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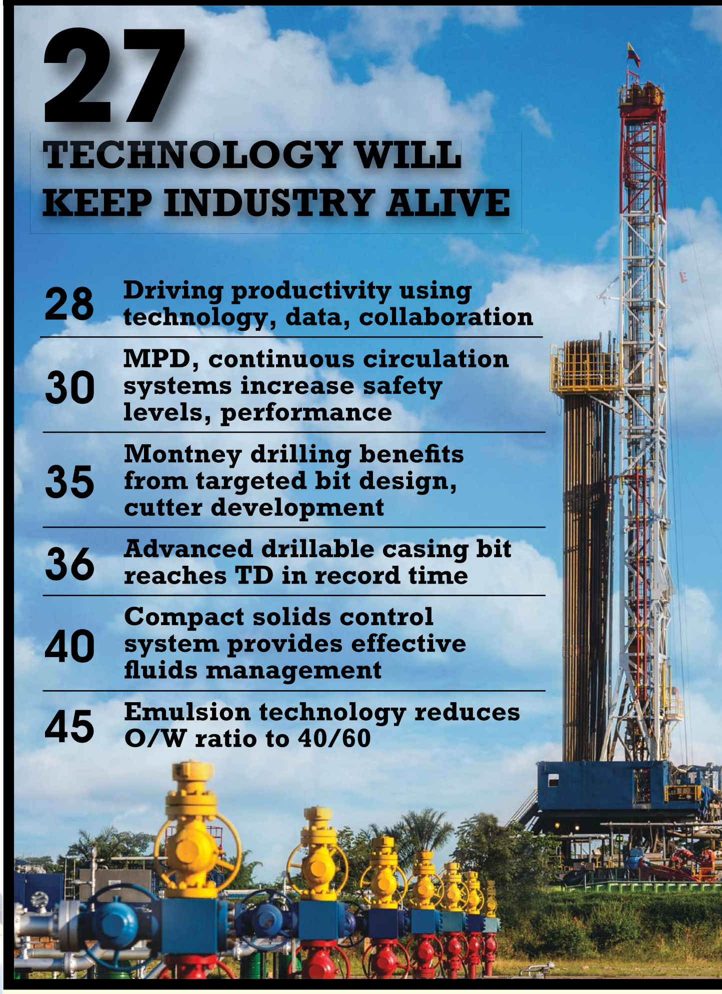

AGENDA

Monday, March 28

11:00 am **Golf Tournament Barton Creek**

6:30 pm **Reception**

7:00 pm  **Welcome Reception and Dinner**

Featuring **Gary McCord**, longtime CBS commentator, former PGA Tour golfer, and bestselling author

Tuesday, March 29

7:30 am **Registration, Breakfast & Networking**

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

8:35 am **Opening Keynote: A World View**

- **S. Wil VanLoh Jr.**, Co-Founder, President & CEO, ***Quantum Energy Partners***

9:00 am **Panel: Capital Markets Speak**

- **Doug Reynolds**, Managing Director and Head of US Business, ***Scotiabank***

9:45 am **CEO Of The Year: *Oil and Gas Investor's* Excellence Award Presentation & Remarks**

10:15 am **Networking Break**

10:45 am **Roundtable Discussion: Private Capital Waits In The Wings**

- **William W. McMullen**, Managing Partner, ***Bayou City Energy***
- **Doug Swanson**, Managing Partner, ***EnCap Investments L.P.***
- **Ken Friedman**, Managing Director, ***SFC Energy Partners***

11:30 am **Spotlight: Impacts & Opportunities By Basin & Sector**

- **Jessica Pair**, Manager, Upstream, ***Stratas Advisors***

12:00 pm **Luncheon Keynote: Reading The Economic Tea Leaves**

- **Richard Yamarone**, Senior Economist, ***Bloomberg***

1:45 pm **Financing Of The Year: *Oil and Gas Investor's* Excellence Award Presentation & Remarks**

M&A Deal Of The Year: *Oil and Gas Investor's* Excellence Award Presentation & Remarks

2:15 pm **Roundtable Discussion: A Critical Eye On Debt**

- **Phillip Z. Pace**, Managing Director, ***Chambers Energy Capital***
- **Christina Kitchens**, Managing Director, Head of National Energy Finance, ***EastWest Bank***
- **Brian N. Thomas**, Managing Director, EFG Oil & Gas, ***Prudential Capital Group***

3:00 pm **Panel: Case Studies In Successful Capital Raises**

- **Frank D. Bracken III**, CEO and Managing Director, ***Lonestar Resources LLC***

3:45 pm **Conference Adjourns**

Speakers

S. Wil VanLoh Jr.
Co-Founder, President & CEO
Quantum Energy Partners

Doug Reynolds
Managing Director and Head of US Business
Scotiabank

William W. McMullen
Managing Partner
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Managing Director, Head of National Energy Finance
East West Bank

Jessica Pair
Manager, Upstream
Stratas Advisors

Parker Reese
President and Chief Executive Officer
American Resources Development LLC

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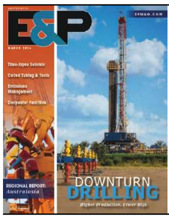
Hosted by: Oil and Gas Investor

DEPARTMENTS AND COMMENTARY

COMING NEXT MONTH The April issue of ***E&P*** will focus on subsea solutions. Other features include marine seismic, MPD/UBD, IOR/EOR and a rig and drillship report, 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 Pad drilling will continue to allow companies to continue drilling operations and maintain production with fewer rigs. This WDI rig is drilling a well in Colombia. Left, development plans, primarily for natural gas resources, are underway in Australasia. AWE made a final investment decision for Stage 1A of its Waitsia development in Western Australia. *(Cover image courtesy of WDI; left image courtesy of AWE Ltd.; cover design by Carleigh Pearson)*

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PREMIUM CONTENT

Sogo III announces Hinyard Field well results

An oil producer by Sogo III LLC in Pecos County, Texas, has reestablished production in West Texas' Hinyard Field. The #1 Hinyard 6 was tested pumping 45 bbl of 29.4-degree-gravity oil and 22 bbl/d of water. In the same section, Sogo plans to drill #2 Hinyard 6 and has permitted #2 Hinyard 7.

Woodford discovery flows 13.3 MMcf/d of gas

A Woodford discovery by PetroQuest Energy LLC was completed flowing 376,614 cu. m/d (13.3 MMcf/d) of gas, with 1,850 bbl of water. The Arkoma Basin horizontal, #1-35/2H Blair, is in Section 35-7n-10e of Hughes County, Okla.

More gas found in offshore Egypt's Nouros Field

Eni has announced another gas discovery at the Abu Madi West Concession on Nouros Field in Egypt. Appraisal well #3NW Nidoco, which was being drilled to delineate the discovery at #2NW Dir Nidoco, penetrated a Messianian gas-bearing sandstone layer of about 65 m (213 ft). The discovery well, #2NW Dir Nidoco, is currently producing about 15 Mboe/d.

AVAILABLE ONLY ONLINE

Chevron dealing, but play-by-play a secret for now

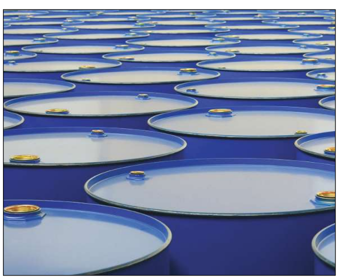
By Velda Addison, Senior Editor, Digital News Group

Although merger, acquisition and divestiture activities have been down lately, some believe change is coming.

Giving oil and gas executives a gameplan for 2016

By Len Vermillion, Hart Energy

At Hart Energy's Viewpoint Executive Energy Club, Stratas Advisors directors gave industry executives a wide-ranging view and key to competing in the upcoming year.



Small oil pools can produce big results for UK North Sea

By Mark Thomas, Editor-in-Chief

With about 210 small pools already discovered but not yet developed, reducing costs by half would make the development of those 150 fields economically viable, according to a speaker at Subsea Expo.

