HARTENERGY

E&P

MAY 2016

EPMAG.COM

Land Seismic

Drillpipe Advances

Offshore Artificial Lift

Subsea Trees & Controls

REGIONAL REPORT:

GHANA'S TOP TEN

TESTING

OFFSHORE'S RESOLVE

Operators Investing in the Long Term

2016 Meritorious Awards for Engineering Innovation


KLX Energy Services
THESE DAYS YOU
CHOOSE
NEED AN EXPERT
WISELY
From wireline that supports plug and perf to custom-engineered products, choose the experts at one of the nation's leading oilfield service companies.
• WELL CONSTRUCTION AND COMPLETION SERVICES
• WELL INTERVENTION SERVICES
• WIRELINE SERVICES
• RENTAL AND ACCOMMODATIONS
LEARN MORE ABOUT OUR SERVICE EXPERTS,
AND HOW THEY CAN HELP KEEP YOUR WELL ON TRACK AT
KLXENERGY.COM

EXPLORATION & PRODUCTION
WORLDWIDE COVERAGE

MAY 2016
VOLUME 89 ISSUE 5

A HART ENERGY PUBLICATION

www.EPmag.com

ONLINE SPECIAL:

OTC 2016 TECHNOLOGY SHOWCASE

View the showcase in the May E&P issue at EPmag.com to peruse a sampling of the innovative products and services that will be exhibited during the Offshore Technology Conference in Houston, May 2-5, 2016.

TTS Drilling Solution's

Casing XRV

The Missing Piece To Efficiently Completing Your Well.

Save Rig Costs.

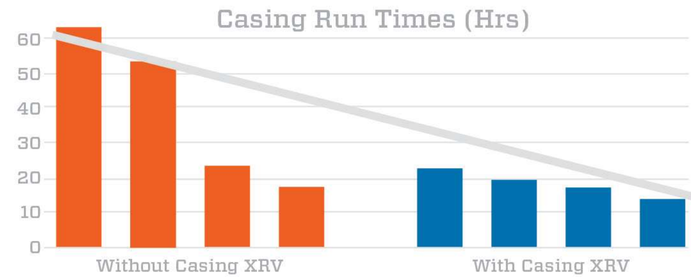
The Casing XRV's ability to break static friction allows operators to run casing to TD without excessive force, thus protecting the string from unnecessary stress and high friction. Minimizing casing stress during installation safeguards the operator from costly remedial operations in the future. In addition, the friction breaking technology increases run speed which results in decreased rig time, providing immediate cost savings for the operator.

Cost Saving Advantages:

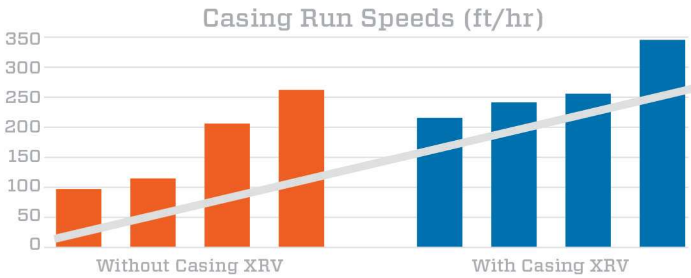
- Save Rig Time
- Reduce Mud Costs
- Improve Cement Bond
- Reach TD In One Run
- Eliminate High Torque Threads

Visit our website to watch the Casing XRV in action.

On an eight well pad comparison …



48% Decrease In Rig Time



94% Increase In Run Speed

The average casing run time, utilizing the Casing XRV, was 19 hours; saving the operator an average of 18 hours, signifying a 48% decrease in rig time. This directly correlates to a 94% increase in run speed when utilizing a Casing XRV; proving the friction breaking technology of the Casing XRV is significantly reducing operators rig costs.

TTS DRILLING SOLUTIONS™

www.ttsdrilling.com • info@ttsdrilling.com

A Division of Thru Tubing Solutions

47th Annual

HARTENERGY

Meritorious Awards for Engineering Innovation

Each year, the world's best new tools and techniques for finding, developing and producing hydrocarbons are recognized.

MEA entries are judged on their game-changing significance, both technically and economically. Judges include professionals who have extensive knowledge of the categories they are judging.

ENTER YOUR SUBMISSION IN 3 EASY STEPS!

1. **Gather all supporting documents**
2. **Go to *MEAentry.com* and create an online account.**
3. **Submit your entry**

All entries must be submitted by January 31, 2017.

Questions? Please contact MEAinfo@hartenergy.com.

DEPARTMENTS AND COMMENTARY

COMING NEXT MONTH The June issue of ***E&P*** will focus on reservoir characterization. Other features will include frontier exploration, drillbits and drillbit records, and production management as well as arctic and harsh environments, and the regional report will focus on the Gulf of Mexico. 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 Eni Norge's *Goliat* FPSO facility on its way to its eventual field location in the Arctic Barents Sea offshore Norway, where it is now producing close to 100,000 bbl/d of oil. Left, Tullow's TEN development was approved by Ghana's government in May 2013, just over four years after the Tweneboa discovery well was drilled by the *Eirik Raude* semisubmersible rig. The field is expected onstream in July-August this year. *(Cover image courtesy of Eni; left image courtesy of Tullow Oil; cover design by Carleigh Pearson)*

E&P (ISSN 1527-4063) (PM40036185) is published monthly by Hart Energy Publishing, LP, 1616 S. Voss Road, Suite 1000, Houston, Texas 77057. Periodicals postage paid at Houston, TX, and additional mailing offices. Subscription rates: 1 year (12 issues), US $149; 2 years (24 issues), US $279. Single copies are US $18 (prepayment required). Advertising rates furnished upon request. **POSTMASTER: Send address changes to E&P, PO Box 5020, Brentwood, TN 37024.** Address all non-subscriber correspondence to E&P, 1616 S. Voss Road, Suite 1000, Houston, Texas 77057; Telephone: 713-260-6442. All subscriber inquiries should be addressed to E&P, 1616 S. Voss Road, Suite 1000, Houston, TX 77057; Telephone: 713-260-6442 Fax: 713-840-1449; custserv@hartenergy.com. Copyright © Hart Energy Publishing, LP, 2016. Hart Energy Publishing, LP reserves all rights to editorial matter in this magazine. No article may be reproduced or transmitted in whole or in parts by any means without written permission of the publisher, excepting that permission to photocopy is granted to users registered with Copyright Clearance Center/0164-8322/91 $3/$2. Indexed by Applied Science, Technology Index and Engineering Index Inc. Federal copyright law prohibits unauthorized reproduction by any means and imposes fines of up to $25,000 for violations.

Printed on recycled paper

ACTIVITY HIGHLIGHTS

Subscribe @ EPmag.com/subscribe

Perth Basin venture hits 53 m of gas pay

In Western Australia's Perth Basin Block EP389, Empire Oil & Gas NL reported completion information on the #1-Red Gully North-1 discovery. The venture penetrated 53 m (174 ft) of net gas pay.

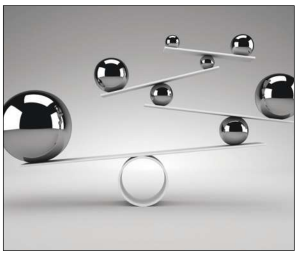
Lower Springer Shale well flows 1,800 bbl of oil

A high-volume Lower Springer Shale discovery was announced by Newfield Exploration Co. in the SCOOP play. The #1H-21X Doyle is in Section 16-2N-4W of Stephens County, Okla.

Northwestern Paraguay estimate shows 440 MMbbl of oil

President Energy Plc has increased its estimated gross mean prospective resources in the onshore Pirity and Hernandarias concessions in northwestern Paraguay.

AVAILABLE ONLY ONLINE



Analysts: oil market rebalancing nears as non-OPEC production falls

By Velda Addison, Senior Editor, Digital News Group

A group of analysts is confident that market conditions will rebalance by mid-year, and the signs are evident.

Norway sees positives in unmanned platform option

By Velda Addison, Senior Editor, Digital News Group

A study provides Norway with insight on a development concept the region has not used as much as others across the world.

Emissions rule spurs technological innovations

By Joseph Markman, Hart Energy

A new device now being tested in the Utica Shale and the Eagle Ford Shale can destroy vapors while generating electrical power at remote oil and gas operations.

Panel: Opportunities exist in Brazil, despite scandal

By Velda Addison, Senior Editor, Digital News Group

The corruption scandal hits debt-laden Petrobras hard during one of the worst downturns in the oil and gas sector's history. But it's not all bad news for potential investors.

DOWNLOAD THE APP

E&P


ONSHORE. OFFSHORE. EVERY SHORE.
IT ALL STARTS WITH API.™
No matter where you go around the world, the oil and natural gas industry relies on API Certification, API Training, API Events, API Standards, API Statistics, and API Safety. Show the world your commitment to quality. Start with API.
energy API®
It's times like these you need people like us.®
See us at OTC 2016, booth 5009.
877.562.5187 (Toll-free U.S. & Canada) | +1.202.682.8041 (Local & International) | sales@api.org | www.api.org
© 2016 – API, all rights reserved. API, the API logo and the "It All Starts with API" tagline are trademarks or registered trademarks of API in the United States and/or other countries.

1616 S. VOSS ROAD, STE 1000
HOUSTON, TEXAS 77057
P: +1 713.260.6400 F: +1 713.840.0923
EPmag.com

Editor-in-Chief	MARK THOMAS
Executive Editor	RHONDA DUEY
Group Managing Editor	JO ANN DAVY
Senior Editor, Drilling	SCOTT WEEDEN
Senior Editor, Production	JENNIFER PRESLEY
Chief Technical Director, Upstream	RICHARD MASON
Senior Editor, Digital News Group	VELDA ADDISON
Associate Managing Editor	ARIANA BENAVIDEZ
International Editor	JOHN SHEEHAN
Corporate Art Director	ALEXA SANDERS
Senior Graphic Designer	CARLEIGH PEARSON
Production Manager / Senior Graphic Designer	GIGI RODRIGUEZ
Vice President of Publishing	RUSSELL LAAS

Editorial Advisory Board

CHRIS BARTON
Wood Group Mustang

DICK GHISELIN
Consultant

DONALD PAUL
USC

EVE SPRUNT
Consultant

MIKE FORREST
Consultant

JOHN M. GILMORE
Schneider Electric

KEVIN BRADY
Highway 9 Consulting

KEITH RAPPOLD
Aramco Services

GARRETT FRAZIER
Magnum Oil Tools

OLGA KOPER
Battelle

ERIC NAMTVEDT
Superior Energy Services Inc.

HARTENERGY

Editorial Director
PEGGY WILLIAMS

President & Chief Operating Officer
KEVIN F. HIGGINS

Chief Executive Officer
RICHARD A. EICHLER

MARK THOMAS
Editor-in-Chief
mthomas@hartenergy.com

Read more commentary at
EPmag.com

Keeping a balance

There's no convenient universal law when trying to balance short-term needs against long-term goals.

According to Sir Isaac Newton's third law of motion, "For every action there is an equal and opposite reaction." After listening to various oil company presentations, there are clearly results emerging from their determined reaction to the extended crude price downturn.

Eni's CEO Claudio Descalzi highlighted this dilemma as occurring during a period in which the oil price has fallen 70% since second-half 2014, but with costs not falling by nearly as much. "The industry needs to face this very complex challenge—to reduce costs to fulfill short-term financial targets without destroying long-term value," he said.

With continued uncertainty over any likely price recovery, Descalzi acknowledged the industry has cut capex by more than 35%, mostly by postponing or canceling projects. "But this is a short-term solution," he said. "It's not viable for the long run because it will impact long-term growth and asset values. The only solution to reconcile long- and short-term goals is to rapidly align costs and prices in order to continue to profitably invest also when the oil price is low."

Eni is doing this, and its percentages are pretty representative of operators as a whole. It started renegotiating contracts mid-2014 and last year achieved savings of 500 million Euros (US $570 million), a combined savings of 18% on roughly 2,000 contracts from renegotiation and tenders.

It intends to accelerate this cost-trimming renegotiation process, even bringing tenders forward. The 2016 plan is to renegotiate 1,600 service contracts. This "strict attention" to the supply chain, as Eni terms it, has lowered the average breakeven of the company's upstream projects from $45/bbl to $27/bbl ($15/bbl for onshore, circa $30/bbl for shallow and deep water).

Statoil is doing likewise, having renegotiated about 500 contracts since 2014, CEO Eldar Saetre said. Its own portfolio breakeven cost has dropped to less than $50/bbl, with some projects under $30/bbl.

Any new activity after the vacuum left by 2015's brutal projects massacre is encouraging.

But Saetre also added that Statoil is making changes to its operating model "to make sure that the current improvement sticks and that we don't repeat the mistakes of the past." Other CEOs also used the same terminology.

Unfortunately the "past" referred to contains an industry with a track record of overreacting at times of crisis by cutting too deeply into its supply chain and then suffering the consequences as that cash-starved chain itself almost unavoidably reacts in equal and opposite measure when better times return.

Sir Isaac would only say he told us so. E&P

Mark

Major players thinking outside the box—but will it last?

A panel of industry experts discusses findings from Trelleborg's 'Next Level' report, including the benefits of marginal gains and the need for sustained collaboration.

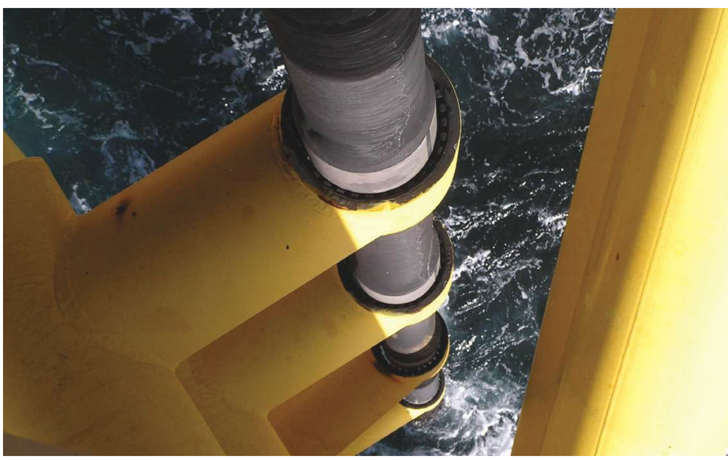
Jo Shailes, Trelleborg Offshore

Imagine thinking that $10 million in savings is just not worth wasting time on. That's precisely the case on many multibillion-dollar projects, especially during boom times.

This was a key discussion point at a roundtable on the findings from Trelleborg's recent "Next Level" report. During the past several decades, oil companies often were not interested in improvements unless they led to savings on the order of 20% or 25%. Today, sustainable savings, albeit much smaller, are starting to have more appeal.

The question is whether or not this approach will be thrown out when markets improve along with other positives such as enthusiasm for innovation and a shift toward mutually beneficial outcomes with suppliers.

"In the past, by the time we entered the project phase, specifications were nailed down, and the opportunity for creativity from the supplier had gone. There was no time for thinking out of the box or bringing something new to the table," said John Dury, managing director of Trelleborg's offshore operation in the U.K., during the roundtable. "Now we're seeing a real shift toward collaboration."



This riser prototype is an example of how innovation and collaboration can thrive in a downturn. (Source: Trelleborg)

Debarati Sen, global business director for 3M's Oil and Gas Division, agrees that it's frustrating to be told what to deliver rather than having an opportunity to present ideas. "We are now seeing an appetite for innovation, but sometimes it's stated as, 'What are some ways for us to reduce costs?'" she said.

Sen noted that 3M views those openings as an opportunity to bring in new materials that make parts fail less, increasing the mean time between failures. "In that way, you are bringing down costs, direct as well as indirect."

Report findings

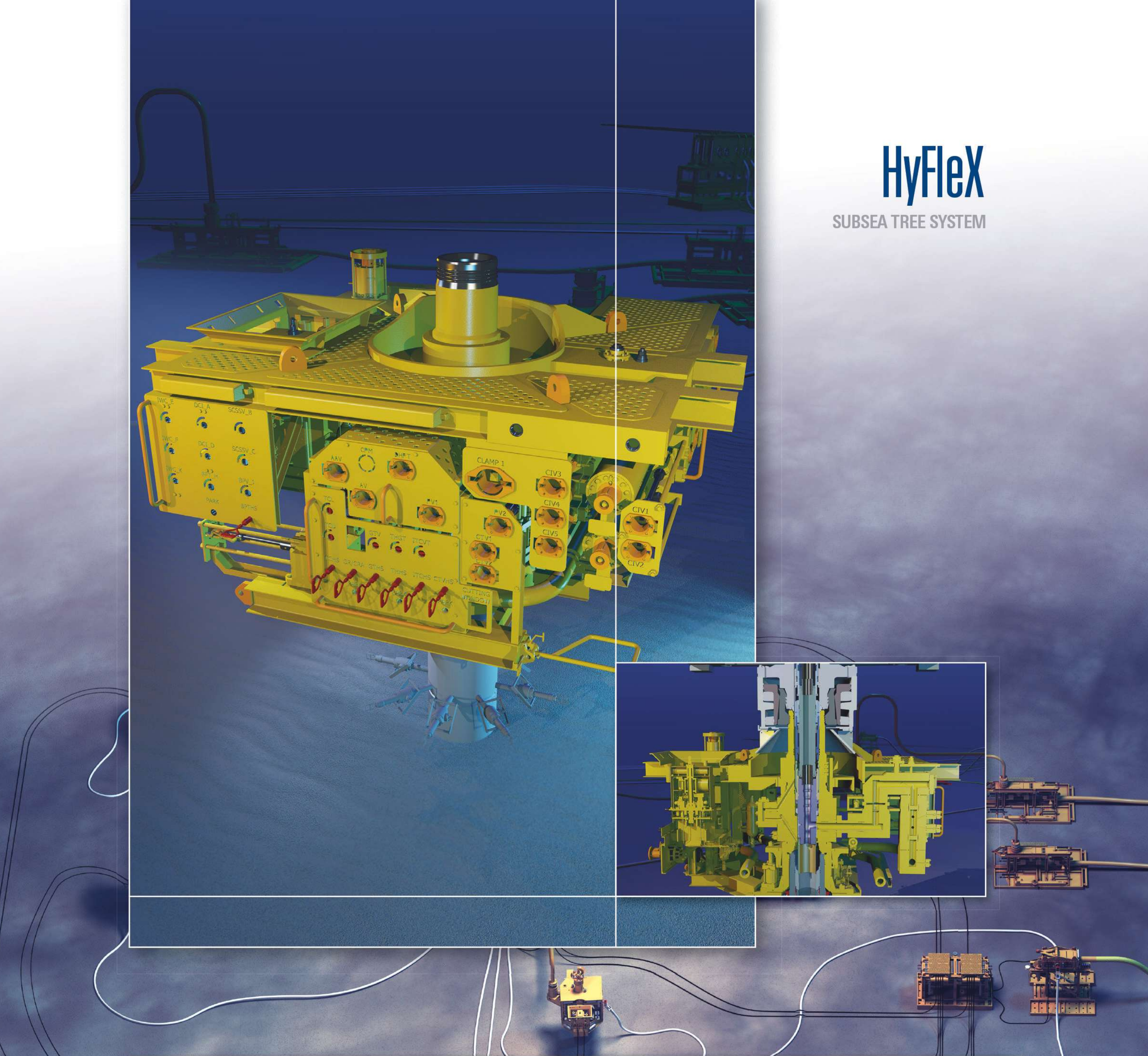
The report found that:

- 78% admitted to changing the specification of a project to save costs;
- Only 30% are prepared to pay for additional services such as installation training and ongoing project support;
- 4% cited cost as the primary factor in selecting a maintenance supplier; and
- Asked which supplier attributes they seek for reducing risk and ensuring compliance, 37% cited depth of expertise; 29% cited track record; 15% cited breadth of resources; and less than 10% cited geographic accessibility, financial security and creative approach to the brief.

Adding up small gains

Not everyone is approaching this marketplace as an opportunity, however. Philip Lawson, head of Aberdeen Consultancy and ABB Oil & Gas UK, said one result of the industry slimming down has been a split into two camps. Some companies, particularly those with older assets, are taking a batten-down-the-hatches-and-ride-out-the-storm approach.

"They don't want to change; they just want to survive and get through the next 18 to 24 months," Lawson noted. Other companies are



HyFleX

SUBSEA TREE SYSTEM

Based on field-proven components and designed for operational flexibility to reduce life-of-field costs.

The HyFleX* subsea tree system provides benefits of both vertical and horizontal conventional trees without the usual compromises. Designed so that the tubing hanger and tree can be installed and recovered independently of each other, the HyFleX subsea tree system can provide significant cost savings with multiple installation and recovery options.

Based on field-proven components, the patented HyFleX subsea tree system offers functional flexibility and the ability to batch set wells, mitigates risk, and can help deliver operators significant cost savings in field development over the life of the field.

Learn more about our leading technology at

onesubsea.slb.com/HyFleX

OneSubsea

A Schlumberger Company

All referenced trademarks are owned by or licensed to Schlumberger. © 2016 Schlumberger. All rights reserved. OSS-1069

treating this period as an opportunity to make improvements, even if they result in marginal gains. In isolation, $10 million in savings may not mean much on a multi-billion-dollar project, but when several gains are put together, they become significant, Lawson said.

"Customers say, 'Show me where this has been done before,'" said Philip Cooper, an independent consultant to subsea and pipeline companies. "They want results based on the same water depth, pressure and temperature conditions—almost a blueprint of someone who has already done exactly what you are proposing. Of course, if we all worked that way, nothing would ever change."

Sen agrees in part with Lawson and Cooper. "There are some who will not change, who want to find [an existing] blueprint and use it," she said. "But other operators are far hungrier now and want to try things out. Some are looking for ways to bring a project to a different level while achieving the best ecology."

New primers are one of many advancements in technology. (Source: Trelleborg)

Survival of the collaborators

The key to that type of industry innovation, all the panelists agreed, is collaboration. Lawson points to changes in the auto industry brought about by poor market conditions. "The motor industry was crashing and had to share best practices to survive," he said. "Now we look at the industry, and it is probably one of the strongest in the world. The way that was achieved was through collaboration."

Lawson said he strongly believes the challenge does not lie with the suppliers but the operators who tend to be resistant to change. "Their minds are firmly set on 'their' price and what they bring to the table. Around the table, the suppliers probably hold the key to the future, and it is about collaboration," he said.

Dury and Sen supported this line of thought. "Relationships are now about technology, understanding, collaboration and solving problems," Sen said. "The industry needs to become more mature on the supply chain and purchasing side. Companies are sending their people for purchasing training, and in some cases they are coming back more adversarial. That is where the industry just needs to stop itself and become more collaborative across the functions."

That approach could stifle innovation and speed of response, Dury said. "The current procurement philosophy is contradictory to an industry that needs more innovation and faster routes for new ideas into the field."

Price matters

The panelists were skeptical about the honesty of respondents to one survey question. Only 4% cited cost as the primary factor in selecting a maintenance supplier.

"We get into price conversations frequently," Dury said. "Once we've gotten through the discussion about are we going to deliver and is the product right, there's never a decision made without a discussion about price."

Lawson noted that cost cuts might potentially affect safety and/or performance. "If you're asked to reduce cost by 10%, you'd look to reduce costs in any form. I think the people who will be here in the future are those who will take that 10% reduction but make sure it doesn't affect safety or performance."

Sen said she sees some variation in how cost cuts are handled and that the tone is set at the top. "Typically, the responsible operators make very well thought-out decisions, squeezing where they can but not squeezing as hard in places where it might compromise the viability of the project."

Drury added that he is currently optimistic about both the way cost cuts are being handled and the opportunity for innovation. "For example, we have new technology that allows seals to be welded *in situ* on an FPSO platform, eliminating the need for the platform to disconnect and return to shore," he said. "It feels like there is a hunger for collaboration up through the value chain to the operators in the current climate."

The bottom line, the panelists said, is to never waste a crisis. "I think that rather than stifling innovation, this period should drive us to something more economical and more sustainable," Lawson said, and Cooper agreed. "We're in a period of change. Make those changes work for you as an individual and an organization," Lawson said. "There will never be a better opportunity to find better ways to do things than there is right now." E&P

GENIUS™ SERIES

POWER SYSTEMS & SUPPLY

TECHNICAL SUPPORT

FLUID MANAGEMENT

EQUIPMENT PROTECTION

GAS MANAGEMENT

THE **GENIUS SERIES** FROM FLOTEK BRINGS TOGETHER OUR PROVEN, TECHNOLOGY-ENABLED ESP EQUIPMENT, OUR WORLD-CLASS CUSTOMER SERVICE, AND OUR PROPRIETARY SOFTWARE INTO A PERFECT PACKAGE THAT **CAN HELP YOU INCREASE EFFICIENCY, PROFITS AND SAFETY.**

Plus, our technicians are equipped with digital solutions to reduce installation time, minimize the chance of errors, and provide accurate and thorough reports with each installation or service call.

REDUCE INSTALLATION TIME

MINIMIZE CHANCE OF ERRORS

PROVIDE ACCURATE + THOROUGH REPORTS

FLOTEK

Learn more about how you can make your artificial lift operations smarter with the GENIUS SERIES FROM FLOTEK

WWW.FLOTEKIND.COM

RCP begins next phase

Tom Davis is retiring from the successful consortium he started more than 30 years ago, but his legacy will endure.

Rhonda Duey, Executive Editor

When this reporter first started covering the oil and gas industry in 1995, the concept of asset teams was just emerging. The managers driving that change may, in part, have been graduates of the Reservoir Characterization Project (RCP) at the Colorado School of Mines (CSM).

The project was formed in 1984 by Tom Davis, a professor in the geophysics department. In the 10 years prior to the formation of RCP, Davis was a faculty member working on mapping faults and fracture zones in the Denver Basin.

"Bob Weimer put me onto this as a potential problem," Davis said. "I think part of his insight was based on the evolution of fractured reservoirs in Colorado.

"It was an opportunity, and I said, 'Count me in.' I figured I'd sign on for a year, and 40 years later I'm still here."

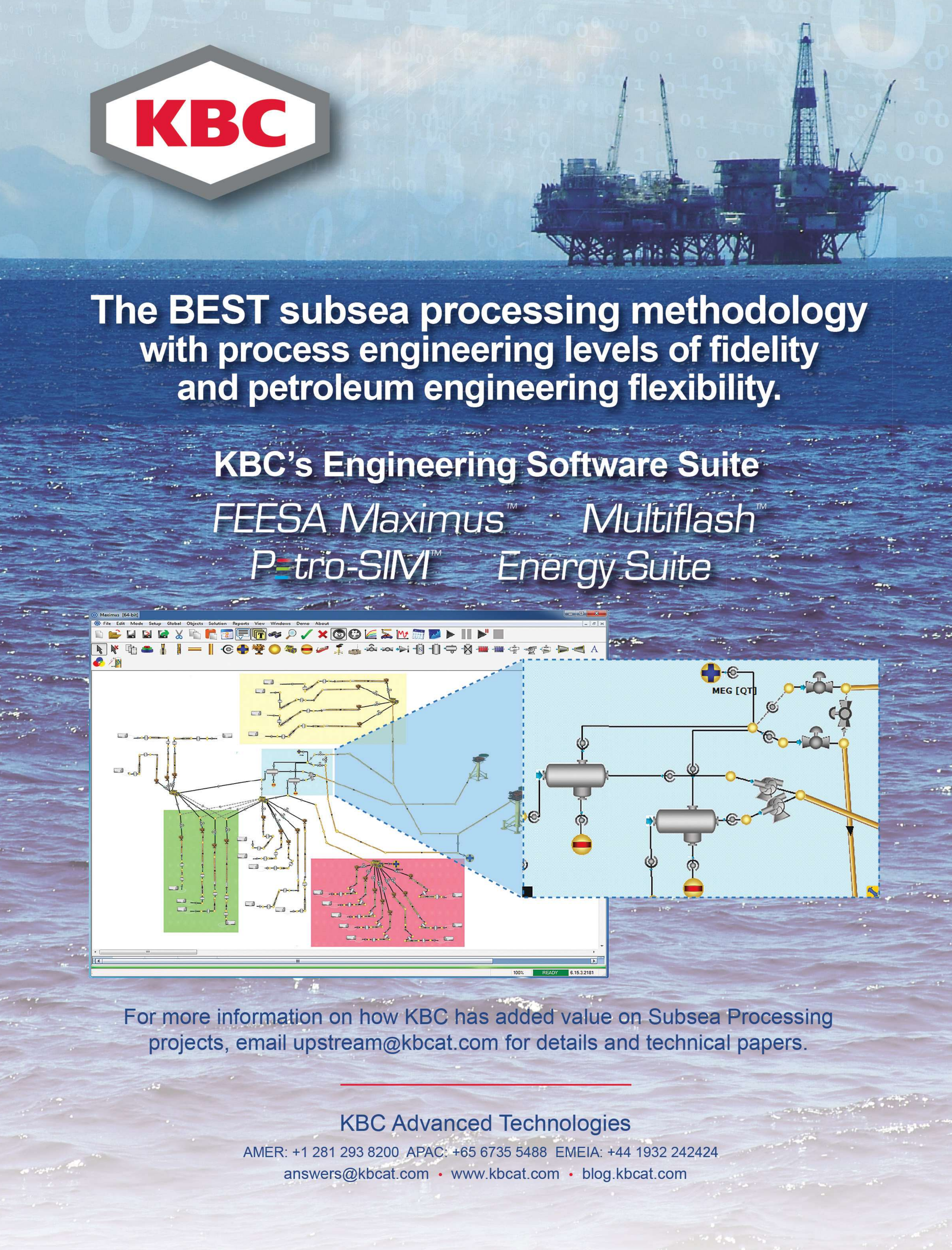
But not for long. Davis is retiring from his teaching and RCP at the end of the 2016 spring semester. He recounted to *E&P* some of the fascinating changes he's observed during his tenure.

The context

Davis said the context of developing the research program was a focus on fractured reservoirs and the use of seismic technologies to find them. One of the early areas of his studies was the Wattenberg Field in the Denver-Julesburg Basin, and that field, which sits atop the Niobrara and Codell shales, is one of the current RCP phases.

"It's coming full circle," he said. "Instead of using 2-D seismic like we did in years gone by, we're now using 3-D and 4-D and multicomponent seismic. And we're tying it in with other disciplines. That's been the whole crux of my career in a nutshell. That's one of the advantages of an institution like Mines—we can develop a focus and carry it forward with our students."

The RCP class of 2015 poses outside the Green Center at CSM. (Source: Colorado School of Mines)


KBC
The BEST subsea processing methodology with process engineering levels of fidelity and petroleum engineering flexibility.
KBC's Engineering Software Suite
FEESA Maximus™
Multiflash™
Petro-SIM™
Energy Suite
MEG [QT]
For more information on how KBC has added value on Subsea Processing projects, email upstream@kbcat.com for details and technical papers.
KBC Advanced Technologies
AMER: +1 281 293 8200 APAC: +65 6735 5488 EMEIA: +44 1932 242424
answers@kbcat.com • www.kbcat.com • blog.kbcat.com

DOWNLOAD THE APP

RCP is a research program for graduate and doctoral students that challenges those students with real-world problems brought forth by industry sponsors. Current projects include the Wattenberg Field, Vaca Muerta Shale, Kuwait deep gas project, Montney Shale and Denbury project.

During his tenure at CSM and RCP, Davis has certainly seen changes in technology. One technology that is seeing only mild uptake is multicomponent seismic. "I would like to say that the multicomponent technology we've been working on and developing over the course of 30-some years is going to be the technology of the future," Davis said.

"I still think it is. People keep asking, 'When is it going to happen?' I think the framework is that as we go forward, we're going to find out that these reservoirs are even more complex than we think. And if we're going to increase the recovery from these reservoirs, it's going to be important to use the best technologies that we can apply," he continued.

He added that RCP has used multicomponent seismic on all of its projects, from the Silo Field in the mid-1980s up to its current use in Wattenberg today. "It enables us to see those fractures and fault zones, which then enables us to develop reservoir models."

Processing these data was a hurdle in earlier days, but Davis said that the main hurdle now is integrating the data and tying them to the engineering model as well as the geological model.

"This helps with the orientation of wells, the length of wells, the completion of wells, the recompletion in terms of refracturing the wells and maybe even EOR through injection of CO_2," he said. "I think the future, whether it's in Wattenberg or the Bakken or the Permian or someplace else in the world, will be in this area of reservoir modeling and the enhancement of recovery in these reservoirs.

"Right now with an average recovery of 5% to 6% [in the shale plays] there's a huge resource that's here in our backyard. It's important for us, especially at CSM, to have the foresight to say we can do better and to align ourselves with the industry to make that wish come true," he emphasized.

Another change he's seen is a shift from trying to get better images from seismic data to quantification of the reservoir parameters. Here again multicomponent seismic can help. "Even as early as the early 1980s companies like Arco and Amoco were working on multicomponent," he said. "We stumbled onto it at Silo Field as well. By the middle of the 1980s, the industry had gone into a downturn, and the first thing that was cut was research. We benefitted from that because companies shifted their focus to working alongside academia. They could see the potential to do real-world experiments. That was the evolution of RCP in 1985."

Davis blames the current downturn, in part, on the industry's ability to evolve technology to solve its problems. "The oil industry is a slow adopter of technology, but once we get good at what we're doing, sometimes we're too good," he said. "We go through these cycles, and they're driven by technology to a large degree."

Business changes

Prior to going to CSM for first his doctoral degree and then his teaching position, Davis worked at Amoco for more than three years and had an internship at Chevron. "Back then we were still looking for structures [and] bumps to drill," he said. "The view of integration was not really embraced.

"That changed, and I'd like to say that we were part of that change because when I started developing integrated exploration development courses in 1980, we were probably one of the first if not the first to do that with the idea that students could have an integrated experience. I think those early courses served the foundation of where some of our students went, taking this idea of integration with them. It transformed the industry in the late 1980s and into the 1990s into asset teams, and that structure is still playing out today."

He also sees more collaboration between companies, as evidenced by the number of industry conferences and other events. "In the framework of unconventionals, we have to get together and talk, and we have to try to find technologies that work across the disciplines," he said. "We're having to do that in a difficult economic environment where companies have the aspiration of holding on to their best people and assets. But it will change."

All about the students

Having taught at the college level for more than 40 years, Davis has seen his share of students come and go at CSM. How have they changed during that time?

"They're more adaptable," he said. "I think they're more astute about the real world. They're more aware of their surroundings and the environment. I think it's up to us to develop educational systems that these folks can embrace.

"How do you tune them in and not have them tune out? One of the things I've found is that if you give them a real-world problem to work on, they'll work on it, and they'll work together. The learning experience is next to none."

Cost-Effective Solutions for Your H_2S Treatment Needs
Hexion provides a full line of MEA and MMA-based hydrogen sulfide (H_2S) scavenging products specifically designed for the oil and gas industry. With our global manufacturing footprint and direct sourcing of required raw materials, we are positioned to meet your needs for base products or customized finished blends. As a leader in the industry, we provide effective solutions to help you economically manage your sulfur issues.
Visit us at hexion.com/h2sscavengers
Tel: +1 800 626 2116
HEXION™
Helping you make it in today's world.
© 2016 Hexion Inc. All rights reserved.
®, ™ and SM denote trademarks owned by or licensed to Hexion Inc.

Next iteration in drilling rigs

Two international service providers are well advanced on new-concept digital rigs.

Richard Mason, Chief Technical Director

With domestic rig count down 77% from peak, it might seem odd that a multinational oil services firm and one of the globe's largest international land contractors are talking about a new upgrade cycle in rigs.

But that's exactly what is happening.

Both Schlumberger Ltd. and Nabors Industries Ltd. discussed new rig concepts in New Orleans at the Scotia Howard Weil investor conference in March.

The new-generation rigs integrate digital sensors in downhole tools with surface equipment in real time via software to enhance ROP and accuracy in staying within zone in horizontal drilling.

- **Nabors and Schlumberger are testing new digital rig designs.**
- **Commercialization is expected by 2017.**
- **Concept rigs employ an iPhone approach to drilling or the integration of hardware and software to advance the drilling process.**

Nabors announced its new rig, the *M800*, at the Scotia Howard Weil conference. The concept employs advances in rig control systems with the company's proprietary MWD system and a directional drilling software interface to allow the driller to conduct automated geosteering operations and incorporate directional drilling services into the rig's normal operations rather than relying on third-party service providers.

Nabors has completed one prototype of the *M800*, which it is currently showing to customers, and plans to finish two more by fourth-quarter 2016. The unit will feature an 850,000-lb hookload, stack 7,620 m (25,000 ft) of 5-in. drillpipe and incorporate a 7,500-psi circulation system. The rig is a beefed-up version of the pad-capable PACE-X concept.

Significantly, the software control systems can be retrofitted to Nabors existing premium AC-variable frequency drive (VFD) rig fleet and older legacy diesel electric silicon-controlled rectifier rigs.

Meanwhile, Schlumberger will begin field-testing a prototype integrated rig in Ecuador and the U.S. domestic market in 2016. The rig is the first product of the joint venture finalized in December 2015 between Germany's Bauer Maschinen GmBH and Schlumberger and will incorporate surface equipment, top drives, pipehandling and BOPs from the Cameron International Corp. acquisition.

The Schlumberger drilling rig is part of a larger integrated approach to drilling and well completion that leverages the company's manufacturing presence in drillbits, drilling fluids, bottomhole assemblies (BHAs), LWD and directional drilling.

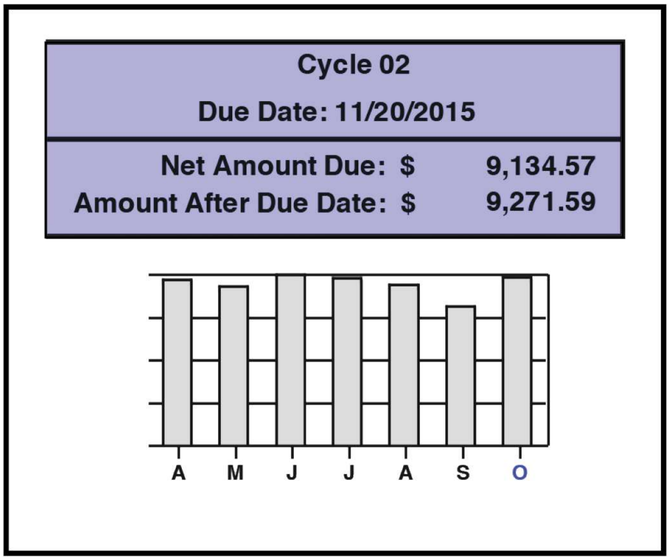
Schlumberger first discussed its new rig technology as a component of its international business at Scotia Howard Weil in 2015. This past year, the multinational revealed it will be testing the rig for the U.S. market, with full commercialization in 2017. The drilling unit is part of a broader corporate strategy to move from supplying discrete individual technologies to creating digitally based integrated systems as a means of lowering the per-barrel cost of hydrocarbon extraction.

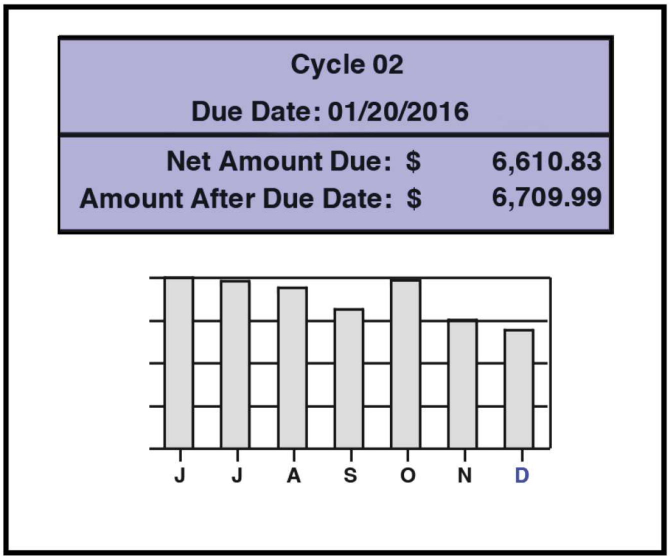
The bumper sticker explanation suggests that the next threshold in rig performance will digitally integrate the drilling process from the bit and BHA to surface equipment using software to automate mechanical processes such as geosteering and expand the ability for the human operator to make informed decisions.

Both rigs are entering a marketplace that is currently characterized by more than 450 stacked Tier I AC-VFD 1,500-hp units ideally suited for drilling the 2,286-m to 3,048-m (7,500-ft to 10,000-ft) laterals that are becoming commonplace in unconventional resource development, including landing laterals in ever-narrowing windows of quality rock.

Still, the latest evolution in rig design is a sign that the industry is moving from drilling efficiency toward drilling effectiveness. These new concept rigs will test whether operators will relinquish control of a drilling process that, under the direction of their in-house engineering staffs, has brought astonishing improvements in hydrocarbon harvest. Stay tuned. E&P

Power bills killing your ESP's bottom line?





No risk guaranteed 20% power reduction PowerSave™ ESP

PowerSave@novomet-usa.com

Do *Casing Clearances, Dog Leg Severity, Gas, or Rod Wear* Present Operational Barriers?

Slim-Line Is The Solution!!

- 2.72" & 3.19"
- High Efficiencies
- 80-3500 bpd

Not Just Another ESP Provider

NOVOMET®

SlimLine@novomet-usa.com

DISCOVER

Innovative solutions for complex E&P challenges

FROM CGG GEOCONSULTING

cgg.com/geoconsulting

CGG
GeoConsulting

The little outcrop that could

A 'scrappy' outcrop in eastern Mexico might just have the answers to geological puzzles in the GoM.

RHONDA DUEY
Executive Editor
rduey@hartenergy.com

Read more commentary at
EPmag.com

Some of the largest recent finds in the Gulf of Mexico (GoM) are in places where nobody thought they could be—ultradeep water.

How did the Wilcox Formation, a prolific play onshore the U.S. and Mexico, end up there? How could it have traveled so far from home?

A recent article in *Interpretation* offers up compelling data that imply that drastically changing sea levels in the GoM ("drastic" by geologic time, at least) might have led to erosion that allowed these sediments to "roll down the shelf," as it were, and be deposited into the deeper basin. And this evidence, in large part, comes from an outcrop that has attracted attention for years but only recently has been studied in detail.

Steve Cossey, an independent geologist, told me that the outcrop is "very insignificant" but contains an unusual black bed in the middle that for years was assumed to be coal. But after taking samples and sending them to laboratories, a very different story unfolded.

This photo represents the excavated bitumen bed that was discovered in the outcrop. (Source: Cossey *et al*)

"I talked to a coal expert who told me how to take the samples," Cossey said. "I very carefully took the samples and sent them to Calgary. He said, 'Well, it's not coal.' He sent them off to a colleague who was an expert in bitumens and oil shale, and she pronounced it a fossilized bitumen."

