, making it past the final investment decision stage in July 2015 with project costs down 20%.

Teledyne Marine is "participating strongly" in the Appomattox development with its electrical active flying lead and corrosion monitoring, Teledyne Marine President Mike Read said during the company's Technology Focus Day recently held in Houston.

"Many of you are coming to us for new ideas on how to take costs out of the next-generation system. … We've been driving standardization factories that are more automated," Read said. "We're using tools such as product configuration to really simplify and standardize," making customers' jobs easier and more cost-efficient.

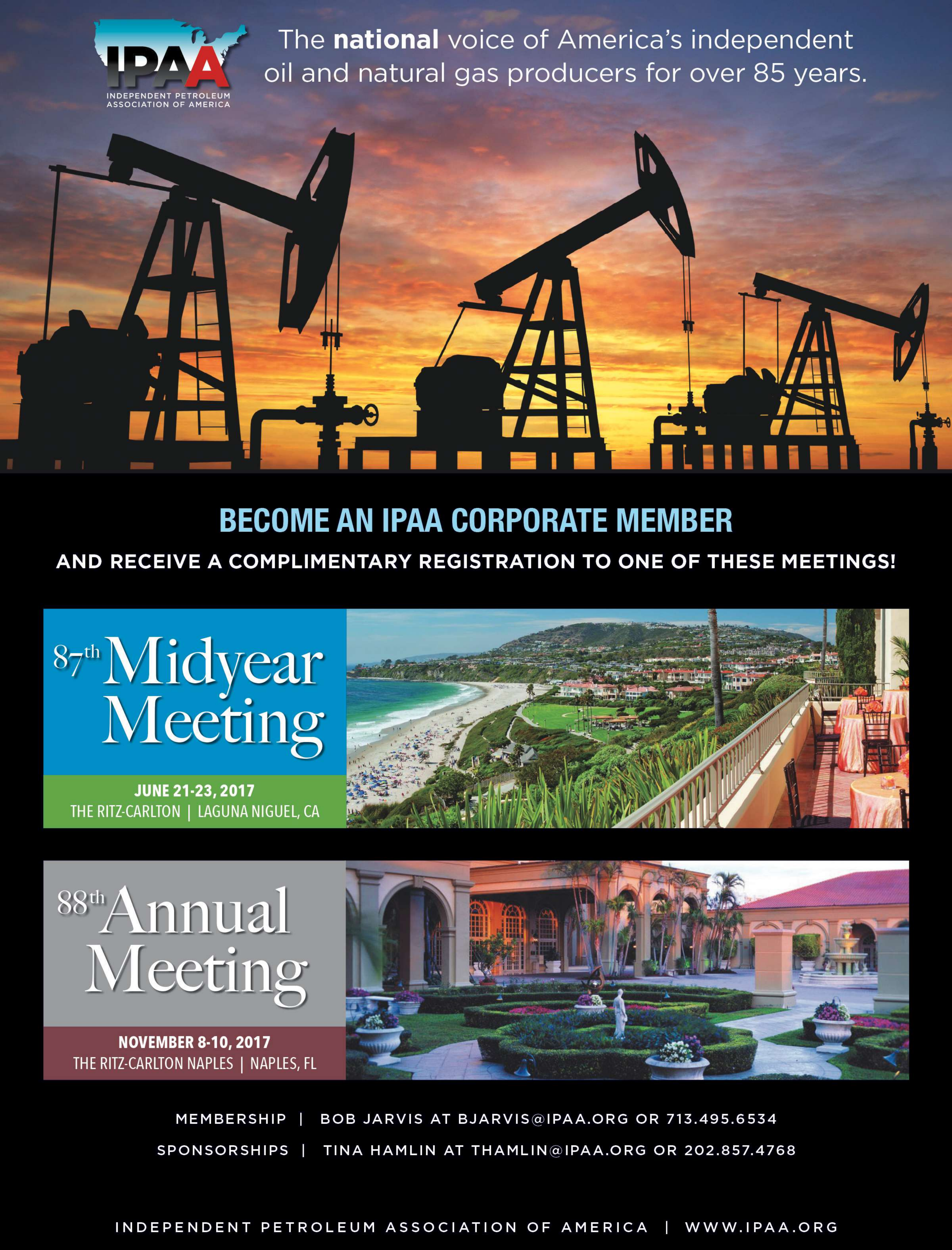


Shell's Appomattox development is located in the Gulf of Mexico's Norphlet trend. (Source: Shell)

Shell has attributed cost savings at Appomattox to supply chain savings, lowering the number of well needs for the development and design improvements. New data transmission technology from Teledyne led to one of the design changes, according to the company.

The flying leads, or electrical and fiber-optic connections, include wet-mate connectors that are joined by subsea hose, providing a link from the topside facilities to subsea control modules on the seabed, Teledyne explained on its website. Such connections are needed for each well to power subsea equipment and transmit data.

"New flying lead technology now has the ability to embed electrical-to-optical conversion equipment into the hose itself, removing the need for some of the routing modules on the seabed," Teledyne said. "A new product with this technology, an electrical optical flying lead, will provide a direct link from topside to a subsea control module to transmit data regarding pressure, temperature, flow rates, equipment health and a host of other functions while at the same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88th Annual Meeting
NOVEMBER 8-10, 2017
THE RITZ-CARLTON NAPLES | NAPLES, FL
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Teledyne's electrical optical flying lead embeds electrical-to-optical conversion equipment into the subsea hose. (Source: Teledyne)

time streamlining the field architecture into a simple, cost-effective layout."

Teledyne Marine will provide more than 40 electrical optical flying leads needed for the development, which calls for a semisubmersible unit, four-column production host platform and a subsea system with six drill centers along with 15 producing wells and five water injection wells. The development, in which Shell has 79% interest with partner Nexen Petroleum Offshore USA holding 21%, is located at a water depth of 2,195 m (7,200 ft) in the Mississippi Canyon and Desoto Canyon areas.

The electrical optical flying lead technology is one of many ways Teledyne is putting R&D efforts to work.

The company is bringing in record R&D dollars despite market conditions, Read said, noting the figure peaked at $13 million in 2015.

"We're increasing our global presence, we're deepening our customer partnerships [and] we're focused on factory consolidation centers of excellence. We will be the cost leader," Read said. He challenges the Teledyne team to "think bigger, be bolder and speed it up. … At Teledyne Marine, we're moving from defense to offense."

Looking forward

Another division of the company, Teledyne Scientific & Imaging, also is making strides in areas that could benefit the subsea oil and gas sector.

The company is applying machine learning technology to its sensors. The goal is to embed learning capabilities in sensors, said Berinder Brar, president of Teledyne Scientific & Imaging.

One of Teledyne's sensor companies also has taken visible infrared imagery and fused it, making it possible to get infrared information in the context of a typically recognizable image, Brar said.

"Algorithms are getting more sophisticated, and this is going to change the way the world will be in the future," he said. "As an industry we have to learn to utilize these sensors better as well as be able to take information out of the sensors and make more efficient and lower cost alternatives."

> "Algorithms are getting more sophisticated, and this is going to change the way the world will be in the future."
> —Berinder Brar,
> *Teledyne Scientific & Imaging*

Teledyne Scientific also has worked with the Defense Advanced Research Projects Agency (DARPA), part of the U.S. Department of Defense, and North Carolina State on drone technology, developing an unmanned aerial vehicle that can fly out of water and land in water.

In addition, there is a new material coming out—also funded by DARPA—called gallium nitride (GaN), a semiconductor material with a large band gap that is capable of operating in high temperatures, Brar said.

"New materials like gallium nitride can be very, very important for the future of oil and gas," he added. GaN can operate at high temperatures and at high frequencies and also can handle high voltages. "It allows you to take power supplies and compact them significantly. We're doing work on gallium nitride at Teledyne as well," he said. E&P

The value behind the STACK

What's driving all of the recent interest?

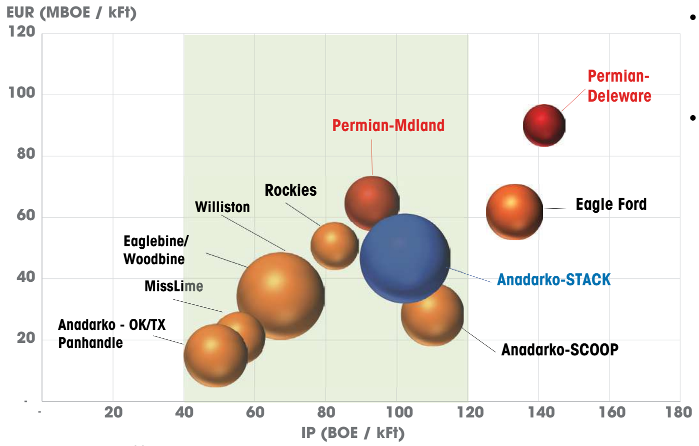
Contributed by **Stratas Advisors**

Several factors drive success in a basin's drilling campaign, and optimizing the risk-reward tradeoff is key, particularly in today's market. Oklahoma's STACK play exhibits many of the key characteristics needed to interest investment capital.

For one thing, the play has multiple target formations, providing plenty of source rock potential. Additionally, the establishment of key drilling areas has led to successful well delineation. And impressive well results are leading to positive valuations for STACK players. Given current economics, the play is likely to continue its forward momentum and be poised to explode when prices recover. E&P

CHARACTERISTICS OF THE STACK

Comparison of normalized wells sized by % change in lateral length from 2014 to 2015



Wells drilled since 2014 were used in this analysis.

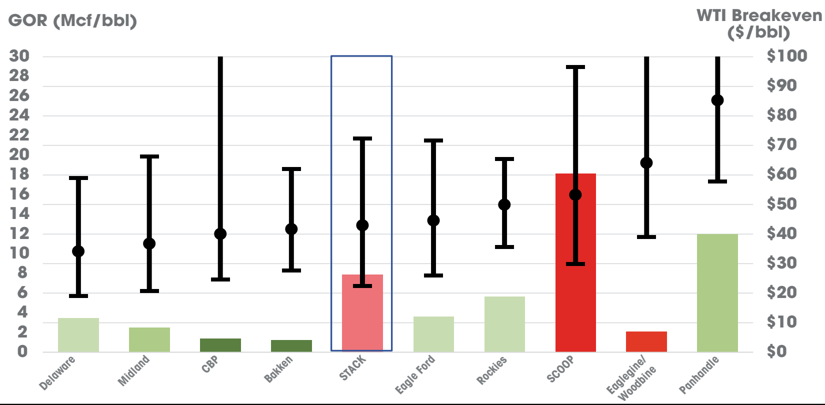
- The STACK has increased its lateral length by 10% over 2014 and shows the largest increase among oily sub-basins.
- The STACK is able to achieve larger IP than the Midland and Williston with a lateral length below the average and median for the group.