Simplicity becomes new watchword for oil, gas sector

By John Sheehan, International Editor

Simplification, standardization and collaboration are the new calls to arms for the industry.

E&P

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Walking the walk

Talking the talk and walking the walk are very different things. But there's evidence the E&P industry's talk a year ago of collaboration and cutting costs was more than just hot air.

Returning to any annual event the following year can be enlightening. I don't know about you, but opening sessions tend to stick in my memory, and the often bold soundbite statements made by various VIPs as they set the tone for the rest of an event can often sound more than hollow a year on.

At the 2015 edition of the Subsea Expo event in Aberdeen, Scotland, I recall one oil company keynote speaker commenting, "We should not waste a good crisis. It's time to show that we are making progress. It's time to get back to basics and do the basics well."

To be honest, we've probably all heard similar statements made at various events around the world over the past year. There's nothing like quoting a good quote to get quoted, my PR friends tell me.

But it is clear that the industry is not wasting this crisis—it has no choice if it wants to survive and eventually thrive once again.

At this year's Subsea Expo one plenary session speaker pointed out that for the U.K. North Sea, cutting development costs by 50% would unlock at least 150 small fields and kick-start an estimated $20 billion of project investment. Matt Nicol, director of production and nonoperated assets at U.K. operator Centrica, added that a 50% cost reduction would drop the average economic minimum for these small pools to 6 MMboe and eventually achieve production of about 1 Bboe of extra reserves in total.

Centrica's own internal cost-reduction program, which Nicol said was dubbed the "Hackathon," saw its close work with suppliers on potential new solutions succeed in cutting the costs on some projects by up to 52%.

Similar evidence has seen Statoil confirm it has reduced the forecast capex for its presanction Johan Castberg project offshore Norway by about half, from an eye-watering $11 billion to between $5 billion and $6 billion.

Chris Bird, managing director of MOL Energy UK, added that with the industry having let its offshore costs soar "by between 200% and 300% over the last five years," such measures are a must—but still not enough. The U.K. North Sea is "not an investable basin at present, and it cannot just rely on the oil price to come back up," he said.

So Centrica's work, and that of all operators both onshore and offshore, is far from done—but crucially, it is being done.

Last year it all sounded like the same old lip service being paid to what needed doing. This year the upstream sector is clearly turning those words into quantifiable action, although it's by necessity rather than choice. In a year's time we will know whether the industry has walked far enough. E&P

Better approach to managing operating expenses

A robust method for integrating cost management can lead to a more efficient and economic operating environment.

Timothy Gilblom and **Janice Gilblom**, Gilblom Consulting

While there are many good technology tools for managing production operating costs, their impact can only be optimized by also employing a better organizational approach to handling expenses. Presented here is a robust method for naturally integrating cost management into the everyday habits of a production operations staff. It can lead to more efficient and economical operating practices that will pay dividends now and also when the economic environment improves.

This is accomplished by spreading the authority and accountability for budgeting, booking, tracking and forecasting opex to the lowest level possible in the organization. Done properly, this works by a) increasing the transparency of where, how much and by whom expenditures are made, and b) creating accountability for expenditures with those who are actually making them.

The major benefits of this method are that it

- Lowers lease operating costs;
- Requires no capital investment;
- Clarifies where and how money is spent;
- Increases engagement and satisfaction of operations personnel; and
- Can lead to increased production and improved safety.

But to be effective, the corporate culture must accommodate

- Trust between management and the field crew;
- Managers who are comfortable not only relinquishing significant control over expenditures to field personnel but supporting and mentoring them along the way;
- Field personnel who take responsibility for budgeting, booking, tracking and forecasting operating expenses for their areas; and
- Willingness to embrace the practice as a new and ongoing approach to business, not simply a temporary cost-cutting effort.

The problem

In many companies expenses are coded and booked into a Chart of Accounts (Figure 1) in such a way that it is nearly impossible to precisely track and analyze individual cost accounts at the lease level. Although standard accounting principles provide guidelines, they still allow flexibility in how operating expenses can be assigned. Throw in variations resulting from multiple human coders (including clerks and accountants who might be only peripherally involved in field operations) or automated allocation routines and misinterpretation of account code definitions, and it's easy to see why accuracy is lost at all but the highest levels of the accounting hierarchy.

The solution

The solution is to create a system that removes ambiguity about account code definitions and about who is accountable for each expenditure. The first step is to openly discuss and decide on specific rules and practices that will be followed by all involved. While it is not necessary for every group in the company to settle on identical rules and practices, it is necessary that those within each work group agree to act consistently with each other.

It also is imperative that the company's accounting system and policies be up to the task of facilitating this

Typical Chart of Accounts
DIRECT
Salaries, Wages, & Benefits
Contract Services
Maintenance & Repair
Salt Water Disposal
Utilities
Chemicals
Paraffin Solvent
Operating Supplies
Equipment Rental
Transportation
Injection
Safety
Environmental
Automobile
Well Testing
All Other
Travel & Entertainment
Postage
Misc.
Permits & Fees
Subscriptions & Dues
Donations
Recruiting
Prof. Development
Office Equipment
PC Hardware
PR & Advertising
Relocation
Maps, Logs, Surveys, Etc.
Offshore Living
Fines & Penalties
INDIRECT
Department Allocations
Field/Facility Allocations
Property & Office Rent
Other Indirect

FIGURE 1. A typical Chart of Accounts can make it difficult to precisely track and analyze individual cost accounts at the lease level. (Source: Gilblom Consulting)

Introducing a new controlled optimization process for multistage completions

A field-level program based on consistent frac placement and measured downhole pressures and temperatures

Controlling key variables enables true optimization

You can't truly optimize plug-and-perf completions, because frac spacing and propped volume are uncontrolled variables. The same is true for openhole packer/ball sleeve completions. Even when a completion is economically acceptable, there is no methodical way to improve the design from well to well, because the number of fracs, frac spacing, and frac size are not controllable or repeatable.

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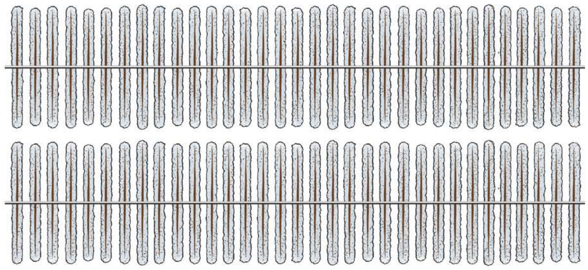
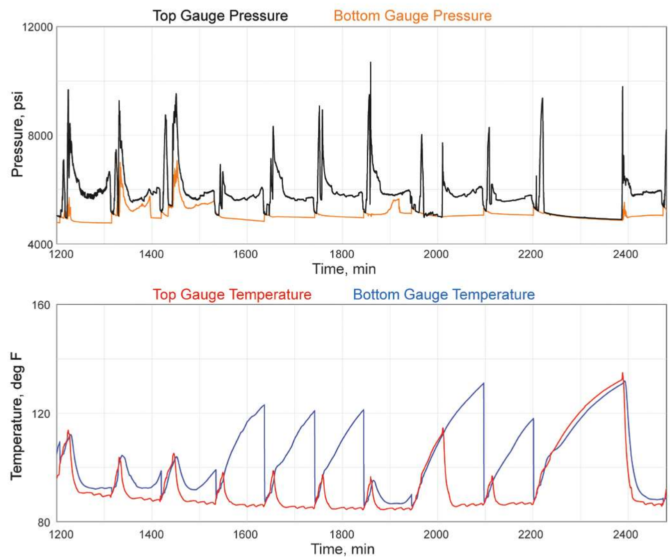
Recorded downhole data describes every frac

At every stage, our standard Multistage Unlimited frac-isolation assembly records actual pressures and temperatures at the frac zone and in the wellbore below (see chart at right). The data reveals both the presence and type of any interzone communication (natural fractures, cement failure, longitudinal frac), so you can establish minimum frac spacing in a given formation. The data also identifies the presence and source of near-wellbore restrictions, as well as proppant bridging, if it occurs. Stage-by-stage details give you insights you don't get with other multistage completion methods, unless you pay for separate and costly monitoring systems.

