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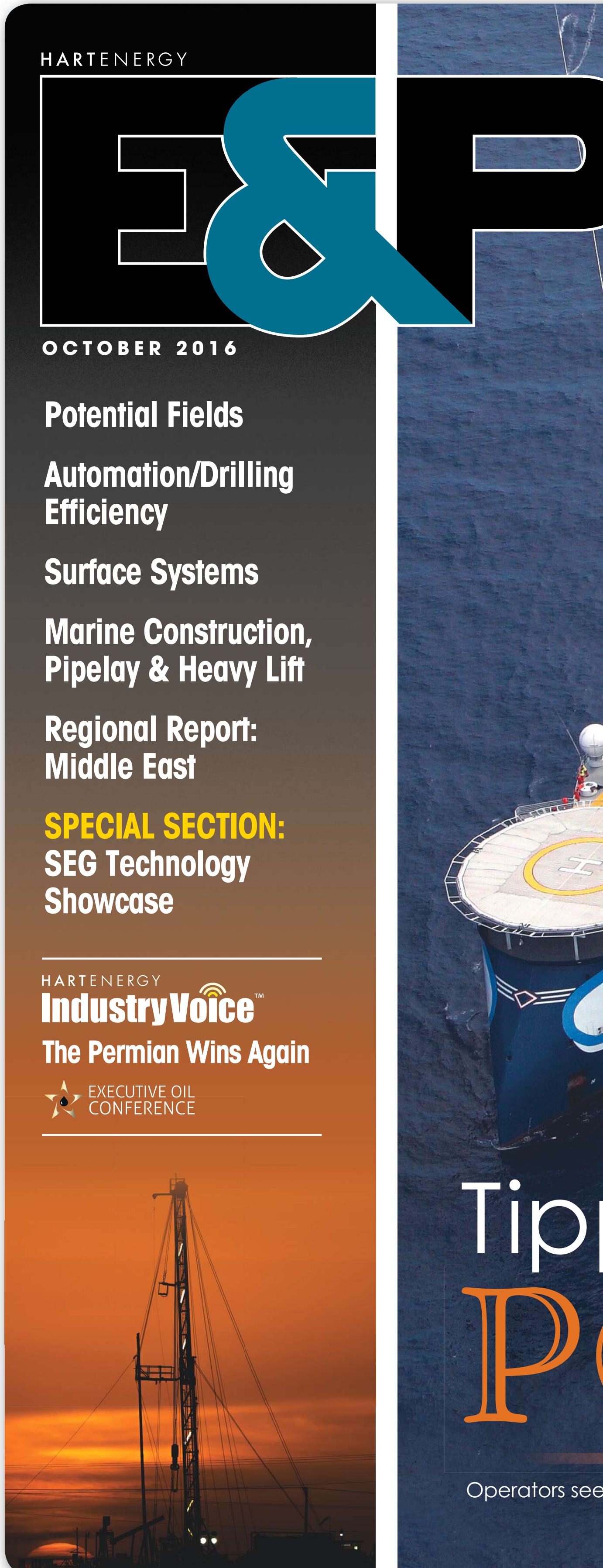
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Apache CEO to Discuss 'Alpine High' Discovery

Apache Corp. recently announced its discovery of a significant new resource play called **Alpine High**. It has identified **3,000+ future drilling locations** in the Barnett and Woodford shale formations alone. Hydrocarbons in place include an estimated **75 trillion cubic feet (Tcf) of rich gas and 3 billion barrels (Bbbl) of oil**. The new play also has significant oil potential in the shallower Pennsylvanian, Bone Spring and Wolfcamp formations.

"We are incredibly excited about the Alpine High play and its large inventory of repeatable, high-value drilling opportunities," **John Christmann, Apache's CEO and president**, said. "We have thousands of low-risk locations in the Woodford and Barnett formations alone, and we are looking forward to further delineating what we believe will be a significant number of oil-prone locations in the Pennsylvanian, Wolfcamp and Bone Springs."

Christmann is set to discuss **Apache's plans for the discovery** during a keynote address entitled 'Alpine High & Permian-Wide' at 1:15 p.m. Tuesday, November 8, during Hart Energy's 2016 **Executive Oil Conference**. Learn more.

Keynote Speaker:

John Christmann
CEO & President
Apache Corp.

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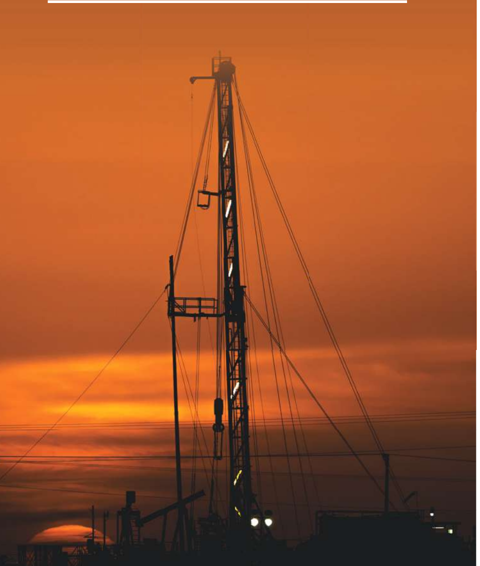

Tipping POINT

Operators seek solutions to turn around global exploration decline

EXPLORATION & PRODUCTION
WORLDWIDE COVERAGE

OCTOBER 2016
VOLUME 89 ISSUE 10

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The Permian Wins Again

The contrarian basin

Look at West Texas' Permian Basin and you see a more positive story than in other oil-producing regions. With unmatched economics, robust midstream infrastructure and layer upon layer of productive formations, the Permian Basin has become a lightning rod of activity (and profit) for producers and investors alike.

According to ***Oil and Gas Investor***, in 2016, the region has seen more than 25 deals of at least $20 million, for an estimated total of $12.3 billion. In the past 30 days alone, Midland and Delaware Basin transactions have accounted for $6 billion.

Are we in the beginning stages of a market recovery? That's certainly up for debate. But one thing is for sure– the Permian Basin is experiencing a resurgence of activity. U.S. rig counts are on the rise, and the Permian leads the way. Permian rig counts are up nearly 50% in recent months, accounting for almost half of all active U.S. rigs.

For almost a century, the Permian Basin has been a cornerstone of the U.S. oil and gas industry. It doesn't look like that trend will end anytime soon.

Region-specific market intelligence

Hart Energy's 22nd annual **Executive Oil Conference**, scheduled Nov. 7-8 in Midland, Texas, will unite the region's top players for an in-depth look at activity across West Texas. Industry professionals seeking ways to stay connected to the latest intelligence coming from the Permian should attend. The event has more than 15 executive-level speakers in 11 conference sessions, more than 60 exhibitors showcasing efficiency-focused solutions, and 9 hours of networking events.

The hallmark of the **Executive Oil Conference** is its world-class speaker lineup. Presenters like Pioneer Natural Resources Chairman and CEO Scott Sheffield, Apache CEO and President John Christmann and Approach Resources Founder, Chairman, President and CEO J. Ross Craft will provide insights on key topics, such as:

- **Superior wellhead economics:** Pioneer's Sheffield claims Saudi-like production costs. What's the secret? How sustainable are the margins?
- **The outlook for oil prices:** It all comes down to the price of oil. Is $40 the new $60? Can producers expect $80 again?
- **Investment opportunities:** What commodity-price point or sales metric is needed to make sellers willing to place acreage on the market? Is private equity still in the hunt, or is it too late for newcomers to get in?

Visit **ExecutiveOilConference.com** to keep up with speaker announcements as the ambitious agenda is completed. Hart Energy strives to produce relevant and timely programs.

Permian deep and 'Alpine High'

Apache's Sept. 7 Alpine High announcement sent ripples through the industry because of the sheer size of the find. Located in an overlooked portion of the Delaware

"The Permian stands as an outlier—a contrarian basin in 2016. Operators here have added rigs, made flashy A&D transactions and cranked up production."

—Oil and Gas Investor

Basin, Alpine High is estimated to hold 75 trillion cubic feet of rich gas and 3 billion barrels of oil. To put that in perspective, the company estimates the new play could be worth at least $8 billion. Apache CEO and President John Christmann is set to share the company's plans for this major resource play discovery with the **Executive Oil Conference** audience through his presentation and Q&A session.

Honoring a legend

Beyond his keynote address, Scott Sheffield will be honored with Hart Energy's inaugural Industry Leadership Award at the **2016 Energy Executive Dinner**, scheduled for 6:00 p.m. Nov. 7 at the Midland Country Club. Few industry leaders have left their mark on the Permian Basin like Sheffield. Since joining the industry in 1979, he has ascended to Chairman and CEO of Pioneer Natural Resources–one of the region's largest independent E&P companies. Sheffield has announced his retirement later this year. But before he passes the baton, he will share his unique vision for the Permian.

Stay Connected—Networking opportunities

Beyond the conference room and 60-booth exhibit floor, the **Executive Oil Conference** offers networking opportunities at the annual golf tournament (which sells out each year) and the **Energy Executive Dinner** (featuring awards from Hart Energy and Hearst). The event is sponsored by finance and investment firms, operators and service and supply companies. A limited number of exhibit and sponsorship opportunities are still available.

After more than two decades in Midland, the **Executive Oil Conference** has had its three biggest years since 2013. Be part of the experience–register today. E&P

The **Executive Oil Conference** *takes place Nov. 7-8, 2016, at the Midland County Horseshoe Pavilion in Midland, Texas. To register to attend or learn more about exhibiting and sponsorship opportunities, please visit* **ExecutiveOilConference.com**.

DEPARTMENTS AND COMMENTARY

COMING NEXT MONTH The November issue of ***E&P*** will focus on shales. Other features will include presalt/subsalt; land rig advances; onshore well intervention; and ROVs, AUVs and remote intervention. The regional report will focus on Southeast Asia. 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 CGG's *Ocean Sirius* cuts a lonely swath on a recent survey. The downturn has caused the rate of new discoveries to plummet. Left, a rig is outlined against the setting sun in the Middle East. The region is benefitting from new technology adoption. *(Cover image courtesy of CGG; left image courtesy of Murty/* Shutterstock.com*; cover design by Felicia Hammons)*

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ACTIVITY HIGHLIGHTS

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Grady County well flows 1.6 Mbbl/d of oil, 2 MMcf/d of gas

Citizen Energy II LLC has completed an undifferentiated Mississippian venture in Grady County, Okla. Located in Section 31-10n-w, #1H-32 Governor James B. Edwards flowed 1.6 Mbbl/d of 45-degree-gravity oil, 63,146.5 cu. m/d (2.23 MMcf/d) of gas and 757 bbl/d of water.

Faroe Petroleum announces results from Brage Field testing

Faroe Petroleum has completed and tested its wildcat #31/7-1 and appraisal well #31/7-1 A located in the North Sea. Total gross volumes of recoverable hydrocarbons are estimated to be 28 MMbbl to 54 MMbbl of oil and 2.5 Bcm to 4.4 Bcm (89 Bcf to 158 Bcf) of gas.

Samson gets permits for 12 Niobrara/Codell exploratory tests

According to IHS, Samson Resources Co. has been granted drilling permits for 12 horizontal Niobrara/Codell exploratory tests in Laramie County, Wyo.

AVAILABLE ONLY ONLINE

Splashdown: Anadarko lands $2 billion Gulf deal

By Darren Barbee, Hart Energy

The company said cash flow will allow it to deploy two rigs to the Delaware and Denver-Julesburg basins.

Video vistas: Eyes on Eagle Ford

By Hart Energy

What oil price is needed for economical activity? What will drive those prices for the rest of the year? And is the Eagle Ford headed for consolidation? Attendees at Hart Energy's DUG Eagle Ford Conference and Exhibition in San Antonio were asked their opinion.

Demand seesaws for drilling services in Marcellus, Utica

By Hart Energy Market Intelligence Series

The oil price bump in June created additional inquiries on the availability of drilling rigs in the Appalachia. However, inquiries for rigs in the region also softened when oil fell in early August.

Subsea giant in the making tackles innovation, integration

By Velda Addison, senior editor, Digital News Group

By reinventing products, integrating technologies and simplifying architecture, FMC Technologies and Technip aim to redefine the subsea industry while improving project economics—as one company.


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On the shoulders of giants

The responsibility for surviving the downturn is being shouldered mainly by innovators and explorers.

When a leading CEO admits the upstream business got caught with its pants down, you know he's sincere.

Statoil's Eldar Sætre is a veteran—he was 10 years old when Norway spudded its first well—so he's seen downturns before. Speaking at the Offshore Northern Seas (ONS) event in Stavanger, he spoke of the industry facing not only new realities but also opportunities.

Sætre recalled at ONS 2014 the price was close to $100/bbl. "But the low oil price has exposed us all," he admitted. The industry needs a culture where it allows improvement, irrespective of where it is in the commodity cycle, Sætre said. It must continue changing how it works and must collaborate.

His clarion call was echoed by Saudi Aramco's senior vice president for Upstream, Mohammed Al-Qahtani, who said a downturn "is a prime time to look at project fundamentals through a lens. Reducing costs is a must. But it's a mistake to cut our ability to innovate."

The company wants to increase its reservoir recovery rates to 70%, which would lead to an estimated 900 Bboe resource base increase. It has been carrying out R&D for several years on technologies such as nano-scale reservoir robots, dubbed "resbots," to dramatically improve its reservoir management capability. "We have barely scratched the surface of technology development," he said.

Scott Sheffield, CEO of Pioneer Natural Resources, highlighted how in the U.S. Permian Basin the company has innovated by using wind power to supply electricity. Pioneer's breakeven in the Permian is $25/bbl, he said. By using wind to provide its electricity in Texas, the opex figure for those wells is just $2/bbl. It's innovative, not ironic, that Texas, the largest U.S. oil producer at 3 MMbbl/d, is also the country's second largest user of wind and solar power.

E&P's cover feature this month also highlights the other basic necessity—to keep finding hydrocarbons. Statoil's exploration chief, Tim Dodson, said at ONS, "If we stand still, the world will just not have enough oil and gas to meet demand. We need to explore to fill the gap. The industry has depleted its stock of fields, so new discoveries need to be made. In any province the biggest discoveries are usually made fairly early in their exploration. So opening up new areas like the Barents Sea is a must. We need to test big structures."

Luca Bertelli, Eni's chief exploration officer, pointed out without hesitation to delegates that its giant Zohr gas field in the Mediterranean will go from 849 Bcm (30 Tcf) discovery to first phase production in just 28 months. The block was only awarded to Eni the year before Zohr was drilled.

The industry is clearly transitioning how it works. If it is to survive and prosper, it will be, as Sir Isaac Newton said, "by standing on the shoulders of giants." E&P

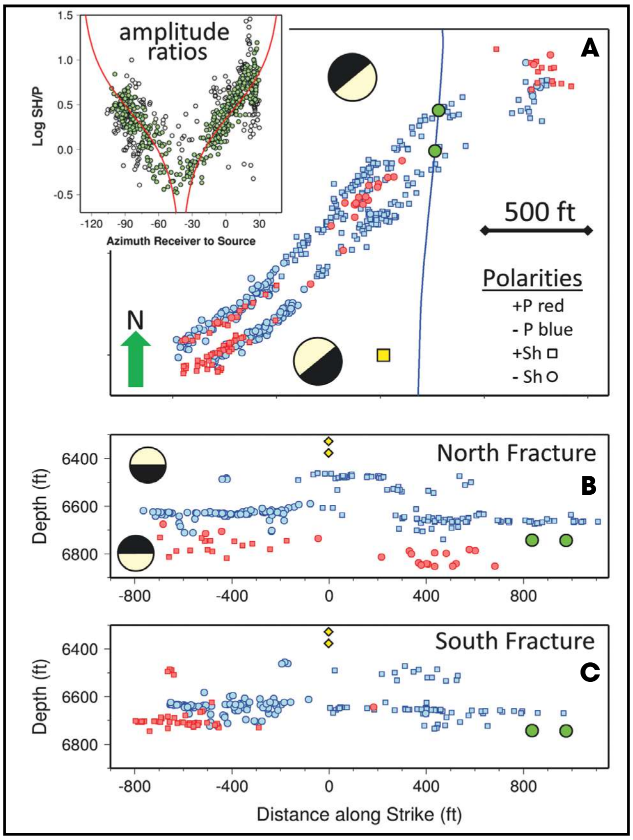
A passive microseismic shakeup

Science needs to trump market perception.

Stephen Wilson, Seismogenic Inc.

The prospect of using higher value microseismic products founded upon the application of advanced location methodologies, mechanism estimation and the increased understanding of the physics of rock failure and its seismogenic expression is an exciting concept. However, current market conditions are pushing service providers back into a low-cost model founded upon overly automated location estimation with undeclared location error, mechanism estimates with questionable robustness and an overly simple understanding of rock physics. This state of the market and its effect on product quality is in turn having a harmful effect on the perception of what is in reality a very useful diagnostic technology.

There is a great opportunity to use the improvements in this understanding to better characterize the hydraulic fracture from its seismogenic interaction with existing discontinuities and thereby constrain fracture models and forecast stimulation behavior.



Cloudy events provide cloudy interpretation

Let's start with some comment on the subject of error. In the geothermal world, in earthquake seismology and nuclear test ban monitoring the issue of error has been targeted, and systematic research has been carried out that has established straightforward methods for estimating and then reducing it. As Paul G. Richards noted at the Lamont Colloquium in 2002, "Whenever we have achieved orders of magnitude improvement in the accuracy of event locations over a wide area, we have gained new insight into earthquake physics and/or new insight into earth structure and processes."

The oil and gas industry would do well to follow the lead established by these other seismic disciplines, systematically applying advanced location methodologies and rigorously using error estimation as a metric of quality. Doing so will enable more sophisticated interpretation and decision-making and thereby improve the value of the product.

Figure 1 is taken from a paper by Rutledge *et al.* that shows where advanced location methodologies, source mechanism analysis and sensible interpretation can lead us. The figure illustrates a set of high-precision event

FIGURE 1. Microseismic locations for one stage from the Barnett Shale are shown. Two perforation intervals (green circles) spaced 61 m (200 ft) apart were stimulated simultaneously. Figure A is the plan view. Figures B and C are two separate fractures growing from the isolated perforation intervals that are resolved and displayed separately in depth. The data were acquired on a 20-level vertical array of three-component geophones spanning 290 m (950 ft). The monitor well is shown as the yellow square in figure A; the two deepest geophones are shown by yellow diamonds in the depth views in figures B and C. Figure A inset: The horizontal shear-to-compressional (Sh/P)-wave amplitude ratios averaged over the array are shown with respect to the azimuth from the monitor well. Red curves correspond to the theoretical Sh/P for the dip-slip first-motion fault-plane solutions displayed in plan view. (Source: Rutledge *et al.*, 2015. "Microseismic shearing driven by hydraulic-fracture opening: An interpretation of source-mechanism trends." *The Leading Edge. http://dx.doi.org/10.1190/tle34080926.1*)

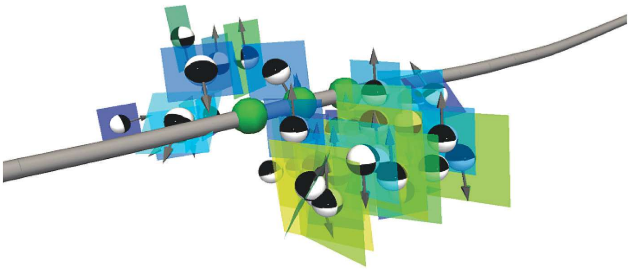


FIGURE 2. Microseismic events are represented as beach balls, failure planes and displacement vectors. (Source: Seismogenic Inc.)

locations (mean residual = 0.2 ms) that appear as very clear structural features aligning along bedding surfaces. Most intriguingly, the sense of displacement seems largely specific to each layer. If these active layers mark the upper and lower limits of fracture growth, such interpretation offers great scope for constraining the dimensions of the hydraulic fracture and feeding this information back into the fracture models.

To improve the quality of microseismic deliverables, the user of such services needs a useful comparative yardstick for quality. The industry is in need of a benchmark synthetic. Given such a yardstick, it will be possible to demonstrate how improved location and mechanism estimation drives interpretation. Operators will be able to establish what good locations and mechanisms are really worth. Furthermore, if the geomechanical sophistication and complexity of the synthetic can be improved over time, products can be tested and validated with the creation of best practice documents and increased understanding.

SEAM is actively pursuing the creation of a suite of synthetic microseismic datasets. The author would welcome any suggestion or comment regarding what the industry feels such a synthetic needs to encompass.

Fracture networks, marketing and science

The industry is enthusiastically trying to figure out how to use microseismic information to constrain understanding of stimulation performance and future production by creating microseismically derived fracture networks.

Although this approach is useful in pushing the boundaries of the technology, as commercial products these fracture network products often are insufficiently grounded in the physics of stimulation to provide meaningful constraint. Presently, the marketing is ahead of the science, yet this need not be the case if the industry can direct its attention to what is important.

Important topics or issues to address include:

- Creating a better understanding of the failure mechanisms and their associated seismogenic expression such that in the models the presence of an event is represented meaningfully.
  - o This would mean the inclusion of shear events relating to slip on existing features, extension-shear events associated with growth of the hydraulic fracture along existing discontinuities, bedding slip events that explain the propensity of half-moon mechanisms characteristic of some stimulations and finally the inclusion of the indirectly mapped "superhighway" of flow that is the largely aseismic hydraulic fracture.
- Dealing with the realities of microseismic physics and its detection.
  - o *Presence of multiplets*: Reduce each multiplet group to a single feature and thus avoid the conflation of error with spatial separation. This would then remove the problem of populating a volume with a catalog of discontinuities that do not exist;
  - o *Absence of microseismic evidence*: Recognize that absence of evidence is not necessarily evidence of absence and then find a method to sensibly fill in the gaps or accept that the constructed network is not an answer; and
  - o *Location error and mechanism robustness*: Establish clear location error bounds beyond which such network construction should be avoided.

So where does this all leave us?

Firstly, if readers agree or disagree with any of these statements and have evidence to back them up, they are encouraged to join in on discussions related to this topic on the LinkedIn Microseismic Technology group.

Secondly, those who buy or use microseismic services should not take this article as an excuse for avoiding their purchase. Due diligence and an insistence on the quality shown in Figure 2 will result in a positive outcome.

In terms of the future for microseismic technologies in oil and gas, the industry is at a bit of a fork in the road. On the one side, market conditions are pushing the business down a potentially dark and uninteresting path, but on the other is a potentially bright future as long as resources can be put into better understanding the physics of failure and its seismogenic expression.

There is useful information within microseismic data that is presently underused but that can help constrain fracture models and thereby improve the understanding and forecasting of stimulation performance.

To make this happen will take good benchmark synthetics and the surety that marketing always comes after the science, not before it. E&P

References available.

Norwegian Shelf's diet plan paying off

Evidence is increasingly emerging in Norway that its recent lean-and-mean approach is paying dividends, reducing previously prohibitive costs to economically viable levels.

Mark Thomas, Editor-in-Chief

The Norwegian Continental Shelf, like every other sector, has been on a dramatic diet for the past two years.

The slimming plan adhered to by Norway's technologically pioneering offshore industry is all about reducing the crippling weight of cost, something that for decades has been the sector's only real downside. Like all diets, there's no getting around the fact that to achieve the end goal, the slimmer has to stick to the plan or risk excess fat returning—and excess is something the upstream business can no longer afford.

Statoil has achieved a breakeven price on its Johan Sverdrup project currently under development of less than $25/bbl, while it has reduced the forecast breakeven price on a further 30 presanction projects to $41/bbl so far. (Source: Statoil)

With the oil industry's focus falling on Norway for the Offshore Northern Seas (ONS) event in Stavanger, it was time to step on the scales and tick off some milestones. Statoil did not disappoint, having worked hard to get itself into better shape.

The company's CEO, Eldar Sætre, was chief cheerleader at the show, and his passion on the subject was clear. "We face new realities but also new opportunities, so this is a time to lead and also to shape the industry," he said. "Culture and collaboration are key to the success of this transition: culture because fundamentally we have to change how we work; collaboration because the challenge is bigger than any challenge the company can do on its own."

Exposed

He admitted, "On the opening day at the last ONS two years ago the oil price was almost $100/bbl. But the low oil price has exposed us all. We need a culture where we allow improvement, irrespective of where we are in the commodity cycle."

Those words have been heard a little too often in recent years from various companies, with some dismissed as being little more than lip service to keep stakeholders at bay until the oil price turned upward once again.

However, with no upturn likely in the short term—if at all—Statoil and its partners have gotten on with the job and are producing tangible results that those improvements are taking effect.

A high-profile case in point is the operator's success in reducing the development cost of Phase 1 of its giant Johan Sverdrup project by 21% to NOK 99 billion (US$12 billion). It's done this, it said, while also managing to expand the full plan by adding an additional processing platform to the development's production capacity.

The 21% cut in forecast capex on the four-platform Phase 1 to NOK 99 billion is a reduction of NOK 24 billion (US$2.9 billion) from when the original plan for development and operation (PDO) was submitted along with an estimate of NOK 123 billion (US$14.9 billion).

Breakeven of $25/bbl

It also means the operator and its partners have achieved an impressive breakeven price for Johan

Sverdrup's Phase 1 of less than $25/bbl—an astonishing figure compared to Norway's offshore megaprojects of the past, which often had equivalent figures at least double this amount.

Contributing to this has been a focus on areas such as debottlenecking and optimizing the Phase 1 processing facility, resulting in the oil production capacity being raised from its original range of between 315,000 to 380,000 bbl/d to 440,000 bbl/d. Other improvements came from higher drilling and well efficiencies as well as better project planning and execution. Phase 1 production is planned for late 2019.

Statoil also has delayed the full-field development's schedule by about six months to further improve it but maintains that the full development's onstream date is still targeted for 2022. The PDO for Phase 1 originally called for project presanction of future phases this year, with an investment decision by year-end 2017. According to the updated plan, the project presanction will now be made in first-half 2017 with a final investment decision reached and the PDO submitted during second-half 2018.

With the addition to the plan of the extra processing facility—already agreed by the field partners but still subject to a formal presanction decision—Johan Sverdrup's eventual full-field production capacity is put at 660,000 boe/d. This compares to the original range of 550,000 bbl/d to 650,000 bbl/d.

Challenging every element

Lower end recoverable reserve estimates also have been firmed up and raised to a slightly higher range of between 1.9 Bboe and 3 Bboe, added Margareth Øvrum, the company's executive vice president for technology, projects and drilling.

She said the improvements in cost had been achieved "by challenging every single element." This has resulted in another impressive forecast breakeven figure for the full development of less than $30/bbl.

"At the same time, we want to stay on schedule for full-field production start and for establishing an area solution for land-based power by 2022 as per conditions stated in the approved PDO for Phase 1," she stated.

"It's a massive project. We're spending NOK 24 billion per year on it. But it is running to plan, and we have completed 31% of the first phase so far," said Øvrum, who pointed out that more than 70% of the Phase 1 contracts had gone to Norwegian companies.

She also stressed that further reductions might be on the way. "We still see further room for improvement. There's no time to relax," she said.

Other end of the scale

Toward the other end of the project development scale but reflecting the same focus on cost, Statoil also confirmed within the same 24-hr period that it had brought onstream a relatively small two-well subsea tieback project at half the development cost originally envisaged when it was first considered. It also was four months earlier than scheduled.

The operator gave itself an early Christmas present by confirming first production from the Gullfaks Rimfaksdalen Field well ahead of the planned startup on Dec. 24.

With the original development cost put at an eyebrow-raising NOK 8.8 billion (US$1 billion), hindsight begs the question as to why those costs were ever thought acceptable at any time.

However, according to Arne Sigve Nyland, Statoil's executive vice president of development and production, this was dramatically reduced through an intensive cost reduction exercise to NOK 4.8 billion (US$580 million) at the time of the submittal of the PDO. Since then, the good work has obviously continued, with the project's development cost now further reduced to NOK 3.7 billion (US$445 million), a much more acceptable figure.

Recoverable reserves from Gullfaks Rimfaksdalen are put at about 80 MMboe, mostly gas. Statoil is the operator with a 51% stake with its partners Petoro (30%) and OMV (19%). The standard subsea template development sits in a water depth of about 135 m (443 ft) with two gas production wells flowing and with the possibility for the tie-in of two further wells. The wellstream is connected to an existing pipeline leading to the Gullfaks A platform.

30-project pipeline

Looking farther ahead, Nyland also went on to highlight that Statoil currently has 30 projects in the nonsanction phase, where it also has brought its focus on costs to bear. According to Nyland, so far it has reduced the estimated breakeven cost for these 30 potential developments from $70/bbl to $41/bbl.

Referring to the cost efficiencies on Gullfaks Rimfaksdalen, Nyland admitted that when the project was first mooted it was clearly at a time of "higher oil prices but also higher costs." The oil price downturn, he said, has been "a true wakeup call for the entire industry," which for Statoil has meant having to improve its ways of working with its partners and suppliers.

Gullfaks Rimfaksdalen is perhaps symbolic of what can be achieved. The end result, he concluded, is that the project "is a sign of recovery—not of the market but that the industry is recovering. We are gradually regaining our competitiveness on the Norwegian Continental Shelf." E&P

Appalachian green shoots?

An improving natural gas market has Appalachian well stimulation providers hopeful for activity expansion.

Richard Mason, Chief Technical Director

Is Appalachia making the turn?

The region has clearly evolved into the center of the U.S. natural gas universe over the last half-decade with its astonishingly productive wells, whether located in the liquids-rich southwest quadrant of Pennsylvania or the state's northeast dry gas zone.

Signs of recovery may be in the air. Well stimulation providers tell Hart Energy they expect an increase in activity this winter as the natural gas storage overhang dissipates following another record-setting hot summer. Outside the industry some of the more optimistic pundits are talking about natural gas prices above $4/Mcf.

At first glance nothing appears to have changed in a region beset with takeaway challenges and flat activity levels. Horizontal rig count in the Utica Shale is bumping along at slightly more than a dozen units, with another couple dozen horizontal rigs active in Pennsylvania's Marcellus Shale. Neither tally has changed much since industry onshore rig count bottomed at the end of May.

- **Appalachian operators are reducing backlog of DUC wells.**
- **The regional market added three well stimulation crews.**
- **Well stimulation pricing is rising.**

Yet other signs provide hints of a winter-time expansion. Pricing for well stimulation is up 15% to $43,750 per stage on average vs. the regional bottom one year ago. Furthermore, average stage count per well rose 18% incrementally over the same time frame on the basis of longer laterals and a reduction in spacing between stages to as low as 46 m (150 ft) in leading-edge laterals. Average stage spacing across the region is now below 61 m (200 ft).

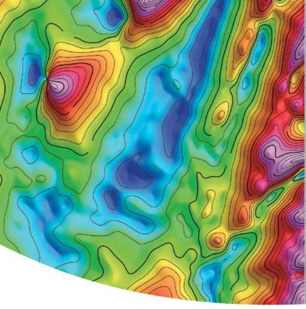
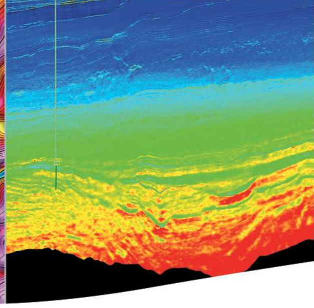
Although completion techniques remain remarkably uniform—slick water, plug and perf, and sand volumes in the 10.5 million pounds per lateral range—operators are finding additional ways to squeeze more natural gas goody out of those incredibly productive Devonian formations. Operators are employing data gathered during the horizontal drilling process to guide optimal placement of perforation clusters between stages to generate more efficient hydrocarbon harvest. That is partly what lies behind the headlines on the monster IP rates that have come out of the region this summer.