IP (boe/thousand ft)	
SCOOP:	110
STACK:	102
Midland:	93
Rockies:	82

(Source: NavPort and Stratas Advisors)

BREAKEVEN COMPARISONS

Mitigating Risk

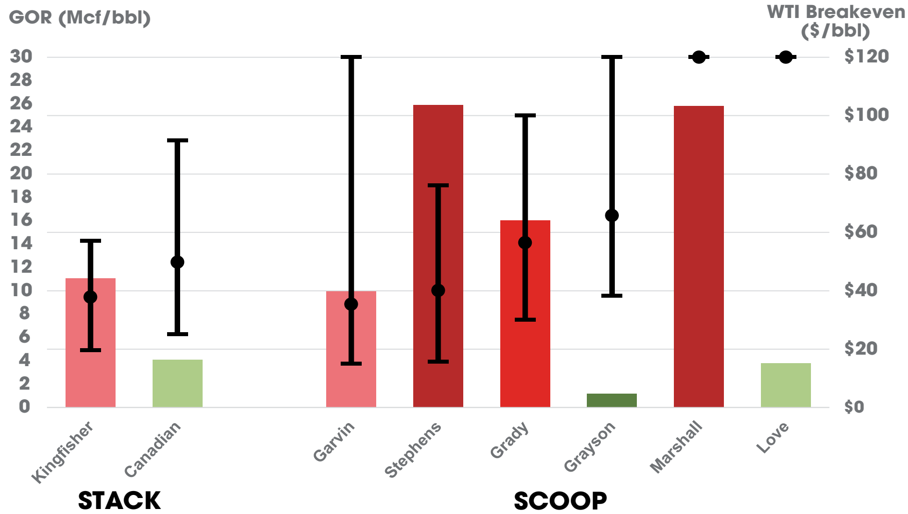


- Stacked pay potential can drive activity in the times of tight budgets.
- Profitable wells can be drilled in many plays – the risk is in missing the optimal kickoff point and targeting the right formation.
- Outside of Permian and higher cost Bakken, the STACK is a relatively profitable area, particularly given the amount of gas it includes.

(Source: Stratas Advisors)

COUNTY ECONOMICS

Kingfisher County provides the best economics within the STACK

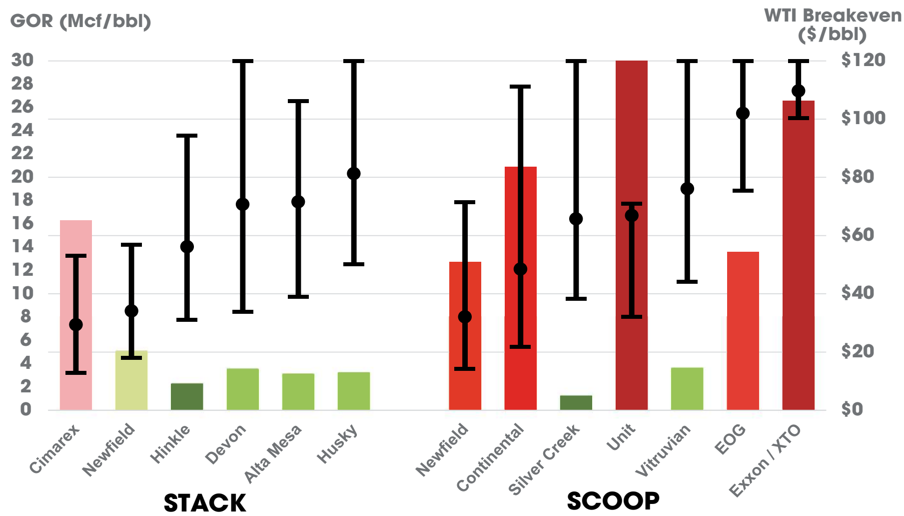


Sub-basin	County	Adj. Wtd. Avg. BE
STACK	Kingfisher	$ 37.26
	Canadian	$ 49.75
SCOOP	Garvin	$ 35.36
	Stephens	$ 40.10
	Grady	$ 56.46
	Grayson	$ 65.74
	Marshall	$100.00 +
	Love	$100.00 +

(Source: Stratas Advisors)

OPERATOR ECONOMICS

Newfield and Felix Energy/Devon show the lowest median breakevens in the STACK



Sub-basin	Operator	Adj. Wtd. Avg. BE
STACK	Cimarex	$ 29.38
	Newfield	$ 34.12
	Hinkle	$ 56.17
	Devon	$ 70.69
	Alta Mesa	$ 71.60
	Husky	$ 81.29
SCOOP	Newfield	$ 32.08
	Continental	$ 48.48
	Silver Creek	$ 65.74
	Unit	$ 66.89
	Vitruvian	$ 76.06
	EOG	$ 100.00 +
	Exxon/XTO	$ 100.00 +

(Source: Stratas Advisors)

Onshore regulatory overview

Jack Belcher and **Beth Everage**, HBW Resources LLC

It is no secret that over the past several years the U.S. oil and gas industry has faced an onslaught of stringent federal and state regulations that have severely hampered and threatened operations. This has been especially challenging during the recent period of low commodity prices.

The surprising results of the 2016 presidential and congressional elections signal a potential new course regarding energy policy and federal regulations. President-elect Donald Trump has vowed to reverse many of the Obama Administration regulations targeting fossil fuels and embark on policies that support the exploration, development, transportation, processing and utilization of fossil energy. While many policies and regulations are difficult to reverse, the industry can expect a few major announcements and reversals early on. Others will require actions by new cabinet-level and other political appointees in the federal departments and agencies. Still other changes will require congressional action.

Over the coming months the industry can anticipate several pro-energy regulatory efforts to impact unconventional oil and gas development including:

- *Executive orders:* overturning numerous punitive regulatory actions from the Obama administration that negatively impacted energy (i.e., methane rule, well control);
- *Hydraulic fracturing:* reversing regulatory actions such as the Bureau of Land Management (BLM) rule regarding hydraulic fracturing on federal lands and creating jurisdictional for unconventional activities;
- *LNG exports:* simplifying and expediting the permitting process for LNG export facilities; and
- *Pipelines and infrastructure:* addressing permitting and regulation of pipelines, transmission lines and other critical energy infrastructure.

In the meantime, a wave of punitive regulations, ballot initiatives and public relations campaigns have culminated into a last-minute regulatory push.

Below is a list of specific regulatory actions that are ongoing at the federal and state levels. HBW Resources will be providing monthly updates to this list.

Federal actions

- *Venting and Flaring: Waste Prevention and Use of Produced Oil and Gas* (final rule effective Jan. 17, 2017): This rule requires oil and gas producers to implement measures to reduce natural gas emissions. The rule also revises existing royalty rate provisions to clarify when operators owe royalties on flared gas and restores the government's congressionally authorized flexibility to set royalty rates.
- *Amendment to Commercial Oil Shale Regulations* (final rule expected February 2017): This amends the BLM's commercial oil shale regulations to address concerns about the royalty system in existing regulations and to provide more detail to the environmental protection requirements.
- *Farmington RMP: Mancos-Gallup Amendment* (comment period closed Dec. 20, 2016): This addresses issues related to additional oil and gas development in the San Juan Basin.

State/local actions

Colorado:

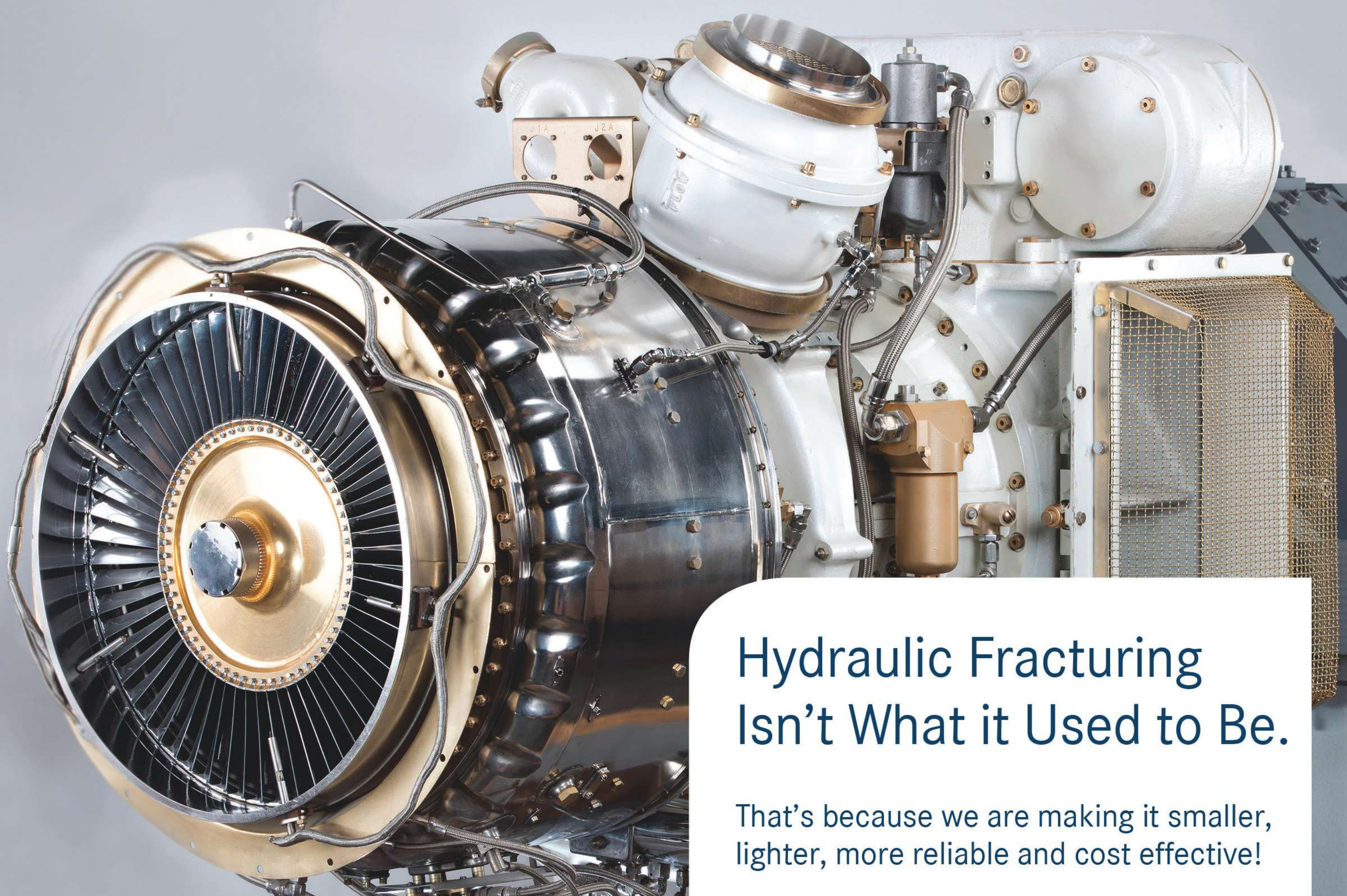
- Residents in Greeley have filed a lawsuit asking the Colorado Oil and Gas Conservation Commissions to vacate their approval of the proposed Triple Creek project;
- Boulder County commissioners approved a "temporary emergency moratorium" extending the county's current moratorium on oil and gas development through Jan. 31, 2017; and
- The City of Broomfield will consider a temporary moratorium through June 13, 2017.