The combination of consistent frac placement and downhole data is your best and fastest route to truly optimized completions and field-development strategies. Learn more at ncsmultistage.com.



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



These charts show pressure and temperature above and below the isolation assembly for ten stages. The data reveals and describes any interstage communication and important frac and formation characteristics.

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Original M&R Account List	Modified M&R Account List
MAINTENANCE & REPAIR	MAINTENANCE & REPAIR
3100 M&R Supplies	3100 M&R Supplies
3101 M&R Supp Subsurface	3101 M&R Supp Sub Surface
3102 M&R Supp Surface	3102 M&R Supp Surface
3103 M&R Supp Mobile Equipment	
3104 M&R Meters & Instrumentation	3104 M&R Meters & Instrumentation
3199 Misc M&R Supplies	3199 Misc M&R Supplies (MS)
3200 M&R Labor	3200 M&R Labor
3201 M&R Labor Subsurface	3201 M&R Labor Sub Surface
3202 M&R Labor Surface	
3203 M&R Labor Major Maint Pro	
3204 M&R Labor Meters Inst	3204 M&R Labor Meters Inst
3299 Misc M&R Labor	3299 Misc M&R Labor (MS)
3300 Well Pull	3300 Well Pull
3301 Misc Well Pulling	
5700 Major Maint Provision	
	OTHER M&R
	3103 M&R Supp Mobile Equipment
	3202 M&R Labor Surface
	3203 M&R Labor Major Maint Pro
	3301 Misc Well Pulling
	5700 Major Maint Provision

FIGURE 2. Through group discussion, the original M&R Account List (left) was modified (right) to improve clarity and ensure common usage by all. (Source: Gilblom Consulting)

process. The system must facilitate drilling down to individual account codes and operating entities and be flexible enough to allow modification to account codes.

Step-by-step process

1. *Obtain and interpret your company's Chart of Accounts.*
   Review historical expenses in detail down to the lowest possible account code and the lowest possible operating entity. Understand current account definitions and actual usage, accruals and reversals, large regularly scheduled charges, issues related to government requirements, fixed vs. variable cost practices, and allocations to multiple entities.
2. *Document the definition of each account code as it is currently being used.*
   Ask people independently how they use the codes. Look for codes used as "dumping grounds." Understand who is using each code, including those in the office. Seek out ambiguity, redundancy, errors and inconsistency.
3. *In a team discussion, redefine line items as they will be used going forward.*
   Give each code a clear and unique definition. Use the definitions as written, redefining or supplementing only where necessary. Collaborate with other users to address their unique needs and obtain their buy-in.
4. *Assign each line item to an individual or a functional group.*
   Make each group immediately responsible for all charges to that code and, going forward, for budgeting as well. Follow up to assure that rules are being followed.
5. *Hold regular (monthly, quarterly) meetings to discuss expense results.*
   Require each group to discuss their line items using performance graphs, clear explanations and updated forecasts. Use these meetings to hand out guidance and praise.

The result

As the new program takes hold, the changed behavior of the personnel becomes quickly obvious. Individuals understand costs more clearly as they take ownership. Expenses trend lower as "anonymous" coding is eliminated, and the ability to forecast costs at the lowest level develops.

These forecasts have increased legitimacy since they are produced by those who are spending the money. Ownership of forecasts by the "money spenders" drives commitment to meet or beat them. This leads to costs trending downward naturally with no deterioration of operating efficiency. In this environment, production rates, safety and job satisfaction tend to improve as well.

Potential roadblocks

This is not a quick fix. Real benefits show only after several forecast/reporting periods. However, those benefits are sustainable over the long term. Although the program can be implemented successfully in a discrete operating area, cooperation of related groups is necessary.

For example, if central accounting has permission to code charges to individual accounts or apply allocation routines to multiple accounts, those actions must be consistent with the new practice. Or, if operating cost budgets are linked to a company's reserve system to facilitate quarterly Securities and Exchange Commission reporting requirements, the cooperation of the corporate reservoir engineering group is required.

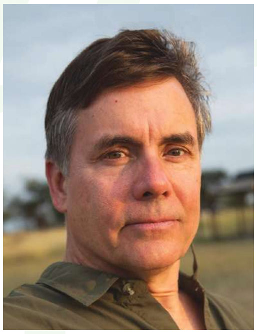
Some companies attempt to smooth reported monthly operating expenses by use of routine accruals and reversals. If the company is unwilling to change this practice, an alternative is to generate custom reports that exclude those monthly adjustments. Allocation routines such as "district" charges can seriously affect individual entity expenditure reports. These charges, as well as the routines, must be reviewed and necessary corrections made.

Even when implemented during a downturn, the correct approach to operating expense management can yield long-term cost savings and a more collaborative work environment. Roadblocks can be surmounted with a little creativity and tenacity. E&P

The view from the other side

Well-known geophysicist Michael Bahorich retired from Apache Corp. eight months ago. The break has given him some time to ruminate about the industry.

Rhonda Duey, Executive Editor



Mike Bahorich

During his 34-year career in the oil and gas industry, Mike Bahorich acquired nine patents, became president of the Society of Exploration Geophysics and generally solidified his status as an outstanding geophysicist. Now retired (but still almost working full-time) and a recent addition to the board of directors at Sigma^3, he sat down with *E&P* to discuss the state of the industry, new technological advances and how things are changing.

E&P: ***Why did you choose to join the board of Sigma^3?***

Bahorich: They understand something that is important, which is that the best answer generally doesn't come from a single discipline but from a team that provides a broader perspective. I've been on a number of academic boards, and some of the more successful universities will bring together people from different disciplines to solve problems. They know that they'll get a better product that way. No single person tends to have all the answers, so we often benefit from an interdisciplinary team.

E&P: ***Tell us about your early days at Amoco.***

Bahorich: The company drilled a dry hole in the Beaufort Sea that cost about $160 million in 2016 dollars. They asked me to take a look. So I looked at the data and wanted to map the patterns I saw in the seismic, but when I went to the workstation, there was no way to do that. So that was my first patent, which was interval seismic attribute mapping.

At that point they said, 'Bahorich, you're kind of a geeky guy, so we'll send you to the lab.' So I went to the lab for a few years. And I absolutely loved doing that. But I wanted to get back into exploration. So I became an exploration manager for Amoco.

E&P: ***How did you end up at Apache?***

Bahorich: They called me in 1996, and I asked Steve Farris what the corporate technical infrastructure of the company looked like. He said, 'We don't really have one. We're a relatively small independent.' The next 10 years or so was incredibly fun because I was fortunate to be on the management team, and company earnings grew 28 times under the leadership of Ray Plank and Steve Farris.

But there comes a time when the younger generation needs to take over, which is what happened at Apache, and I think honestly it's the right thing; it needs to happen. To me it was a very natural thing to leave. The young leadership needs to build their own team and do it their own way.

E&P: ***How is retirement so far?***

Bahorich: In all honesty I've been a terrible retiree. My initial plan was to not work very much and spend some time on a couple of boards, and I've ended up consulting almost full time. Part of the reason that I don't want to step out of the industry entirely is because I have enjoyed it, and although I'm very happy to have a new chapter, I'm not ready for the rocking chair.

E&P: ***Are you concerned about the dip in exploration spending because of the commodity price plunge?***

Bahorich: Right now the most important thing is for companies to survive. In some cases that might be trimming back exploration a bit, but for E&Ps most of the money is related to capital, and that makes it a little easier to survive by cutting capital and hanging on.

We all know that this low oil price is not sustainable. So I'm certain it will come back, and that's why it's so important to focus on survival right now. If you play your cards well in a downturn, you can make a lot of money when things turn around.