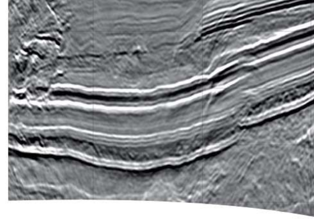
Meanwhile, operators are quietly working through the region's drilled but uncompleted (DUC) well backlog, with inventory dropping 10% to 15% during third-quarter 2016, according to participants in Hart Energy's *Heard in the Field* survey program. Indeed, the volume of zipper fracks, which is a proxy for batch completions, rose 11% to 59% sequentially during the third quarter, which suggests operators are finally addressing the DUC inventory. Operators also are completing more of the wells drilled on pads.

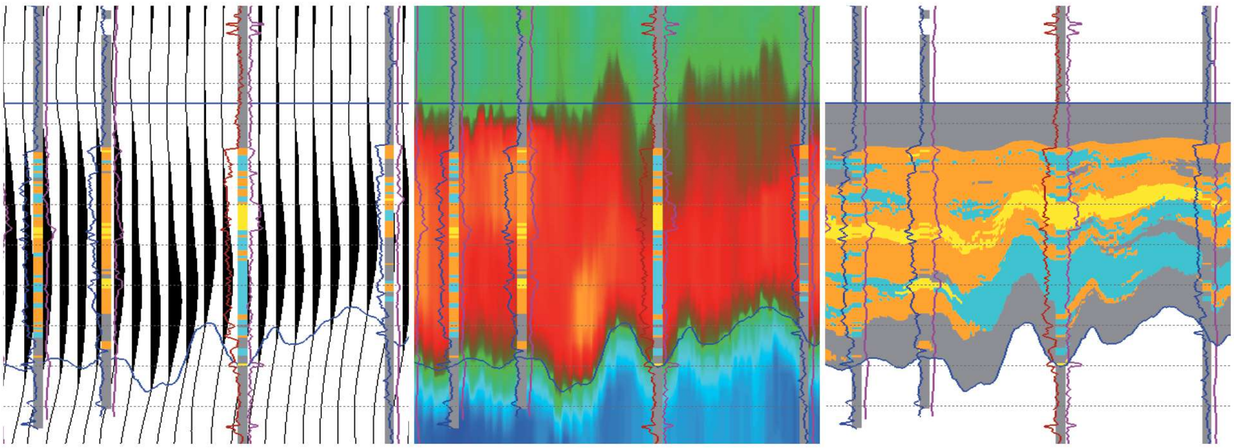
Other signs are evident in the slight increase in regional hydraulic horsepower (hhp) for well stimulation capacity to 830,000 hhp, plus the addition during third-quarter 2016 of three more frack crews to the market. Well stimulation is experiencing the first modicum of increased demand even as Appalachian workover contractors report an uptick in demand for routine maintenance on existing wells.

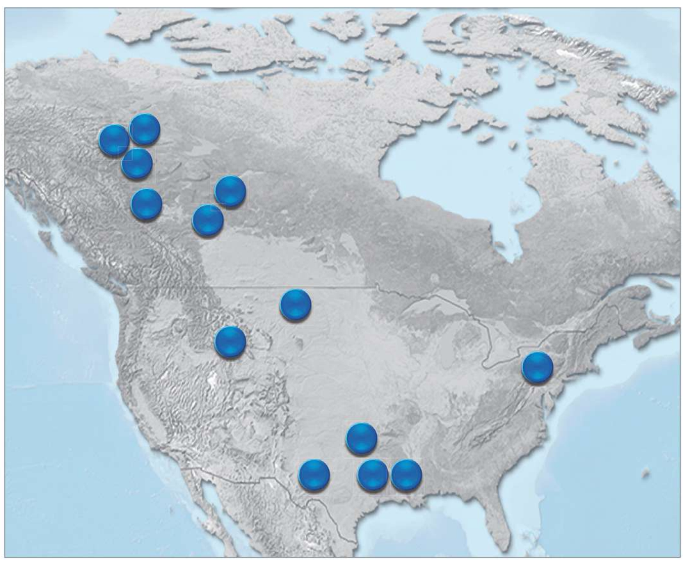
To date, drilling contractors have not reported an increase in demand for rigs this winter, which is confirmed by flattish trends in new well permitting. Although volume is lackluster, most new permits have been concentrated in southwest Pennsylvania. Indeed, 39% of new filings over the last six months centered on Washington and Greene counties in southwest Pennsylvania, with leading filers for new permits including Range Resources Corp., Rice Energy Inc., EQT Corp. and private equity-backed Vantage Energy.

Taken as a whole, the region is not out of the woods, especially when viewing third-quarter well drilling levels. But improvements in completion techniques might imply a need for fewer rigs. That said, Appalachian prospects appear to be improving. Just ask the well stimulation sector. E&P







Blast from the past

An old geophysical journal has found new life on the SEG website.

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Once in a while a story comes along that just screams "exploration technologies," and recently I was gifted with this one. Jim Sledzik, president and senior partner at Energy Ventures, made sure that this one found its way into my inbox. If one really needs a timeline of the evolution of geophysical technology over the past 60 years, one needs to look no farther than this.

Here is the description: "*Western Profile* was the employee magazine of Western Geophysical from the 1950s to 2000, when the company became part of Schlumberger and was renamed WesternGeco.

"*Western Profile* chronicles not only the development of geophysical technology but also tells the personal and timeless stories of geophysicists, mechanics, surveyors, land and marine personnel, administrators, safety professionals, engineers, and the many other skillsets required in the ever-changing search for hydrocarbons.

"The *Western Profile* historical archive came to life on the SEG [Society of Exploration Geophysicists] website through a collaboration of interested parties. Gary Jones had the idea of preserving such history for coming generations. Rhonda Boone, long-time managing editor of *Western Profile* and today a communications consultant to Schlumberger, provided him with a complete set of bound magazines. Richard White, Jeff Springmeyer and Jones underwrote the scanning of the entire collection under the guidance of Mike Forrest and Bill Barkhouse of SEG, who recognized the value of this archive and were instrumental in seeing the project come to fruition."

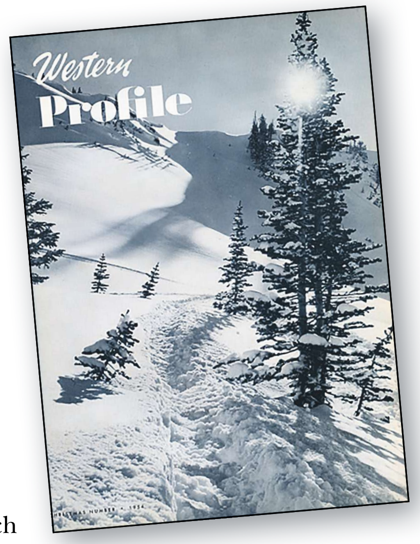
What an undertaking! And what a very generous gift to the geophysical community. Naturally I had to poke around, and here are some of the gems that I found.

January 1954. In the inaugural issue, then-president Henry Salvatori noted that the magazine was being launched because employees requested it. "With the far-flung nature of our operations and the continuous changing of field locations, you told us that a magazine would serve to maintain contact with your employee friends," Salvatori wrote.

The issue also commemorated the one-year anniversary of the company's research laboratory in Los Angeles as well as including articles penned by several company employees. These are loving snapshots of the crews and their families, with one anonymous author noting, "When the words 'magazine' and 'writing' were mentioned to me, my first thought was 'Oh, horrors.'"

And then they chose to rerun an article that ran in the January 1950 issue of *The Reader's Digest* about a gas station attendant in Ohio who pulled people out of auto wrecks in his spare time. Still looking for that perfect tone, apparently.

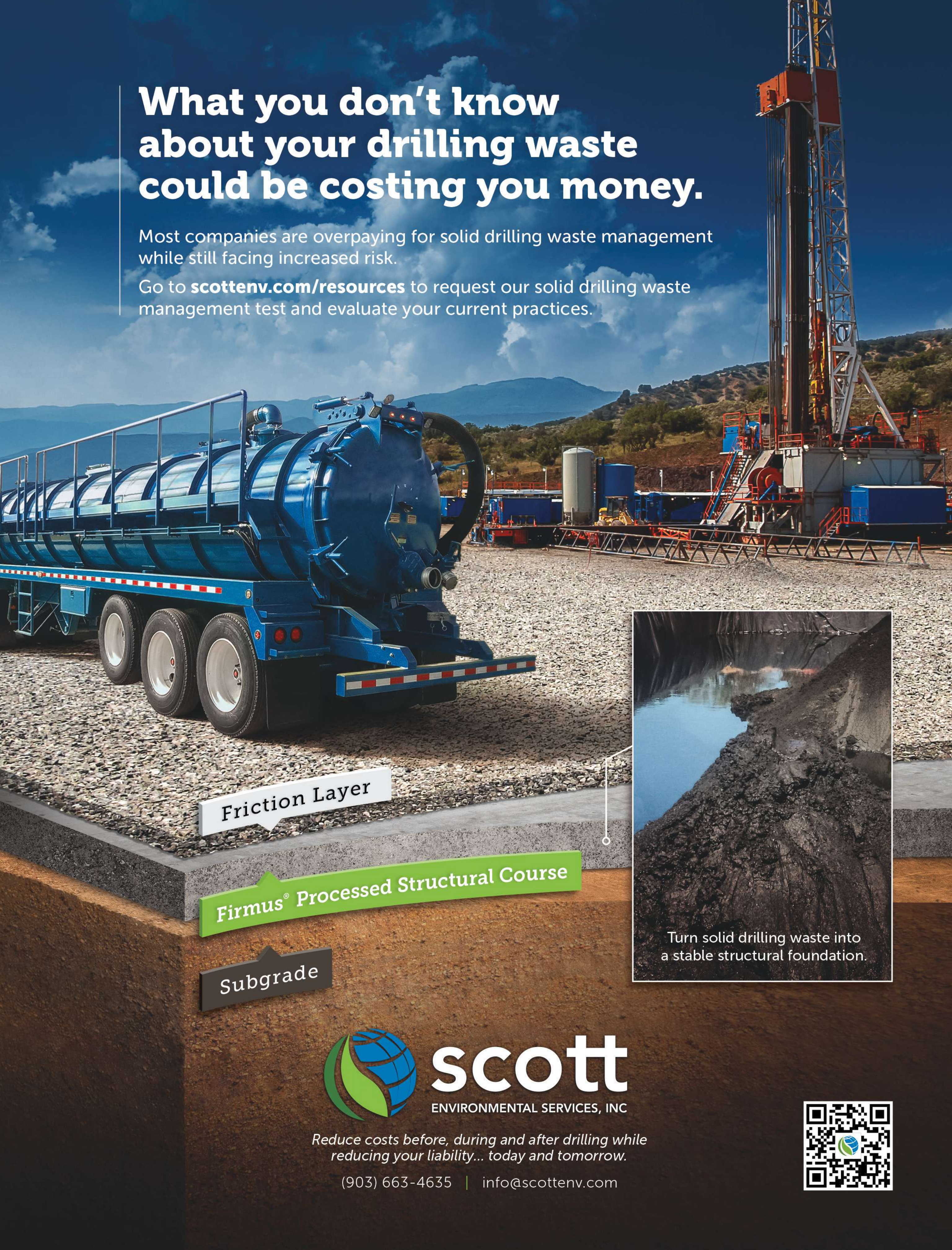
Winter 1985. By the 1980s the magazine had evolved to include a color photo on the cover and included a lengthy article about the development of multiclient surveys, then referred to as "spec." There were still crew updates, but these were professionally written articles that didn't sound quite so much like someone's holiday letter.



An early issue of *Western Profile* had a festive feel. (Source: SEG)

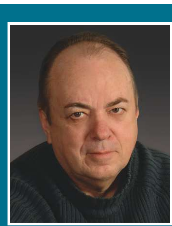
Spring/summer 2000. This issue focused on the upcoming merger with Geco-Prakla, and the *Western Profile* ceased publication. But its annals live on. Check it out at *http://seg.org/Publications/Journals/Western-Profile.* It makes for some interesting reading. E&P

Rhonda



US rig count responding to oil price; $50 price needed for big jump

Oilfield service companies and drilling contractors face a mountain of debt and are challenged to be able to wait out the downturn.



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With oil prices hovering in the mid-$40 range in early September, the oil industry is sputtering toward a recovery. The Baker Hughes U.S. rig count reached 497 for the week ending Sept. 2. The rig count topped 500 rigs for the week ending Sept. 9 at 508 rigs. The last time the rig count was above 500 units was the week ending Feb. 26 when it was 502 rigs.

Moody's Investors Services recently evaluated 35 U.S. and Canadian E&P companies. "Assuming $55 oil [and] $3 gas, full-cycle costs are projected to be $42/boe for oil-weighted producers and $3.37/Mcfe for gas-weighted producers," Moody's reported.

The profit margin for most shale plays is razor thin if there is any margin at all. However, the lower cost plays can make some money with prices at about $44. The Permian Basin is the prime example. There were 202 rigs working in the basin Sept. 2, which is 40.6% of the U.S. total.

Although there are some signs of a recovery, there are also some major obstacles to overcome.

The 35 companies that Moody's evaluated continue to adjust capital spending to mesh with the new environment of lower oil and gas prices. "Average production costs declined for the companies in 2015 as a result of increased drilling efficiencies and lower service costs. General and administrative costs also fell due to higher production as well as reductions in headcount at most companies," according to the report.

In a report released Aug. 9 Moody's noted that nearly $110 billion of debt associated with oilfield service companies and drilling contractors will mature or expire over the next five years. Speculative-grade companies account for 65% of all maturities and expirations.

"While some companies will be able to delay refinancing until business conditions improve, for the lowest-rated entities, onerous interest payments and required capex will consume cash balances and challenge their ability to wait it out," said Morris Borenstein, Moody's assistant vice president.

Moody's analyzed 67 companies for the report. Analysts expect that more than one-third will have debt and earnings before income tax, depreciation and amortization above 10 times in 2016. Depressed drilling activity and weak pricing has driven down earnings. These companies are most at risk for debt restructuring and defaults.

On June 30 Moody's reported that capital efficiency of select North American E&P companies will improve to better-than-2015 levels on the back of higher oil and natural gas prices.

The number of active rigs in the Permian Basin represents 40.6% of the Sept. 2 Baker Hughes U.S. rig count. (Photo by Tom Fox, courtesy of *Oil and Gas Investor*)

"Amid persistent low oil and natural gas prices, E&P companies have been searching for ways to become more efficient in finding and replacing reserves, reducing costs, and avoiding leverage from creeping higher," said R.J. Cruz, vice president and senior analyst at Moody's.

Operators continue to spend within cash flow. Their emphasis is on developing assets that will provide the highest cash flow. Companies that can develop stacked plays in shales like the Permian and Appalachian basins have the best economics. It will take a West Texas Intermediate price remaining more than $50 to see the rig count surge. E&P

Scott

Is it time to 'trade in the hard hats'?

The increasing role digital technologies play in production optimization could lead to the trading of hard hats for desktops.

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"Time to trade in the hard hats for desktops," was a phrase I heard on two separate occasions at the recent DUG Eagle Ford Conference and Exhibition. One of those occasions was at the tail end of a presentation on proven rod lift solutions in the Eagle Ford delivered as part of the artificial lift session of the Technology Showcase. It was made in reference to the increasing role that digital technologies are playing in production optimization.

Technology advances that led to today's real-time monitoring helped to reduce the number of hours a pumper can spend behind the wheel driving to check wells. In one example provided in the presentation, footage from a surveillance video of a well site showed a rod lift pump at work. The footage's audio sounded the clarion bell to those in attendance that can "know" just by listening to the humming whine of the pump that something just wasn't right with the well.

While it is now possible to see and hear the well without logging hours behind the windshield, further confirmation that there might be an issue with the pump is available by remotely accessing the pump's measurement dashboard. Reading the gauges might not give 100% troubleshooting accuracy, but it does help give the pumper a better idea as to what tools, parts and mechanical expertise might be needed to repair the troubled pump before making the trip.

This ability to better plan and be more efficient in operations demonstrates the many benefits that technology provides to those working in the oil and gas industry. It also demonstrates the transition from an industrial to a digital age, one where the workforce is more adept at working with bits and bytes than screwdrivers and socket wrenches. It is a transition I heard framed nicely in late August at the 2016 Landmark Innovation Forum & Expo.

"We are now all technology companies. You are technology executives, and your strategy is a technology strategy," said Peter Sondergaard, senior vice president for Gartner Research, in his keynote at the event.

The transition to 100% digital is a better fit for the realm of science fiction. Or is it?

This year is the 50th anniversary of *Star Trek*. In it, "we saw the ability to beam something or someone up. Today we can beam things, every product. Every physical asset has a digital twin that I can send anywhere in the world that I want," Sondergaard said. "What we believed was unimaginable in 1970 is what we're doing today."

This digital push is accelerating the transition from industrial to more desktops and fewer hard hats. When compared to the high-speed computing power of today, the slide rule and calculator take on the prestigious sheen of museum-worthy artifacts, although the time for both to join their father, the abacus, under the display glass is still far off.

And as long as there is a need for a pumper to log some windshield time to check a faulty pump or for a mechanic to physically repair or replace wellsite components, the hard hat will have to wait to enter the Smithsonian. E&P

Jennifer

Tipping the exploration balance

Low prices and a dearth of discoveries are not looking promising for the long-term health of the industry.

Rhonda Duey, Executive Editor

The years 2015 and 2016 have seen some remarkable discoveries—Zohr in Egypt, Teranga offshore Senegal and, just recently, Apache's massive oil discovery in the Permian Basin. But these significant announcements belie a deeper problem. The industry just isn't exploring as much as it used to, and when it does, its success rate is dismal.

Several factors come into play here, but by far the most important are the continued depressed commodity prices. Major discoveries are most likely in deep water, and these fields simply aren't economic at $50 oil. Add to that the fact that $50 oil sounded downright dreamy in January 2016, when prices dipped into the $28/bbl range, and most companies weren't even considering the location of the next big elephant.

In some ways, of course, this makes sense—why look for more oil when the world already has too much of it? But an industry plagued by quarter-itis still needs to look farther into the future and consider the importance of reserves replacement, not to mention world demand.

Lying low

According to an article by Gaffney, Cline & Associates, uncertainty over sustained low prices has caused companies, and their investors, to change their focus. "A clear trend has developed whereby investor interest has moved away from exploration and predevelopment assets to developed mature assets that can demonstrate an active and positive cash flow under the current market conditions," the article stated. "These mature assets tend to have reduced subsurface uncertainty due to extensive data acquisition and production history, with EURs often determined solely by simple decline curve analysis."

This type of focus can offset the need for exploration for quite some time, according to Leta Smith, director of IHSMarkit. "This actually can be substantial," Smith said. "We did a study last year looking at field growth in terms of the reserve sizes, the 2P reserves. Sometimes it's just having better data, but other times it's actual field growth—finding another horizon to drill, drilling infill wells. Some of the larger fields that are more worthy of investment can increase in size by as much as 25%." She cited Chevron's recent decision to invest $37 billion in its Tengiz Field as a good example of this.

But this type of reinvestment can only go so far. A recent Deloitte webcast indicated that the industry needs to meet a demand growth of 1% to 2% yearly as well as overcoming natural field declines of between 7% and 8% annually. Before prices started falling, the industry was replacing 125% of its production, but today companies are spending about 80% of their capital just to keep their proved and developed reserve share flat.

The webcast also indicated that, based on the finding and development costs of 50 to 70 of the world's largest E&P companies, the industry will need to invest at least $3 trillion between now and 2020, a figure that is a good 40% higher than spending plans for 2016.

Finding new reserves

An even more disturbing trend is emerging, one that predates the drop in commodity prices. Data from both IHSMarkit and Richmond Energy Partners indicate that conventional discoveries are on the decline and have been for several years. Smith, for instance, authored a report that indicated that conventional discoveries outside of North America in 2015 were lower than any year since 1994. "I went back and looked at the discovery

CONVENTIONAL OIL AND GAS VOLUMES DISCOVERED ANNUALLY

	LIQUIDS (MMbbl)	GAS (MMboe)
2005	13,245	14,194
2006	20,597	15,508
2007	11,124	10,719
2008	13,053	11,845
2009	11,747	13,858
2010	28,969	29,840
2011	8,229	22,583
2012	15,553	20,610
2013	11,050	12,376
2014	8,047	9,262
2015	4,061	12,656

Conventional discoveries of both oil and gas have been dropping since 2005. (Source: IHSMarkit)

Low commodity prices have curtailed exploration in many parts of the world. (Source: Alex Polo/*Shutterstock.com*)

volumes since 1952, and we've never seen a downturn in discovered volumes that lasted more than a couple of years," she said. "I think 2016 is going to be even lower than 2015, and 2015 was the fifth straight year in overall declining volumes found."

A recent study by Richmond Energy Partners echoed these findings. "In a world awash with the stuff, new oil discoveries continue to be elusive," the report stated, adding that global exploration drilling in 2016 is forecast to be down 73% over 2014 levels, with discovered oil volumes at a decade low. The current downturn certainly doesn't help.

"Industry has responded to the downturn by slashing exploration budgets … Sustained oil prices above $60 per barrel are needed to stimulate exploration. The geology economic to explore at $40/bbl is actually quite limited," the report stated.

Additional findings from the report include the fact that oil finding costs reached an eight-year high and that fewer than half of the 40 study group companies replaced production through conventional exploration over five years.

Managing Director Keith Myers said that no new multibillion-barrel conventional oil play has emerged since the presalt finds offshore Brazil in 2006 despite intense industry effort in frontier exploration. Exxon Mobil's recent Liza discovery offshore Guyana might be the most significant, but whether it heralds a new multibillion-barrel province remains to be seen.

What can tip the balance?

In addition to investing in mature fields, oil and gas companies also have a few other cards up their sleeves. For one thing, North American shale plays certainly can't be ignored. While production in these plays has been curtailed significantly during the downturn, they remain prolific producers of oil and gas. And the inventory of drilled but uncompleted wells (DUCs) gives shale producers some future insurance.

But will this be enough? "I don't think so," Myers said. "In an unconventional play, when the price drops, the drillable area of the play shrinks. The higher the oil price, the more area you can afford to explore.

"At the same time, the larger the oil price, the more players explore conventionally. It's not an either-or situation."

Added Smith, "We've been looking at what kind of production we're going to have in the future, and even by 2040 we'll still be heavily dependent upon conventional oil and gas, particularly conventional oil." She added that the U.S. can rely more heavily on its unconventional resources than other parts of the world.

According to Ed Morse, global head of commodities research for CitiGroup, the DUCs could indeed increase U.S. production in the short term. "If you model it at 600 bbl/d per well initial production, you get close to a 450,000 bbl/d increase from the beginning to the end of the period in which you are completing that inventory," Morse said. "But then you don't have that robust push again."

Then there are the frontier areas. Mexico, for instance, could be the future home of major discoveries, and Exxon Mobil, Hess and Chevron recently signed a joint operating agreement to bid in that country's deepwater bid round, which closes Dec. 5. According to a Reuters report, Energy Minister Pedro Joaquin Caldwell estimates that 76% of Mexico's prospective resources are located in deep water.

"There's going to be a farming out of PEMEX deepwater discoveries by the end of this year," Morse said. "It looks like the line of companies interested in participating in that farm-out is very large, and they're deep-pocketed companies."

He added that the cost deflation in deepwater fields has not yet hit bottom. "We still have more deep cost deflation on the drilling side, cost deflation on the completion side and mammoth cost deflation on building platforms, where iron ore and steel costs have plunged," he said.

Morse's take on the near-term potential for price recovery indicates an eventual response to a supply shortage as deepwater projects continue to be postponed. "It's likely there will be a price surge that can't be dealt with solely by OPEC countries on the one hand and the U.S. on the other hand," he said. E&P

Geomechanics modeling service balances complexity, accuracy

One-dimensional models are acceptable for many modeling scenarios.

Gerco Hoedeman, Baker Hughes

The current state of oil and gas E&P finds operators continuing to move into more challenging drilling and production environments, where recoverable volumes might be low compared to the complexity of the reservoir and the high costs of production. Geomechanical challenges in the form of wellbore and fault instability, surface subsidence, and sand production might pose high risks to an operator's field development plans and threaten the profitability of each well if not properly assessed and resolved.

Advances in geomechanical modeling have helped operators develop better well plans and define safer operating windows to optimize drilling performance, minimize drilling risks and improve safety. However, geomechanical modeling is not a "one size fits all" proposition, and operators do not need to select the most technically complex, laborious and costly model if the situation does not require it. Implementing the right geomechanical model, one with a scale and sophistication that matches the complexity of the reservoir under study, is critical to identifying rock mechanics challenges while also arriving at an optimized well plan without wasting time, computational power and software license costs.

This article compares different geomechanical models built using the Baker Hughes JewelSuite Geomechanics software application. The models are analyzed for their accuracy and resource efficiency in different structural settings.

Model fundamentals

The JewelSuite Geomechanics application builds precise models ranging in scope and complexity from 1-D well-centric to 4-D full-field geomechanical models, giving the operator greater insight to optimize well plans. The application's 1-D model module uses log

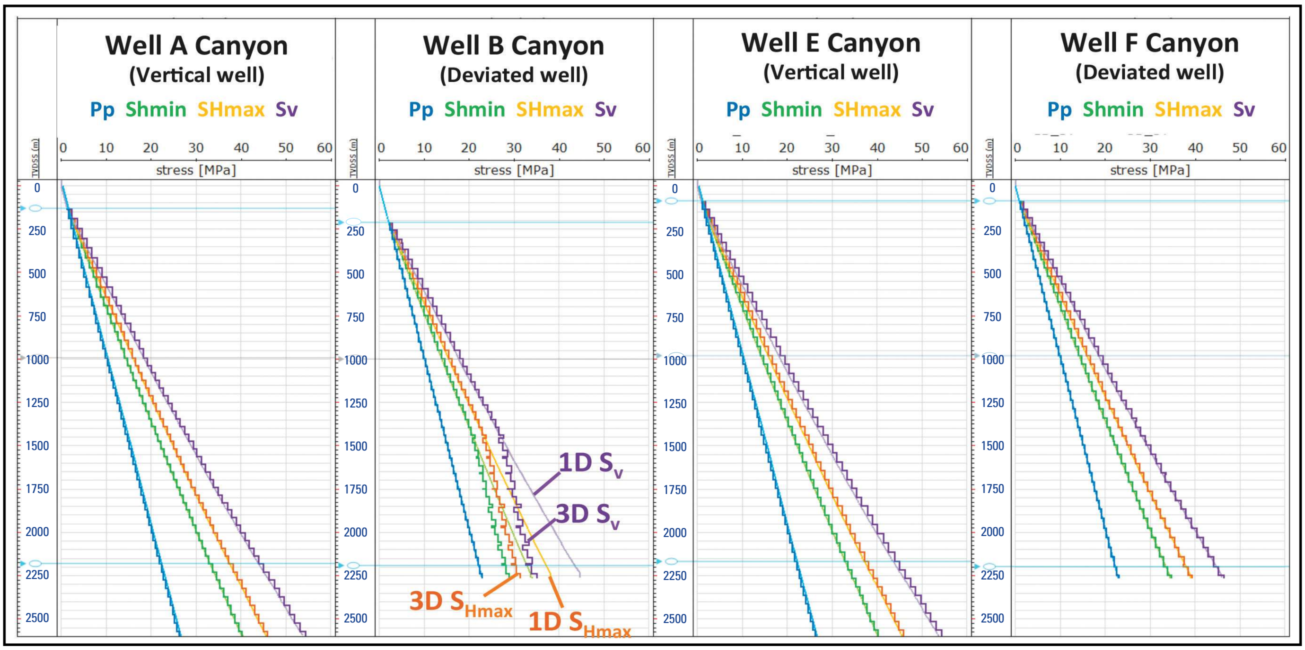


FIGURE 1. This table shows a comparison of pressures (Pp) and stresses (Shmin, SHmax, Sv) in the 1-D and 3-D geomechanical models along trajectories of Wells A, B, E and F. The 1-D and 3-D model results correlate strongly for Wells A, E and F, with the 3-D results (darker color and blocky) essentially overlaid on the 1-D results (light colored). (Source: Baker Hughes)

data and core sample data to build preproduction workflows that include lithology, overburden, pore pressures, stress orientation and magnitude, mapping, wellbore stability, and fracture gradients. Stress orientation is identified by interpreting caliper and image logs, while stress magnitudes and pore pressures are found from rock modeling and well tests such as leakoff or minifrack tests. The software lets the user display drilling events, manage multiple wells, depth-stretch logs and formation tops, manipulate logs graphically, analyze local correlations and generate customizable reports.

For more sophisticated interpretations, the application's 3-D model module builds accurate 3-D static reservoir-scale geomechanical models from 1-D models and a 3-D structural model. For this methodology a 3-D grid is populated with the properties of the 1-D geomechanical model using geostatistical methods. Vertical stresses, pore pressures and horizontal stresses are then calculated by adopting a similar workflow to those used in 1-D models. In this case, calculations are not performed along a well but along the vertical orthogonal pillars of the grid.

While a 3-D geomechanical model is effective at capturing lateral variations in formation properties, it is less applicable in more geologically complex situations. Such settings include a salt dome where the formation cannot withstand differential stresses, situations when reservoir pressure changes over time or in reservoirs experiencing varying depletion in compartments.

These complex geological settings are resolved through numerical techniques such as finite element modeling. Unlike with 3-D models, these techniques simulate rather than calculate the stresses on a reservoir scale. Finite element modeling enables the simulation of a complex stress field with changing boundary conditions over multiple time steps. The resulting 4-D geomechanical models allow better understanding and mitigation of the effects of geomechanical changes over the life of the field.