Maryland:

- The Maryland Department of the Environment introduced rules (comment period closed Dec. 15, 2016) preventing hydraulic fracturing within 305 m (1,000 ft) of a private drinking water well as well as requiring protections against contaminated well water. The proposed rules will be the most stringent in the nation unless the state's General Assembly intervenes with legislation to ban fracking statewide.

Virginia:

- Gov. Terry McAuliffe approved new hydraulic fracturing regulations requiring mandatory disclosure of fracking chemicals, baseline water testing and monitoring, and spill prevention and response training. There is legislation proposed for the upcoming General Assembly session that will shield certain fracturing chemicals from disclosure under a "trade secrets" exemption. ■



NEW CONTENT FOR 2017

The **Marcellus-Utica Midstream** conference covers a wide range of topics within the midstream sector. Take a look at some of the key sessions at the upcoming event.

OPENING KEYNOTE

Alan Armstrong
President and CEO
The Williams Cos.

The Markets Evolve

The Marcellus and Utica have emerged as world-class plays that are reshaping the energy industry. Find out what Williams Cos. President and CEO Alan Armstrong sees for the region's future.

OPERATOR SPOTLIGHT

Frank Tsuru
President and CEO
M3 Midstream LLC

Plumbing The Utica

M3 Midstream has worked in eastern Ohio since the early days of the Utica play, offering its customers services ranging across all phases of NGL production and sales. President and CEO Frank Tsuru will share how he sees the market today and what his company plans for the future.

PROJECT SPOTLIGHT

Michael D. Frederick
Vice President,
LNG Operations
Dominion Energy

Cove Point Moves Ahead

The nation's second, large-scale LNG export facility is scheduled to go online in 2017. Michael D. Frederick, vice president of LNG Operations, will share updates on Dominion's exciting Cove Point project.

Hear from 20+ executive-level speakers in 15 in-depth conference sessions

OPERATOR PANEL

Utica Rising

The Utica now produces some 3.5 billion cubic feet of natural gas and nearly 100,000 barrels of liquids. And those numbers are projected to keep rising. How will midstream operators meet the demand?

- **Marc A. Halbritter,**
  Senior Vice President,
  Business Development,
  Blue Racer Midstream
- **Steven M. Woodward,**
  Senior Vice President –
  Business Development,
  Antero Resources Corporation/ Antero Midstream Partners LP

OPERATOR PANEL

Taking Marcellus To Market

The Marcellus continues to confound the industry with its breadth and scope. These midstream operators provide updates on the near-term and long-term needs of the big play's producers.

- **Patrick Redalen,**
  President,
  Stonehenge Energy Resources II LP
- **Gregg Russell,**
  Senior Vice President -
  Commercial Development,
  DTE Gas Storage and Pipelines
- **R. Douglas Walker,**
  Vice President,
  Tallgrass Energy Partners LP

FINANCE ROUNDTABLE

Midstream & The Markets

Despite commodity price worries, the midstream holds investor interest. These financial experts tell how operators can convert that interest into capital to pay for new infrastructure.

Justin Carlson
VP & Managing
Director, Research
East Daley Capital

Ben Davis
Partner
Energy Spectrum Capital

Guillermo Sierra
Managing Director
Macquarie Capital (USA)

Hosted by
HARTENERGY

Presented by
MIDSTREAM Business
Oil and Gas Investor
E&P
UNCONVENTIONAL OIL & GAS CENTER
DOWNSTREAM BUSINESS

Light in the darkness reveals unlimited possibilities

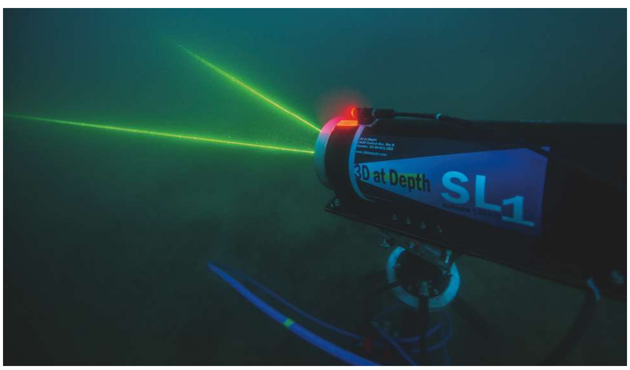
In a first-of-its-kind application, subsea LiDAR delivers the data needed to 3-D print an accurate physical model of a damaged subsea part.

Jennifer Presley, Senior Editor, Production Technologies

Light detection and ranging (LiDAR) technology is used to acquire highly sophisticated 3-D models of structures and natural features. The concept is simple: illuminate a target with laser light and measure how long it takes for the reflected signal to return to the source. For many years the technology was used in terrestrial and airborne surveying, space mapping, and weather. It has now become an industry standard due to the proven ability to create repeatable and accurate datasets.

LiDAR's features compared to other "triangulation" laser technology includes unlimited range—hence the space applications and the ability to extract critical information from complex 3-D datasets. As the technology continues to expand into other applications like the use of unmanned aerial vehicles or drones to perform remote asset inspection, subsea can now be added to LiDAR's list of survey and inspection capabilities with the development of the world's first commercially available subsea 3-D laser scanning system by 3D at Depth.

3D at Depth's SL1 and SL2 subsea laser technology was fast-tracked from invention and pilot programs through commercialization due to the support of the Research Partnership to Secure Energy for America (RPSEA) Ultra-Deepwater Research Program.



Designed for use on ROVs, the SL1 subsea LiDAR laser scanning system brings light to the darkness, making it possible to create 3-D versions of subsea metrologies. (Source: 3D at Depth)

Considered the world's first subsea 3-D LiDAR company in the oil and gas industry, 3D at Depth recently completed another world's first, delivering subsea survey and inspection data to 3-D print an accurate 1:1 physical model of a damaged well part. The ability to deliver this type of complex and accurate data to subsea operations and inspection has positive implications across a wide range of applications subsea. But before the technology could "beam," it had to prove its reliability and capability through tests and pilots made possible through its selection as a research project under RPSEA.

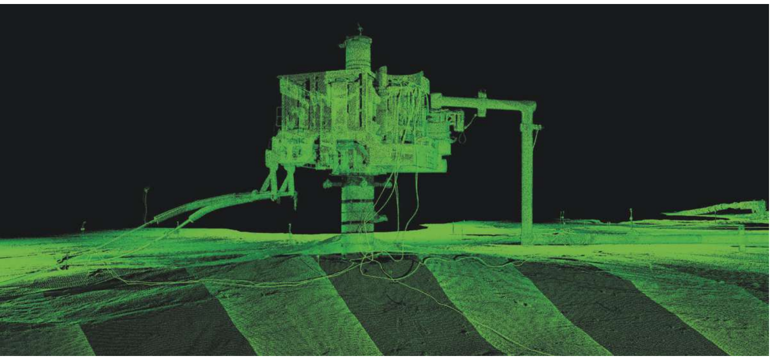
Getting started

The idea for subsea LiDAR came from above.

"While I was in the aerospace industry, I could see firsthand the incredible impact LiDAR technology was bringing to the remote sensing of soft and hard targets, including mapping, surveying and inspection. I watched the number of value-add applications grow for the technology for multiple industries including terrestrial, airborne and aerospace," said Carl Embry, managing director of 3D at Depth. "And then we looked at the subsea world and saw an open market. So 3D at Depth approached the problem from the technology side and said, 'This is something we can build,' and we began the process of building it."

It was through identifying the challenges encountered with topside surveying, construction, retrofits, as-built analysis and decommissioning that the 3D at Depth team could see that terrestrial and airborne LiDAR was gaining considerable traction to address the same issues that existed subsea.

"It appeared to be a good opportunity, and the market was proven for several terrestrial applications, with lots of tools and software being developed along with best practices and procedures. We weren't completely creating the wheel, as a lot of the infrastructure was there," Embry said. "What was really needed was the specialized hardware to go subsea. We have since come to realize subsea is different enough compared to topside that new best practices and procedures needed to be developed. But the hardware was the key; it was the first stepping stone required to make it possible."



A point cloud image of a subsea production well is generated with the data acquired during the subsea LiDAR scanning process. (Source: 3D at Depth)

3D at Depth was awarded a RPSEA contract in January 2011 to bring high-resolution 3-D laser imaging for inspection, maintenance, repair and operations from a laboratory setting into an underwater environment for the oil and gas industry. Included in the project were two underwater trials that demonstrated the feasibility of using LiDAR technology in a subsea environment. To accomplish this, 3D at Depth worked with CDL Inc. and UTEC Survey to marinize a LiDAR acquisition system. Thirteen months later at the conclusion of the project's Phase 1, the world's first demonstration of a subsea LiDAR occurred, with 3-mm measurement accuracy at greater than 8 m (26 ft) for an underwater laser sensor integrated with a ROV.

Phase 2 saw the development of a LiDAR system capable of working at greater water depths, with the first successful open water trial performed in March 2013. A primary goal of this phase was the development of a sensor that could perform and survive multiple deployments into an ultradeepwater environment.

In the time since the company has gone on to use its LiDAR system on a variety of surveying and mapping projects in the Gulf of Mexico, Australia, the North Sea, the Mediterranean, the Pacific Ocean, the Caribbean and elsewhere, including the *USS Arizona* at Pearl Harbor. As of press time the company had completed more than 100 projects and 175 spool-metrologies worldwide.

3-D model project

Fugro and 3-D at Depth announced in late October 2016 the use of subsea 3-D data to 3-D print a physical model of a damaged wellhead part. It was the ability to use accurate spatial data in the fabrication of the subsea part, according to a press release. This subsea part fabrication was part of a larger project conducted in early 2016 using 3D at Depth's SL 2 technology and point cloud software on a well abandonment project offshore in Oceania.