As in a petrified surface oil seep. Where none should have been. With turbidites, suggesting deepwater deposition, both below and above the bitumen bed, this implied a rather swift emptying and refilling of the GoM.

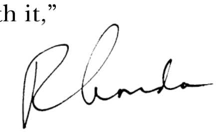
Don Van Nieuwenhuise, director of professional geoscience programs at the University of Houston, said that a drastic lowering of sea level in the GoM, most likely due to it being landlocked during part of its evolution, would explain the Paleocene-Eocene thermal maximum, a period during which temperatures increased dramatically. But why?

"If you lower sea level, you're going to be reducing the pressure on the gas hydrates," Van Nieuwenhuise said. "They'll start to come out of crystal form into gas form, and they'll bubble up."

Not only that, but reduced pressure could reduce overburden pressure on hydrocarbon reservoirs as well. He said that a drop in sea level of 183 m (600 ft, and maybe more) would drop the overburden pressure by about 400 psi. "Some reservoirs whose seals are right at balance will leak out," he said.

Cossey plans to go back with a bobcat to dig out more of the outcrop. However, some of the area of interest is under a dwelling, so he's hoping to incorporate electromagnetic techniques to look for resistivity underground. And he's hoping to find some fossilized biostratigraphy that will help date the deposit more accurately.

"We've got the smoking gun in the outcrop and the bullet (the seep) that came with it," Van Nieuwenhuise said. "The more we look at it, the more amazed we get." E&P



A WORLD-LEADING SEISMIC PROGRAM

IN ADVANCE OF SCHEDULED LICENSE ROUNDS.

Offshore Newfoundland and Labrador is the subject of one of the most comprehensive seismic data acquisition programs in the world today. Since 2011, we have been working with global partners to acquire over 110,000 km of 2D seismic data covering the offshore and collecting significant multi-client 3D surveys in advance of the 2016 license round. These efforts are shedding exciting new insights on the region's prospectivity: In 2015, this work resulted in the identification of 12 billion barrels of oil and 113 trillion cubic feet of gas potential in an area representing merely 1.6% of our offshore, and off the coast of Labrador three new deepwater basins have been delineated and another expanded. Less than 5% of offshore Newfoundland and Labrador is currently under license in an area that is 1.5 times the size of the Gulf of Mexico.

Through the acquisition of new geoscience data, new scientific knowledge is being shared with the global oil and gas industry to help reduce exploration risk in offshore Newfoundland and Labrador.

nalcor energy
OIL AND GAS

Visit nalcorenergy.com/exploration

Shades of Stroud, Okla.: Yards full of stacked rigs bring reminders of 1980s

Once the rig count hits bottom historically, the rig count tops 1,000 rigs again within 12 to 18 months.

In an article in the *Los Angeles Times*, Benny Teegarden, the owner of Venture Drilling Co. in Cushing, Okla., said he had to cut his employees' salaries and shut down work. Like many other oil men, he believed that "sooner or later the price of oil would go back up and there would be another boom. It is the cyclical nature of the business, and if you are an oil man, you take that for granted and just hope you can pull through the bad times."

Another operator pointed out there is no point in producing oil from stripper wells. With the price of a barrel of crude hovering at about $12, he would earn less than it would cost him to extract it from the ground.

But, you might say, oil prices aren't at $12 per barrel. But they were when this article was printed March 23, 1986.

For those of us who were around at that time, we remember John Cassidy's equipment yard outside Stroud, Okla., which was filled with "millions of tons of rigs and giant motors—and everything else needed for drilling," according to the *Los Angeles Times* article.

As the article continued, "While the rest of the country is enjoying lower prices, Texas, Oklahoma and Louisiana are suffering," said John Reid, a spokesman for [then] Oklahoma Gov. George Nigh. "It isn't good."

Now you can add North Dakota, Wyoming and Colorado to the list of suffering states.

In Morgan City, La., "Ray Oubre, a tug boat captain servicing rigs in south Louisiana, has taken to building custom duck blinds to help make ends meet," the article added. In today's market I guess he could start his own reality TV show to make some money.


SCOTT WEEDEN
Senior Editor, Drilling
sweeden@hartenergy.com

Read more commentary at
EPmag.com

A forest of stacked rigs near Midland, Texas, is an indicator of the latest downcycle in the oil industry. (Photo by Tom Fox, courtesy of *Oil and Gas Investor*)

In the article Alexander Holmes, an economist at the University of Oklahoma, said, "The Oklahoma oil industry is literally coming to the end of its time."

All of this points to how many times the oil industry goes through these cycles. And the rhetoric doesn't change. Oklahoma's oil industry was coming to the end of its time—until the SCOOP and STACK plays came into existence.

The first time the Baker Hughes rig count dropped below 1,000 was March 2, 1970. By Dec. 28, 1981, it was at 4,530 rigs. On July 14, 1986, it reached a low of 663 rigs (a decline of 85.4%). On Aug. 24, 1987, it was back over 1,000. Then it bottomed at 603 rigs on April 16, 1993, rising to 1,032 rigs on Sept. 5, 1997, before dropping to 488 rigs on April 23, 1999.

Recently, the rig count decreased to 450 rigs for the week of April 1, 2016—no fooling. That's down from 2,026 rigs during the week of Nov. 4, 2011—a decrease of 77.8%.

And one of those old sayings, "what goes around, comes around," is appropriate today. The rig count is still a good indicator of industry ups and downs. E&P

Scott

SHALE
SUPPORT

RETHINKING PROPPANT SOLUTIONS

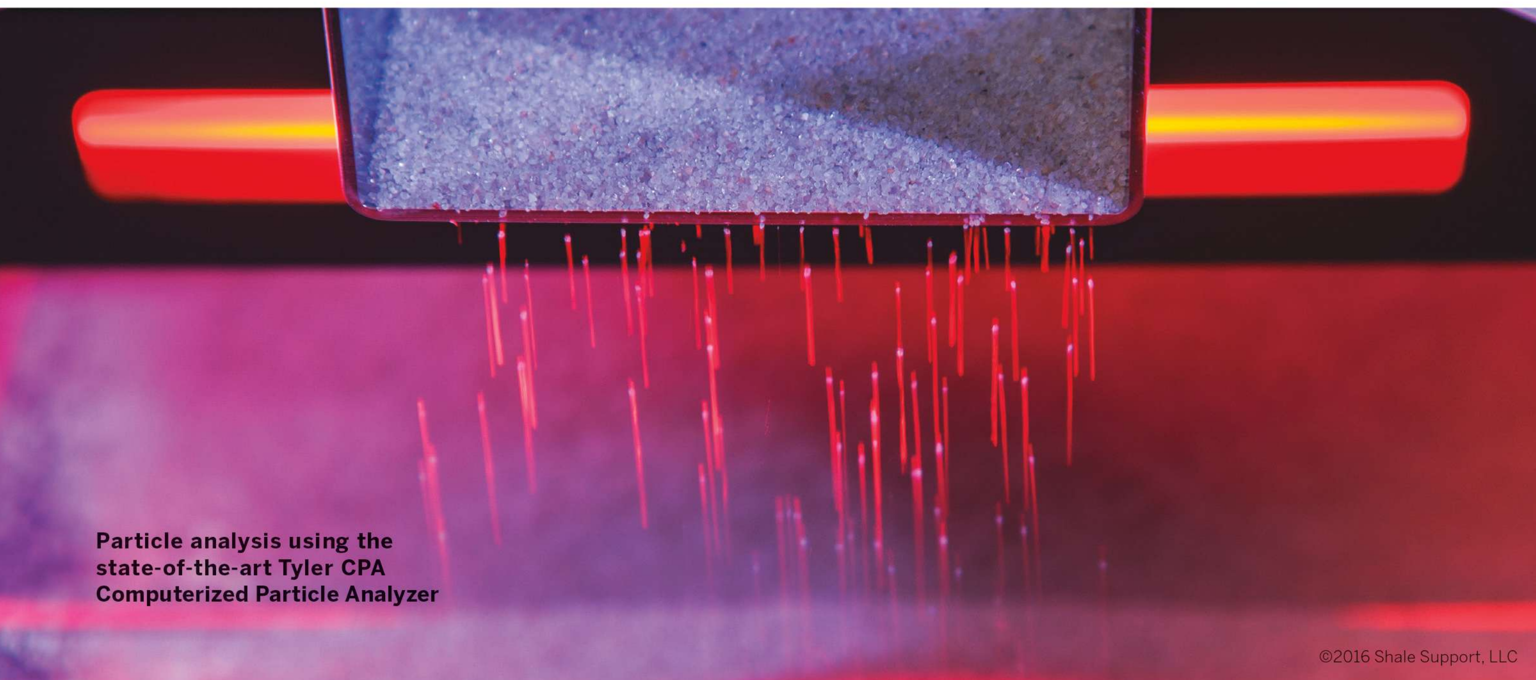
EST. 2012 Delta Pearl PURE PROPPANT

Shale Support supplies Delta Pearl® proppant to every major domestic shale play. Our clean, white sand has single digit turbidity and high conductivity, but that's just half of the equation. With strategically located transloading and storage capabilities nationwide, we respond to unique changes in customer demand instantly, so you can minimize downtime and establish production on time.

Shale Support. FracFaster™.

PROPPANT | LOGISTICS | AGGREGATE

SHALESUPPORT.COM



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

©2016 Shale Support, LLC

Help wanted

The market may be down, but the need for young talent willing to innovate the tried and true into the next generation of artificial lift technologies is greater.


JENNIFER PRESLEY
Senior Editor,
Production Technologies
jpresley@hartenergy.com
Read more commentary at
EPmag.com

Much has been made over the last decade about the "great crew change" facing the oil and gas industry. The concern is—now more than ever—real, as many that recently entered the industry might now be looking for positions in other industries due to the market downturn.

"The industry is expected to go through a lot of change over the next five to 10 years," Ron Holsey, digital commercial leader for GE Oil and Gas' Surface business, told *E&P*. "Our industry has relied for decades on very smart people with in-depth knowledge and who learned the business from the field up. A lot of that talent is going to be retiring, and to bridge that expertise gap, I think, we will need to rely on innovation and technology. The industry has been traditionally slow to adopt new technology, but I think that will change.

"At GE we are investing in digital solutions and data analytics to connect equipment, data and people to drive operational field efficiency and productivity. We think that's going to be key to deliver results for our customers."

The field is the best classroom for new production engineers to learn about artificial lift systems. (Source: Rostislav_Sedlacek, *shutterstock.com*)

Development of hybrid solutions and other forms of new artificial lift technologies are rooted in fieldwork, an important hands-on component of training for any new oil and gas professional.

"They need to spend as much time as they possibly can in the field," said Mike Berry, an independent petroleum engineer. "They need to visit and ride around with the production foreman and the pumpers. They need to understand what the problems are in the field that aren't necessarily being reported to the front office. You can't talk to the field too much, as far as I'm concerned, or spend too much time out there."

For those working with artificial lift systems for the first time, Bill Lane, vice president emerging technologies for artificial lift systems at Weatherford, believes that success is more a function of how to best use the equipment one has rather than spending considerable amounts of time trying to find the exact best piece of equipment. The differences between equipment are real, but it is more important to correctly and effectively use whatever system you have chosen.

"It's more about optimization than it is about equipment selection," he said. "Well conditions change constantly, so wells should likewise be monitored and optimized constantly. An investment in optimization technology usually provides a better return than money spent on the subtle differences between similar lift systems."

The oil and gas industry will never have a shortage of challenges for the next generation of problem solvers to tackle.

"Continued learning is so important, and our new engineers are put on teams solving our toughest problems," said Lawrence Burleigh, technical support director, artificial lift systems for Baker Hughes. "New engineers need to seek out challenges and learn. To them, I say 'welcome to the energy business with its ever-changing challenges.'" E&P

WE MAKE IT WORK RIGHT THE **FIRST TIME.**

Coordination of the efforts of multiple design teams and contractors may now be the most important factor in the success of large, complex projects. Yet too often we are left with installations that are designed in isolation and that then require unnecessary time, effort and money for us to figure out how to operate them.

At GATE, we promote a systems-level view of engineering problems. Taking a larger view of the interactions and intricacies of the system as a whole enables us to develop an optimized solution that crosses many different disciplines and boundaries. Are you ready to make your project work right the first time? **www.gateinc.com**

Lundin knows drillbit is gold

Lundin Norway will be restarting its intensive drilling efforts in the Southern Barents Sea this summer.

JOHN SHEEHAN
International Editor
jsheehan@hartenergy.com

Read more commentary at
EPmag.com

Companies with strong exploration activity during the lean times will reap the benefits when the oil price starts to pick up again. Obvious, yes, but how many out there are following that mantra?

Exploration in the U.K. sector has dropped to almost nothing, but across the water in Norway, things are looking more promising.

Lundin Norway, which has management with a strong geoscience ethos, understands that exploration is king and is still working hard with the drillbit, particularly in the Barents Sea, where it will resume its intensive exploration program in the coming months.

Despite being the second most active explorer off Norway behind Statoil, the company has been the most successful over the past eight years in terms of gross discovered resources.

It has adopted a focused approach, targeting the Utsira High as a core area for E&P and development as well as the Alvheim area, which has delivered a steady source of income.

The company's first discovery—Edvard Grieg—was brought onstream last year on time and on budget.

The *Island Innovator* will be used to test the Filicudi prospect later this year. (Source: *offshoreenergytoday.com*)

The new focus region for Lundin is the Loppa High area in the Southern Barents Sea, where it has been successful with its Alta and Gohta discoveries. The company sees the South Barents generally as being vastly underexplored, with just 100 wells drilled so far.

In the Barents Sea as a whole it estimates there are 8.8 Bboe of yet-to-find resources, with 1 Bboe discovered over the past four years.

Lundin's managing director, Kristin Færøvik, told *E&P*, "The next big thing for us is in the Barents Sea. It holds the largest volume of yet-to-find resources in terms of any basin on the Norwegian Continental Shelf.

"We are going to further appraise Alta this summer, and then we're going to go north to the Neiden prospect, which is not too far from Statoil's Johan Castberg development."

She said that following on from Alta and Neiden, Lundin will target the Filicudi prospect to the west of Alta. "That license holds a string of prospects, so we are very excited about Filicudi as well. Last but not least, there are some humongous structures on offer in the 23rd round, and we have of course applied for some of that. Awards should be made before the summer."

The wells will be drilled with the *Island Innovator*, which is undergoing a full winterization program at the moment.

Færøvik puts down Lundin's success with the drillbit to people, the organization and the owner. "We have very creative explorers; we have an environment where you are definitely allowed to think out of the box; and we have been at the forefront of developing seismic technology, not just in terms of interpretation but also in terms of acquisition. We have very good geoscientists.

"The third important ingredient is owners who are willing to take risks. We have a geoscientist running the company, so he understands and is as excited about the exploration as anyone else in the company."

Lundin looks to be putting itself in a good place for when the upturn begins. E&P

John

Giant challenge brings innovative solutions

Eni's Goliat development represents much of what is both best and worst about offshore megaprojects—a technological marvel but with giant-sized budget and schedule challenges.

Mark Thomas, *Editor-in-Chief*

The industry is acutely aware of the challenges faced by operators undertaking so-called megaprojects. With many blighted in past years by well-publicized soaring costs and schedule overruns, the offshore sector today is still painfully going through the brutal process of addressing those issues and their causes so it can eventually pick up the pace of exploration and development once more.

But it also has often conveniently been ignored by many of the industry's more Philistinic observers that the majority of these and other more "conventional" offshore projects have been true technological pioneers, employing innovative solutions that were absolutely essential to produce oil and gas.

Eni's Goliat project offshore Norway is a case in point. Some of the criticism aimed at the company during its challenging development of the world's northernmost offshore floating production facility—and the first oil project in the Barents Sea—was more akin to the scorn legend attaches to the biblical giant Goliath when he called out the Israelites, only to be confronted by the diminutive David. We all know how that story ended.

Eni is no David-sized underdog, however. A giant in its own right, the company has had to dig deeply into its reserves of project experience to overcome this Goliathan headache.

Slow burner

As with all major field developments, it's a long-term investment that can take a long time to come to fruition. In Goliat's case, the story began back in 1991 when Eni first got involved in the Barents Sea. That program culminated in the company submitting a record 40 applications for the area in 1997, resulting most significantly with the award of Production License 229 (PL229), which would reveal the Goliat discovery three years later in 2000.

It took about nine years from then before Eni's plan for development was approved by the Norwegian government and a further seven years before the project was brought onstream in March 2016 as the first surface production facility in the country's Arctic Barents Sea sector (Statoil's subsea-to-shore Snow White gas field came onstream in 2007). Eni holds a 65% stake as operator in PL229, while Statoil holds the remainder.

Taken from when Eni first submitted its application for Goliat's license area, that's nearly 20 years for the rewards to start flowing—by no means an unusual period for an oil company to have to plan ahead.

But even Eni has to admit that its luck in terms of the development's timing could have been better, sat almost entirely within a period in which—with the very unfair advantage of hindsight—offshore project costs soared on the back of an unprecedented and sustained upward oil price curve before the current and equally sustained price collapse.

Negative equity

A report by analysts Bernstein Research earlier this year nicely illustrates this point. Fields brought onstream during 2015—and the report said 2016 will be just as bad—suffered from simple negative equity.

Those that started up last year did so "at an average oil price that was $53/bbl lower than when they were approved, the greatest negative position in oil industry history," the report stated. This negative equity metric, based on how much the oil spot price moved between project approval and project first production, is a strong driver of decisions on whether to go ahead or not with the development of new fields.

The obvious result is that these existing fields recently brought onstream such as Goliat are generating much less cash flow than originally planned.

Breakeven costs

As a result, within a week of Eni happily trumpeting the flow of first oil from Goliat, located 85 km (53 miles) northwest of Hammerfest, CEO Claudio Descalzi was having to reassure analysts in an investor briefing that the project's breakeven cost was less than $50/bbl. Some analysts had put the breakeven figure at anywhere between $75/bbl and $95/bbl, figures that Eni always declined to comment on.

Stressing that the company's overall breakeven costs were coming down fast because of the ongoing market adjustment, Descalzi said that the average breakeven on Eni's projects across the board had now been brought down from $45/bbl to $27/bbl, with the onshore figure at about $15/bbl and the figure for shallow and deep water put at a combined $30/bbl.

Descalzi went on to admit Goliat was "very complex," with its breakeven cost "the highest that we have now. But it is below $50/bbl and is in production." He pointed out that less than a week after first oil in March 2016 it was producing 90,000 bbl/d and closing in on the plateau production target of 100,000 bbl/d, so its operational performance and efficiency so far are looking good.

Complexity

The project's complexity impacted Goliat's schedule as much as its cost. Not only did the capex figure climb nearly 50% higher than Eni's first estimate to about $5.6 billion, but the onstream date shifted back by about two years from its original target date. Even though it was on location as of May last year, the process of bringing the facility onstream was delayed several times, toward the end because of problems with its electrical system.

However, although no endorsement, those schedule and budget overruns are not out of the ordinary for such large and complex offshore projects. Ernst & Young confirmed in research nearly two years ago that 64% of oil and gas megaprojects (more than $1 billion) at that time were facing cost overruns to complete, while 73% were suffering schedule delays.

With the plunge in oil prices that occurred after that report, the conditions for a perfect storm were created that impacted not only Goliat but virtually every offshore project of any scale since then.

With that in mind it is admirable but not surprising, given its long-term strategy focused on basin-opening projects, how Eni has stuck to its guns with its pioneering development in the cold waters of the Barents. The operator has consistently looked at the full life-cycle returns on its projects when weighing them, and with a planned production life for Goliat of a minimum 15 years, the operator expects to more than cover its total investments as well as a likely return on its investment.

Largest circular FPSO

Goliat is instantly recognizable for its use of the distinctive Sevan 1000-design circular FPSO unit, currently the largest and most sophisticated example of its kind in the world.

With a storage capacity of 1 MMbbl of oil, the 18-deck facility will eventually receive production from 22 subsea wells (17 have so far been completed) connected to eight subsea templates in 350 m to 400 m (1,148 ft to 1,312 ft) of water. Of the total, 12 are oil producers, seven are water injectors and three are gas injectors.

The 64,000-ton platform was built at the Hyundai Heavy Industries yard in Ulsan, South Korea, and is 115 m (377 ft) in diameter and 100 m (328 ft) tall, with the unit held in place by 14 anchor lines.

The environmental aspects of operating in the Barents Sea have been paramount from the start and influenced Eni to opt for solutions including powering the fully winterized facility from shore via a 110-km (68-mile) high-voltage 75-MW subsea cable, which itself weighed 6,000 tonnes. *(Read "Offshore power is shore thing" featured in this issue's cover story.)*

Other aspects include the offloading system, with the hose reeled out and in for each individual oil export operation as well as the use of three dedicated and fully winterized dynamically positioned shuttle tankers.

Such decisions have helped reduce estimated CO_2 emissions by about 50% compared to alternative solutions, helped also by any produced gas (up to 3.9 MMcm/d [137 MMcf/d]) and water (up to 126,000 bbl/d capacity) being reinjected back into the reservoir.

Barents upside

There is definite upside to Goliat and the surrounding waters as it continues on its productive life, with the field currently estimated to contain reserves of about 180 MMbbl of oil but with that figure expected to rise.

According to Descalzi, "around Goliat we still have a lot of structures. That is oil that will be ready to be linked to Goliat in the future, so we will continue to have the plateau. That is our aspiration," he said.

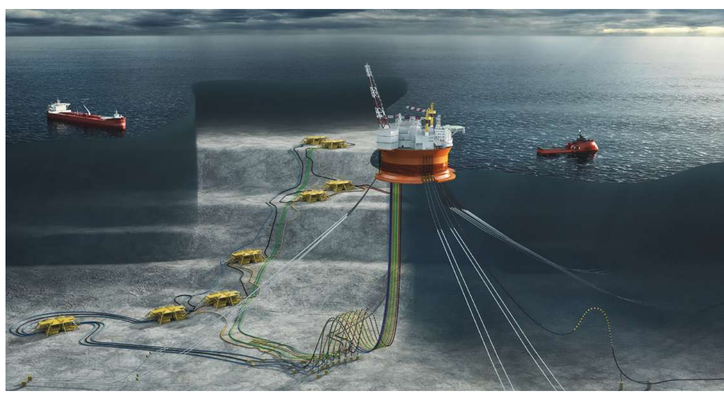
The field represents a genuine breakthrough for the Norwegian sector and its ambitions to build and sustain oil and gas production from the Barents Sea as output from its established mature continental shelf continues to gradually decline.

In response to the issues that have so challenged Goliat and its peer projects around the world, the industry is now—finally—making tangible progress.

In the Barents itself, Eni's Goliat project partner Statoil has managed to dramatically cut estimated development costs on another oil development in the vicinity, Johan Castberg. The operator has in fact driven down breakeven costs for its development projects across its portfolio to less than $50/bbl, according to CEO Eldar Saetre.

Capex reductions

Speaking at the Subsea Valley conference in Norway early in April, Saetre said, "In 2013 we had an average



The *Goliat* FPSO unit was close to its 100,000-bbl/d production capacity within a week of coming onstream in March this year, with 22 wells eventually to feed the facility via eight subsea templates. (Source: Eni Norge)

At peak more than 600 personnel were working offshore during the hookup and commissioning phase for the Goliat Field last year, with the Floatel *Superior* drafted in to ensure enough manpower was available onsite. (Source: Eni Norge)

breakeven price for the portfolio of about $70/bbl, including Johan Sverdrup.

"Today the breakeven point has been reduced to about $40/bbl. In the meantime we have sanctioned several projects with an average breakeven of less than $30/bbl. This is quite impressive with improvements of more than 40% and with capex reduction on the Trestakk project of 30% and typically 30% to 50% cost reductions in the portfolio."

It is doing this, as are all of its offshore peers, by reworking concepts, finding new ways to work internally, challenging solutions and addressing projects from the subsurface to the facilities and onward.

Saetre continued, "Today more than 80% of the capex in the portfolio is at $50/bbl. To get even further, we continue to depend on more technology development, new and innovative solutions, and engineering.

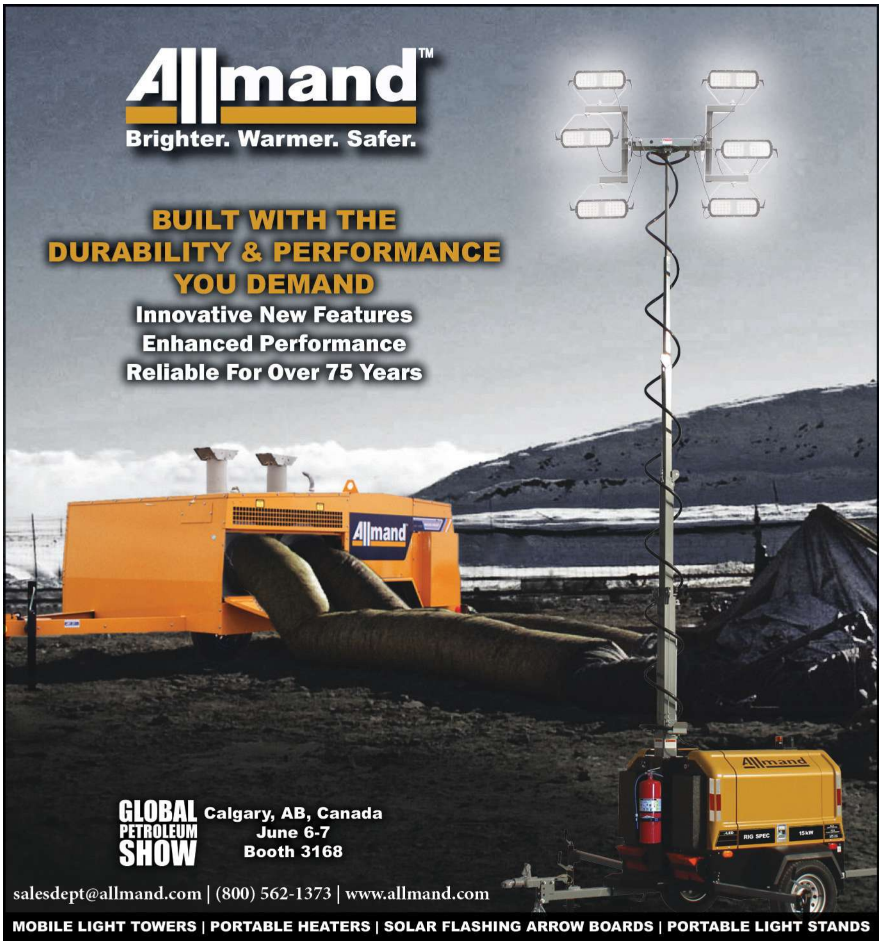
"On Johan Castberg we have been able to reduce the breakeven price from above $80/bbl to below $45, and it is heading below $40/bbl. We have reduced the capex by 60% by selecting a floating production concept combined with cost-efficient subsea solutions and an efficient drainage strategy."

The company's Snorre expansion 2040 project is another example where a subsea solution has been selected, allowing Statoil to optimize and mature the project.

Past mistakes

The work also is being done elsewhere. "On Peregrino 2 in Brazil, a project we have been working on intensely, we have seen breakeven prices coming down from approximately $70 to less than $45 in about a year," Saetre said. "We're making a lot of changes in our operating model to make sure that the current improvement sticks and that we don't repeat the mistakes of the past."

Looking to the future, Saetre was perhaps speaking for the entire industry when he commented that it was essential for Statoil to keep investing. "I need to push the final investment decision button so that the barrels are actually in place when we need them and we can capture the upturn in the environment." E&P



Offshore power is shore thing

When it comes to powering installations from shore, operators are increasingly happy to flip the switch.

Mark Thomas, Editor-in-Chief

Using electricity from shore to power offshore facilities rather than generating it onsite is a solution that's been around for well over a decade.

Production facilities have mostly generated their own electricity by burning fossil fuels to run their onboard equipment such as diesel-powered generating units or gas turbines. But shore-based electrification solutions—when the development case fits—hit the spot when it comes to today's environmental requirements and the need to continue reducing or eliminating CO_2 emissions.

There is also a simple practical design and cost requirement to keep facilities' weights to a minimum while maximizing use of the available footage with platform topsides remaining among the most expensive real estate per foot in the world.

Eni's Goliat platform is no exception, so the decision was taken to power it from shore, removing the requirement for a power equipment footprint topsides.

ABB carried out the completion and commissioning of the crosslinked polyethylene (XLPE) subsea cable system that connects the FPSO unit to the Norwegian mainland's power grid. It is the most powerful and longest power-from-shore AC cable in the world, with ABB saying the high-voltage (123-kv) system, among other advantages, can reduce estimated CO_2 emissions by half while suffering only low electrical losses.

The 75-MW three-core cable AC system includes a 105-km (65-mile) long static seabed section in up to 350 m (1,148 ft) of water as well as a 1.5-km (.93-mile) long dynamic section reaching up from the seabed to the FPSO unit.

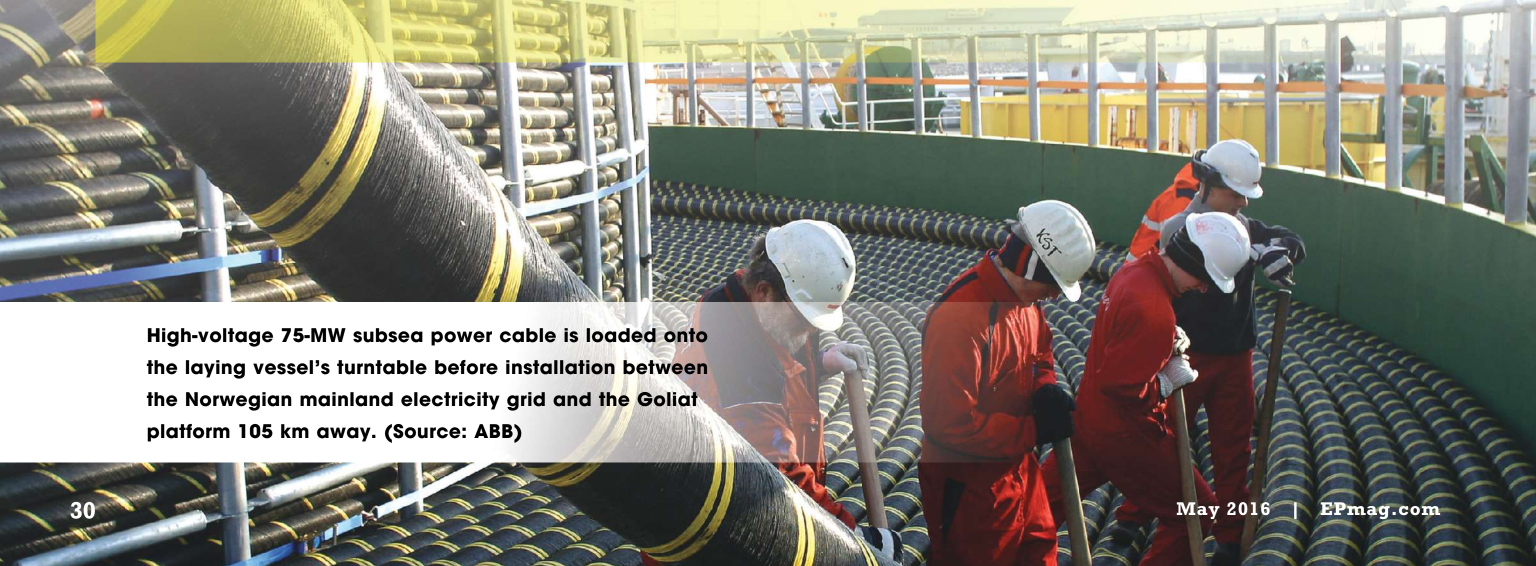
Flagbearer

Goliat is not the original pioneer here though. The Norwegian sector has been one of the flagbearers for power-from-shore solutions since 2005, with ABB delivering the world's first such solution that year using a high-voltage DC (HVDC) power transmission system. This was a 70-MW link to Statoil's Troll A platform, 70 km (43.4 miles) off Norway's west coast.

That was followed five years later by the company delivering the world's first AC power-from-shore dynamic cable connection to Statoil for the operator's Gjøa floating facility. That flowed 40 MW of electricity over a 101-km (63-mile) long cable system fed by the Norwegian grid.

Nexans also has been heavily involved, supplying its kit for the Valhall Field complex's major revamp completed in 2013. Nexans manufactured and installed 293 km (182 miles) of HVDC subsea cable and a separate fiber-optic cable for the power link. The 150-kV DC cable was installed using the *Skagerrak* cable-laying vessel, with ABB installing the converter stations.

Last year ABB also was awarded a contract for two 100-MW 80-kV cables that will stretch 200 km (124 miles) to a riser platform on Statoil's Johan Sverdrup Phase One oil development, due onstream in 2019. E&P



High-voltage 75-MW subsea power cable is loaded onto the laying vessel's turntable before installation between the Norwegian mainland electricity grid and the Goliat platform 105 km away. (Source: ABB)

ROOM TO WORK

2016 EVENT HIGHLIGHTS

PRE-CONFERENCE MIDSTREAM PROGRAM

Permian producers enjoy the benefits of well-connected midstream infrastructure. But in the last seven years, upstream growth has consistently outpaced midstream capacity. Attend this targeted pre-conference program to hear from the region's most-active midstream players!

DUG *PERMIAN BASIN* CONFERENCE AND EXHIBITION

From the wellhead to the corporate office, companies are finding innovative ways to save time and money. Find out how the region's top producers continue to defy the world's expectations by improving EURs and lowering breakevens.

NEW FOR 2016: TECHNOLOGY SHOWCASE

The all-new Technology Showcase brings the latest solutions to the exhibit floor with live case studies and demonstrations from leading companies. You'll hear from experts from MEA Winners Select Energy Services and Baker Hughes plus Schlumberger, Magnum Oil Tools, Packers Plus and more.

To ATTEND, SPONSOR or EXHIBIT,
visit DUGPB.com

Presented by:
HARTENERGY

Hosted by:
E&P · Oil and Gas Investor · MIDSTREAM Business · UNCONVENTIONAL OIL & GAS CENTER

DEVELOPING **UNCONVENTIONALS**
DUG
PERMIAN BASIN

May 23-25, 2016
Fort Worth, Texas
Fort Worth Convention Center

According to Raymond James, the Permian Basin holds four of the six U.S. plays still profitable at ~$40 oil – the Midland Wolfcamp, Midland Spraberry, Delaware Wolfcamp, and the Delaware Bone Spring.

What's Working, What's Not, & What's Next for Permian Producers

At ~$40 WTI, West Texas' Permian could very well be the last basin standing. With **superior wellhead economics** and **a deep bench of productive formations**, the Permian Basin has become a safe haven for many E&Ps. But even the nation's most prolific oil province is challenged by the current downturn. Armed with efficiency-focused technologies and strategies, producers are digging deep to protect margins.

If your business is oil and gas in West Texas, you can't afford to miss this year's **DUG *Permian Basin*** conference and exhibition! Over **2,000 industry professionals** are converging in Fort Worth to hear from the region's most-active producers and midstream operators. Don't miss this once-a-year chance to explore the latest strategies and technologies with **35+ senior-level speakers** and **170+ exhibitors**.

Conference Agenda

Monday, May 23

1:00 pm **Pre-Conference Midstream Program**

5:00 pm **Kick-Off Party in the Exhibition Hall**

Tuesday, May 24

8:30 am **Welcome & Opening Remarks**

8:35 am **OPENING KEYNOTE: Loaded With Prospects**

- **Joey Hall**, Executive Vice President, Permian Operations, ***Pioneer Natural Resources Co.***

9:00 am **ECONOMICS PANEL: All About Balance**

- **Michelle Michot Foss, Ph.D.**, Chief Energy Economist and Program Manager, Bureau of Economic Geology's Center for Energy Economics, ***The University of Texas***
- **Matthew Portillo**, Managing Director, E&P Research, ***Tudor, Pickering, Holt & Co. Inc.***
- **Jessica Pair**, Upstream Manager, ***Stratas Advisors***

10:00 am **NETWORKING BREAK**

11:00 am **TECHNICAL SPOTLIGHT: North America vs. OPEC—Making Unconventional Resources Economic**

- **Ian Bryant**, President, ***Packers Plus Energy Services Inc.***

11:20 am **PRIVATE OPERATORS PANEL: A Special Approach**

- **Mike Wichterich**, President, ***Three Rivers Operating Co. III LLC***
- **Curtis Newstrom**, President & CEO, ***Blue Whale Energy North America Corp.***

12:00 pm **NETWORKING LUNCHEON**

1:40 pm **MIDSTREAM SPOTLIGHT: Accessing National & Global Markets**

- **Gary Conway**, Principal, President and CEO, ***Vaquero Midstream***

2:00 pm **TECHNICAL ROUNDTABLE: Sand, Spacing & Slickwater**

- **Ward Polzin**, CEO, ***Centennial Resource Development LLC***
- **Mark Hiduke**, CEO, ***PCORE Exploration and Production II LLC***
- **Jim Wicklund**, Managing Director-Equity Research, ***Credit Suisse***
- ***Schlumberger***

2:40 pm **SPOTLIGHT: Resolving the Geopolitical Petroleum Chaos**

- **Tom Petrie**, Chairman, ***Petrie Partners***

3:00 pm **NETWORKING BREAK**

3:40 pm **OPERATOR PANEL: Delaware Basin–The Rising Star**

- **Richard E. Muncrief**, President & CEO, ***WPX Energy Inc.***
- **Kyle D. Miller**, President & Chief Executive Officer, ***Silver Hill Energy Partners LLC***
- ***Matador Resources Co.***

5:00 pm **NETWORKING RECEPTION**

Wednesday, May 25

9:00 am **A&D PANEL: The Stampede to West Texas**

- **Craig Lande,** Managing Director, ***RBC Richardson Barr***
- **Mike Kelly**, CFA, Managing Director and Senior Analyst, ***Seaport Global Securities LLC***

9:40 am **OPERATOR SPOTLIGHT: Horizontal San Andres on the Central Basin Platform**

- **Terry Dobkins**, President & CEO, ***Elk Meadows Resources LLC***

10:00 am **NETWORKING BREAK**

10:40 am **SPOTLIGHT: Drilling, Completing, Financing in a Down-Cycle**

- **Marc Rowland**, Founder & Senior Managing Director, ***IOG Capital LP***

11:00 am **CLOSING PANEL: The World-Class Wolfcamp**

- **Tom Layman**, Vice President, Geoscience, ***Parsley Energy Inc.***
- **J. Ross Craft**, Chairman, Chief Executive Officer & President, ***Approach Resources Inc.***

12:00 pm **CONFERENCE ADJOURNS**

Agenda subject to change.
See online for the most updated agenda.

Featured Speakers

Joey Hall
Executive Vice President, Permian Operations
Pioneer Natural Resources

Richard Muncrief
President and CEO
WPX Energy

Tom Layman
Vice President, Geoscience
Parsley Energy Inc.

J. Ross Craft
Founder Chairman, President and CEO
Approach Resources

Ward Polzin
CEO
Centennial Resource Development

Curtis Newstrom
President and CEO
Blue Whale Energy North America Corp.

Michael Wichterich
President
Three Rivers Operating Co. LLC

Thomas Petrie
Chairman
Petrie Partners

Kyle D. Miller
President & Chief Executive Officer
Silver Hill Energy Partners LLC

Terry Dobkins
President & CEO
Elk Meadows Resources LLC

Mark Hiduke
President CEO
PCORE Exploration and Production II LLC

Gary Conway
Principal, President and CEO
Vaquero Midstream

Introducing the Technology Showcase

Efficiency-focused technologies and strategies have become the lifeblood of the shale revolution. Producers and service providers continue to defy the world's expectations by finding innovative ways to produce more for less. With its all-new Technology Showcase, **DUG *Permian Basin*** brings the latest solutions to the exhibit floor with live case studies and demonstrations from leading companies.

Don't miss this opportunity to give your leadership team (and younger professionals) two days of hands-on access to the solutions driving the industry today.

COMPANIES PRESENTING:

- Carbo
- Stabilis Energy
- Magnum Oil Tools
- Packers Plus
- Seismos
- Dover Artificial Lift
- Priority Energy
- Flowco Production
- Hydrozonix
- Baker Hughes
- Select Energy Services
- Schlumberger

TUESDAY, MAY 24

10:40 am – 12 pm **ENHANCED COMPLETIONS** – Enhanced completions incorporate a broad array of technologies and well designs to deliver success at the wellhead. Presentations in this session will address advanced proppant technologies and new completions tools.

2:00 – 3:20 pm **ARTIFICIAL LIFT/EOR** – Artificial lift and EOR technologies are the natural next steps when production begins to decline. Efficient management of the challenges that each present can result in higher production.

WEDNESDAY, MAY 25

10:40 am – 12 pm **WATER & FLUIDS MANAGEMENT** – Water can sometimes be a rare and precious commodity in the Permian Basin. Technologies and applications to do more with less water are the focus of presentations in this session.

Operators Enter For Free!

Hart Energy invites all employees of **E&P companies, pipeline operators, refineries** and **utility companies** to enter the exhibition hall at **DUG *Permian Basin*** at no cost. Plus you have the option to upgrade to a full conference pass.

To submit your qualifying application and register, visit **HartEnergyConferences.com/operatorpass.**

Sponsored by:

MAGNUM OIL TOOLS INTERNATIONAL

**This program does not include the Pre-Conference Midstream Program. Completing the application does not guarantee your registration. This pass is valid for new registrations only, is not retroactive and cannot be applied for refunds.*

Find out what midstream operators are planning for 2016

PRE-CONFERENCE MIDSTREAM PROGRAM

IN-DEPTH MIDSTREAM COVERAGE
from the Prolific Permian

For almost a century, the Permian Basin has been a cornerstone of the U.S. oil and gas industry. With **100,000+ miles** of interstate and intrastate crude oil and natural gas pipelines, **75,000+ miles** of gathering lines and **10,000+ mmcfd of processing plant capacity**, the region is well connected to centers of demand. But as production slows in the current downturn, midstream operators are completing a record buildout of new midstream infrastructure.

Register now to attend this targeted pre-conference program and **hear from the region's top upstream producers and midstream operators**! You'll get the latest **updates on current and planned midstream projects** in the Permian. Plus, you'll **learn where industry experts forecast oil prices and regional activity** to be in the coming months.

Source: Hart Energy's Rextag Solutions

Featured Speakers

Bryan W. Neskora
COO and
Founding Partner
Navitas Midstream Partners, LLC

Andrew Deck
Senior Vice President,
Permian Basin
EnLink Midstream

Tom Ramsey
CEO
Centurion Midstream, LLC

Craig V. Meier
President and CEO
Sunland Construction Inc.