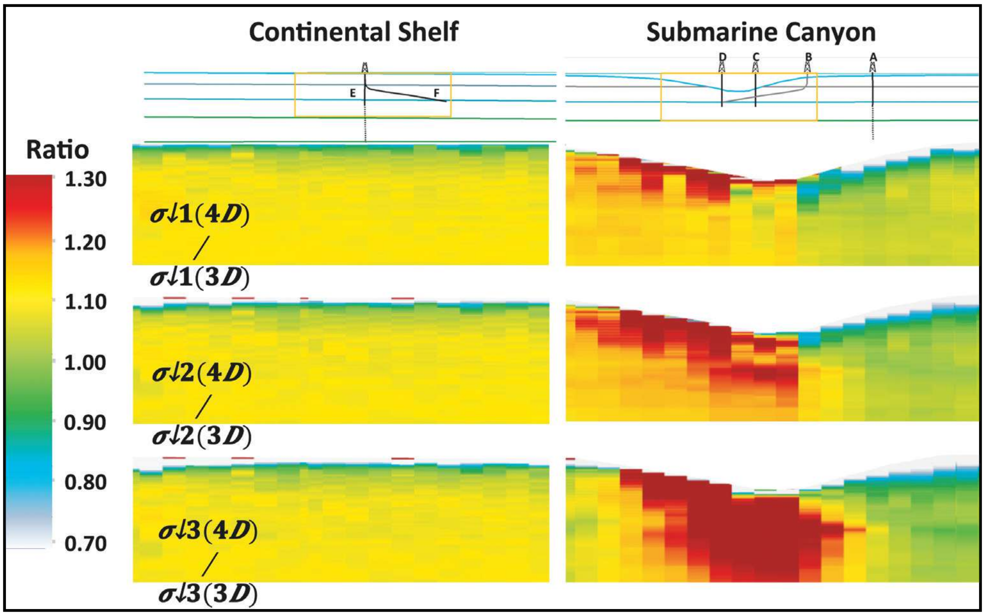


FIGURE 2. Ratios are shown between the principal effective stress magnitudes in the 3-D and 4-D geomechanical models for the continental shelf (left) and submarine canyon (right). From top to bottom are the ratios of the maximum principal effective stress, σ1 (about vertical), the intermediate, σ2 (about horizontal) and the minimum, σ3 (about horizontal). (Source: Baker Hughes)

Comparing geomechanical models

The geomechanics software application was used in a study aimed at comparing three different geomechanical models—1-D, 3-D and 4-D—for their accuracy in estimating the state of stress in a real-world simulation. A synthetic bathymetrical map was created to represent a general coastal setting of a continental shelf containing a 1,400-m (4,600-ft) deep submarine canyon. The full seafloor area covered 180 km by 150 km (112 miles by 93 miles).

Geomechanical modeling is not a "one size fits all" proposition.

To shorten the computation time required for the 3-D and 4-D reservoir-scale models, two smaller areas with lateral dimensions of about 32 km by 32 km (20 miles by 20 miles) were selected for analysis. One of the areas covers part of the continental shelf and the other part of the submarine canyon.

Using the software application, researchers created multiple 1-D geomechanical models using well data;

these 1-D models were subsequently used to construct 3-D geomechanical models for both the submarine canyon and the continental shelf area. Two 4-D geomechanical models also were created using the structural framework of the 3-D model, rock properties and knowledge on the initial stress state of the 1-D geomechanical models. Then the stress state along the well paths was extracted from the 3-D and 4-D geomechanical models and compared.

Results and discussion

A comparison of the pressures and stresses for four different wells—two vertical wells and two deviated wells—generated by the 1-D and 3-D geomechanical models is presented in Figure 1. Two of the wells (denoted as Wells A and B) were located in the submarine canyon area, while the other two (Wells E and F) were on the continental shelf.

The results indicate a good match for Wells A, E and F using the 1-D and 3-D models but a significant difference for Well B, which was an inclined well with a long lateral section. This difference is likely due to the fact that Well B's lateral was located below the submarine canyon, which meant that there was less rock and therefore less overburden weighing down on it. As a result, much less overburden was used for the vertical integration in the 3-D grid, which led to a lower vertical stress.

Figure 2 compares the stress difference in cross sections between the 3-D and 4-D models. The models match closely for the continental shelf but show a greater disparity for the submarine canyon. This is because the 3-D model calculates the stresses along the vertical stacks of grid cells without considering lateral effects. The 4-D model simulates the stress state while accounting for the stress effect of the canyon walls.

This study supports the claim that accurate answers do not always come from the most complex modeling solution. While a 4-D model might be required to accurately simulate the state of stress in a complex submarine canyon setting, a 1-D wellbore-scale geomechanical model can be an efficient way to model stress states in geological settings that do not experience dynamic processes like depletion or salt creep. And by not automatically resorting to building 3-D or 4-D reservoir-scale models for every well, an operator can still gain the subsurface insight required to optimize well plans but in less time and at lower costs. Additionally, it can save time for better analysis of the results, adding uncertainty assessment to the model and/or doing a sensitivity analysis. E&P

Bubbling crude and understanding seeps

Satellite detection can be a low-cost alternative for offshore exploration.

Joel MacDonald, MDA Geospatial Services Inc.

For the offshore oil and gas industry costs of exploration in deep and ultradeep water are immense, and the industry is currently in a state where many operators are limiting exploration activities. In an effort to minimize risks and costs, offshore exploration companies are continually seeking other methods of developing assets that are known producers. It is currently very hard to predict when oil prices will rebound and stabilize; the current market situation increases exploration companies' need for proven methods of identifying hydrocarbons in offshore basins around the world.

Natural marine hydrocarbon seeps

An overlooked method for hydrocarbon identification is the use of long-term historical space-based radar images and associated analysis methods. These tests enable oil and gas operators/companies to understand natural episodic oil seep patterns over active and unexplored offshore basins. Large numbers of naturally occurring oil seeps are expected in offshore basins and can occur when natural liquid or gaseous hydrocarbons escape to the earth's surface and atmosphere, normally under low pressure or flow. Seeps are generally found above terrestrial or offshore petroleum accumulation structures.

When oil is released from the ocean floor, it bubbles through the water column and coalesces on the surface, where the oil is advected by the prevailing mean and surface currents. For example, in California there are hundreds of seeps, and much of the hydrocarbons found during the 19th century were discovered by the observation of seeps on the ocean's surface. In the Gulf of Mexico, hundreds of seeps result in more than 1 MMbbl/year of oil leaking naturally to the ocean's surface. Figure 1 illustrates the typical life cycle of naturally occurring oil on the ocean's surface.

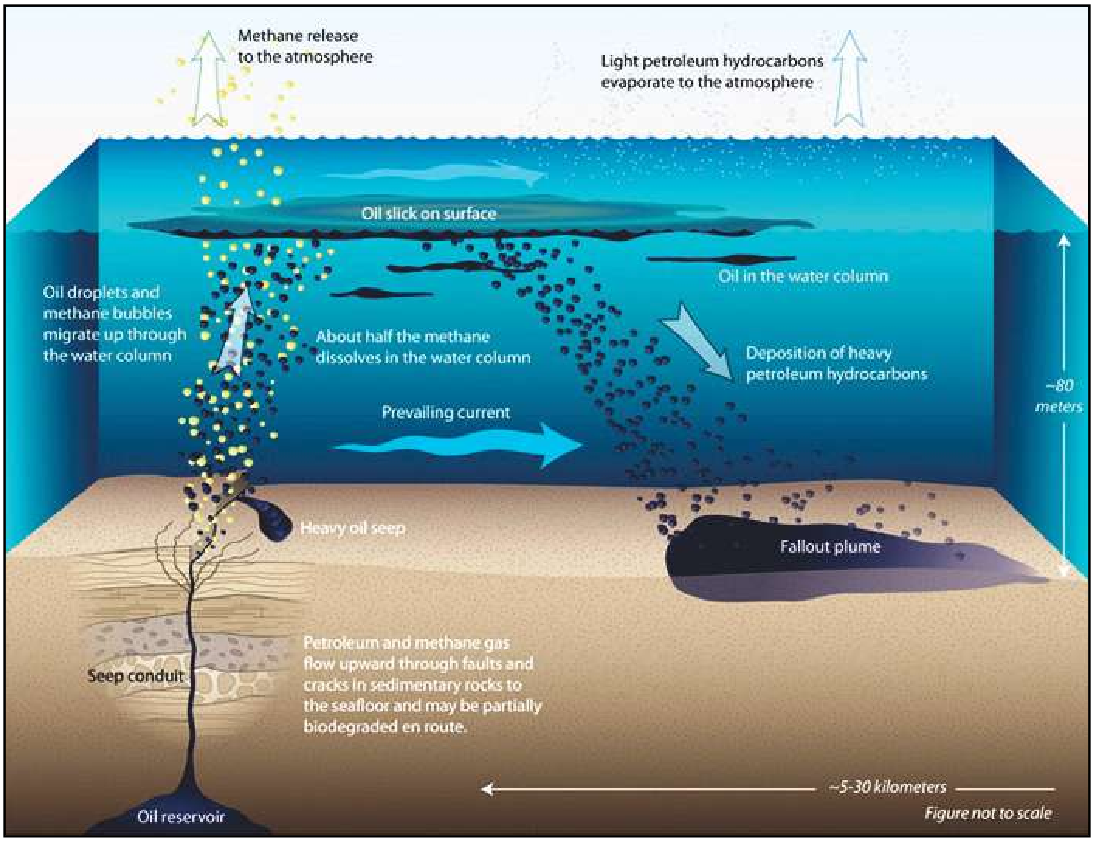


FIGURE 1. This figure shows the genesis of natural marine hydrocarbon seeps. (Source: Jack Cook, Woods Hole Oceanographic Institution)

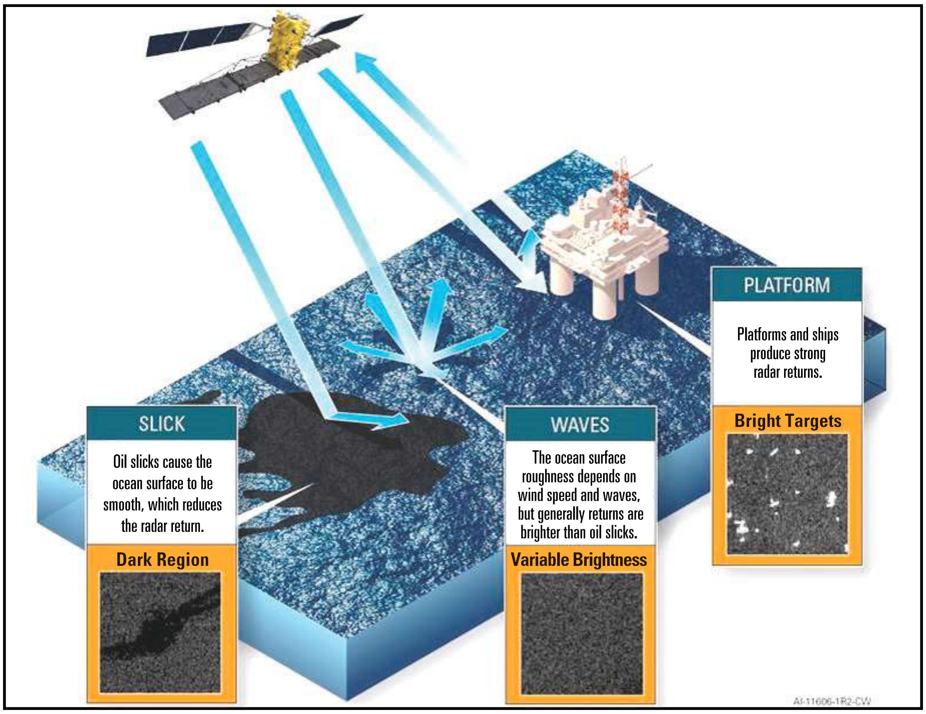


FIGURE 2. Satellites pick up oil seeps due to their smooth appearance. (Source: MacDonald, Dettwiler and Associates Ltd.)

Generally, platforms and ships produce strong radar returns, resulting in bright targets that are easy to identify. Oil slicks cause the ocean surface to appear smooth, reducing the radar return. The ocean surface roughness depends on wind speed and waves, but generally radar returns are brighter than those from oil slicks. Figure 2 shows how a satellite image "sees" oil on water.

Using nonintrusive radar satellite imagery from missions like RADARSAT-2 enables analysts to detect surface seeps and might provide insights into the location of hydrocarbon basins beneath the ocean floor. Satellite coverage is available to locate hydrocarbon systems anywhere in the world. Archived data and seep analysis can leverage more than 20 years of global data coverage. Without the need to deploy any resources offshore, seep analysis is a low-cost risk and impact solution to support lease-block evaluation, and it contributes to exploration companies' datasets about potential hydrocarbon systems. In addition to performing static analysis from a seeps database, the operator can use historical seep patterns and real-time satellite data to identify areas for geochemical sampling and analysis. Collecting samples from an active seep can provide easy access to evaluate the type of hydrocarbon available at the target location. Employing a satellite-based solution allows exploration companies to have data in hand to help make better decisions about where to invest in higher cost exploration techniques such as piston core campaigns and seismic surveys. The spatial and temporal persistence of the seeps can be used to guide more detailed geophysical surveying.

Some of the key benefits of using satellite-based information that allow the E&P companies to know more and know early are to:

- Cue and target geochemical sampling, seismic studies, piston core drilling programs and seafloor surveys based on seep location and frequency;
- Corroborate seep data to other geological data to reach higher levels of confidence in "telling the data story" early in the exploration decision process; and

Seeing oil from space

Using space-based radar satellites to detect oil on water is a proven technique that has been used for nearly two decades and has multiple applications, including pollution monitoring from all sources (including but not limited to platform/vessel incidents).

> Large numbers of naturally occurring oil seeps are expected in offshore basins.

Synthetic aperture radar (SAR) satellites are active sensors that produce energy pulses to illuminate the area under observation. Unlike other passive sensors (such as those on optical satellites), radar sensors are not constrained by lighting conditions and/or cloud cover. SAR satellites also have wide-area capabilities to provide all-weather monitoring for oil on water and metocean support with coverage up to 300,000 sq km (115,831 sq miles) in a single imaging event.

- Establish an environmental baseline as evidentiary bases for future work, including production (to help discriminate between naturally occurring oil and oil incidents when producing in an environment with active natural seeps).

Seep products

Although the seep products might vary from vendor to vendor, seep assessment products most often include summary reports, full-resolution images, wind maps derived from satellites images, oil seep delineations and seep cluster reports.

Seep studies can be catered to the client's need whether only for a single targeted area or part of a global exploration program with multiple hydrocarbon systems in various exploration phases.

Satellite use for oil spills

Although oil slicks can occur naturally in the form of oil seeps, oil slicks also can be the result of a spill such as the 2010 Macondo incident in the Gulf of Mexico or an accidental discharge from an offshore platform or vessel. When an oil spill occurs, history shows that it is imperative to act quickly to minimize the environmental impact. Using the same tools as for seep analysis, offshore operators can leverage space-based satellites for routine monitoring around their operating areas.

Offshore operations are challenging. Adding tools that require offshore logistical support to monitor accidental discharges is not always cost-effective and introduces even further risks to an already multifaceted operation. Satellite imagery available over the area of interest contains important information and can provide critical data to assist with:

- Situational awareness for security and HSE requirements;
- Metocean and weather support over wide areas; and
- Archiving to support regulatory and legal issues.

Once a satellite image is obtained, it can be analyzed to ascertain the origin of the oil slicks detected. It is possible to discriminate oil that originates from known sources such as offshore drilling platforms or ship bilge-dumping. In both of these cases, the platforms and ships have strong radar returns and can be easily identified. Offshore platforms are stationary, so their location will be constant. The location of ship bilge-dumping is variable, but it is usually characterized by a long linear region of reduced radar backscatter. When known oil slicks have been separated from the unknown oil slicks, the unknown slicks are further discriminated to isolate slicks from slick imposters such as meteorological, oceanographic and coastal processes.

The value of oil slick information is significant, whether for naturally occurring oil seeps or manmade occurrences. If the seeps are naturally occurring, they can be an excellent, low-cost method of determining hydrocarbon presence that are potentially worth exploring further. Alternatively, if slicks are manmade, having satellite imagery available enables the response to be rapid, focused and effective, all the while posing no additional exposure or further damage to the environment. E&P

New technologies form future of exploration

SEG will showcase the latest technologies to find the next great fields.

Staff Report

The Society of Exploration Geophysicists (SEG) will hold its annual meeting and exhibition Oct. 18 to 21 in Dallas. During this time participants will have the opportunity to view more than 1,100 technical presentations ranging in topics from new frontiers in exploration to practical applications. The exhibition will feature a variety of companies showcasing the latest exploration technologies.

Some of the highlights of the show include the opening session and presidential address, the annual Challenge Bowl, networking events for students and women, and the Applied Science education program. This year's program will feature Shaunna Morrison, a member of the NASA Mars Science Laboratory, who will discuss "Assessing the Red Planet's habitability using the Rover *Curiosity*."

In this special section *E&P* has highlighted some of the latest products and technologies to be shown at the SEG Annual Meeting and looks at how they will benefit companies in their ongoing search for new reserves.

The copy herein is contributed from service companies and does not reflect the opinions of Hart Energy.

Anisotropic inversion aids well planning in fractured reservoirs

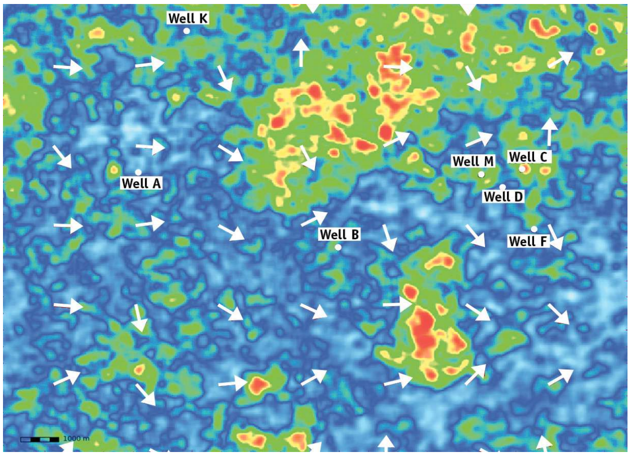
At SEG 2016 CGG will be highlighting the latest releases across its GeoSoftware reservoir characterization portfolio and how their integration of multidisciplinary workflows helps overcome the most complex subsurface challenges in all types of reservoirs, including those that are naturally fractured. Better identification of fractures, differential stress and reservoir architecture is essential for effective well design and optimum production.

By revealing essential reservoir facies and rock property information, a new anisotropic inversion product within GeoSoftware's Jason portfolio improves characterization of reservoirs with significant anisotropy and realizes the full value of azimuthal seismic data. The power of azimuth-based amplitude vs. offset inversion is used to make direct measurements of reservoir anisotropy. A dedicated analysis application provides information on critical parameters: anisotropy magnitude and direction, fracture density, and rock weaknesses, all calibrated to well control.

In shales a proper understanding of local anisotropy is critical in designing any well program. Engineers must ensure that horizontal wells are drilled along the directions of minimum local stress to obtain the best fracturing results. The outcomes of fracturing are better predicted when there is an understanding of local rock brittleness and fracture density.

In heavy oil applications reservoir caprock competency is important to avoid the catastrophic effects of escaping steam. Anisotropy-corrected density estimates from inversions also are required to define the lateral and vertical extends of bitumen-laden sandstones.

Workflows can be tailored to fit specific project needs. Companies can plug into their own preferred petrotechnical platform and processes as part of the seismic-to-simulation workflow.



This image generated by Jason Anisotropic Inversion displays a clastic reservoir under tension. Arrows show direction, and the color map shows magnitude of anisotropy. (Source: CGG GeoSoftware)

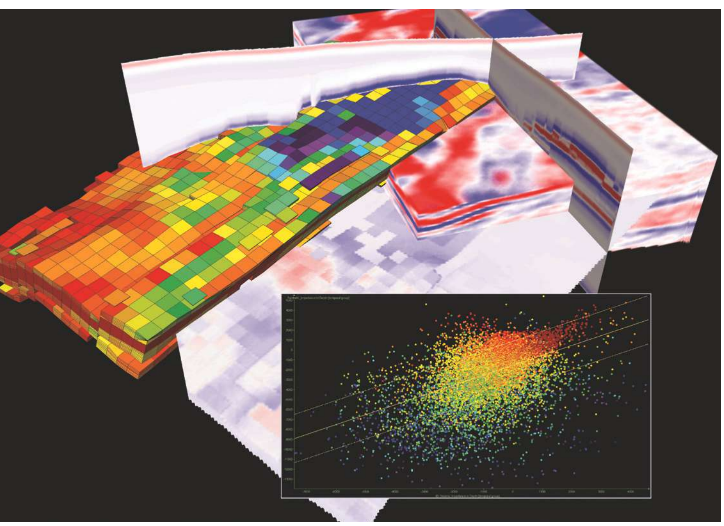
Software aids in time-lapse interpretation

CoViz 4D from Dynamic Graphics Inc. is a software platform for advanced data integration. In particular, the newly enhanced Sim2Seis and 4D Geomechanics options in CoViz 9.0 provide a fully integrated and customizable environment for analysis of 4-D seismic datasets.

Time-lapse (4-D) seismic data are more widespread than ever before. Their potential to monitor conditions throughout the reservoir through time is being used to maximize produced oil while also reducing costs and risk. But however useful these data are, operators are understandably under increasing pressure to prove the value of 4-D volumes yet to be collected and to maximize the return on investment after acquisition. Typically this is accomplished through feasibility studies and seismic history-matching.

The true value of 4-D seismic data can only be maximized when fully integrated and analyzed alongside all other relevant subsurface data. These could be reservoir simulations, production data, well histories, microseismic, etc. So whereas feasibility studies and seismic history-matching have value, that value is compounded when these processes are analyzed in the context of other decision-critical information.

The CoViz 4D platform offers unparalleled levels of data integration in a dynamic, time-aware 4-D analytic environment. Vendor-neutral data importers for a wide range of formats can make imports as easy as drag-and-drop. World-class visualizations and animations can reveal hitherto unseen connections between diverse datasets. But most importantly, the CoViz Sim2Seis and 4D Geomechanics modules are fully integrated into this quantitative analytic environment for better, faster and more complete analysis of time-lapse seismic.



Time-lapse seismic data can only be maximized when fully integrated and analyzed alongside all other relevant subsurface data. (Source: Dynamic Graphics Inc.)

Electroseismic technology used as DHI

The idea of coupling electromagnetic and seismic energies for useful purposes dates back to the 1930s but was most recently enhanced by Exxon Mobil starting more than 30 years ago. Since then, *ES* Xplore was formed within the Hunt Energy Enterprises LLC, a venture startup incubator within Hunt Consolidated Inc., to provide E&P operators with better imaging technologies for identifying potential hydrocarbon deposits.

ES Xplore has developed a novel direct hydrocarbon indication technology for onshore fields. The key physical mechanism underlying *ES* Xplore's technology is the ability of rocks to convert electromagnetic energy into seismic or acoustic energy and, in turn, convert seismic energy into electromagnetic energy. The significance of these conversions is their enhancement by the presence of very electrically resistive fluids such as hydrocarbons in the rock pore space and by more highly permeable rocks.

ES Xplore's technology is a totally passive technique that utilizes the earth's naturally produced electromagnetic fields to directly detect hydrocarbons. Unlike other electromagnetic techniques that measure the earth's electrical resistivity on gross scales, *ES* Xplore relies on different rock physics and has spatial resolution on the order of seismic resolution. *ES* Xplore's technology is the only passive exploration method that senses the electrical resistivity and permeability of a formation at seismic resolutions. *ES* Xplore holds eleven patents on the technology and has several additional patent applications pending.

Technique increases offshore confidence

A trial application of Ikon Science's Ji-Fi to a known gas field correctly highlighted the presence of three thin gas sands at an existing well location. In contrast, industry-standard methods for inversion of seismic data failed to detect two of these three gas sands. Consequently, Murphy Exploration & Production, the operator, concluded that the new technology offered by Ji-Fi is indeed superior to existing methods for sample-based full-volume inversion of seismic data. A subsequent application of Ji-Fi to the seismic data at a proposed new well location on Murphy's acreage in the Gulf of Mexico revealed the likely presence of oil-bearing sand. The Ji-Fi results were used to determine both the likelihood of an oil accumulation and the possible range of in-place volume. The increase (or potential decrease, in other cases) in confidence in the likelihood of finding oil and the range of volumes are critical in the decision-making process. Murphy balanced the costs of drilling with the expected reward of finding and producing oil. The well was subsequently drilled and found the expected oil sand. "Ji-Fi is rapidly becoming the new standard in inversion of seismic data within Murphy; there is no scientific argument not to take up this exiting capability," said Norbert Van De Coevering with Murphy Exploration & Production. "Even if nothing is perfect, it is still far better than standard industry inversion techniques, which have substantial bias."

Unified system for mixed mode seismic acquisition

With exploration activity today taking operators into more challenging environments, the need to acquire seismic data efficiently and often in mixed modes is a growing challenge. Variations in terrain where open and relatively unrestricted areas can be abruptly contrasted with villages, foothills, mountains, lakes and river deltas pose tremendous operational challenges for the seismic contractor.

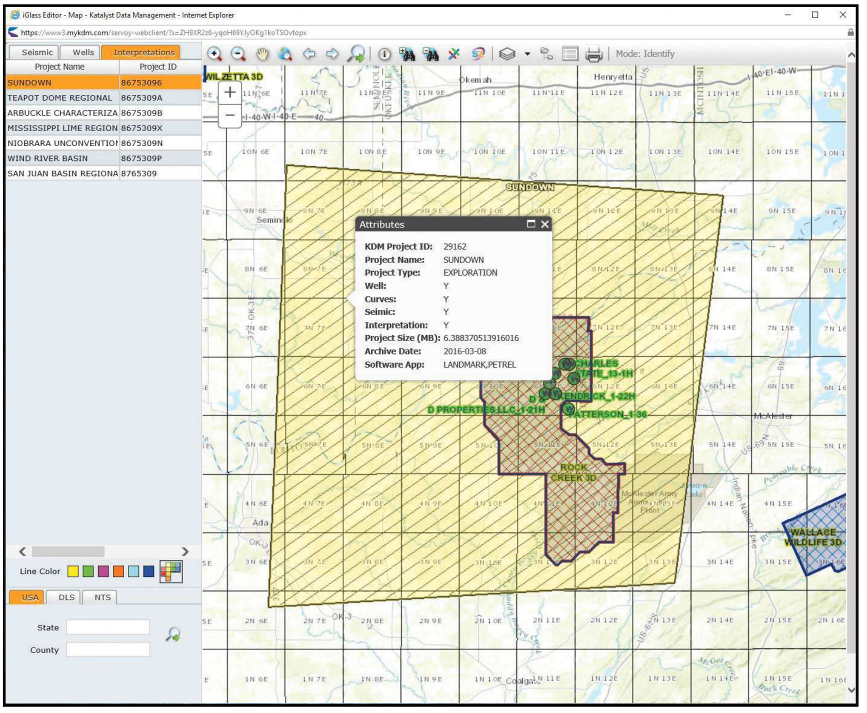
When faced with such challenges, the list of acquisition equipment required to tackle the project can grow dramatically. Traditional heavy vibroseis sources might need to be complemented with lighter and more maneuverable vehicles, with shot hole or even weight drop equipment required for terrain outside the scope of vehicles. Cable-based systems might not have the flexibility required to cope with all the environmental challenges; hence, the need for additional cableless channels to complete the coverage might become apparent. And if marine sections also are encountered, specialized transition zone (TZ) equipment also might be required.

All of this becomes even more traumatic to the contractor if different manufacturers provide the equipment and multiple recording systems are installed, each with their own unique training requirements, data formats, workflows and quality control (QC) capabilities. This is one of the main reasons that INOVA Geophysical recently has released a new unified central system for seismic operations—iX1.

With iX1 contractors can mobilize G3i HD (a cabled recording system) with TZ capability, integrate with autonomous nodes (Hawk) and receive support for vibroseis and dynamite source types, all controlled from the same software platform. With a single platform delivering common data format to the client, regardless of whether the data are acquired by cable, nodal or TZ equipment and with common operational and QC workflows for ease of use and training, contractors working in these tough environments now have one less thing to worry about.

Module provides immediate data access

iGlass, a full subsurface life-cycle management solution that is a web-based ESRI GIS map interface from Katalyst Data Management, now has a new module for managing interpretation project archives called ProjectDataStor. Built on the PPDM 3.8 public data model, iGlass provides geoscientists direct access to their data when they need it rather than having to search through volumes of archives and wait for weeks or longer using traditional storage methods. Designed primarily for seismic, iGlass has since expanded to support multiple domains. Geoscientists can now view interpreted information such as filtered volumes, horizons, grids, faults, wells, etc., contained within technical projects in the same view as the field and original processed seismic data already in the system. Currently, the iGlass global data centers manage 618,000 unique seismic surveys covering 45 million km (28 million miles) of data for a total of 17.2 petabytes of storage.



The iGlass global data centers manage 618,000 unique seismic surveys. (Source: Katalyst Data Management)

SeismicZone.com provides a convenient, budget-friendly alternative for licensing seismic data via ecommerce. Anyone can visit the site and search their area of interest to see what's available for license, and many of the associated transactions can be easily handled online. The online marketplace has more than 3.5 million km (2.2 million miles) of 2-D data and 119,318 sq km (46,069 sq miles) of 3-D data available for license.

CSEM aids in EOR

EOR is always challenged by the knowledge of the oil/water front. Only limited geophysical techniques have been applied. In addition to flood front movements, reservoir seal integrity has become an issue. Seal integrity is best addressed with microseismic, and waterflood front identification is best addressed with electromagnetics.

KMS studied the fluid imaging using electromagnetics and, after careful 3-D feasibility and noise tests, selected controlled-source electromagnetics (CSEM) in the time domain as the most sensitive method. From the 3-D modeling it was determined as a key requirement that borehole and surface data needed to be integrated by measuring between surface-to-borehole and also calibrated using conventional logs.

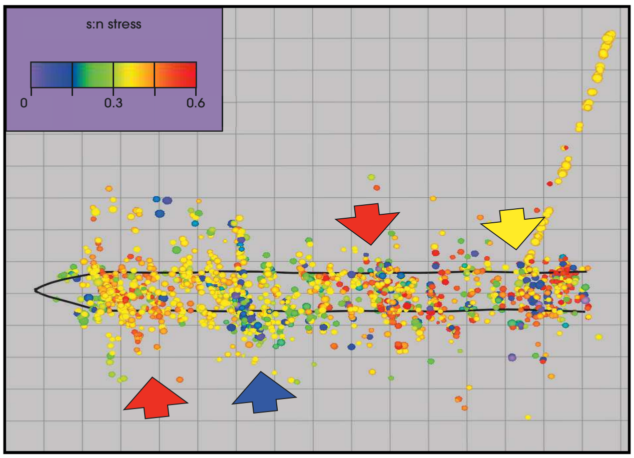
The world's first EOR pilot with this method is presently running onshore Thailand based on several years of 3-D modeling-based design and fit-for-purpose hardware. The system is based on the KMS array electromagnetic receiver systems (KMS-820). It consists of unlimited nodes, each of which can be extended with a cabled 32-bit subacquisition controller. The company is presently adding shallow borehole 3-C microseismic/electromagnetic receivers and has started the development of deep borehole receivers. Concurrent to this project, KMS is commercializing the first generation of deepwater microseismic/electromagnetic marine nodes that will allow the concept to be extended into deep water.

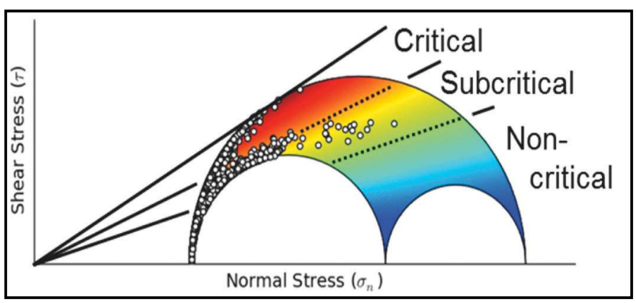
Getting Mohr from microseismic

Microseismic Inc. recently has extended its proprietary data analysis workflow to allow the accurate estimate of focal mechanisms for the majority of recorded microseismic events in any fracture monitoring project. This *in situ* analysis reveals the strike, dip and rake of the failure plane of the event, which in turn can be used to estimate two important reservoir parameters:

- The magnitude and direction of maximum horizontal stress (SHmax); and
- The minimum stimulation pressure for the activation of natural fractures at different orientations.