The plugged and abandoned wells were located in a water depth of 110 m (361 ft) and were drilled decades earlier and suspended at the time of drilling, the release said. Access to accurate data on the manufacture and specifications of these wellheads was limited due to their age. The 3D at Depth system was selected to acquire the detailed measurement needed to determine feasible abandonment options.

Fugro's *Rem Etive* multiuse vessel was fitted with two work class ROVs, with one of the two ROVs equipped with the SL2 subsea LiDAR system mounted on its crash bar. Near real-time data were sent to the operator on the vessel using a fiber-optic multiplexor.

About 44 million datapoints were collected at the well in 13.5 hours. The LiDAR laser data were processed using point cloud processing tools to compute the spatial relationships, measurements and orientations of the seabed structures. The resulting deliverables included a 3-D point cloud database, a dimensional report for each well, computer-aided design (CAD) files and a 360-degree animation of each well, modeled from the point cloud, the release said.

To create a 1:1 model for the design of an appropriate hot tap connector, a 3-D print of the top of the well with its damaged stub at full scale was required. As the large size of the well cap structure made the cost prohibitive, a hybrid computer numeric control machining process combined with a 3-D print of the damaged part was proposed by 3D at Depth as a viable alternative solution.

The first step was to reprocess the point cloud data from the top of the well and then create 3-D CAD models of the separate parts. However, this process proved more challenging than first thought due to the complexity of the shape. For this particular part the auto meshing algorithms, which convert point clouds into surfaces, did not perform well, and as a result the CAD model was developed manually, which is also common when modeling complex shapes from terrestrial laser scans, the release noted.

The part was then 3-D printed by means of fused deposition modeling technology using acrylonitrile butadiene styrene thermoplastic material. One of the other two computer numeric control machined parts was made from acetal and the well cap from ultrahigh-molecular-weight polyethylene. E&P

Editor's note: Visit rpsea.org/projects/09121-3300-06 *for detailed project reports and presentations on the "High Resolution 3-D Laser Imaging for Inspection, Maintenance, Repair and Operations" project.*

Nanofluidity mitigates problems

Nanophysics can be harnessed to reduce downhole deposition of paraffin, asphaltene and scale while improving fluid viscosity at the surface.

Monte Swan and **Amber Krummel**, Revelant

Nanofluidity increases average production, reduces operating expenses and protects the environment. Unlike traditional thermal, chemical and mechanical methods, which are remedial, Revelant's nanofluidity technology is preventative and uses nanophysics to drive better oil chemistry during production and transport.

This technology has seen use in diverse geological settings in 23 countries but has only recently launched in the U.S. Its production optimization technology, known as the Enercat, minimizes and often prevents paraffin crystallization, asphaltene flocculation and scale precipitation, all the while minimizing or preventing the usual increase in viscosity of crude oil as it rises in the well. First used in 1991, the technology lowered the pour point of paraffin-rich oils in northwestern Canada. With patents pending, Revelant is pioneering a new area of nanophysics called nanofluidity through an R&D partnership with Colorado State University (CSU). This partnership is advancing the measurement, tuning and focus of the Enercat to respond to various oil types and address perennial problems such as barium sulfate.

Description

The Enercat is a material composite that is not magnetic or radioactive and requires no external power source, maintenance or servicing. It has no internal restrictions and is installed below the depth of paraffin and/or asphaltene deposition and below the depth at which viscosity begins to increase up the wellbore. For scale problems only, depth is not an issue. It also can be installed in a series to handle high oil production rates.

The Enercat TubingTool is designed for downhole installation in the production tubing string of a well. It is installed during a completion operation or workover as an industry-standard 1.2-m (4-ft) pup joint that meets required installation specifications. Handling capacities vary by tubing size: 2⅜ in. at 30 bbl/d, 2⅞ in. at 35 bbl/d and 3.5 in. at 70 bbl/d.

The Enercat TrimTool is installed without pulling the tubing string by attaching the tool to the bottom of the pumping assembly on a producing well. This allows tool installation independent of workovers, making it ideal for low-producing wells. The 12-in. version handles up to 10 bbl/d, and the 28-in. version handles 15 bbl/d to 20 bbl/d (Figure 1). In addition, Revelant has completed the initial design specifications for an Enercat Slickline Through-TubingTool designed for offshore wells with 1,000 bbl/d or less production. Each tool has a handling capacity of 40 to 50 bbl/d.

Installation configurations

Each tool works in virtually any well that experiences deposition, including dual completions and directional, horizontal, steam-assisted gravity drainage, water source and water injection wells. Each also works with any pumping system with the exception of electric submersible pumps. Each application is customized for specific wells depending on tubing size and fluid volume. The tools typically run below the pump intake or above the pump discharge or, in the case of a flowing well, as a tail joint at the end of the tubing string.

FIGURE 1. The Enercat TubingTool is designed for downhole installation in the production tubing string of a well during a completion operation or workover. The Enercat TrimTool is designed for installation at the bottom of a pumping unit on a producing well during well servicing. (Source: Revelant)

More than 80% of the 4,500-plus Enercat installations have successfully solved paraffin, asphaltene, scale and heavy oil production problems. Rare failures are due to improper installations, water cuts greater than 90%, long-chain paraffin with greater than 40 carbon atoms and salinities greater than 100,000 parts per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CONTROL
WITH BETTER
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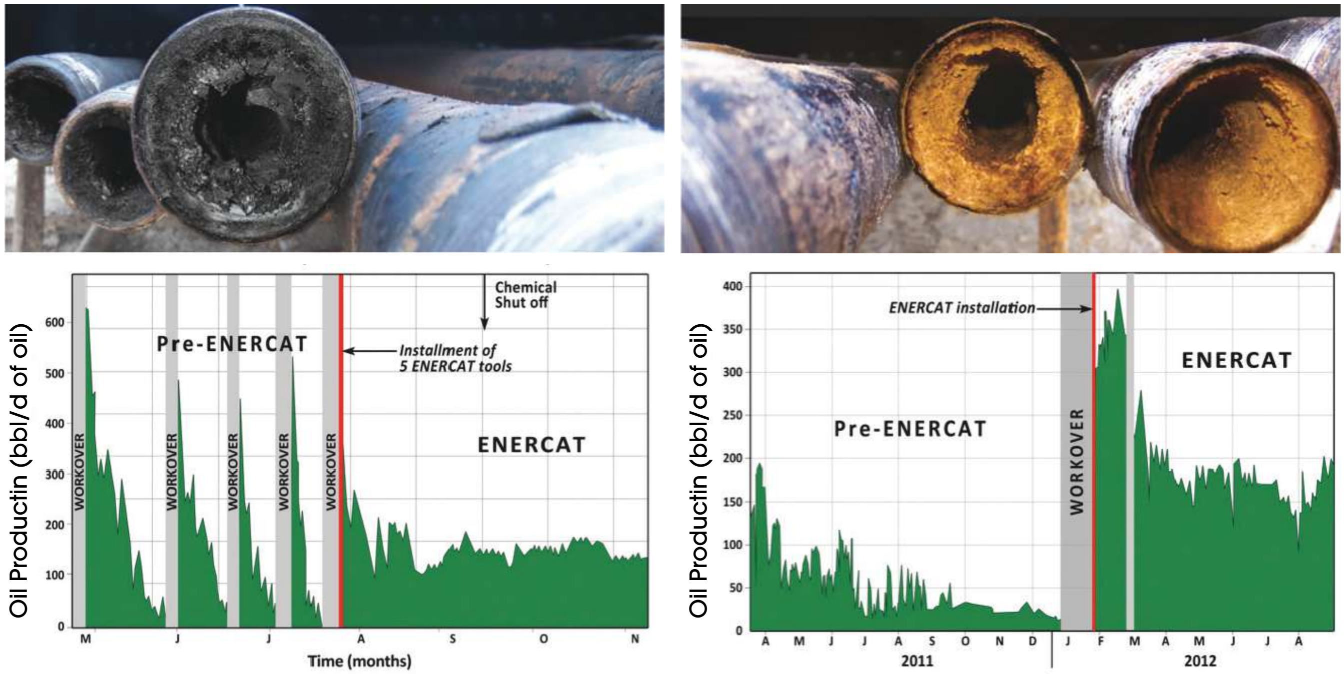


FIGURE 2. Stabilization and increased production result from the installation of the Enercat at the end of standard workovers. (Source: Revelant)

million. A paraffin case history from Venezuela and an asphaltene case history from the Eagle Ford in Texas are shown in Figure 2.

Revelant's nanofluidity technology saves time and production costs, improves safety, protects the environment and increases revenues by stabilizing and enhancing oil production. As oil prices decline and profit margins tighten, these inverted relationships become more critical (Figure 3).

FIGURE 3. Reduced costs, increased revenue and environmental benefits result from the use of Revelant's nanofluidity technology. (Source: Revelant)

Science CSU partnership

Revelant partnered with faculty at CSU to work out the details of the physics and chemistry underpinning the Enercat. A refined understanding of the tool will allow further tuning and addressing of specific problems with fluid stability in the oil and gas industry. The tool acts as a paraffin crystal modifier delaying the onset of crystallization by increasing paraffin solubility, which minimizes or prevents paraffin from crystallizing inside the wellbore. It also acts as a resin proxy by increasing the stability of asphaltene molecular dispersions, thus minimizing or preventing asphaltene flocculation and deposition and increasing viscosity as crude oil rises up the wellbore. The tool drives the crystallization of nonscale-forming aragonite over calcite in the crude oil bulk fluids, thus minimizing or preventing calcite from depositing inside the wellbore.