View the full midstream PROGRAM, AGENDA and SPEAKER lineup at **DUGPB.com**

DEVELOPING **UNCONVENTIONALS**
DUG
PERMIAN BASIN

May 23-25, 2016
Fort Worth, Texas
Fort Worth Convention Center

12:00 pm — Networking Lunch

1:00 pm — Welcome & Opening Remarks

- **Paul Hart**, Editor-in-Chief, *Midstream Business*, ***Hart Energy***

1:05 pm — OPENING KEYNOTE: Responding to the Permian's Growth

Despite the current downturn, the midstream continues a record buildout of new pipeline capacity to link Permian Basin producers to customers. How has the midstream industry's approach to projects evolved?

- **Bryan W. Neskora**, COO and Founding Partner, ***Navitas Midstream Partners, LLC***

1:30 pm — PROCESSING SPOTLIGHT: Does Plant Standardization Work?

Should processing plants be custom designed or based on standardized templates? The answer may lie somewhere in between.

- **Chuck Laughter**, Vice President, Engineering and Operations, ***Joule Processing***
- **John Y. Mak**, Technical Director, Senior Fellow, ***Fluor USA***

1:55 pm — SECURITY PANEL: Responding to Multiple Threats

Midstream operators today face multiple security threats. On location, they must deal with traditional theft and vandalism problems, while the Internet opens the potential for dangerous hacks to vital control systems. These security specialists review advanced technology that can blunt multiple security challenges.

- **Lance White**, CEO, ***PetroCloud***
- **Robert Ream**, Chairman, ***Energy Security Council***

2:45 pm — NETWORKING BREAK

3:15 pm — SPOTLIGHT: Expanding Compression Options

Midstream infrastructure is needed in the Permian Basin to ensure prompt response when the market rebounds. Midstream companies must strategically think about compression and reliability to ensure success for the entire value chain.

- **Andrew Deck**, Senior Vice President, Permian Basin, ***EnLink Midstream***

3:40 pm — ROUNDTABLE: Trucking Troubles

Trucks are a vital link in the midstream service chain but an often troublesome one. These trucking experts discuss how the industry can ease some of trucking's lingering challenges.

- **Tom Ramsey**, CEO, ***Centurion Midstream, LLC***
- **Jake Thigpen**, General Manager, ***Reynolds Energy Transportation***
- **Mark C. Thibaut**, Senior Vice President, Marketing Supply, ***GulfMark Energy***

4:20 pm — CLOSING KEYNOTE: Leaning into the Headwinds

Production volumes are dramatically reshaping the national grid. Hear from this industry expert on the recently released study by the INGAA Foundation on North American infrastructure through 2035, and his take on the contractors' perspective of the immediate future.

- **Craig V. Meier**, President and CEO, ***Sunland Construction Inc.*** and Past Chairman, ***INGAA Foundation*** (2013-2014)

4:50 pm — Midstream Conference Adjourns

5:00 pm — DUG *Permian Basin* Kick-Off Party

'The most boring company in the Gulf'

LLOG doesn't care about being the first or the biggest. But its attention to fundamentals makes it one of the best.

Rhonda Duey, Executive Editor

With field names like "Who Dat" and "Delta House," one might think the folks at LLOG don't take things very seriously. This couldn't be farther from the truth.

The company prides itself on its quiet success. It's the largest private deepwater Gulf of Mexico (GoM) producer, the sixth most active deepwater GoM driller and the eighth largest deepwater GoM producer. According to a recent presentation, the company has no intention of going public, feeling that staying private gives it "greater degrees of freedom regarding the efficient and timely exploration and development" of its assets.

And those assets are impressive. The Who Dat Field is a floating production unit (FPU) located in 845 m (3,100 ft) of water. Ten wells are linked to the facility, and estimated reserves are 100 MMboe to 300 MMboe. The facility has a capacity of 60,000 bbl/d and 4.2 MMcm/d (150 MMcf/d). It was the first FPU in the GoM post-Macondo and the first built on spec. It went from concept selection to installation in less than a year and was the first privately owned FPU.

Delta House came onstream April 16, 2015, and was a truly ambitious project. Designed to develop multiple fields in the Mississippi Canyon Miocene play, the project came online only three years after the first discovery. The FPU engineering work and the bidding of construction yards began before the first well (Son of Bluto 2) was even drilled. This type of confidence seems to characterize the company's philosophy and approach.

Good-looking metrics

According to Eric Zimmermann, vice president of geology for LLOG, opportunity has driven the company in its almost 40-year history, from early successes on land in Louisiana and Texas to state waters, then the GoM Shelf and finally deep water.

"We continued to see opportunities develop in the offshore arena, so we started to work in deepwater areas and do some subsea tiebacks onto the shelf," Zimmermann said. "As we saw opportunities present themselves, we became interested in bigger ways to develop to the point where we are today, where we've installed two floating production units that are producing our deepwater assets."

The company boasts a remarkable 70% exploration success rate, and Zimmermann attributed that to several things. The company is geologically focused and is a good customer for companies that license multiclient seismic data.

"In the exploration arena our biggest driver is having large amounts of data," he said. "Why would we want that? The more data we have, the more analog work we can do. We can study in greater detail and with greater success what we've done in our previous wells and what our competitors have done. "The more you can learn about the attributes for success and failure, the more you can implement into your exploration and development programs."

He added that new marine seismic technologies like wide-azimuth and broadband acquisition are critical in the near-salt and subsalt regions of the GoM, but he considers regional coverage equally important.

Engineering work for the Delta House facility began before the discovery well was drilled. (Source: LLOG)

"Having a patch of expensive data doesn't necessarily help you understand the play any better," he said.

Safety is another important metric for the company, and LLOG is in the top 1% of the safest operating companies in the industry. "We as a smaller company realize that outsiders might wonder whether we can maintain our safety culture," Zimmermann said. "That means we double up on our safety focus. I think from a cultural standpoint we have individuals who are responsible for all aspects of the safety culture. We recognize the responsibility of the individuals to that safety culture."

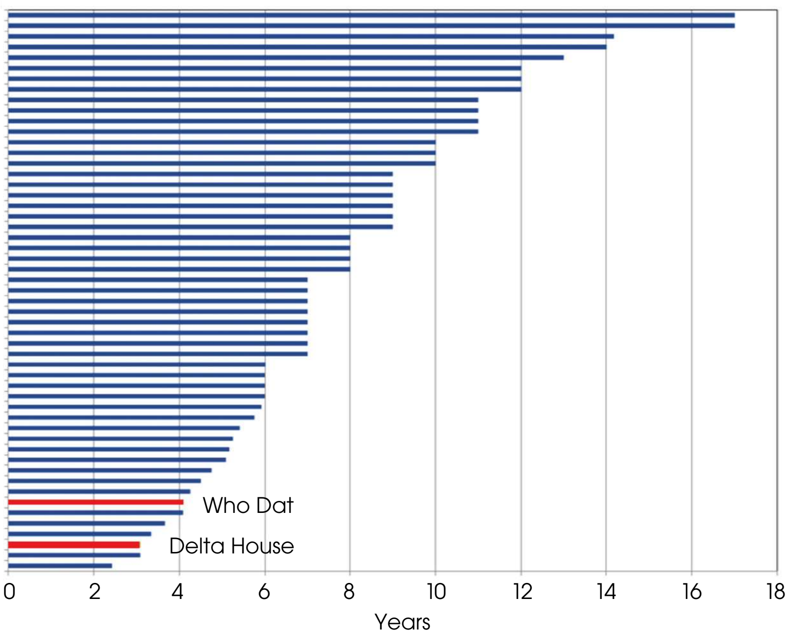
Zimmermann attributes both the exploration success and the safety record to a focus on the fundamentals. "We like to say that we're the most boring company in the Gulf of Mexico," he said. "When we think of 'boring,' we think of 'truly fundamental.' We need all of the steps and processes that are intrinsic to hydrocarbon exploration to be in place before we drill a well. When you keep that methodical approach, you tend to see repeatable success."

The company sticks to its guns on these fundamentals. Zimmermann added that LLOG is typically not the first entrant to a basin or play type. "We are close observers of the industry and try to figure out what has been successful and what has been unsuccessful," he said. "Then we move quickly to replicate the successful and learn from the unsuccessful. We have a comfort in not being basin openers, and we also are comfortable being fast followers."

Standardization is another key to LLOG's success. Zimmermann said that leveraging the ability to develop assets quickly helps to lower the threshold of economic success. By speeding upcycle times and decreasing costs, the company can decrease its minimum commercial field size. "If we can differentiate ourselves in that area, we can be exploring in areas that may not be open to other companies that may have a longer development cycle or a larger cost structure," he said.

He added that having a clear idea of how an asset will be developed before it's even acquired is critical. LLOG

DISCOVERY TO FIRST PRODUCTION FOR FPS PROJECTS IN GOM

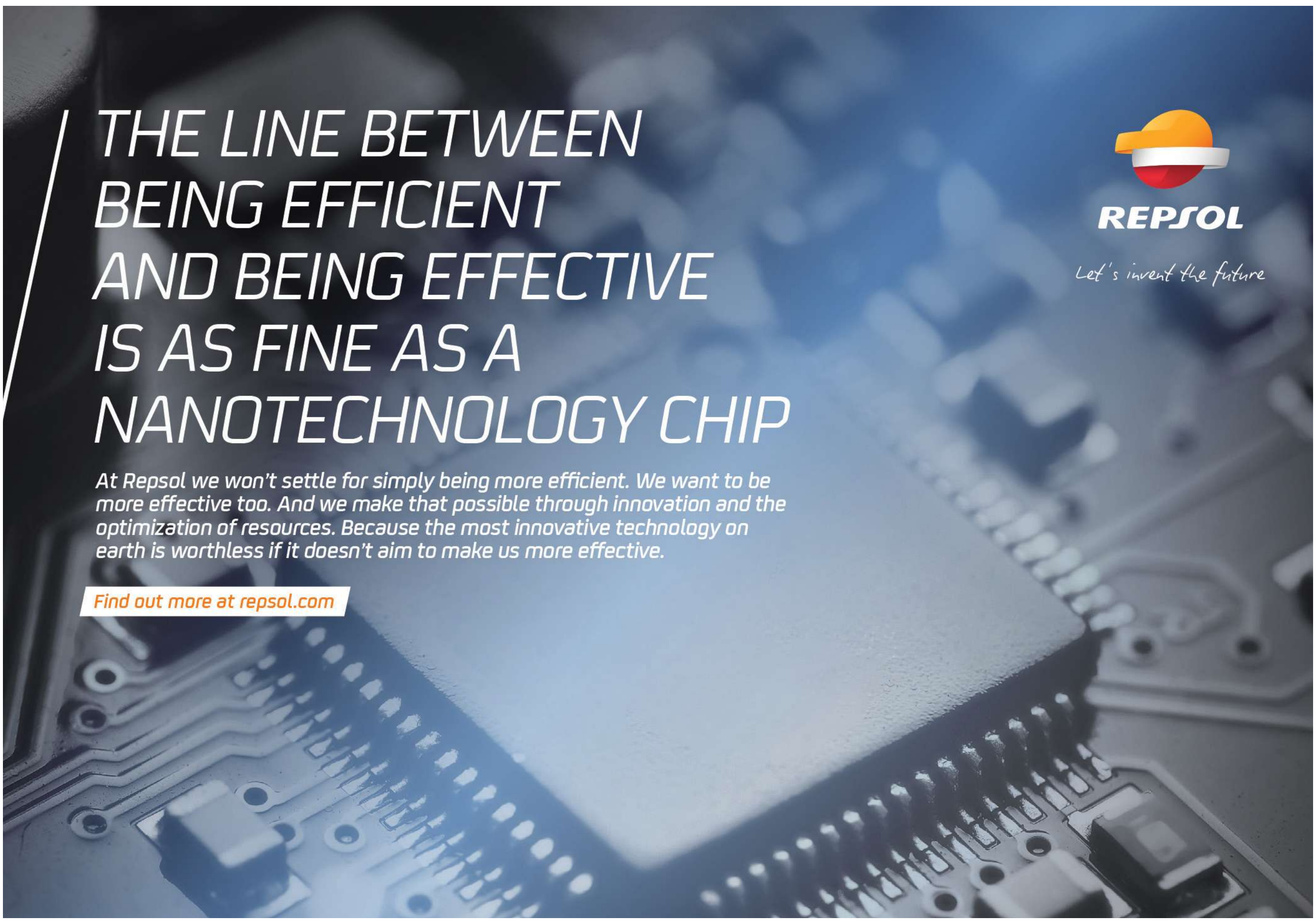


LLOG's two deepwater projects, Who Dat and Delta House, have been among the fastest FPU projects brought online in the GoM. (Source: LLOG)

has the internal expertise and the external relationships in place to execute the development plan, and it even keeps inventories of standard kit like subsea trees so that it's not waiting on equipment.

"Typically, before we've acquired the prospect, we have a fairly well developed plan on how we're going to bring that commodity to market," he said.

So what about those field names? "We have a very serious business here," Zimmermann said. "We have a high focus on safety, a high focus on investment. It's the one place that the geologists and the prospect generators can have a little fun." E&P



Global offshore market spend set for upturn

2016 has been consigned to the trash can by most, but 2017 sees rising demand and capex.

Neda Djahansouzi, Infield Systems

The past 18 months have been a tumultuous time for the offshore sector, and industry players continue to look ahead with trepidation, but the global offshore capex forecast to 2020 has long-term promise.

With the oil price-induced budget cuts over the past year, global offshore capex is still expected to fall significantly during 2016. However, after bottoming out this year, the market shows potential in the long run as a result of increased project volume.

Pipelines

Looking at capex by market sector, the pipeline market is expected to account for the largest share of global capex demand going forward, accounting for 44% of spend between 2016 and 2020.

The subsea umbilicals, risers and flowlines market could drive pipeline demand over the forthcoming period as the industry sees a growing number of returning deepwater developments, especially offshore Brazil and West Africa. Up to 260 companies could invest in offshore pipeline projects globally, with Petrobras anticipated to spend the most.

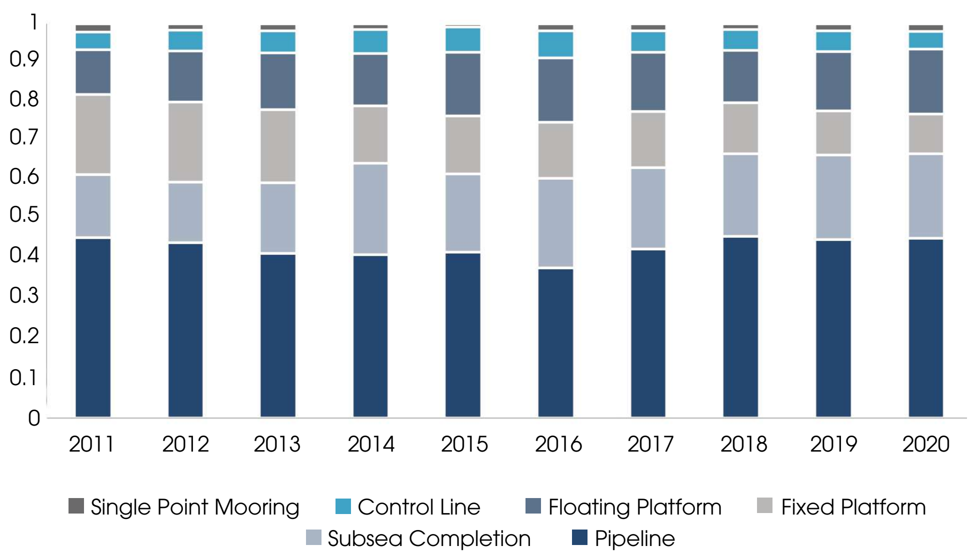
A key pipeline project going forward is BP's Shah Deniz (Phase 2) development, which is expected to add a further 16 Bcm (565 Bcf) per annum of gas production to the about 9 Bcm (317 Bcf) per annum produced by Shah Deniz (Phase 1). This capital-intensive $28 billion development phase will inaugurate what is known as Europe's Southern Gas Corridor, with development of strategic pipeline infrastructure ongoing to export up to 6 Bcm (211 Bcf) per annum of gas to Turkey and a further 10 Bcm (353 Bcf) per annum of gas to markets in Europe, primarily Italy.

Floating production

Since the collapse in global commodity prices, a number of high-profile floating production system (FPS) projects have experienced delays or cancellations, and question marks hang over several other such developments where a final investment decision (FID) has yet to be given.

Despite this, forecast demand within the FPS sector remains relatively strong, with floating systems projected to make up a 15% share of total global capex over the 2016-2020 time frame. In the near term, floating production facility demand is expected to be driven by a number of capital-intensive projects that received a FID prior to the decline in crude prices, such as Total's Kaombo Complex offshore Angola, Chevron's delayed Big Foot Field in the U.S. Gulf

GLOBAL EPCI CAPEX (%) 2011-2020 BY MARKET SECTOR



Global offshore capex is expected to recover and grow over the coming five-year period. (Source: Infield Systems)

SAINT-GOBAIN

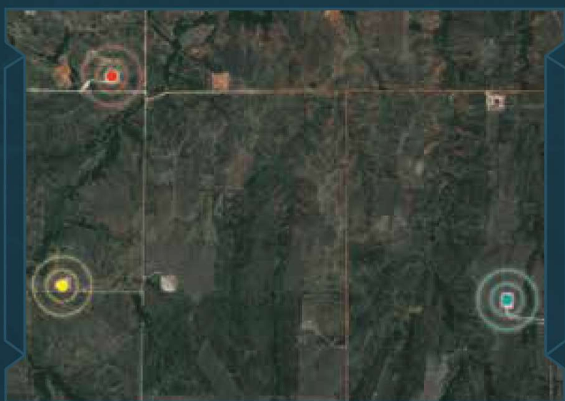
Saint-Gobain Proppants

WELL WORTH IT™

WELL-TO-WELL COMPARISON

Through our series of well-to-well comparisons, we track the performance of our proppants where it matters most: in your wells. The results confirm that our high-performance proppants are well worth the investment, delivering greater oil and gas production and higher cash flow.

CASE SUMMARY 3 OF 9 | MIDCON, ROGER MILLS COUNTY, OK



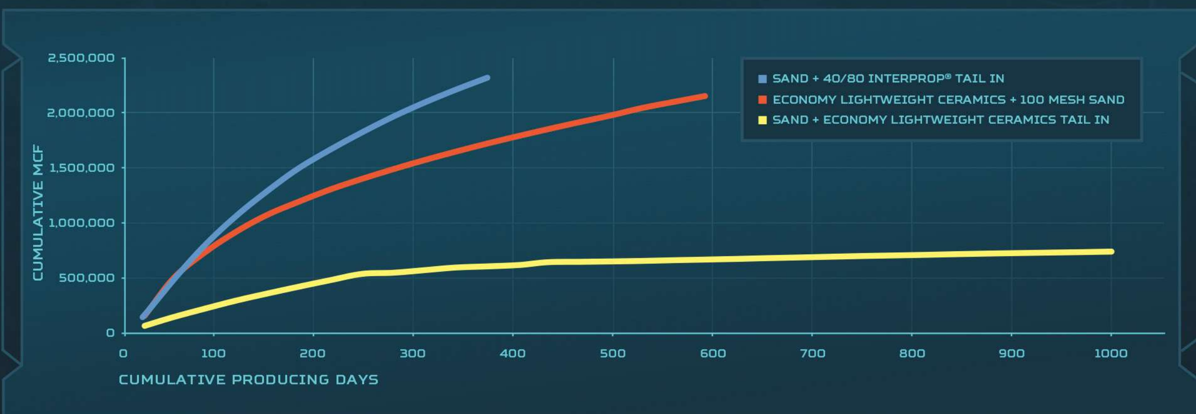
INTERPROP® 40/80
TAIL-IN DIFFERENTIATION

OVER ECONOMY LIGHTWEIGHT CERAMICS COMPLETIONS

96% INCREASE
365-Day Cumulative Gas Production

$3.3M HIGHER
3-Year Cash Flow

PARAMETERS USED IN ANALYSIS:
GAS @ $4.00, 20% ROYALTY

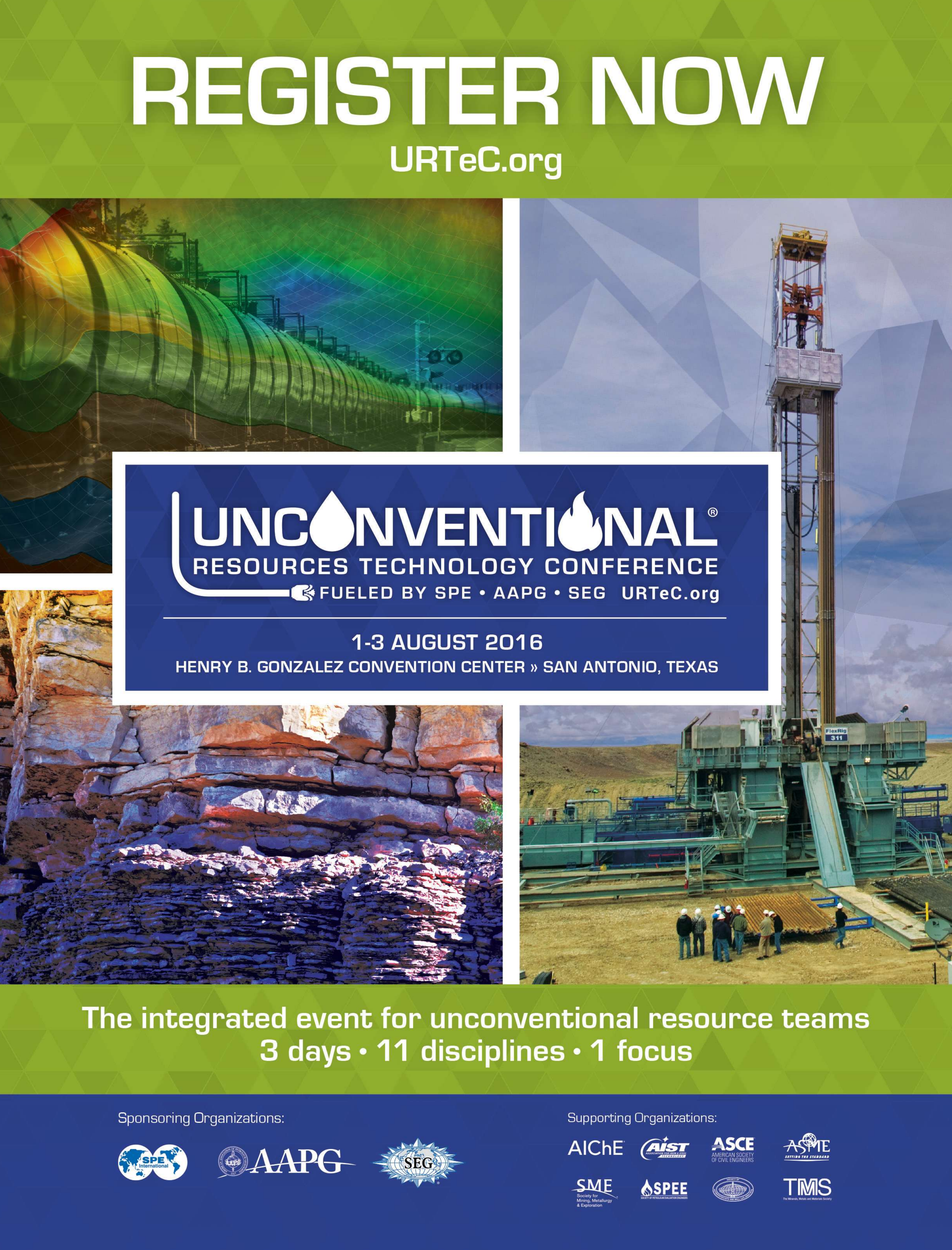


Stay tuned for Well-to-Well Comparison Case Summary 4 of 9 coming soon!

ENVIRONMENTALLY CONSCIOUS PROPPANTS · SAFE FOR HUMAN HANDLING

FOR MORE INFORMATION, VISIT:
PROPPANTS.SAINT-GOBAIN.COM/WELLWORTHIT
Learn more about our other brands: InterProp® • VersaProp® • UltraProp® • Titan™

MADE IN U.S.A.


REGISTER NOW
URTeC.org
UNCONVENTIONAL®
RESOURCES TECHNOLOGY CONFERENCE
FUELED BY SPE • AAPG • SEG URTeC.org
1-3 AUGUST 2016
HENRY B. GONZALEZ CONVENTION CENTER » SAN ANTONIO, TEXAS
The integrated event for unconventional resource teams
3 days • 11 disciplines • 1 focus
Sponsoring Organizations:
SPE International
AAPG
SEG
Supporting Organizations:
AIChE
AIST
ASCE
AMERICAN SOCIETY OF CIVIL ENGINEERS
ASME
SETTING THE STANDARD
SME
Society for Mining, Metallurgy & Exploration
SPEE
TMS

of Mexico (GoM) and Petrobras' multiphase Buzios FPSO project.

A recent and impactive setback for the FPS market was the announcement by Noble Energy and its partners concerning the ultradeepwater Leviathan development in the eastern Mediterranean Sea offshore Israel. The project is now expected to be developed via a subsea production system tied back to a fixed platform as opposed to the original concept based around a joint floating LNG and FPSO development plan.

The replacement plan envisages up to eight production wells to be tied back to a single platform, which could save the operators an estimated $1 billion in capex. One of Noble's partners, the Delek Group, said it expects an FID by fourth-quarter 2016 for the purpose of enabling first gas production from the Leviathan project in fourth-quarter 2019.

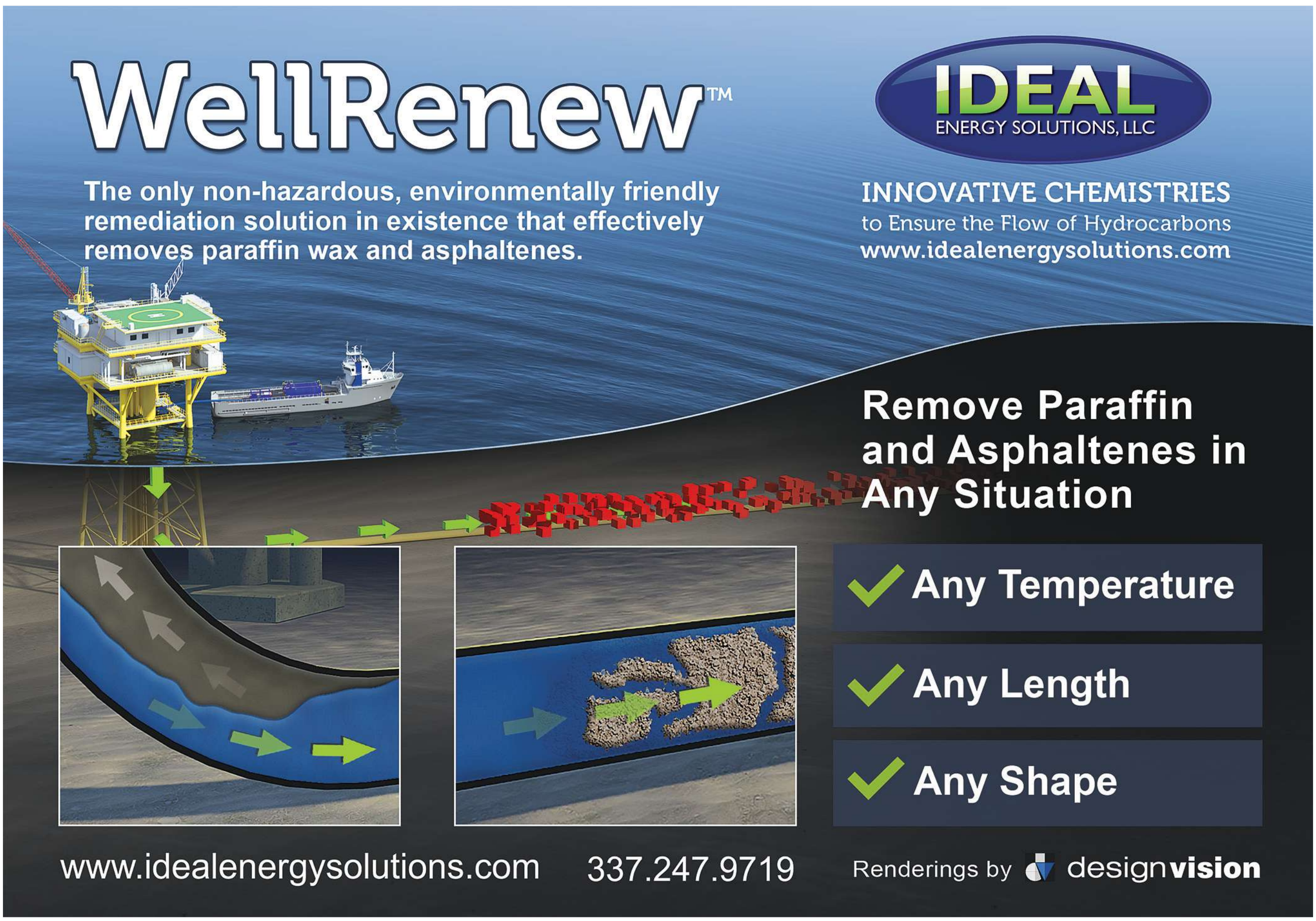
Fixed platforms

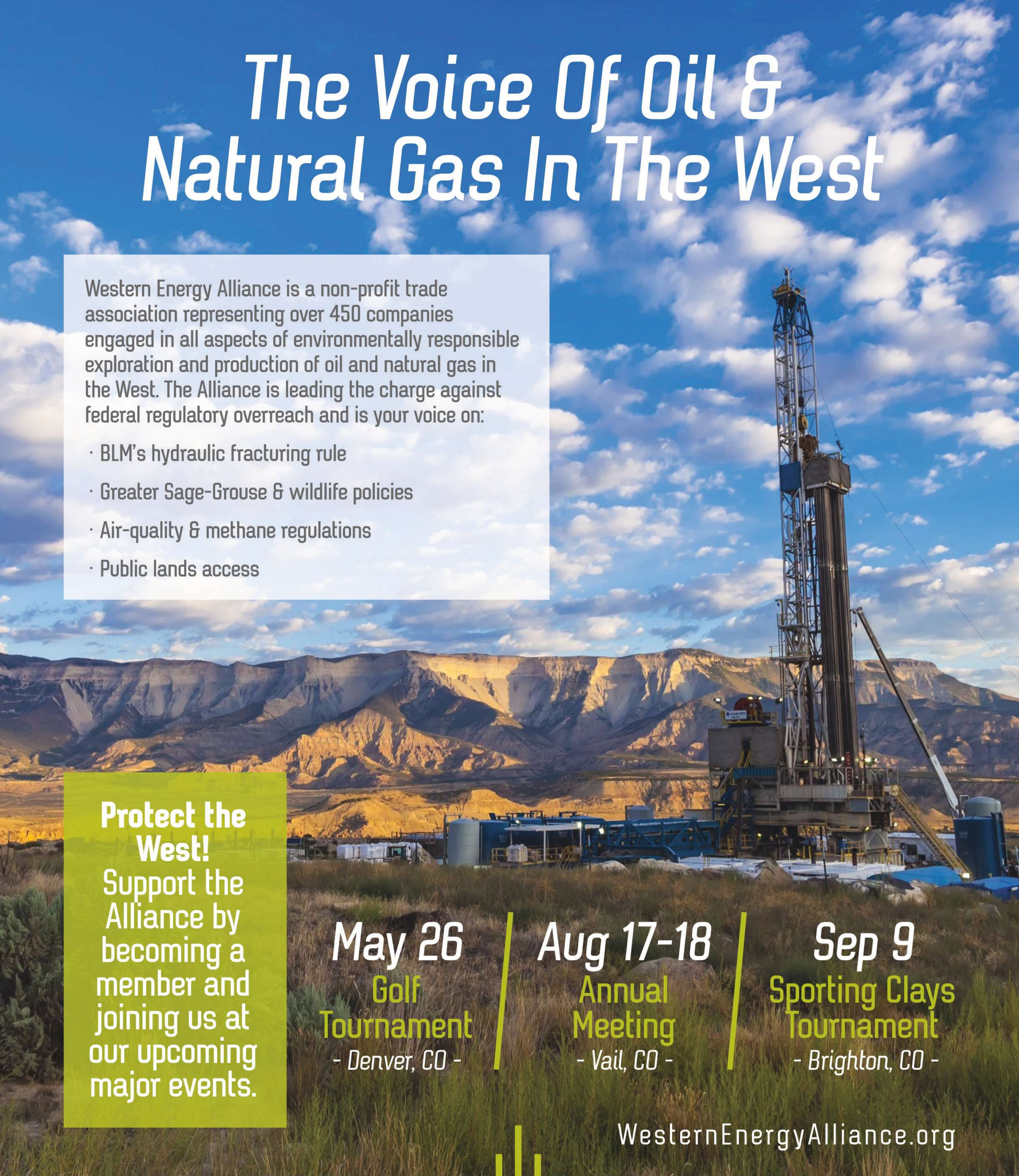
The fixed platform market, meanwhile, is expected to remain relatively resilient over the forthcoming five-year period as declining demand in the GoM and North Sea is offset by continued high activity levels in Asia and the Middle East. There is also some potential growth within Africa.

The continued long-term drive into deeper, harsher waters would suggest greater demand in the floating production platform market as opposed to the fixed platform sector. However, in the current low oil price environment opportunities are likely to remain in lower cost shallow-water provinces, where fixed installations are usually better suited.

Johan Sverdrup is the standout development in the fixed platform sector and is expected to dominate demand over the next five years, accounting for 90% of Norway's fixed platform capex demand between 2016 and 2020.

In September 2015 operator Statoil significantly cut its capex estimates for the project amid keen price competition among contractors. This resulted in the budget





WESTERN ENERGY ALLIANCE

For membership information, please call 303-623-0987.

Photo Credit: Jim Blecha

for the full-field development being reduced from $20 billion to $25 billion to $18 billion to $22 billion. Altogether, the field is estimated to hold between 1.7 Bboe and 3.3 Bboe, with the development expected to consist of a processing platform, drilling platform, riser platform and living quarters, all of which will be bridge-linked.

Subsea

Within the subsea sector, short-term capex is expected to be hit by the ongoing dramatic slowdown in the subsea tree market.

Beyond 2017 increased demand is expected, however, which will be driven predominantly by a number of projects that have been deferred over the last 18 months.

Over the next five years Africa is forecast to be the leader in global subsea capex demand, surpassing Latin America to become the leading region for subsea investment. Total is a key player in the region, representing 35% of Africa's subsea capex over the forthcoming five-year period with a number of capital-intensive ultradeepwater projects driving demand, including its Kaombo Complex offshore Angola and Nigeria's Egina development.

Egina is expected to be the largest subsea development taking place globally over the forecast time frame, with Infield expecting 39 tree installations on the field between 2017 and 2020. The field was sanctioned in 2013 and is forecast to produce 200,000 bbl/d of oil and 4.5 MMcm/d (160 MMcf/d) of gas, with first oil expected in 2018.

While the short-term outlook for each of the above market sectors is expected to remain challenging, global offshore capex is expected to recover and grow over the coming five-year period, with an overall compound annual growth rate of 9% between 2016 and 2020. This will be driven by the reemergence of recently deferred projects and some material deepwater developments in remote areas. E&P

Fighting back with innovation

A perspective on operating in today's North Sea oil and gas industry.

Paul Landers, TNW Group Ltd.

The story of North Sea oil is technologically exciting, in some respects as exciting as the Apollo moon landings of nearly half a century ago. But it is also one of the most expensive oil producing regions in the world and is therefore liable to remain at a cost disadvantage. This situation is severely handicapping efforts to attract investment to develop proven and potential oil reserves. In what is likely to become a slimmed-down North Sea industry, the region's economic viability over the next quarter century is dependent on operating a different business model and using new technologies.

Improving the recovery of hydrocarbons in what, given the present challenging economic environment for the North Sea, might become stranded fields, using lower cost techniques and nimble collaboration is no mean feat. However, the TNW Group is confident that it has the answer to what must become a new way and a new approach to operating in the region.

TNW's early focus will concentrate its efforts on the urgent need for well stimulation services through the group's StimLite company. There is a growing concern that a large percentage of the remaining North Sea oil will never be recovered as companies active in the area have scaled down investments due to the weak oil price. Improving the recovery of hydrocarbons from mature fields and new small pools with greater efficiency and lower cost will be TNW's focus.

Operators across the North Sea have little or no budget available to increase production; therefore, StimLite will perform well intervention and stimulation at no upfront cost and within very short time frames. The company will take the risk on its shoulders but will share some of the reward with participating companies with a solution that immediately assists the operator by lowering the lifting costs per barrel and providing major increases to bottom-line income. TNW will be using the company's own nontoxic biodegradable cleaning solution and two other nonintervention techniques which, in combination with each other, will significantly increase existing production while monitoring future production.

To provide a complete stimulation service to operators at the lowest cost and highest margins, small-diameter coiled tubing can make interventions in depleted wells both economical and feasible.

Anything TNW can do to increase the life of a platform is good for its North Sea clients and the industry as well as being good news for the U.K. economy and employment market. Essentially, if the remaining hydrocarbons in the region are to be recovered, there needs to be a fundamental shift in the way technology is developed and deployed and the way business is done in the North Sea. As challenging as today's marketplace is, TNW is pleased to be part of what it believes will be a revolutionary approach to operating in the region. E&P

A new approach is needed to operate successfully in the North Sea. (Source: TNW Group Ltd.)

ORHD
CUT AND IMPACT PROTECTION
ORHD® KNIT CR3 CUT LEVEL 3
EN 388 CE 4341
ORHD® KNIT CR5 CUT LEVEL 5
EN 388 CE 4544
ORHD® THERMAL KNIT CR3 CUT LEVEL 3
EN 388 CE 3342
OIL AND GAS HAND PROTECTION
US: 800.222.4296 | WWW.MECHANIX.COM
#mechanix
MECHANIX WEAR

Electric-powered pressure pumping solves regulatory, cost concerns

A quieter, cleaner pressure pumping option is now available.

Jared Oehring, US Well Services

Throughout the U.S. many operators are facing significant environmental regulatory pressures such as emissions, noise and silica dust. State and federal agencies are getting stricter with nonattainment areas and are tightening emission regulations for nitrogen oxides (NO_X), carbon monoxide, methane and other emissions.

Noise pollution is likewise being more tightly regulated in multiple basins, specifically how both high- and low-frequency noise affects residential communities as well as wildlife. Permissible exposure limits (PELs) for silica dust from proppant are being tightened over concerns about silicosis.

In this low-price commodity environment improvements to address these issues must be made while simultaneously looking to reduce overall costs and improve efficiencies. New technologies such as Clean Fleet with Whisper—the first fully electric, fully mobile electric-powered hydraulic fracturing fleet fueled 100% by field natural gas—delivers cost savings and addresses these environmental regulatory pressures.

Electric-powered fracturing

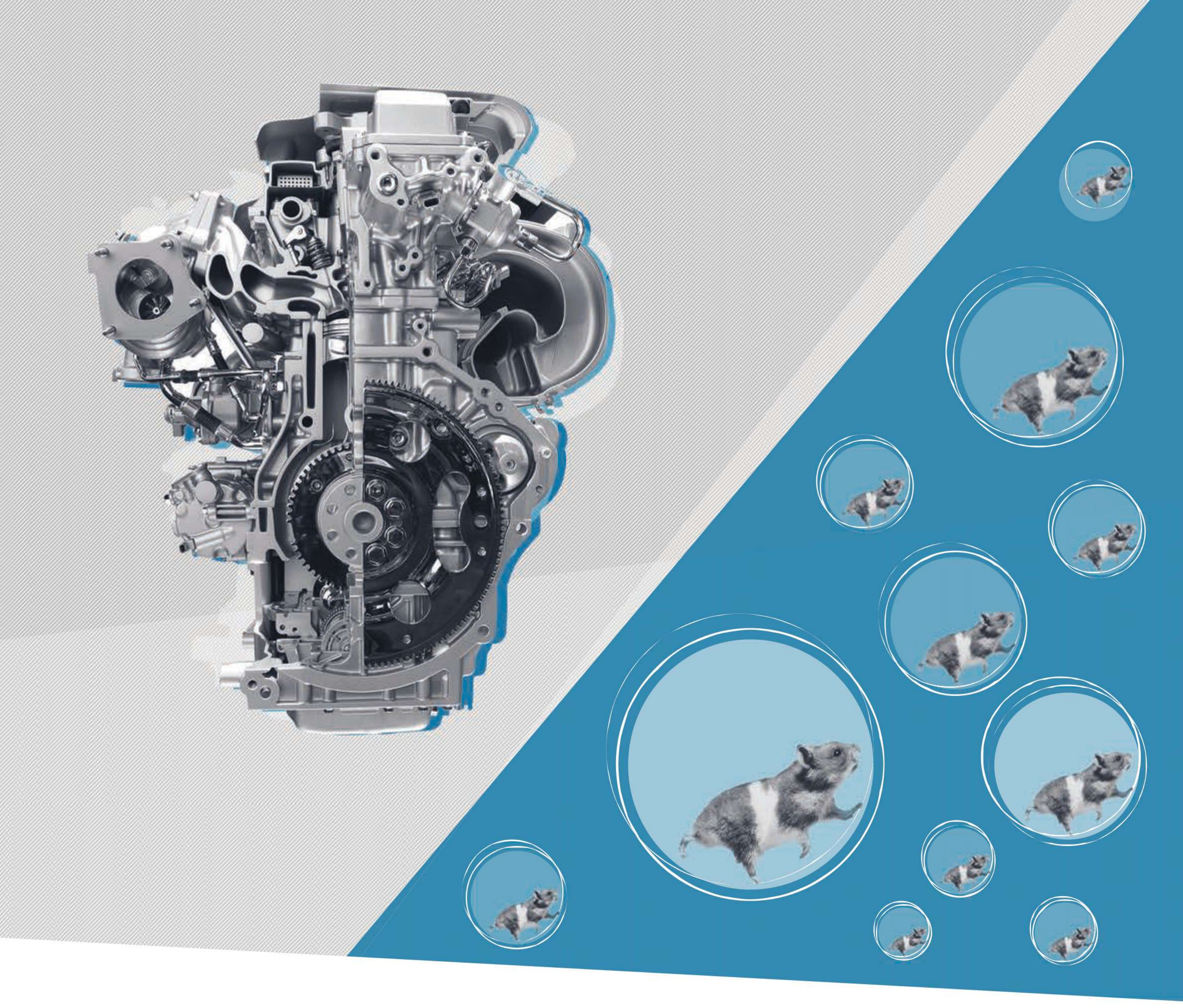
Traditional hydraulic fracturing fleets are powered by more than 20 large diesel engines up to 2,500 brake horsepower (bhp) each. By removing all diesel engines from a pressure pumping site and replacing them with mobile turbine engine generator units, a fleet can be run completely on electric power. This technology was first deployed in 2014 in the Marcellus Shale in West Virginia and has since also been deployed in Colorado. There are currently two active electric-powered fleets in North America.