E&P: ***What role is technology playing, and what role will it play going forward?***

Bahorich: Technology has made a fundamental change in the way that we produce oil and gas. Let's take natural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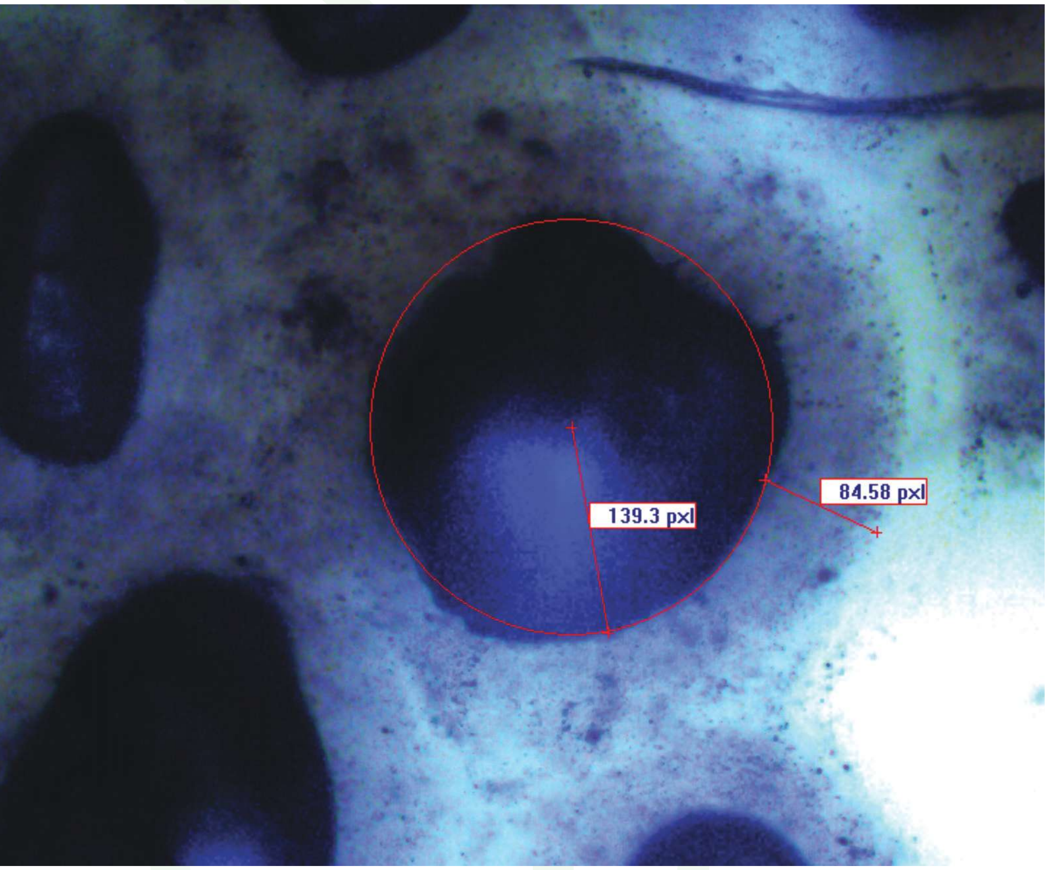


A polymer coating lowers the specific gravity and settling velocity of proppants. (Source: Superior Silica Sands)

gas for a starter. Natural gas will never have sustained high prices in my lifetime again. The simple reason for that is that the U.S. now has a 200-year supply of natural gas, and we have drilled enough holes to know where many of the sweet spots are. So we can now focus on quality acreage—the top one-half of 1%.

Secondly, every single year technology gets better. And there are several things that are being tested now that could end up making a big difference. One of the things I'm interested in is polymer-coated proppant. Some of the initial tests are starting to look reasonably good. The polymer lowers the specific gravity and settling velocity of the proppant. In addition, it puts a jacket around the grain, which helps prop it up.

Dissolvable plugs are interesting because they can eliminate the drillout. It will be interesting to see where cemented sliding sleeves go. It's currently a niche application, but if you can put a sliding sleeve every 60 ft [18 m], you can have fewer frack hits because you can control the half-length of your fracture better than you can with 10 clusters, one of which might take all of the fluid.

I think oil is a different scenario because it's a diverse global market. Unconventional technology will not keep oil prices at this low level. However, you can bring on unconventional oil pretty quickly in a high-price environment, and this will put a governor on the high end of the oil price.

E&P: ***How do you feel about the U.S. crude oil export ban being lifted?***

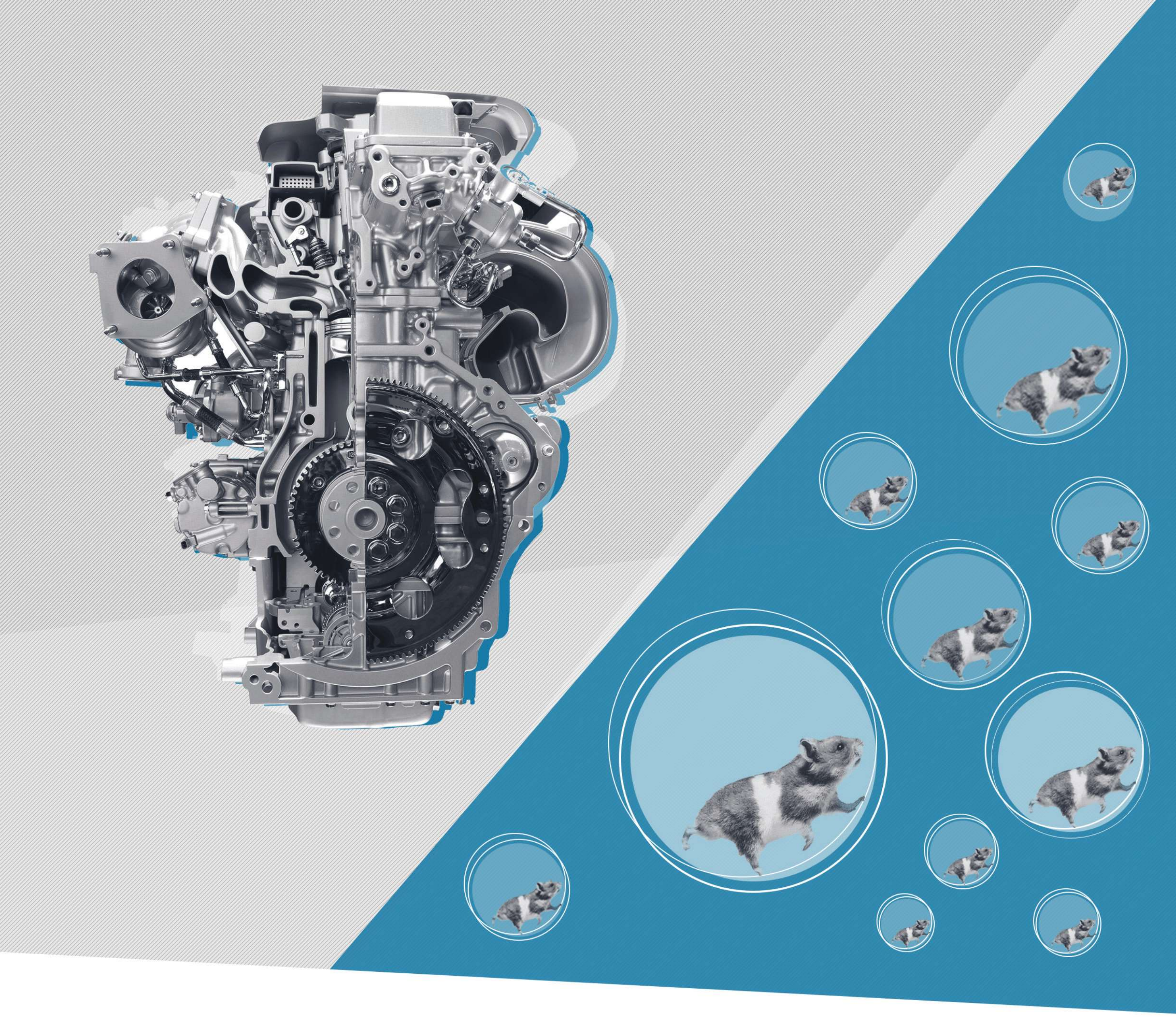
Bahorich: I think crude exports are a very good idea. Export bans were put in place at a time when the political and oil supply situation was very different than it is today. So it's good that people are able to change and do the right thing.