The Enercat's international track record, documented by case histories and testimonials from 23 countries, provides valuable insight into the mechanisms of Enercat technology. The empirical results from the case histories point toward physics driving chemistry at the nanoscale influencing the nanofluidity of the reservoir fluids. This changes the distribution of seed nucleates for crystal growth in the fluid, meaning the low-frequency molecular vibrations of the crude oil are affected by the generation and transmission of fields through the Enercat. Ambient conditions (energy) surrounding the tool downhole are the "hammer" that drives the fields. The generated frequencies influence fluids at the nanoscale, moving molecules in a constructive direction through quantum affects and classical mechanics. E&P

Water clarifiers, demulsifiers help improve fluid separation performance

Baker Hughes has released its TRETOLITE SNAP fluids separation technologies, designed to help oil and gas operators maintain dry oil and good water quality while also stabilizing operations and reducing costs—without limiting production, a press release stated. This next generation of chemical solutions includes water clarification and demulsification technologies that deliver improved performance in multiple production applications, including steam-assisted gravity drainage (SAGD) facilities as well as conventional and other unconventional onshore and offshore fields. TRETOLITE SNAP technologies help minimize oil-in-water levels to improve water quality for reuse, reducing heat exchanger fouling and related equipment cleanout expenses. The new products also help lower basic sediment and water content in the oil to decrease recycling and slop oil trucking. TRETOLITE SNAP technologies enable SAGD producers to increase profitability by getting a more controlled oil/water interface that improves production volumes and throughput capacity. *bakerhughes.com*

New services integrate modeling with monitoring and control

Schlumberger has released its AvantGuard advanced flowback services. These services protect the connection of the hydraulic fracture to the wellbore to optimize productivity in conventional and unconventional wells, a press release stated. AvantGuard services comprise flowback design and proactive fracture protection that complement fracturing operations. Damage to the well and the formation is actively prevented by tailoring a predictive flowback design strategy with a defined secure operating envelope. Application of the flowback design during the transition to production protects and stabilizes hydraulic fractures to efficiently enable all the clusters in each zone to produce without productivity impairment. *slb.com*

Microseismic analysis service to optimize unconventional recovery

ESG Solutions has released a new service within its Enhanced Reservoir Characterization (ERC) offering for hydraulic fracturing, a press release stated. The Flow Dynamics Suite uses a statistical approach to understand seismicity and reservoir processes for improved hydraulic fracture efficiencies and demonstrates a unique potential for outlining production from hydraulic fracturing. ESG's newest microseismic analysis service represents a dramatic shift in the way that microseismic data are evaluated. "While an individual microseismic event corresponds to slip on a discrete surface, the combined deformation of a group of events results in a collective behavior," said CTO Ted Urbancic. "Here we are invoking new statistical theories drawing from the field of fluid mechanics that demonstrate that it is the collective behavior of seismicity that actually reveals the most valuable information about reservoir deformation." The Flow Dynamics Suite uses a selection of dynamic parameters to identify processes that play important roles in the dynamic expansion of a fracture network during hydraulic fracture stimulations while evaluating reservoir deformation efficiency. *esgsolutions.com*

First digital chemical management system for oil and gas industry

Clariant has released its VERITRAX intelligent chemical management system, which offers oil and gas producers a fully transparent automatic chemical control, monitoring and ordering system that optimizes chemical management tasks and labor-intensive processes, a press release stated. The support platform takes advantage of automation and cloud-based technologies to optimize the chemical supply chain, ensure maximum production uptime and provide producers with an understanding and control of their chemical spend. The offering, which can be fully integrated into existing production

Clariant's remote tank level sensor with a chemical tank is shown. (Source: Clariant)

setups such as SCADA and distributed control systems, provides a continuous real-time data flow that is delivered directly to a laptop or smartphone. It allows users to monitor multiple data streams such as well production and chemical injection rates and to optimize inventory management, with new chemical deliveries coordinated automatically. Additionally, continuous system monitoring alerts the operator to potential problems, allowing rapid interventions to minimize production losses. *clariant.com*

Extending the performance of traditional elastomer seals

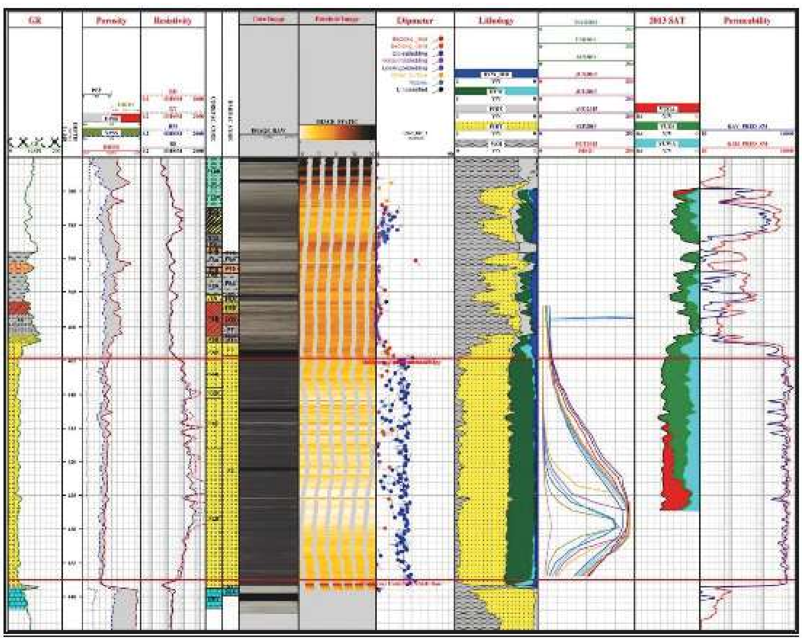
Peak Well Systems' new IRIS-3D technology provides a high-expansion mechanical support system that can be applied to a wide range of possible applications, the company said in a release. For downhole applications in particular, it can be used to extend the performance of traditional elastomer seals and therefore enables an entirely new suite of wellbore sealing systems. The IRIS-3D system already has undergone extensive testing, achieving excellent results in practical testing of system performance, reliability and debris tolerance. Simply through the addition of IRIS-3D components to Peak's existing downhole SIM plug system, the team has been able to extend the performance of the SIM seal from 150 C (302 F) and 5,000 psi up to 200 C (392 F) and 10,000 psi. On the back of these early tests, the development path is following two project tracks: One focuses on the ability of IRIS-3D to develop a new range of high-performance medium expansion plugs, and the other explores the potential of IRIS-3D in high-expansion seal systems. *peakwellsystems.com*

Lower cost resin-coated proppants

The Oilfield Technology Group of Hexion Inc. has released its kRT resin-coated proppants, a press release stated. Hexion's kRT proppants are a resin-coated sand available in 20/40, 30/50, 40/70 and 100 mesh sizes. The company's Stress Bond technology delivers many of the benefits that curable resin-coated proppants have over uncoated fracture sand. This includes the reduction of proppant flowback, reduction of proppant fines generation, minimization of proppant embedment, enhanced well production and the reduction of silica dust generation during the pneumatic transfer and conveying process, which helps improve health and safety on location. The 100-mesh product, kRT 100 proppant, is a low-cost option for those that want to pump 100-mesh proppant and are concerned with proppant flowback or excessive silica dust. Large amounts of silica dust can be produced by uncoated 100 mesh sand when it is transported due to the small grain size. *hexion.com/oilfield*

Collaboration delivers advanced borehole data analysis service

Task Fronterra, a geoscience consultancy, has standardized Paradigm's advanced borehole data analysis service offering on the Paradigm Geolog petrophysical analysis and formation evaluation solution, according to a press release. The services will include geological and geomechanical analysis as well as borehole data processing and quality control. *pdgm.com*



Seamless integration of borehole image logs with other wellbore data in Geolog allows high-resolution delineation of critical reservoir features. (Source: Paradigm)

Marine seismic technology eliminates distortions and uncertainties

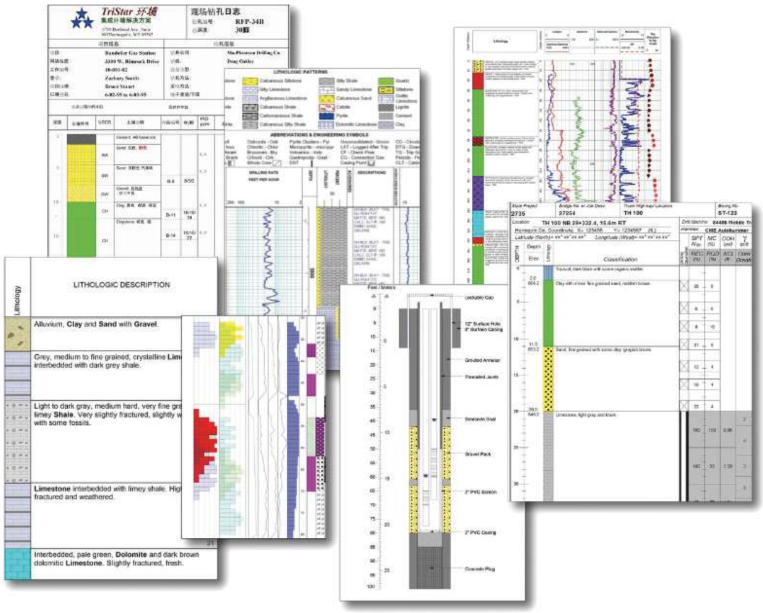
In October 2016 Geology Without Limits explored the Barents Sea's Norwegian shelf segment employing its new FloatSeis marine seismic technology, a press release stated. The survey was conducted with help of SeaBird Exploration's research vessel *Harrier Explorer*. It was the first shallow-water basin application of FloatSeis. The seabed area under scrutiny was deliberately selected to include geological section complexities such as multiple seismic faults and lithological heterogeneities that cause poor reliability of data obtained with the use of the traditional common depth point (CDP) wave reflection method. Implementation of FloatSeis technology enables amending the standard CDP reflection data with those resulting from capturing the refracted waves produced at both the upper sedimentary layer and the basal top surfaces to eliminate distortions and uncertainties associated with wave-based modeling of geologically similar seabed structures and obtain more coherent seismic image of the surveyed area. The company planned to obtain first results in December 2016. *floatseis.com*

Digital ecosystem for securely implementing the Industrial IoT

Emerson has released the expanded Plantweb digital ecosystem, a scalable portfolio of standards-based hardware, software, intelligent devices and services for securely implementing the Industrial Internet of Things (IoT) with measurable business performance improvement, a press release stated. In addition to highly secure process control, safety and asset management systems, Plantweb supports enterprise-wide operations with an expanded portfolio of Pervasive Sensing field instruments; the Secure First Mile family of software, gateways, security devices and services; the Plantweb Insight and Plantweb Advisor scalable suite of software applications; the AMS ARES Platform; and the Microsoft-enabled cloud-based remote expert Connected Services. *emerson.com*

Comprehensive borehole log software displays data as graphic logs

RockWare has released LogPlot 8 to assist geoscientists with the display of their geotechnical, environmental, geophysical, mud/gas and mining data as graphic logs, a press release stated. According to the company, this new version makes the creation of detailed and professional borehole and well log reports easier and more flexible, with updated data editing tools and connectivity to the RockWorks17 database. The company adds that additions to the program include new text formatting tools, contact line styles, an enhanced pattern editor and dozens of new display options for subsurface and well construction information. The Log Designer interface also has received major improvements, including the capability to be undocked and an easily accessible list of design items. *rockware.com*



LogPlot 8 offers updated data editing tools and connectivity to the RockWorks17 database. (Source: RockWare)