The electric fleets are completely fueled by field natural gas that is supplied from a pipeline. If needed, CNG or LNG also can be used as a fuel when field natural gas is not available. Two large electric compressors boost the natural gas pressure to a constant 300 psi as required by the turbine engine generators. Combined, the compressors provide up to 84,950 cu. m/d to 113,267 cu. m/d (3 MMcf/d to 4 MMcf/d) for the mobile turbines.

The electric fleets can run with the power from three or four turbines depending on the hydraulic horsepower (hhp) requirements to stimulate the well. Each one produces 5.67 MW of three-phase power at 13,800 v for a total of 17.01 MW to 22.68 MW electricity output at the International Organization for Standardization conditions. The power generated by the turbines then runs through a set of switchgear trailers. These trailers distribute the electricity, provide circuit breakers and establish safeties in the equipment such as ground fault detection. The power then leaves the switchgear and is stepped down to 600 v using multiple transformers. Each transformer is a dry cast coil type rated for 3,500 kilovolt-ampere.

At this point the electric fleets are similar to a conventional hydraulic fracturing fleet except that all the fleet's diesel engines and transmissions are replaced by electric motors and variable frequency drives (VFDs). Each electric fleet has eight dual hydraulic fracturing pump trailers that all run on 600-v power. Each dual pump trailer is rated at 3,500 hhp for a total of 28,000 hhp per fleet. The dual pump hydraulic fracturing units have two independent triplex pumps.

The Clean Fleet offers a quieter, cleaner wellpad environment. (Source: US Well Services)



What powers your water solutions?

Some water solutions may look the part; but none of them are powered by as much technology, as much efficiency, as much expertise as AquaView® from Select Energy Services. Our full suite of telemetry services integrates with each step in the water lifecycle to ensure increased efficiency throughout your operations. Every piece of technology we deploy and those who put it in place serve just one purpose- to deliver analysis and optimization that's unmatched in the industry. That means with AquaView® , nothing is for show; because we know that without effective water solutions, you'll never achieve effective production.

E&P SPECIAL MERITORIOUS AWARD FOR ENGINEERING INNOVATION

AquaView
Real data in real time.

aquaview.com

SELECT ENERGY SERVICES

100% Water Focused

The Clean Fleet with Whisper is the first fully electric, fully mobile electric-powered hydraulic fracturing fleet. (Source: US Well Services)

On a traditional diesel-powered unit, a large radiator typically sits on the gooseneck. On the electric pump units the large radiator is removed, and in its place sits a VFD house with two independent VFDs. In addition to the electric pumps, blenders, hydration, data van, sand equipment and a silica dust suppression vacuum are all also completely electric powered.

Emission reduction

One of the most notable environmental benefits of the electric-powered fleet is reducing emissions to near-zero levels. Excess NO_X can lead to acid rain and contribute to unhealthy ground-level ozone and smog. The reduction is primarily achieved by eliminating the conventional diesel engines and using natural gas as a fuel. The emissions on the turbines were measured in the exhaust ports by a third party, and the NO_X levels were found to be less than 0.036 g/kWh. This is a dramatic reduction when compared to Environmental Protection Agency requirements for off-highway diesel engines.

Natural gas is a cleaner fuel than diesel, and it produces fewer potential pollutants. Natural gas turbine engines also allow a continuously burning combustion chamber that results in a more complete burn, which greatly reduces emissions when compared to a diesel engine's four-stroke cycle. The gas turbines have a significant advantage because they use lean premixed combustion technology to ensure a more uniform air and fuel mixture and to prevent the formation of regulated pollutants. Up to 60% of the airflow on the turbine engine is allowed to be premixed with the fuel, resulting in a much more consistent air and fuel mixture.

Noise reduction

The Colorado Oil & Gas Conservation Commission has set strict noise regulations for both high-frequency and low-frequency noise. About one-third of all complaints received in 2015 in Colorado were related to noise. One of the electric fleets operating in the Wattenberg Field in Colorado was measured to be 7 decibel A (dBA, A-weighting describes audible, higher frequency noises) and 12 dBC (C-weighting describes low-frequency vibration noises that can shake windows) quieter than a comparable diesel fleet. This correlates to an 80% reduction in sound intensity on the dBA scale and a 95% reduction on the dBC scale.

Silica dust reduction

Both of the electric hydraulic fracturing fleets have electric-powered dust control to reduce silica dust significantly below PEL requirements. Like the rest of the stimulation equipment, the dust vacuum system is powered by 600-v electricity. This engineered system reduces measured silica amounts up to 80% below PEL requirements. To increase safety, engineering controls like this are more effective at controlling hazards rather than merely using administrative controls or personal protective equipment.

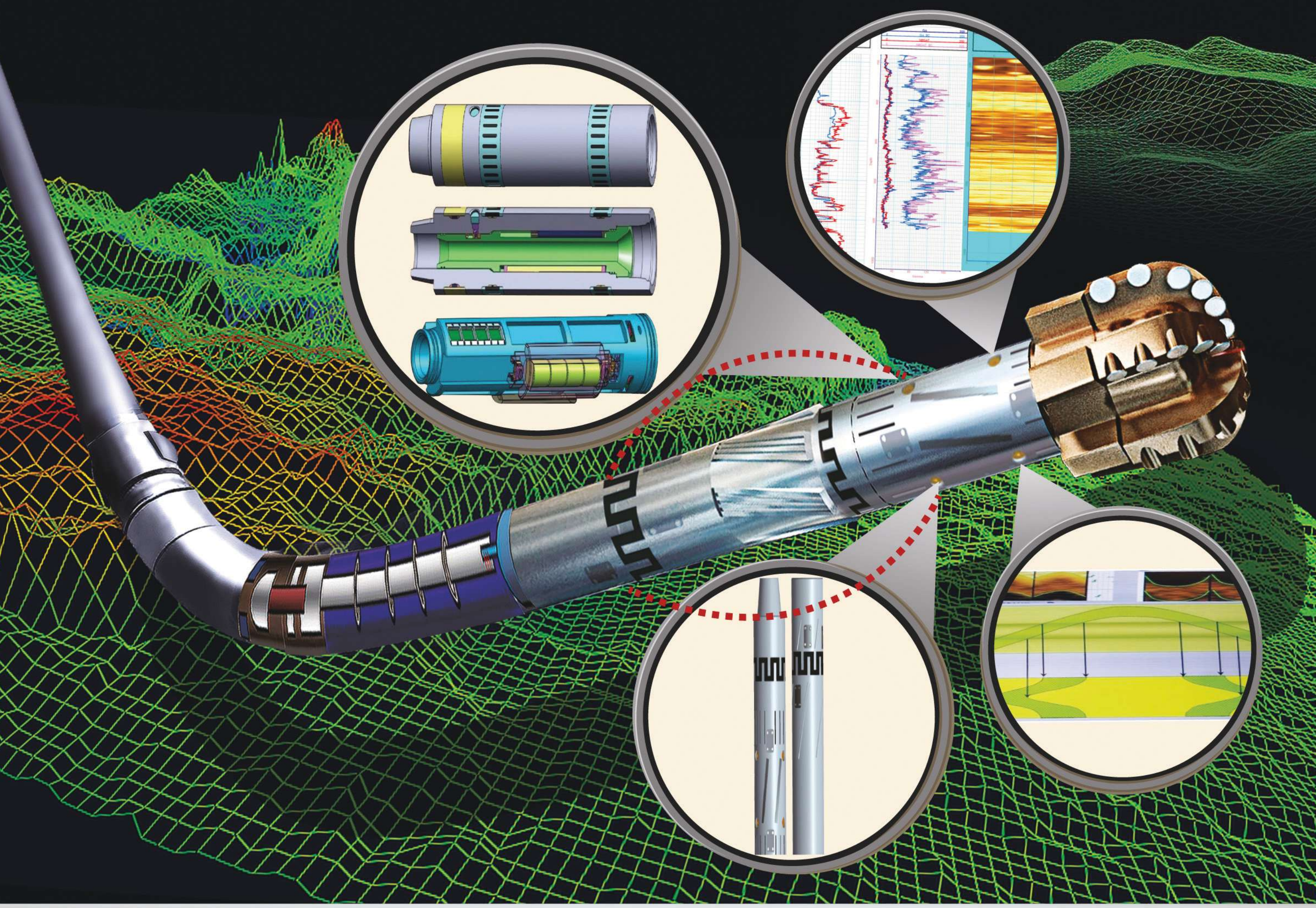
Cost reduction, increased efficiencies

Fueling the turbines with field natural gas reduces fuel costs by up to 90%. The turbines consumed an average of 3,030 cu. m (107 Mcf) of natural gas per hour while powering more than 10,000 hhp of fracturing equipment during stimulation. An equivalent diesel hydraulic fracturing fleet can consume about 1,000 gal of diesel fuel in 1 hr of pumping. These dramatic fuel savings come from both the reduced commodity price of unfiltered field natural gas over diesel fuel as well as not having trucking costs for the natural gas.

The electric motors used by the electric fleets have their first maintenance period at 30,000 hours and an expected life of up to 20 years. The first electric fleet also went from pad to pad for more than one year without needing to go back to the shop for repairs and maintenance, allowing increased pumping time and decreased nonproductive time. Diesel fleets will need to go back to the yard every other month for repairs and maintenance such as oil and filter changes that the electric fleets do not have to do. The longer life, reduced maintenance schedule and increased pumping time are an important economical advantage. E&P

GWDC Serves the World

GWDC Near Bit (GW-NB) Technology
Reaches the reservoir with speed and accuracy



The GW-NB system consists of measurement transmission motors, a wireless receiving system, a positive pulse of wireless LWD system, and surface processors and geosteering decision software. It is designed to improve the discovery rate for exploratory wells, drilling encounter rates and oil recovery for development wells.

- Zero length, small blind area realizing real-time geo-steering
- Speedy access to bit's position in the reservoir
- More accurate directional drilling
- Discover the changes to the formation dip-angle
- Particularly suitable for complex formations and thin oil layer development wells
- High resolution and fast data transmission and conducive to directional drilling

E-mail: marketing3.gwdc@cnpc.com.cn   www.gwdc.com.cn   www.cnlc.cn   Tel: 86-10-59285691

RSS expands operating envelope, reaches targets in UHT reservoir

The 200 C-rated RSS was used successfully in a high-temperature exploratory well with a complex trajectory in the Sureste Basin offshore Mexico.

Guillermo Gomez Sanchez, PEMEX; **Luis Morales**, **Gustavo Salinas** and **Juan Restrepo**, Schlumberger

High temperature, a phenomenon of the industry's drive into new and complex frontiers, continues to push the limits of technology, as evidenced by ongoing development of tools that can deliver performance and reliability in extreme environments. Rotary steerable systems (RSS) are commonly deployed in wells that present challenging trajectories and temperatures as high as 175 C (350 F), enabling operators to drill and produce wells that were once inaccessible.

However, the continued push into increasingly harsher environments, where downhole temperatures can reach or exceed 200 C (392 F), has established a new threshold for ultrahigh-temperature (UHT) performance.

When it comes to the reliability and longevity of downhole electronics exposed to UHTs, distortion of plastic components is among the industry's biggest challenges. This limitation, which often results in failure or drilling blind, has raised the bar yet again for a new wave of innovation and technology development when it comes to RSS. As operators strive to meet drilling objectives and manage costs, drilling systems that can improve performance in these downhole conditions is now essential.

A newly designed system with UHT-rated electronics has expanded the operating envelope in extreme downhole conditions, enabling drillers to accurately and efficiently reach total depth (TD) using standard drilling procedures. Petróleos Mexicanos (PEMEX) successfully used the 200 C-rated system on a high-temperature exploratory well with a complex trajectory in the Sureste Basin, one of Mexico's most prolific and long-producing offshore oil fields.

Introduced in March 2015, the PowerDrive ICE ultraHT system was developed by Schlumberger specifically to overcome the effect of UHT on the electronics of downhole RSS components (Figure 1). Historically, the industry has met this challenge by flasking the electronics or mitigating failures by staging to reduce the thermal shock of the electronics, which slows down the operation. A lot of time is spent circulating to ensure that non-UHT-rated tools properly cool down.

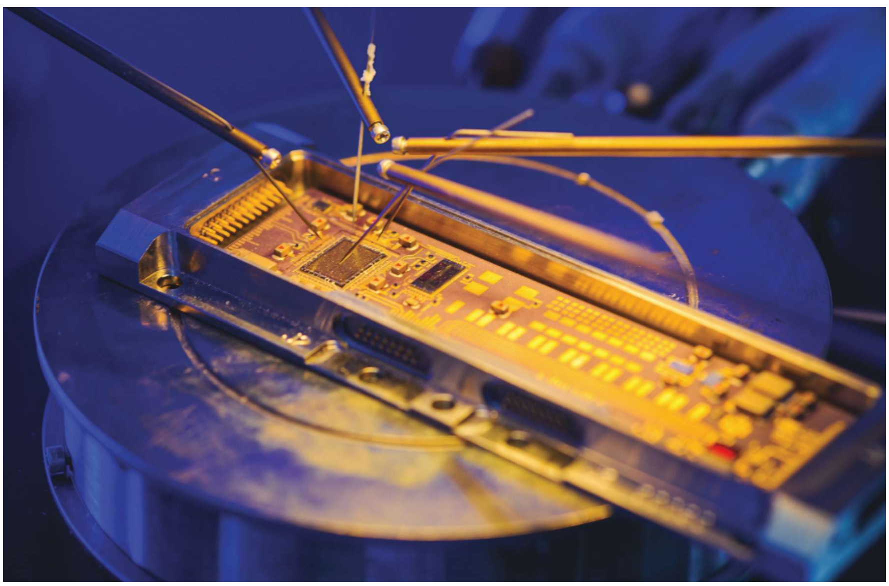


FIGURE 1. The UHT-rated multichip modules in the PowerDrive ICE have been verified to 200 C, providing consistent performance that saves rig time by maximizing ROP. (Source: Schlumberger)

The new system has been designed and built to drill UHT wells using standard operating procedures. This greatly reduces time spent circulating to cool the bottomhole assembly (BHA) and eliminating the need for costly mud coolers at the surface.

As the latest addition to the PowerDrive RSS portfolio, the new ultraHT system offers a drilling solution that features integrated ceramic electronics (ICE) and multichip modules with metal-to-metal sealing components that replace elastomeric seals to withstand rugged downhole conditions, including UHT.

The fully rotating system delivers precise directional control and automatic steering to increase ROP and reduce risk. This capability gives operators greater assurance that the system will not experience failure, which can result in pulling out of the hole and thus adding time and cost to the operation.

Prior to field testing in 2014, the ultraHT system underwent extensive verification and validation, with thousands of hours of rapid testing above 200 C and as low as -40 C (-40 F) for thousands of cycles and under shock to ensure the electronics in the system would function normally in extreme operating environments.

Complex well trajectory in UHT reservoir

In conjunction with a new exploratory campaign in the Sureste Basin, PEMEX faced a host of challenges in drilling an 1,100-m (3,609-ft) 8½-in. hole section in a deep formation with extreme conditions. The plan called for drilling a J-shaped well profile with precise inclination control to achieve a 25-degree inclination. The deviated configuration was unusual for an exploration well, which is typically vertical.

Further complicating the project, BHA temperatures in the reservoir were anticipated to exceed 190 C (374 F), as evidenced by the 170 C (338 F) temperature measured just above the 8½-in. section, dangerously close to the 175 C rating of most high-temperature-rated RSS technologies. The hard formation also necessitated using a heavy mud weight of up to 17 ppg, which likely would result in high solids content.

The project represented a collaborative effort between PEMEX and Schlumberger, with extensive upfront planning and decision-making to find a solution that would overcome the limitations of conventional drilling tools. A downhole mud motor was tried in the 8½-in. section with no success in providing directional control because of the difficulties in sliding at the 6,067-m (19,904-ft.) depth. The use of a turbine was not viable because it would likely present problems with rig pressure capabilities.

After determining that RSS technology provided the only reliable method for achieving the dogleg severity to reach the planned trajectory, PEMEX opted to integrate the UHT system into the BHA, rated to withstand the UHTs up to 200 C and also precisely steer the difficult trajectory in the hard formation and heavy mud weight conditions.

Using an integrated drillbit design platform, Schlumberger modeled the interaction of the bit and the rock and determined that a high-abrasion-resistant polycrystalline diamond compact bit would provide the greatest ROP for the hard rock conditions when combined with this BHA, which also included MWD tools for transmitting real-time resistivity, gamma ray, inclination and annular pressure-while-drilling data for optimized reservoir evaluation.

Reaching geological target

With the ultraHT system deployed for 333 m (1,093 ft), PEMEX was able to build the inclination of the well from 17.5 degrees to 26.3 degrees to both obtain a geological target and then maintain the tangent in automatic hold mode to reach the planned trajectory at an estimated static temperature of 181 C (358 F) at the end of the last run.

The BHA achieved a dogleg severity of up to 2.94 degrees per 30 m (100 ft). The metal-to-metal seals in the system withstood the UHT as well as the heavy mud weight and high solids content. Throughout the 13-day operation, the system performed reliably in BHA temperatures that reached 181 C. PEMEX plans to deploy the system for several upcoming exploratory wells targeting the same reservoir, where more UHT wells are expected.

The ultraHT system, which can be used on land as well as offshore, has had several runs in Mexico as well as the Gulf of Mexico and Vietnam. It also has potential applicability for the growing high-temperature markets in North America and the Middle East.

The new system is designed to work in concert with the TeleScope ICE ultraHT MWD service, which transmits survey and formation evaluation data at high speed to optimize real-time well placement and reduce risk in harsh drilling environments. The new UHT MWD service was designed and built with exactly the same objective as PowerDrive ICE—to operate reliably in the UHT environment as a standard operating procedure. Together, the two systems make up the industry's first complete BHA designed to operate at 200 C.

Precision, reliability and durability are critical for meeting drilling objectives and managing costs in UHT wells, where conventional RSS cannot efficiently or cost-effectively meet operators' objectives. By providing a solution that can address the multiple challenges of this growing market, the ultraHT system is expanding the operational envelope, enabling drillers to overcome significant hurdles to drill otherwise undrillable wells. E&P

Automation and the need for cybersafety

The 'virtual asset' provides a working view of the asset that is critical to system operation, evolution and protection, and recovery.

John M. Jorgensen, ABS

Until very recently, many offshore platforms and vessels operated their entire working lives using only the safety systems and features that were installed during construction. Their mechanical systems perform certain sets of functions that can be regulated and monitored by crews that possess complete knowledge of the systems and their interactions.

But the offshore industry and its business processes are evolving rapidly. As the offshore industry continues to deploy highly instrumented, automated and connected assets, unforeseen technical problems and risks have emerged.

Control systems

Today systems interconnect more widely than before, and this introduces concerns with system integrity. So one major area of concern is control systems, system interfaces and data management.

System integrity is central to offshore OT systems largely because of the complexity inherent in applications like drilling systems, which are highly integrated. (Source: suwatpo *123RF.com*)

System integrity is the degree to which a particular system can operate completely deterministically—that is, its behavior in all circumstances is known, predictable and within designed boundaries and remains in that condition without conscious operator action despite potential failures or interfering influences. System integrity provides reliability and dependability, but it is affected by system modifications.

Typical requirements for systems on offshore units include the functions and considerations associated with software-intensive systems. Life-cycle requirements—which at one time were based largely on finite numbers of improvements or replacements to hull machinery and equipment resulting from long technology evolution cycles—now also include software updates and upgrades along with associated asset configuration and version control efforts.

Software modifications, updates and upgrades during the asset life cycle affect system behavior and response and therefore affect system integrity. This is most visible where real-time (RT) and near-real-time (NRT) control systems are used.

RT and NRT control systems are critical to the safe and effective operation of offshore assets. Their quick responses, data capture functions and labor-multiplying effects deliver vastly expanded capabilities. These types of control systems are referred to as operational technology (OT).

System integrity is central to offshore OT systems largely because of the complexity inherent in applications like drilling systems, which are highly integrated. On an offshore asset, many individual OT systems function together to produce the desired functionality. When the overarching functionality is defined and documented, the goals, purposes and critical natures of the connected subsystems are clear. It is at that point that the notion of system integrity is created as a required and expected function that has to remain unaffected by either internal or external conditions.

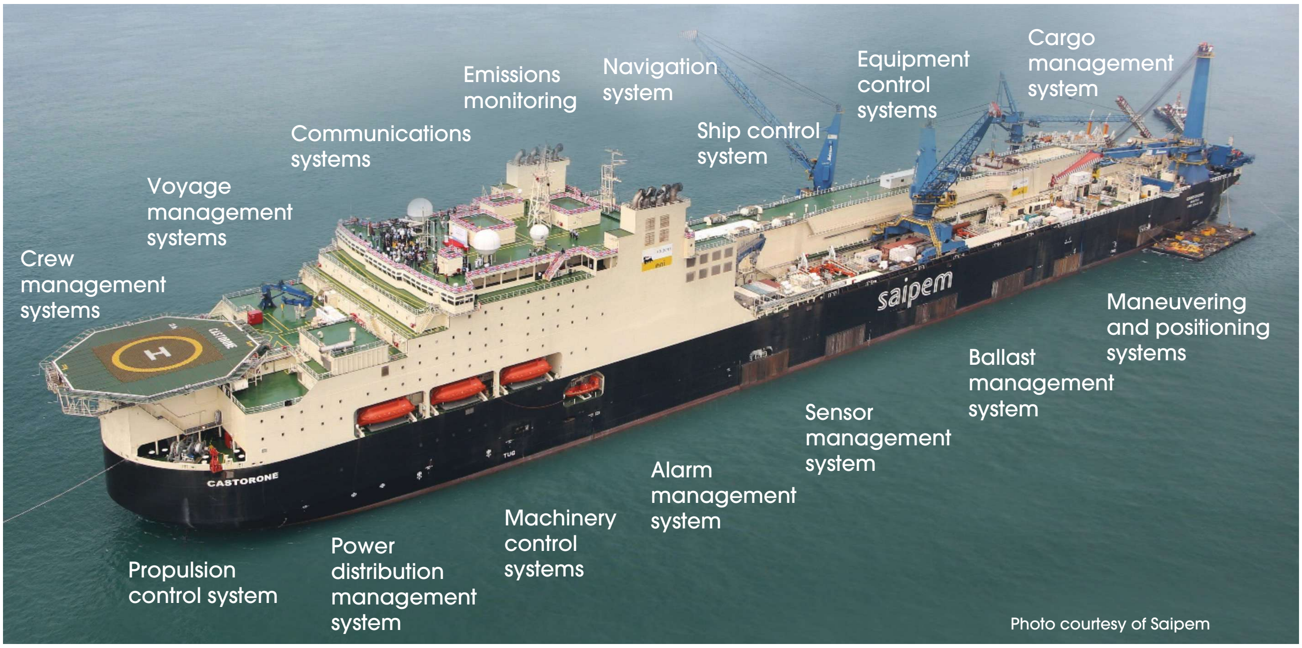
What about the issues you don't see?

Work with us to find innovative solutions to subsea issues.

Learn more and watch a full video at:
www.rpsea.org/subsearesearch

VISIT US AT OTC BOOTH #S18

RPSEA
Research Partnership to Secure Energy for America



The offshore environment includes extensive and growing numbers of cyberphysical systems. This diagram shows elements of cybersafety that are common on both onshore and offshore assets. (Source: ABS)

Upgrades, vulnerabilities

The second major area of concern is configuration control. While there are many integrity-reducing conditions, a fair number of them can be managed through disciplined implementation of a relatively small number of comprehensive software quality engineering practices that include a detailed OT system architectural description, strict control of OT software and hardware evolution, and disciplined physical and cyber-OT system security protection.

Inadequate understanding of OT system architecture opens the door to threats to system integrity. For offshore crew members to maintain system integrity, they need to understand their systems completely, and they must have a detailed functional description of the OT system architecture. This transparent view of the "virtual asset" provides a working view of the asset that is critical to system operation, recovery, system evolution and system protection.

Clearly, controlling and managing updates and upgrades are critical to maintaining system integrity. Cost control measures, however, can work against good configuration control in two areas. One is in perceived return on expenditures. Owners commonly look for rapid and measurable value in return for software updates because the updates rarely associate with physical construction or drydocking. The lack of value recognition can result in decisions to defer updates to OT systems.

The opposite effect can occur when systems are updated simply because contracts include clauses for maintenance updates that allow external third parties to perform updates to maintain specified performance levels. If original equipment manufacturers (OEMs) or third-party maintenance personnel make software modifications without owner or crew knowledge, the working system configuration becomes very fragile.

Strict OT system software, firmware and hardware control is possible if all changes are vetted and authorized prior to installation. This evolutionary process can be orderly and effective if managed conscientiously.

Managed system evolution includes applying software management-of-change practices to all systems. It demands supplier transparency in change and configuration management during software development and maintenance, disciplined pre-installation review of new OT system elements, pre-installation supplier testing protocols for both computer hardware and software, disciplined warm- and cold-stacking of OT systems, and preplanned OT system end-of-life management.

Cyberthreats

The third major area of concern is cybersecurity. As remote connectivity through the Internet has increased, it has opened OT systems to integrity threats. Networked and remote connectivity bring major high-profile threats to OT systems.

Threats to remotely accessible systems have created a need for new types of corporate expertise and new practices and protective imperatives to manage threats to OT system integrity. Now more comprehensive policies for establishing organizational, technical and procedural capabilities are being applied to protect OT systems.

Two practices are particularly useful in protecting integrity: formal requirements management and documented system traceability. Documenting the linkages of formally stated requirements to the as-built system architecture, test procedures, and criticality and safety analyses allows those in the change management approval workflow to base decisions about system evolution on the original functional intent of the software.

These processes are part of normal systems engineering. Positive control of systems integrity and systems configurations is required before effective cybersecurity is possible. Cybersecurity of safety-critical systems really translates to maintaining integrity and deterministic outcomes of those systems.

Dependence on software, automation

Growing dependence on software, increases in control system integration and more widespread connectivity to onshore monitoring systems have made cybersecurity a serious issue. Expanding automation means more interconnections, which present additional hazards, whether through the introduction of malicious code, malevolent actions, or imprudent care and maintenance.

There is greater pressure on OEMs, software developers and shipyards to design assets for which the system architecture is well defined, documented and communicated so informed decisions can be made throughout the asset's service life—before, during and after modifications. Better system architecture and engineering should require that the unit be delivered with a documented process in place so security updates can be carried out easily.

The role of classification in this evolving environment is to apply technical competence and experience to determine risks and hazards and to provide a framework for practical and appropriate safety infrastructure without unduly restricting the potential for progress. E&P

Automation advances drive new efficiencies in pressure testing

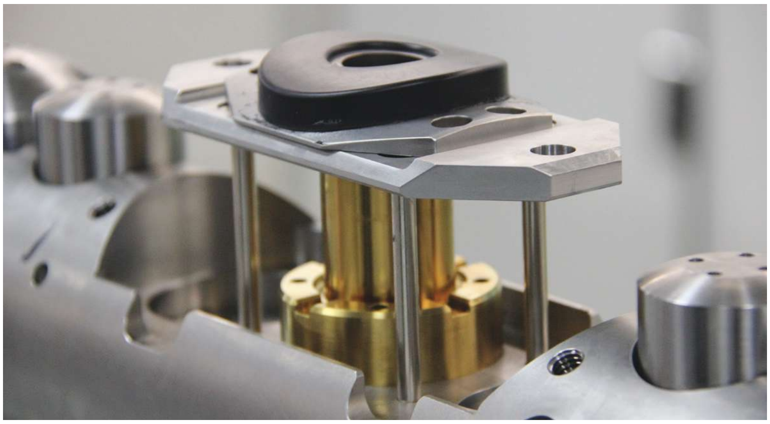
New tool acquires pressure data accurately and reliably with real-time control.

Hermanus Nieuwoudt and **Denyse Di Miele**,
Baker Hughes

Formation pressure data are a crucial guide in an operator's decision to move a newly drilled well into production. Using pressure data obtained during logging runs, the operator determines fluid contact, fluid properties, reservoir pressures and, ultimately, the production potential of the reservoir. This information subsequently guides reservoir development plans, completion designs, and the type and size of surface facilities.

But in an environment of tight exploration budgets, full well-testing programs can be cost-prohibitive, and operators will instead use wireline instruments to obtain the required data. However, traditional wireline pressure testing methods rely on manual operation and measurements, which can extend testing times and raise the risk of inaccurate data and inconsistent test outcomes.

Any error in pressure measurements can severely impact an operator's development plans. A wide error bar in the pressure measurements collected at different depths introduces a great deal of uncertainty in determining fluid contacts in a well.



The formation pressure-testing service deploys a small extendable probe to seal tightly to the formation wall prior to activating the piston to draw down the pressure. (Source: Baker Hughes)

Misjudging a fluid contact by even a few meters can result in the calculated value for the assets being significantly under- or overestimated. If these same erroneous measurements are carried over into subsequent formation tests in other wells, the operator risks making serious mistakes in investment decisions and leaving otherwise recoverable reserves in the ground.

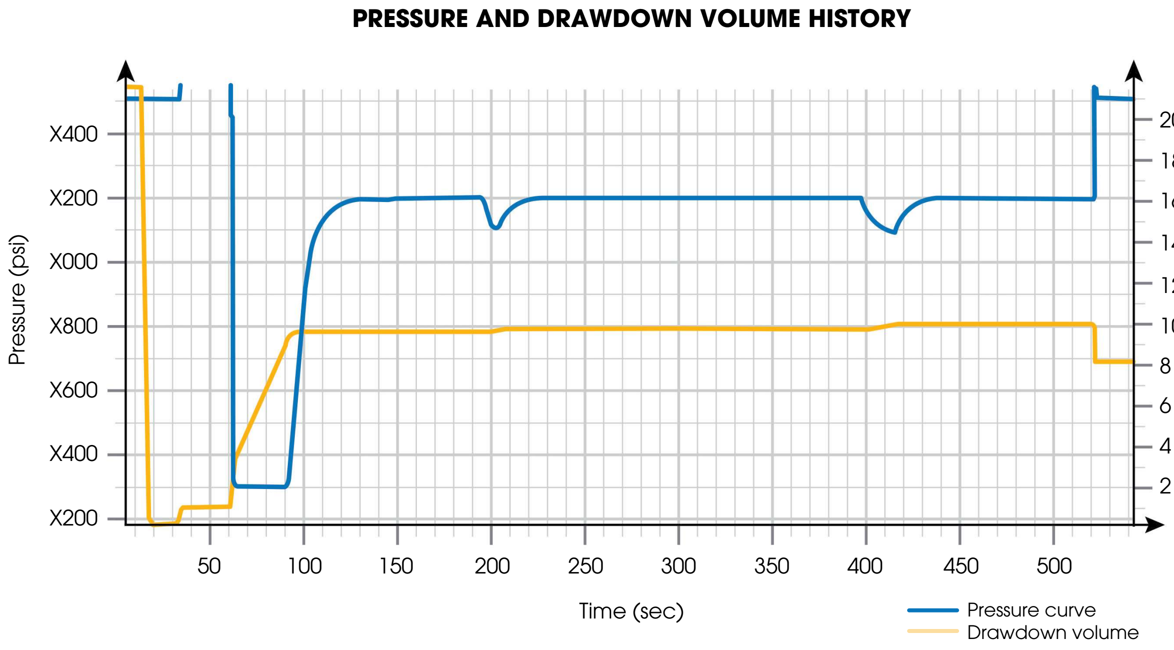
This was the potential risk facing the operator of a major North Sea field development, which required fluid type and contact information for a well drilled into a formation characterized by widely varying permeability and high overbalance pressure in some zones. The operator wanted to conduct formation pressure tests to obtain this information across the different zones, but faced with a tight execution timeline, these tests had to be run efficiently with a minimal number of trips downhole.

Automated solution

Baker Hughes recently developed the FTeX advanced wireline formation pressure testing service designed to deliver reliable and accurate pressure data through a combination of downhole automation and real-time control. The service replaces manual control with an intelligent downhole platform that reduces the possibility of human error by automating pressure measurements and minimizes testing time by real-time optimization of the operating sequence.

The service comprises all the components of a wireline formation tester, including deployment pump, extendable probe, drawdown pump, pressure gauges and packer into a single unit with an outside diameter of 3⅞ in. A precise drawdown controller commands the motor that directly drives the drawdown pump.

Drawdowns are initialized based on preloaded algorithms that use piston position, speed and pressure for feedback. The controller determines the end of the buildup period based on user-defined stability criteria. The service can operate reliably at ambi-



The automated formation pressure-testing service enabled pressure testing in the low-mobility formation (0.4 mD/cP) of the North Sea well. Based on the formation response of the first volume control drawdown test, subsequent tests were automatically expedited with pressure control and steady-state tests. (Source: Baker Hughes)

ent temperatures of up to 350 F (177 C), pressures of up to 30,000 psi and in boreholes ranging from 4¾ in. to 16 in. in diameter.

Testing parameters and drawdown control are calculated automatically in the service. It then determines optimal pressure measurements by adapting to the formation response in real time and refining the parameters for subsequent drawdowns, thereby increasing data accuracy and minimizing measurement time. Reservoir engineers can constantly monitor the pressure measurements from the surface and, where necessary, change the progression of each test based on their assessment and expertise, providing a degree of customization to the automation process.

While previous formation pressure testing tools required a standalone run downhole, this automated service can be deployed with the full spectrum of openhole logging tools, including standard petrophysical logs, nuclear magnetic resonance and induced spectroscopy imaging services in the same tool string to save rig time.

Data collected by the automated service, which includes pressure and mobility profiling and fluid contact and density determination, can be obtained in the first logging run. This allows reservoir engineers and petrophysicists to make earlier decisions about how to proceed with their formation evaluation objectives.

Streamlined test sequence

Each testing sequence typically begins by selecting the optimal pretest protocol based on the expected formation response; however, the system also incorporates options for generic test initiation where reservoir properties are less certain. In either case, the automation will optimize the testing sequence once the formation response is measured. Customized pretest protocols can be developed for specific customer needs and specific applications but, in general, the available predefined testing schemes are suitable for all applications.

Once the tool is deployed downhole to the zone of interest, a typical operation would start with selecting a generic testing sequence such as a medium mobility test. This would then initiate a volume-controlled pretest, in which a predefined volume of fluid is withdrawn from the formation. This drawdown is performed and analyzed in such a way that the pressure falls a predetermined value below formation pressure and that any pressure shocks to the formation are minimized.

Downhole software constantly analyzes the pressure response data from this first drawdown test and automatically determines the targeted pressure drop and flow-rate parameters for the next test. The drawdown in the second test is controlled to slowly change the pressure and is controlled automatically until the target pressure is reached, when the drawdown slowly comes to a halt.

The final test evaluates the formation under Darcy flow conditions. Based on the mobility obtained from the previous drawdown, the drawdown rate is increased so that the tool reaches the defined pressure drop quickly. The drawdown rate and pressure drop are then held constant for a period of time—typically 30 seconds or less—to achieve Darcy flow.

Taken together, these three tests allow the testing service to perform a smooth, controlled and efficient pressure measurement in about half the time required for other formation pressure testing tools.

North Sea deployment

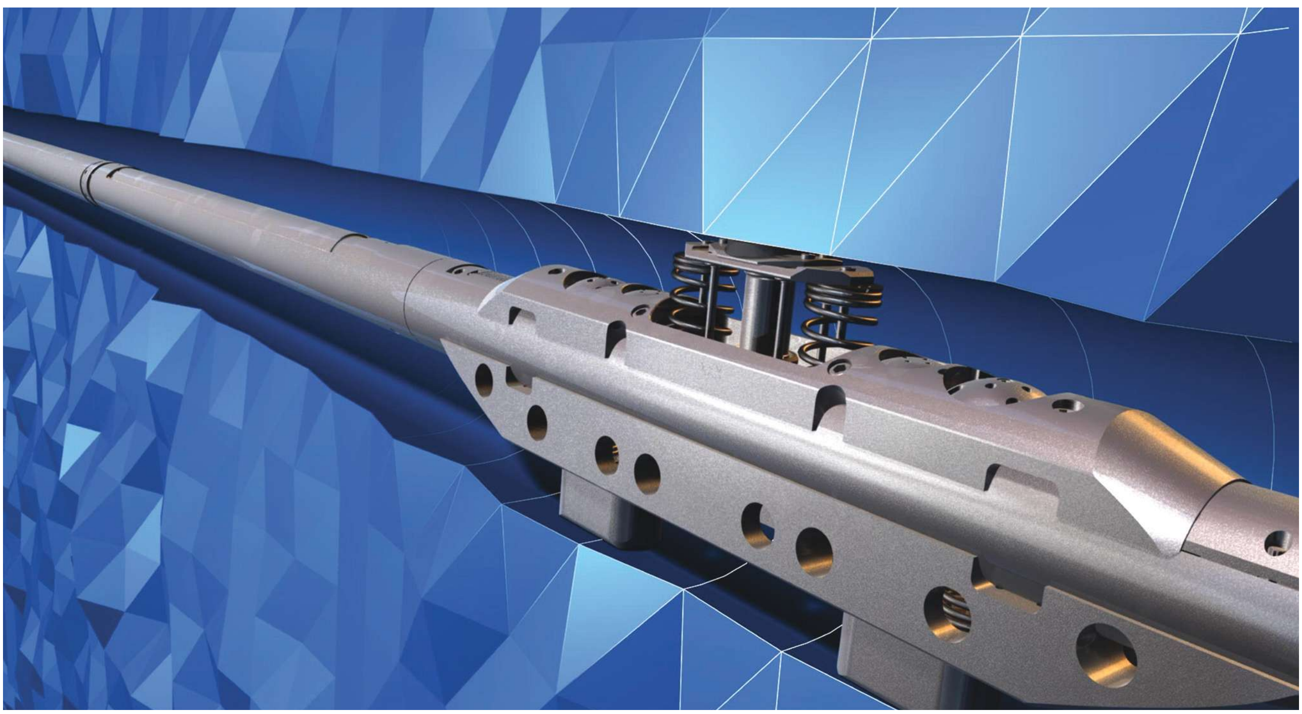
A North Sea operator selected the service for its well with the objective of acquiring the pressure measurements through highly variable permeability contrasts. The service had to minimize the error in each pressure measurement to ensure an accurate understanding of the pressure distribution in the field and allow an improved calculation of total hydrocarbons in place.

The service was combined with other openhole wireline services during the logging operation for maximum efficiency. With data from combined logs being used to pick the pressure stations, more than 50 pressure stations were attempted.

Pressures were acquired through formations with mobilities ranging from 0.2 mD/cP to 500 mD/cP, and stable, repeatable pressure measurements were recorded at 0.2 mD with 0.05 psi/min stability criteria within only a few minutes.

The service acquired all data from the well accurately and efficiently, taking on average less than half the time required for previous-generations formation testers in the same environment. Combining it with other openhole logs together with the advances in tool design and automation allowed the operator to avoid an additional trip and saved 20 hours of rig time in the process.

The successes observed in this North Sea well have made the tool the formation pressure tester of choice for the operator. And, thanks to its automated operation and wide specification range, the formation pressure testing service promises similar measurement improvements for both openhole and slimhole logging operations in all formation types. E&P



The automated formation pressure-testing service combines automation with real-time control for reliable pressure measurements in a single run. (Source: Baker Hughes)

DELIVERING STRATEGIC INSIGHTS
ACROSS THE ENERGY VALUE CHAIN

Stratas Advisors is a global consulting and advisory firm that provides data, analysis and insight to the world's leading businesses, governments and institutions. We can help you develop a deeper understanding of the developments that are shaping the future of oil & gas. Our support includes independent consulting that is focused on a client's specific strategic objectives, competitive challenges and asset base. Additionally, we offer support through subscription services and comprehensive market studies.

OTC2016

VISIT US IN BOOTH #3217

and see a live demo of our new Offshore Projects Service.

StratasAdvisors.com

UPSTREAM | MIDSTREAM | DOWNSTREAM | FUEL & TRANSPORT

STRATAS ADVISORS

A HART ENERGY COMPANY

SUBSCRIPTION SERVICES • CUSTOM CONSULTING • RETAINED ADVISORY SERVICES

1616 SOUTH VOSS ROAD, SUITE 675 | HOUSTON, TX 77057 | UNITED STATES | +1.713.260.6423

BRUSSELS | DENVER | HOUSTON | LONDON | NEW YORK | SAN DIEGO | SINGAPORE | WASHINGTON, D.C.

A solution for reliable onshore reservoir-quality seismic

High-density broadband data overcome near-surface challenges.

Michel Denis, CGG

From exploration to production through development, reliable seismic data can play a key role in de-risking and making better informed strategic decisions. Indeed, having reliable seismic data at hand is essential for revealing the finest details of the geological structure, predicting reservoir lithology and fluid content and updating reservoir models.

But how do we get reliable seismic data for reservoir characterization in onshore environments such as the Middle East that are known to be particularly challenging for seismic data quality? To address this question, CGG has developed UltraSeis, an integrated solution delivering high-density broadband seismic data that address the near-surface effects that have plagued onshore data and enable reliable quantitative interpretation and more accurate modeling of onshore reservoirs.

Increasing trace density

For land seismic data, limited bandwidth and the significant noise contamination have for a long time been major obstacles to the delivery of reliable reservoir-quality onshore seismic data. The answer to tackling this significant noise contamination lies mainly in addressing the near-surface effects that encompass all of the undesirable effects on the signal.

Trace density has a major role to play in addressing these near-surface effects. Over the last decade, experience gained from the high channel-count surveys deployed in the Middle East has identified trace density as a key quality metric. Trace density is the ratio between the fold and bin size which, when increased, clearly shows signal-to-noise ratio (S/N) improvement and subsequently enhances the quality of seismic images (Figure 1). Increasing the number of traces per surface area unit allows a better sampling of the noise contamination generated by the near-surface effects, which leads to a more efficient removal of the undesirable noise.

The advantage of being able to better resolve (and therefore compensate for) the near-surface effects leads to a significant uplift in imaging resolution, both laterally and vertically. Further investigation has demonstrated that, beyond the already dramatic uplift in structural imaging, mitigating the near-surface effects by increasing trace density is also of benefit to the derivation of more reliable quantitative reservoir information.