Both numerical simulations of hydraulic fracturing in naturally fractured reservoirs and microseismic observations of actual treatments demonstrate the impact of the horizontal stress anisotropy on the final stimulation pattern and the mechanical interaction between consecutive fractures. Horizontal stress anisotropy is defined as the difference between the magnitude of minimum (SHmin) and maximum horizontal stresses. Higher stress anisotropy promotes more planar fracture patterns that extend away from the injection point, while lower stress anisotropy leads to more fracture complexity closer to the injection point. Knowledge of the existing anisotropy prior to stimulation is key to the optimum design of well spacing and stage length. While the magnitude of SHmin can be determined using well test data (e.g., a mini-fracture test or diagnostic fracture injection test), there has not been an easy and reliable method to determine the magnitude of SHmax along horizontal wells. This new development fills this gap and provides a mathematical approach to the determination of local SHmax using microseismic field observations. Knowing the full stress tensor allows the required minimum stimulation pressure to activate natural fractures to be calculated assuming a Mohr-Coulomb failure criterion.





The Mohr-Coulomb criterion identifies zones of critically stressed fractures vs. noncritically stressed fractures using microseismic events and focal mechanisms. (Source: Microseismic Inc.)

Fiber optics for shale

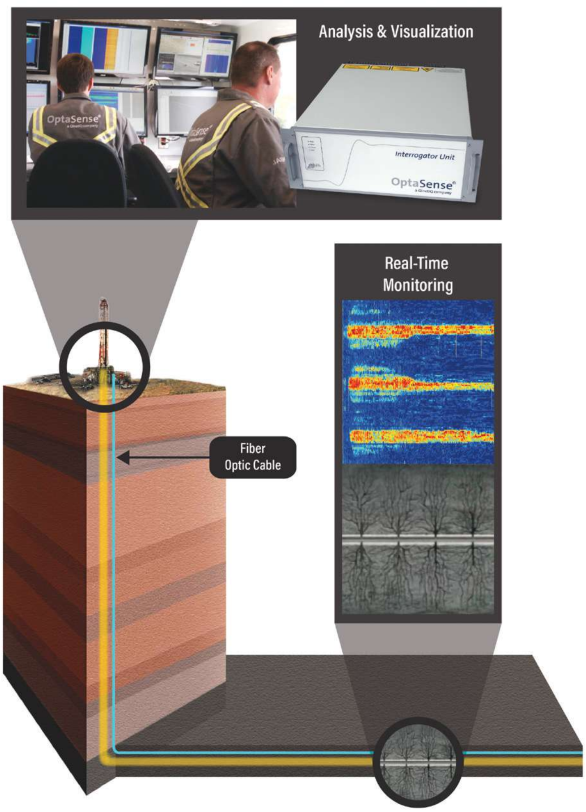
OptaSense Oilfield Services has released a distributed fiber-optic sensing (DFOS) system for shale reservoirs that provides vertical seismic profiling (VSP), hydraulic fracture profiling and production flow monitoring in real time from a single system.

Using distributed acoustic sensing technology, the DFOS system transforms a permanently installed fiber-optic cable into an array of distributed acoustic sensors that detects changes in temperature, stress and acoustics along the entire wellbore.

The system acts as a borehole seismic sensor array capable of acquiring 2-D, 3-D and 4-D VSP data in both vertical and horizontal wells. These data enhance the understanding of near-well and interwell structural integrity, rock mechanical properties, *in situ* stress and natural fractures, which is critical for profitable site selection, well positioning and fracture placement.

For optimal fracture completions, the DFOS system confirms the integrity, seating and placement of bridge plugs and perforation guns. It also monitors the distribution and placement of proppant and fluid in real time, allowing operators to optimize pumping schedules, prevent understimulated or overstimulated zones, adjust stage spacing and monitor cross-well communications.

With the DFOS system, users also can visualize inflow and axial flow at the perforation level for the life of the asset. This allows them to pinpoint underperforming clusters while monitoring the impact of production on the reservoir over time. And, unlike other production logging methods, the system enables repeat surveys and continuous monitoring without the need for well intervention. Visit *optasense.com* or booth 2413 at SEG for more information.



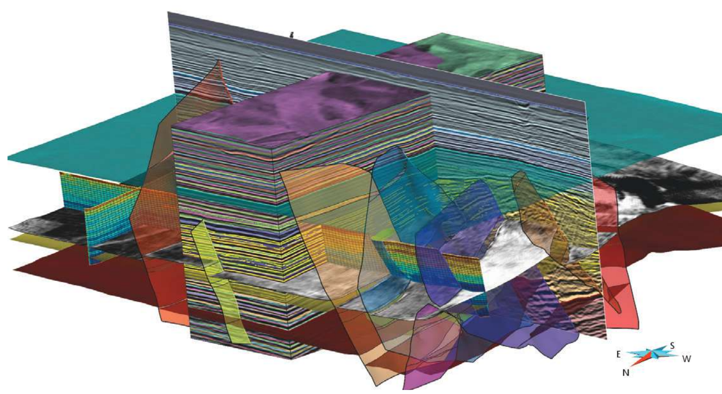
The DFOS system provides VSP data, hydraulic fracture profiling and production flow monitoring in real time from a single system. (Source: OptaSense)

Theater features exploration, development workflows

At SEG 2016 Paradigm will use its theater program to feature a series of high-definition workflows in support of strategic exploration and development in onshore North American basins and offshore deepwater basins.

In seismic processing and imaging the program will include a novel full-azimuth diffraction imaging product to recover low-energy faults, a well marker mis-tie tomography workflow for precision depthing, a time-variant broadband deghosting approach for upgrading legacy and modern offshore acquisitions and new solutions to improve the efficiency of geophysicists working with multiline 2-D projects.

In seismic interpretation the program will feature its flagship Interpretation suite running in a new application framework (Epic) designed to foster higher levels of usability and productivity. New workflows for quantitative seismic interpretation will be introduced, including prestack elastic inversion with stochastic refinement for



Volumetric Interpretation combined with UVT modeling in SKUA-GOCAD produce accurate paleospace imaging for chronostratigraphic interpretation and generate 3-D models matching intraformation seismic details. (Source: Paradigm)

thin bed evaluation and a new probabilistic lithofacies workflow that integrates rock typing, electrofacies models and seismic data for improved facies modeling.

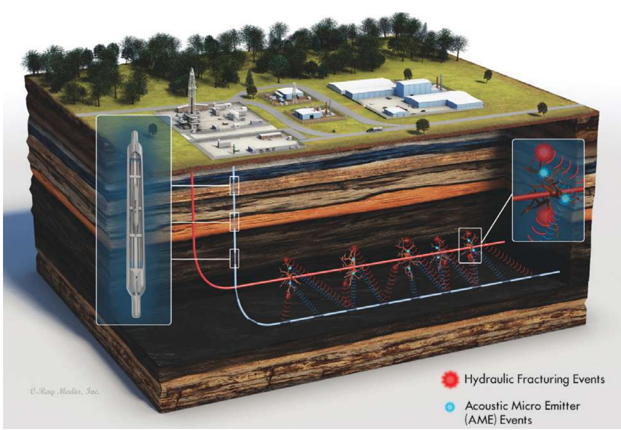
In subsurface modeling Paradigm will demonstrate the application of its chronostratigraphic modeling product for simultaneous volumetric seismic interpretation and modeling. The application is designed to facilitate the interpretation correlation problem, recover stratigraphic features and resolve interpretation errors. The application also will be used to support unified geologic and velocity modeling activities.

Formation evaluation solutions will focus on geomechanics, shale analysis and integrated wellbore and seismic data-driven pore pressure solutions suitable for overpressure predictions in all types of basins and source conditions.

Special presentations will include reservoir-driven production optimization and a look at future directions.

New sensor provides improved images

Paulsson Inc. has developed a line of innovative all-optical-based seismic vector sensor technologies for high-resolution oil and gas reservoir characterization and monitoring. The development has been funded by the U.S. Department of Energy and the Research Partnership to Secure Energy for America since 2010. The ultrasensitive high-vector fidelity large-bandwidth high-temperature fiber-optic seismic sensors have been integrated into a borehole seismic system using an optical data transmission technology and have been successfully field-tested. The system is capable of long-term deployment at 30,000 psi and 300 C (572 F), so it can meet the most stringent requirements for well operations. In parallel, an optically based ultralarge hydrophone array technology has been developed that will for the first time allow cost-effective large-aperture 3-D vertical seismic profiles to be recorded in the deepwater Gulf of Mexico.



The fiber-optic seismic sensor system was deployed in a horizontal well near a hydraulically fractured well. (Source: Paulsson)

In several tests the fiber-optic seismic sensors have shown to have superior performance relative to state-of-the-art seismic sensors such as exploration-type coil geophones and high-performance accelerometers in terms of bandwidth, sensitivity and high-temperature performance. The lower noise floor, the flatter spectral response and the higher sensitivity of the new fiber-optic seismic sensor will allow higher resolution imaging and detailed reservoir characterization and monitoring.

To deploy the new vector sensor system, a drillpipe-based deployment system has been developed allowing the receiver array to be deployed in both vertical and horizontal wells, which is an operational requirement in shale oil and gas wells since many of the wells drilled for shale oil and gas are highly deviated or horizontal.

Integrating seismic imaging and inversion

For years processing, imaging and inversion have been undertaken by separate teams, often in different companies. However, such siloed workflows are inefficient and can lead to errors. Precision is required from the beginning to the end of the geophysical process. The only way to achieve this goal is with an integrated team, leading-edge software and technical innovations.

As a first step, Rock Solid Images integrated seismic imaging and inversion workflows to optimize the time to solution of a seismic characterization project while improving the quality of rock property prediction in depth by ensuring consistency throughout. The process was tested using a faulted model including both wet and pay scenarios. Synthetic seismic data were generated using full waveform anisotropic elastic simulation. The resulting data were migrated using a wavefront reconstruction Kirchhoff summation prestack depth migration (PSDM).

The resulting gathers were then inverted using a simultaneous elastic impedance inversion. Both velocities and surfaces were consistent through the imaging and inversion stages. The elastic attributes obtained were transformed to rock properties using a multiattribute rotation scheme and compared to the input model. The observed misfit between the input and predicted reservoir properties is small.

Results demonstrate that PSDM preserves the relative amplitude of the data, allowing rock properties to be robustly predicted and positioned in depth. The value of close integration of imaging and inversion is clear. Further studies will use integrated imaging and inversion to investigate the amplitude responses underneath layers such as basalt or salt with the aim of estimating reservoir properties in such challenging scenarios.

World's first smart sensor is released

The world's first smart seismic sensor product, SmartSolo IG-16 Intelligent Seismic Sensor, has been released by SmartSolo Inc. Different from traditional seismic data acquisition systems that focus mainly on data transfer and storage methods, SmartSolo targets the root of seismic—sensors. The core of this smart sensor is DTCC's DT-Solo high-sensitivity geophone available in 5-Hz and 10-Hz options. The smart sensor knows its location (line and station number) and timing and records seismic reflections with the highest fidelity.

Each sensor weights about 2 lb including internal lithium batteries that can support recording up to 50 days. The SmartSolo has no external connectors exposed during normal field use operations. This greatly improves reliability.

SmartSolo mobile apps (iOS and Android) can be used for spread layout, navigation, technical support, training and inventory management. With the help of mobile Internet technologies, clients are able to get the highest efficiency at the lowest possible equipment and operational costs.

The target market for smart seismic sensors is ultra-scale, high-density and high-resolution seismic projects. Only extremely cost-effective equipment such as SmartSolo can make such projects possible.

Source reduces stress on marine life

The eSource from Teledyne is the first bandwidth-controlled seismic source designed to limit unwanted energy in the frequency range used by marine life. The eSource can be tuned to three levels that reduce high-frequency energy while retaining output that is crucial to seismic exploration, depending on regulatory and geological requirements.

Teledyne also will be showcasing other products at SEG, including:

- *RTS SmartSource Gun Controller*: The SmartSource is the next generation in digital marine seismic source control. With a simplified user interface and troubleshooting process, the system is now more reliable and functional than ever. The new design enables the most modern seismic source array and includes new controller and power supply units and a new solenoid control valve assembly with integrated real-time pressure, depth and continuous near-field hydrophone monitoring. The SmartSource works with existing sources, minimizing new equipment.
- *RTS/AG 24 Bit Hydrophone*: The rugged, encapsulated Smart Phone D, an integrated 24-bit digital hydrophone, sets new standards in near-field measurements. Digitizing at the sensor element provides the lowest noise interconnect, eliminating the issues of long signal lines and cross-coupling while providing unprecedented signature fidelity. The unique straight-to-digital design allows maximum flexibility in umbilical design by providing digital clarity regardless of length.

Wireless data acquisition system eliminates cabling

Wireless Seismic Inc. is releasing its RT System 2—a cable-free seismic data acquisition system featuring a high-bandwidth radio network that handles the real-time data transmission associated with the thousands of recording units required by modern 3-D surveys. Seismic contractors get the operational benefits of eliminating cables but no longer need to operate "blind" and deal with the significant overhead of manual data collection and transcription associated with autonomous nodal systems.

WRUs digitize reflected signals and relay these data along the line of WRUs to the central recorder. (Source: Wireless Seismic Inc.)

Wireless remote units (WRUs) placed at each recording location have a dual function: digitizing reflected signals generated below the surface and relaying these data along the line of WRUs to the central recorder. Since the radios only communicate across the interval distance of adjacent WRUs, modest battery power (from small custom lithium-ion batteries) efficiently supports hundreds of WRUs in a single "line" during deployment. Test results, battery capacity, data quality and other key facts are relayed back to the central recording system in real time; recorded data are safe from theft or failure, and the system operator can validate data quality and data integrity without delay.

The RT System 2 ensures that the seismic data are recorded properly via continuous quality control. The system requires significantly less crew personnel than a cabled system or autonomous nodal system. Because it is lightweight, the number of vehicles on the recording crew is substantially reduced, thus saving significant fuel costs and further reducing personnel costs. E&P

Taking a studied approach to drilling waste

Operators can calculate the risk and liability associated with their waste management policy.

Jeffrey Tyson, Scott Environmental Services Inc.

What is risk? As Leigh Buchanan and Andrew O'Connell put it in the January 2006 issue of the *Harvard Business Review*, "Risk is an inescapable part of every decision." Decisions regarding waste management policy in the oil and gas industry are no exception.

Drilling waste is one of the largest waste streams generated from oil and gas E&P in the U.S., with about 200 MMbbl of solid drilling waste produced in 2014 alone. Drilling waste consists of the drilled cuttings and unrecovered drilling fluids, including water- and oil-based fluids (e.g., diesel). The risk management of drilling waste should be an important aspect of every drilling mud program. There are multiple publications that include important guidelines as well as several companies that are able to help assess and manage this risk.

Risk is a balance of probability and liability

In a mathematical sense risk is a function of the probability of a poor or undesirable outcome and the associated costs or liability of that outcome. This is directly related to both probability and liability. One must first understand the probability and liability associated with a decision to determine risk. In accounting this liability is generally referred to as a "loss contingency" and may or may not be reported on the balance sheet, depending on the probability of a loss event occurring. For an environmental risk assessment, human health and ecological risk assessments should first be calculated. The degree of risk can then be a factor in estimating financial liability.

A land farmer distributes drilling waste over agricultural land. Drilling waste can include chlorides, heavy metals, hydrocarbons and other chemicals and additives that are necessary for drilling a well. (Source: Scott Environmental Services)

Taking risk into account when making decisions regarding waste management in upstream oil and gas is an important step toward sustainability and can be an integral part of a company's environmental, social and governance reporting. The American Society for Testing and Materials (ASTM) has published multiple guides for performing risk assessments and estimating costs and liabilities. These include ASTM E2137, *Standard Guide for Estimating Costs and Liabilities for Environmental Matters*, and ASTM E1739, *Standard Guide for Risk-based Corrective Action Applied at Petroleum Release Sites*. There also are various publications from other sources, including several from the Interstate Technology and Regulatory Council. These guides can be used for such things as business decision-making, regulatory requirements, insurance premium calculation and claim settlement, compliance planning, analysis of remedial alternatives, budgeting, strategic planning, financing, and investment analysis by shareholders.

Drilling waste management requires risk assessment

Incorporating risk assessment into a drilling mud program first involves determining what the various risks are for each disposal or remedial option and then estimating the costs and liabilities of each. Types of risk associated with drilling waste will generally include environmental risk, human health risk, ecological risk and business risk. Once each risk is evaluated, cost and liability estimates can be used to support the decision-making process.

One operator that used a similar approach in calculating risk and liability regarding its waste management policy was able to improve its waste management practices, thus reducing the company's liability and environmental footprint while also reducing overall costs. Prior to calculating the risk and liability, the operator was using a drilling waste management technique known as landfarming or soil farming to dispose of both water-based mud and cuttings and oil-based mud and cuttings. Landfarming involves spreading drilling waste over a large area of land with the goal of diluting the inorganic constituents such as chlorides and heavy metals and naturally bioremediating the organics, generally hydrocarbons such as diesel fuel. Both the water-based and oil-based cuttings contained an assortment of constituents with known risk and toxicity values but also contained proprietary chemicals with unknown risk and toxicity values. These unknowns increased the uncertainty of the risk assessments.

Based on chemical analyses of the water-based drilling mud and cuttings, it was determined that the controlling constituent was almost always the chloride concentration, but this did not take into account any proprietary chemicals that were added to the drilling mud. Chlorides are generally not a big concern to human health; however, much of the land where drilling waste was being applied was agricultural land, where constituents such as chlorides can have a negative impact on plant growth. Not wanting to negatively impact agricultural land, the operator was able to use this information in the decision-making process and adjust the spread rate of the water-based mud and cuttings according to the chloride concentrations from each well. This ensured that the final chloride concentration of the land did not exceed the maximum desirable concentration. Because chlorides do not degrade over time and move rather freely through the environment, the operator plans to monitor the soil quality and plant growth to determine if additional waste can be spread across the same land in the future. In certain areas the chloride concentration in the water-based mud and cuttings was so high that the amount of land necessary to apply the cuttings was more than what was determined to be acceptable. When this situation occurred, the operator opted to use alternative disposal methods such as landfilling or treatment and recycling.

After analyzing the waste from the oil-based section of the well, it was determined that petroleum hydrocarbons (TPH) would almost always be the controlling constituent for the risk determination. Oil-based cuttings from a 3,048-m (10,000-ft) lateral can contain more than 30,000 gal of TPH, much of which falls within the diesel range. The operator determined that to adequately mitigate this risk, the spread rate for landfarming oil-based cuttings would need to be very low. When calculating the amount of land that would be required at a reduced spread rate, the

Drilling waste containing diesel-range organics and other constituents is being stored at a receiving site prior to landfarming. (Source: Scott Environmental Services)

operator realized that the overall environmental footprint would be increased to nearly 100 acres per well. It was ultimately determined that the best course of action in this situation was to recycle the oil-based mud and cuttings using a solidification and stabilization technology. This allowed the waste to be recycled into new drilling pads and lease roads, thereby reducing the need to purchase raw materials for construction, lowering costs and decreasing the overall environmental footprint of the well. Once the waste is properly solidified and stabilized, the constituents, including the hydrocarbons, are chemically and physically sequestered, resulting in an elimination of nearly all of the risk compared to landfarming. Liability was reduced because the treated waste remained on the operator's lease rather than being spread on private land.

To control liability, waste management policies—including those for drilling waste—should be made using a risk-based approach. Differences in waste type, volume or chemical constituents can have a significant impact on the associated risk, but by using a formal risk-based approach to drilling-waste management, operators can have confidence that their waste management policies will reduce their exposure and minimize liability. Multiple methods and guidance exist that an organization can follow to make structured risk-based decisions about drilling waste. These decisions will fit well with a company's sustainability goals and will prove favorable in regard to environmental, social and governance reporting.

As shown by this case study, vigilance and adherence to a proper balance of risk and liability can have a significant impact on the bottom line, a primary advantage in these days of economic challenges to the oil and gas industry. E&P

References available.

DEVELOPING **UNCONVENTIONALS**

DUG MIDCONTINENT

October 26-28, 2016
Cox Convention Center
Oklahoma City, OK

BOOMING BREAKEVENS

PLAYS COVERED: **STACK • Meramec • Granite Wash • SCOOP • Woodford • Springer Shale**

AN ENDURING LEGACY

Midcontinent Producers Play Key Roles Driving Hopeful Recovery

Oklahoma has been a sleeper in the shale oil and gas world. After crude prices bottomed, the Midcontinent region, especially the SCOOP and STACK plays, saw a frenzy of asset deals. A small roster of oil and gas operators has been growing as legacy leaseholders double-down on core acreage (or add more), and cut debt or raise development capital by marketing producing and prospective leasehold to newcomers.

The fourth annual **DUG *Midcontinent*** conference and exhibition provides an ideal place to assess what's happening, what's working, and what's next. Among financial and producer viewpoints on the SCOOP and STACK and private operators' perspectives on the Anadarko Basin, speakers will reveal drilling strategies in the condensate- and NGL-rich Granite Wash, the Cleveland and other pay zones.

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Opening Keynote, Day 1

Stacked & Powdered Up

Wade Hutchings
Regional Vice President, Midcontinent Assets
Marathon Oil Corp.

With a key and growing position in the Stack play, capital raises and a strong equity valuation, Marathon Oil is poised to monetize the Meramec and other pay zones in the home of the legendary Sooner Trend. Learn about the company's Stack resource potential, current plans, and how it is further driving down costs and driving up EUR. Hear directly from Wade Hutchings, regional vice president of Midcontinent Assets.

Opening Keynote, Day 2

Derisking Over-Pressured Stack and Developing Scoop

Jack Stark
President and Chief Operating Officer
Continental Resources Inc.

Continental Resources brought in the Scoop-Woodford and Scoop-Springer discoveries earlier this decade. Soon, its legacy leasehold north of the play became promising for Meramec pay. One of its wells in the over-pressured window is flowing at more than 4,200 psi after six months online. Hear findings and plans directly from president and COO, Jack Stark.

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  New technologies offer operators a variety of ways to tackle their water and fluids challenges.
  Presenters include: TETRA Technologies, Fountain Quail Energy Services, Veolia and Digital H2O
- **Artificial Lift**
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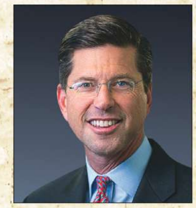
  Presenters include: NOV Completion & Production Solutions, Summit ESP, Baker Hughes and Flowco Production Solutions
- **Enhanced Completions**
  Enhanced completions incorporate a broad array of technologies and well designs to deliver success at the wellhead.
  Presenters include: Superior Silica and Thru Tubing Solutions

Featured Speakers



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FTG gets a makeover

A revamped design will improve sensing power by 20 times, providing more accurate geological information for exploration.

Rhonda Duey, Executive Editor

Full-tensor gravity gradiometry (FTG) is not necessarily a new technique—it was developed by Bell Aerospace Textron (later acquired by Lockheed Martin) in the 1970s and deployed by the U.S. Navy to aid in covert navigation. In 1990 the technology was declassified as an exploration tool, driving its commercialization into the energy industry.

Various notable improvements to reduce noisy gravity data have been made to FTG technology over the years, making it a viable technology for natural resource exploration. However, noise in the measurements still limits what can be inferred about the geology being explored.

A new player has entered the multiphysics acquisition field. NEOS, which was previously a multiphysics processing and interpretation company, announced its plan to acquire the Multi-Physics group of CGG in April; the deal is expected to close in the near future. NEOS recently announced a new generation of FTG sensor that it's developing with Lockheed Martin called FTG Plus. It promises to be 20 times more powerful than current technology. The technology, which reduces sensor noise to the point where it is no longer a limitation on the use of gravity data, can be deployed on a vessel or aircraft.

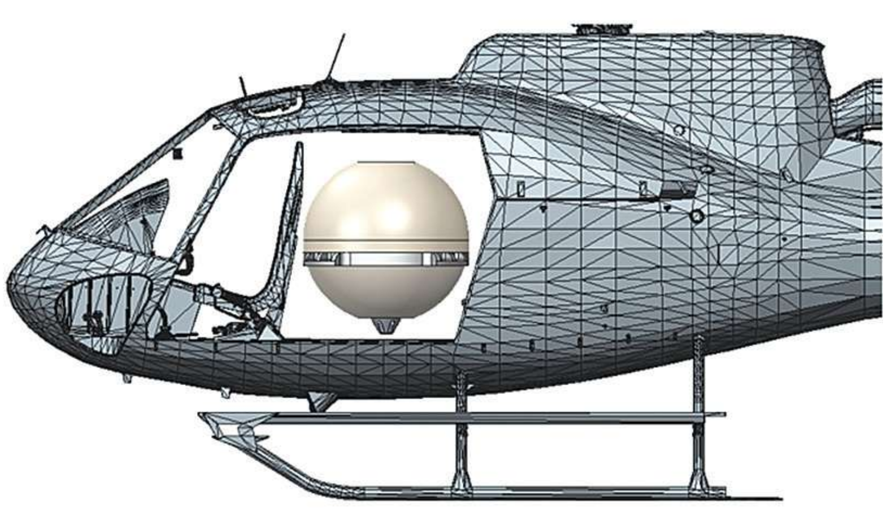
E&P talked to Mark Dransfield of NEOS, the chief scientist for the program.

E&P: ***Can you explain how current FTG methods work?***

Dransfield: 'FTG' is a name for a type of gravity gradiometer. Gravity gradiometers provide very sensitive measurements of the changes in the Earth's gravity field while traveling in an aircraft. Accelerometers are used to measure the gravitational acceleration, but achieving sufficient accuracy to be useful for exploration requires overcoming several challenges.

The first challenge is that the accelerometers cannot distinguish the accelerations due to motion from those due to gravity. This is overcome by measuring the difference in signal between two accelerometers joined rigidly together but spatially separated. Because they are rigidly connected, the two accelerometers experience the same acceleration due to aircraft motion, and this cancels out when the difference is taken. Since they are spatially separated, one accelerometer will generally be closer to the gravitational source than the other and will have a larger gravitational measurement. The result is a residual gravitational signal when the difference is taken, and this is the gravity gradient. The greater the spatial separation, the greater the sensitivity to gravity.

The second challenge is that rotations also cause accelerometer signals not distinguishable from gravity. This is tackled in two ways. Firstly, the use of a second pair of accelerometers oriented orthogonally to the first pair provides for cancellation of centrifugal accelerations. Secondly, mounting the set of accelerometers on a rotationally stabilized platform allows the accelerometers to be kept pointing in a constant direction while the aircraft rolls and pitches as it travels. This



The greater sensitivity of the FTG Plus will improve the mapping of small deep faults, salt features and intrusives such as volcanics. (Source: NEOS)

second approach also is used to keep cameras pointing in a constant direction so that movies can be shot from moving vehicles. Current gravity gradiometers operate mounted in a nested set of three rotationally stabilized gimbals.

E&P: ***What tweaks are necessary to make FTG Plus 20 times more powerful?***

Dransfield: Making a gravity gradiometer with 20 times more sensitivity requires first increasing the separation (called the "baseline") between accelerometers. This must be done without increasing the size or weight of the gravity gradiometer so it remains light enough to be carried on small aircraft, including helicopters. Current gravity gradiometers have the accelerometers mounted on a rotating wheel inside three nested gimbals, and we need to have the rotational control moved to the center with the accelerometers on the outside. This reversal of the relationship provides a large increase in baseline and hence sensitivity.

The current nested-gimbal technology is a limiting factor on improving sensitivity, and the FTG Plus replaces the rotational control geometry with a single-point air bearing. The air-bearing technology is the key to allowing us to perform rotational control inside the accelerometers. Air bearings are essentially frictionless and will provide better rotational control than gimbals. This better rotational control means less error due to the pitch and roll of the aircraft in flight and so allows additional sensitivity for the FTG Plus.

E&P: ***What are NEOS and Lockheed Martin bringing to the development?***

Dransfield: NEOS is bringing several things. Based on our knowledge of industry needs and our decades of experience flying airborne geophysical surveys, we set the specification goals for the technology. We are responsible for the interface designs that determine how the instrument integrates with the various other systems onboard the aircraft, and we are responsible for the necessary improvements in survey design and logistics to maximize the value of the FTG Plus. We also will lead the development of the data processing software and will spearhead turning the processed data into information (for example, interpretations and 3-D earth models) that is of direct value in exploration.

Lockheed Martin brings decades of experience in building gravity gradiometers. It is the only company to build a working commercial airborne gravity gradiometer, and it has incrementally improved many times on the first working gradiometers to build better systems. For the FTG Plus technology, Lockheed Martin's engineers are driving a major step change in gravity gradiometer technology. Lockheed Martin is designing and building the entire gravity gradient sensor.

We will be working closely together on the entire project. FTG Plus is the first time Lockheed Martin has specifically built a sensor for our precise use and needs. That is a fundamental change; it is an entirely new design for us, and we will have exclusive rights to use it.

E&P: ***What benefits do you expect the oil and gas industry to realize from this new technology? Are there places where it's unlikely to work?***

Dransfield: The FTG Plus sensor will provide more geological information at greater accuracy in every application from near-surface to deep basement. The greater sensitivity will allow the detection of small and subtle fault structures at greater depths than is possible today. This will improve the mapping of small deep faults, salt features and intrusives such as volcanics. At intermediate depths, sedimentary geological features below basalt layers and subsalt will be better resolved, providing more certain identification of their size, shape and density. The better spatial resolution will allow mapping of very shallow features such as karsting, shallow compaction, velocity anomalies, geohazards and so forth. There will be value in structural mapping, seismic survey planning, shallow reservoir estimation, joint seismic-gravity inversions, velocity models, salt modeling and many other aspects of oil and gas exploration. With this technology gravity gradiometry will become useful in deeper basins and will supplant detailed ground gravimetry for mapping shallow features.

E&P: ***On a cost-per-kilometer basis, how will this compare to 2-D and 3-D seismic, current FTG technologies, electromagnetic technology, etc.?***

Dransfield: Airborne geophysical technologies are dramatically more cost-effective than seismic, typically by about two orders of magnitude or more. This also will be true for FTG Plus. Of course, actual prices vary depending on survey design, operational logistics, location and the type of aircraft. Furthermore, acquisition from the air is more environmentally friendly and can be completed faster than traditional seismic.

We look forward to commercializing FTG Plus in the market and providing greater value to our customers than possible with other gravity gradiometer technologies. E&P

Gravity and magnetic geophysical methods in oil exploration

Potential fields measurements bring a needed boost to geological interpretation.

Henry Lyatsky, Lyatsky Geoscience Research & Consulting Ltd.

Gravity and magnetic methods are an essential part of oil exploration. They do not replace seismic. Rather, they add to it. Despite being comparatively low-resolution, they have some very big advantages.

These geophysical methods passively measure natural variations in the earth's gravity and magnetic fields over a map area and then try to relate these variations to geologic features in the subsurface. Lacking a controlled source, such surveys are usually environmentally unobjectionable.