E&P: ***Are you concerned about the "great crew change" and the potential brain drain that results when people like you leave the industry?***

Bahorich: One of the things I did to provide a bit of help was to develop a Wikipedia for the oil and gas industry. The idea was to take the three professional societies in engineering *(petrowiki.org)*, geology *(wiki.aapg.org)* and geophysics *(wiki.seg.org)* and have them build wikis to provide knowledge from those that are leaving the industry. Young people get information today through Google. If you do a Google search on 'waterflooding' you will hit *petrowiki.org*, and that wiki now gets 300% of the hits of *spe.org*.

All three of my sons are petroleum engineers, and the most satisfying moment was when one of them called me and said, 'Dad, I'm using your wiki thing to solve a problem. I found it through a Google search.' That's the way young people do it.

What's really happening here is that the oil price is dropping, a lot of us are gone, and when the price comes back up, it will be a different industry. I think it'll be more computer-savvy with more young people in control. E&P



Drilling down

Land drillers are enduring collapsing utilization and deflating rig rates.

Richard Mason, Chief Technical Director

There is no rest for weary land contractors as the sector enters the second year of the worst oil and gas downturn since 1986. The Baker Hughes Inc. U.S. rig count is down more than two-thirds from the late 2014 peak, including an astounding 80% collapse in the Bakken, a demoralizing 73% decline in the Marcellus, an accelerating 69% erosion in the Eagle Ford and a sobering 52% drop in the Permian.

Indeed, as this edition of *E&P* magazine goes to press, the 70-week-long decline in drilling activity has become the second longest in the last quarter century. Should weekly rig count declines continue to the next edition of *E&P* magazine, this downturn will exceed the 1991-92 event, which at 75 weeks was the longest in a generation. Clearly, contractors are weathering an economic storm of historic proportions.

- **At 70 weeks, the decline in domestic rig count is the second longest drop in a generation.**
- **Contractors are stacking equipment rather than working below cash operating costs.**
- **Utilization is 40% or less in all major drilling markets.**

Although much has been said—and written—about the emerging performance characteristics of modern technology rigs, the reality is that severe downturns impact rigs in every class, as the 500-plus stacked Tier I AC-VFD rigs illustrate.

Hart Energy surveys of drilling contractors across the U.S. find utilization below 40% in all regional markets. February 2016 examples include 26% utilization among Midcontinent drilling contractors, 30% in the greater Rockies (ex Bakken Shale), 36% in the Permian Basin and 38% in the Eagle Ford.

Rig rates have followed. The steep activity decline at the close of 2015 coincided with an astounding 7% average quarterly drop in day rates across all rig classes. Rig rates for the benchmark 1,500-hp AC-VFD Tier I unit averaged less than $18,000 per day across the land market, down 27% from the $24,700 average when rates peaked during the newbuild boom in fourth-quarter 2012.

Those are average rig rates and incorporate higher rates from long-term contracts that have yet to run their course. When those contracts end, the benchmark 1,500-hp unit will enter a brutal spot market where rates are $16,000 and lower—assuming the rig does not stack out. Long-term contracts, which had been the norm under higher commodity prices when operators were scrambling to obtain rigs to convert unconventional acreage into production and reserves, have given way to month-to-month or well-to-well contracts.

"It is going to get cutthroat around here because there are so many rigs stacked and there is not any work," one mid-tier Permian Basin contractor told Hart Energy surveyors.

Another Midcontinent mid-tier driller noted the impacts on his business.

"We have just come to a stop, and quite frankly we are looking at the whole year as nothing. We are just going to continue to have everything laid down until the market improves for our piece of the business."

Reality has settled in for drilling contractors. Few expect activity to pick up in a meaningful way until pricing exceeds $50 on a sustained basis in the Midcontinent and $55 in the Bakken and Eagle Ford shales, according to regional contractors. Meanwhile, operators were belatedly announcing 2016 capital spending plans that called for drops of 25% to 50% over 2015 levels.

The drop in oil prices at the beginning of 2016 extinguished any remaining hope that contractors would see recovery in 2016.

All have cut wages, stacked equipment and pressured suppliers for lower costs. Some contractors have bid equipment at substantial discount only to find no takers since operators cannot make money in the present economic environment even if the rig provided is free. As contractors face diminishing options, many are stacking equipment rather than working below cash operating costs. All contractors are impatiently waiting for 2017. E&P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Planning for Shale 2.0

New tool helps find the sweet spots.

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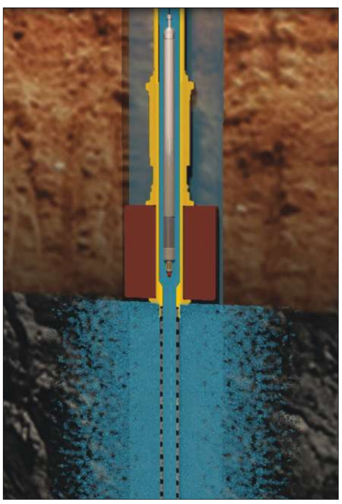
Raman spectroscopy is not a new technology—it was invented in 1928 and won a Nobel Prize in 1930. Raman spectrometers have been a common sight in universities and laboratories for years, large, hulking machines that take up entire rooms.

Not exactly the kind of thing you'd try to put into a wellbore.

But WellDog is doing exactly that. After using Raman technology in coal mines and coalbed methane (CBM) developments for years, the company decided to apply the technology in the shale plays in the U.S. Already it had miniaturized the Raman concept into a logging tool for CBM. It has taken that farther and now offers a tool with a 2.6-in. outer diameter for shales.

"Raman spectroscopy works by shining light of one color on a sample, typically using a laser beam, and then watching as the color of the light changes when it bounces off the sample," said James Walker, WellDog's COO. "The amount of color change indicates the energies at which the sample is excited, which is highly characteristic of each type of molecule, and provides a fingerprint indicating the presence of the molecule. More photons at those colors indicate more of the molecule in the sample."



Raman spectroscopy shines colored light onto samples and measures the energy that bounces back to fingerprint specific molecules. When used downhole, it can help find the sweet spots in a reservoir. (Source: WellDog)

He added that unlike other types of spectroscopy, Raman spectroscopy is not overly sensitive to water.

As shale operators face "Shale 2.0"—the use of Big Data analytics to harvest the vast amounts of information being captured in shale plays—a better reservoir characterization tool fits the bill nicely. The company's experience in coals has enabled it to work in high volumes, which is important in unconventional fields.

"As the volumes get bigger, our processes are fine-tuned," Walker said, adding that the complexity of shale reservoirs is not an inconsequential challenge.

The benefits of a downhole measurement vs. a core measurement are obvious. "The customer wants information as quickly as possible," he said. "It's instant information; it's a classic logging tool. The customer gets repeatable measurements and is not destroying its sample to get one answer from the lab three months later."

The tool is now ready for commercialization for shales after a successful beta te st earlier this year. A commercial launch was expected in late February.

"That's the dream," Walker said. "If you could log the well and identify the sweet spots with a direct measurement, that would be very valuable to the operators."

The company continues to work with the industry to find additional applications for the technology. It could potentially be used to measure fluids coming back from the wellbore as well as looking at cuttings to determine things like thermal maturity and total organic carbon. This in turn could help determine the relative ductility or brittleness of the rock. It already is being tested for use in EOR operations to determine how much CO_2 is coming into a monitor well.

"This has taken years of work from a Raman spectroscopy standpoint," Walker said. "We're talking to the industry on how we can best apply it.

"We're going to be here for another 50 years with shale, and this is the start of using a new suite of sensors," he emphasized. E&P

Windfall profits tax has new name: Transportation system tax

This time around the Obama Administration's proposed tax is more like a windfall losses tax that will do nothing to support U.S. energy independence.