Matching density, productivity rates

Building on the understanding of how trace density impacts the quality of reservoir attributes from seismic inversion, multidisciplinary teams are able to propose survey design and acquisition solutions that meet the dual challenge of offering the appropriate trace density that will deliver reservoir-quality seismic while optimizing oper-

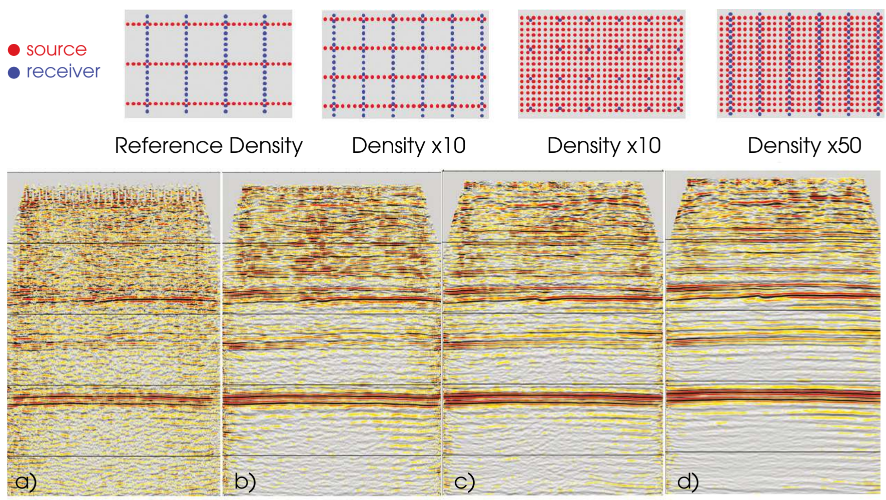


FIGURE 1. Seismic stack sections A to D illustrate how increasing trace density improves the S/N of the seismic image. Seismic sections B and C show how a particular trace density can be achieved with different acquisition designs adapted for different environments and crew equipment distributions. (Source: CGG)


When guiding you to East Coast Canada prospects,
one company shines the brightest.
The newest, most expansive data coverage of East Coast Canada.
Now available, Northeast Newfoundland 2015 3D. Modern long offset, broadband and AVO compliant. No other company brings it all together, and reaches out as far as TGS. With two new multi-client 3D surveys in Flemish Pass and NE Newfoundland, and more than 171,000 km of 2D and interpretive projects. It's the right data, in the right place, at the right time.
Let's explore.
See the energy at TGS.com
TGS
© 2015 TGS-NOPEC Geophysical Company ASA. All rights reserved.

ations in the field for efficient rollout of the survey. This leads to new trends in acquisition design and layout of equipment.

Traditionally, the equipment was deployed on 3-D sparse geometries featuring large intervals between lines, long arrays for both receivers and sources and a tendency to use powerful but heavy sources. This resulted in coherent noise being filtered directly in the field through the receiver arrays and each source point benefitting from high source energy, both through the use of a large number of vibrators per array and the use of long sweep times. Addressing the need for 3-D high-density surveys, the seismic industry therefore first moved to geometry designs featuring smaller intervals between lines for both receivers and sources. Smaller source and receiver arrays can be deployed using geophones with a very low-frequency response and high S/N, a new generation of vibrators delivering broadband sweeps have been introduced and new recording systems that support the high channel count and high productivity operations requirements are available. Although the reduction in the number of vibrators along source arrays can generate a decrease in the source energy, this is not a trade-off since the outstanding effects on the seismic image S/N brought by the higher trace density greatly benefit the quality of the seismic in terms of better resolution both laterally and vertically.

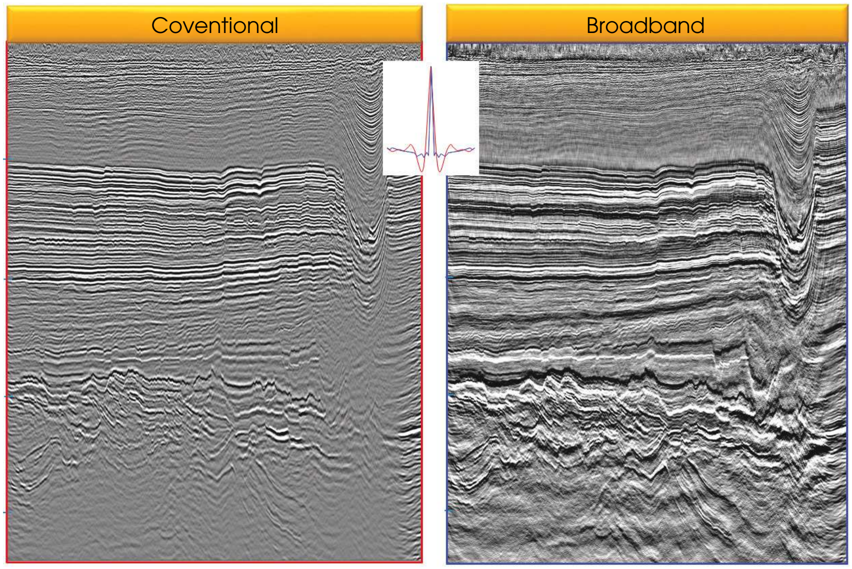


FIGURE 2. This figure shows an example of the uplift gained from onshore conventional 4-octave seismic at 8 Hz to 128 Hz (left) to broadband 6-octave seismic at 2 Hz to 128 Hz (right). Resolution and the ability to discriminate layering and geological detail are greatly enhanced by the addition of the low frequencies. Inset shows conventional (red) and broadband (blue) wavelets for comparison, showing the important role the low-frequency content in the 2-Hz to 8-Hz range has in suppressing the sidelobes of the conventional wavelet (Source: CGG; data courtesy of PDO).

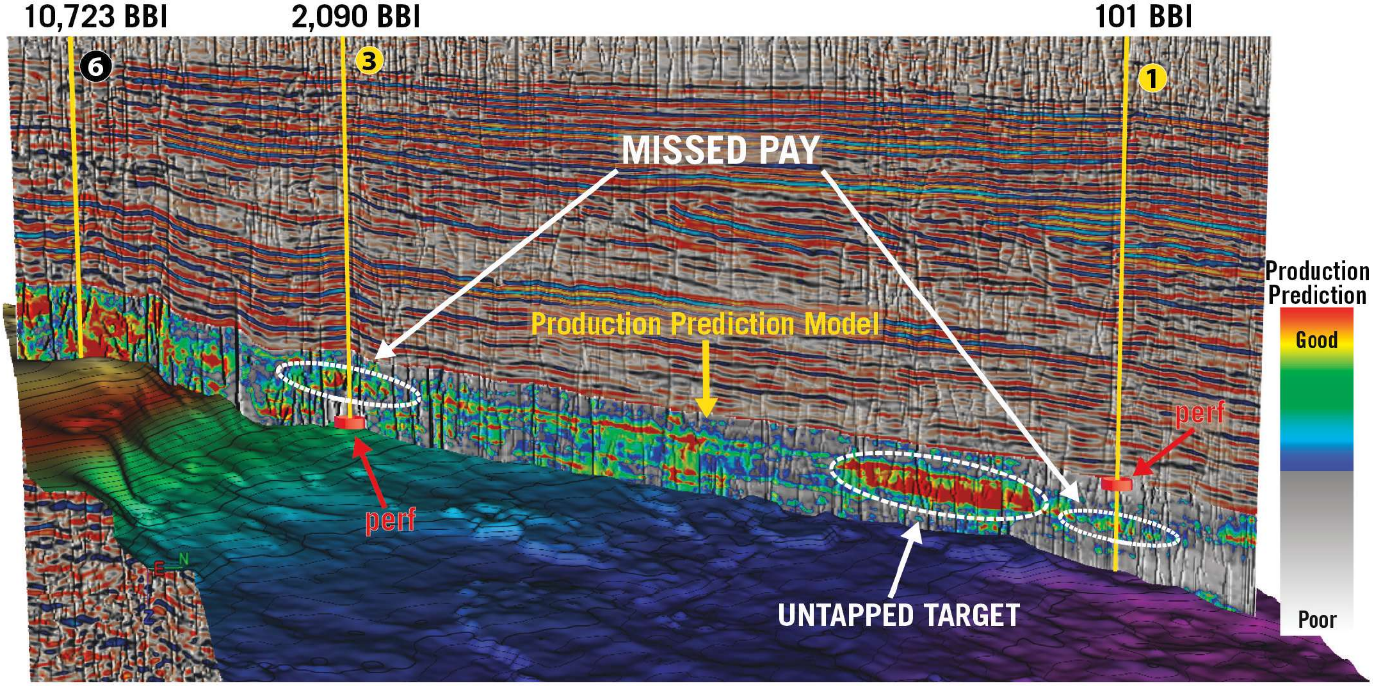
Onshore reservoir characterization

The outstanding benefits of broadband data for reservoir characterization have been widely demonstrated over the last years, with most of the emphasis being given to offshore examples. Nevertheless, the advantage of broadband data is equally important for onshore reservoir characterization, allowing better wave penetration and deep target illumination thanks to lower frequency content and sharper wavelets, leading to more reliable horizon interpretation and better lithology prediction. Increasing trace density is intrinsically an enabler for broadband data, and when combined with technologies that allow contractors to efficiently emit a broadband signal, record it with integrity and process it reliably, land seismic data with a bandwidth in excess of 6 octaves and frequencies as low as 1.5 Hz can be achieved. This combination takes land seismic into the new era of broadband data and promises to unlock onshore reservoir knowledge.

The ability to emit and record a broad frequency bandwidth is undoubtedly a major step forward for onshore reservoir-quality seismic. However, if not handled properly during the processing phase, the lowest frequencies can be easily damaged or lost. New processing workflows and quality controls performed on frequency bands (octave) are being progressively adopted to make the most of the low-frequency content. Figure 2 shows the uplift from conventional 4-octave data to 6-octave broadband data facilitated by the use of new processing workflows.

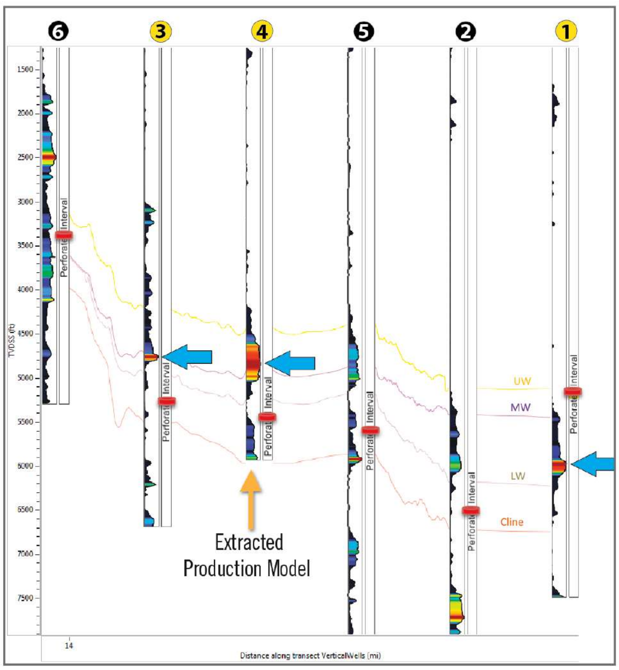
UltraSeis offers a solution for the delivery of more accurate structural information and more quantitative and reliable reservoir attributes for reservoir modeling. It does this through the efficient delivery of high-density broadband seismic, data that address undesirable near-surface effects that commonly obscure reservoir information in the seismic data. The success of the solution resides in a good understanding of the geological and geophysical challenges of the survey area and the appropriate responses to them through an integrated workflow that spans survey design, acquisition, subsurface imaging and reservoir characterization. E&P

SEISMIC-BASED ANALYTICS



An arbitrary line through 3 vertical wells in the West Texas Permian Basin shows the lateral variations of the Production Prediction Model and reveals refrac potential for Wells 1 and 3 where the red disks indicate the actual completion intervals and the white circles highlight the missed pay. Note the untapped target near Well 1.

FIND WHAT YOU'VE BEEN MISSING



An arbitrary cross section through 6 vertical wells in the Permian with single zone completions. The log displayed in color is the extracted production model along these wells. The red disks show the actual completion intervals. Wells 1, 3 and 4 (highlighted in yellow) have the highest probability for refrac success.

In today's challenging market, no one can afford a bad well. Global's seismic-based analytics can help you avoid the pitfalls and pinpoint the sweet spots. By integrating seismic, geological, and engineering data, this proprietary workflow identifies the most prospective areas and zones for drilling - down to the stage level! This reduces risk, optimizes spend, and greatly increases the chance for every well and stage to be a winner.

- High-grade prospective drilling areas and zones
- Enhance well planning and geosteering
- Optimize completion placements and frac design
- Predict well performance at stage level
- Boost EUR of individual wells
- Identify candidates for refrac

Global's seismic-based analytics approach is field-proven with successful projects in both conventional and unconventional reservoirs. Contact us today to find out how Global can help you make every well a winner.

Download the ANALYTICS CASE STUDY at www.globalgeophysical.com/Analytics or Contact us at ANALYTICS@globalgeophysical.com

tel +1 713 972-9200 **www.globalgeophysical.com**

Global Geophysical Services

Evolution of land seismic acquisition in South America

Wireless systems and single sensors are making an impact on this continent's rugged terrain.

Jack Caldwell, Geospace Technologies

While overall seismic activity is down in South America, like many other places in the world today, there are signs that newer land seismic acquisition technology seems to be making inroads in the South American market. Newer technology means using wireless seismic systems instead of cabled systems and/or using high-sensitivity single sensors instead of receiver arrays.

The land wireless (or cableless) seismic acquisition revolution hit North America in the 2008-2009 time frame and very quickly proved to be a technical and economic success. A couple of years after that, tests in Africa and Europe convinced Total to make wireless systems their corporate technology choice for land seismic data acquisition. The rationale for the choice to use wireless rather than cabled systems has been presented in numerous publications and venues, so suffice it to say that increased productivity, reduced costs, comparable or better data quality and lesser HSE effects have catalyzed its acceptance by the industry. Furthermore, the wireless systems are evolving to address what some have perceived as the inherent weaknesses of these systems: the inability to provide sufficient information in real time about the status of the live spread of receiver stations and to deliver in real time substantial amounts of seismic data. This evolution is indicated by the improvement in systems to deliver a greater volume of seismic data and the development of devices such as the Line Health Recorder, a pocket-sized unit (small enough that every crew member can easily carry one) that records station status, including root mean square noise levels.

Greater acceptance

It has taken longer for wireless systems to make inroads in other places in the world outside of North America, and one place in particular is South America. However,

SOUTH AMERICAN WIRELESS SEISMIC SURVEY SUMMARY

COUNTRY	YEAR	CONTRACTOR	2D OR 3D	ARRAY (ARR) OR SINGLE SENSOR (SS)	CABLE (CAB) OR WIRELESS (LESS)	REFERENCE
Brazil	2016	SAE	2D	SS	Less	
Peru	2016	GeoEstratos	2D	SS	Less	
Bolivia (Huacaya)	2014	SAE	3D	SS	Less	Munoz *et al.*, 2015, EAGE Ext Abstr, Munoz *et al.*, 2015, SEG Exp Abstr,
Colombia	2014	Vector Geophys	3D	Arr/SS	Less	
Peru (Sagan)	2014	SAE	3D	SS	Less	Munoz *et al.*, 2015, EAGE Ext Abstr,
Argentina	2013	UGA	3D	Arr	Less	
Brazil	2013	Global	2D	Arr	Less	
Colombia	2013	Global	3D	Arr	Less	Alfonso, 2014
Colombia	2013	Petroseismic	2D	Arr	Less	
Colombia	2013	Sismopetrol	3D	SS	Cab/Less	
Paraguay	2013	Global	3D		Less	President Energy Update_2013_08_05
Brazil	2012	Panamerica	2D	Arr	Less	
Colombia	2012	CGL	3D	Arr	Cab/Less	
Colombia	2012	SAE	2D	SS	Less	
Colombia	2011	Sismopetrol	3D	Arr	Cab/Less	Lansley, 2012, First Break
Peru	2009	SGS	2D	Arr	Less	
Brazil	2008	GeoRadar	3D	Arr	Less	
Chile/Argentina	2008	Global	3D	Arr	Cab/Less	Yates *et al.*, 2009, TLE

TABLE 1. This table (not guaranteed to be complete) lists land seismic surveys done in South America using wireless seismic acquisition systems. Also indicated in the table are those where high-sensitivity single-sensor receivers were used instead of receiver arrays along with publications that further describe details about some of the surveys. (Source: Geospace Technologies)

BGP – *Your reliable partner*

BGP is a leading geophysical contractor, providing geophysical services to our clients worldwide. BGP currently has 53 branches and offices, 65 seismic crews, 6 vessels and 14 data processing and interpretation centers overseas. The key business activities of BGP include:

* Onshore, offshore, TZ seismic data acquisition;
* Seismic data processing and interpretation;
* Reservoir geophysics;
* Borehole seismic surveys and micro-seismic;
* Geophysical research and software development;
* GME and geo-chemical surveys;
* Geophysical equipment manufacturing;
* Multi-client services.

CNPC BGP

BGP Inc.

Tel: 86-10-81201850 / 81201469
E-mail: marketing@bgp.com.cn
Fax: 86-10-81201392
http://www.bgp.com.cn

FIGURE 1. SAE shot a 3-D survey in 2014 in Bolivia for Repsol involving 27,000 wireless stations and high-sensitivity single-sensors. This photo shows the efforts made by the seismic crew to place sources and receivers. (Source: Geospace Technologies)

there are signs that this situation is changing there, even though the industry is currently in a contraction mode.

In addition to the increased use of wireless technology in land 2-D and 3-D seismic surveys in South America, the use of high-sensitivity single-sensor receivers in place of receiver arrays (most typically with six elements) also is increasing. Table 1 gives at least a partial listing of surveys done since 2008 involving wireless systems as well as single-sensor stations.

One of the appealing reasons for the use of high-sensitivity single sensors rather than arrays is the reduced field effort due to (1) lower weight of a single phone rather than three, six or 12 phones on a string of cable, (2) a smaller volume of equipment to transport and carry in the field and (3) the reduced effort in planting a much smaller number of phones. While these reasons are valid in flat or rolling but easily accessible terrain, it is notably true in operationally difficult terrain (see, for example, Figure 1), which are among some of the most prospective areasw in South America.

There are some good arguments for the use of receiver arrays when they are designed with some forethought, with the intent of the design (1) to minimize some particular wavelength(s) of noise based on tests (or experience) in the survey area and/or (2) to reduce random noise. When such forethought is absent, which is often the case in the industry today (outside of the Middle East), or when the ambient noise is not random, the effectiveness of arrays becomes much reduced. Over the last few years there have been several published studies concluding that ambient noise typically encountered (wind noise, rain noise, etc.) during seismic surveys is not random and that arrays deliver a bit less than 50% of what they theoretically would deliver if the noise was truly random.

In areas with rugged terrain, the use of arrays generally degenerates to simply planting all the sensors in a small bunch, which produces no array benefit and effectively only increases the sensitivity to ground motion by the number of sensors planted. A high-sensitivity sensor accomplishes the same result with much less effort in deployment and retrieval. Many 2-D and 3-D surveys in South America are now using the high-sensitivity single-sensor approach, delivering data with no discernible difference in interpretability at a reduced cost compared to using strings of multiple sensors at each station. When it is recognized that the survey located in the terrain shown in Figure 1 required the services of all the available professional mountain climbers in Bolivia to deploy and retrieve the equipment, it becomes obvious why strings of sensors (as well as cable recording units) would have been cost-prohibitive.

Surveying concerns

As elsewhere in the world, oil companies in South America can face challenges for a variety of reasons in obtaining the required permits and permission to shoot seismic surveys. Environmental concerns are obviously one important reason for the necessity of permits. There can be a variety of reasons to obtain permission from local communities before shooting a seismic survey, and some of those reasons have contributed to slowing the adoption of new technology. For example, there have been instances of local opposition to using wireless systems that require the employment of fewer locally hired crew members.

In other instances, poor communications have led to local communities being misinformed about exactly what the operations would entail in shooting a seismic survey. An extreme example of this occurred when the operations associated with a gravity survey were presented to, and approved by, a group of town residents, and then shot-hole drillers with explosives appeared. The miscommunication was unintentional, but nonetheless the local community was very upset. The industry must learn very quickly from such incidents and ensure that communications are accurate, informative, straightforward and useful. Again, as throughout the world, operators continue to work to establish better relationships with people living in areas where seismic surveys are desired. And finally, there are areas in South America where securing the safety of the seismic operations is still not a foregone conclusion.

Because the industry in South America is intent on increasing the production of oil and gas, it is quickly learning how to address the myriad complications that can stop, delay or make cost-prohibitive the acquisition of seismic data. One of the major approaches it is employing is the increased application of advanced seismic acquisition technologies such as wireless acquisition systems and high-sensitivity geophones. E&P

References available.

MIDYEAR
The Broadmoor

IPAA
INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

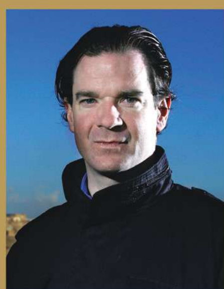
June 27-29, 2016
IPAA's 86TH MIDYEAR MEETING
COLORADO SPRINGS, CO

Five Reasons To Attend Our Midyear Meeting

1 Keynote Speaker who will change the way you think about the **face** of the American voter.

RON BROWNSTEIN

2 CNN National Security Analyst will address the #1 concern of American voters—**Terrorism in the U.S. & abroad.**



PETER BERGEN

3 Industry experts will provide their views regarding the **volatility** of the oil and gas markets.

BOB FRYKLUND

DAVID A. PURSELL

PAVEL MOLCHANOV

4

DR. TIM BOERSMA

Think tank expert will look at the evolving role of the U.S. in **international energy** markets given the recent lifting of the **export** ban.

5 Opportunities to **network** with industry colleagues from across the country and market your services to attendees.

WWW.IPAA.ORG/MEETINGS-EVENTS

Visit our webpage to:

- Register to Attend
- Become a Sponsor!
- See the latest updates to our detailed Schedule of Events
- Read the full bios of our featured speakers and industry experts
- Learn about the *#1 Concern of American Voters*

Secure your sponsorships today by contacting Tina Hamlin at thamlin@ipaa.org or 202-857-4768

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA | WWW.IPAA.ORG

Drillpipe for shale drilling improves WOB, reduces SPP

Three areas were identified with the most benefits in the field: hydraulics improvement, buckling resistance and tube wear reduction.

Contributed by Valllourec Drilling Products

The learning curve for the oil and gas industry has been steep and fast—over the last decade operators drilling in North American shale plays have migrated to highly complex and extended-reach wellbore geometries that require tremendous engineering effort. Increasing energy demand has challenged the industry as never before to improve the ROP and drive down costs in these shale plays without compromising safety.

Drilling longer laterals in wells presents challenges in terms of wellbore hydraulics, borehole cleaning, drillstring buckling, poor weight-on-bit (WOB) transfer and reduced drillpipe service life. Typical symptoms include reduced ROP, difficulty sliding, frequent wiper trips, excessive back-reaming, poor hole quality and severe drillpipe wear along with potential connection damage.

What is Shale Drill Pipe?

Shale Drill Pipe (SDP) is a new 4¼-in. design. The drillpipe body consists of a 4¼-in. outer diameter (OD) tube, 15.4 lb/ft with a wall thickness (WT) of 0.33 in., and is fabricated from S-135 steel as standard material. The SDP tool joint consists of a high-torque tool joint with a 4⅞-in. OD and a 2-11⁄16-in. inside diameter (ID), manufactured from 130,000-psi material.

Hard-banding is provided flush to the dual OD, and internal plastic coating is a standard feature. The 5¼-in. dual OD is intended to provide improved elevator capacity and additional tube standoff while still allowing it to be fished in a smaller hole size.

The SDP incorporates the VAM Express connection, which has a proprietary thread profile and high-performance single-start double-shoulder design. In fact, it is one of the most rugged and user-friendly high-torque connections available. This thread form has several design features that are meant for easy stabbing and thus improve user friendliness.

Modeling was performed with several software packages to compare 4¼-in. SDP to 4-in., 14-lb/ft (0.33-in. WT) drillpipe in a typical 6,096-m (20,000-ft) horizontal profile Bakken well. The 8½-in. or 8¾-in. section was drilled to 3,048 m (10,000 ft) vertically, then drilled horizontally with a 5⅞-in. or 6-in. section that extended 3,048 m. Three areas were identified with the most benefits.

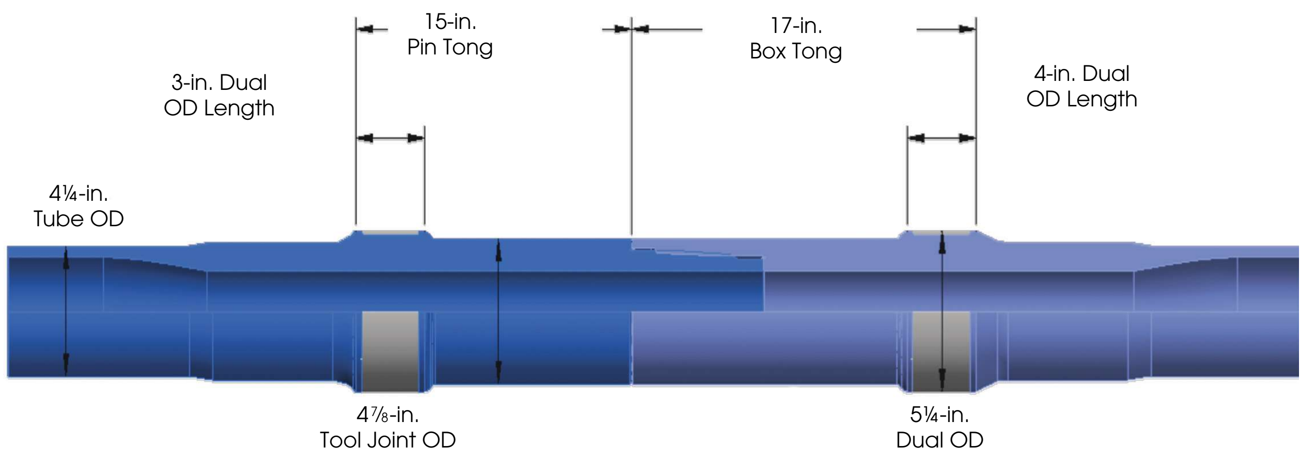


FIGURE 1. The SDP schematic shows that the 5¼-in. dual OD is intended to provide improved elevator capacity and additional tube standoff. (Source: Vallourec Drilling Products)

Hydraulics improvements: Hydraulics modeling was performed when drilling the 6⅛-in. lateral in a typical Bakken well. When comparing 4¼-in. and 4-in. drillstrings, 30% lower circulating time was required to clean the well. The increased annular velocity allowed the operator to reduce the flow rate, which in turn can allow lower output pumps.

Buckling resistance: The 4¼-in. SDP tube additional stiffness results in a 65% improvement in maximum WOB before lockup when slide-drilling in the 8¾-in. vertical section and a 15% improvement in maximum WOB before helical buckling while rotary-drilling in the 6-in. lateral compared to the standard 4-in. 14-lb/ft drillpipe.

Tube wear reduction: One of the concerns in certain Bakken horizons is pipe body wear, so one of the design goals of the SDP was to reduce tube body wear.

Tube-to-wellbore contact was about 100 lb/sq ft lower with 4¼-in. drillpipe, which amounts to a 40% reduction in side forces.

CASE HISTORY 1: PEREGRINE FIELD TRIAL, SDP APPLICATION IN THE CLEVELAND SAND	
Location: Western Oklahoma Well Profile: Horizontal with 1,372-m to 1,524-m (4,500-ft to 5,000-ft) lateral leg and drilled to TD at +/-4,267 m (+/-14,000 ft) MD	Customer concerns: • Improve hydraulics and hole cleaning in the lateral Achievements: • Drilled intermediate and lateral sections with 4¼-in. SDP • 6% less SPP at the end of the 8¾-in. hole section with SDP • 24% less in SPP in the 6⅛-in. lateral • Hole cleaning improved • 6⅛-in. lateral drilled with 5,000 lb less WOB for similar ROPs • SDP used to drill any wellbore profile and lithology

Table 1. The larger ID of the drillpipe allowed the intermediate section to be drilled at the desired flow rate with an average SPP reduction of 6%. (Source: Vallourec Drilling Products)

CASE HISTORY 2: SDP APPLICATION IN THE BAKKEN SHALE	
Location: Williston Basin, North Dakota Well Profile: Horizontal with 3,048-m (10,000-ft) lateral leg and drilled to TD at +/-6,584 m (+/-21,600 ft) MD	Customer concerns: • Improve drilling time in the lateral leg • Improve hydraulics in the horizontal section • Reduce repair and maintenance costs Achievements: • Improved drilling efficiency • 16% time savings to drill the lateral compared to the baseline • 15% improvement in ROPs • 16% less WOB, yielding a 13% improvement in ROPs • Improved hydraulics in lateral leg • $230,000 saved on four-well pad due to time savings

Table 2. Case History 2 provides a summary of the benefits that this new pipe has provided to a Bakken operator. (Source: Vallourec Drilling Products)

Peregrine Field trial

For one operator in western Oklahoma the SDP was seen as a solution for overcoming some operational standpipe pressure (SPP) restrictions on the drilling rig. Many wells have been drilled in this area, so these wells provided an excellent opportunity to test the new 4¼-in. drillpipe in a known environment with established metrics to judge well-to-well performance improvements. These wells were drilled with the same mud systems, had similar well profiles and total depth (TD), and targeted the same reservoir.

Three wells were chosen as a baseline for use of standard 4-in. drillpipe, from which Vallourec compared the results of five wells where the operator used the 4¼-in. SDP. When nearing TD in each of these sections, the SPP would frequently approach the limits of the rig's capabilities, particularly in the lateral. These instances required the flow rate to be decreased, which compromised hole cleaning and ROP.

All five horizontal wells were drilled to TDs of +/-4,389 m (+/-14,400 ft) measured depth (MD) and +/-2,798-m (+/-9,180-ft) true vertical depth with +/-1,372-m (+/-4,500-ft) lateral leg. The larger ID of the drillpipe allowed the intermediate section to be drilled at the desired flow rate of 550 gal/min with an average SPP reduction of 6%. In the lateral section, the pump rate was decreased by 12% while still obtaining the desired annular velocities to sufficiently clean the hole due to the increased OD of the SDP. This resulted in a 24% reduction in SPP at the end of the lateral.

In addition to the Peregrine Field trial, another operator in the Bakken Shale has just successfully finished using the SDP on a four-well pad. Case History 2 provides a summary of the benefits that this new offer has provided to this operator. It is important to note that in the second case history the SDP was compared to an already optimized 4-in. drillpipe, and even higher levels of improvements would have been seen if it was compared against standard 4-in. drillpipe. E&P

Wired drillpipe provides repeatability, operational efficiencies

The ability to transmit data from downhole at a rate of 57,600 bps to the surface could radically change the way the industry drills wells.

Brian Van Burkleo and **Robert Foster**, NOV IntelliServ

Drilling engineers are seeking repeatability and greater operational efficiencies. But geology and narrow pressure windows, among other factors, get in the way of that in many cases.

Enhanced real-time data through high-speed wired drillpipe (WDP) telemetry enables drilling engineers to make more data-driven decisions with clarity and confidence of downhole conditions. If an operator wants repeatability, that's where it begins. WDP gives that operator a toolset that makes it readily achievable.

For operators in the oil industry now is the time to develop a competitive advantage. WDP is a key to that competitive edge. It opens doors, expands possibilities and creates opportunities for greater efficiency and reduced nonproductive time across a wide range of operations.

Multifunctional tool

Operators that are using the technology today see WDP as a multifunctional tool. It cannot only be used as a single string to perform the normal functions of drilling and completing a well but also provides the ability to transmit data through the drillstring at very high speeds—57,000 bits per second (bps)—between downhole tools and the surface.

Drilling repeatability comes more readily with solid data with which to make operational, strategic and tactical alterations while drilling. Improving the timeliness of the availability of data to make those decisions is paramount to making sound engineering decisions while drilling.

The ability to transmit data from downhole at a rate of 57,600 bps to the surface radically changes the way the industry drills by taking a data-driven approach to drilling optimization.

The basis for this technology is conventional double-shouldered drillpipe with inductive coils placed in the secondary shoulders of the box and pin (Figure 1), which are connected via armored coaxial cable that is embedded in the tool joint. It is this inductive coil that allows data transmission to pass from one joint of WDP to the next.

WDP is used just like conventional drillpipe. Here are some questions that often are asked along with responses to those questions:

- *Do wires have to be lined up during makeup?* No, that is the purpose of the inductive coil. It is called the IntelliCoil, and it is made up like normal drillpipe.
- *Does WDP require special doping methods?* No, operators can use the same doping methods that have always been used.
- *Can cementing be done through WDP?* Yes, operations such as cementing and dropping balls, pills and darts can be done just like normal drillpipe.

High-speed communications

WDP has been used and continues to be used by operators around the world to drill wells faster and drive down well construction costs. This is achieved first by high-speed com-

FIGURE 1. Conventional double-shouldered drillpipe with inductive coils placed in the secondary shoulders of the box and pin allows data transmission to pass from one joint of WDP to the next. (Source: NOV IntelliServe)

Global NATURAL GAS Service

Anticipate Market Changes of a Cleaner Energy Source

It's essential for your long-term planning and your company's success to know how the **natural gas market** will evolve. Stratas Advisors' **Global Natural Gas Service** offers an integrated perspective on current and future growth and shifts in gas demand, as well as international supply and trade flows for the next 15 years.

This service has the answers you are looking for, including projections for:

- *Conventional and unconventional production through 2030*
- *Growth and shifts in global gas demand across key consumption sectors*
- *Forecasts on a global, regional, and key country level*
- *Ongoing analytical insight and content responding to key trends*
- *Pipelines and LNG flows between regions and key markets*
- *Short-term and long-term pricing forecasts*

STRATAS ADVISORS
A HART ENERGY COMPANY

To learn more, visit:

GlobalNaturalGasService.com

*Or email **GlobalNatGas@stratasadvisors.com** to schedule a demo of this service.*

How We're Different

High-level data and projections are drawn from Stratas Advisors' five research practices. We leverage our proprietary projections for energy demand, LNG flows, pipeline use, pricing integrated with macro-level outlooks, and industry-focused analysis into a single platform. Additionally, you have access to interactive tools for custom charting, data tools as well as access to our experts. This service enables informed strategic thinking for you and your team.

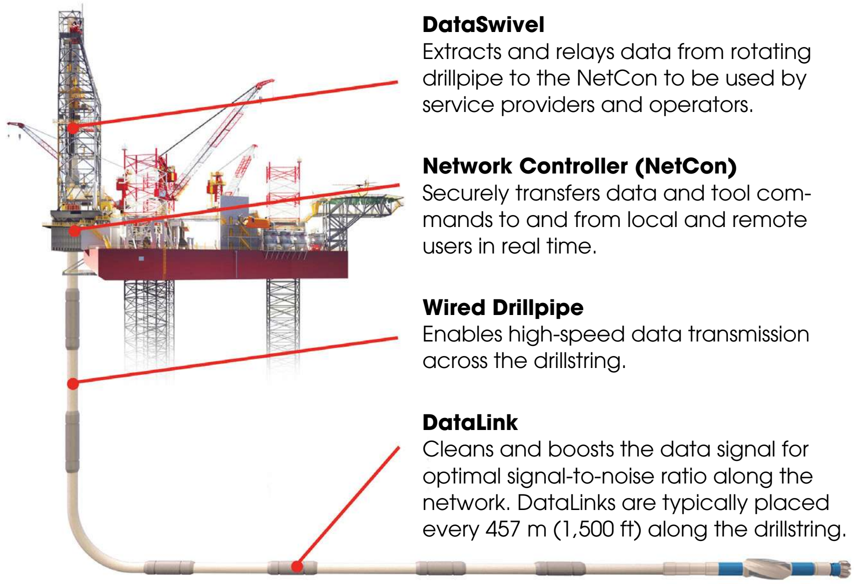


FIGURE 2. The main components of the IntelliServ Network provide the ability to transmit data through the drillstring at very high speeds (57,000 bps) between downhole tools and the surface. (Source: NOV IntelliServe)

munication with MWD/LWD tools and rotary steerable systems, basically eliminating the time it takes to communicate with these tools. It's about transmitting the same data using conventional telemetry methods, simply faster. The instantaneous telemetry with WDP significantly reduces survey, downlinking and slide times, shaving off minutes for each of these activities and eliminating up to one to two days of "invisible lost time" per well in most cases.

Network increases reliability, performance

In late 2014 the IntelliServ2 Network was launched to further increase reliability and performance. The engineering team looked at each component of the system and effectively did a ground-up redesign with an eye toward increased reliability and performance and lower cost of ownership for the end user. The network is now available to operators worldwide (Figure 2).

Several changes were made to the IntelliServ2 Network to improve reliability and performance:

- The Network Controller (NetCon) was condensed into a smaller stainless steel case. The entire software interface was rewritten with simplicity of use as a primary directive, using a simple top-down semaphore approach with an easy-to-use touchscreen;
- Enhanced DataCable now encapsulated in Inconel armoring material provides increased resistance to corrosion and damage;
- The DataLink was completely redesigned, increasing network performance and reliability; and
- The inductive coil was improved by embedding it in a more durable material and recessing it slightly on the pin end, which affords the coil some natural protection. The coils field also was made replaceable and reusable, reducing overall maintenance costs by 80%.

Case study

A U.S. land operator on the Bakken recently used the IntelliServ2 Network on a 16-well project. Through WDP telemetry, downhole data drove the rig surface equipment to safely increase drilling performance.

In this case the operator drilled 16 wells on four different pads. It drilled 8¾-in. vertical curves between 762 m and 3,537 m (2,500 ft and 11,600 ft) measured depth and drilled 43,586 m (143,000-plus ft) with wired pipe. Major highlights were the 99.6% uptime of the IntelliServ2 network over 1,451 possible data hours, proving the effectiveness of the changes made from the previous generation system.

The operator drilled 13 of 16 wells in the top quartile for the area on a rig that had not drilled a top quartile well in three years. The client saw a 25% average reduction in total drilling time on wells with automation services, with a 31% reduction for the vertical sections. Mileage might vary, but this is typical.

Something else that was learned is that a real-time view sheds light on downhole events, which in turn changes human behavior and the ensuing dialog. The use of drillcollars in conjunction with SoftSpeed and real-time data provided by WDP reduces stick/slip in the vertical. TrueDrill shows potential to improve ROP by using downhole weight on bit as set point and rpm outside normal limits to produce a stable environment.

The performance, reliability, system stability and reduced drilling times are typical, although there have been even higher performance in some instances using IntelliServ2 WDP. E&P


We
make
the step from innovation
to cost optimization
possible
By co-designing the pipe solutions from the start of a major offshore oil development project in Ghana, Vallourec demonstrates its ability to anticipate its clients' requirements and constraints. The Group not only supplies non-standard pipe dimensions to optimize pipe-in-pipe design, it also leads complex operations such as coating, double-jointing and logistics. Thanks to its unique and efficient project management approach, Vallourec ensures smooth execution, risk mitigation, and lower cost of ownership. Vallourec contributes to making all your projects possible, wherever you need us, whenever you need smart tubular solutions. **vallourec.com**
vallourec
SMART TUBULAR SOLUTIONS
HAVAS PARIS Vallourec – French limited liability company with a share capital of €271,376,864 – 27, avenue du Général Leclerc 92100 Boulogne-Billancourt (France) – RCS Nanterre 552 142 200. © Narmada Gharat/Dreamstime.com.

Jet pump deployment lifts well to new operating heights

Unique pairing of a hydraulic jet pump and an automatic downhole master valve provided a safe and economic solution for an offshore Alaska well.

Toby Pugh and **Osman Nunez**, Weatherford

Operators tapping into the sizeable oil and gas resources in the U.S. Arctic—up to 23 Bbbl of recoverable oil and 3 Tcm (108 Tcf) of natural gas by some estimates—have to navigate a complex set of challenges. These include intrinsically high E&P costs related to the remoteness of the region, extremely low-temperature operating conditions, and stringent well containment and emergency response requirements mandated by government regulatory bodies.

This was the environment an operator faced in 2010 when attempting to complete an offshore Alaska well with an artificial lift option that would boost declining production rates and also restore production to some wells that were closed due to completion problems. The operator considered a number of artificial lift solutions but had to carefully weigh their suitability against factors such as the production potential of the well and anticipated installation and operating costs.

Exploring alternatives

Sucker-rod pumping, the most widely used artificial lift method in onshore operations, offers low upfront installation costs and a wealth of well-established operational knowledge. In this offshore Alaskan well, however, rod pumping would have been difficult to execute given the small deck space available on the platform. The risks of frequent and costly workovers to replace worn-out rods also proved too great.

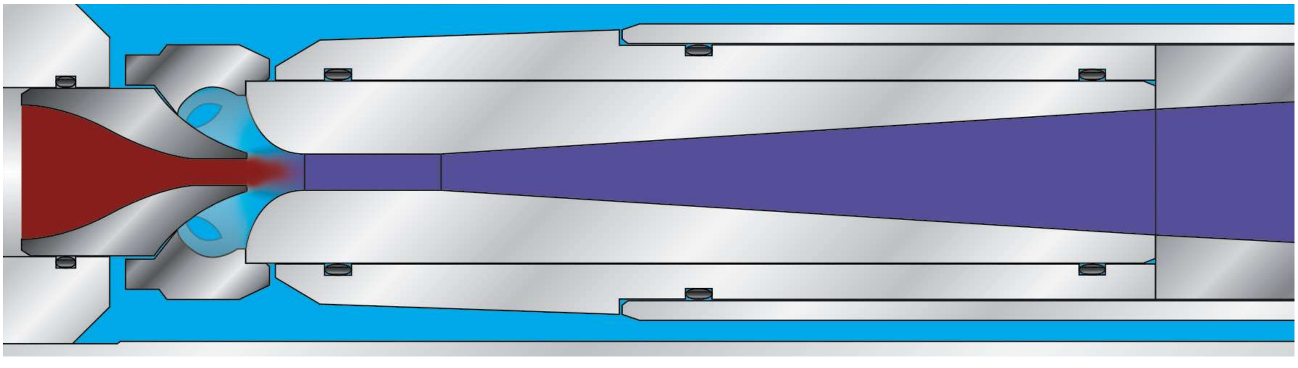
The operator considered gas lift, but the lack of adequate and long-term volumes of gas supplied from the well would have made this a relatively short-lived solution. Gas lift also requires large and cost-intensive gas compressors at the surface that take up considerable space on the platform and add to maintenance costs.