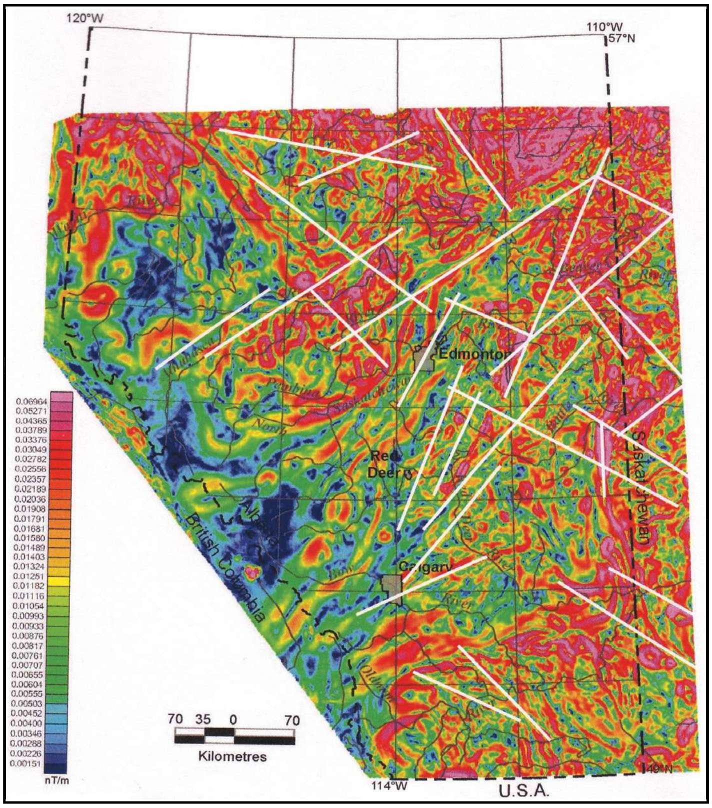


FIGURE 1. This regional horizontal-gradient magnetic map of central and southern Alberta shows selected lineaments highlighted as straight white lines (after Lyatsky *et al.*, 2005). (Source: Lyatsky Geoscience Research & Consulting Ltd.)

At a comparatively low cost, airborne potential-field surveys can provide coverage of large areas. Allowing quick regional coverage, even gravity urveys can now be recorded from an aircraft with airly high reliability.

In Canada, digital regional gravity and magnetic data are available at zero cost from federal government agencies. Local and detailed surveys are acquired by exploration companies.

Because many college programs tend to overemphasize seismic as almost the only geophysical tool for oil exploration, other methods are sometimes overlooked by explorationists and managers. Where useful gravity and magnetic data are disregarded, risk reduction is incomplete, and the results of exploration programs are less reliable.

What anomalies mean

The physical rock property that links gravity anomalies to rock composition is density. The rock property that links magnetic anomalies to rock composition is total magnetization. Thus, each potential-field method valuably provides its own picture of the subsurface.

Density is scalar, but magnetization is a vector total of a vast and commonly unpredictable variety of remanent and induced magnetizations. Unlike density, magnetization can depend on very slight variations in the occurrence and distribution of particular minerals, which may have little relation to the overall lithology.

A geophysical anomaly is the difference between the observed (measured) geophysical field value and the value that would be observed at the same location if the Earth were more uniform. Nonuniformities in the physical properties of rocks give rise to geophysical anomalies.

Being responsive to lateral variations in rock properties, gravity and magnetic methods are best suited for detecting steep discontinuities such as faults. Seismic methods, by contrast, are best for detecting vertical rock variations and low-angle discontinuities such as layer boundaries.

The gravity field is simple, unipolar and almost perfectly vertical. The geomagnetic field is complicated: It has two or more poles, and it is commonly strongly nonvertical. Besides, it changes all the time, necessitating frequent updates by government agencies.

Gravity lows (negative anomalies) occur where rocks in the subsurface have a comparatively low density, which reduces their downward gravitational pull. Where the rock density is relatively high, the gravitational pull is increased, and a gravity high (positive anomaly) occurs.

Magnetic anomalies are more complex because the magnetic field and rock magnetization are both complicated. With a nonvertical dipolar field, a single rock-made anomaly source can be deceptively associated with a pair of apparent anomalies: a high and a low side by side.

Gravity and magnetic surveys should be designed purposefully to resolve the specific kind of anomalies that are expected from geologic targets of interest in a particular study. If a survey is too tight, money is wasted on redundant coverage. If a survey is too sparse, the desirable anomalies are undersampled and not delineated sufficiently. The idea is to design the sparsest and smallest, hence cheapest, survey that would resolve all the expected desirable anomalies.

Examples of exploration use

In the platformal Phanerozoic Alberta and Williston basins, most big magnetic and gravity anomalies are associated with ductile structures and rock composition variations in the crystalline basement inherited from orogenic events in the Precambrian. Such ductile ancient structures were fairly seldom reactivated, and they had relatively little influence on the Phanerozoic basins above.

More important are the later brittle basement faults and fractures, whose offset can be as little as a few meters, sometimes below seismic resolution.

Such brittle faults had a variety of direct and indirect influences on many intervals in the Phanerozoic sedimentary cover. They are commonly associated with subtle gravity and magnetic lineaments, some of which cut across the regional pattern of major anomalies. To help delineate fault networks, researchers created a regional

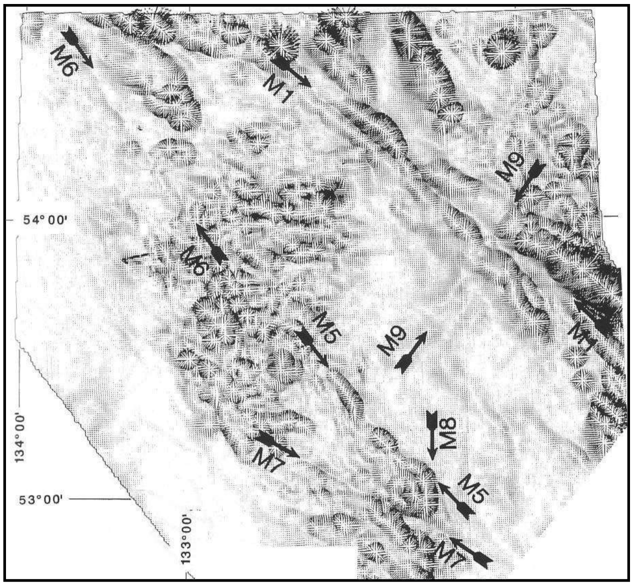


FIGURE 2. In this horizontal-gradient magnetic vector map of the Queen Charlotte Islands and Hecate Strait, British Columbia, the numbered heavy black arrows indicate magnetic lineaments. Light thin lines indicate the magnetic horizontal gradient, with length proportional to the gradient magnitude and pointing "downhill." (Source: Lyatsky Geoscience Research & Consulting Ltd.)

gravity and magnetic atlas of the southern and central part of the Alberta Basin.

A gravity or magnetic lineament can be a gradient zone, linear break in the anomaly pattern, straight anomaly or even an alignment of separate local anomalies. Long lineaments are more likely to be associated with faults than short ones, especially if they occur in swarms or are a part of a regional pattern.

The best data processing methods are simple and intuitive so that derivative maps and anomalies are easy to relate to their precursors in the raw data.

Gravity and magnetic data can be processed specifically to highlight subtle lineaments (Figure 1). Particularly useful processing methods tend to be first and second horizontal and vertical derivatives, third-order residuals, automatic gain control, total gradient (analytic signal) and shaded-relief maps (shadowgrams). Wavelength filtering has a major pitfall in that Gibbs ringing can produce lineament-like artifacts, so it is best avoided.

To help identify faults, gravity and magnetic lineaments should be compared with topographic and drainage lineaments. Seismic data and geological studies can help to determine if suspected faults had an influence on any particular play interval.

In horst and graben basins such as the offshore Queen Charlotte Basin on the west coast of British Columbia, the first step is to examine geological information from the surrounding areas on land and from drillholes in the basin. The pattern of raised and lowered crustal blocks in and around the basin can be determined from geologic field mapping and from a combination of seismic and gravity data.

Magnetic data (Figure 2) in the Queen Charlotte Basin were used to further delineate the networks of local and regional faults. Seismic data in this basin suffer from an uneven maximum depth of signal penetration due to the presence of numerous volcanic stringers. On land and offshore magnetic data were instrumental in the delineation of extrusive and intrusive igneous rocks, which was crucial for understanding the patterns of organic maturation.

Teaching of gravity and magnetic methods

The relatively low priority given to potential-field methods in many oil-oriented college programs impoverishes students and their employers. Where gravity and magnetics courses exist, too often they focus—with intimidatingly advanced mathematics—on the physics of potential fields at the expense of exploration applications, survey design and methods of geological interpretation.

Too many gravity and magnetics textbooks are also very mathematical (with a superb exception of Nettleton, 1971). Too little tends to be said about the relationships between anomalies and variations in rock composition, which is the key to geological interpretation.

Misleadingly, numerical inversions of potential fields data are sometimes presented as interpretations. However, mathematics is abstract. Interpretation is essentially geological, with geophysical data used to provide geological information.

When geologists, seismologists and potential fields experts are too narrowly specialized, they do not talk to each other enough. The result is commonly disregard of valuable gravity and magnetic information. Alternatively, interpretations are too numerical to be useful if geological considerations are ignored.

Gravity and magnetics experts in oil exploration should talk less in an echo chamber among themselves. They should learn to think more like their clients, who tend to be geologists and seismologists. Their work should be presented from first principles, with minimum mathematics and with maximum geological consideration. Only then can interdisciplinary walls be brought down and exploration managers can vividly see the essential practical utility of gravity and magnetic methods. E&P

References available.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Collaboration leads to rig advances

The first system for fully automatic tripping is the result of the joint effort between a drilling rig manufacturer and an integrated operator.

Gilberto Gallo, Drillmec

The negative general trend of the past two years of the oil price has put a considerable strain on the upstream side of the oil and gas industry, generating a Darwinist market consolidation. E&P investments fell by 30% in 2015 and will reveal similar numbers in 2016, posing some serious doubts on the structure of the existing business model. The overall drilling rig count is down, though it is growing at a slow pace, counterbalancing the industry's overreaction to the downturn. The volatility of the oil price could endure indefinitely since there is no clear model that indicates a consistent positive pattern despite an overall growth in oil demand.

Necessity for technology improvement

Therefore, the industry is once again facing restructuring through cuts and adjustments, losing talent and resources to keep going. A long-term solution needs to encompass a reevaluation of the downfalls of the system in place and the allocation of investments to actuate the required changes and find a way to match the current market. Reducing the breakeven point is the main objective and is realistically achievable only through the development of new technology. However, the companies that managed to survive need positive cash flow and low-risk investments to start reducing their accumulated debt. In the past decade the most important performance and efficiency improvements through technology advances have been reached in onshore activities, while the investments in the offshore segment presented difficulties and unsatisfactory results. Onshore drilling also requires less financial exposure for a relatively shorter time period when compared to offshore projects given its cash flow structure and therefore looks like the best path out of this slump.

Looking at the existing drilling rig fleet, there undoubtedly still are several underperforming land drilling rigs, while many others have been stacked, have not been maintained properly, or are simply obsolete and not able to perform at economically feasible rates. All of these factors should give birth to more efficient and high-specification newbuilds with more room for automation, better data management and overall performance improvements.

The HH-300 hydraulic hoist 600,000-lb hookload capacity drilling rig has been performing operations with DATS for the past year. (Source: Drillmec)

Burden of the investment

The underlying issue arises when seeking investment allocation for drilling technology development in such an unpredictable period. Innovation should surely fall onto equipment manufacturers, the main stakeholders at a first glance. The R&D expenditures would then fall on the final user, the drilling contractors, which are in fact currently unable to make conspicuous long-term financial commitment. High-tech drilling rigs come with a premium, and the contractors are not in any position to invest during a period in which their contracts' lengths and daily rates are at their lowest in quite some time. The oil companies, therefore, seem to have the upper hand, being able to choose from a variety of contractors and service companies willing to work at lowered fees. Nevertheless, to achieve a better final price point, the changes need to be promoted by a joint effort between manufacturers, contractors, oil companies and, ideally, service companies. While the funding and risk remuneration would appear to be complex to split, the integration on the planning side is surely the way to improve overall efficiency. Designing new drilling rigs and equipment focusing on coinciding objectives of overall performance in total safety and improved efficiency is the path to follow.

Drilling automation

Drillmec has responded to this need with the creation of the Drillmec Automatic Tripping System (DATS), the first system for fully automatic tripping. The company has been pushing drilling automation since the 1990s and has released numerous new technologies such as the first hydraulic hoisting system, the first totally unmanned automated pipehandling system and the first super singles land drilling rigs.

DATS is the result of the joint effort between a drilling rig manufacturer and its client, an integrated operator also performing the drilling operations. This latest automatic configuration of the Hydraulic Hoist (HH) Series Rigs represents a huge step toward complete automation and human errors reduction. The company worked closely with its client to develop the DATS technology, also comparing performance data gathered from some of the 200 HH Series units across the globe. The cooperation worked for a number of reasons, with the common goal of improving performance in a cost-effective and repeatable pattern based on direct and transparent feedback from the client. It was a joint effort in both technology development and financial risk. Indeed, the client covering both the operator's and the drilling contractor's roles proved to be instrumental for this achievement.

Drillmec was able to develop and sell its technology with the opportunity for further improvement through a tight cooperation that guaranteed access to the well and to the rig mainly for tracking purposes.

With the introduction of DATS, Drillmec's HH Series Rigs can perform both the trip-in and trip-out operations automatically.

DATS

The system is a package that comprises software and hardware that enables secure, efficient and stable run-in-hole and pulling-out-of-hole movements under the passive supervision of a driller.

The intelligent tubular management system automatically records each pipe's length, hours spent in the hole and hours of rotation in a precise way without the aid of any external device, contributing to simplifying the operation as well as enhancing safety and tracking the tubulars' working lives.

Another aspect that contributes to safety and efficiency is the DATS' human machine interface. This intuitive new system includes different alerts and security verifications that work both as safety gates to the start of the operations and preferential paths throughout the drilling process. It gives a just-in-time operational assessment through a complete display of the most important key parameters combined with an algorithm that automatically provides different prearranged options for the driller to pick.

DATS is applicable to any configuration of Drillmec's pipehandling systems and symbolizes another step toward the reduction of human error, increase of personnel safety and the complete automation of drilling rigs. The system has been shown to guarantee consistent and improved average performance and also is effective in terms of the utilization of the drilling crew. In fact, during the automatic trip-in and trip-out phases, rig floor personnel might be used for other activities while the driller is only supervising all of the operations.

Since the beginning DATS has shown to be efficient and reliable as well as providing repeatable rig performance and predictable operation times. The next frontier for DATS is the application of part of this technology to add and rack back stands during drilling operations. This new development together with the HH Series auto-driller supervision will enhance the performance level in terms of safety, efficiency and rig utilization.

The system also can be accessed remotely by Drillmec's dedicated service, the Drillmec Diagnostic System, which improves safety and support and dramatically reduces equipment downtime through predictable maintenance parameters and a built-in troubleshooting diagnostic system.

An evolution of the upstream section of the industry is due and necessary to continue to represent the world's main energy source. The industry might never reach the 3,670 global drilling rigs registered in November 2014, but production levels can rise with new high-specification rigs with improved performance, efficiency and safety and a lowered breakeven point. Efficient innovation resulting from cooperation between the different stakeholders of the industry are examples to follow. E&P

LCM reduces risk, saves time

Resilient characteristic of material compresses and rebounds with pressure changes.

Donald Whitfill and **Sharath Savari**, Halliburton

Lost circulation generates significant risks and associated costs, particularly in an offshore drilling environment. In an ideal application, prevention is the best remedy, but this is not always possible. A material that can both help prevent losses and aid in mitigating losses when they occur is ideal.

STEELSEAL resilient graphitic carbon (RGC) lost circulation material (LCM) from Halliburton Baroid helps prevent lost circulation by sealing porous and fractured formations. It is designed with a unique resilient characteristic that allows it to compress within a fracture as downhole pressures increase during fracture closure stress, then rebound if pressures decrease, such as during tripping.

Tests available from a joint industry project in 2000 indicate that LCM type, concentration and particle size distribution are important factors for lost circulation control. Of these parameters, particle type seemed to be the most important variable for obtaining a fracture sealing response in the test apparatus. Repeated fracture sealing responses were seen in tests using STEELSEAL RGC. Further, combinations of this material were effective when used in conjunction with other materials that were ineffective on their own.

Manufacturing process

Resiliency is a compressive property allowing the material to mold itself into a fracture tip, promoting screenout. If pressure is released, the material rebounds, thus continuing to plug the fracture. The RGC materials are manufactured in a proprietary electric furnace process that produces a material with a high resiliency plus other desirable characteristics. The LCM is a purified resilient calcined petroleum coke that has been processed and structurally modified by exposure to high temperatures. The precursor, calcined petroleum coke, is processed in a continuous electrothermal purification furnace. The furnace operates in an inert environment at temperatures reaching 2,400 C (4,352 F). The resulting thermally purified calcined coke is uniquely modified to offer high carbon purity (99.5% C) and a more ordered crystalline structure with high resiliency.

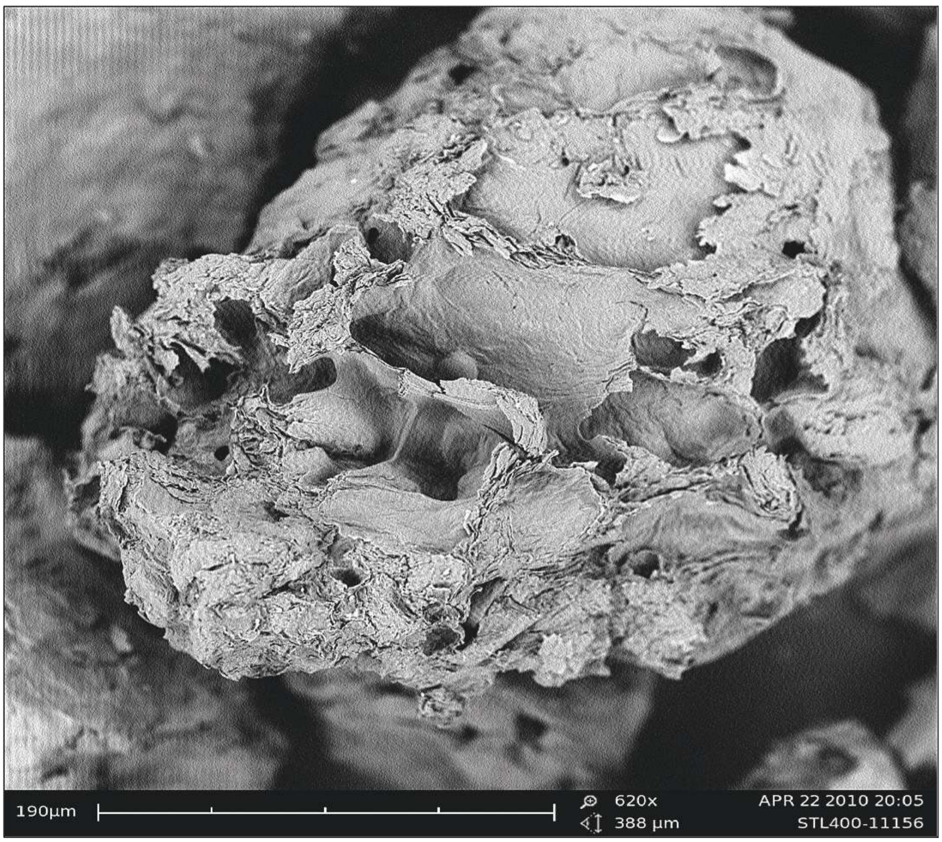


FIGURE 1. The STEELSEAL's irregular shape and open pores lock particles in place. (Source: Halliburton)

Resiliency testing

Since resiliency is not a general characteristic of most other LCMs, special test equipment and protocol must be used to measure this characteristic precisely. A special cell along with a compressive device to provide a measurable force on the test material is required and shows that RGC materials possess a unique spring-back effect greater than all other graphite-based materials. There are a number of unique attributes that lend to their solution as a wellbore strengthening and loss circulation management additive, including resiliency, morphology, true density and lubricity.

A hydraulic press that can apply load in the range of 10,000 psi was used to determine the resiliency. Steps followed for determining the resiliency were based on the standard operating procedure of Superior Graphite. Determination of resiliency requires two measurements to be made, height of the compacted sample when load has been applied and height of the rebounded sample when load has been removed. To accomplish these measurements, certain modifications in the Superior Graphite operating procedure were done. Full details of the testing method are covered in the SPE-133484-MS technical paper "Wellbore Strengthening: The Less-studied Properties of Lost-circulation Materials."

Characteristics

Morphology. Irregular shape and open pores aid in locking the particle in place (Figure 1).

True Density. Lower true density with respect to conventional graphite and carbon materials makes it possible to achieve higher loading values (parts per barrel [ppb]) and reduction of particle settling in the drilling fluid.

Lubricity. The LCM is unique in the fact that the surface is partially graphitized during the purification process and offers only enough lubrication to optimize interparticle locking and packing. A solid lubricant physically separates surfaces; a liquid lubricant cannot. Moreover, a solid lubricant is particularly effective in reducing hard-faced tool joint wear and liner running and aids in casing rotation and placement.

Nonmagnetic. The material is also not magnetic, as it is sometimes mistakenly perceived. Refer to SPE-153154 paper for more details on this perspective.

Resistance to size degradation. The benefit of resiliency is that it imparts significant resistance to size degradation. This is particularly important when it is used in loss prevention modes as a background material in the drilling fluid. STEELSEAL LCM was measured to have the highest resistance to size degradation (under similar test conditions) when compared to LCMs like ground marble and other regular conventional graphites. These results have been reported by several investigators and can be found in publications such as SPE-133484, AADE-12-FTCE-27, SPE-151227, SPE-165150 and SPE-163512.

Worldwide field applications

The versatility of the RGC has been proven in many field applications. Examples range from use in moderate to high concentrations to combinations of materials.

In the Middle East in an application where a well control event and subsequent lost circulation occurred, 20 ppb of sized 100 and 400 LCMs were incorporated into the active system through drilling operations, gamma ray, resistivity and sonic LWD tools. The well was killed successfully, and shut-in casing pressure was reduced from 900 psi to 0 psi. The INNOVERT fluid oil-water ratio changed from 80/20 to 60/40 with no loss of stability.

Additionally, an operator in North America that was drilling with a low solids nondispersed fluid experienced severe lost circulation, and about 1,500 bbl of fluid was lost to the formation. Historically, losses were previously minimized to less than 10 bbl/hr, and full returns were never regained. In more severe cases, cement plugs had to be placed to continue drilling operations. Several 50-bbl pills with 100 ppb of STEELSEAL LCM were mixed and spotted on bottom through the troublesome intervals. After spotting the pills the operator applied a gentle squeeze to the formation. After applying each squeeze, it was noted that the formation integrity was increased by more than 1 parts per gallon (ppg), and full returns were regained.

STEELSEAL has demonstrated benefits in deepwater environments as well, including a case where an operator encountered lost circulation at a rate of 15 bbl/hr. The formation integrity test (FIT) had not yet been conducted. The drilling fluid in use was a 14.2-ppg synthetic-based mud. The density was decreased to 13.8 ppg, but losses continued at 2 bbl/hr. To drill ahead, the operator needed to achieve a FIT equivalent to 14.6 ppg. This problem had not been encountered on other wells in this field. Halliburton developed a customized high-concentration LCM pill prepared on the surface to be ready for deployment. The 100-bbl pill consisted of the STEELSEAL engineered composite solution and BARACARB sized ground marble.

The 70-ppb pill was pumped through a 10⅝-in. by 11¾-in. drilling bottomhole assembly that had 8 12⁄13-in. bit nozzles and included downhole tools such as pressure-while-drilling, resistivity, gamma ray, sonic, density and neutron services. After spotting in the open hole, small hesitation squeezes were performed in 2-bbl increments. The operator was able to increase the wellbore stress by 915 psi. Then 3 m (10 ft) of new formation was drilled and the required FIT of 14.6 ppg was achieved. The production interval was drilled successfully to the target depth with no additional losses. E&P

Combined techniques drill through tough formations

Coupling two different specialized drilling techniques can produce significant benefits.

Steve Rosenberg, **Ming Zo Tan**, **Juan Valecillos** and **Maurizio Arnone**, Weatherford International

As operators have moved into more challenging areas, conventional drilling systems have fallen short of reaching total depth (TD) efficiently, safely and economically. Service providers have responded by developing specialized technologies and techniques that enhance efficiency, safety and economics. Drilling with casing (DwC) and drilling with liner are among the specialized techniques that have emerged and are increasingly being deployed to overcome challenges encountered in mature fields, deepwater basins and wells with depleted or unstable intervals. Coupled with closed-loop drilling (CLD) systems and techniques such as managed-pressure drilling and underbalanced drilling (UBD), operators can navigate difficult wells and problem zones to reach reservoirs that would otherwise be inaccessible or economically unviable.

This integrated multidisciplinary approach harnesses the benefits of both CLD and DwC techniques. First, the use of a CLD system enables precise control over the annular pressure profile. This capability enables drillers to avoid unnecessarily high overbalanced levels that often lead to mud losses, differential sticking and formation damage. CLD systems also help prevent formation influxes by adjusting the bottomhole pressure (BHP) as needed to suppress a kick or control flow.

Additionally, CLD systems reduce HSE risks as well as nonproductive time (NPT) related to fluid kicks and losses. DwC systems further optimize CLD operations by reducing the number of trips and associated surge and swab effects, improving borehole wall sealing through the smear effect and in some cases eliminating the need to kill the well prior to cementing. Current casing-bit technologies also eliminate the requirement for a dedicated drill-out trip.

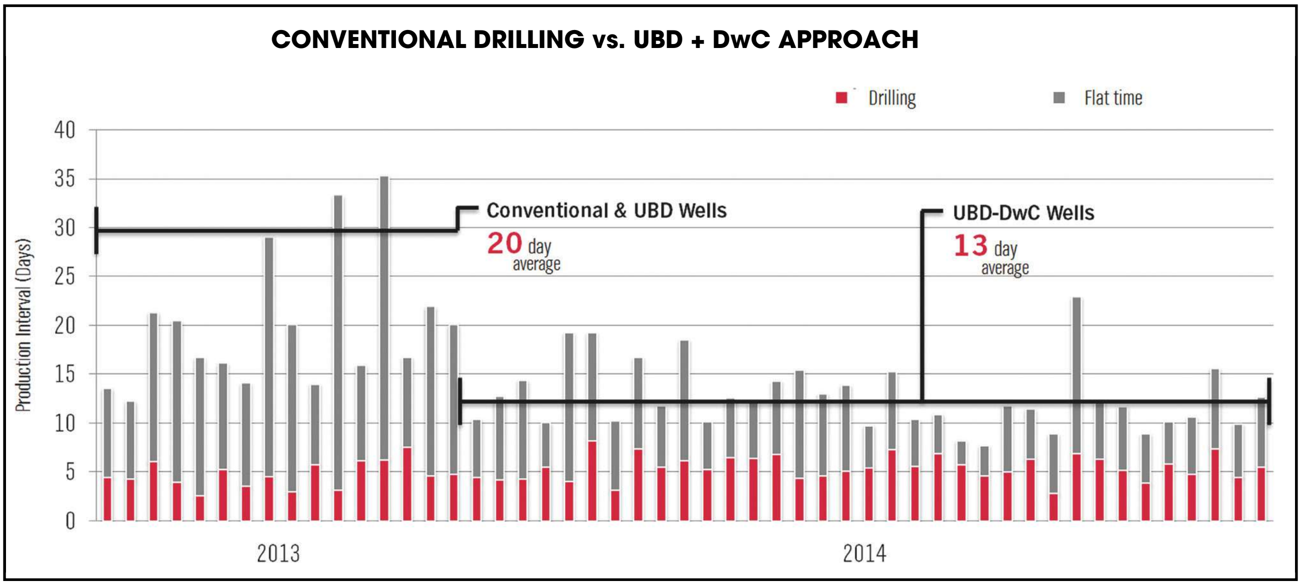
Under a conventional drilling philosophy, challenging sections with narrow pore and fracture pressure windows are generally addressed with high mud densities and additional casing and liner strings. However, these strategies often lead to NPT due to mud losses, differential sticking or severe kick-loss scenarios. By drilling such challenging sections using a DwC system in an underbalanced state, wellbore pressures can be maintained below the pore pressure, allowing the formation to produce while drilling, and by mitigating well-control issues, the technique enables operators to evaluate the formation productivity potential as the interval is being drilled.

Salt Creek Field

The value of combining these two techniques has been demonstrated in several fields across North and South America. One such operation took place in the mature Salt Creek Field in Natrona County, Wyo., where an operator encountered multiple well control problems while attempting to conventionally drill a gas injection well and eventually abandoned the well. While drilling previous wells in this field, the operator had experienced issues related to formation pressure uncertainties resulting from CO_2 injection activity. To resolve the abnormal pressures encountered, the operator had used high mud weights, which caused numerous problems during well control operations.

Weatherford was contracted to reenter the abandoned well and drill from the top of cement at 147 m (483 ft) inside the 7⅝-in. surface casing to the planned TD at 701 m (2,300 ft). The team selected 5-in. 18-lb/ft casing, a 6¾-in. polycrystalline diamond compact (PDC) bit and an initial mud density of 8.6 parts per gallon (ppg). The main objective was to avoid killing the well between tripping out the drillpipe and running the casing string, even if abnormal pressures were encountered. Secondary objectives included minimizing formation damage, maximizing post-completion injectivity, minimizing the risk of differential sticking and eliminating additional trips to condition the well and run casing.

To address these challenges and improve efficiency, Weatherford implemented an integrated approach that combined the UBD and DwC techniques. Before drilling, the engineering team performed a comprehensive evaluation based on offset well information and the data recorded during the initial drilling operation. The resulting pressure and flow predictions informed the selection of surface equipment, including a rotating control device, a UBD choke manifold, a



Using the UBD plus DwC approach, the operator saved seven days of drilling time. (Source: Weatherford)

four-phase separator capable of handling 1.1 MMcm/d (40 MMscf/d) and 20,000 bbl/d, a flare stack and pipework. The engineering evaluation also defined a flow-control matrix that provided clear limits for the UBD operation based on flow and pressure conditions as well as the CLD equipment ratings and capacities.

During drilling, the combined DwC and UBD methodologies effectively managed the annular pressure profile and well effluents and enabled the well to reach the target TD. Throughout the 35.5-hr operation there was zero NPT related to kicks or losses, and the average ROP was 16 m/hr (54 ft/hr), significantly higher than the average rate of 8.5 m/hr (28 ft/hr) for conventionally drilled wells in the field. The annular pressure profile was managed throughout by adjusting the surface backpressure, effectively avoiding influxes and maintaining a steady BHP environment during static conditions.

In addition to the time savings achieved through efficient annular pressure control, the cement job was completed just 3 hours after reaching TD because of the single-trip DwC system.

Time, cost savings in South America

Weatherford also has implemented this approach to drill development and exploration wells in a basin in South America, which covers an estimated 69,685 km (43,300 miles) in Argentina and central Chile. The basin comprises multiple fields and sub-areas with diverse well designs and types. In one project, wells with type-S profiles were drilled using the combined CLD and DwC approach. The vertical intervals were executed with a 6½-in. PDC bit and 5-in. casing.

On these wells after the casing was landed at TD there was no well kill operation performed prior to the cement job. Having a good knowledge of the BHP conditions, managed-pressure cementing operations were carried out. During these operations the circulating BHP is adjusted by means of the choke manifold to be within the limits provided by the pore and fracture pressure limits throughout the pumping operation.