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Although U.S. President Barack Obama's proposed tax of $10 per barrel is likely dead on arrival, it does point to continued efforts by the government to raise money. The oil industry is a convenient target for new taxes; however, this tax will hit the working class very hard through higher gasoline prices and increased crude oil imports.

The tax is framed to garner support for improving the nation's deteriorating transportation infrastructure. The administration wants to spend $300 billion over the next decade to expand rail and mass transit infrastructure while reducing greenhouse gases.

Rep. Joe Barton (R-Texas) quickly responded to the $10 fee per barrel. "I am in total disbelief that the president and his advisers would even entertain this proposal. This 30% tax on oil will not clean our air, it will not create a new transportation infrastructure, but it will hit the checkbooks of hard-working American families, and it will hurt our economy in countless ways.

"In three decades of working in energy policy, I cannot remember a more outlandish or impractical proposal. The administration has not seriously considered the destructive implications for millions of Americans and their communities. To me, this is a political stunt and is dead on arrival in the House [of Representatives]," he emphasized in a Feb. 4 press release.

This proposal continues a long tradition of the federal government seeking financial gain from the oil industry. The windfall profits tax harkens back to President Jimmy Carter's administration when the Crude Oil Windfall Profit Tax Act was passed in 1980. You might remember that administration for several other shortsighted but long-lasting actions, including banning use of natural gas in power generation and stopping exports of crude oil, which was only reversed recently.

Those low gasoline and diesel prices that consumers are enjoying at the moment would disappear in the slash of a pen. The benefit of low energy prices that manufacturers are realizing now would be gone with the smokescreen the administration is blowing.

The oil industry will keep the lights on despite tax proposals. (Photo by Mark Fox, courtesy of *Oil & Gas Investor*)

Such a tax burden would not result in any additional oil and gas production in the U.S. Instead, it would aid Saudi Arabia in decimating the U.S. petroleum industry. Given the current state of U.S. oil and gas companies, this proposal would increase the number of companies in bankruptcy court.

How President Obama can say he supports U.S. energy independence and make such an ill-advised proposal, I do not know. I guess he is counting on the opposition to the oil industry to pull the tax through.

What will be evident is the oil industry's dedication to meeting U.S. energy demand in the face of debilitating legislation. Keep calm, and drill on. E&P

Scott

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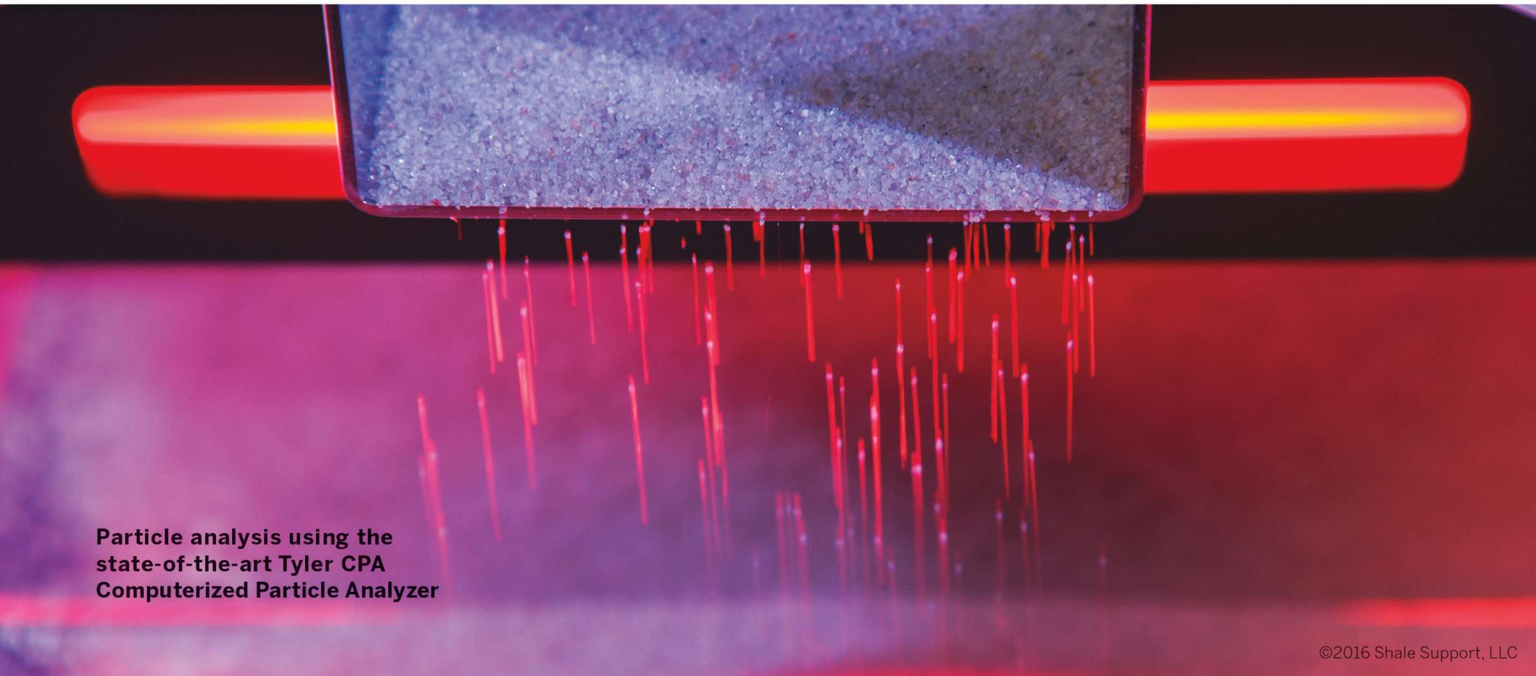

Particle analysis using the state-of-the-art Tyler CPA Computerized Particle Analyzer

Finding the positive

The price war helped make for a more competitive and efficient shale operation.

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Here lately it seems like there's been more bad news than good for the oil and gas industry. However, the clouds haven't been all black. If you look closely enough, you might spot a tinge of silver lining in one or two of them.

A few weeks ago I had the opportunity to speak with Fred Lawrence, the vice president of economics and international affairs for the Independent Petroleum Association of America, about what he thought were some of the bright spots in the less than shiny year that was 2015 and what 2016 might have in store. Here's what he had to say.

"From a 36,000-ft view, I think the largest positive so far—and it has probably gone a little bit unnoticed—is how the price war with OPEC did the disruptive thing of making the shale industry that much more competitive and efficient," he said. "It really accelerated the speed of progress. I believe it's going to be one of the large benefits of this conflict going forward, but in the near term that creates a lot of challenges for a company—especially those that are more financially leveraged.

"However, we've seen some major improvements by companies in terms of improving their IPs and their EURs while at the same time reducing their cost structure," he said. "For example, it could be through higher proppant volumes or longer, more efficient laterals, or more focus on their core plays, but companies are really accelerating the technological speed of improvement throughout this lower price environment."

As is often repeated, this is not the first downturn that the industry has faced. However, in this downturn, operators snagged a few pages from the history book to apply lessons learned in the past to weather their current situation.

"We saw this with natural gas companies when natural gas prices were low. Those companies have had a bit more experience at maturing their technologies and efficiencies under low prices," Lawrence said. "We've seen the oil and liquids companies go through this process of maximizing their efficiencies and cost structure as well as take advantage of the cost deflation on the service side. I believe it's a bright spot that will not go away."

Challenges will not be in short supply in the year ahead, and finding ways to balance them all will be key. Internationally, the reentry by Iran into the oil markets will impact pricing in the first quarter and possibly the second, he noted. On the domestic front, Lawrence sees that the regulatory policy will remain paramount, with particular focus on hydraulic fracturing on public lands with the Bureau of Land Management, crude exports and endangered species.