Electric submersible pumps (ESPs) represented another option. While ESPs have been successfully deployed in offshore wells throughout the world, their low tolerance for sand and need for workovers to make repairs made them a prohibitively expensive option in this particular application.

The optimal lift solution for this well, and one that the operator had successfully used in the past, came in the form of hydraulic jet pumping.

Jet pumping basics

In a jet pump lifting system, a power fluid—typically oil or water produced from the reservoir—is pressurized and pumped down the well via a surface pump. The power fluid travels through the downhole jet pump, which is equipped with a nozzle, throat and diffuser. Power fluid flows through this nozzle to create a



In a jet pump, the pressurized power fluid (red) flows through the nozzle to mix with reservoir hydrocarbons (light blue) in the mixing tube before the comingled fluids (dark blue) are transferred to the pump diffuser. (Source: Weatherford)

low-pressure jet core at the end of the nozzle. The low pressure draws reservoir fluid into the pump intake, and the jet core drags reservoir fluids into the throat or “mixing tube,” where the two streams of fluid combine and momentum transfer takes place. The mixed homogenous flow then transfers to the pump diffuser, where static pressure is increased to raise the combined fluids to the surface.

With no moving parts and a compact, durable design, jet pumps have a reputation for reliability and long runlives. Pumps are deployed without a rig simply by using pressurized fluid to set the pump downhole. Redirecting the flow of the power fluid brings the jet pump back up the wellbore for easy retrieval. Recovery of a gas-lift system or ESP typically requires a workover rig.

A common drawback cited with jet pumps is their relative energy inefficiency. It is true that jet pumps commonly run at 20% to 30% efficiency—which means that only 20% to 30% of the total power supplied goes to lifting fluids out of the well—vs. other forms of lift that operate at 30% to 50% energy efficiency. But its other operational benefits, like low installation costs, ease of retrieval and repair, high reliability, low downtime, and tolerance to sand and gas production, combine to make jet pumps a dependable and economical solution for offshore wells. These benefits also enable hydraulic jet pumps to work where other artificial lift systems cannot.

Developing the solution

Weatherford worked with the operator to arrive at the optimal jet pump size for the well, which was producing 36°API oil and operating at a water cut of 88%. The prejob planning process involved building inflow performance relationships (IPRs), plots of liquid production rate inflow against flowing bottomhole pressure, to get a sense of the well’s deliverability.

In this case the operator was able to supply the data to build out an accurate IPR for the well. However, this is not always the case. Incomplete, inaccurate or old datasets are common, which results in problems such as oversizing and prematurely having to replace a downhole motor or even the entire pump. Incomplete or inaccurate IPRs do not significantly slow down the deployment of jet pumps.

When an IPR is not available, Weatherford engineers elaborate a technical analysis based on statistics or data from nearby wells. Later, hydraulic lift technicians install the jet pump, run it for a few days and closely monitor injection pressures and production rates at the surface. If these data indicate that the jet pump is improperly sized, the pump is retrieved from the well and resized to match the precise well conditions.

Even with a properly sized jet pump, the operator was still concerned that this option would exceed its operating budget. Weatherford reviewed the architecture for the subsurface assembly and suggested a design change that would allow the operator to use the jet pump without going over budget. The solution centered on finding a replacement for the well’s subsurface safety valve (SSSV), which is the safety device installed below the jet pump bottomhole assembly to provide emergency shutdown of the well in case of overpressure and to avoid the uncontrolled release of reservoir fluids.

The new design would use the hydraulic jet pump in combination with an automatic downhole master valve (DHMV) to achieve wellbore isolation. The DHMV is less expensive than an SSSV and is designed to hold pressure in both directions. The valve closes when hydrostatic pressure exceeds a preset value and opens when hydrostatic pressure is reduced.

The operator received approval to make this valve change from federal regulators in the Bureau of Safety and Environmental Enforcement. The approved DHMV and jet pump were installed as part of a straddle packer assembly. The lower packer assembly containing the DHMV was deployed downhole and set first. The upper assembly with the jet pump assembly was then run downhole, with the upper packer stabbed into the lower assembly and set. The pump was installed at a seating depth of 2,545 m (8,350 ft) true vertical depth.

This installation option saved the time and cost associated with having to pull the tubing to install a valve and lifting method. Most SSSVs installed as part of the completion design are classified as tubing retrievable; should the valve malfunction, a workover is required to retrieve it. With DHMVs the tubing remains in the hole during installation, and the valve is retrieved via wireline instead of a workover.

Produced water was used as the power fluid, pumped at a rate of about 2,700 bbl/d and an injection pressure of 3,500 psig. The jet pump operated without incident from day one and required about 190 hp to operate. The producing pressure at pump intake was 700 psig, which provided a jet pump production rate of about 700 bbl/d of fluid.

The jet pump has been operating continuously and without incident for more than five years, resulting in a cumulative production of more than 1 MMbbl. E&P

ESP system engineered for extended runlife in challenging fields

Collaboration leads to improved ESP systems for the Forties Field.

Mike Munro, Apache Corp.; and **Aziz Romany** and **Gian-Marcio Gey**, Schlumberger

The electric submersible pump (ESP), a tried-and-true workhorse of artificial lift systems, has a long track record for improving production and recovery rates in oil fields worldwide. As the industry has moved into more challenging frontiers and pushed to boost production from brownfields, ESP technology has evolved with the development of increasingly robust mixed-flow systems that can handle varied flow rates and provide expanded operating ranges for a wide variety of hydrocarbon environments.

The decline of "easy" oil, however, has raised the bar even higher for artificial lift, including ESP performance. Many production companies are finding that the typical two-year runlife for ESPs is a limitation, especially in complex, often harsh offshore dry-tree and subsea environments and remote locations where intervention costs are high and lead to poor field economics. In these intervention-constrained markets, the expense of ESP replacement, including workover costs and deferred production, can be at least five times greater than the price of the ESP itself, costing up to tens of millions of dollars.

The risks of early ESP failure and inconsistent performance in high intervention-cost environments in challenging fields are the reasons many producers often choose alternative mechanisms such as gas lift for artificially lifting their wells that typically do not deliver the highest recovery rates. That conundrum has led operators to put the need for a consistently reliable, longer lasting ESP system at the top of their wish lists as they strive to maximize efficiency and reduce their total cost of ownership.

In response to that call Schlumberger developed the MaxFORTE high-reliability ESP system that extends the runlife over conventional ESPs, integrating best-in-class existing technologies to deliver lift assurance with quality and reliability built into every step of the process. Officially launched in December 2015, the system was deployed by Apache Corp. on four wells in the North Sea, where it already is delivering greater efficiencies.

Schlumberger experts discuss how to design and tailor a MaxFORTE system for the well's unique conditions to optimize well performance, increase runlife and maximize ROI. (Source: Schlumberger)

Designed for intervention-constrained offshore wells and difficult-to-access land wells, the high-reliability ESP system was developed with a holistic approach, integrating proven technologies that have been improved for greater performance. Each step of the process, from engineering design to manufacturing, field operation, installation and ongoing surveillance, was enhanced to meet the objectives of higher reliability and longer runlife.

Improved design, rigorous testing

The new system marks the culmination of an evolution that Schlumberger embarked on in 2008 to meet production demands in Brazil's deepwater presalt Jubarte Field. The desire to replicate that early presalt success, taking all that was good about the project to industrialize the process so that it could be applied anywhere, led to this advance in artificial lift technology that encompasses strict design, strong quality control manufacturing, flawless installation and full-time surveillance. The end result is a system that is expected to double average ESP runlife, eliminate unplanned workovers due to early failures, reduce nonproductive time (NPT) and optimize uptime with enhanced monitoring.

By coupling together the best technologies from the conventional ESP system with select technology from the subsea high-reliability ESP systems developed for the Jubarte Field and high-temperature systems used at 250 C (482 F), Schlumberger engineered a production system to significantly extend runlives in the offshore market.

Apache's primary objectives were to achieve a longer ESP runlife and reduce early pump failures, thereby decreasing the need for intervention, including rig time and NPT. With less deferred oil production and the potential to eliminate 14 to 21 days per well of future workover rig time, the company would be better positioned to boost overall production efficiency. The initial goal to achieve 2½ years runlife through incremental improvements was broadened with Apache's selection of the high-reliability ESP system to deliver the significant step change of a four-year runlife.

The collaborative effort between Apache and Schlumberger included examining ESP failure modes from January 2009 to January 2014 to address those issues in engineering the new high-reliability ESP system. Analysis of those failures determined they occurred due to many factors, including rotor-bearing wear, motor failure, electrical winding, damaged O-ring, aging and cable failure. The engineering team targeted not only primary failure modes but also looked at other components that were starting to wear. The new high-reliability ESP system was designed to address those issues through engineering and manufacturing improvement.

The first deployment of the high-reliability ESP system commenced in April 2015 on an Apache platform in the long-producing Forties Field in the U.K. sector of the North Sea. At the time, Apache was running 57 ESP completions out of 110 active Forties Field wells, with 40% of the operator's North Sea production coming from ESP-lifted wells. The company's strong usage of ESP for artificial lift made it an ideal candidate for installing several new ESP production systems, with the initial installation of four units.

Leveraging breakthroughs in technology developed for hostile environments, the high-reliability ESP system features robust components designed to resist abrasion, corrosion and temperature. Components are manufactured and tested in a dedicated environment using advanced processes and machinery. Equipment is assembled using a protocol that is fully traceable and audited to arrive free of defects to the well site. In a rigorous testing process, the system is subjected to frequency and operation range sweeps to mimic varying pumping regimes, with numerous starts and stops to stress bearings, shafts and compensation systems, ensuring the equipment can reliably withstand continuous field restarts and intermittent operation.

MaxFORTE systems are assembled using a protocol that is fully traceable and audited to arrive free of defects to the well site. (Source: Schlumberger)

Increased efficiencies

For the North Sea operation, four MaxFORTE ESP systems were shipped directly from the manufacturing center to the well site in specially designed bend-proof shipping boxes that reduce vibration levels by more than 50%. Installation was conducted by a dedicated field crew using detailed checklists and procedures. An enhanced specification spooling machine continually monitored the electrical integrity of the ESP system while running in hole. All four installations were carried out with no recorded NPT.

Since installation in the well, the system has been monitored 24/7 by dedicated surveillance engineers focusing on early critical event notification and intervention from a Schlumberger remote surveillance center to ensure continual optimum production rates and prevent failures. A customized alarm system prevents the system from operating beyond the engineering limits of the equipment within the well application.

Following the first installation in April 2015, three subsequent units were installed. As of April 1, 2016, the four systems have achieved a cumulative run time of more than 1,000 days.

Early observations and surveillance indicate the ESP systems already are achieving improved performance and efficiency by addressing most of the anticipated failure modes. Between April and November 2015, Apache saw a 3% increase in average runlife uptime, from 94% to 97%. All four systems have resulted in no NPT. E&P

Subsea tree players awaiting green shoots of recovery

The subsea tree market has tanked, but the technology remains viable and vital in the long term.

Mark Thomas, Editor-in-Chief

When a market has plunged 79% from where it was just three years ago, the first thing to get cut almost immediately is company headcounts followed by brutal contract negotiations. Industry collaborations are launched to share the R&D load, and standardization initiatives are undertaken in a bid to cut out the deep-rooted cancer that is soaring cost.

The above actions have all been in full effect since the subsea trees market collapsed after the stellar years of 2012-13 that saw nearly 1,000 trees awarded over that period, according to FMC Technologies in one of its latest presentations.

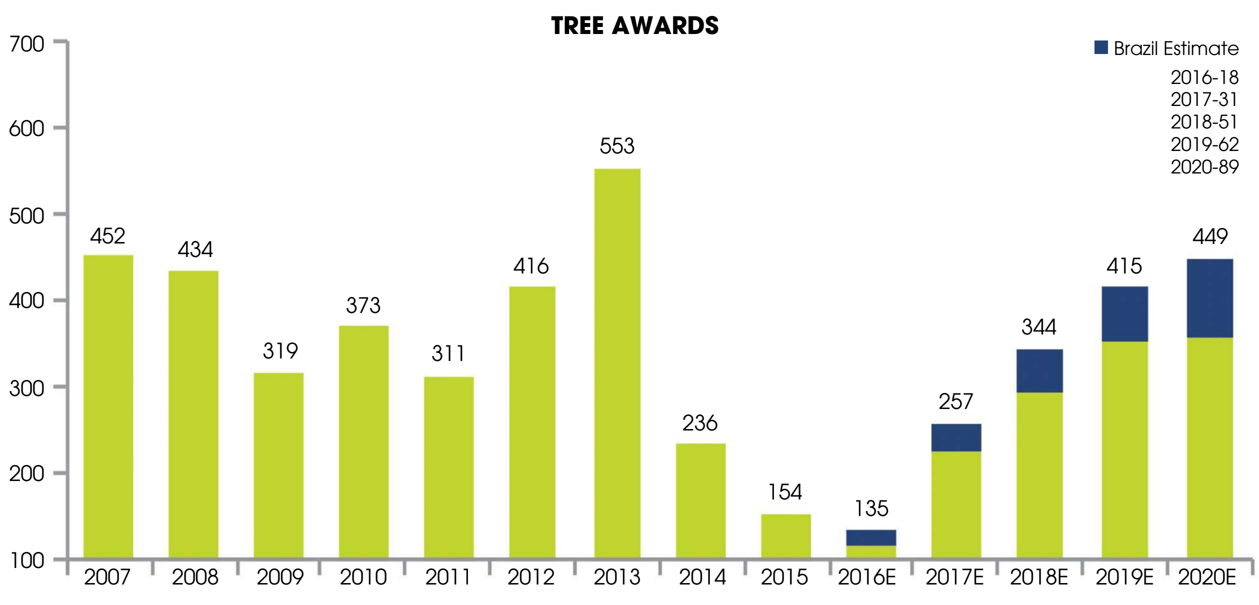
That spectacular demise was highlighted by Cowen and Co. in its latest analysis of the sector, with a forecast decline of 26% in tree awards in 2016 from the already depressed prior year. "In 2016, total tree awards are expected to be 113, down 26% from 153 in 2015," the company stated in an industry overview released in late March. "This implies total awards will be down 79% from the cyclical high of 551 in 2013."

Battle for larger prizes

The larger tree award projects (valued at more than $150 million) are set to prove a cutthroat battleground for FMC and its rivals OneSubsea, GE Oil & Gas, Aker Solutions and Dril-Quip over the course of the next two years (2016-17).

These are expected to include:

- Eni's Coral project offshore east Africa's Mozambique in the Rovuma Basin, where plans include six subsea wells and a floating LNG facility followed later by its larger Mamba project (up to 21 trees);
- Shell's 100,000 boe/d Vito floating production project in the Gulf of Mexico's (GoM's) Mississippi Canyon area (up to 14 trees);



After 2013's peak in subsea tree awards, the estimate for 2016 is just under a quarter of that figure. (Source: Quest Offshore Resources)

- BP's Mad Dog Phase 2 in the GoM (up to 22 trees);
- Exxon Mobil's Hebron project offshore Newfoundland and Labrador in the Jeanne d'Arc Basin, being developed via a standalone concrete gravity-based structure but including the Hebron Pool 3 Phase 1 subsea tieback project;
- Eni's Zohr Phase 1 early development offshore Egypt, requiring five trees and expected to be followed by its Shorouk project off Egypt (up to 24 trees);
- Hess Corp.'s Equus project offshore Australia (up to 18 trees);
- Tullow Oil's Greater Jubilee project offshore Ghana (up to six trees);
- Shell's Bonga South West offshore Nigeria (up to 48 trees); and
- Statoil's Johan Castberg offshore Norway (up to 31 trees).

These and other similar sizeable projects needing at least an estimated five subsea trees are expected to account for 56 of this year's subsea awards, according to Cowen and Co., but again that figure for this year is down from 112 trees in 2015.

Cowen and Co. said in its analysis that while 2017 is expected to show a 55% improvement to 175 subsea trees, "We note that visibility is limited and low commodity prices may result in further project deferrals or cancellations."

Automated subsea future

Despite the shorter-term lack of visibility, classification society DNV GL said subsea is seen as a key technology for the upstream sector, particularly due to the E&P industry's increasingly automated and digital future progression.

According to its new Technology Outlook report, the society indicated that the industry should expect particular evolutions in subsea production system technology by 2025, especially around smarter subsea tie-ins as well as fully automated drilling operations, simpler and smarter completions, and the autonomous inspection of pipelines.

Referring to the industry's actions so far on costs, firstly by cutting its headcount and renegotiating contracts and secondly by more collaboration and standardization, Bjørn Søgård, segment director for subsea and floaters at DNV GL, said during a talk in Oslo, "We are now about to enter a third stage characterized by a willingness to open up for radical new ideas that can reshape industry processes. We believe that in the longer horizon, offshore production and processing systems are going down to the seabed as a cost-effective and safe alternative for platforms and floaters.

"Subsea systems have traditionally been quite simple from a control and monitoring perspective. This simplicity has enabled subsea systems to deliver reliable production from 5,000 wells around the globe."

Søgård continued, "Currently, subsea system integrity and main flow parameters are monitored from remote control rooms 24/7, but according to the DNV GL report, by 2025 subsea solutions are expected to rely actively on monitoring and data analytics. Digitalization will be a game changer also for subsea by 2025, helping the industry to achieve optimum flow conditions for stable production."

Qualification drive

Referring to Norway, where the Norwegian Petroleum Directorate believes that subsea tiebacks represent the most relevant solution for 68 out of 88 currently undeveloped discoveries on the continental shelf, DNV said in a separate initiative that new subsea technologies and systems should be qualified before use to build confidence that they will function as intended. It is calling for a standardized system qualification approach, with joint industry effort to drive faster take-up of new subsea technology and value creation.

The classification specialist is proposing a three-step industry effort to enable more effective technology development and implementation in the field:

- Establish common industry principles and consolidate a common framework for system qualification founded on existing industry procedures;
- Develop a methodology to standardize system qualification for common use across the upstream oil and gas industry; and
- Pilot and demonstrate the developed methodology and roll out a recommended practice.

"The subsea industry needs to overcome key challenges such as cost reductions, enabling increased recovery and complex field developments. At the same time, the future trend still points toward more complex systems, which require integrating process, power and control systems subsea," said DNV GL's Tore Myhrvold.

"Developing a standardized approach to subsea technology qualification will enable companies to leverage on each other's qualification efforts and results, reduce the overall development time and ultimately enable faster innovation in the subsea sector," he added.

Previous experience has shown that focus on qualification in the early phases of development reduces risk of failures in later phases of testing, avoiding potentially expensive fixes. E&P

DEVELOPING UNCONVENTIONALS

DUG EAST

David L. Lawrence Convention Center
June 21-23, 2016
Pittsburgh, PA

PLAYS COVERED: Marcellus Utica

World-Class Gas

With some **1,200 Tcf of recoverable resources**, the world's largest natural gas play spanning the Marcellus and Utica shales, accounts for **25% of Lower 48 gas production in the U.S.** The region's biggest midstream operators are **bulking up to export gas out of the region**. Yet even the prolific 'Beast in the East' isn't immune to the downturn in commodity prices. With rig counts slashed in half, Appalachia's producers are taking drastic measures to **cut costs and lower breakevens**.

Find out **what's working,** what's not and **what's next** for producers and midstream operators in the East. Plan now to join **2,500 industry professionals**, **20+ executive-level speakers** and **250+ exhibiting companies** in Pittsburgh for an in-depth look at the state of the region.

NEW FOR 2016!

Technology Showcase

Efficiency-focused technologies and strategies have become the lifeblood of the industry. Producers and service providers continue to defy the world's expectations by finding innovative ways to produce more for less. With its **all-new Technology Showcase**, **DUG *East*** brings the latest solutions **to the exhibit floor** with live case studies and demonstrations.

Presented by:

HARTENERGY

Hosted by:

Oil and Gas Investor | E&P | UNCONVENTIONAL OIL & GAS CENTER | MIDSTREAM Business

AFTERNOON KEYNOTE

Ray N. Walker, Jr.,
Executive Vice President, Chief Operating Officer,
Range Resources Corporation

With a premier position overlying huge resources in the Marcellus, Utica and Pt. Pleasant, Range Resources has boosted results by lowering costs, extending lateral lengths and increasing EURs. In the past three years its reserves- replacement record averaged over 600%. Beyond outstanding field operations, Range is well-hedged through 2016, and is the first Northeast producer to export ethane to Europe, opening a new market for prolific NGL production.

Featured Speakers:

Tim Dugan
Chief Operating Officer
CONSOL Energy Inc.

D. Randall Wright
P.E., President
Wright & Company, Inc.

Bernadette Johnson
Managing Partner
Ponderosa Advisors LLC

Tom Petrie
Chairman
Petrie Partners LLC

Oleg E. Tolmachev
Senior VP Drilling & Completions
Eclipse Resources Corp.

Callum Streeter
Chief Operating Officer
EdgeMarc Energy Holdings, LLC

Mark Rothenberg
CEO
APEX Energy, LLC

Craig Harris
Senior Vice President
Columbia Midstream Group

Greg Haas
Director, Integrated Oil & Gas
Stratas Advisors

Tony Angelle
Vice President Northeast Area,
Southern Region
Halliburton

Operators Enter For Free!

*see website for details

Hart Energy invites all employees of **E&P companies, pipeline operators, refineries** and **utility companies** to enter the exhibition hall at **DUG *East*** at no cost. Plus, you have the option to upgrade to a full conference pass for only $795. To submit your qualifying application and register, visit HartEnergyConferences.com/operatorpass.

**Completing the application does not guarantee your registration. This pass is valid for new registrations only, is notretroactive and cannot be applied for refunds.*

Sponsored by:

MAGNUM OIL TOOLS INTERNATIONAL

To ATTEND, SPONSOR or EXHIBIT, visit DUGEast.com

2016 MERITORIOUS AWARDS FOR ENGINEERING INNOVATION

An expert panel of judges has selected the top 18 industry projects that open new and better avenues to the complicated process of finding and producing hydrocarbons around the world.

The *E&P* editors and staff proudly present the winners of the 2016 Special Meritorious Awards for Engineering Innovation, which recognize service and operating companies for excellence and achievement in every segment of the upstream petroleum industry. The pages that follow spotlight the 18 winners the independent team of judges picked that represent a broad range of disciplines and address a number of problems that pose roadblocks to efficient operations. Winners of each category are products that provided significant changes in their sectors and represented techniques and technologies that are most likely to improve exploration, formation evaluation, drilling, production, completions, onshore rigs, intelligent systems, remediation, water management, subsea systems, floating systems, marine construction and HSE efficiency and profitability.

This year some of the brightest minds in the industry from service and operating companies entered exceptionally innovative products and technologies that have now been measured against the world's best to be distinguished as the most ground-breaking in concept, design and application.

The award program recognizes new products and technologies designed by people and companies who understand the need for newer, better and constantly changing technological innovation to appease the energy-hungry world.

The winners were selected by an expert panel of judges comprising geologists, geophysicists, petrophysicists and engineers from operating and consulting companies worldwide. Each judge was assigned a category that best called on his or her area of expertise. Judges whose companies have a business interest were excluded from participation. The products chosen by the judges represented the best of a long list of winners.

E&P would like to thank these distinguished judges for their efforts in selecting the winners in this year's annual awards competition.

As in past years, *E&P* will present the 2016 awards at the Offshore Technology Conference in Houston.

An entry form for the 2017 Special Meritorious Awards for Engineering Innovation contest is available at *EPmag.com*. The deadline for entries is Jan. 31, 2017.

2016 MEA JUDGES

Ken Arnold *K Arnold Consulting*	**Allen Bertagne** *Consultant*	**Ben Bloys** *Chevron*	**Mike Forrest** *Consultant*
Dick Ghiselin *Qittitut Consulting*	**George King** *Apache*	**Vianney Koelman** *Shell*	**Carl Montgomery** *NSI Technologies*
Nelson Oliveros *Petrofac*	**Michael Payne** *BP*	**Bill Pike** *NETL*	**Lanny Schoeling** *Kinder Morgan*
Chris Singfield *Chevron*	**Eve Sprunt** *Consultant*	**Mark Thomas** *Hart Energy*	**John Thorogood** *Drilling GC*
Scott Weeden *Hart Energy*	**Doug White** *Consultant*	**David Zornes** *Consultant*	

DRILLBITS WINNER
BAKER HUGHES | TALON FORCE PDC BIT

The Talon Force platform of polycrystalline diamond compact (PDC) bits were developed by Baker Hughes by designing the bit holistically, using bit behaviors and responses rather than just focusing on features to solve the most difficult drilling problems. Talon Force products incorporate multiple technologies to improve durability, boost ROP in challenging drilling environments, increase consistency from run to run and reduce bottomhole-assembly-damaging vibrations.

The product platform leverages cutter and frame enhancements to improve cutter abrasion and durability while enhancing lateral and torsional stability. Talon Force bits combine the latest cutter technology advances with application-specific cutting structures to maximize overall ROP and footage drilled.

Blade layout and hydraulic configurations contribute to increased lateral stability and improved drilling efficiency. Talon Force incorporates the latest advancements in synthetic cutters with the StaySharp 2.0 PDC offering, which use the latest HP/HT diamond synthesis technologies to deliver wear resistance, toughness and thermal stability.

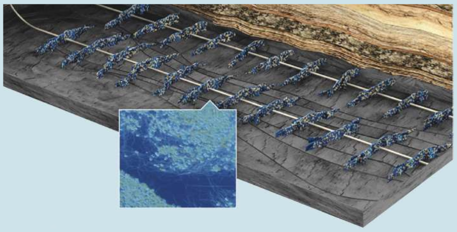
The PDC bit introduces a differentiating cutter size, the 1-in. cutter, to increase drilling speed and efficiency in applications requiring high depth of cut. Coupling the StaySharp 2.0 technology with an innovative geometry modification, Stabilis cutters improve cutter durability and reduce torsional oscillations to drill longer runs at higher overall ROP. Talon Force products with Stabilis cutters deliver more footage at higher speeds in places like the Wolfcamp, where the new bits have cut drilling time 36%, improved ROP by 25% and drilled 55% farther compared to standard PDC bits with standard chamfer cutters. ■

Talon Force bits with 1-in. Stabilis cutters have improved ROP and drilling efficiency for operators worldwide. (Source: Baker Hughes)

DRILLING FLUIDS/STIMULATION WINNER
SCHLUMBERGER | BROADBAND SERVICES' COMPOSITE FRACTURING FLUIDS

The BroadBand unconventional reservoir completion services portfolio includes composite fracturing fluids with next-generation fibers and fluid additives to transport and place proppant within complex fracture networks.

Designed to overcome the limitations of conventional hydraulic fracturing fluids by providing broader transport of proppant to maximize coverage in the fracture, the fracturing fluid mitigates settling to promote formation of high-conductivity flow channels across all fractures to their total length and height to connect far-field areas with the wellbore. These fluids are designed for both openhole and cased-hole completions, refracturing operations, shales, dirty carbonates, tight sands and coalbed methane reservoirs with bottomhole temperatures between 43 C and 149 C (100 F and 300 F).



Comprising a blend of proprietary fibers and rheology-controlled fluids, the composite fluids promote effective proppant transport and placement by forming highly conductive channels. (Source: Schlumberger)

Once the pumping operation ends, proppant is suspended in the fracture with degradable fibers that impede settling and promote heterogeneous distribution of proppant across each fracture. The composite fracturing fluids can be used with composite-based fluids including slick water, linear gel, viscoelastic gel and crosslinked gel.

With the addition of fiber technology, these fluids now can transport proppant great distances while pumping and suspend proppant during fracture closure.

Endeavor Energy Resources stimulated a well in the Permian Basin's Bone Spring Formation with the BroadBand services' composite fracturing fluid. Compared with six offset wells treated with conventional stimulation fluids and similar amounts of proppant and water, the well treated with the composite fracturing fluid delivered the best production performance. ■

DRILLING SYSTEMS WINNER
SCHLUMBERGER | ICE ULTRAHT DRILLING SERVICES

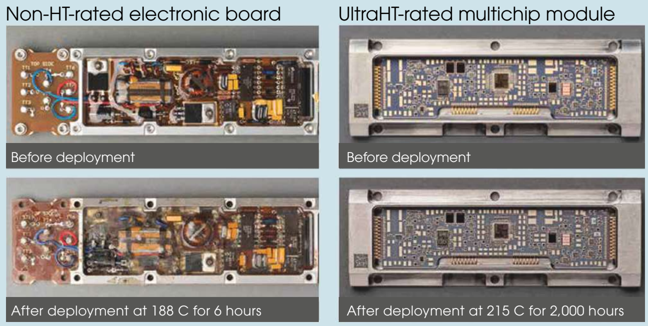
Integrated ceramic electronics are at the heart of the Schlumberger PowerDrive ICE ultraHT rotary steerable system (RSS) and TeleScope ICE ultraHT MWD service. The ICE bottomhole assembly (BHA) is rated to 200 C (392 F). These ultrahigh-temperature (UHT) drilling services have the capability to precisely place wells deemed undrillable since the wells could not be steered to total depth in UHT reservoirs.

Laterals and deep boreholes expose BHAs to UHT environments for days or even weeks. Electronic circuitry sealed in plastic or elastomeric seals can fail when exposed to high temperatures, leading to unnecessary trips.

In a complete reengineering of key components of the PowerDrive ICE RSS and TeleScope ICE MWD service, multichip electronic circuitry was embedded in a 100% ceramic substrate that was hermetically sealed in an inert gas, resulting in a new multichip module that resists both heat and shocks. Power is supplied by a power-generating turbine within the TeleScope ICE system.

ICE UHT drilling services have been field-tested worldwide in various UHT reservoirs, saving time and money and reaching planned depths with precise well placement.

One company reported a 16% improvement in ROP while drilling compared with the previous record achieved in one field. A reduction of nine operating days was reported, amounting to $1.35 million in savings. ■



The non-HT-rated electronic board (left) failed after being exposed to 188 C (370 F) for about 6 hours. The UHT-rated multichip module had full functionality after being tested to 215 C (419 F) for 2,000 hours. (Source: Schlumberger)

EXPLORATION WINNER
HALLIBURTON | THE HALLIBURTON ADVANCED PERFORATING FLOW LABORATORY

In a slumping market where prices and demand for oil and gas are declining, operators must make the best economic decisions possible for their wells. The effectiveness of perforated cased completions can depend on choosing the best gun system with the most suitable shaped charges as well as preparing the wellbore for the dynamic fluid and pressure responses that occur. The tests performed at Halliburton's Jet Research Center give customers precise answers on the exact depth of penetration into the formation in different types of rock and also what the crush zone and skin value of that perforation is expected to be. These insights help identify or develop the best perforating system for any given well condition.

Testing a specific perforating application and well pressure regimen prior to completion adds minimal cost to the overall well but allows maximized production. (Source: Halliburton)

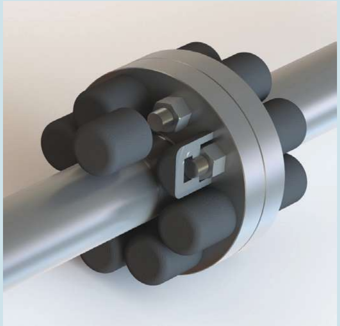
To maximize project economics, an operator approached Halliburton to determine the optimal gun system and perforating method for a challenging environment. The reservoir is a very weak shaly laminated sandstone. The timeline was short, and answers were needed quickly for determining well construction. The 12-shot Section IV test program compared the performance of three shaped charges in a gas-filled rock. Charges were shot into single- and dual-casing targets matching the projected well configurations. The study showed that the use of a typical perforating system without an intimate understanding of the reservoir and well construction wouldn't provide the performance required to optimize production. ■

FLOATING SYSTEMS AND RIGS WINNER
TRELLEBORG OFFSHORE & CONSTRUCTION | FIRESTOP

Safety on all offshore facilities is and should always be the industry's No. 1 priority, and a crucial part of that is the fire protection systems onboard those facilities. Their performance is vital to ensure the safety of personnel, protect assets and prevent events from escalating. Trelleborg Offshore & Construction's Firestop is a passive corrosion-free rubber-based solution that helps to provide time to evacuate people and close down critical equipment and for responders to gain control of the fire.

Rubber-based materials are becoming a more popular choice within the offshore industry due to their flexibility and durability, with the diverse material able to damp, seal and protect as well as having an extremely long lifetime. It can be used for fire and corrosion protection, mechanical protection, thermal insulation and antifouling. Examples of applications include for rigid and flexible riser protection, I-Tubes and deck protection. The coating can withstand blasts of up to 2.1 bars and jet/hydrocarbon fires for more than 2 hours.

On Maersk's *Ngujima-Yin* FPSO vessel on the Vincent Field offshore Western Australia, the facility's existing carbon steel seawater deluge system had corroded over the two years since its installation, requiring constant maintenance, cleaning and testing. Trelleborg was awarded a contract to supply its high-performance Elastopipe corrosion-free fire safety deluge system to replace the existing carbon steel pipework on seven of the vessel's modules while the FPSO unit remained in production. The system required 1,687 m (5,535 ft) of pipe work in diameters ranging from 25 mm (1 in.) to 200 mm (8 in.), and associated fittings and accessories. ■



Rubber-based materials such as those found in FireStop are becoming a more popular choice within the offshore industry due to their flexibility and durability. (Source: Trelleborg Offshore & Construction)

FLOATING SYSTEMS AND RIGS WINNER
ZENTECH INC. | R-550D

Built in China, Zentech's R550-D lightweight jackup drilling rig is the first of its kind. (Source: Zentech Inc.)

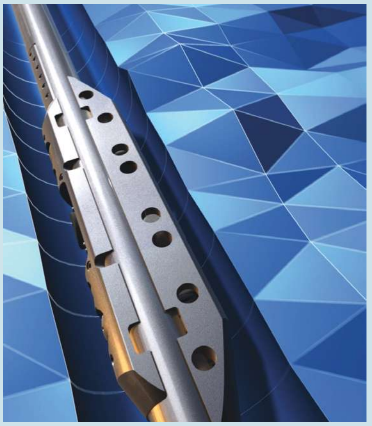
The R550-D jackup drilling rig is capable of drilling in up to 122 m (400 ft) of water and is the first of its kind. Built, tested and jacked up at the CSSC shipyard in China, the lightweight rig is able to be built at significantly lower cost than comparable units and has a high operational variable deck load (11,000 kips) that gives it excellent operational efficiency. Three categories lead to higher utilization and improved drilling efficiency for operators:

- *Safety:* Jacking with full preload can be done, greatly enhancing safety in "punch through" situations. Preload tanks can be filled in less than 7 hours and are designed to ensure an even fill. The superior movement-carrying capacity of the legs provides enhanced safety during rig moves. The patented locking device, Zenlock, also guarantees disengagement from the leg racks due to an innovative gap designed into the engaging lock that provides enhanced safety.
- *Construction cost and efficiency:* The lightweight design of the R550-D along with large deck space means more equipment on board and less boat runs, which leads to higher utilization and improved drilling efficiency.
- *Operational efficiency:* The R550-D design has the longest cantilever reach of equivalent rigs of 24 m (80 ft), allowing more wells to be drilled and a high return on investment for the operator. Its bracing-to-leg-chord design, large-diameter high-strength steel braces and optimized truss pattern for higher stiffness along with the carrying capacity allows moving the rig to location in higher sea states (3-m to 3.6-m [10-ft to 12-ft] waves in varying soil conditions). ■

FORMATION EVALUATION WINNNER

BAKER HUGHES | FTEX FORMATION PRESSURE TESTING SERVICE

The ability to evaluate formation pressures pays dividends at various stages of a field's life cycle. The field operator can use precise pressure data obtained during logging runs to determine fluid contact, fluid properties, reservoir pressures during exploration and development and, ultimately, the production potential of the reservoir. However, traditional wireline-deployed pressure testing services require significant manual operation and measurements, which are prone to longer testing times and raise the risk of inaccurate or incomplete data and inconsistent test outcomes. The Baker Hughes FTeX advanced wireline formation pressure testing service was designed to deliver reliable and accurate pressure data through a combination of downhole automation and real-time control. The service replaces human operator control from the surface with an intelligent downhole platform that reduces the possibility of human error by automating pressure measurements and significantly minimizes testing time by optimizing the operating sequence. This, in turn, minimizes the time the tool is in contact with the formation, reducing the risk of differential sticking, which can ultimately result in costly fishing operations. The data, which include pressure profiles, fluid contact and mobility information, can be obtained as early as the first logging run to significantly reduce overall logging time. This feature affords reservoir engineers and petrophysicists the opportunity to make earlier decisions about how to best proceed with their formation evaluation objectives. ■

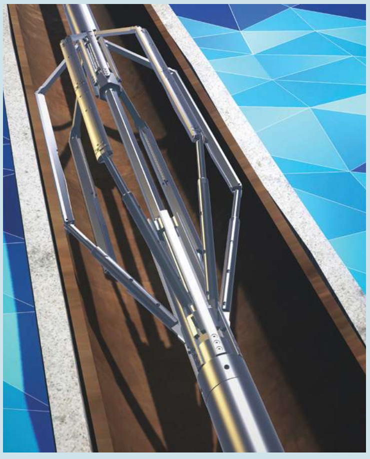


The FTeX service acquired pressure data from 51 pressure tests in an accurate and efficient manner, taking on average less than half the time that a traditional formation pressure tester would have taken per test. (Source: Baker Hughes)

FORMATION EVALUATION WINNER

BAKER HUGHES | INTEGRITY EXPLORER CEMENT EVALUATION

Wellbore integrity and zonal isolation provided by cement placed between casing and formation rock are of utmost importance to safe and productive oilfield operations. Operators rely on the accuracy of cement-bond logs to make critical decisions that can affect long-term well integrity and the environment. While cement compressive strength has typically been used as a key indicator of cement quality, today's challenging environments require more detailed assessment. The Baker Hughes Integrity eXplorer cement evaluation provides a new foundation for cement integrity evaluation of all types of cement slurries in oil and gas wells. The electromagnetic-acoustic transducer technology that forms the basis for the service allows operators to directly assess the integrity of cement bonds in any current wellbore environment or cement mixture.



As cement density drops toward 11 ppg, its acoustic impedance properties decrease, making it invisible to traditional acoustic-based cement evaluation services. (Source: Baker Hughes)

The Integrity eXplorer service incorporates proprietary electromagnetic-acoustic transducer technology to generate a shear acoustic mode—not possible with conventional acoustic transducers—to accurately evaluate these types of cements. The acoustic waves used to assess the cement bond are generated and transmitted directly to the casing. The shear acoustic mode provides a new foundation for cement evaluation by responding to the cement shear modulus, which is a true indicator of solid cement behind the casing. This allows operators to directly assess the integrity of cement bonds in any current wellbore fluid environment and in any current cement mixture. ■

HSE WINNER
WEATHERFORD | HAND AND FINGER INJURY PREVENTION PROGRAM

The statistics speak for themselves—35% of all injuries companywide at Weatherford are hand- and finger-related. The company had tried several approaches to tackle this issue in the past, but nothing achieved the desired result, which was to send every employee home safely at the end of the day. With this goal in mind, the company set out to create a new Hand and Finger Injury Prevention Program. Teams worked together to produce training collateral including an analysis of the most common types of hand injuries; a detailed instructor presentation; posters; and a supplemental reference booklet and video content featuring controlled demonstrations of proper vs. improper hand placement, a key contributor to injuries.

The program incorporated compelling content that got employees thinking about their life outside of work. It also incorporated interactive activities. Employees were asked to try doing daily activities such as tying their shoes or unbuttoning a button with just one hand. This exercise got the participants moving and engaged in the training session. Another exercise walked employees through scenarios based on past incidents and asked them to use the Hierarchy of Control to identify ways of preventing similar incidents from occurring in the future. Finally, the program encouraged employees to conduct a hazard hunt at their workplace to identify areas where the Hierarchy of Control could be used to prevent future hand and finger incidents. ■

A new safety program at Weatherford already has reduced hand and finger injuries by 3%. (Source: Weatherford)

HYDRAULIC FRACTURING/COMPLETIONS WINNER
TAM INTERNATIONAL | POSIFRAC TOE SLEEVE

A number of products have been developed to establish a flow path from the casing inside diameter (ID) to the annulus in cemented plug-and-perf completions so perforating guns can be pumped downhole on wireline in lieu of being deployed on coiled tubing (CT) for stage-one stimulation. This saves the operator valuable time and money by eliminating requirements for CT equipment and personnel on location during this initial phase. However, the vast majority of these tools preclude the ability to perform a valid casing integrity test (CIT) prior to the commencement of stimulation operations since they are activated only after the recorded test pressure has been exceeded.

The PosiFrac Toe Sleeve (PTS) is the industry's only flow-path initiation and stage-one stimulation tool that is actuated during the final bleed-down cycle following one or more successful CITs. A field-proven valve design leveraged from an array of other TAM products enables operators to test the casing to maximum values for as long as necessary and subsequently establish communication with the reservoir without ever exceeding the validated CIT values or incorporating ancillary tools, which add unnecessary cost and complexity.

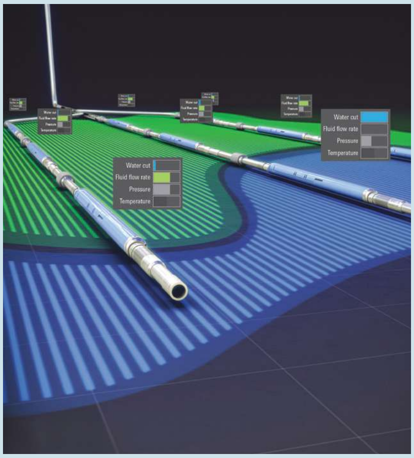
Once open, the sleeve is held in place by a mechanical locking feature and via hydraulic forces, preventing it from closing at any time post-actuation. The PTS also has an extremely large ID, which enables the utilization of a variety of industry-standard wiper plugs (as validated by a series of flowloop tests). A number of other products have reduced IDs requiring extremely costly specialized plug sets and landing collars to ensure adequate wiping efficiency is achieved. ■

The PosiFrac Toe Sleeve is a flow-path initiation and stage-one stimulation tool. (Source: TAM International)

INTELLIGENT SYSTEMS AND COMPONENTS WINNER
SCHLUMBERGER AND SAUDI ARAMCO | MANARA PRODUCTION AND RESERVOIR MANAGEMENT SYSTEM

As "easy oil" has declined, complex and extended-reach wells, multilaterals and deepwater operations are now commonplace in hydrocarbon recovery. However, gaps in completion technology have historically limited the operators' ability to obtain comprehensive sandface measurements for making informed decisions and developing control mechanisms.