Broadening drilling horizons

The cases described above demonstrate that coupling two different innovative drilling techniques can, with proper planning and implementation, produce substantial benefits. The key to successfully combining multiple disciplines to execute challenging drilling operations is increased time and effort during the planning phase. During this stage, comprehensive engineering analyses, including tubular mechanics evaluation, hydraulics modeling, and kick tolerance and risk analysis, should be performed to assess the feasibility of the integrated operation and to verify the compatibility of all systems involved.

Considering the preliminary results of combining CLD and DwC technologies to efficiently drill complex well profiles, the potential of integrating multiple methodologies is clearly an area that deserves further exploration. Service companies must continue to develop innovative, integrated drilling techniques as the needs of operators become more complex, especially at a time when reducing drilling costs is necessary. E&P

Remote advisory service improves drilling performance in offshore environments

Service helps minimize both NPT and ILT.

Fernanda Gandara and **Mark Schellhaas**, Baker Hughes

During the process of drilling a well, operators must continually react to a complex interplay of geologic, hydraulic, mechanical and human factors if they are to successfully reach target depth. Despite continuing technological advances designed to drill longer and more complex wells, opportunities remain to improve drilling efficiency and safety in the face of tighter operating budgets.

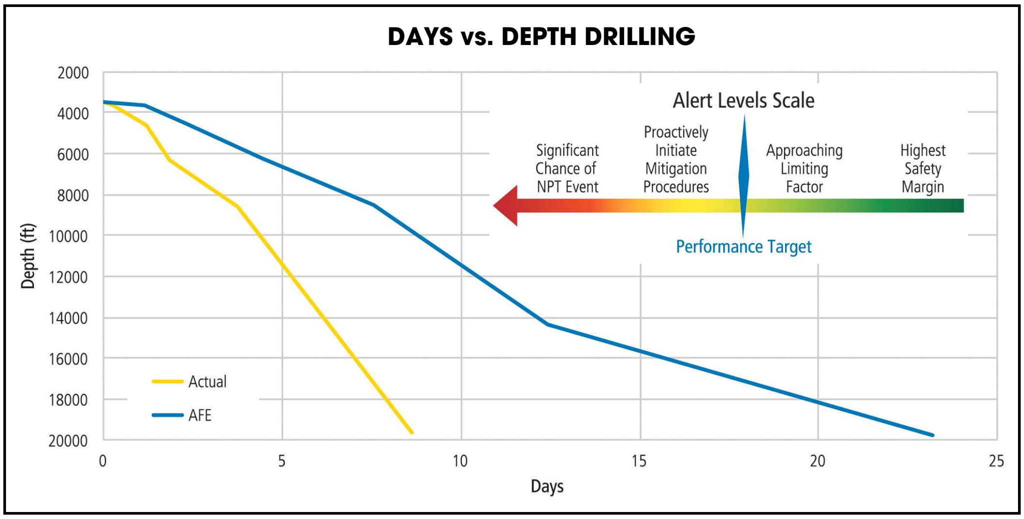
Increased efficiency during the drilling process is directly related to the ability to mitigate nonproductive time (NPT), the time lost from events like wellbore issues and equipment failures, and invisible lost time (ILT) caused by inefficiencies in routine operations such as tripping pipe, back-reaming, or making up and breaking down equipment. NPT is the common target of most drillers' efficiency measures, while ILT is difficult to identify, is rarely quantified and often accumulates during drilling activities. According to some industry sources, NPT can account for 10% to 40% of an operator's budget, and ILT can add 20% to 40% in operating costs.

Improving surveillance, communication

Current shortcomings in improving drilling efficiency and safety prompted Baker Hughes to develop the SIGNALS remote drilling advisory service, designed to identify factors leading to ILT/NPT and proactively mitigate them in real time. The service, which leverages the company's WellLink Drilling Suite software, combines skilled personnel, smart visualization, key performance indicator (KPI) monitoring applications and alarm manager software. This combination of people and tools identifies leading indicators of drilling-related problems in five categories that include KPI analysis, equivalent circulating density (ECD) management, hole cleaning, torque and drag, and drilling dynamics. Taken together, these categories provide a comprehensive analysis of hole condition and operational efficiency that affords a systematic means of characterizing drilling performance in terms of safety and efficiency.

In addition to the real-time analysis, the service's extensive pre-section reviews minimize any surprises that might threaten the efficiency of the drilling process or the safety of the rig crew.

The drilling advisory service fosters a collaborative work relationship between the crew at the rig site and



The remote drilling advisory service saved 14.5 days of rig time compared to the AFE. The Alert Levels Scale in the upper right corner depicts the approach the advisory service team used to drive performance while drilling the well. (Source: Baker Hughes)

office-based personnel. Rig crews are highly task-focused and have numerous duties on the rig, while office personnel are frequently tied up in meetings and cannot consistently monitor field operations. To avoid any disconnects between rig practices and office expectations, a remote services engineer is tasked with directly communicating with drilling engineers and relaying information offshore.

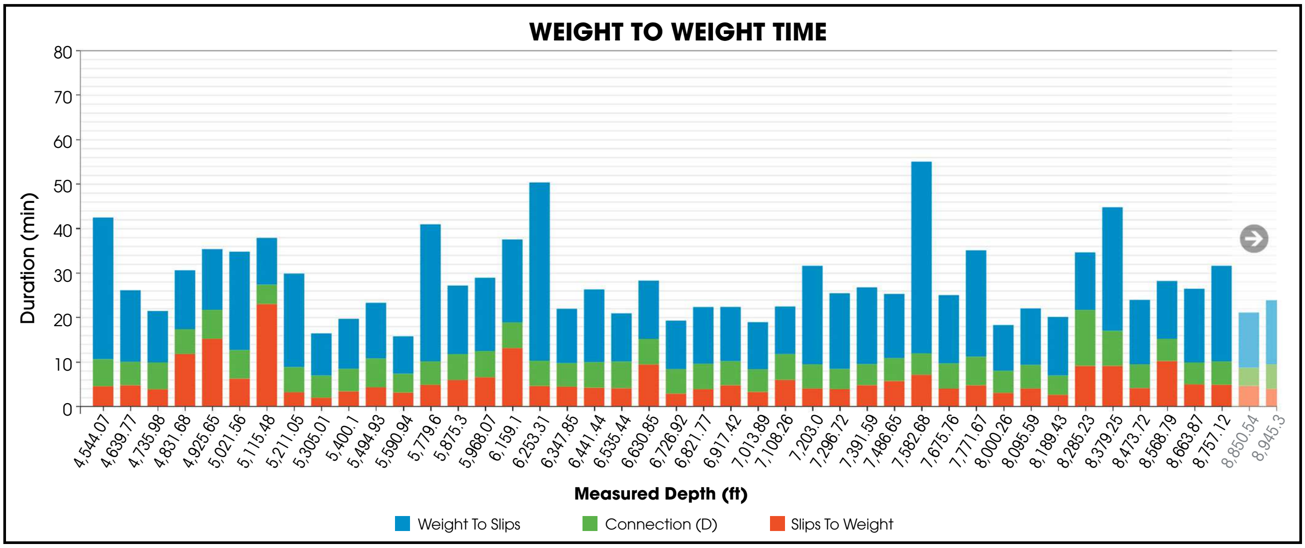
The remote engineer also performs offset well analysis to benchmark target times, identify problem zones and offer suggestions to the well plan. The engineer and rig personnel collaboratively review the plan and devise mitigation strategies. During drilling operations the remote engineer maintains communications with rig and office personnel to ensure that plans are being followed, hazards are properly mitigated and new opportunities for efficiency improvements are pursued.

Finally, the service's post-section reviews ensure that lessons learned are captured, good performance is highlighted and best practices are implemented in future sections of the well. Target times are refined after each section to reflect the capabilities of the rig and its crew. This post-analysis exercise saves time and costs on the very next section of the well to be drilled.

Saving rig time

Several deepwater operators have deployed the drilling advisory service to improve drilling performance under current adverse market conditions without compromising operational safety margins. One operator in the Gulf of Mexico implemented the service to increase operational efficiencies by targeting ECD margins, drilling parameters and back-reaming procedures.

Following a collaborative pre-well planning exercise with the operator, the Baker Hughes drilling crew went to work on the rig, with the remote services engineer maintaining constant communication between the rig and office personnel. The remote engineer's analysis during the drilling phase directed multiple rig interventions aimed at staying ahead of problems that could increase rig times and costs.



An example of the Weight to Weight KPI visual from WellLink Performance depicts the time from kelly down after drilling a stand to back on bottom drilling after the connection. This visual is used to easily identify best practices as well as outliers in comparison to performance target times. (Source: Baker Hughes)

The pre-well planning, including benchmarking target times, and real-time intervention enabled the integrated team to avoid hazardous events and safely drill the well significantly under budget. Each hole section was drilled under the planned time compared to the authorized funds for expenditure (AFE). Actual drilling time was less than nine days, a 60% reduction in drilling time compared to the 23 days of cumulative drilling time in the AFE.

In total, the well was drilled in just more than 36 days, a significant improvement over the 54 days allotted in the AFE plan. Nearly 80% of the time saved was attributed to operations while drilling. The comprehensive analysis achieved through collaboration between rig and office personnel established benchmark times and lessons learned for future wells.

Identifying future time savings

Operators also have benefited from the advisory service's historical well analysis to identify areas where future time and money might be saved during drilling. The service company deployed the service for a historical KPI analysis of 29 wells and 40 wellbores drilled by four rigs in four fields located offshore South America. The operator wanted to identify and mitigate areas of NPT and ILT to save money and provide tighter and more realistic budgets for future projects.

Data gathered by the advisory service was then integrated into the company's WellLink RT service, a web-based service that optimizes the delivery of advanced visualization and analysis of real-time drilling data including LWD, mud logging, surface and environmental measurements. The data were analyzed to identify data density, hole size, casing concept evaluation, and rig type and capacities to ensure reasonable comparisons for accurate results. Corresponding sections of all wells also were incorporated in the analysis to build a visual concept of a composite ideal well that highlighted areas for real-world performance improvement.

Drilling operations KPIs were evaluated for connection procedures, circulating times, reaming at connections, ROP and tripping speeds. These KPIs were evaluated by field, rig, well, section and rig crew using the company's WellLink Performance service, which analyzes historic and real-time wellsite data to identify a comprehensive drilling performance solution. The analysis uncovered areas of ILT due to inefficient practices, which the crew corrected for future wells.

Overall, the drilling advisory service helped the operator build a composite best well and implement NPT and ILT solutions, resulting in a time savings of about 6.5 days or 24% on the fastest well drilled in all four fields.

These are two examples of how the SIGNALS remote drilling advisory service successfully marries continuous surveillance and proactive communication to bridge the gap between the rig and the office. By identifying and mitigating NPT/ILT in real time, the service highlights opportunities for improved drilling efficiency and safety in future wells on tighter budgets, allowing operators to remain competitive in a struggling market. E&P

Automation delivers multiwell pad control

PLCs can deliver operational and cost advantages over RTUs in increasingly demanding multiwell pad operations.

Zack Munk, Rockwell Automation

The world's annual energy consumption of oil and gas will steadily increase from less than 200 quadrillion Btu in 2015 to nearly 250 quadrillion Btu by 2040, according to projections from the U.S. Energy Information Administration.

With demand continuing to grow, oil and gas producers will need to find new and better ways to capture energy resources. And they must do so while managing financial factors such as dynamic pricing and production costs. The most successful upstream producers will be those that embrace new technologies.

One area in which this already is occurring is in the upstream segment of the oil and gas industry. Operators are shifting from simplistic vertically drilled single-well pad fields to laterally drilled multiwell pads. These multiwell pads typically consist of anywhere from four wells to 12 wells, although some operators are reaching as many as 32 wells and even 52 wells on just one pad.

These advancements have increased efficiency in upstream production, particularly in unconventional areas. But they also place much greater demands on well pad control systems. As a result, oil and gas operators as well as their equipment suppliers must reconsider their control-system approach for multiwell pad operations.

Control options

For decades the remote terminal unit (RTU) was the best control technology that could be implemented in upstream oil and gas production. It was rugged and power-conservative, and it could handle the lower bandwidth communication networks between the SCADA and the production site.

Increasingly, however, oil and gas producers have demanded more from their RTUs. The industry has reached a point where the modern multiwell pad, with dozens of wells per site, has pushed the limits of RTU technology to its capacity. Producers are seeking a better solution to help them be more efficient and reduce costs.

An alternative to the RTU is available in the form of the programmable logic controller (PLC). These controllers are modular, scalable and capable of handling a wide variety of communications and application support.

PLCs have not traditionally been built for inhospitable and harsh environments. They are also not a low power-consumption device. But today's modern well pads have environmentally controlled

Modular, scalable PLC architecture enables oil and gas operators to monitor and control a wide variety of field instruments. (Source: Rockwell Automation)

buildings and utility or generator power. This creates an ideal environment for PLCs.

Demands exceeding capabilities

The greater control and data acquisition demands required in today's multiwell pads are now exceeding the capabilities of RTUs. As a result, multiple RTUs often are required on these well sites to control and optimize asset performance.

Upstream producers have had success with multiple-RTU implementations, but they've also encountered challenges. For instance, multiple RTUs require oil and gas producers to maintain multiple application configurations and programs, and they must manage the communications of many RTUs on one site.

Oil and gas production workers must also have the required training and expertise to support multiple vendors' hardware in multiple-RTU implementations. While some producers are fully staffed with the trained personnel needed to handle the maintenance of these systems, many are not. These producers must rely on either manufacturer support or contract-engineering support to maintain their control systems, resulting in additional maintenance overhead.

Another key challenge is "black box" RTUs. These are systems that are designed with specific inputs to control specific outputs. This limits flexibility for changing or upgrading systems. As a result, an oil and gas producer either needs to work with a vendor to make a change or simply keep the system as is, settling for the fact that the RTU will not meet its requirements.

Modular, scalable alternative

A modular and scalable PLC architecture can address the challenges experienced with RTUs.

A modular system design means that PLCs can be configured in many different ways. This enables oil and gas operators to monitor and control a wide variety of field instruments. A modular PLC also supports communications for many different network types.

From a scalability standpoint, PLCs offer libraries of predeveloped and documented code that can be quickly added as well as predeveloped upstream oil and gas libraries that can be configured onsite. This minimizes the need for a technician with specialized expertise to write new code when hardware is added. Instead, operators need only enable and configure the required data from the human/machine interface to commission the equipment.

Remote input/output (I/O) functionality is another key component of a PLC's scalability. PLCs that offer native remote I/O functionality can save on installa-

The equipment components required on sites can include lease automatic transfer units, compressors, pumps and more, with all requiring new reliable multiwell pad solutions to manage and control operations. (Source: Rockwell Automation)

tion costs compared to RTUs. Additionally, equipment skids can come with premounted and wired I/O and instruments, making startup as simple as plugging an Ethernet cable into a switch and configuring the I/O in the controller.

Programming in the PLC environment allows program changes and the addition of I/O without needing to shut down the process. Such online editing capabilities are not available in traditional RTUs. Instead, RTUs must be taken offline to accept the changes. Such downtime is unacceptable in a modern multiwell pad environment because it results in lost production.

In addition to online editing, PLCs can include hot-swappable hardware modules. For example, if an I/O module fails, or if technicians need to add a module to a remote I/O rack, they can simply plug the module in and configure the I/O for control.

Alternative

Multiwell pads have made data and application requirements in upstream operations greater than ever. RTUs remain a feasible option, but their memory limitations, added maintenance requirements and overall higher production costs provide a strong incentive for operators to consider a better alternative.

Modular and scalable PLCs are capable of handling the scalable architectures required by modern well pads. They also are more efficient and can help reduce installation, operating and maintenance costs. E&P

New wellhead design speeds up operations

Solution rises to challenge of debris resistance.

Johnson Koa Choon Seng, **Sebastien Bories**, **Kok Yen Hau**, **Dave Brown**, **Olivier Frelat** and **Jason Busch**, Cameron, a Schlumberger company

Removing debris from the wellbore has been an industry goal for years. But now eliminating the opportunity for debris to build up or become stuck inside the wellhead is taking on a higher priority because drilling debris is not just a production and HSE risk; it is a financial risk. Drilling debris significantly impairs drilling, delays production and is a major cost to operations.

Drilling managers are seeking to keep the wellhead clean and are searching for protection against remnants of drilling fluid and other debris such as metal shavings or cement plug. The problem begins with debris being deposited at the same time the hanger is landed. As cement returns through the riser, debris or shards can be deposited in the profile of the wellhead and on its load shoulders. Debris also can scratch the elastomer seal elements passing through it, causing well control issues. Packoffs, wear bushings and BOP testers also are subject to the effects of debris.

Periodic removal of debris is needed and often is not completed to speed up drilling operations. As cuttings are circulated back to the surface, they meet with increasing hole diameters as they move from inside the casing into the wellhead. This slows the velocity of the cuttings, causing them to settle in exactly the place that causes the most issues.

Reality of risk, cost of status quo

Whether drilling a complex well on land or offshore, remnants of drill fluid or other debris can interfere with the proper installation and performance of wellhead systems, leading to costly remedial operations. In fact, based on operator feedback, it is estimated that installation issues due to debris occur a significant amount of the time and could lead to several millions of dollars in nonproductive time (NPT). NPT costs could be double for new wells with new crews or new rigs.

For example, an operator received a call from the rig informing him that the christmas tree could not fully land on the tubing hanger/compact housing. After taking measurements, the team ascertained that the tubing hanger was locked in the housing but tilted. The connector was modified, installed and tested 48 hours later. While the operator praised the service company for its fast response and great support, the installation failure cost the operator two days of NPT. This could have been avoided if not for debris sitting on top of the seal assembly.

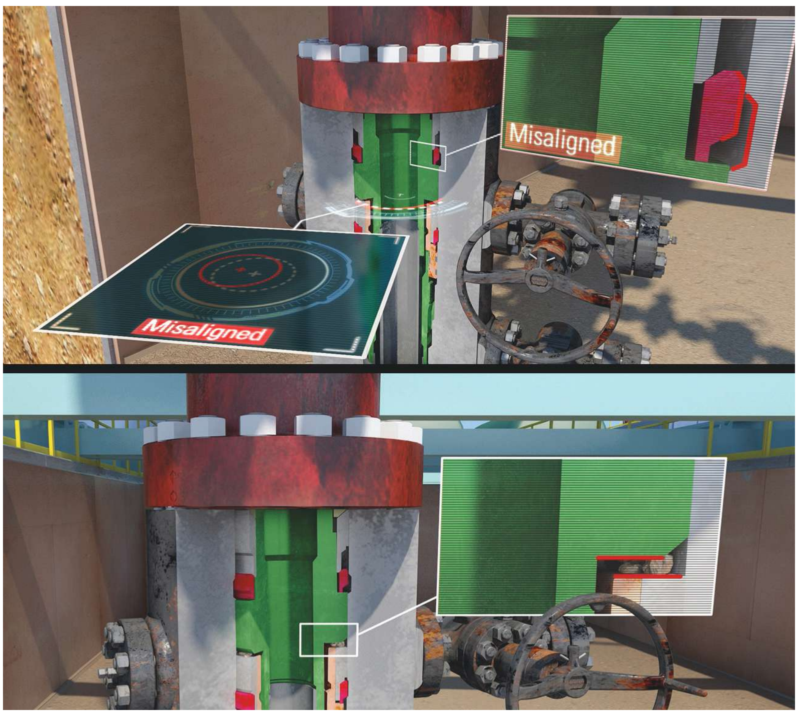


FIGURE 1. A small piece of debris can cause installation problems such as the hanger not landing properly, and the problem is magnified as attempts are made to land successive components. (Source: Schlumberger)

Debris, misalignment impact

These wellhead installation failures can be traced to casing hangers not being landed correctly, resulting in the inability to set

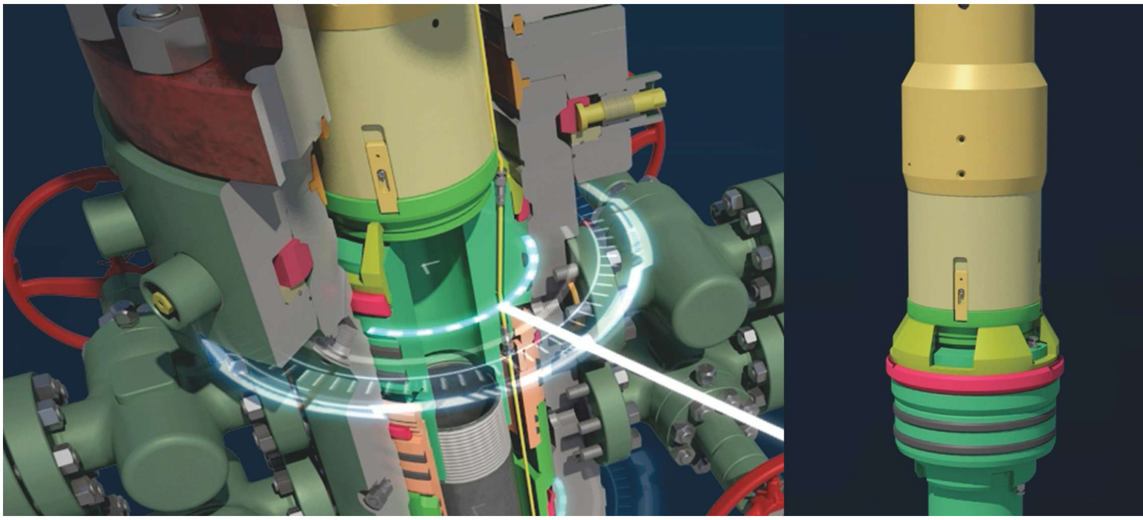


FIGURE 2. The specially designed hanger neck protector for workover applications leaves little room for debris to accumulate and solidify. (Source: Schlumberger)

the packoff or causing it to leak. Leaking packoffs and tubing hangers are mainly caused by hangers not being centralized or not being able to fully land due to debris on the landing shoulders. Wells with a shallow deviation can add further risk to alignment and centralization.

While debris removal using tools such as washover or cleanout tools provides insurance to installation, workovers and production by reducing risks, it requires downtime and high cost. Tool inventory must be managed onsite, and availability is not always certain.

With the use of outward biased lock rings for the tubing hanger, debris often accumulates and solidifies behind the ring for years, preventing the ring's collapse to free the hanger. It is sometimes necessary to machine onsite to retrieve a completion.

Tiny shard of debris, major problems

To put the impact of debris and misalignment into perspective, if each casing section of a well requires a total of 1 hr to drain the stack and flush the wellhead plus another 30 minutes to centralize the rig over the wellhead, then a 10-well project will require 25 hours just to try to avoid a hanger from landing high or landing off center (tilted) in a two-stage housing. Take into account the high probability of one of these wells failing to install properly, and one can add another 5 hours for a total of 30 hours of NPT for a potential per well expense of about $625,000 (Figure 1).

Wellhead design minimizes trouble, BOP rig down

Downtime is minimized with the new wellhead design through an ability to accommodate a wide range of casing and tubing programs from a single system, which affirms full land-out and significantly reduces the potential for debris to become trapped in the wellhead. Washout tools are not required.

Instead of landing the tubing hanger on top of the casing hanger packoff, Cameron's SOLIDrill modular compact wellhead system provides a high degree of debris and misalignment tolerance. The tubing hanger is installed on its own dedicated landing shoulder. This system is designed with angled shoulders to prevent debris from accumulating; there are no flat shoulders or pockets to catch dirt or metal shards. This reduces the need to drain the stack and flush the wellhead prior to landing the packoff and tubing hanger. The wellhead also has angled grooves and landing shoulders that deflect debris away from the bore. Constructed with substantially more socketing (the ability to guide the casing within set boundaries) to hang casing, the wellhead also reduces the risk of hanger tilt.

Workovers can be simplified using the new wellhead system, which uses an inward biased lock ring so there is little room behind the ring for debris to accumulate and solidify. Once the energizing ring is released, the lock ring can retract inward, and future workovers will be easier with its specially designed neck protector (Figure 2).

Modular compact wellhead systems that meet American Petroleum Institute 6A standards can be configured in two- or three-stage arrangements and are available in 11 in. and 13⅝ in. They are rated for severe service conditions that include pressures up to 10,000 psi and steep kickoff well angles up to 60 degrees kickoff at 80 m (262 ft).

Equipped with a self-aligning hanger, centralizing features and position indication, the wellhead is designed to provide reliable wellhead installation. An optional temporary lockdown mechanism for landing casing hangers further facilitates the cementing process. A lock ring is used to remove the potential for hanger lift during casing cementing. E&P

Lifting the spirit

The term 'game changer' is sometimes thrown around too easily, but it is completely deserved in the case of the giant vessel *Pioneering Spirit*.

Mark Thomas, Editor-in-Chief

The successful lifting of the topsides of the decommissioned Yme platform offshore Norway by the world's first single-lift vessel in August was a watershed moment for the offshore history books.

With the North Sea set to be a ripe hunting ground for decommissioning projects large and small over the course of the next several decades, the proof that innovative and bold Swiss-based contractor Allseas' unique flagship vessel is up and running was a rare and welcome bright spot in what has been a downbeat time for the marine construction and heavy lift sector.

Yme was the first commercial job for the twin-hulled *Pioneering Spirit*, with the Repsol-operated jackup production facility's 13,500-tonne topsides well within the lift vessel's capabilities, but it still represented the largest single lift ever undertaken offshore.

Bigger tasks

Bigger tasks await the offshore behemoth. Next year in the U.K. North Sea it is set to tackle what will be a world-record single lift of Shell's Brent Delta platform topsides, weighing 23,000 tonnes.

The oil company's three other Brent platforms, Alpha, Bravo and Charlie, also are lined up for similar topsides removal work over the next few years under a contract and options awarded to Allseas in 2013. Those four Brent field topsides decks have a combined weight of more than 100,000 tonnes, with the heaviest weighing in at about 30,000 tonnes.

The contract also includes the removal of Alpha's steel jacket (the other three Brent platforms are concrete gravity-based structures). All sit in water depths of about 140 m (459 ft) about 186 km (115.5 miles) offshore.

The *Pioneering Spirit* straddles its twin bows around the Yme platform before securing the structure, cutting the jackup facility's steel legs and lifting the 13,500-tonne topsides. (Source: Allseas)

Trial run

A few weeks before the work on Yme was carried out, there was a crucial first offshore test for the topsides lift system beams on the *Pioneering Spirit*. It successfully installed a test platform topsides weighing 5,500 tonnes on a substructure in the K-13 Field in the Dutch sector of the North Sea Aug. 7.

The motion-compensated lift system accurately positioned the topsides, after which installation went exactly as planned, according to Allseas at the time. It also then carried out dynamic-positioning (DP) trials as well as a series of installation and removal trials with the test platform topsides under varying conditions.

The Class 3 fully redundant DP and maneuvering system was supplied by Kongsberg Maritime and relies on a distributed and open system design, employing a fully backed-up systemwide standardized communication network. This was a complete solution custom-made for the vessel's uniquely demanding duties.

The *Pioneering Spirit* has two fully equipped and redundant Kongsberg Navigation bridges, one fore, one aft and occupying separate fire zones. The "K-Bridge" system also utilizes radar transceiver interface technology and has the ability, for example, to combine radar images from multiple radar transceivers and display them as a single composite picture. This provides a 360-degree view around the vessel and eliminates blind spots, according to Kongsberg.

Yme lift

It was after the successful test on K-13 that the maiden job on Yme about 100 km (62 miles) offshore was undertaken. The jackup facility stands on a trio of 3.5 m-diameter (11.4-ft) steel legs, which are inserted inside the field's subsea storage tank columns in a water depth of 93 m (305 ft).

Pre-lift preparation work by Allseas included the installation of temporary strain fenders around caisson and leg cutting and the design and development of leg-cutting equipment.

The sheer size of the *Pioneering Spirit*—measuring 382 m (1,253 ft) in length and 124 m (407 ft) in width—enables it to have a slot between its bows that is 122 m (400 ft) long and 59 m (194 ft) wide. This enables it to straddle platforms such as Yme and other larger facilities to remove topsides in a single lift. In this first case it used eight sets of horizontal lifting beams.

The fact that it can do this without the need for jacking down the platform also results not only in a simpler and safer operation but also further cost savings for the field operator.

Once in place, the Yme topsides were lifted and offloaded in a matter of seconds, sea-fastened onboard and then transported to an onshore decommissioning yard at Lutelandet in Norway.

The vessel then returned to Rotterdam in the Netherlands for its remaining four topsides lifting beams of 65 m (213 ft) in length to be installed ahead of its work on the Brent Field, which is due to start with the Delta topsides in the summer of 2017.

Motion compensation system

The active motion compensation system is a crucial aspect that enables the vessel to undertake large lifts in harsh environments, in waves of up to 3.5 m in height, while eliminating impact forces on the topsides.

According to Allsea's Founder and President Edward Heerema, on Yme it worked absolutely to plan. "She was very steady on the waves, and the motion compensation system worked very accurately, so we were delighted with the performance," he said during an interview at the Offshore Northern Seas event in Norway, just days after the Yme work was completed.

$12 billion saving on decommissioning using SLVs

Single-lift vessels (SLVs) could help the offshore industry save almost $12 billion on the decommissioning of North Sea projects between 2016 and 2040, according to analyst Douglas-Westwood.

The analyst said in its latest North Sea Decommissioning Market Forecast covering the period 2016-2040 that it expects the U.K. and Norway to dominate abandonment expenditure due to the large amounts of installed infrastructure in both sectors, much of which is past design life.

Decommissioning costs are forecast to total $88 billion over the period, but Douglas-Westwood's report states those costs could be as low as $76 billion if SLV technology "is fully embraced and successful."

Legacy costs

The report added, "We expect spend on decommissioning in the North Sea to grow extensively in the next few years, becoming a major part of oil and gas industry expenditure. This will be spurred on by the low oil prices, which have led operators to embark on major cost-cutting exercises. As a result, removing legacy maintenance costs from their annual budgets will be crucial.

"Operators have known for many years that decommissioning had to happen, but deferral has generally been chosen, with operators preferring to pay the smaller maintenance costs than the large (one-off) decommissioning cost—even for fields that have ceased production."

It added that due to the large number of aging fixed platforms in its sector, the U.K. is expected to see the majority of the early abandonment activity, with large-scale Norwegian activity following later in the forecast period. ■

Heerema, whose father Pieter Schelte Heerema famously was the first to think big and draw up the vessel's original design several decades ago, has made that vision a reality—albeit at a cost of more than $2 billion. He pointed out that the vessel's next job for Shell will be another world record lift. "Nobody before has lifted 13,500 tonnes in the history of the offshore, but the Delta lift will be even more of a record because it will be 23,000 tonnes," Heerema said.

Doubters

While there were plenty of doubters out there who felt that the concept would never work, Heerema praised those—especially oil companies—who he said recognized the technical possibilities and potential. "They asked dozens of questions, critical questions, but we were able to convince them that it would work and they went with us, and that is also very remarkable," he said.

His faith in the giant single lift concept is now increasingly set to pay off. Aside from the Yme and Brent Field decommissioning work, Statoil also stepped forward, awarding Allseas a contract not for removal but for transportation and installation of topsides for three of the platforms for its Johan Sverdrup field offshore Norway, which is currently under development. It also has an option to install the interconnecting bridges between the drilling, processing and living quarter installations.