"I think those are probably our biggest issues going forward," he said. "[The year] 2016 will be a challenging year as everyone is convinced that this is a 'lower for longer' market. I am hoping that there is some relief going into the second half of the year. Balance is really going to be important." E&P

Jennifer

Subsea must shape up for $30 oil

With the subsea industry facing arguably its toughest year ever, companies have been told to get fit for $30 oil.

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Despite many subsea oil developments regarded as sub-economic at below $50/bbl, the subsea industry has been urged to "get fit" for $30/bbl oil. In the lower-for-longer price environment, subsea is seen as being particularly at risk because costs have soared. The sector is in danger of falling behind in the scramble to win new business.

The signs of a switch-off from subsea are emerging, and already Statoil, which has long been a champion of the subsea sector, has chosen an unmanned platform for its Oseberg Vestflanken development. Statoil also is weighing the pros and cons of subsea installations vs. unmanned platforms for Phase 2 of the giant Johan Sverdrup development off Norway. It will all come down to cost.

The subsea sector needs to get lean. (Source: Statoil)

The challenges facing the subsea industry were laid bare at the Subsea Expo in Aberdeen, where delegates were told that the cost of subsea developments have tripled over the past 10 years while subsea wells now take up to one-third longer to drill than they did 10 years ago.

CEO of Subsea UK Neil Gordon said, "We cannot keep hoping that the price, and therefore investment and activity, will pick up in a year or so. Transforming the way we work is crucial. A large dose of vision and courage from the leaders in our industry is needed to achieve the behavioral changes that will ensure we are profitable and sustainable at $30 [per barrel oil].

"Much greater collaboration will drive standardization and simplification, which are key to getting the cost base down."

Simplification is the new buzzword that the industry has added to the lexicon to join standardization and collaboration as antidotes for these challenging times.

Technip's President and CEO Thierry Pilenko, who has seen a few ups and downs in his career, also called for simplification at the recent GE Oil & Gas annual meeting in Florence, Italy. He said, "This is probably the worst crisis that our industry has known in a generation and maybe more. Most indicators are showing it is probably worse than in 1986.

"Nobody has a crystal ball, but we know what we can do, and we know what we must do. We need to do something about costs, and we need to do it now."

Cost cuts of 10% could be made fairly easily, he said, but in the short term contractors are being asked to make cuts as large as 30% to 50%, particularly for deepwater projects.

"We measure the amount of man-hours we spend engineering per piece of equipment such as compressors, and over the past 10 years we have gone from around 1,500 to 2,500 to 3,000," he added.

Analyst Douglas-Westwood (DW), meanwhile, warned of a shock for the subsea market in 2016. DW believes that subsea installation activity is yet to bottom out, with current backlog disguising the reality of the industry. A decline of at least 15% is forecast in global subsea tree installations in 2016. DW said it is important to note that backlogs are falling rapidly; only a few projects were sanctioned in 2015—a bigger jolt could be yet to come. E&P

John

Technology keeps drilling industry alive for next upturn

The oil and gas industry continues to design new ways of doing business to survive the current price downturn and prepare for the next upswing.

Scott Weeden, Senior Editor, Drilling

The Baker Hughes rig count reached its peak during the last week in December 1981, at 4,530 rigs. The rig count bottomed out at 488 rigs during the week ending April 16, 1999. With the rig count for the week ending Feb. 5, 2016, dropping to 571 rigs, the industry was facing another nadir for working rigs.

However, this particular downturn is different than previous drops in the market, and technology has played a major role in that difference. High production from shale plays continues to baffle industry forecasters. The technology developed for directional and horizontal drilling over extended-reach wells and long laterals has changed the game and will continue to change the game.

Technology transfer from other industries is making an impact on how the industry conducts its drilling operations, maintains safety and reduces risks. At the same time, adding a new perspective from other industries to old oil industry problems has provided some impressive improvements in efficiency and equipment dependability.

In this report, *E&P* looked at how GE Oil & Gas is fully integrating technology across all of its businesses. The articles also delve into continuous circulation MPD, new bit design for long lateral drilling, improving drilling with casing, implementing a new shale shaker design and enhancing oil-based mud.

The next generation of drilling technology is already in development, preparing for the next upswing in oil and gas markets.

Driving productivity using technology, data, collaboration

GE is working on an industrial Internet for all of its businesses. To be truly an industrial company in the future, a company has to go digital.

Scott Weeden, Senior Editor, Drilling

Imagine taking nondestructive testing (NDT) technology from the healthcare industry and using it to "fingerprint" BOPs. Or imagine taking a control system platform from the wind energy business for a very strong control system on the safety-critical equipment in the drilling industry. Imagine a companywide store concept that leverages things that come from the healthcare business, business models from the transportation or aviation business and material science that comes either from the aviation or turbomachinery business.

That's what GE Oil & Gas has in development along with other GE companies across many businesses aimed at technology transfer. The GE Store is a concept where innovation is leveraged from all GE businesses, explained Chuck Chauviere, president of drilling systems, GE Oil & Gas.

Driving standardization, analytics

At the GE Oil & Gas annual meeting on Feb. 1-2 in Florence, Italy, many of the operators at the meeting were saying that a great deal of optionality has been introduced into all of the deepwater solutions. That optionality has attracted challenges that impact cost and serviceability as well as the ability to replicate and leverage what was learned, Chauviere said.

"The industry is going to drive in a much stronger standardized way. To help with the service and cost equations, we need to have a very strong, structured product to solve the deepwater challenges. We have one big equation where we're working on structuring and standardizing the product so we can make it even more robust and apply that to the industry," he emphasized.

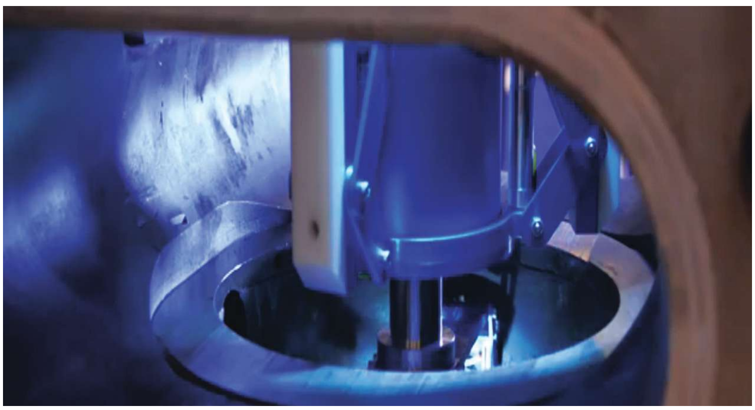
"The second piece is around analytics and data. The analytics or the data are going to come in multiple forms—collecting basic usage data on the equipment and then also getting the environmental and the fleet elements associated with those data such that we can feed that back into the structured product to increase overall equipment performance," he continued.

The theme for GE's conference this year for drilling was around how the industry drives productivity using technology, data and collaboration in different commercial models. People across the industry recognize that something different has to be done. That something different includes the primary pillars of being smarter with data, structuring and commercial models that can all improve the way value is delivered, he added.

One new commercial offering is a first-of-its-kind engageDrilling Services model announced with Diamond Offshore where the full accountability for BOP performance is transferred to GE Oil & Gas. In this model Diamond Offshore will compensate GE Oil & Gas only when the BOP is available, incentivizing reduced downtime and improved BOP system reliability.

"We have launched a site as well as a services platform called 'engageDrilling.' We're trying to be successful at closing the white space between a customer request and the customer getting an answer to that request.

"We realize that to be contemporary and to pull all this together, we need to be a much simpler and more



GE is leveraging technology from its healthcare business for *in situ* NDT of BOPs. The method reduces downtime, improves productivity and reduces costs. (Source: GE Oil & Gas)

efficient organization. So we've launched engageDrilling. In there you can actually see your orders progress through our factory. You can place orders. You can research deliveries and prices. You can see what your history was, if there are engineering bulletins on the equipment and if you have your data books associated with the equipment. We have online videos on how to work on the equipment," Chauviere explained.