Elastomer provides long-life sealing

The latest perfluoroelastomer offering from DuPont Performance Materials, Kalrez Spectrum 7275, offers a high level of sealing performance in the most aggressive chemical processing and manufacturing environments that are known to be difficult for sealing, including ethylene oxide; acrylic monomers, silanes and chlorosilanes; and strong oxidizers such as nitric acid, chlorine and chlorine dioxide; a press release stated. Kalrez Spectrum 7275 has shown improved chemical and compression set resistance and mechanical property retention vs. other competitive elastomers. It is based on a proprietary cross-linking system and is uniquely identifiable from its light brown color. Targeted applications for Kalrez Spectrum 7275 include industries that depend on mechanical seals, pumps, valves, compressors, filtration columns and analytical equipment as part of their critical processes. *dupont.com* E&P

New survey highlights enormous resource potential

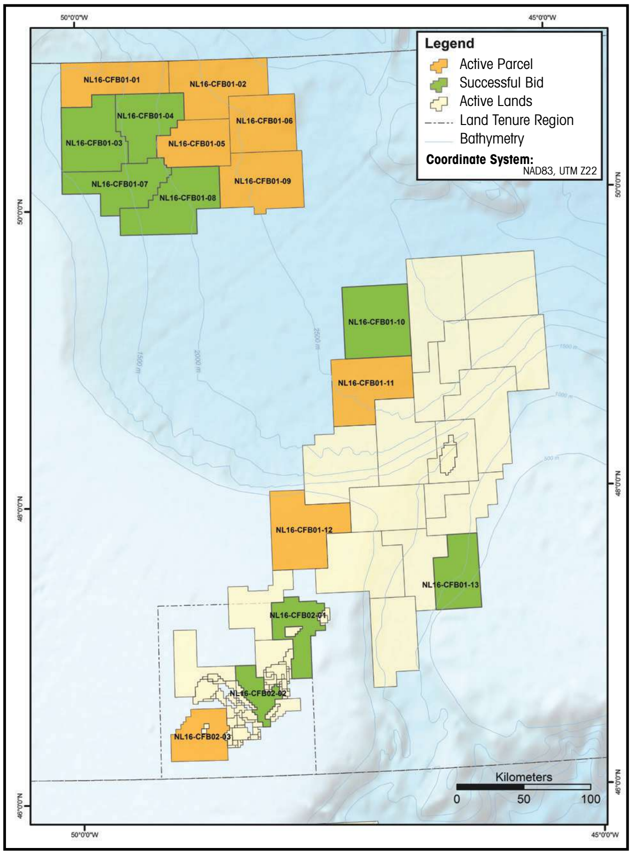
The first 3-D seismic survey ever shot offshore Newfoundland and Labrador has delineated a new Lower Tertiary play.

Rhonda Duey, Executive Editor

It started, as all great exploration stories do, on a very large scale. Nalcor Energy put together an exploration strategy in 2010 that began with a satellite oil seep survey covering 1.5 million sq km (580,000 sq miles) offshore Newfoundland and Labrador. This was followed by a large-scale 2-D seismic program from the tip of Labrador to the Canada/Greenland border and down toward Flemish Pass. Seabed coring also was undertaken.

But it wasn't until summer 2015 that Nalcor brought in the big guns—a 3-D seismic survey using long-offset broadband acquisition technology. Early data from that survey became available in summer 2016, boosting the already considerable estimated resource potential to 25.5 Bbbl and 583 Bcm (20.6 Tcf), just in time for a licensing round in November 2016.

And the industry responded. The call for bids received almost $758 million in work commitments and lured three new companies—Hess Canada Oil and Gas, Noble Energy Canada and Delek Group—to the region. Sixteen parcels of land totaling more than 33,000 sq km (12,741 sq miles) was up for grabs, 13 of which are in the Eastern Newfoundland Region and three of which are in the Jeanne D'Arc Basin.



The latest bid round attracted new companies to the region. (Source: Nalcor)

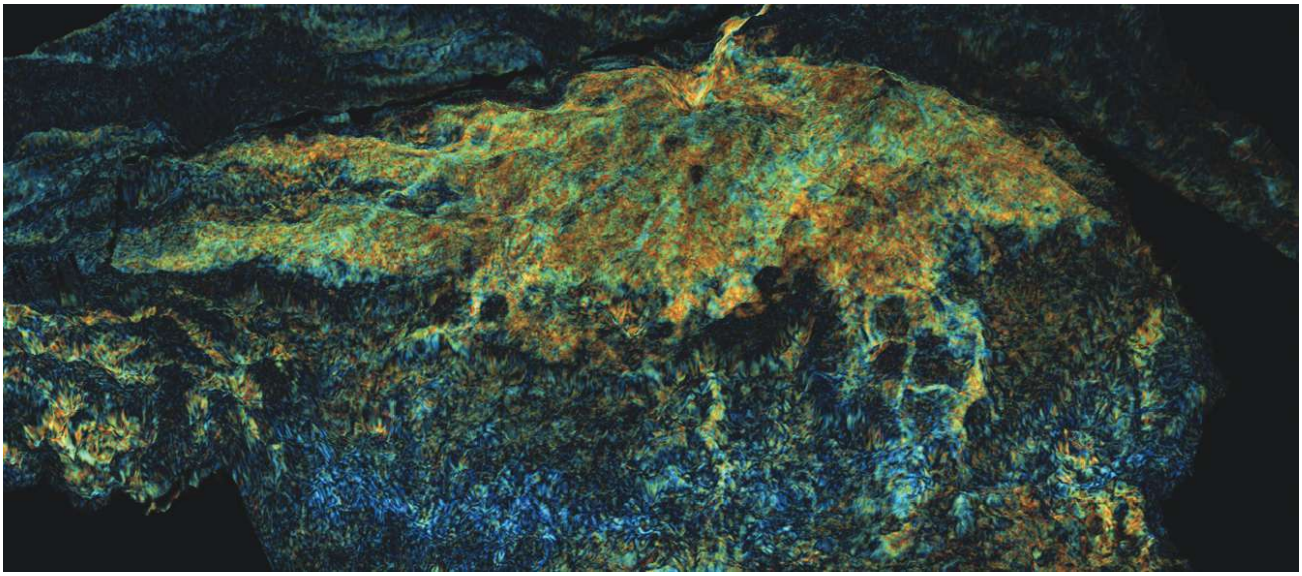
Regional look

The survey covered the West Orphan Basin located within the area of the Canada-Newfoundland and Labrador Offshore Petroleum Board 2016 Eastern Newfoundland Call for Bids. It's part of a longer term goal to assess the vast stretches of virtually unexplored territory belonging to the country.

"We are focused on advancing exploration activity that will scientifically assess our entire offshore. This can only be accomplished by utilizing state-of-the-art technology to acquire the highest quality data to form the greatest understanding of its potential," said Jim Keating, executive vice president of Corporate Services and Offshore Development at Nalcor Energy. "The 3-D seismic survey added an additional layer of insight that has played an essential role in helping us risk reduce key prospects from a one-in-20 to a globally competitive one-in-six chance of success."

According to a paper presented at the recent Society of Exploration Geophysicists annual meeting and authored by several people from Nalcor as well as PGS and TGS, which conducted the seismic survey, and Airbus Defence and Space, which conducted the seep survey, the new data provide evidence of potential hydrocarbon sourcing and migration. Material sized prospects have been imaged, it stated.

The 3-D survey, which covered 4,600 sq km (1,776 sq miles), used 8-km (4.9-mile) streamers, and the authors



From the fast-track 3-D study a 3-D perspective view of a spectral decomposition image of a sediment source channel (near top of image) and a deepwater fan complex can be seen. (Source: PGS)

noted that this is important to properly image the potential targets. "The recent 2-D lines that uncovered the play trend demonstrated that the long-offset cable length was highly important in finding this play as the Oligocene, Eocene and Paleocene sands in this area are characterized by Class II AVO [amplitude vs. offset] responses, and the turbidites and fans are only properly imaged by looking at the full range of angle stacks out to far angles. … The shorter cable legacy data in the area did not image these features due to the limited angle range available."

The comprehensive nature of the data gathering is paying off. The authors noted that when the Lower Tertiary trend was first identified, the nearest 2-D line was 60 km (37 miles) away. An infill program helped assess the regional extent of the play and determined that it generally follows the present-day bathymetric contour in this part of the basin. That, in turn gave some of the seep data more potential context as well.

"There were a number of satellite slicks imaged around the present-day shelf break updip from the turbidite complexes at the paleo toe of the slope," the authors noted. "In addition, there were potential DHIs [direct hydrocarbon indicators] imaged updip along the Eocene unconformity … This could potentially be evidence of a petroleum system in the region, though much work remains to evaluate the presence and maturity of potential sources in the region."

Early results from a 2015 seabed coring program also indicate that thermogenic hydrocarbon sources exist in the area, they added.

The 3-D survey has added insight into the sand distribution and potential charge in the Lower Tertiary units. The authors included a far-angle depth section from the fast-tracked 3-D volume that shows evidence of an Eocene turbidite fan prospect underlain by the Paleocene and a thick section of Mesozoic-age formations. Within the section is a potential chimney feature, possibly evidence of a mud volcano.

It also contains a flat spot with negative trough amplitudes higher above the spot than they are below. The authors reported that evaluation with seismic amplitude characterization and rock physics modeling is underway to separate lithology effects from fluid effects. "With the thickness and nature of units potentially in the maturity window and possible DHI evidence (chimneys, flat spots, etc.), there are early indications of potential hydrocarbon charge existing in this newly defined play trend," the authors wrote. "To further advance our understanding of the nature and characteristics of these fan features, we have undertaken additional work on seismic inversion and spectral decomposition." The spectral decomposition shows a sediment source channel and a deepwater fan complex.

Overall, the Nalcor authors have been quite encouraged by the information revealed in the 3-D survey. "These studies will help to further de-risk this region as exploration advances in this newly defined play trend," they wrote. E&P

1 US

Statoil completed an extended-reach horizontal Bakken and a Three Forks producer from a common drillpad in Section 8-152n-98w in McKenzie County, N.D. The #1H Cheryl initially flowed 4.209 Mbbl of oil, 296 Mcm (10.461 MMcf) of gas and 3.189 Mbbl of water per day. Production is from a horizontal lateral in Middle Bakken extending from 3,523 m (11,558 ft) southeastward to 6,581 m (21,590 ft). It bottomed in Section 21-152n-98w, and the true vertical depth is 3,448.5 m (11,314 ft). It tested a $^{44}/_{64}$-in. choke following 39-stage fracturing. The #6TFH Cheryl 17-20 was tested flowing 1.979 Mbbl of 46.1-degree-gravity oil, 134 Mcm (4.743 MMcf) of gas and 5.012 Mbbl of water per day from Three Forks. The 6,541-m (21,460-ft) well has a true vertical depth of 3,440 m (11,286 ft) and is producing from 3,561 m (11,684 ft) to 6,541 m after bottoming to the south in Section 20-152n-98w. It was tested on a $^{46}/_{64}$-in. choke after a 38-stage fracture treatment.