The topsides weights will range from about 19,500 tonnes up to 26,000 tonnes, with the installation work expected to get underway for the drilling platform's topside in 2018, followed by the processing and living quarter topsides in 2019. The field is due onstream in 2020.

Big is beautiful

The *Pioneering Spirit* was built at Daewoo Shipbuilding and Marine Engineering's yard in Okpo, South Korea, after being ordered in 2010. With a topsides lift capacity of 48,000 tonnes and a jacket lift capacity of 25,000 tonnes, it is undoubtedly big.

But apparently not big enough. Allseas made it known in 2013, while the first vessel was being built, that it had a larger one on the drawing board.

Named *Amazing Grace*, Heerema said its concept emerged after Allseas carried out lifting studies for a number of clients that showed that for some older, very large platforms, even the *Pioneering Spirit* was not big enough. The second vessel, if it does come to reality, will be able to lift wider, longer and heavier topsides than its predecessor. It could lift up to 77,000 tonnes, the company has said previously, with a vessel width put at 160 m (525 ft). E&P

Monday, November 7th, 2016

ANNUAL EXECUTIVE OIL CONFERENCE GOLF TOURNAMENT

9:30am Shot gun start

ENERGY EXECUTIVE DINNER

Featuring the Hearst Energy Awards

6:00pm Cocktails

6:30pm Dinner

Conference Agenda – Tuesday, November 8th, 2016

8:30am WELCOME TO MIDLAND

8:40am A FIRESIDE CHAT WITH A PERMIAN LEGEND

Pioneer Natural Resources maximizes its commanding Spraberry and Wolfcamp positions with enhanced completions and will add rigs in 2016. But before he passes the baton later this year, CEO and founder Scott Sheffield will share his unique Permian vision.

Scott Sheffield
Chairman and CEO
Pioneer Natural Resources

9:00am HIGHER OR LOWER: THE OIL PRICE OUTLOOK

Given how efficient producers have become, how sustainable are the new margins seen throughout the Permian? In the end, it all comes down to the price of oil. Listen in as these top analysts debate the macros ahead: is $40 the new $60, or can we expect $80 again?

9:40am OPERATOR SPOTLIGHT: DELAWARE HOTSPOT

This producer was one of the first to head west to unlock the Delaware's rich reserves. It continues to drill longer and faster for impressive results.

10:00am NETWORKING BREAK

10:30am PANEL: REEVES COUNTY ROUND-UP

These CEOs and recent buyers compare notes on the vast potential of the region, and the technology and infrastructure required to drive future production. Will it surpass the Midland basin?

11:00am OPERATOR SPOTLIGHT: HEAD NORTH

The Northern Midland Basin continues to attract more attention as buyers in Howard, Martin and other counties pay some eye-popping valuations. This operator shares why this is so and what lies ahead.

11:20am ROUNDTABLE: LEARNING OUR ABCS

These operators discuss the ways they pursue the Wolfcamp A, B and C with greater success, using enhanced completions to yield higher EURs and lower costs.

12:00pm NETWORKING LUNCH

1:15pm AFTERNOON KEYNOTE: ALPINE HIGH & PERMIAN-WIDE

With some 1.75 million net Permian acres, Apache has positions in the Delaware and Midland basins as well as on the shelf and platform, including in its new Alpine High deep Woodford and Barnett play in Reeves County.

- **John Christmann**, CEO & President, ***Apache Corp.***

1:35pm TECHNOLOGY ROUNDTABLE: MAKING IT ALL PAY

Enhanced completion designs continue to augment strong drilling practices to ensure the many stacked zones found throughout the Permian Basin reveal their prize.

2:15pm NETWORKING BREAK

2:45pm OPERATOR SPOTLIGHT: MIDLAND BASIN DELIGHTS

The Wolfcamp in the heart of the Midland Basin is where everyone wants to be. Multiple laterals and pad drilling are the new normal as this producer maximizes the value on its holdings.

3:15pm RIGS & SERVICES SPOTLIGHT

Activity in the Permian is still increasing off its lows, but are the rigs, crews and equipment going to be available as companies add rigs or frack crews by year end? What kind of pricing scenarios can producers anticipate going into first-half 2017?

3:35pm PANEL: THE PERMIAN BUYERS CLUB

These recent buyers and M&A advisors gaze into the crystal ball to discuss deal flow in the region. What commodity price point or sales metric is needed to make sellers willing to place acreage on the market?

4:30pm CONFERENCE ADJOURNS

ExecutiveOilConference.com

Appalachian Basin shows upward trends in well characteristics

When compared by vintage, both the Marcellus and the Utica have had improved overall EURs and IP rates since 2012.

Jessica Pair, Stratas Advisors

Overall completions in Appalachia have been down due to the strategic growth of drilled but uncompleted inventories. Companies have stated that this maneuver was in response to the high volatility of gas prices throughout 2015 and infrastructure downtimes, which have resulted in bottlenecking throughout the region. However, these bottlenecking issues are beginning to be mitigated due to infrastructure coming back online and the market rebalancing.

Within both the Marcellus and Utica operators have been mirroring completion techniques where two key trends have appeared over the course of the downcycle: a continued increase in the average proppant mass per well and a falling completion count. The Marcellus has experienced an increase in average proppant mass of about 25% from January 2014 to January 2016 to average about 10 million pounds per well. During this time the number of completions in the Marcellus has decreased substantially to fewer than 100 wells on average being completed per month in 2016.

Operators have been able to optimize the targeting of both the Utica and Marcellus by drilling Utica test wells on already constructed Marcellus well pads, thereby saving a portion of operational costs.

The average proppant mass being pumped per well in the Utica has jumped significantly by about 30%, from less than 6 million pounds per well in January 2014 to about 14 million pounds per well in May 2016, with monthly well completions dropping from more than 250 wells to under 20 wells within the same time frame. This trend shows how operators are spending less capital in cutting completions by such an astounding number while simultaneously ramping up proppant use to maximize well productivity.

When analyzing about 7,000 wells and comparing the average 30-day IP rates (boe/d), it is found that Marcellus wells exhibit slightly higher IP rates when compared to the Utica (Figure 1). In 2012 IP rates in the Marcellus were about 350 boe/d, focused mainly within Lycoming, Bradford, McKean and Susquehanna counties. As the play shifted into the southern region, IP rates

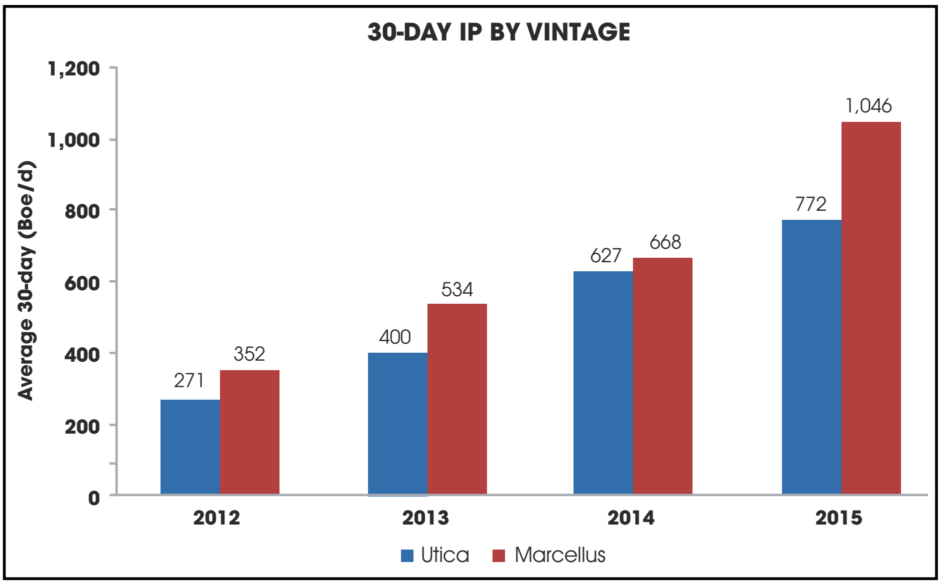


FIGURE 1. The average 30-day IP rates (boe/d) have been climbing steadily in the basin. (Source: Stratas Advisors)

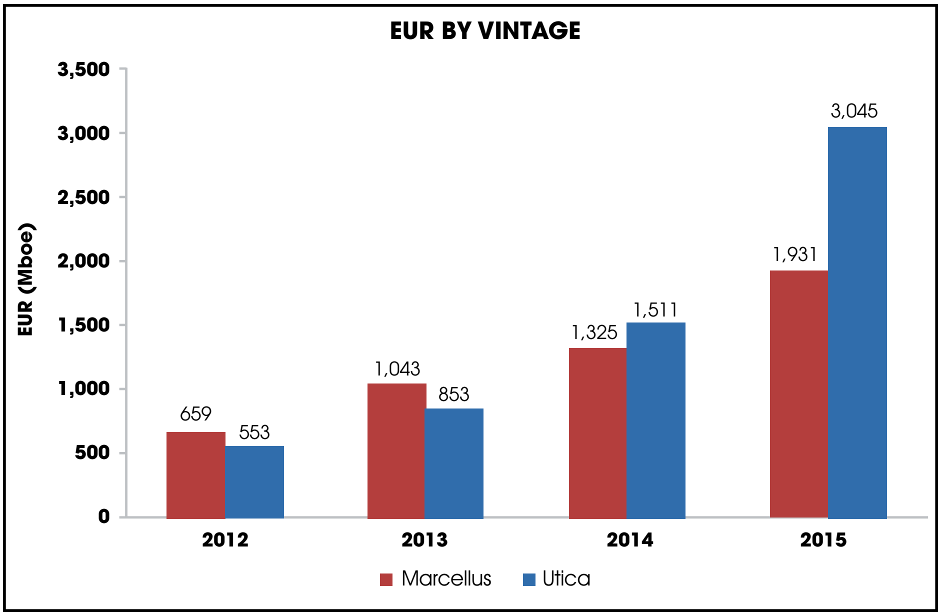


FIGURE 2. The Utica exhibits much higher average EURs (Mboe) than its underlying neighbor. (Source: Stratas Advisors)

have increased by about 65%. Currently, Marcellus wells are achieving 30-day IP rates upward of 1,050 boe/d. Similarly, the Utica's rates also trend upward, increasing by about 20% year-over-year. Within the Utica the largest IP rates are currently situated within Belmont and Monroe counties.

Similar to the IP trends, the average EURs also have been on the upward climb. The Utica has surpassed the Marcellus in terms of ultimate recovery potential in 2014 and has continued on that path. Despite this climb, well costs and ease of extraction are still a detriment to full-scale Utica production. Operators have been able to optimize the targeting of both the Utica and Marcellus by drilling Utica test wells on already constructed Marcellus well pads, thereby saving a portion of operational costs. In 2014 the Utica saw an average EUR of 1,510 Mboe, about 12% larger than the Marcellus EUR of only 1,325 Mboe. Moving into 2015, the Utica further increased its EURs by 50% to a playwide average of 3,045 Mboe (Figure 2). This rivals the Haynesville, another well-known gas play in the U.S., which shows an average EUR of 2,674 Mboe, falling between the Marcellus and Utica 2015 averages. When comparing both the IP and EUR trends of the Marcellus and Utica, it is evident that Marcellus wells, with the overabundance of primarily gas, yield larger IP rates with slightly larger declines, while Utica wells exhibit a more uniform life cycle.

Historical and current operational trends suggest that companies currently active in both the Marcellus and Utica will continue to test and push operational limits.

When comparing expected production growth estimates in each play, both the Marcellus and the Utica are likely to continuing growing as they experience positive economics across the majority of core counties. The onslaught of production has created bottlenecking issues previously within the basin, but companies are coming along with planned infrastructure projects to increase takeaway capacities in the region. The anticipated projects planned will allow the Marcellus and Utica to reach full production potential within the next several years and will likely boost the local economy from jobs to tax breaks for companies. Historical and current operational trends suggest that companies currently active in both the Marcellus and Utica will continue to test and push operational limits.

When looking at production in the short term, Stratas Advisors and the U.S. Energy Information Administration anticipate decreases in growth rates for each play compared to the 2015 exit rates. These decreases due to diminishing activity levels are expected to be mitigated to some extent given the increase in production experienced per well. Although rig counts have sharply declined in the region, by 67% since 2014, production on a per rig basis has increased, and the Appalachian Basin expects to be able to return to higher production volumes while utilizing fewer rigs in the future. E&P

For more information, contact Jessica Pair at 713-260-4604 or jpair@hartenergy.com.

Futuristic plant brings laser-like focus to technological innovation

The Talamona manufacturing plant in Italy has been equipped with a completely automated production line as well as additive manufacturing capabilities.

Giulio Ardini and **Massimo Giannozzi**, GE Oil & Gas

Since the oil price drop in second-half 2014, the oil and gas industry has been faced with considerable challenges. However, these challenges also present new opportunities for optimizing the performance of the sector. To adapt to the prevailing economic headwinds, oil and gas companies have been forced to put maximizing efficiency and productivity at the heart of their business models. Doing this not only allows them to cut costs in the short term, but it also prepares the ground for a leaner, stronger industry in the long run as the sector's growth outlook gradually improves and normal service is resumed.

Technological innovation in particular is playing an ever more pivotal role in helping the oil and gas industry deal with the challenging climate. Leaders at GE believe there is huge potential for innovative technology to help streamline operations, making them more resilient to today's market conditions and more robust and profitable in the years ahead.

GE Oil & Gas celebrated the inauguration in May of two new high-tech component production lines at its plant in Talamona in northern Italy. These include a new nozzle production line, which is the first completely automated line for GE Oil & Gas, and a new additive manufacturing line, which will use laser technology to 3-D print end burners for gas turbine combustion chambers.

Both advanced manufacturing lines will be used to make parts and products that previously had to be assembled from multiple components. They will serve to establish the site as a center of technological excellence for the oil and gas industry. Talamona coming online brings years of automation and 3-D printing development and investment to fruition.

Robotic technology

The official unveiling of the upgraded turbine components manufacturing facility is the result of a multimillion-dollar investment over two years to establish the plant as one of the most advanced oil and gas production centers worldwide. Previous investments in 2013 already increased the plant's production capacity, but this latest injection of capital moves the plant toward realizing the big technological trends reshaping the industry in the 21st century.

The GE Oil & Gas facility in Talamona, Italy, has two high-tech component production lines. (Source: GE Oil & Gas)

The new nozzle production line is the first completely automated line in a GE Oil & Gas plant. It utilizes two anthropomorphic robots capable of employing 10 different technologies, including electrical discharge machining, measurement and laser beam welding. With this new line, GE Oil & Gas is now able to produce components in Talamona that it previously purchased from third-party suppliers. The new production lines already are working and will be fully operational by the start of 2017.

Next frontier for the energy industry

GE Oil & Gas also is helping to accelerate the industry's foray into additive manufacturing, which offers increased speed and accuracy in component production. Additive manufacturing is a nascent industry undergoing something of a boom, having grown by $1 billion for the second consecutive year.

R&D work at GE has centered primarily on developing new applications for additive manufacturing. While the technology already is used heavily in the aviation, medical and design industries, it now represents the next frontier for manufacturing equipment for the energy industry. After extensive validation of additive manufacturing during prototyping of the NovaLT16 gas turbine, GE Oil & Gas decided to move the technology into full production, leveraging the design enhancement capabilities, cycle time reduction and improved product quality.

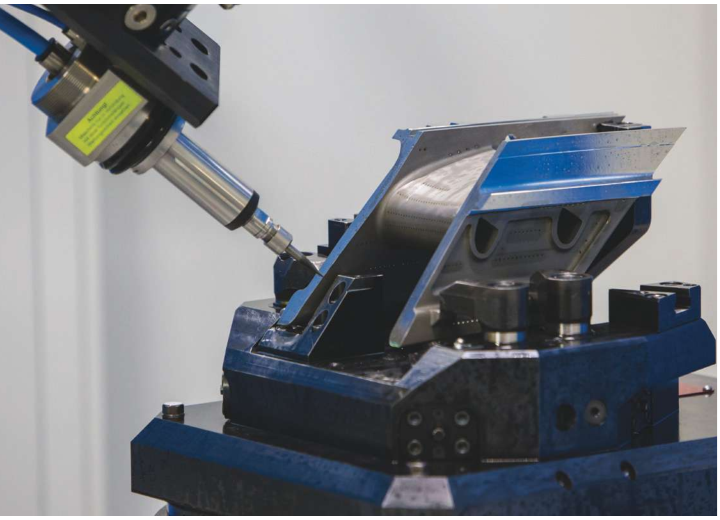
The site also is managed with software with the capacity not only to schedule activities but also to support maintenance activity that is no longer simply preventative but predictive, leveraging GE digital capabilities through the Predix platform to optimize value chain operations.

The use of automated production and new techniques like additive manufacturing allows the company to develop parts and products more efficiently, precisely and cost-effectively, accelerating the speed at which the company can bring products to market.

Investing in the future

The company has been investing and growing its work in additive manufacturing across R&D sites located in Bangalore, India; Niskayuna, N.Y.; Pittsburgh; Shanghai; Munich; and Florence, Italy, where GE Oil & Gas opened an additive laboratory in 2013.

The Florence laboratory was given a direct metal laser melting machine and since then has grown its capabilities further thanks to the addition of two further machines for the development of turbomachinery components and special alloys. The Florence additive manufacturing laboratory has been crucial to paving the way for innovation in GE Oil & Gas, and a series of collaborations with GE Aviation and the GE Global Research Centre have significantly accelerated the development of this technology.



A robot polishes a nozzle for a gas turbine. (Source: GE Oil & Gas)

The 3-D-printed turbine blades are manufactured at the Talamona plant. (Source: GE Oil & Gas)

Pushing the boundaries of innovation

The opportunities for the application of additive manufacturing and 3-D printing in the oil and gas industry are many and open-ended. They are only just starting to be explored and will require constant innovation in terms of material science, component design and production approach. GE Oil & Gas is fostering the development of this technology to produce complex components for gas turbines while cutting costs, boosting performance and reducing emissions.

GE will always be seeking to identify new applications for its technology in the years to come and will be interested in working with both new and existing partners to address a broad range of industry challenges. For example, although initial work centered on predominantly developing turbomachinery components, GE now is also in the process of applying its 3-D printing expertise to optimize other production lines such as subsea. The applications for the components being produced using 3-D printing also span the entire GE footprint, including the use of cobalt-chromium alloys for jet engines, which were originally used for joint replacements and dental implants.

Working closely with its partners, GE will continue to strive to help them overcome barriers to growth and emerge with businesses that are more efficient, flexible and productive than before. GE's aim going forward will be to build on the technological innovation taking place at the Talamona site to develop more technological solutions that possess the potential to unlock profound value for the sector. E&P

References available.

'Great Crew Change' is driving producers toward modern field connectivity

The benefits of modern network connectivity in the field make for a better, safer and more productive operation.

Renner Vaughn, ABB Wireless

Upstream operations teams are smaller these days, but the demands of the onshore field remain the same. Operators still have to manage thousands of wells spanning large geographic regions, most of them in rural territories. Wellheads have some basic automation, but the SCADA system might not be reliable enough to detect a sensor alarm that leads to an overflowing storage tank. Fines for detectable emissions at a storage tank can reach $15,000/day in many U.S. shale plays, so it should be no surprise that leak detection continues to be a high priority across the value chain.

When a leak is suspected, one option is to immediately dispatch a technician to the site without any indication of the specific problem. The actual time to site could be a few hours depending on the size of the field and the condition of the roads. The technician arrives onsite but has trouble finding the source of the leak, so he or she tries to get in touch with a more experienced team member and report visual status. Spotty cellular service prompts the technician to drive to a nearby hilltop to make the call. The expert might be busy helping other junior technicians address problems elsewhere in the field and does not answer the phone. Meanwhile, the clock is ticking.

As the clock ticks on for the leaking storage tank, consider a few alarming figures: 50% of the oil and gas workforce is retiring in the next five to seven years. Two people retire as one new employee enters the workforce. The gap between ages 35 and 55 is in the tens of thousands, and it raises many issues for oil and gas companies that rely on skilled and experienced operators to run their fields. This phenomenon has been dubbed "The Great Crew Change."

The younger generation and tech-savvy senior operators expect a more digital, connected production environment with decision-making based at least in part on dashboards and data. "That mindset from some younger workers who are more data-driven, more empirical, less intuitive is probably the prevalent mindset and the way companies will be run in the future," said Oklahoma Oil and Gas Association President Chad Warmington in a Jan. 1, 2016, article in the *The Oklahoman*.

A visit to a field office of any major producer will certainly validate Warmington's statement. Desks are lit up with computer screens showing alarms, graphs and other data visualizations that can make maximizing production volumes and optimizing resource allocation seem almost like a video game. There's nothing wrong with a little friendly competition in the workplace.

Modern wireless networks form the fabric that connects the digital oil field. (Source: ABB Wireless)

Equally as important are the more traditionally minded senior operators who rely on experience and intuition to guide them in the field. In many ways there is no substitute for time spent at the plant or on the well pad solving everyday challenges year in and year out. As resistant as they might seem to change, this group will definitely embrace new technology if it makes their lives easier. For evidence, just consider the tiny supercomputer, or smartphone, that goes with people everywhere every day.

Real-time monitoring, control

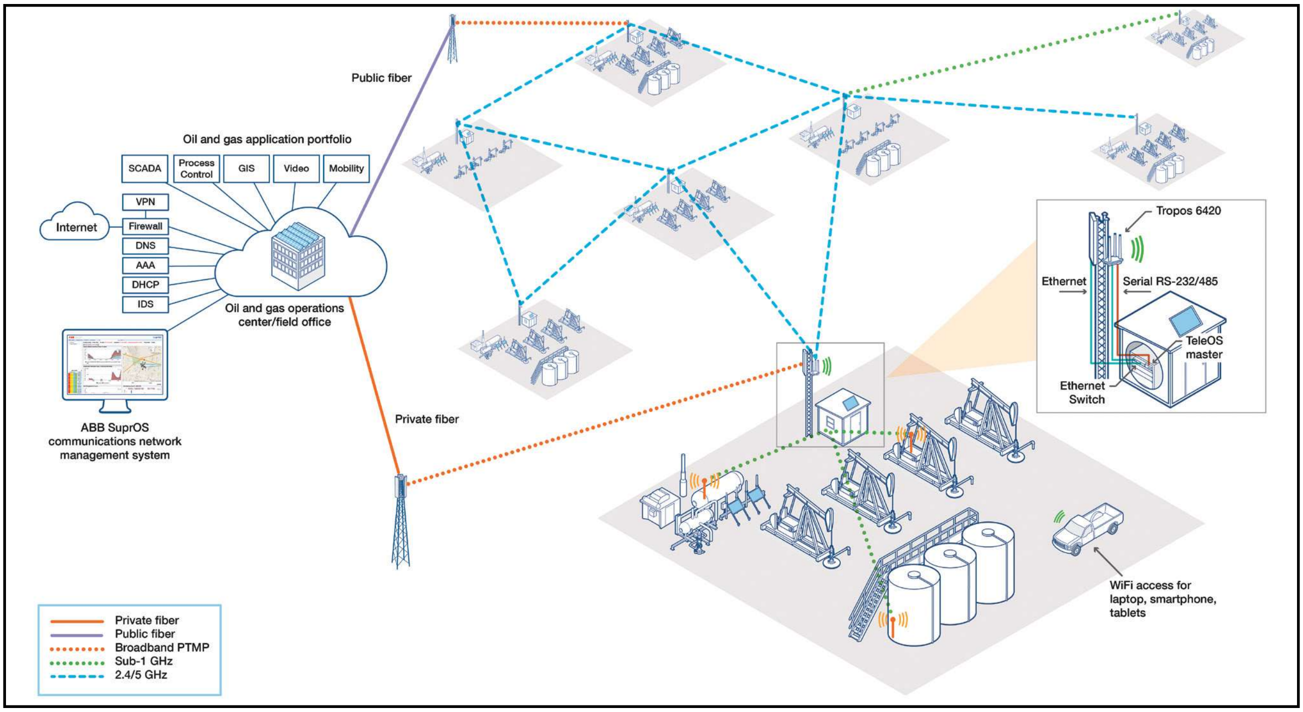
Switching back to our leaking tank scenario, could it have been avoided? What if the field network had the bandwidth to support real-time monitoring and control, with video analytics software adding another layer of intelligence on top? Modern private wireless networks enable the technician troubleshooting the leak to transmit a live video image from a head-mounted camera, while engineers at the field office remotely pan and zoom in to visually inspect the equipment from the same viewpoint.

The team can collaborate and formulate a game plan to fix the problem within minutes of using the network. Because he or she can order parts in the system and check email from the field, the technician knows to pick up the right materials at the warehouse before heading back out to the site. When the technician arrives at the well pad, a video messaging application can show others the status of repairs as they happen. By enabling smart remote monitoring and video calling applications, the field network already is saving the company precious hours of downtime, but with analytics software connected to the SCADA historian, the operators also might have been able to predict a failing level sensor and avoid a tank leak altogether.

Increasing efficiency, lowering costs

Producers also must consider the cost of operating a vehicle fleet. One operator reported that its San Juan Basin operations team drives more than 12.8 million km (8 million miles) per year, covering a territory that spans 14,504 sq km (5,600 sq miles). Operators who repeatedly interrupt their routes to return to the field office to access production application data can easily multiply their daily driving distances. This waste of time can be avoided if they have reliable access to the same data while in the field.

A gathering company in the same region reports that after it implemented a private broadband wireless network for vehicle and well pad communications, it lowered daily driving distance from 483 km (300 miles) to under 161 km (100 miles) per operator. Field technicians no



Modern wireless network architecture for onshore upstream fields includes fiber, broadband point-to-point/point-to-multipoint (PTP/PTMP), broadband mesh and narrowband PTP/PTMP. (Source: ABB Wireless)

longer had to drive to the top of the nearest mountain to pick up cellular coverage from towers located in the adjacent valley. Instead, the private network automatically formed mesh links between existing radio towers and poles mounted at the well pad, creating coverage in targeted areas. In each vehicle the operators use high-power radios to connect into the mesh network even if they are miles from the nearest well pad. This is a huge advantage over the past scenario, in which operators became frustrated with ongoing cost and low performance of cellphone radios and signal boosters.

Custody transfer is another function that can be automated to significantly improve measurement accuracy, particularly in fields where materials are transported by truck. The custody transfer process has traditionally been tracked manually via paper tickets. Tickets get lost, and volumes get misreported, which results in significant discrepancies and lost revenue.

There was much less focus on volume lost in custody transfer when oil was trading at $100/bbl. These days every drop counts. The custody transfer process can now be entirely automated, and real-time data can be sent to the field office as well as the midstream partner receiving the product. The product received can be reconciled immediately and, most importantly, accurately. Using automated custody transfer applications with digital meters and flow computers that communicate over a modern wireless network, producers can now be sure that they are paid for the exact volume transferred to the midstream partner.

For today's upstream field, moving to a modern wireless network that uses all available spectra, both licensed and unlicensed, coupled with intelligent radio resource management software that both mitigates interference from other sources and minimizes self-interference, makes the most sense. Such a broadband wireless network offers multimegabit speeds and high reliability, which are essential for real-time SCADA and video collaboration. The sub-1 gigahertz narrowband frequencies are still the most economical way to reach remote sites, especially those running on solar and wind power; therefore, the intelligent combination of frequency bands and radio technologies is still a necessity. One thing is for sure: One size does not fit all when it comes to oilfield communications.

With modern network connectivity throughout the field, teams can reliably access data to make better, timelier decisions about the health of the remote asset, possibly delaying an emergency site visit to a future scheduled trip. Because they spend less time on the road, teams are safer, more productive and able to meet the daily challenges of upstream operations. E&P

Shale sweetspot technical service reduces costs

WellDog has released its Shale SweetSpotter service, which is the first commercial reservoir-evaluation analysis technology specific to unconventional oil and gas, following successful field trials with its industry partner in the Marcellus Shale, a press release stated. WellDog's next-generation downhole technical service uses lasers and sophisticated detectors to identify the locations where hydrocarbons occur in shale formations, allowing producers to focus development efforts, reduce drilling costs, optimize production and reduce the number of hydraulic fracturing stages and associated water usage. The service uses WellDog's Reservoir Raman System, which was originally developed to find sweet spots in coalbed methane developments. In 2014 the company began developing new shale-based applications for the technology. Shale SweetSpotter was developed with the target of doubling the number of producing fractures. This is accomplished by using the industry's only downhole Raman spectrometer to directly identify locations of producible hydrocarbons across the formations. *welldog.com*

Flowback service improves well productivity

Halliburton has released the CALIBR engineered flowback service, which applies advanced diagnostics and a collaborative workflow to continuously manage flowback operations to improve well productivity. It also helps maximize water recovery and reduce damage to fractures caused during drawdowns, a product announcement stated. Halliburton recently partnered with an operator in the Permian Basin to demonstrate the advantages of implementing an optimized flowback strategy to increase productivity. The well was drilled in what was believed to be marginal acreage, but by using CALIBR the operator was able to complete the well with the highest productivity index within its portfolio. *halliburton.com*

Hydraulic fracturing gets quiet

Liberty Oilfield Services has released its new Quiet Fleet technology, a press release stated. The Quiet Fleet utilizes patent-pending Liberty-developed sound reduction technology incorporated directly into fracturing equipment to dramatically reduce noise emissions during hydraulic fracturing operations. Noise levels are reduced by a factor of three compared to a conventional fracturing fleet, far more effective than costly sound walls. This noise reduction is achieved without any impact to operational performance or rigup time. The design of the Quiet Fleet also allowed the incorporation of a sophisticated three-stage fire suppression system on each unit, which is not viable on a conventional fracturing fleet. The Quiet Fleet recently was deployed in the Denver-Julesburg Basin for Extraction Oil & Gas and completed 210 frack stages in the first 10 days of operation. *libertyfrac.com*

Virtual reality improves safety, productivity

Optech4D partnered with a manufacturer of high-speed rotating equipment (turbines, pumps and compressors) to develop a custom virtual reality product to support its training program, a press release stated. To ensure the safety of its employees and equipment, Optech4D's client exercises the Lockout-Tagout (LOTO) system by which equipment is de-energized, locked and tagged so it cannot be started during maintenance or when highly explosive environments are present. The Optech4D Fully Immersive Training Simulator simulates the LOTO procedure training using virtual reality. By partnering with Oculus Rift, Optech4D developed a virtual world where the trainee can walk through the facility to check all critical equipment and verify that it is properly de-energized, tagged and locked out. In addition, Optech4D has leveraged augmented reality safety glasses and tablets and its SafeBeacon sensor technology to give operators in the field real-time assistance during LOTO. *optech4d.com*

The ECOPOD system is operating in a Kern County oil field, cleaning 340 bbl/d of oilfield wastewater and salvaging it for agricultural irrigation. (Source: OriginClear Inc.)