To overcome that limitation, Saudi Aramco and Schlumberger developed the Manara Production and Reservoir Management System. It is the industry's first intelligent completion system that provides simultaneous and continuous real-time control and monitoring of multiple zones across multiple well sections through the entire well-bore using a single electric line. This expanded capability improves recovery while reducing drilling, production logging and intervention costs.



The Manara system substantially reduces lifetime lifting costs and increases recovery by compartmentalizing the reservoir with maximum reservoir contact and extreme reservoir contact well branches. (Source: Schlumberger)

Providing a simpler way to improve monitoring and control across the sandface and enable deployment capabilities in the mother bore and associated laterals, the system provides real-time status of the well's performance, updates reservoir and production models and recommends adjustments to keep wells on production and continuously optimize recovery. The system uses metal-enclosed inductive couplers to provide bidirectional power and telemetry in up to 60 compartments across an unlimited number of lateral junctions. ■

IOR/EOR/REMEDIATION WINNER
HALLIBURTON | SMARTPLEX DOWNHOLE CONTROL SYSTEM

With the current economic climate, many operators are revisiting their strategies for their mature fields. Operators are looking to lower their cost per barrel through the use of technology that will increase efficiency and lower cost. Various EOR techniques have been explored to increase reserves—wells are being strategically redrilled to accommodate a desired injection flood pattern, laterals are sidetracked from existing wellbores to maximize the drainage area and long extension horizontal wells are being drilled, all with the aim of maximizing the pay zone for production or injection.

However, controlling numerous laterals from the main bore or the numerous segments in a horizontal wellbore can be challenging and expensive. The SmartPlex downhole control intelligent completion system enables operators to remotely control up to 12 laterals or segments in an extended-horizontal reach wellbore with three control lines, allowing maximum efficiency in reservoir drainage and management.

On a 7,620-m (25,000-ft) deep well, more than 15% (four-zone) or more than 40% (12-zone) cost savings can be achieved when compared to completing with direct hydraulics. There also is added cost savings of capex and opex gained through drilling and completing fewer wells, reduced installation and operational time (fewer terminations compared to direct hydraulics). The ability to accelerate production through controlled commingling and to isolate a watered out segment or lateral are other benefits. ■

The SmartPlex downhole control system uses two hydraulic and one electric line from the surface to remotely and selectively actuate multiple downhole flow control devices. (Source: Halliburton)

MARINE CONSTRUCTION WINNER
TRELLEBORG SEALING SOLUTIONS | SEALWELDING

The swivel stack is a vital part of an FPSO vessel, and avoiding production downtime to carry out repairs is a major advantage. Trelleborg Sealing Solutions' unique SealWelding technology repairs leaking swivels and turrets *in situ*, avoiding that downtime. The solution allows seal replacement and repair without the vessel heading to port, a major benefit in terms of operational efficiency and costs.

It involves bonding the ends of a cut seal offshore while other swivel stacks are still in production. The technology comprises self-contained portable seal welding equipment that is loaded onto a ship with Trelleborg employees to perform the intervention. SealWelding starts in the company's plant, where the seal is manufactured and then cut. It is then shipped to the FPSO unit and installed onto the Weld Head Enclosure, which is part of the welding machine, and pressurized so welding can take place.

In one case an FPSO operator used the SealWelding technology to repair a leak on its swivel stack containing seals 3 m (10 ft) in diameter. If the FPSO unit had gone to port for repairs, the docking rate would have averaged $500,000 per day, and the repair typically would have taken two weeks, constituting a minimum $7 million cost plus the loss of produced oil and gas. Overall, the estimated cost to the operator of the leaking seals would have been about $14 million. By fixing it on location, the repair was done in one week, with the operator avoiding having to move the FPSO unit or disconnecting from the subsea flowlines. ■

Trelleborg's SealWelding technology enables repairs to leaking FPSO swivel and turret seals *in situ*, avoiding downtime. (Source: Trelleborg Sealing Solutions)

ONSHORE RIGS
FLEXGEN POWER SYSTEMS | FLEXGEN SOLID STATE GENERATOR

By integrating energy storage in the form of batteries and/or capacitors, advanced power conversion, and proprietary controls with rig power systems, FlexGen Solid State Generators (SSG) have shown to significantly reduce fuel consumption, engine maintenance and emissions while improving rig reliability and reducing downtime.

FlexGen Power Systems has developed and fielded hybrid power systems that can change the way the oil and gas industry provides power to the electrical power system requirements of the land drilling industry.

Current rig power systems are oversized to handle peak and transient loads while only using their fully rated power 15% to 20% of the time. By pairing a FlexGen SSG with any diesel, dual-fuel or natural gas power system, operators can reduce the size and number of generator sets needed as well as increase the substitution rate for dual-fuel systems.

This increases total available power, increases reliability through improved power quality, saves fuel costs, reduces maintenance costs and lowers overall operating costs.

The FlexGen SSG ties directly into the 600-volt AC bus of any AC or silicon-controlled rectifier rig. By monitoring voltage, frequency and other critical power quality metrics, the system responds to any transient or peak load spikes with full power (1.2 MW) in less than 20 ms. Several operators have shown 15% to 25% reduction in fuel costs, 35% to 45% reduction in maintenance costs and significant reduction in emissions.

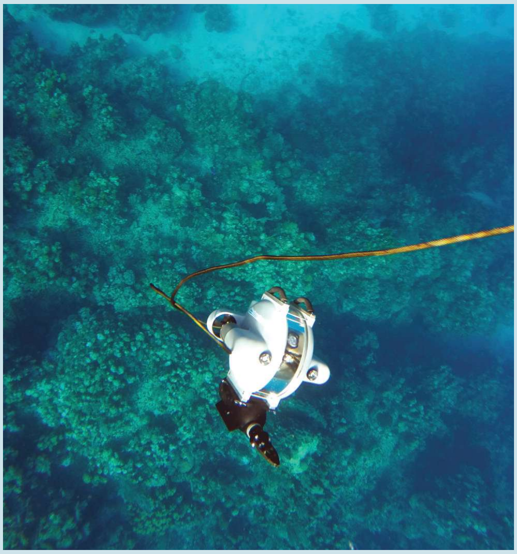
FlexGen is backed by Altira Group, General Electric and Caterpillar. ■

The FlexGen Solid State Generator reduces capital costs by decreasing the size and number of generator sets and alternators required to support load demand. (Source: FlexGen Power Systems)

SUBSEA SYSTEMS WINNER
DEEP TREKKER INC. | DTG2 ROV

Being small and fleet-footed can sometimes be exactly what is required in marine environments. The use of quickly deployed portable equipment is becoming increasingly applicable for inspection tasks in shallow water on offshore facilities, vessel hulls and infrastructure, where costs need to be kept low.

ROVs have long been recognized for their role in making offshore operations safer—for example, avoiding the need to use divers for inspection tasks—as well as more efficient. But traditional ROVs have been relatively costly and difficult to manage for certain tasks. Canadian company Deep Trekker Inc.'s DTG2 solution is a mini-ROV that is 100% case portable with onboard batteries lasting 6 to 8 hours on a single charge.



Deep Trekker's DTG2 solution is a portable mini-ROV deployable within three minutes. (Source: Deep Trekker Inc.)

With a deployment time of less than three minutes, it is particularly suited when eyes are quickly needed in the water for operations taking place in sensitive areas such as environmental sites, where potential occurrences such as a generator leak could be detrimental to operations and the surroundings.

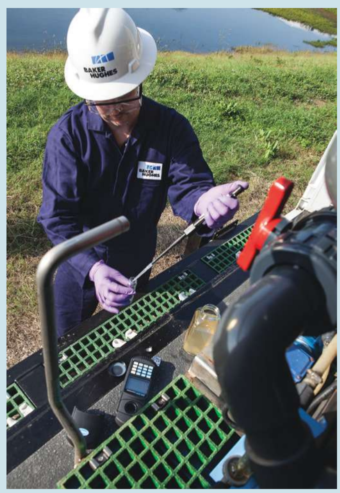
The DTG2 range has been used in the Norwegian Arctic, for example, for under-ice inspections. It also has a patented pitching system, which means it can fly horizontally and vertically with only two thrusters, providing increased maneuverability. ■

WATER MANAGEMENT WINNER
BAKER HUGHES | BRINECARE FRACTURING FLUID SYSTEMS

Mounting concerns about freshwater deficits plus environmental concerns and regulations, droughts in water-scarce areas, and growing transportation costs are driving demand to reduce the volumes of freshwater required for hydraulic fracturing and, instead, reuse produced water for subsequent fracturing operations.

As part of its efforts to make unconventional resources more sustainable, Baker Hughes developed the BrineCare family of fracturing fluid systems that transforms former waste streams into cost-saving alternatives to freshwater systems. While the solution sounds simple, the reality is more complex. The challenge is to reuse water to create fracturing fluids that have the properties necessary to maximize production across a well's or field's life cycle and that also can address operators' short- and long-term environmental and economic needs.

BrineCare provides an effective solution that delivers predictable performance by incorporating produced water containing high total dissolved solids (TDS) as part of the fracturing fluid solution. Fluid treatment composition is tailored to each well's TDS levels and temperature profiles by first conducting a quick and comprehensive analysis of a produced water sample. This fast and efficient screening process also identifies whether any treatment of the produced water, such as filtering, is required prior to application to deliver a minimally treated fluid solution that strikes the ideal balance between high-quality fracturing treatments and the most cost-effective water reuse program. ■



The BrineCare system has demonstrated reliable stimulation performance while minimizing environmental impact. (Source: Baker Hughes)

WATER MANAGEMENT WINNER
SCHLUMBERGER | XWATER INTEGRATED WATER-FLEXIBLE FRACTURING FLUID DELIVERY SERVICE

Water usage accounts for up to 25% of the total cost in hydraulic fracturing operations. Freshwater sourcing, transportation, treatment, storage and disposal of produced water negatively impact field economics and raise significant safety and environmental concerns. Developed to mitigate water management challenges, the xWATER Integrated Water-Flexible Fracturing Fluid Delivery Service from Schlumberger allows operators to reuse up to 100% of produced water, thereby reducing or eliminating costs associated with water acquisition, conveyance, treatment and disposal. The xWATER service provides a customized fracturing fluid solution specifically engineered to enable the use of any available water rather than synthetically derived water that attempts to match the reservoir characteristics. This flexibility allows operators to use flowback or produced water from previous hydraulic fracturing jobs or nearby water sources, including brackish groundwater or seawater. The ability to reuse produced water by adding tailored fluids improves reservoir integrity and maximizes production as compared to freshwater.

Reduce or eliminate the need for freshwater sourcing, treatment, transportation and disposal using a fracturing fluid customized for any available water. (Source: Schlumberger)

The xWATER service is made possible by the latest advances in fluid chemistry, including salt-tolerant polymers and chemicals, scale prediction and mitigation, targeted water treatment technologies, and hardness-immune components compatible with saline matrices. Reusing produced water in tailored fluids reduces reservoir damage and can improve production as compared to freshwater. Preserving the fluids' natural ability to stabilize clay also maximizes production. The xWATER service delivers significant savings (40%) in total water management cycle costs. ■

WATER MANAGEMENT WINNER
SELECT ENERGY SERVICES | AQUAVIEW

Integrating technology and operational knowledge creates opportunities for substantial improvements in water management. These systems allow operators to have real-time visibility of water assets while reducing labor, storage and drive time. Automation and tracking also provides users the ability to more closely control water quality and can result in meaningful operational cost savings and reduced management overhead. The AquaView system is a technology and service platform that improves communication between water resource teams and the completion program. With declining rig counts and low-priced oil, E&P companies are looking for opportunities to extract the most value from every capital dollar.

With variable expenses such as raw water costs, water transfer rates, loss of water from evaporation and damage from overflowing pits, it is crucial to have accurate water volumes prior to the completion. Not only will operators invest in an asset they will not utilize, if regulations stipulate that a breach of containment is considered a spill, costs will increase significantly. Conversely, underfilling prior to a fracture will add considerable expense due to service company downtime until sufficient water is procured. There are many challenges in obtaining, managing and transferring large quantities of water for fracture completions. ■

AquaView technologies are a cost-effective and efficient system that can be an important tool for the required planning and attention in water resource management. (Source: Select Energy Services)

47th Annual HARTENERGY MERITORIOUS Engineering Awards

Enter your award submission today at MEAentry.com!

Now in its 47th year, the ***Special Meritorious Awards for Engineering Innovation*** is the industry's most established and widely respected engineering awards program. Each year, the best new tools and techniques for finding, developing and producing hydrocarbons are recognized.

MEA entries are judged on their game-changing significance, both technically and economically.

Judges include respected professionals with engineering and technical backgrounds who have extensive knowledge of the categories they are judging.

We invite you to enter the 2017 awards competition –**entry is free**. Winners will be recognized May 1, 2017, at the Offshore Technology Conference (OTC) in Houston.

ENTER YOUR AWARD SUBMISSION IN 3 EASY STEPS

1. **Gather the required documents to support your award submission. A complete list is available at *MEAentry.com.***

2. **Go to *MEAentry.com* and create an online account.**
3. **Use your personal entry page to submit and edit your entry.**

Entries can be made throughout the year, but the final deadline is Jan. 31, 2017.

Questions? Please contact meainfo@hartenergy.com

2017 MEA AWARD CATEGORIES

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

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

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

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

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

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

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

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

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

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

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

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

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

Hydraulic Fracturing/Completions: surface equipment, frack trees, hhp, plug-and-perf, sliding sleeves, cementing, perforating, horizontal drilling, stages, frack balls, zipper fracks and microseismic

E&P

Testing data relationships in the Mississippi Lime

A 3-D survey area provides a practical test that, when validated with reservoir knowledge, could be helpful in identifying prospective trends.

Brad Torry, **James Keay** and **Ted Mirenda**, TGS

Production from the Mississippian extends from the south-central region of eastern Colorado through southwestern Kansas and northern Oklahoma, generally considered the "sweet spot" for current production along trend. As with many conventional and all unconventional plays, the factors controlling production are multiple and are not always easily quantified. One common challenge of this trend remains excessive water cut and the increasingly negative impact it has on the economics of the play as well as water disposal restrictions.

Considerable attention has focused on Mississippian reservoir characterization due to the extensive array of lithofacies and pore types, including fractures, all contributing to substantial variations in production characteristics. Since the explosion of unconventional exploration, key geological, petrophysical and geomechanical attributes have been extrapolated from available well data and often back-calibrated to seismic data. Each parameter is intended as input to engineering models constructed to optimize horizontal drilling and completion parameters and realize optimal production performance.

The influence of faulting and fracturing with respect to water production in the Mississippi Lime reservoirs is difficult to assess due to lack of reported water data in states such as Kansas. Of course, operators familiar with local trends can sometimes avoid problematic areas, but consistent risk reduction requires calibration to known data and the ability to extrapolate knowledge to surrounding areas.

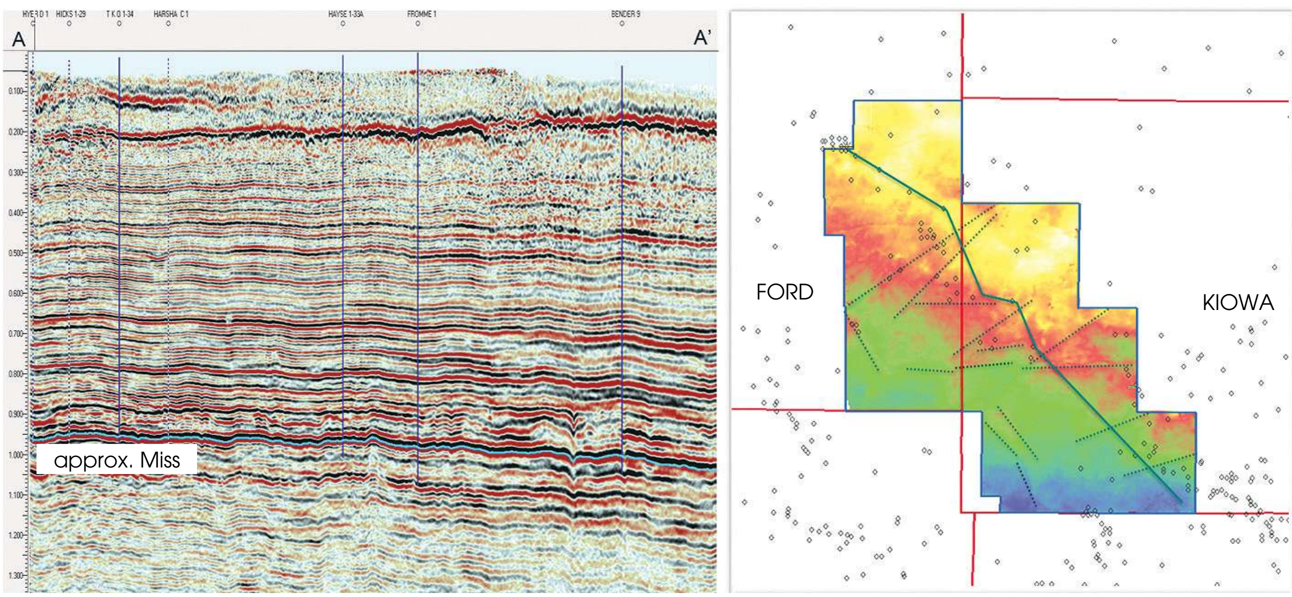


FIGURE 1. This figure shows a representative PSTM seismic section with a near Mississippian event in light blue. Example well locations are in dark blue. The map on the right is time structure on the event with the section line A-A. Dashed lines are interpreted fault zones. (Source: TGS)

ENGINEERED

PREVENTION AND INTERVENTION

With over 35 years of experience, Cudd Well Control (CWC) provides first-class engineering and critical well intervention services to identify risks and design solutions that reduce non-productive time. With highly trained and certified engineers and specialists, CWC is prepared to handle your engineering and critical well control events, safely and efficiently.

Well Control Services

- Well Control and Kick Resolution
- Oil and Gas Well Firefighting
- Blowout Response

Special Services

- Surface and Subsea Hot Tap Operations
- Dry Ice and Cryogenic Freeze Operations
- Gate Valve Drilling

Engineering Services

- Rig Inspections/Well Control Equipment Inspections
- Relief Well Planning
- Kick Modeling
- Drilling Plan Reviews
- Blowout Contingency Plans
- Regulatory Compliance Verification
- Shear Test Verification/Witnessing
- Dynamic Kill Planning and Modeling
- Gas Dispersion Modeling
- Workover Completion Audits
- Basic/Advanced Well Control Rig Training
- High-Pressure/High-Temperature Contingency Planning

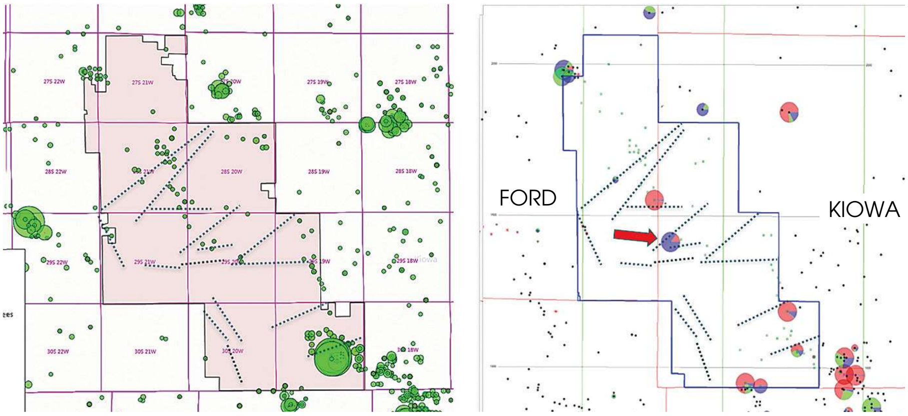


FIGURE 2. The left image shows Mississippian lease oil relative one-year cumulative bubbles. The right image shows IP test data with relative volume bubbles and oil (green), gas (pink) and water (blue) test proportional volumes. Interpreted fault trends are shown in dotted lines. (Source: TGS)

Area of interest

To gain some perspective on possibilities with existing data, a recent scoping exercise looked for correlations of current production trends and IP test data with significant fault and fracture zones highlighted on a recent TGS Bucklin 3-D prestack time migration (PSTM) seismic survey. This scoping exercise focused on Ford and Kiowa counties in southwestern Kansas, with the 3-D survey covering about 673 sq km (260 sq miles) over modest Mississippian production.

Figure 1 displays a northwest-southeast seismic time section as well as a map view illustrating near–Mississippian time structure and interpreted fault zones. The seismic in the area has significant localized structural complexity that is not recognized in mapping from well control. Fault trend orientation in the area is remarkably consistent with a dominant northeast-southwest and northwest-southeast fabric as well as an east-west trend. Faults are dominantly near-vertical and normal in offset; however, a number of areas display more complex deformation.

The left image in Figure 2 is a simplified display of Mississippian lease oil production with bubbles representing one year's relative cumulative production. To deliver data at the well level, TGS runs the lease volumes through a lease-to-well allocation algorithm each month. The algorithm leverages test data results and production start and stop dates to assign a logical and weighted "ratio" to each individual well.

The display on the right shows Mississippian IP tests for the same well set with proportionate volumes of oil, gas and water. TGS well performance Kansas production data are obtained directly from the Kansas Geological Survey (KGS). Starting in 1987 KGS began reporting monthly oil and gas volumes at a lease-level, but it does not report water volumes. Until KGS mandates reporting monthly water production, one alternative is to use IP test records, also reported by the KGS, which reflect water volume flow captured during a well test event. Water flow is reported in barrels, typically during a 4-hr or 24-hr test period.

Even this sparse IP dataset affords some opportunity to explore multiple relationships when leveraged with seismic attributes. However, every observation needs to be correlated and validated against the available geology and reservoir characteristics.

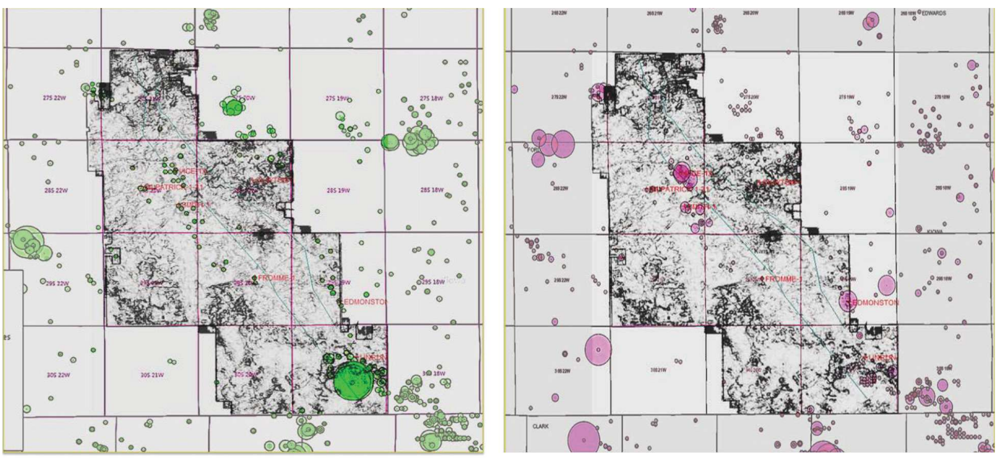


FIGURE 3. The coherency attribute on the approximate Mississippian surface is shown in grayscale. Lines indicate discontinuities. Bubbles are first-year relative cumulative Mississippian allocated lease oil production (left) and allocated lease gas production (right). (Source: TGS)

WE'VE PACKED A LOT INTO 25 YEARS.

For over a quarter century, we've set the standard for excellence by providing high-quality, precision-built tools, outstanding service and unsurpassed value. Like our products, D & L Oil Tools is built to last.

25 YEARS ANNIVERSARY

D&L OIL TOOLS

(800) 441-3504 | dloiltools.com

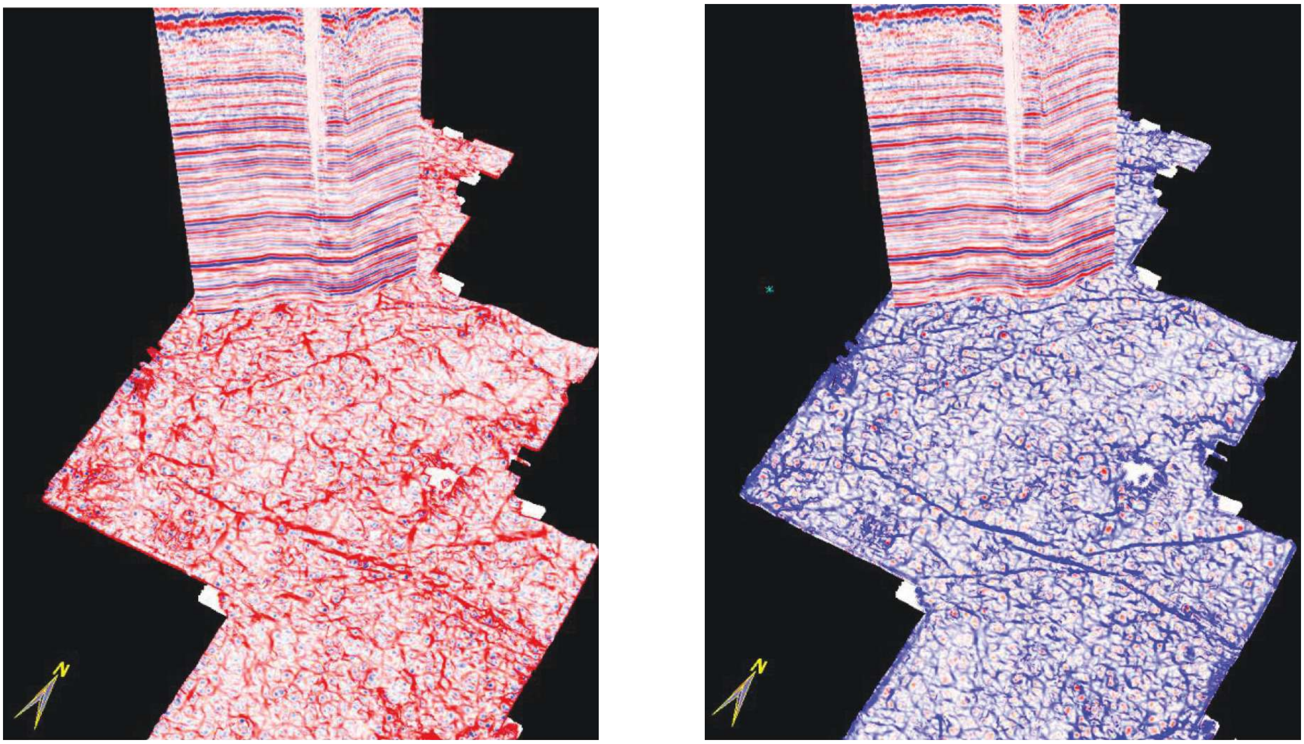


FIGURE 4. This chair display shows most positive curvature (left) and most negative curvature (right) on the approximate Mississippian event. (Source: TGS)

Test data must be validated with KGS completion reports and compared to known local data. An example of this is the Stewart 1-H well indicated with the red arrow. The IP recovered 3,000 bbl of water over a 24-hr period. Water recoveries from tests in the area of interest are typically less than 100 bbl, so this large volume is the result of fracture fluid recovery rather than proximity to an aquifer.

The correlation of fault zones to the Mississippian oil production data range selected in this survey area appears to be minimal; however, some relationships do need to be investigated.

Figure 3 shows a coherency display with a lease oil relative first-year cumulative bubble overlay. The coherency attribute highlights areas of discontinuity (dark lines) on the Mississippian event which, in this play trend, might indicate features such as karsting, fracturing and faulting. Some linear features are observed, but in general the image shows patches and clusters of low coherency.

Some correspondence to oil production might exist in the southeast and northwest of the survey. Well data in these patches might shed some light on the nature of the deformation.

Observations on the seismic most positive and most negative curvature attributes on the Mississippian event provide more support to the structural interpretation. Figure 4 shows the curvature volume as a chair display. The curvature attribute clearly highlights major faults and fault trends consistent with the interpretation presented in the previous figures. The combination of most positive and most negative curvatures with coherency data might prove to be a powerful interpretation tool in this trend.

Understanding the volumes from all hydrocarbon phases (oil, gas, liquids and water) is instrumental to maximizing results. The lease production reporting system in Kansas imposes significant limitations in the complete understanding of the reservoir and the ability to effectively explore and identify sweet spots.

TGS continues to work on ways to enhance available production and test data. The Bucklin 3-D survey area provides a practical test with some basic 3-D seismic data and tools that, when validated and leveraged with strong reservoir knowledge, could be helpful in improving identification and risking of prospective trends and assumptions and estimates on reservoir potential. E&P

HENRY®
TRIBUTE RIFLE SERIES

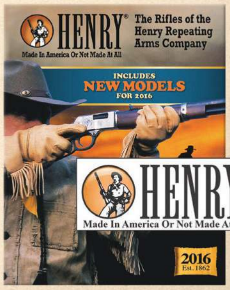
"FOR THOSE WHO DARED TO DREAM"

Henry Repeating Arms Company

THE AMERICAN OILMAN TRIBUTE EDITION

HENRY BIG BOY .44 MAGNUM

We're proud to offer this hand-crafted rifle to honor the American Oilman. To learn more about this unique tribute rifle and the entire line of Henry rifles please order a free catalog and decal today.



Get a FREE catalog and decal at henryrifles.com or 800-845-1408

HENRY®

Made in America, Or Not Made At All

Replacing FPSO seals made easier

New seal welding solution cuts down repair time of FPSO swivel stacks.

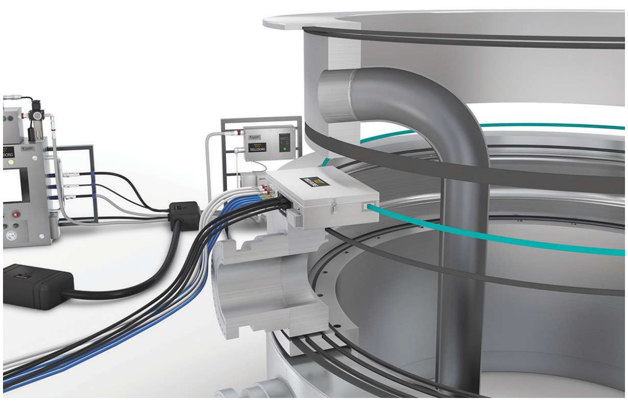
Henk Willem-Sanders, Trelleborg Sealing Solutions

To make a clear case for how seal welding technology can substantially reduce downtime and provide significant cost savings for FPSO vessels, it is helpful to first assess the estimated cost of that downtime. What types of investments are usually involved in running an FPSO vessel?

According to an oil and gas expert at ABS Consulting, estimating a realistic value can be deduced by simply taking the FPSO vessel's day rate and doubling it to take into account transportation services, rentals, communication services, drilling services, support services, security services, shore-based support and all the other myriad items.

For example, if an FPSO rate of $500,000 per day has an average "spread" cost of $1 million per day, then the assumption can be made that the hourly costs are about $42,000. Two hours of downtime would be a loss of $84,000. If you dive in deeper and calculate the per-minute impact, then the cost is $700 per minute. A $700-per-minute loss due to downtime can add up very quickly.

Certainly less expensive FPSO units will have proportionally lower support costs, but the approximation is still close enough for the purposes of assessing the costs of downtime in general.



The swivel stack seal (teal) is welded together in the weld head enclosure. (Source: Trelleborg Sealing Solutions)

The offshore oil and gas sector has more applications that have evolved to accommodate the growing and demanding offshore needs to drill deeper and reach farther, which has led to increased use of enhanced FPSO vessels to extend business opportunities and derive additional value. There are currently about 225 FPSO vessels in use worldwide. Many FPSOs stay *in situ* for years.

Overcoming obstacles

FPSO vessels have become economically attractive for use in smaller oil fields, which quite often can be exhausted in a few years and do not justify the expense of installing a pipeline. Additionally, maintaining these installations often can prove difficult and time-consuming, especially as environments at deeper depths can become more demanding.

When onshore maintenance of the FPSO is required, the cost of shutdown and traveling time required to return an FPSO vessel to shore can add up very quickly. Offshore operators are continually on the lookout for ways to reduce the need for shutdown to avoid the associated downtime.

A critical element onboard an FPSO facility, the swivel stack, is the heart of the turret, mooring and fluid transfer system. The swivel stack ensures that all fluids, controls and power are transferred safely from the geostationary components to the rotating vessel and its process plant under any environmental conditions.

Seals are vital when it comes to ensuring the efficient and safe operation of a swivel stack. The seals within the swivel stack are of various diameters. They're engineered to withstand arduous conditions and to be compatible with aggressive media, using high-specification materials such as polytetrafluoroethylene compounds and advanced elastomers specifically developed for oil and gas processing.

Swivel stack seals are usually specified to have a life expectancy of 25 years, and if correctly engineered, this objective is generally met. However, there are situations when seals fail before the 25-year target and need replacement.

Failure of the seal is commonly indicated by leakage. Simply replacing the seal will not solve the issue, and seal experts should be called in to identify the root cause. This might be that the seal was not specified correctly in the first place or the result of outside impact such as grit in the pipeline at a particular field.

Trelleborg Sealing Solutions is working with numerous operators on a daily basis to solve swivel-stack sealing issues. Some seals have needed to be regularly replaced within several months of fitment. Engineering the seals for the applications solved these problems and, with the added benefit of replacement onsite, the solutions provided short- and long-term savings for operators.

Saving downtime

Replacement of the seals in a swivel stack usually requires the FPSO unit to travel back to shore so that components can be completely disassembled and seals replaced. This operation is extremely time-consuming and requires huge preparation time, meaning the FPSO vessel can be down six to 12 weeks.

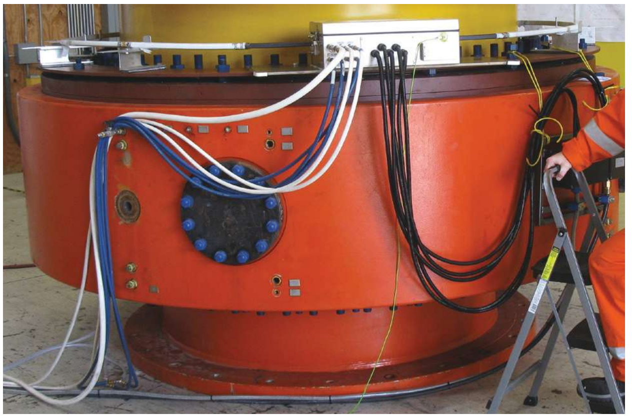
Repair of the seal on the FPSO unit not only alleviates traveling time back to shore but also cuts the time required to replace the swivel stack seal from two weeks to one week. In addition, subsea flowlines can remain connected; disconnection normally requires a couple of days to get the pressures right. The risk of potential problems that can come with disconnecting equipment and moving the vessel also are mitigated.

With every second saved in downtime being an addition to the bottom line of the operator, cutting out the traveling time required to return an FPSO unit to shore and the time to disconnect and reconnect plus the seal replacement can provide operators with huge financial savings in downtime.

Straightforward concept

The solution to the issue of offshore seal maintenance might seem like an obvious one—to provide a solution that would allow removal and replacement of seals on the FPSO unit offshore. However, to do this and create a technique that would fulfill this seemingly straightforward idea was complex to achieve.

Expert seal engineers set forth to develop a technique that would bond the ends of a cut seal offshore, which would prove extremely arduous to do. Complicating matters, preferably the seal welding should take place when other swivels are still in production. With a lot of risk to be mitigated, specialized safety features needed to be incorporated into the welding equipment. The equipment needed to be portable so it could be transported relatively easily to the FPSO vessel. Also, for safety and compliance requirements, a dedicated and well-trained service team would be required to go offshore to perform the operation.



The SealWelding process enables operators to maintain swivel stack seals offshore. (Source: Trelleborg Sealing Solutions)

To meet the requirements of offshore operators, the company has developed a viable, fully tested portable system that will replace seals *in situ*. This allows seals to be welded *in situ* on FPSO vessels, eliminating the need for the vessel to disconnect and return to shore.

Fully compliant solution

The SealWelding process begins in a controlled manufacturing environment where the seal is produced and then cut in one place using a specially designed tool. It is then packed carefully to ensure it is protected to avoid damage in transit.

Once the product arrives onboard the FPSO vessel, it is unpacked and installed by trained personnel onto the swivel stack into the weld head enclosure, which is then pressurized so that the welding can take place. Fully enclosed, production on other swivel stacks can continue without risk.

A control cabinet, which is purged and certified to Atmospheres Explosibles Directive Zone 1, ensures a smooth process. It monitors and logs all data as a part of a procedural audit. When complete, the seal is removed, polished and then checked. If the values from the recorded data are satisfactory, then the seal will be released for installation.

It is important to use a proven material as opposed to a modified substance to avoid integrating something that has not been fully tested into the new system. Offshore operators quite often double-check to ensure full compliance and reliability of the material.

The end result offers a technology process where operators can realize significant savings by maintaining seals offshore. This further enhances the already economically attractive FPSO solutions, especially for addressing the needs of smaller oil fields. E&P

New horizons in a changing world

Automation and efficient use of digitalization remain key to controlling cost and increasing productivity.

Mark Thomas, Editor-in-Chief

Asgeir Drøivoldsmo, program committee chairman of the 2016 SPE Intelligent Energy (SPE IE) international conference and exhibition, was interviewed by Mark Thomas, *E&P*'s editor-in-chief.

E&P: ***The SPE IE 2016 conference theme is "New Horizons: Intelligent Energy in a Changing World." What would you say those new horizons are, and how have they been impacted by the changing world of 'lower for longer' oil prices?***

Drøivoldsmo: The situation in the petroleum industry is challenging. At the same time as new oil and gas fields are more difficult to access for recovery, the competition from alternative energy sources is tougher. Looking only at the percentages of energy production might not give the full picture. There is an equally important battle over the political agenda, where the incentives for R&D and facilitation of opportunities seem to go more in the direction of alternative energy sources than earlier.

The way to cope with these challenges is through the development of cleaner, smarter, safer and more efficient technology. In addition, the time from development to implementation of the current and future technologies will have to be significantly reduced. In the end, the 'lower-for-longer' oil price is building a sense of urgency where automation and efficient use of digitalization is the obvious solution for getting control of costs and increasing productivity compared to other mature industries.

E&P: ***Has the downturn damaged the industry's drive toward implementation of intelligent energy and digital oilfield solutions, or has it enhanced the reasons why it needs to be done?***

Drøivoldsmo: The industry sees technology as a central part of the solution to the current challenges. The industry must send clear and unambiguous signals that intelligent energy solutions have a bright future. There is no doubt that the downturn in itself should be a very good reason for more and smarter use of data and new technology. The data gathering and analytics capabilities developed are in many areas well established in the industry.

Another question is whether the petroleum industry itself is able to send the right signals to the world about the way forward. Political and economic support for renewables is massive, and it is crucial for the oil and gas sector to avoid short-term panic and a reputation for instability.

Recent numbers from Norway show that the number of students applying for petroleum-related lower degree studies is rapidly declining. The specialization of well technology, for example, has 67% fewer applicants than in 2015 and 87% fewer than in 2014. Bachelor degree programs and the five-year master's [degree] in petroleum and offshore experienced a sharp decline in last year's number of applicants. It is now more pressing than ever to ensure that academic institutions and professionals with the digital skills needed see an industry that is robust and that can offer a prolonged career.

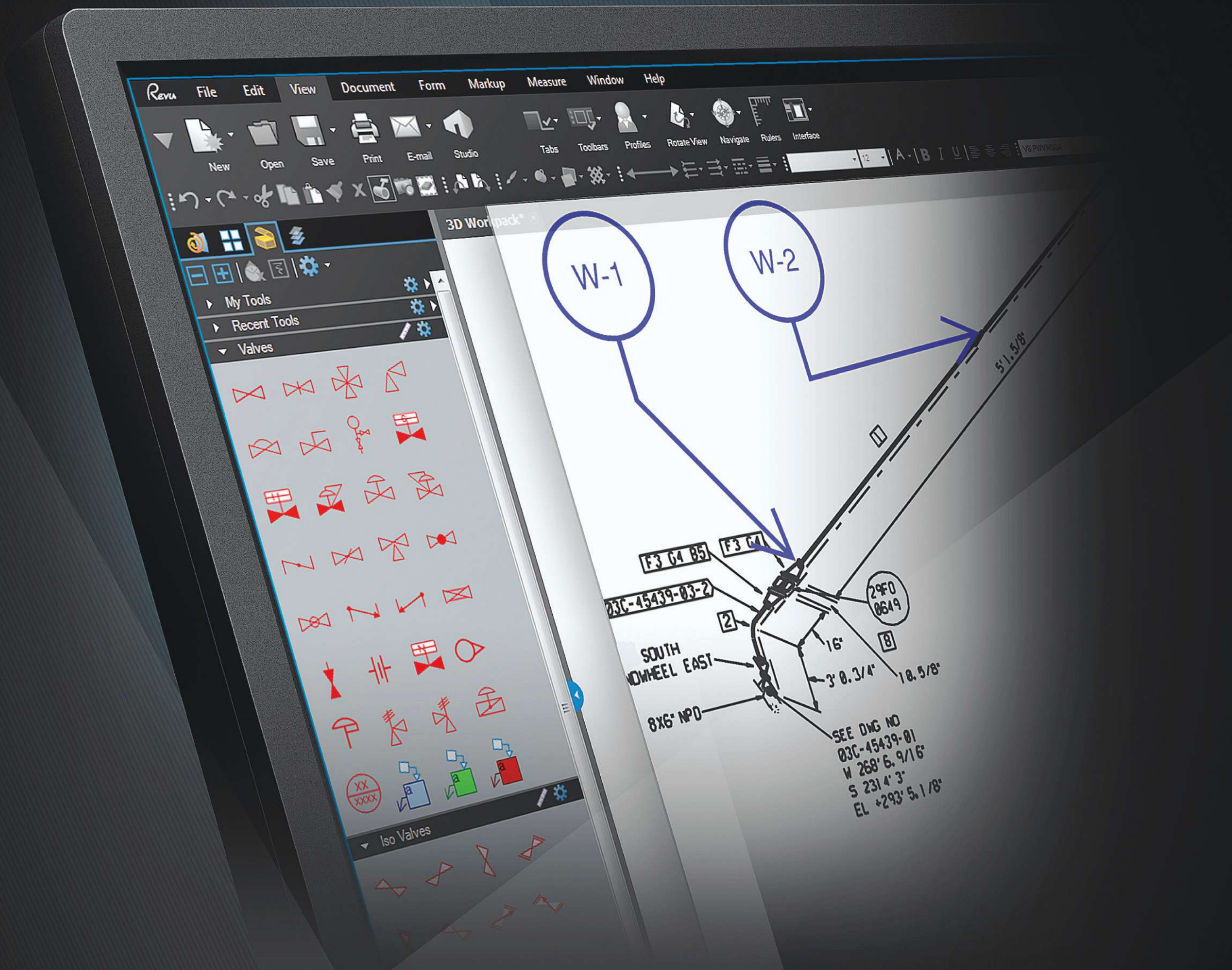
The message that new technology and green developments in oil and gas are one of the best contributors for the environment must be communicated more clearly. We need to show that making the sector more technologically advanced has a positive effect. The fact that intelligent energy knowledge developed in petroleum already is searching for new markets in other sectors is a natural development, but strengthening the petroleum sector as a stronghold for digital development is a key factor for its future development.