2 Colombia

Gran Tierra Energy reported drilling and completion results from two development wells in the Putumayo Basin in Colombia. The #5-Acordionero was completed and cased as a Lisama A and C producer, with 304 m (997 ft) of gross oil pay. An electric submersible pump was installed and is flowing 1.557 Mbbl/d of oil with a gas-oil ratio of 2.7 cu. m/bbl (98 cf/bbl) and 1% water-cut. Additional completion information has not been released. The rig is being moved to horizontally drill #7-Acordionero and will test Lisama A with a planned depth of 3,320 m (10,894 ft). In the PUT-7 Block the company completed exploratory well #1-Cumplidor in N Sands. It was drilled to 3,438 m (11,280 ft), and the true vertical depth is 2,865 m (9,399 ft). It hit 20 m (65 ft) of a gross interval in N Sands, with two sands having 10 m (34 ft) of interpreted net oil pay based on LWD. Logging also confirmed average porosities of 21%, with maximum porosities of up to 28%. The well has been cased, and additional testing is planned. The rig will be moved to drill #1-Alpha in the same block to test N Sands.

3 Guyana

ExxonMobil Corp. reported results from appraisal well #3-Liza on offshore Guyana's Stabroek Block. The estimated recoverable resources in the field will be in line with the previously predicted volume range from 800 MMboe to 1.4 Bboe. A development plan for the Liza Field has been submitted to Guyana's Environmental Protection Agency for review. Two rigs are planned for development drilling, with production from an FPSO vessel capable of handling some 100 Mbbl/d of oil. Current expectations are that Liza will come onstream in 2020 to 2021.

4 UK

IGas Energy has received permission to drill two exploratory tests in Misson Springs, North Nottinghamshire in East Midlands, England. One vertical well and one horizontal well are planned. The exploratory tests are targeting Bowland Shale as well as possible coalbed methane deposits for development in North Nottinghamshire. Partner in the development, Total, has a 40% stake in the license area PEDL 140. The exploration area is in the Gainsborough Trough.

5 Morocco

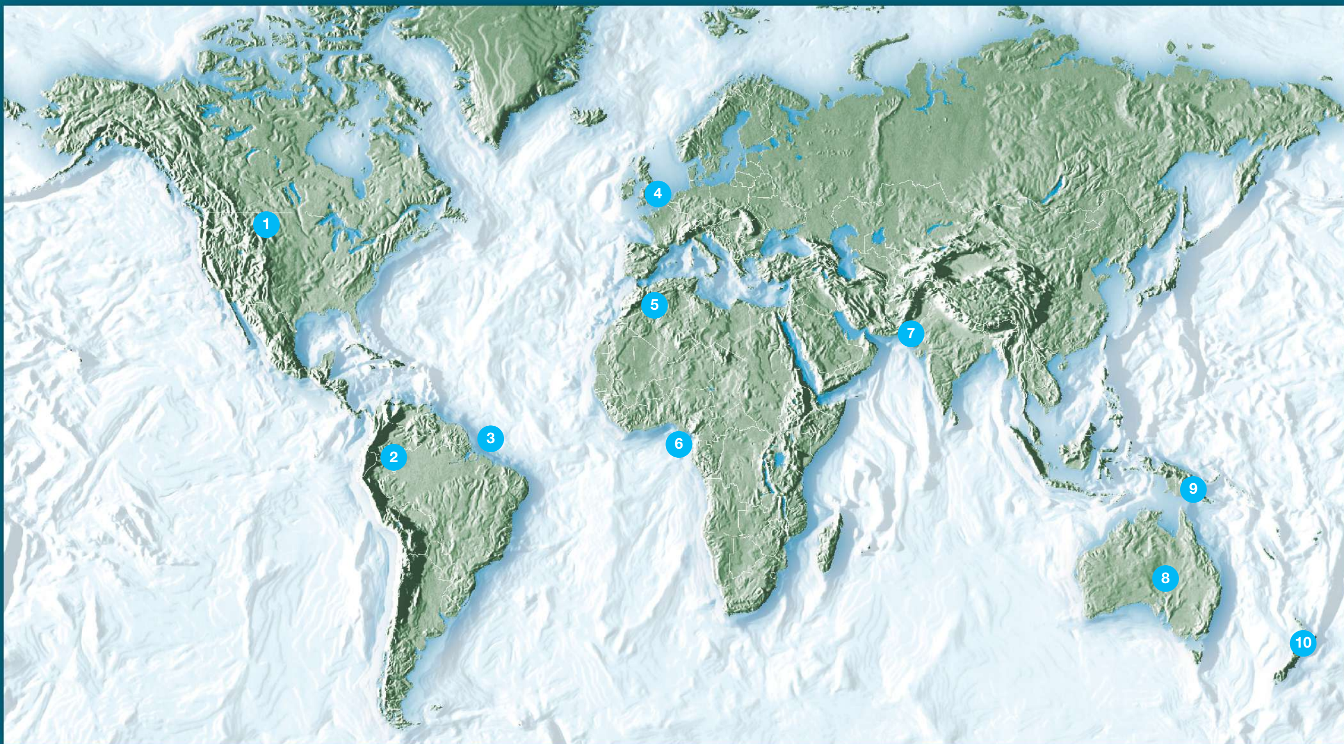
Sound Energy Plc reported results from discovery #7-TE in eastern Morocco's Tendrara license. The well was drilled to 3,459 m (11,348 ft) and is producing from an 837-m (2,746-ft) section in the TAGI reservoir, including a 700-m (2,296.5-ft) sub-horizontal section. During a flowtest on a $^{32}/_{64}$-in. choke, it produced 249 Mcm/d (8.8 MMcf/d) of gas from an unstimulated openhole test of the first 28% of the gross reservoir interval. Sound Energy plans to perform a mechanical stimulation and well test of the entire sub-horizontal section, with an extended well test to confirm production sustainability and to aid field development planning. The company has a net effective interest of 27.5% in the Tendrara license.

6 Nigeria

An offshore Nigeria discovery has a potential recoverable resource of between 500 MMbbl and 1 Bbbl of oil. According to operator ExxonMobil Corp., the Owowo Field well, #3-Owowo, hit about 140 m (460 ft) of oil. The #3-Owowo extends the resource discovered by #2-Owowo, which encountered about 157 m (515 ft) of oil in a sandstone reservoir. The #3-Owowo was drilled to 3,173 m (10,410 ft) and is in 576 m (1,890 ft) of water in OPL 223.

7 Pakistan

In onshore Pakistan's Khewari Block, Oil & Gas Development Co. Ltd. hit gas at a site in the Sindh Province's Khairpur District at exploration well #01-Mithri. It was drilled to 4,250 m (13,943.5 ft) and flowed 182 Mcm/d (6.44 MMcf/d) during testing on a $^{32}/_{64}$-in. choke with a wellhead flowing pressure of 1,600 psi. Production is from the Lower Goru (Massive Sand).



8 Australia

In South Australia's Cooper Basin Block PEL91 Beach Energy reported results from a Western Flank exploration well, #1-September. The exploratory well targeted Poolowanna oil in a structural closure within Namur Sandstone and tested the McKinlay Member, Birkhead and Poolowanna as secondary targets. The well intersected an 8-m (26-ft) gross interval with oil shows within Poolowanna. A drillstem test was performed between 1,928 m and 1,936 m (6,325 ft and 6,352 ft) and recovered 15.2 bbl of 42-degree-gravity API oil at a calculated flowrate of 210 bbl/d. It has been cased and suspended as a future oil producer. This discovery validates the Poolowanna as an additional exploration target within the PEL91 permit area. Review of the results is underway, and further production testing is planned to confirm the size of the resource. Further mapping of the Poolowanna oil play will occur in 2017, with potential appraisal and near-field exploration activities during 2018.

9 Papua New Guinea

InterOil Corp. is underway at appraisal well #7-Antelope in PRL 15 in Papua New Guinea. According to the company, the well is designed to provide structural control and reservoir definition on the field's western flank. The proposed true vertical depth is 2,300 m (7,546 ft), and it is about 1.5 km (.93 mile) southwest of appraisal well #5-Antelope.

10 New Zealand

Preliminary test results were announced by TAG Oil Ltd. from the #1-Supplejack discovery well. The venture is in Block PEP57065 in the onshore Taranaki Basin on New Zealand's North Island. During a production test the well flowed 198 Mcm/d (7 MMcf/d) and was constrained by surface facilities. Wellhead pressures during the test were sustained at more than 1,000 psi. The well was originally drilled in 2005 and was completed in an oil-bearing zone but was shut in after failing to produce commercial quantities—analysis of well logs identified a gas pay zone in an upper formation. Additional well testing is planned by the company. E&P

PEOPLE

Frank's International named **Douglas Stephens** president and CEO.

ENGIE Fabricom, part of the global energy group ENGIE, selected **Wichard Huigen** as CEO for the U.K.


Jannicke Nilsson (top) has been appointed executive vice president and COO of Statoil ASA. She takes over the role from **Anders Opedal** (bottom), who will lead the development of Statoil's operations in Brazil as new country manager.

Arcadis selected **Peter Turton** as vice president and project director.

Wood Group appointed **Jan Dell** vice president of clean energy.

Jim Hengehold, senior vice president, engineer, and **Frank Parker**, senior vice president, manning manufacturing, retired at year-end 2016 from Powell Valves.

CMS Energy named **Jean-Francois Brossoit** vice president of transformation and shared services.

Global Maritime Consultancy & Engineering appointed **Imraan Bux** to its Ports & Shipping team as principal port engineer, based in London.

Abrado Wellbore Services named **John Martin Donachie** international commercial director.

Silicon Microgravity Ltd. (SMG), a newly formed University of Cambridge spinout, has formed an advisory board with BP Ventures to explore future cooperation around borehole microgravity logging technology for use in oil and gas exploration. The advisory board comprises **Luis Alcoser** and **Robin Wye** from BP and **Paul Vickery** and **Francis Neill** from SMG.

Greyrock Energy Inc.'s board of directors has been expanded to include **Andrew Hinkly** and **Charles Williamson**.