Produced water to irrigation-grade achieved in a single modular system

An OriginClear licensee has released a complete modular system (ECOPOD)—now in operation at an oil field near Bakersfield, Calif.—to clean up produced water, a press release stated. The ECOPOD pilot scale system uses OriginClear's Electro Water Separation, requires no chemicals and reliably processes 340 bbl/d of oilfield produced water with minimal operator supervision. The ECOPOD System 1.0 can successfully and competitively treat produced water and recycle it into irrigation quality water for local beneficial reuse. OriginClear licensee ECT Services & Solutions developed the compact ECOPOD System 1.0 to transform produced water into clean water for use in irrigation and potable water applications. The centerpiece is OriginClear's commercial-scale P3000, designed to treat up to 3,000 bbl/d. The ECT team implemented additional scrubbing and polishing steps to achieve potable-grade water. The entire process is chemical-free and extremely energy-efficient while reducing the rate water evaporates during reuse. *originclear.com*

Troubleshoot faster with decision support

GE Digital has released a new generation of its automation software portfolio that goes beyond traditional automation to offer decision support capabilities, a critical foundation for efficient operations. The new GE HMI/SCADA software offers the most comprehensive and best-in-class monitoring and visualization capabilities as well as work process management, analytics and mobility, a press release stated. Based on the International Society of Automation's high-performance design principles, this software enables companies to troubleshoot faster, reduce waste and increase productivity. This fourth-generation HMI/SCADA technology can allow operators to spend less time navigating, find critical data faster, improve alarm resolution success, identify relevant screens for an alarm, increase usability and achieve a faster build/deployment. *ge.com/digital*

Virtual reality tool aids ship designers, engineers

The ShipSpace product is a next-generation virtual reality design verification tool. (Source: KNUD E HANSEN)

The ShipSpace product is a next-generation virtual reality design verification tool that allows designers, engineers and key stakeholders to validate design ideas and communicate effectively about vessel concepts and designs, a KNUD E HANSEN press release stated. The product consists of computer hardware and software on the customer's premises and in the cloud. ShipSpace uses the latest virtual reality technologies to enable users to walk around all areas of the vessel and get a better understanding of how spaces work with a true sense of depth and scale not possible with monitors or projectors. *knudehansen.com*

Eccentric casing strings cut with single tool

A new technique developed by Energy Fishing & Rental Services (EFRS) was used to successfully cut totally eccentric 5-in., 7-in., 10¾-in. and 16-in. strings in a Gulf of Mexico well with a single cutting tool, a press release stated. The technique was developed in response to a problem faced by an operator during a plug-and-abandonment (P&A) operation. Because all four casing strings were cemented together, conventional multistep cutting using graduated-size cutting tools and knives was impossible. EFRS used a combination of specially fabricated cutter knives and an EFRS-designed procedure that used the correct combination of pump pressure and torque monitoring to cut all four totally eccentric inner strings using a cutter that typically could not have been used in this application. A job considered impossible was performed efficiently, with all strings cut and pulled. All four eccentric casing strings were cut using an EFRS 3½-in. outer diameter two-blade internal hydraulic casing cutter. The quick visualization, development and execution of specific procedures to complete an extremely difficult job has created a new option for effectively overcoming similar problems in P&A work. *energyfrs.com*

Collaboration improves production efficiency

Emerson and StepChange Global have combined technology and consulting expertise to help producers increase production and cut operational costs by developing, implementing and evolving best practices with integrated operations (iOps) and the digital oil field, a press release stated. Emerson's technology and StepChange Global's consultants help improve collaboration between the operational site and the support teams in the office, maximizing the value that can be gained from operating asset information. With iOps an enterprise can then build confidence in its information and trust among extended teams to implement improvements that include improving operator efficiency and optimizing its core operational processes. By optimizing production using iOps tools and techniques, an oilfield operator can see production efficiency improvements of up to 2%. A closed-loop gas-lift application can see production improvements of 5%. Previous iOps implementations have seen opex reductions of 5% to 20% with payback in less than one year. *emersonprocess.com*

Anticorrosion packaging eliminates rust claims

Cortec has released its EcoShield VpCI-226 Series Film, an easy-to-use packaging for corrosion protection, a product announcement stated. The film replaces the typical oils and desiccants used to protect packaged metal parts, not only guarding against corrosion but eliminating extra labor time and the hassle of removing greasy coatings.

The film can protect parts as small as a needle or as large as the contents of an oceangoing vessel. (Source: Cortec)

Metal parts protected in EcoShield VpCI-226 are ready to use immediately after unpacking. Once removed, the nontoxic film, which does not contain nitrites, phosphates or halogen-based materials, can simply be recycled. Metal parts packaged in the film are continuously protected from the corrosive effects of salt, excessive humidity, condensation, moisture, aggressive industrial atmospheres and dissimilar metal corrosion. Vapor-phase corrosion inhibitors in the film vaporize and condense on metal surfaces in the enclosed package, reaching every area of the part to protect the exterior as well as hard-to-reach interior surfaces. This provides complete product protection during storage and domestic or oversea shipments and virtually eliminates rust claims. *cortecpackaging.com*

World's first controlled pinpoint refrack

NCS Multistage has announced the successful refracturing of a 25-stage well that had originally been completed utilizing the company's Multistage Unlimited coiled-tubing fracturing system and MultiCycle frack sleeves, which gave the operator the ability to manage stage-by-stage formation access over the life of the well, a press release stated. After evaluating production, the operator wished to increase stimulated reservoir volume by placing additional proppant in all stages using a different fluid system and higher pump rates than used in the original completion. The refracturing began by closing all of the sleeves and verifying wellbore pressure integrity. Then, using the NCS Shift-Frac-Close sequence, all 25 stages were individually refractured. At each stage, the MultiCycle sleeve was opened for the fracture and then immediately closed at the end of pumping. When the stimulation was complete, the full-drift wellbore was again successfully pressure-tested, all sleeves were reopened and the well was turned over to production. The entire refracturing took about 36 operating hours, and wellbore pressure and formation access were controlled throughout the operation. *ncsmultistage.com*

Epoxy linings provide long-term protection

With the release of its new Hempaline Defend epoxy linings, Hempel offers a complete range of linings for challenging applications, where heavy-duty performance and a fast return to service are essential for continued production uptime, a press release stated. The Hempaline Defend epoxy linings provide long-term protection for assets in challenging environments, such as bulk storage tanks, process vessels, frack tanks and secondary containment areas. The internal linings protect both steel and concrete from aggressive chemicals, elevated temperatures and abrasive service conditions. The epoxy linings come with a choice of hardeners, enabling users to select a single-coat system that allows a vessel to be returned to service in as little as 24 hours without any drop in performance. *hempel.com*

Perforating system sets Canadian e-coil perforating record

Hunting has announced that its Titan Division's select fire perforating system set a new Canadian e-coil perforating record with a 52- ControlFire assembly gun string deployed by Titanium Tubing Technology Ltd. for Teine Energy Ltd. in Kindersley, Saskatchewan, a press release stated. Titanium achieved the record, previously held by Tucker Energy Services in Canada, after deploying the guns' string in one run with 60.3-mm e-coil. By using Hunting's Titan Division ControlFire switch system, the company was able to perforate in a single trip rather than in the typical two to three runs. The switch system is the latest in perforating switch technology that uses unique switch identification logic to selectively perforate multiple intervals in one trip. Each ControlFire switch provides real-time confirmation and skip-over capabilities through a surface perforating command and control panel. *hunting-intl.com* E&P

Middle East exposition

A methodical approach led to successful market implementation.

Nick Nesterenko and **Vince Fortier**, Tesco Corp.

One piece at a time. That's how the saying goes when answering the question, "How does one eat an elephant?" But where is the practical sense in the lesson being taught? This phrase defines a strategy to overcome a seemingly monumental task by applying a step-by-step approach combined with a little patience.

For the oil and gas industry, few other tasks are as daunting as the market introduction of a new technology or service. By applying a methodical approach to this challenge, Tesco Corp. has taken the very important first step to successfully introduce and implement an evolutionary technology change in the Middle East with the goal to have full-scale adoption across the region.

The company put this strategy into practice when introducing its casing running tool, or Casing Drive System (CDS), in several Middle Eastern countries, yielding very promising early results. Because of the downturn in global drilling activity, growing business meant capturing market share from competitors and advancing technologies in markets where it did not yet exist. To adapt to this, Tesco combined value-driven decision-making with drive to gain market share.

Gauge the market

The Middle East market has been attracting more attention from service companies since the beginning of the downturn. With budgets shrinking in most parts of the world, this region has maintained its share of oil production. Tesco logically was interested by the

Working with regional IPMs enabled Tesco to gain market share in a relatively short period of time. (Source: Tesco) sustained activity in the region, but there were also other factors present that supported a vision of advancing the business there.

First, it is easier to discuss new technology adoption with a party invested in just that. Nearly every oil and gas company in the world has a department dedicated to discovering innovative technology for the purpose of improving the efficiency of drilling operations. Tesco leveraged existing relationships in the Middle East and discovered a receptive audience seeking ways to improve operations and cut costs.

Integrated project managers (IPMs) were an important factor when establishing the CDS in Middle Eastern rig operations. IPMs are essentially large oilfield services companies with an array of experience and capabilities specifically designed to offer turnkey solutions to oil companies at the well site. Most IPMs are global service companies with talented and experienced people who are driven to cut costs while improving wellsite performance. Their support helped drive the adoption of the new technology.

Finally, understanding that national oil companies (NOCs) control or own most of the activity in the region was important because the NOCs contract IPMs to turnkey their wells. There are many layers to consider when developing a sales strategy, and these are just a few specific ones to the Middle Eastern region that Tesco needed to consider before it attempted to implement its new technology into the region and gain market share.

Keep it simple

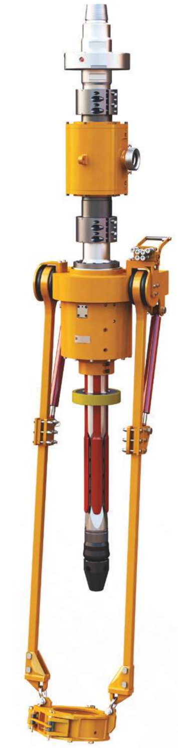
Knowledge and understanding of its customer base supported Tesco's belief that favorable conditions and opportunities existed in the region. To capture market share, a proven plan needed to be implemented in a timely manner. Tesco's "Evolution Model" for simplifying the casing running and cementing processes had been implemented already in parts of the U.S., Latin America and Asia-Pacific. Although there are many layers that make up technology introduction and customer adoption strategy, the underlying theme was expressly straightforward: keep it simple.

Introduce one technology at a time. While Tesco's evolution model is made of several equipment components, experience has shown that bombarding a potential customer with groupings of multiple new products all at once can be daunting for rig crews and customers. Numerous new sets of procedures to learn and adopt combined with multiple new products to operate and maintain can create an overwhelmed state of mind, adding to the typical stress-filled duties of working on a rig.

Even if the full suite of products can bring maximum benefits altogether, management and crews are generally much more receptive to the idea of adding and training on just one new piece of equipment at a time. Safety records improve with single product adoption since crews can focus on the new task at hand while remaining prepared to perform regular duties.

Customer follow-up. Once the first technology solution proves to be a success, there is opportunity to implement additional products or services to yield additional benefits. Crews will be receptive to a product that delivers positive results and makes their jobs easier. In this case, the CDS could provide casing running, cementing and even casing-while-drilling services. Customers were pleased to see the benefits and efficiencies provided by a single product.

Share the success. Customer and employee feedback from surveys also were useful when developing new business and attempting to capture market share. A successful job with a positive customer response can be shared with other areas of that customer's company as a spotlight on best practices. This also helps lay the foundation for case studies and discovering areas for further improvement or customization as well as business development with other potential customers.



Casing running tools provide a mechanized way to run and make up casing. (Source: Tesco)

Prove yourself. Even the best sales pitch is meaningless if performance is not, at the very least, meeting prior operational and HSE capabilities or key performance indicators. Tesco's strategy included seeking partners willing to take a chance to prove the technology on their rigs, with both sides having "skin in the game." With each successful implementation, these services were further introduced into well operations.

Targeting the players

Detailing this simple approach has yet to explain the patience and execution necessary to ensure success. Winning contracts did not happen overnight. Sales and operations teams worked for two years coordinating meetings and technology presentations, providing data and track record evidence, and organizing and executing field trial operations to finally win contracts for the NOCs in the region.

As previously mentioned, many IPMs already were familiar with the CDS, so Tesco specifically discussed with customers how the CDS could benefit the turnkey style of IPM operations. Due to the nature of the CDS and its capability to perform multiple tasks, IPM product and service offerings were able to double or even triple the added benefit of managing a single tool rather than several when performing the same tasks.

Seeing results

Sticking to the evolution model, Tesco's sales effort is starting to pay off. During the downturn, Tesco went from a niche supplier to holding some of the highest market shares of NOC work. Using a focused and simplified sales strategy, the sales team doubled the workload under a single contract in less than two years. Ninety-six jobs were performed under the contract in the month of April 2016 alone.

More than 160 casing running jobs have been performed in the market using the CDS. The CDS performed more than 10 casing-while-drilling jobs, and the tool has even moved into the offshore market. All of the jobs have been completed with reduced nonproductive time.

Technology implementation would not have been as successful had it not been for the sales teams working closely with the IPMs, with whom they have established relationships based on trust and proven performance. Several major service companies in the region allowed the CDS onto their rigs for trial runs, and every one of those trials was converted into a service or sales contract.

Pushing ahead

With the ever-changing dynamics of the oil and gas market, every company must be ready for the challenge that awaits. Developing an effective strategy to position (or reposition) within the market is only a fraction of a success story. The proper direction by management and scrupulous execution excellence by the team members is easy to understate but is critically important. E&P

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1 Trinidad

BHP Billiton Ltd. made a gas discovery with the first deepwater well drilled off the east coast of Trinidad on the LeClerc prospect. The #1 STO1 LeClerc was drilled in deepwater Block 5 to 6,973 m (22,877 ft). The well hit gas in multiple zones and is the first of three deepwater exploration wells in Trinidad's southern offshore region of the Caribbean Sea. The company has announced that the prospect could hold up to 5 Bbbl of oil in place and could produce at least 100 Mboe/d. Up to eight additional wells are planned by BHP, with a second well already underway. BHP Billiton is the operator of Block 5 and the LeClerc discovery well with 65% interest. Shell Oil Co. holds the remaining interest.

2 Guyana

Exxon Mobil reported that the second exploration well #2-Liza has recoverable resources of between 800 MMboe and 1.4 Bboe. The Stabroek Block has confirmed that the Liza Field offshore Guyana extends at least halfway to the neighboring Orinduik Block to the southwest and contains hydrocarbons. The #2-Liza was the second of at least four exploratory and appraisal wells. It encountered more than 58 m (190 ft) of oil-bearing sandstone reservoirs in Upper Cretaceous formations. The well was drilled to 5,475 m (17,963 ft) in a water depth of 1,692 m (5,551 ft). Exxon Mobil operates the Stabroek Block and Liza wells with 45% interest with partners Hess Corp. (30%) and China National Offshore Oil Corp. (25%).

3 Canada

Statoil Canada has completed a 19-month offshore Newfoundland exploration drilling program in Bay du Nord and Flemish Pass. The drilling program consisted of four exploration wells in close vicinity to the Bay du Nord discovery and three appraisal wells on the discovery. In addition, two exploration wells were drilled in areas outside the Bay du Nord discovery. Two oil discoveries were completed at the Bay de Verde and Baccalieu prospects in the Bay du Nord area, which add to the resource base for a potential development at the Bay du Nord discovery. Appraisal and near-field exploration of the Bay du Nord find has confirmed that the volumes are within the original volume estimate of 300 MMbbl to 600 MMbbl of recoverable oil. Only 17 wells have been drilled in the basin, which covers about 30,000 sq km (11,583 sq miles). Work is underway to evaluate results at the recently completed #1-Baccalieu. Statoil is the operator of the Bay du Nord and Flemish Pass discoveries with 65% interest with partner Husky Energy Inc. (35%).

4 Morocco

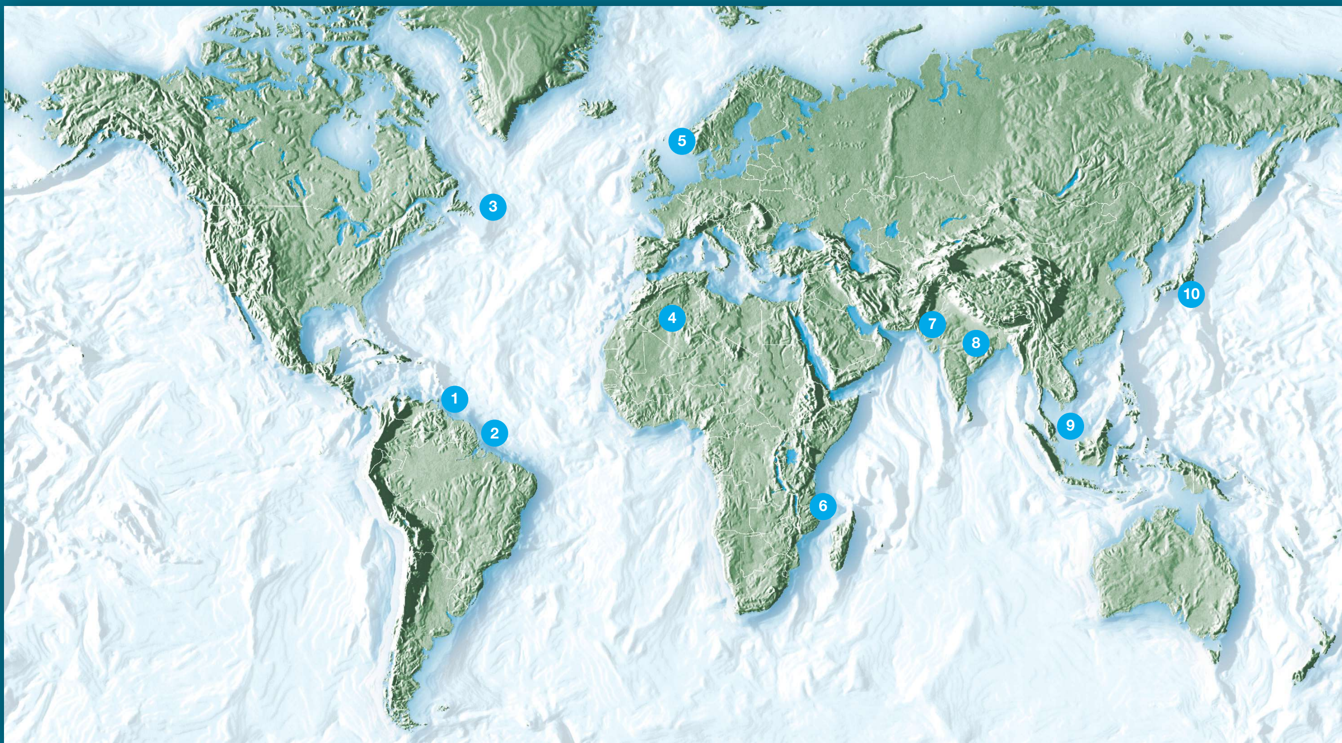
A gas discovery was confirmed in the Tendrara license area onshore Morocco by Sound Energy Plc. The first Tendrara well, #6-TE, was drilled to 2,665 m (8,743 ft), encountering the top of the structure and about 28 m (92 ft) of net gas pay in the TAGI reservoir. A stabilized gas flow rate of 481,386 cu. m/d (17 MMcf/d) was reported after unspecified stimulation. The bottomhole pressure in the reservoir was 6,092 psi and correlates with all of the wells previously drilled in the license area. No gas/water contact has been identified. A second well at #7-Tendrara is using sub-horizontal drilling techniques and is expected to significantly increase the individual well flow. The operator also is planning an extended well test. The company has a net effective interest of 27.5% in the Tendrara license.

5 Norway

Statoil reported that it has struck pay at Oseberg Sor in its Krafla campaign in Block 30/11, PL035 and PL272 in the Norwegian North Sea. The find was made with wildcat exploration wells #30/11-14 and #30/11-14B, which are southeast of the Krafla discovery well, #30/11-8S. Well #30/11-14 encountered a 23-m (75-ft) and a 6-m (19.6-ft) gas column in the upper section of Tarbert. Well #30/11-14B encountered a 38-m (124.6-ft) and a 12-m (39-ft) gas/oil column and a 13-m (42.6-ft) oil column in the upper part of Tarbert. Preliminary estimates indicate that that #30/11-14 has 6.29 MMboe to 12.58 MMboe, and #30/11-14 B has 12.58 MMboe to 31.45 MMboe. The #30/11-14 was drilled to 3,438 m (11,279.5 ft), and the #30/11-14 B was drilled to 4,187 m (13,737 ft) in water depth of 107 m (351 ft). The wells will be permanently plugged and abandoned. Statoil is the operator of PL035/272, Block 30/11 and these wells with 50% interest in partnership with Det Norske Oljeselskap (50%).

6 Mozambique

Wentworth Resources Ltd. received approval for an appraisal well of gas discovery #1-Tembo in Mozambique's Rovuma onshore concession. Under the two-year appraisal period, Wentworth becomes the operator of the concession and increases its participation interest from 11.59% to 85%. State-owned Empresa Nacional de Hidrocarbonetos retains the remaining 15% as a carried partner through to the commencement of commercial operations. Work will begin with reprocessing about 1,000 km (621 miles) of existing seismic data. In 2017 the company will acquire at least 500 km (311 miles) of new 2-D seismic data, with an appraisal well planned in 2018.



7 Pakistan

In the Guddu Block in Pakistan, Jura Energy Corp. has announced results from exploration well #1-Khamiso, which was drilled to 753 m (2,470 ft) in the Eocene Pirkoh Limestone. It produced 83,535 cu. m/d (2.95 MMcf/d) of gas during testing on a 32⁄64-in. choke with an average wellhead flowing pressure of 505 psi. A post-completion acid stimulation test is planned. Jura holds a 13.5% working interest in the Guddu Block, which is operated by Oil & Gas Development Co. Ltd.

8 India

Essar Energy Plc has made a discovery of 226 Bcm (8 Tcf) of original in-place shale gas resources beneath its coal-bed methane (CBM) reserves in the Raniganj East Block in West Bengal, India. The discovery is in addition to the estimated 30.8 Bcm (1.09 Tcf) in CBM reserves. According to Essar, there is a 20% to 25% recovery factor, and the CBM and shale gas resources can be produced simultaneously. Essar is the operator of the Raniganj Block with 100% interest.

9 Indonesia

An offshore Indonesia appraisal well, #4XSLT1-AAL, has produced 828 bbl/d of oil during a drillstem test. According to operator Santos Ltd., production is from a 3.5-m (11-ft) interval in a G Sand reservoir, and the well was tested on a 64⁄64-in. choke with assistance from an electrical submersible pump. The targeted G Sand reservoir is estimated to contain 289 MMbbl of oil in place with 36 MMbbl of gross recoverable oil. Bulk oil samples indicated a specific gravity of 10.7°API, with produced gas and water too low to measure. Preliminary analysis of the wireline log data indicates an 8-m (26-ft) oil column in G Sand and an excellent-quality reservoir with no oil/water contact. Operations are now underway to perform a second drill-stem test in the main AAL Field K Sand reservoir. The well is in about 72 m (236 ft) of water in the Natuna Sea.

10 Japan

Another round of testing offshore production of gas hydrates is planned by Japan Oil, Gas & Metals National Corp. in Japan. A drillship will drill two production wells and two monitoring wells near the last production test site in about 1,000 m (3,281 ft) of water. These tests were at the Daini-Atsumi Knoll in the eastern Nankai Trough. E&P

PEOPLE

Tethys Petroleum Ltd. named **Kenneth J. May** interim CEO. May will replace **Julian Hammond**, who is leaving Tethys after working for the company since 2007 and serving as CEO since 2012.

Andrew Jefferies has been appointed acting CEO of New Zealand Oil & Gas.

Siluria Technologies named **Robert Trout** CEO.

Ray Hood joined P2 as CEO.

Tethys Oil appointed **Jesper Alm** CFO following the decision by **Morgan Sadarangani** to step down. The company also named **Fredrik Robelius** CTO.

Petrobras selected **Nelson Luiz Costa Silva** as the chief strategy, organization and management system officer.

Advisian named **Geeta Thakorlal** (left) president for INTECSEA. Thakorlal succeeds **Neil Mackintosh**, who will take on the role of executive vice president of global sales and marketing.

The Pennsylvania Independent Oil & Gas Association selected **Daniel J. Weaver** as president and executive director. Weaver replaces **Louis D. D'Amico**, who is retiring after 22 years in that position.

Occidental Petroleum named **Oscar K. Brown** senior vice president, worldwide business development.

Bristow Group promoted **Chipman Earle** to senior vice president, chief legal and support officer and **Mary Wersebe** to vice president, human resources.

EthosEnergy appointed **Milton Kolb** senior vice president for global field services.

CMS Energy subsidiary Consumers Energy appointed **Venkat (DV) Rao** senior vice president of strategy and business planning; **Sri Maddipati** vice president, treasurer and investor relations; and **Tamara Faber-Doty** vice president of IT.

EXCO Resources Inc.'s current treasurer and vice president of finance and investor relations, **Chris Peracchi**, has become vice president and acting CFO following the departure of **Richard A. Burnett**. In addition, **Tyler Farquharson**, EXCO's senior director of finance, will be promoted to the position of vice president of strategic planning and will assume the investor relations role.

Marathon Oil Corp.'s **T. Mitch Little** has been promoted to executive vice president of operations and will oversee the resource play and conventional businesses.

Andrew Mitchell has been appointed as business development manager to support AISUS Offshore's plans for future growth.

2H Offshore, an Acteon company, named **Yann Helle** managing director.

The Society of Exploration Geophysicists (SEG) selected **Nancy House** as president-elect for 2016 to 2017. Following her one-year term as president-elect, House will assume the office of SEG president. She will become the second woman to serve as SEG president since the society's founding in 1930.

The American Association of Professional Landmen inducted the following members of the 2016-2017 AAPL Executive Committee: President **Pamela D. Feist**, First Vice President **David W. Miller**, Second Vice President **Jeff Niemeyer**, Third Vice President **Trinidad Hernandez**, Treasurer **Jim Bourbeau**, Secretary **W. Russell Shaw** and Immediate Past President **Marc R. Strahn**.

Aberdeen Harbour appointed **John McGuigan** to the newly created role of operations manager.

Bureau Veritas selected **Nick Brown** as communications director, Marine & Offshore Division. He will take up the post in November, replacing **Philippe Boisson**, who retires after more than 25 years in the role.

Andrew Padman has resigned from Entek Energy Ltd.'s board due to his recent full-time executive appointment at another oil and gas exploration company.

The PESA board of directors nominated and approved four new advisory board members: **Matthew J. Armstrong**, Baker Hughes; **C.A. (Craig) Lange**, Caterpillar; **Carrie Mendiola**, Schlumberger; and **Donald Young** (above), Hoover Group.

Chevron Corp. elected **Dr. Dambisa Moyo** and **Dr. Wanda Austin** to its board of directors.

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COMPANIES

Rovco is a new subsea company that officially launched in September with its first U.K. contract. Rovco is an independent company focused on underwater integrity, ROVs, surveying and subsea services for oil, gas and renewables.

Centurion Group and **ATR Group** are to merge to create a global player in the oil and gas rental equipment and services market. The group, which will have a combined turnover of more than £100 million (US$132 million), will operate from bases in the U.K., The Netherlands, Caspian, Singapore, Australia and the U.S.

The Underwater Centre, a subsea training facility, has developed a new hydraulics course that will provide candidates from a wide range of industries an introduction to fluid power systems.

Siemens has acquired a majority stake (85%) in Materials Solutions Ltd., a leader in additive manufacturing processing and production. The remaining 15% will be held by the founder, Carl Brancher.

S&P Global Platts has signed an agreement to acquire PIRA Energy Group. The transaction was expected to close in third-quarter 2016.

Hoover Container Solutions, **Ferguson Group** and **CHEP Catalyst & Chemical Containers** are merging to form Hoover Ferguson Group. Expected completion of the merger transaction is set for October.

Proserv has formed a strategic partnership with **KLAW Products** to offer an enhanced field safety service preventing offshore spills in the Middle East.

Sembcorp Marine Integrated Yard Pte. Ltd. has entered into a sale and purchase agreement with its existing shareholders to acquire a 100% equity stake in LMG Marin AS for $20 million.

Edgo is expanding its activities into Zambia and Malawi in Africa and setting up an operation in the Zambian capital, Lusaka. E&P

ADVERTISER INDEX

Widening the fracture gradient

Mid-riser pump system provides advantages of MPD while keeping a statically balanced wellbore.

Brian Piccolo and **Christian Leuchtenberg**, AFGlobal

As offshore drilling progresses into deeper water and highly fractured and depleted formations, the drilling window between pore and fracture margins continues to become narrower and less predictable. Under such conditions, maintaining a wellbore pressure that is high enough to prevent an influx and maintain wellbore stability while remaining low enough to prevent lost circulation, differential sticking and permit kick tolerance can be a significant challenge.

As a result, conventional methods of controlling wellbore pressure by manipulating the drilling mud rheology can result in a significant amount of nonproductive time and additional planned and unplanned casing strings. The end result is escalating project costs and the increased probability of a well control event, sidetracks or project failure.

To compensate for these challenges, managed-pressure drilling (MPD) systems can be utilized to provide opportunities for dynamic pressure control without requiring a change in drilling mud rheology. To date, the most common form of MPD used to dynamically adjust wellbore pressure is known as applied surface backpressure-MPD (ASBP-MPD). ASBP-MPD systems have a rotating control device (RCD) that forms a wellbore seal around rotating drilling pipe near the top of the riser to divert drilling returns from the riser to a drilling choke on the rig. The drilling choke permits wellbore pressure to be changed in seconds.

While ASBP-MPD systems have been proven to offer significant benefits, a limitation of this equipment and technique is that the operating range of the drilling choke is limited unless a statically underbalanced mud weight is used. Drilling ASBP-MPD with a mud weight below pore pressure can create the operating window necessary for the drilling choke to add backpressure to yield an optimal wellbore pressure. However, under these conditions, a failure of the RCD wellbore seal can immediately result in an underbalanced wellbore with an influx. As such, ASBP-MPD drilling programs that require a statically underbalanced mud are not permitted in the North Sea, Norwegian Sea and Gulf of Mexico.

To combine the benefits of dynamic wellbore pressure control with the security of drilling with a statically balanced mud weight, AFGlobal has developed the Pumped Riser System (PRS). This drilling system controls wellbore pressure by using a variable-speed subsea pump to lift riser returns around an RCD and inject the discharged flow into the riser column above the pump system. The PRS can be deployed through the rotary table as a joint of riser and uses a positive displacement pump system with a low power requirement. As a result, the PRS does not require any rig or riser modifications, resulting in an installation lead time of roughly one week on any deepwater drilling vessel.

> The PRS operating philosophy permits an optimal level of dynamic wellbore pressure control while still reducing operational risk and complexity.

In contrast to ASBP-MPD, which adds pressure to a statically underbalanced well with a drilling choke, the PRS is designed to dynamically reduce pressure from a statically balanced well by providing head with a pump. Since the PRS is designed to remove wellbore pressure, a failure of the PRS results in adding pressure back to the wellbore, which is inherently safer than ASBP-MPD, where a failure can result in an influx. In effect, the PRS operating philosophy permits an optimal level of dynamic wellbore pressure control while still reducing operational risk and complexity, which can facilitate both corporate and regulatory approvals for challenging offshore drilling programs.

Based on AFGlobal's experiences with developing both ASBP-MPD and mid-riser pump systems, the company believes that the PRS approach to drilling and ease of installation will ultimately enable the greatest growth opportunity for offshore MPD technology adoption in the mid- to long-term future. E&P

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