E&P: ***Intelligent energy, 'smart' digital oil fields and integrated operations—this topic area has had many titles applied to it. How would you describe the status of 'intelligent energy' today? How has it evolved from its early days, and how large a part of the global upstream industry's day-to-day operations is it now?***

Drøivoldsmo: The digital oil field is mature and plays a central role in how things get done. From the early networked reservoir models of 30 to 40 years ago until today,

IMAGINE

TAKING YOUR WORK PROCESSES DIGITAL



The ultimate PDF-based markup and collaboration solution, Bluebeam® Revu® includes customizable annotation and reporting tools for P&IDs and other drawing types. Save time and improve project communication throughout key work processes, including drawing reviews, line walks, test packs and shutdowns.

Download a 30-Day Trial Today!

bluebeam.com/communicate

bluebeam®

A NEMETSCHEK COMPANY

No Limits®

© Copyright 2016 Bluebeam Software, Inc.

the digital oil field has evolved into the perfect arena for collaborative environments, communication, data collection, reporting, monitoring and information exchange. On this journey there have been many areas that needed maturation to make the necessary building blocks for the development to happen. Business process models and workflow automation, technology and methodology to enhance the use of global and more cross-discipline teams have been major contributors to enabling better, more informed decisions to take appropriate actions across the enterprise in real time and when needed. In the current situation there is less uncertainty over where to go and a much better understanding of the need for digitalization.

The development of cleaner, smarter, safer and more efficient technology can help the industry overcome its challenges. (Source: bluebay, *shutterstock.com*)

E&P: ***The E&P industry is heavily focused on increasing productivity, improving efficiency, implementing better standardization and reducing costs. How can intelligent energy solutions help to deliver on these?***

Drøivoldsmo: Intelligent energy solutions are already a big contributor to all these areas and in many different ways, for example, the systems for supporting decision-making in an environment characterized by high uncertainties. But before we can get the full effect, we need to see a shift in the mindset from building to operation of oil fields. There must be holistic thinking in the way we address the technology, organization, competence and processes at all levels.

E&P: ***How are digital solutions improving oil and gas safety, and what still needs to be done?***

Drøivoldsmo: Digital solutions are improving safety both with regard to major accident risk and controlling hazards in day-to-day operations. Between 10 and 15 years of integrated operations characterized by the use of digital communication; access to real-time production data; remote surveillance of production equipment; and increased cooperation, independent of location; have revealed a wide range of areas where digital solutions are central for improved safety. For offshore installations, for example, reduced helicopter transportation of personnel out to the platforms is reducing risk of accidents, condition monitoring is reducing unnecessary intervention with process equipment on installations, advanced monitoring systems are preventing dangerous conditions in drilling, and improved techniques for dynamic assessment of risk are using integrated operations and integrating advanced techniques of hazard identification and risk assessment.

E&P: ***Can you give any 'blue sky' examples of where you believe potentially game-changing advances might occur that could be of major future benefit to the industry?***

Drøivoldsmo: The capabilities the industry has built in sensor technology, applications, standards, data handling, and analytics and monitoring will be used for improved organizational and human performance. As in many other industries, the technology and processes for remote control is well proven and operational. This is telling us that as soon as we have sufficient automation of new and existing installations, the development will continue to go further into full digitalization. For operations this will result in large operation centers handling multiple unmanned installations covering more and more functions and disciplines in the organization.

The 'game changer' will be the ability to develop a fully integrated model. Digitalization will not eliminate the human in the loop, but it will help the human to improve control and the steering of the processes. We need to look at the complete picture rather than just a portion of it. The projects will have to think competence, organization and processes in combination with the technology decisions.

E&P: ***Is there a sector of the E&P industry that you feel still has most to benefit from the full application and integration of intelligent energy solutions?***

Drøivoldsmo: More and improved methods, visualizations and application support for dynamic risk assessment have a big potential for improved safety, at the same time allowing more efficient operations. Current practices for planning and maintenance of facilities are established with clear and secure safety margins. This does not mean that 'time on tool' could not be better. Active use of monitoring of nontechnical barriers, detection of weak risk signals and active use of this information at all levels of planning and execution can have a big impact on an organization's ability to operate and maintain facilities.

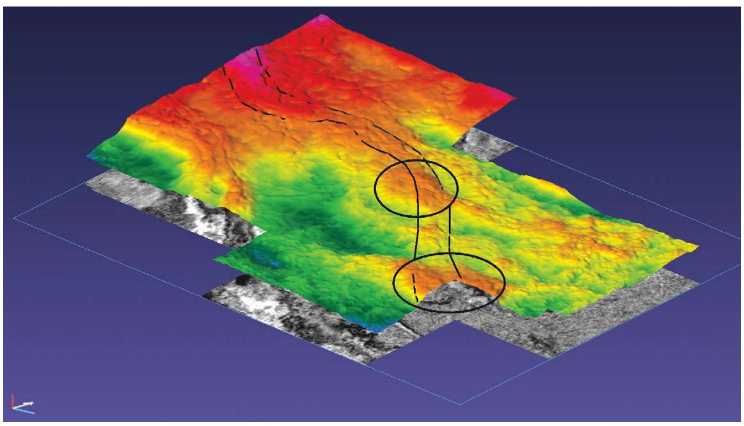
E&P: ***The oil and gas industry is regularly said to be behind other industries (usually aviation, defense, space and automotive) when it comes to remote monitoring, sensors, automation and so on. Is it closing that gap?***

Drøivoldsmo: The pace of development has been much higher in the petroleum sector than any of the other industries mentioned above for many years. Development is not the problem; it is the lack of implementation. At the same time as development in a diverse and varied industry with a high degree of competition between companies does not always enable the clearest path forward, that diversity also can be the advantage. The reason remote monitoring has been lagging in some areas is, in my opinion, due to lack of incentives for implementation. For the last decade the exceptionally high oil price has effectively hindered the big steps in changing the way operations are performed. New installations have been built with a high degree of instrumentation, but the benefit of the investments has never been harvested due to the way the installations have been run. E&P

Hart Energy's E&P *is the official media partner for the 2016 SPE Intelligent Energy event* (intelligentenergyevent.com) *to be held Sept. 6-8 in Aberdeen, Scotland.*

Easier measuring of angles, dips, strikes

CGG GeoSoftware has released a new version of InsightEarth, its software suite that accelerates 3-D visualization and interpretation, according to a product annoucement. High-impact improvements in structural and stratigraphic interpretation capabilities enable oil and gas company interpretation teams to deliver more accurate interpretations with fewer people in less time. These can now generate powerful outcomes quickly with much faster workflows to rework legacy datasets for missed opportunities, the release stated. InsightEarth version 3.0.2 offers improved advanced fault enhancement tools for easier measuring of angles, dips and strikes in real time, producing on-the-spot answers for quick decisions. Users can create projects more quickly with fewer steps and easily access visible windows during each stage. Customizable color bars allow the user to quickly view and understand the value range within volumes. New stratigraphic interpretation capabilities pinpoint areas of interest, streamlining collaboration within interpretation teams and yielding greater geological knowledge from seismic data. *cgg.com*



InsightEarth PaleoSpark rapidly identifies turbidite channel fields and prospects in the U.K. North Sea. (Source: CGG GeoSoftware)

Live QRA view transforms offshore risk metrics, improves operations

Offshore operators need access to quantitative risk analyses (QRA) to support daily operational decisions. If the data are not presented clearly and intuitively, the operator might not take important information into account, causing uncertainties and unqualified decisions. With DNV GL's new Safeti Offshore Viewer, operators can view QRAs live, a company product announcement stated. The Viewer is a dynamic results application for Safeti Offshore, which allows detailed quantitative risk analysis and accurate modeling of hazardous events such as fire, smoke, toxic releases or explosions on fixed or floating platforms. Safeti Offshore provides detailed escalation analysis with the ability to account for the influence of a vast array of safety systems and barriers (e.g., isolation, blowdown, blast and firewalls). The Viewer allows operators to display and examine event trees and view 3-D consequence results. The simple and clean interface is designed for consumers of risk information at all levels of the organization. Analysts run the calculations in Safeti Offshore Viewer and publish the results, which can then be accessed and reviewed by other users. *dnvgl.com*

Saving rig path time

The proprietary Delmar Quick Release (DQR) was successfully installed and activated on a traditionally moored semisubmersible mobile offshore drilling unit in the U.S. Gulf of Mexico, a press release stated. Eight DQRs were installed in offshore mooring systems and deployed for more than 160 days in about 2,377 m (7,800 ft) of water. The DQR was used to save critical path rig time during transit from an offshore drilling site. Through detailed planning and efficient offshore execution, using the DQR resulted in about 3.5 days of saved rig time during disconnection operations. In addition, the DQR was used during weather that prohibited the use of the anchor handling vessel's ROV, which would have further delayed the rig move schedule. The patent-pending DQR is an in-line mooring component developed by Delmar Systems Inc. with a simple mechanical release feature that allows a vessel to separate from its mooring system while the lines are under tension. The system allows the rig to safely and efficiently offset or depart from a moored location with or without the use of support vessels, alleviating the need for waiting on vessels to mobilize and arrive. *delmarus.com*

CO_2 scrubbing technology for early flowback gas

Linde Gases, a division of The Linde Group, has released its mobile technology to economically remove CO_2 from early flowback natural gas, giving producers a cost-effective way to increase recovery and achieve green completions, a press release stated. The new mobile gas cleanup unit (MGCU) uses a membrane technology to remove up to 98% of the CO_2 in the production stream. It was designed to improve well economics with an emphasis on enhanced productivity or EUR, reduced environmental footprint, and improved economics of the field. Natural gas typically contains trace amounts of CO_2. But when a well is fractured with energized fluids containing CO_2 to boost recovery, the early flowback gas might exceed pipeline specifications. The most common practice is to flare off the gas until the well cleans up enough to meet specifications. “Linde has created an economical and environmentally friendly alternative to flaring,” said Robin Watts, program manager, well completions at Linde North America. “Our mobile gas cleanup unit scrubs CO_2 so producers can monetize early flowback natural gas while minimizing flaring and greenhouse gas emissions. One of the many challenges producers face is finding a way to improve well economics while complying with environmental regulations. Linde has designed the MGCU so operators can employ it profitably even during relatively short windows of operation and at low natural gas prices.” *linde.com*

Subsea motion, logging sensor systems process data in real time

Pulse Structural Monitoring, an Acteon company, has released a third-generation INTEGRIpod platform as a new addition to its INTEGRI range of structural monitoring sensor systems, a press release stated. Typical applications for the INTEGRIpod range include linear displacement and static and dynamic inclination of subsea structures such as BOPs, wellheads, conductor systems, mooring lines and jumpers. With onboard processing capabilities, measured data are processed in real time and transmitted wirelessly or hardwired, enabling instantaneous operational decision-making. The new platform also allows deployments in excess of one year between battery changeouts due to new features such as “smart logging,” which enables the device to deploy and only record phenomena over client-defined thresholds. Sandip Ukani, technical director at Pulse, said, “The platform allows communication over various connectivity options, including hardwired and acoustic, and can communicate over various industry-standard open communication standards such as RS232/485. Additionally, a multitude of connectors allows direct integration of Pulse’s proven sensor family, including the INTEGRIstick (curvature sensor) and INTEGRIstrain (custom-bonded strain gauge packages) in addition to any third-party sensor package.” *pulse-monitoring.com*

Linerless containment system protects against spills, leaks

Newpark Mats and Integrated Services has released its DEFENDER linerless spill containment system, a press release stated. The system offers two levels of protection against spills and leaks with its DX4 Sealing Technology. Featuring redundant seals integrated into the overlapping and interlocking lips of the company’s DURA-BASE mats, the system reduces and in some cases completely eliminates the need for liners. Up to $1 million in insurance coverage for environmental cleanup also is available to qualifying customers. The DEFENDER reduces the total cost of operations by minimizing the risks associated with liner use, such as rips and tears that result in added maintenance and repair costs. In addition, it also reduces or completely eliminates the costs associated with liner installation and removal, including trucking and disposal expenses. The DEFENDER system also features a proprietary cellar protection component that fully integrates with the redundant DX4 Sealing Technology. This specialized component offers a third layer of protection at the most critical region where spills are most likely to occur: the cellar. In addition, wall berms and drive-over berms improve work site safety by easing access to the work platform and minimizing the environmental impact to surrounding areas with additional splash protection, the company said. The berms connect directly to the sealed matting system. Site installation also is simplified with the use of Newpark’s custom-designed grappling truck, ensuring optimum seal-to-seal contact while facilitating rigorous quality control. *newpark.com* E&P

DEFENDER is a linerless spill containment system. (Source: Newpark Mats and Integrated Services)

DOWNLOAD THE APP E&P

Tullow's top TEN off Ghana

West Africa's list of stalled projects means Tullow Oil's TEN development is a rare bright spot.

Mark Thomas, Editor-in-Chief

Tullow Oil's Tweneboa-Enyenra-Ntomme (TEN) deepwater development is something of a breath of fresh air in today's thin E&P atmosphere—it's on time, on budget and well on the way to becoming the operator's second world-class field offshore Ghana to come onstream.

Expected to begin flowing oil during third-quarter 2016, the $5 billion project is nearing the 90% completion mark and recently saw its FPSO vessel, named *Prof. John Evans Atta Mills* after the country's late president, arrive in Ghana after setting sail from Singapore in January this year.

The 300-MMboe field's startup is well-timed not only for Ghana but also Tullow itself, with CEO Aidan Heavey saying earlier this year that the startup will allow the company to cut its net debt of $4 billion, having already substantially cut its capital spending in response to the sustained low oil price.

Tullow's TEN development was approved by Ghana's government in May 2013, just over four years after the Tweneboa discovery well was drilled by the *Eirik Raude* semisubmersible unit. The field is expected onstream in July-August this year. (Source: Tullow Oil)

Once flowing, production is initially expected to average about 23,000 bbl/d for 2016, with Tullow holding a 47.18% stake as operator. Its partners are Kosmos Energy (17%), Anadarko Petroleum (17%), Ghana National Petroleum Corp. (15%) and PetroSA (3.82%).

FPSO progress

The FPSO conversion itself has gone remarkably smoothly, taking 26 months to complete at the Sembcorp Marine shipyard. According to Andy Smith, Tullow's FPSO delivery manager, "You're not just looking at an FPSO here. You're looking at 17.5 million man-hours. You're looking at 18,000 tonnes of topsides. You're looking at a 4,200-tonne turret."

Roland Whitton, Tullow's construction manager, added, "The turret is the biggest external turret that's been built to date, so it dwarfs even the *Jubilee* FPSO [unit] that's out in Ghana. It has an 11-m [36-ft] diameter bearing, which again is the biggest that's been produced so far."

Floating production specialist Modec supervised the build and will own and operate the leased FPSO itself.

According to Jeff Knox, Modec's project manager, "The collaboration with Tullow from the Modec perspective has been a big part of the success on this project. The level of completion, the level of quality [and] the level of collaboration on this project is like none other. [Tullow] really got on the ground with Modec; they set up their team, and from that point onward it was a fairly seamless organization between our team and theirs."

Low operating costs

If all continues as smoothly as it has done until now, the project will add significant low-cost production to Tullow and its partners' portfolios. All these companies are focused on keeping operating costs low, as has been done on the Tullow-operated Jubilee Field offshore Ghana, where the operator said operating costs average $10/bbl (and $15/bbl across its West Africa nonoperated portfolio in 2015, according to its full 2015 annual results earlier this year).

Although that is already top-tier performance for a deepwater remote floating production project, Tullow stated in its results analysis that it is working toward maximizing operational synergies between the Jubilee and TEN developments "where combined operating costs are expected to reduce to circa $8/bbl in 2018." TEN is located about 45 km (28 miles) from the main coast and 20 km (12.4 miles) from Jubilee, which came onstream in December 2010.

The industry environment has of course changed dramatically from when the plan of development for TEN was approved by the Ghanaian government in May 2013, just over four years after the Tweneboa-1 discovery well had been drilled by the *Eirik Raude* semisubmersible rig in the Deepwater Tano license. The oil price was around the $100/bbl mark, and there was little sign of the impending plunge that was to come the following year. But in such times, disciplined and well-run projects show their mettle—and TEN will still deliver on the bottom line for its participants despite the current price.

Development progress

Eleven development wells have been drilled so far, with the completions campaign progressing well and the subsea production equipment installed on location during third- and fourth-quarter 2015.

The subsea installation campaign began in July last year and involved 35,000 tonnes of equipment being installed on the seabed, with the first kit installed being the FPSO unit's nine 21-m (69-ft) high steel cylinder anchor piles. These were fabricated in Ghana and installed by the *Normand Installer*.

The majority of the subsea equipment was installed by the Technip-Subsea 7 consortium using the *Seven Borealis* and *Simar Esperanca* vessels, including the installation of three manifolds on Enyenra, one on Ntomme and oil production riser bases on Enyenra and Ntomme. Subsea 7 constructed a new fabrication base in Sekondi to fabricate anchor piles for the subsea manifolds.

FMC Technologies fabricated the subsea infrastructure, including the manifolds and christmas trees, with the components for the trees made in Houston but the kit assembled and tested at FMC's custom-built 6,000-sq-m (64,583-sq-ft) facility in Takoradi, Ghana—the first time this process was carried out in the country. Each tree weighs about 40 tons.

In the final batch of fieldwork, the last of TEN's 60 km (37 mile) total length of umbilicals connecting the FPSO unit to the subsea equipment were due to be installed by the *Deep Pioneer*, with the flexible risers being installed by the *Deep Energy*.

According to Tullow's development schedule, the installation of the umbilicals and risers will be completed in June, with first oil lightly penciled in for July or August followed by final commissioning.

TEN'S SUBSEA STATS	
Water depth	1,000 m to 2,000 m (3,281 ft to 6,562 ft)
Total length of flowlines	70 km (43.4 miles)
Total length of umbilicals	60 km (37 miles)
Total length of risers	40 km (25 miles)
Riser bases	2
Christmas trees	22 to 24
Oil production manifolds	4
Gas export manifold	1
TEN'S FPSO STATS	
Length	340 m (1,115 ft)
Width	56 m (184 ft)
Total height	64 m (210 ft)
Accommodation	120
Water depth	1,425 m (4,675 ft)
No. of risers / umbilicals	24
Topside modules' weight	18,000 tonnes
Crude storage	1.7 MMbbl

Production

After a gradual ramp-up of production over the first few months, plateau production of up to 80,000 bbl/d of oil is expected to be attained early in 2017.

Tullow stresses that it has been committed throughout to maximizing local content.

This led to significant work being completed in Ghana, the company said, including construction of the FPSO unit's module support stools and mooring piles and the fabrication of the subsea mud mats, all by domestic companies.

Greater Jubilee

That experience is likely to be put to further good use as Tullow continues to—cautiously—progress its plans for the Greater Jubilee development.

A full-field development plan for the Greater Jubilee area in the West Cape Three Points Block, including the Mahogany and Teak discoveries, was submitted to the Ghanaian government in December last year, with approval targeted by mid-2016.

Tullow is not the only active developer in Ghana, with Eni perhaps most notably busy with its ongoing FPSO project in the deepwater Offshore Cape Three Points (OCTP) Block, sanctioned in January 2015. First oil is expected from OCTP next year, with gas production to follow in 2018, initially from the Sankofa and Gye Nyame fields.

But it is the Irish independent and its partners that perhaps deserve a mark of 10 out of 10 for continuing to pioneer the development of Ghana's fledgling offshore sector during the toughest of times. E&P

Age of *Aquarius*

Support vessel targets Brazilian market.

Everything about Fugro's new DP2 ROV support vessel (RSV), the *Fugro Aquarius*, has a bit of Brazilian flair. The vessel was built in Brazil and is specifically targeted at the Brazilian market. The vessel was designed by Damen Shipyards Group and built by Wilson Sons shipyard in Guarujá near São Paulo, and its local content is more than 60%. Technology and equipment for the vessel also have been locally sourced.

Measuring 83 m (272 ft) long, the *Aquarius* has a deck area of 520 sq m (5,600 sq ft) and can accommodate 60 people.

The company considers the vessel, which was delivered in November 2015, as the most advanced vessel of her type built in Brazil. She is equipped with two Fugro-built 150-hp work-class ROVs and can operate in water depths up to 3,000 m (9,843 ft).

The company considers the *Fugro Aquarius* vessel, which was delivered in November 2015, as the most advanced vessel of her type built in Brazil.

The vessel's stern A-frame has an active heave-compensated winch system, which allows deployment of 10,000 tonnes. The helideck is suitable for medium-lift helicopters such as the Sikorsky S-92.

The *Aquarius* has two 1,500-kW electric azimuthing thrusters and two 750-kW electric bow thrusters for maneuvering. It can cruise at 11 knots and has a maximum speed of 13 knots. Deck equipment includes four cranes and an abandonment and recovery winch with an operational limit up to 4-m (13-ft) waves.

"*Fugro Aquarius* has been built specifically for the Brazilian market and is ideally suited for subsea inspection, repair and maintenance," said Mathilde Scholtes, managing director of Fugro Brasil, in a press release. The vessel also can support subsea construction projects in Brazilian markets. It is expected to complement Fugro's established presence and capabilities in Brazil and will help the company maintain the performance and production levels of Brazil's oil and gas structure. It was expected to begin service in April 2016. E&P

VESSEL FACTS	
Sector:	ROV Support Vessel
Owner:	Fugro
Name:	*Fugro Aquarius*
Year of Construction:	2015
Yard Built:	Wilson Sons Shipyards, Brazil
First Operations:	2016
Size (length/beam) overall:	82.6 m by 18 m (271 ft by 59 ft)
Transit Speed:	13 knots
Gross Tonnage:	4,144
Operating/Regional Arena:	Brazil

The *Fugro Aquarius* was specifically built for the Brazilian ROV support vessel market. (Source: Fugro)

BUILDING BUSINESS RISK INTELLIGENCE:
PESA CREDIT INTERCHANGE DIVISION

Building business risk intelligence in the oilfield services & supply sector

- Includes the largest network of credit experts in the industry
- Helps companies to strategically manage cash flow
- Connects you to industry experts to share information, experience, and knowledge

PESA
PETROLEUM EQUIPMENT & SERVICES ASSOCIATION

For more information visit **pesa.org/membership**

TRAIN. ELEVATE. NETWORK.

1 Uruguay

Offshore Uruguay exploration well planned in Pelotas Basin

Total and Statoil Inc. plan to begin exploration drilling activities in offshore Uruguay's Block 14 in late 2016. Block 14 is in the Pelotas Basin and covers an area of 6,690 sq km (2,583 sq miles). Area water depth is 1,850 m to 3,000 m (6,069 ft to 9,842 ft). Total has completed an extensive data collection program, including acquiring new 3-D seismic data covering the block. The partnership is now preparing to drill the #1-Raya prospect. Total has a 50% working interest, and Statoil recently acquired 15% interest. Other partners include Exxon Mobil Corp. and Exploration and Production Uruguay with 35% working interest. Block 14 was awarded to Total in 2012.

2 Senegal

Offshore Senegal exploratory well encounters 101 m of gas pay

Kosmos Energy Ltd. has announced results from exploration well #1-Guembeul in offshore Senegal's St. Louis Offshore Profun license area. The 5,245-m (17,208-ft) well hit 101 m (331 ft) of net gas pay in two excellent quality reservoirs, including 56 m (184 ft) in the Lower Cenomanian and 45 m (148 ft) in the underlying Albian. No water was reported. It was drilled in about 2,700 m (8,858 ft) of water. Based on the integration results from #1-Guembeul and nearby #1-Tortue, the P-mean gross resource estimate for the Tortue West structure has increased from 226.5 Bcm to 311 Bcm (8 Tcf to 11 Tcf). The P-mean gross resource estimate for the Greater Tortue Complex has increased from 396 Bcm to 481 Bcm (14 Tcf to 17 Tcf). Kosmos holds a 60% interest in #1-Guembeul, along with Timis Corp., 30%, and Petrosen, 10%.

3 UK

Study indicates P50 oil in place of 219 MMbbl in Isle Of Wight

A volumetric analysis study for UK Oil & Gas Investments indicates that its well, #2-Arreton, is an undeveloped oil discovery (Arreton Main), and the adjacent low-risk Arreton North and South Prospects contain an aggregate gross best estimate (P50) oil in place of 219 MMbbl. According to the London-based company, the estimated resource is within Purbeck, Portland and Inferior Oolite limestone reservoirs in PEDL33. The Isle of Wight discovery well was drilled in 1974 and penetrated the large Arreton Main anticlinal structure, finding strong oil shows in Upper Jurassic Portland. Recent petrophysical analysis of #2-Arreton electric logs calculated a total oil pay of 24 m (78 ft) within the Portland section. A further 39 m (127 ft) of total oil pay also is calculated in limestones within the underlying Oolite. The volumetric analysis indicates that the Arreton Main structure contains an aggregate P50 net recoverable volume of 10.2 MMbbl of oil. UK Oil & Gas owns 65% of the prospect with partners Solo Oil Plc, 30%, and Angus Energy, 5%.

4 Israel

Offshore Israel Daniel East, West fields estimate: 8.9 Tcf of gas

An offshore Israel study by an exploration group led by Isramco Inc. indicates that there is an estimated 252 Bcm (8.9 Tcf) of gas at the Daniel East and West fields. The resource report gave a best estimate for Daniel East Field of 31 Bcm (1.1 Tcf) of gas with a probability for success of 38% to 43%. For Daniel West, it estimated 221 Bcm (7.8 Tcf) with a probability for success of 24% to 57%. Isramco owns a 75% stake in the Daniel licenses, and Modiin Energy LP has a 15% stake, with ATP Oil and Gas Corp. and AGR each having a 5% share.

5 Egypt

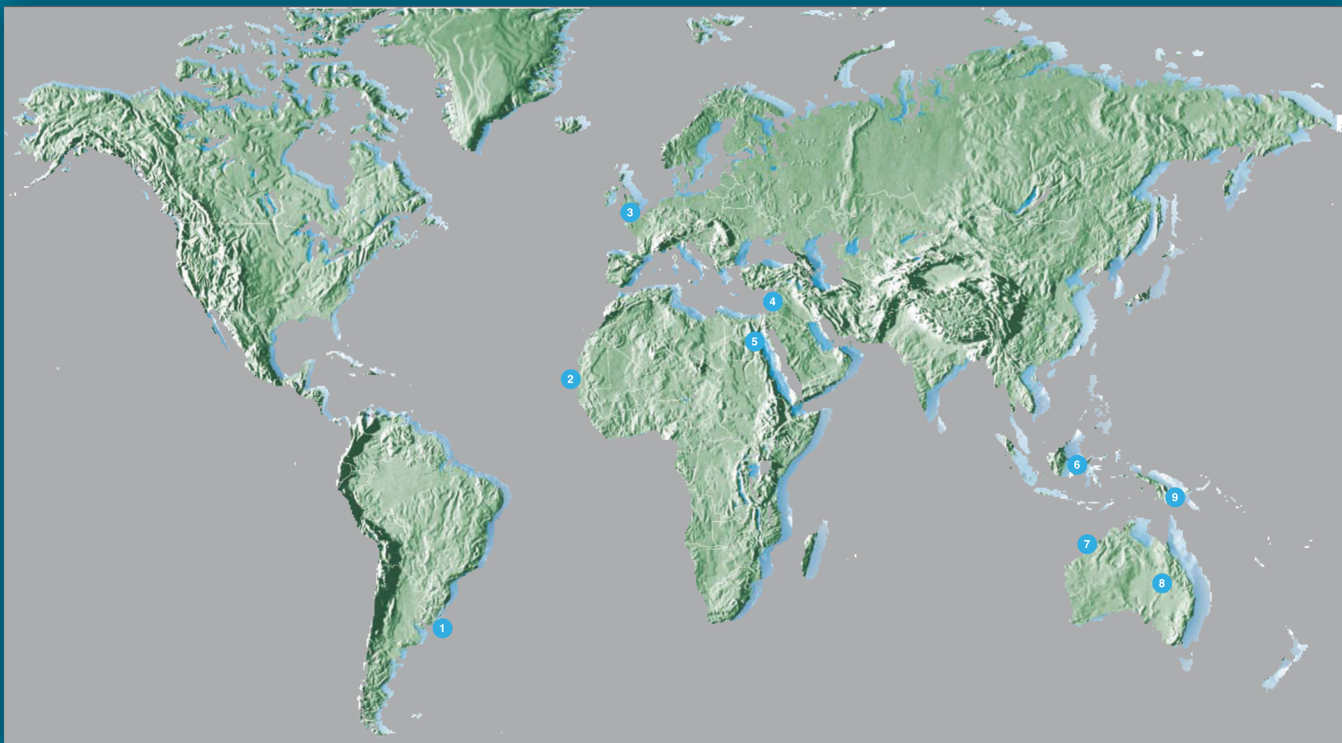
Development well hits oil-bearing reservoirs in Gemsa Concession

In Egypt's Northwest Gemsa Concession, operator Vegas Oil & Gas S.A. reported significant oil-bearing reservoir sections at its development well, #23-SE Al Amir. The venture penetrated the oil-bearing reservoirs in both the Kareem Rahmi and Shagar formations. Log analysis of the 3,017-m (9,900-ft) well indicated 7 m (23 ft) of net Shagar oil pay and 8.5 m (28 ft) of net Rahmi oil pay. The well will be completed as a producer in the Shagar Formation. Two main oil fields are producing light oil, Al Amir SE Field along with the Al Ola extension to the south and Geyad Field to the north. Vegas Oil & Gas is the operator of the Northwest Gemsa Concession, its Al Amir Field and the Al Amir SE-23 well with 50% interest in partnership with Circle Oil, 40%, and SDX Energy Inc., 10%.

6 Indonesia

Cue Energy oil discovered at onshore East Kalimantan test

According to Cue Energy Resources Ltd., the company found oil at the onshore Indonesia well #2-NS, and the well is currently being suspended for future production testing. It was drilled to 357 m (1,170 ft) and is in Mahakam Hilir PSC in the Kutai Basin, East Kalimantan. The well tested a shallow anticlinal closure and had gas shows at 91 m to 96 m (300 ft to 315 ft) and 113 m to 151 m (370 ft to 495 ft), with more gas readings and oil shows below 142 m (465 ft). The lower section of the hole, at 219 m to 357 m (720 ft to 1,170 ft), encountered oil shows and high background gas readings. Equipment problems



due to pressure forced the company to stop testing—$9\frac{5}{8}$ in. casing was run and new testing is planned. The play concept was based on drilling and testing at nearby Sanga-Sanga fields. Cue is the operator and owns 100%.

7 Australia

Results announced from appraisal drilling in Canning Basin

At appraisal well #1 Ungami Far West, Buru Energy Ltd. reported that it hit a 14-m (46-ft) oil interval that had 5 m (16 ft) of net pay in Anderson at 1,560 m (5,118 ft) with good permeability. Wireline logs in the vertical well indicated several zones of interest, and a wireline pressure testing and sampling program are underway. After testing, Buru will be drilling ahead to the top of Ungami Dolomite and conducting coring operations. The Canning Basin venture is in PL21 in the Ungami oil field in Western Australia. Partners include Beach Energy Ltd. and Diamond Resources (Fitzroy).

8 Cooper Basin well in Udacha license flows 1.7 MMcf/d of gas

Beach Energy Ltd. has completed fracturing operations and flow testing at its #1-Udacha well in the Udacha license (PRL 26) in the Cooper Basin in South Australia. Following fracturing, the well produced 48,139 cu. m/d (1.7 MMcf/d) of gas. Tested on a $\frac{24}{64}$-in. choke, the flowing tubing pressure was 650 psi. The Udacha joint venture partners are assessing plans to connect the well to a nearby production facility. Operator Beach holds 15% interest with partners Rawson Resources Ltd., 10%, and Drillsearch Energy Ltd., 75%.

9 Papua New Guinea

Appraisal well will test southern flank of Antelope Field

In Papua New Guinea's PRL 15 in the Gulf Province, drilling by InterOil Corp. is underway at appraisal well #6-Antelope. According to the company, the well is designed to provide structural control and reservoir definition on the field's eastern flank. It has a proposed total depth of about 2,464 m (8,084 ft) and is about 2 km (1.24 miles) east-southeast of #3-Antelope. The venture is part of the appraisal program to define the resource for the Papua LNG Project. The company also is considering an additional appraisal well on the western flank of the Antelope Field that could add 28 Bcm to 84.9 Bcm (1 Tcfe to 3 Tcfe). Operator Total holds a 40.01% interest in PRL15 in partnership with InterOil, 37.4%, and Oil Search Ltd., 22.5%. E&P

For additional information on these projects and other global developments:
READ MORE ONLINE
EPmag.com

PEOPLE

Ditlev Engel joined DNV GL as CEO of the group's energy business area.

AWE Ltd. appointed **David Biggs** as CEO and managing director, to commence early May.

The executive committee of IADC named **Jason McFarland** president of the International Association of Drilling Contractors.

Henkels & McCoy Inc. appointed **James M. Dillahunty** president and COO.

TAG Oil Ltd. named **Henrik Lundin** (left) COO, commencing on or about June 27. With Lundin commencing as COO, he has resigned as a director. **Dr. David Bennett** (right) has been appointed as a director in his place.

Drillinginfo appointed **Jeff Hughes** president and COO.

EQT Corp. named **Robert J. McNally** senior vice president and CFO.

Amanda Berg has joined WECC as CFO.

Blackeagle Energy Services selected **Brady Burleson** as CFO and **Kyle Lenamond** as director of pipeline.

UTEC Geomarine, part of UTEC Survey, an Acteon company, announced key management appointments: **Jim Edmunds** (left), technology director, assumes responsibility for operational and technical project execution as well as development of the company's geotechnical contracting business; **Scott Gooding** (middle) will serve as general manager for the consultancy services; and **Mike Fearn** (right) was named business development manager.

Andrey Fick has been appointed managing director of Gazprom EP International B.V.

Chevron Corp. named **Mark A. Nelson** corporate vice president of strategic planning.

MDU Resources Group Inc. selected **Jason L. Vollmer** as vice president and chief accounting officer in addition to his role as treasurer.

Total's **Philippe Boisseau**, member of the executive committee, president marketing and services and president new energies, is leaving the company. **Momar Nguer**, currently senior vice president, Africa and Middle East, marketing and services was appointed president, marketing and services and member of the executive committee. **Philippe Sauquet**, president refining and chemicals and member of the executive committee, was appointed interim president, new energies.

FOCUS appointed regional managers to lead its three international business units: **Rick Smith** was selected to lead the North and South America unit; **Liam Manderson** will oversee operations in Europe, the Middle East and Africa; and **Tim Hopkins** will lead the Asia-Pacific unit.

Seatronics, an Acteon company and part of its survey, monitoring and data business segment, has appointed **Kevin Strachan** head of finance.

MacGregor appointed **Paul Glandt** director, region Americas, MacGregor Global Lifecycle Support division.

Protea recruited **Maciej Schefke** as its new sales engineer.

Fine Tubes and Superior Tube appointed **Mike Cullum** sales manager and **Rahul Gujar** national sales manager, India.

Rick Comeaux joined William Jacob Management Inc. as a senior sales manager for international and domestic clients, and **Charlie Fife** joined the firm as a business development manager.

IMI Precision Engineering appointed **Ryan Schroeder** president for the America's region.

Wier & Associates' President **Carlo Silvestri**, P.E., has been awarded Engineer of the Year by the TSPE DFW Mid-Cities Chapter.

H.E. Khalid A. Al-Falih, chairman of the board of directors of Saudi Aramco, has been named 2016 Energy Intelligence Petroleum Executive of the Year.

Magdalena Moll (left) will join the OMV Group as senior vice president and take over the management of investor relations. She joins the company in June, succeeding **Felix Rüsch**, who will assume new responsibilities at OMV as head of strategy. In addition, **Peter Oswald** will resign as chairman and member of the OMV supervisory board on May 18.

E&P

MARKETING | SALES | CIRCULATION

Vice President of Publishing
RUSSELL LAAS
Tel: 713-260-6447
rlaas@hartenergy.com

United States/Canada/ Latin America
1616 S. Voss Road, Suite 1000
Houston, Texas 77057 USA
Tel: 713-260-6400
Toll Free: 800-874-2544
Fax: 713-627-2546

Senior Director of Business Development
HENRY TINNE
Tel: 713-260-6478
htinne@hartenergy.com

Director of Business Development
JULIE B. SEDELMYER (FLYNN)
Tel: 713-260-6454
jsedelmyer@hartenergy.com

Director of Business Development
DANNY FOSTER
Tel: 713-260-6437
dfoster@hartenergy.com

Sales Manager, Eastern Hemisphere
DAVID HOGGARTH
Tel: 44 (0) 7930 380782
Fax: 44 (0) 1276 482806
dhoggarth@hartenergy.com

Advertising Coordinator
CAROL NUNEZ
Tel: 713-260-6408
cnunez@hartenergy.com

Subscription Services
E&P
1616 S. Voss Road, Suite 1000
Houston, Texas 77057
Tel: 713-260-6442
Fax: 713-840-1449
custserv@hartenergy.com

List Sales
MICHAEL AURIEMMA
Venture Direct
212.655.5130 phone
212.655.5280 fax
mauriemma@ven.com

HTL Group appointed **Mike Johnson**, group director of engineering, to the board.

KrisEnergy Ltd. selected **Chan Hon Chew**, CFO at Keppel Corp., to join its board of directors as a nonexecutive director.

Jeroen van der Veer was elected as a new member of Statoil's board of directors.

Senex appointed **Dr. John Warburton** independent nonexecutive director of the board.

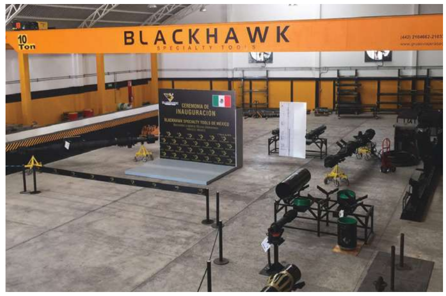
Hess Corp.'s **Dr. Mark Williams**, chairman of the board of directors, has retired due to health reasons. **James Quigley**, former CEO of Deloitte and a current director of Hess, will succeed Williams.

COMPANIES

APPEA welcomed a new energy growth center. The federal government's new energy resources growth center launched in February. The National Energy Resources Australia initiative is located in Perth, with nodes in Brisbane and Adelaide to open later this year.

SeaTrepid International LLC is forming a new division, thus expanding its service offerings to include AUV mapping operations.

Blackhawk Specialty Tools LLC has expanded its international operations in Mexico with the opening of a new subsidiary and operating facility in Villahermosa, Mexico. E&P



Blackhawk has expanded its international operations in Mexico. (Source: Blackhawk Specialty Tools LLC)

ADVERTISER INDEX

The power of the right connections

The cost to get the best connections might be harder to justify in today's climate, but it is much lower than the cost of failure.

Aaron Sinnott, Weatherford

With oil prices at a decade low, everyone is looking for new ways to shave costs. First, they take aim at the low-hanging fruit, cutting things they know that they can reasonably survive without. However, as pricing pressures continue, the decisions get tougher—and the results of those decisions become less predictable.

Faced with such difficult choices, asset managers have tried to maximize the use of every person and piece of equipment already on the rig. This is a logical and in many cases necessary step; however, it must be done carefully and judiciously to increase efficiency without sacrificing quality.

Quality is especially critical when tripping, handling, making up and running tubulars. In deepwater operations tubulars represent as much as 45% of total well construction costs. Such a cost-intensive asset segment demands a partner that can deliver reliable and timely service. Weatherford Tubular Running Services makes connection quality and integrity its primary concern.

Without a reliable torquing system that is backed up by real-time and recorded data, an operator may not know whether a connection is reliable until after it has been sent downhole. Torque/turn monitoring and analysis software brings visibility and quality control to the makeup process by sending real-time data to decision makers on the rig and in remote locations.

Not only must connections be made up correctly and securely, but this process must also be executed quickly and safely. Manual makeup is time-consuming and puts rig personnel in some of the most dangerous positions on the rig floor. Experienced technicians who are trained to recognize and control key connection parameters can help assure compliant makeup.

However, integrated, automated makeup is the most simple and cost-effective way to significantly reduce safety risks and nonproductive time while increasing connection quality. When used in concert, pipe alignment, torquing and casing-running systems create a seamless, efficient tubular program that results in integrity for the life of the well. An experienced tubular service provider can help select the best combination of equipment that will produce high-quality connections within the space and budget available.

For every 10 pipe failures, nine are rooted in poor connection quality. One failed connection can compromise the entire integrity of the asset and require time- and cost-consuming workovers. In the worst cases, where casing integrity is compromised, the only option might be to plug and abandon the well.

Taken in real terms, the cost of a failed connection can range from $100,000 to several million dollars.

In the current economic environment, we all must make sacrifices. However, before making cuts, it's important to weigh the long-term impact of these decisions. The cost to hire an experienced casing-running provider using top-shelf technologies might be harder to swallow in today's climate, but it is much lower than the cost of failure. In an attempt to save cost during the well construction phase, operators might be actually adding millions in costly interventions and lost production. Investing in the right technology and services today will help boost efficiency, mitigate health and safety risks and enhance integrity for years to come. E&P

A technician monitors and evaluates whether or not each connection is secure and ready to be run into the wellbore. (Source: Weatherford)

INCREASE YOUR PRODUCTION.

Find out how at OTC
Booth #9053.

ENVENTURE®
EXPAND YOUR POSSIBILITIES

www.EnventureGT.com

Increase production and manage inflow with real-time information and control in every zone.

With patented inductive coupler technology that provides power and telemetry, the Manara* production and reservoir management system can be deployed in conventional or extended-reach wells, in two or more sections, or across any number of lateral junctions—all with a single control line. Using the Manara system to monitor and control previously unattainable zones, operators can now immediately identify problematic areas, pinpoint the cause, and make the necessary adjustments to maintain the well at optimal production.

Find out more at
slb.com/manara

Schlumberger

*Mark of Schlumberger. Copyright © 2016 Schlumberger. All rights reserved. 16-CO-118244