The board of Woodside has appointed **Ian Macfarlane** a non-executive director. Macfarlane joins Woodside as an independent director.

Decom North Sea elected eight new board directors: **Simon Gibb**; **Kevin Illingworth**; **Dick Lagerweij**; **Donald Martin**; **Mike Pettigrew**; **Will Rowley**; **Ron van der Laan**; and **Tiana Walker**. In addition, **Andrew Sneddon** was reelected as director to the board.



The PESA board of directors approved three new advisory board members: **Kyle Chapman** (top left), Weatherford International; **Michelle Lewis** (top right), DistributionNOW; and **Josh Lowrey** (bottom), Galtway Industries.

COMPANIES

NorSea Group (UK) Ltd. and **Scotoil Services Ltd.**, two service companies in the onshore decommissioning sector, have joined forces as **NSDecom**. The new collaborative venture will provide a single project focal point for all services related to quayside and onshore decommisioning activity.

InterMoor, an Acteon company, has added inspection and testing capabilities to its marine base at the Açu Superport in São João da Barra, northern Rio de Janeiro.

Data Harmonix Corp. announced the formation and launch of a new Energy Services Tech company operating under the same name. Energy Services Tech is a disruptive new type of organization in the $150 billion-plus global energy services market.

Saudi Aramco has acquired the Converge product line and associated operations and technologies from **Novomer Inc.** The transaction was valued at up to $100 million.

HTL Group has relocated to a facility on Raith's Industrial Estate in Aberdeen. The move from HTL's facility in Dyce to Raith's Industrial Estate gives the opportunity to introduce the HTL Group's complete range of products and services delivered via **HTL Group Scotland**.

Churchill Drilling Tools has opened a bespoke tooling and service workshop in Abu Dhabi, United Arab Emirates.

Wellsite Fishing and Rental Services LLC has created a new division, Cornerstone Completion Services.

Alphastrut, a supplier of aluminum support systems and handrails to the offshore oil and gas and marine sectors, has opened an office in Norway.

OMV agreed to sell 100% of the shares in its wholly owned subsidiary **OMV (U.K.) Ltd.** to **Siccar Point Energy Ltd. Aberdeen**. The overall transaction value is up to $1 billion.

E&P

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on the MOVE

Ophir Holdings & Ventures Ltd. and **OneLNG** have signed a binding shareholders' agreement to establish a joint operating company to develop the Fortuna project in Block R offshore Equatorial Guinea using **Golar LNG Ltd.'s** floating LNG technology.

Rubicon Oilfield International has acquired **Top-Co Holdings Inc.**, a supplier of oilfield casing, cementing and completion products.

Lloyd's Register has acquired **RTAMO Ltd.**, a software-enabled consultancy that provides data-driven solutions.

Perella Weinberg Partners and **Tudor, Pickering, Holt & Co.** have entered into a definitive transaction agreement under which the two companies will combine. The combined firm will be called Perella Weinberg Partners, and TPH's energy practice will continue to operate as Tudor, Pickering, Holt & Co.

Woodside entered into binding sale and purchase agreements to acquire half of **BHP Billiton's** Scarborough area assets in the Carnarvon Basin, located offshore Western Australia, in September 2016. The acquisition was completed in November 2016 for a purchase price of $250 million and a contingent payment of $150 million payable upon a positive final investment decision to develop the Scarborough Field.

Drillinginfo acquired the assets, product lines and related services associated with **Ponderosa Energy**.

The Canadian Natural Resources Limited Engineering Complex at the Schulich School of Engineering opened in November 2016. The expansion added 18,300 sq m (196,979.5 sq ft) of new space, accommodating an additional 400 student spaces at the University of Calgary's Faculty of Engineering. Another 11,100 sq m (119,479 sq ft) of existing space is still being renovated as part of the project and is expected to be complete in 2017. E&P

ADVERTISER INDEX

Flexibility and cost effectiveness are new norm

The one-size-fits-all approach is no longer applicable in today's oil and gas sector.

Patrick Babka, Emerson Automation Solutions

Even though the oil and gas sector is facing tough economic challenges, its on the cusp of a new technological revolution—a revolution that is primarily driven by the operators.

Like many industries, the main drivers of this technology revolution involve the need to reduce costs while making incremental improvements on the benefits that these technologies deliver. The pace of this operator-driven revolution has been dramatic over the past few years.

To meet customer needs, especially in the current environment, vendors should be asking themselves key questions related to current offerings: Could my technologies be smarter and easier to use? Could my technologies be more flexible? And most importantly, could my technologies be more cost-effective while still improving customer benefits? Suppliers also still need to ensure that their margins are commercially viable.

While many in the industry focus on digital and IT developments for smart technologies, the best example of a move toward smarter, flexible and cost-effective technologies involves a more traditional oil and gas technology: multiphase meters.

Multiphase meters and their ability to accurately measure the flow rates of oil, gas and water are a vital cornerstone of reservoir and production management. Such meters generate crucial information on well performance and the conditions that affect production flows.

Yet too often in the past multiphase meters have been considered unwieldy and expensive. Many operators have been put off by the scale and potential expense of such deployments as well as the inability to change the solution mid-course.

With the well testing alternative unable to provide real-time flow rate information, operators have been left in the unenviable position of having to choose which wells warrant multiphase meters to control capex.

Thus, at a time in the industry when accessing real-time flow rates and ensuring that wells are performing to their optimal potential has never been more important, operators are having to make compromises.

With multiphase meters, however, the industry is charting a way forward—a path that other technologies should adopt.

This path is based on stripping away the complexities around multiphase meters, establishing a proven measurement technology platform on which all meters can be based and then developing different versions of the meter that can be mixed and matched into a variety of configurations depending on the required operator application. Operators only pay for the features they require.

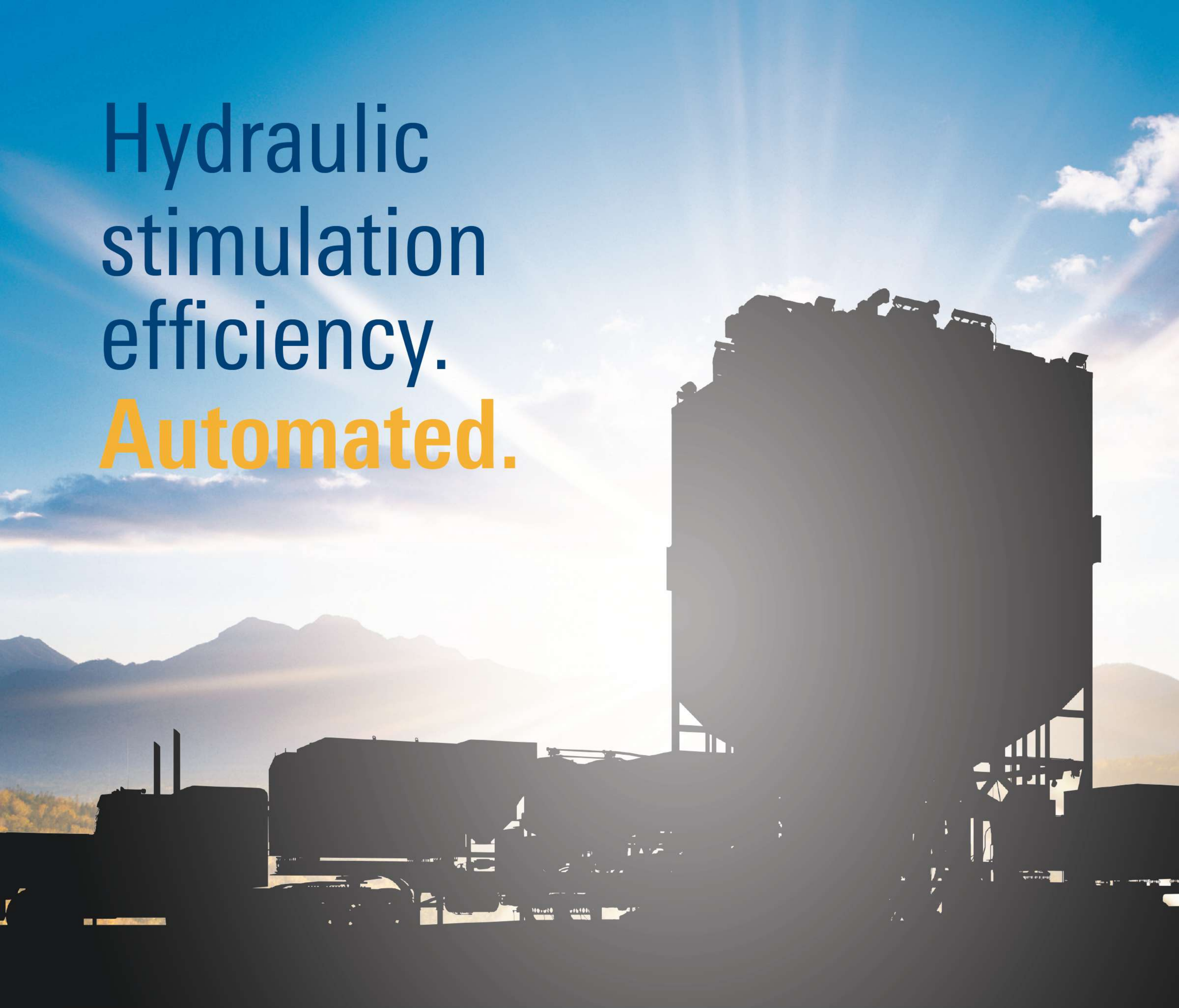
Such applications might include oil or wet gas wells, direct wellhead monitoring, multiwell testing, allocation and fiscal metering, or shale well flowback monitoring. These applications don't require a one-size-fits-all approach but rather flexible, configurable and customizable solutions that not only meet the operators' reservoir management needs but also their budgetary ones.

Furthermore, such flexible and modular multiphase metering technologies have the added benefit of being able to evolve over time as the field and flow conditions change, such as when a field has increased salinity or the growing presence of formation water.

Rather than being dependent on one technology solution for the lifetime of the well with the potential of risk of failure and increased maintenance, the different configurations can be customized according to the here and now. The result is greater simplicity and efficiencies, a truly smart solution and a future where an operator can have a multiphase meter on every wellhead.

Multiphase meters are just one example of how technologies have to adapt to meet operators' changing requirements. Just as multiphase metering technologies are rising to the challenge, there's no reason that other production technologies, from multiphase pumping to subsea separation, shouldn't do so too.

The one-size-fits-all approach is no longer applicable in today's oil and gas sector. A new technology revolution based on flexibility and cost-effectiveness is upon us. Operators who take advantage of flexible solutions will survive and thrive. E&P



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