"Effectively anything you can imagine with regard to the customer-OEM relationship we have put onto the *engage Drilling.com* site. They can see their rigs. They can see where their assets are located. When they're connected with the SeaLytics package, they can actually pull up what their rigs are doing and how they're performing," he continued.

NDT technology from healthcare business

"An example of leveraging our 'GE Store' of technology solutions is using what is going on in the healthcare business for [NDT] technology for BOPs. What we're doing now will benefit not only the operators but the drilling contractors. How can you minimize the inspection requirements for a system in a way that can leave the equipment assembled and just perform the 4-D digital fingerprinting *in situ* inspection at regular intervals to monitor how the equipment is changing over time? The *in situ* inspection is something that we're leveraging from the healthcare business," he said.

"A rough example of that is on some of the older units that we've inspected offshore where we've been able to reduce inspection time by 75% by leaving the equipment in place and using this inspection technology. That way we don't have to disassemble the equipment to perform the inspection. That's just a great example of how we leverage what we're doing in other industries to drive productivity, reduce the cost and decrease the intrusive amount of inspection time," he continued.

"Obviously, the fourth dimension is going to be change over time. Digital fingerprinting is our simple word for effectively getting a fingerprint of the equipment. Then at periodic intervals we can run this technology to monitor how it changes over time."

That is used to feed predictive or condition-based maintenance. Based on what is known of the environment, where the equipment is being run and how it's being used, those data can be used on the backbone of GE's Predix package, which is where SeaLytics runs. The company can then begin to predict the performance of the equipment as opposed to just doing maintenance based on either cycle counts or calendars.

GE's industrial Internet

GE is a digital industrial company working on an industrial Internet for all of its businesses. Industrial apps at users' fingertips will be run on the back of Predix. This will be used in all GE businesses including turbomachinery, aviation, healthcare, and oil and gas. "This is something that GE has been investing in over the last three years in San Ramon, Calif. We have a software center there that is a sizable investment, in the range of about $1 billion. We do believe that to be truly an industrial company in the future, companies have to go digital," he emphasized.

"We have developed a cloud-based and very cybersecure space where we are framing this backbone, which is called Predix. It is where we will store all the data. On top of that, we'll run these applications that we're going to have through SeaLytics," he added. "This is that concept of leveraging the GE Store across the businesses."

The SeaLytics package will use Predix, which is an upfront open architecture. "We're going to encourage our clients and others to help develop the applications that we can all utilize to improve their personal relationship with the equipment and, even better, where the equipment actually talks to one another," he explained.

For example, SeaLytics will feed off the BOP sensors and the BOP control system. It will capture the information, process that information and display it to the user both on the rig and onshore. The operator can look at its entire fleet from onshore and do its own remote assessments of asset performance.

Robust control system from power generation sector

The SeaONYX BOP control system is another example where GE has infused technology that is used in the power generation sector. "We've taken a control system platform that uses our Mark VIe controller pack, which is normally utilized to control the end range of 40,000 to 50,000 datapoints. We're using it in the drilling application, which is something less than 2,000 datapoints. We're using a very robust control system to go to the field and upgrade clients such that we can have a very strong control system on safety critical equipment," Chauviere said.

When SeaONYX is connected to the SeaLytics package, an operator can really start to gain the ability to obtain data and to control the system in an enhanced way. That is how BOP availability is increased, he emphasized. E&P

MPD, continuous circulation systems increase safety levels, performance

The next generation of fully automated drilling rigs will be designed with continuous circulation as an integral part of the mud system.

Scott Weeden, Senior Editor, Drilling

High safety standards on the drilling rig floor combined with the reliability of the system's components are in line with Drillmec's philosophy in all drilling operations. The future of the industry is to move to fully automated remotely controlled drilling rigs, increasing safety standards and profitability, said Angelo Calderoni, vice president, R&D and marketing, Drillmec.

"Consider that in offshore activities 25% of the kicks happen during drilling and circulating, 25% are related to making connections and the last 50% are related to tripping the drillpipe in and out of the well. Through the integration of the Heart of Drilling (HoD) system in conventional rigs, it is possible to avoid 75% of the kicks, those related to making connections and tripping phases. The 25% remaining kicks that can happen during drilling can be immediately detected and mitigated," he explained.

The HoD manifold, connected to the rig mud circuit, acts to divert flow from the standpipe line to the clamp and then to the valve, ensuring uninterrupted mud circulation when the top drive is disconnected. (Source: Drillmec)

E&P interviewed Calderoni on continuous circulation and managed-pressure drilling (MPD) systems and how those systems will become standard equipment on all new rigs.

E&P: ***Why does the drilling industry need continuous-circulation MPD techniques? How will this contribute to a more fully automated drilling system?***

Calderoni: In situations with a narrow drilling margin between pore-pressure fracture gradients, it is not unusual that a well is abandoned before reaching the target, thus failing technical and commercial objectives.

In the last decade, technologies such as MPD and continuous-circulation systems have been developed to manage bottomhole pressure and its related problems. In my long experience in drilling wells all around the world, I have utilized both systems. But for different reasons I believe that interruption of mud circulation for a connection is one of the main causes of typical drilling problems.

The mud acts as the first safety barrier in the well. Most frequent drilling accidents happen when the mud pumps are off due to bottom fluctuations in ECD [equivalent circulating density] and downhole pressure spikes like connection kicks or stuck pipes can happen. In conventional drilling this 'stop/start' cycle of mud circulation occurs very frequently, every 9 m, 18 m, 27 m or 36 m [30 ft, 60 ft, 90 ft or 120 ft] of hole being drilled.

With continuous circulation, the formations do not suffer from pressure oscillations, hole-cleaning improves and the ability to pump out of the hole for extended intervals usually means the string can be moved until it is inside the previous casing, reducing the chance of problems in open hole. I have drilled more than 150 wells onshore and offshore with continuous circulation, always reaching the target. Sometimes continuous circulation made the difference that ensured achieving the target.

This process requires the continuity of drilling operations, where the first objective is the continuity of the first safety barrier, the hydraulic barrier. Important data can be collected from circulating mud, while every time we stop the mud circulation we lose the link with the bottom.

E&P: ***How does the Heart of Drilling system work and what are the advantages?***

Calderoni: The HoD was designed by Drillmec to prevent drilling accidents and improve drilling efficiency. It com-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Before starting the connection/disconnection of the drillpipes, the mud flow is diverted to the manifold. Two operators set this clamp on the sub and move away to a safe position. (Source: Drillmec)

bines the advantages of continuous circulation (HoD^{CC}), a high-resolution flow-rate monitoring (HoD^{FM}) system and an anti-friction device (HoD^{AF}).

In line with Drillmec's philosophy, everything in the HoD's continuous circulation system is designed to guarantee high safety standards on the drill floor, system components' reliability, and easy and fast rigup-down in all rigs in operations.

The HoD^{CC} is composed of a set of valves, integrated in special subs mounted on top of each drill stand used to drill well phases with continuous circulation. Subs are compatible with all sizes of drillpipes, from 4½ in. to 6⅝ in., and their inside diameter allows wireline intervention.

The clamp provides the valve to open and close in a fully automated way, avoiding all kinds of hand-based operations on pressurized equipment. The HoD manifold, connected to the rig mud circuit, acts to divert flow from the standpipe line to the clamp and consequently to the valve, ensuring uninterrupted mud circulation when the top drive is disconnected from the drillstring.

The HoD^{CC} introduces changes to the conventional mud flow circuit only during drillpipe connection/disconnections. Before starting the connection/disconnection of the drillpipes, the mud flow is diverted to the manifold, and in a few seconds the system is able to start the flow switching sequence. Two operators set the clamp on the sub and move away to a safe position where a human-machine interface [HMI] is located.

The HoD's valve configuration consists of a double mechanical barrier between the mud pressure inside the pipes and the outside (both with a working pressure of 7,500 psi), ensuring high safety standards on the drill floor and in the well.

One operator can manage and monitor all phases of the flow's switching sequence by means of a dedicated XHoD control system and its HMI, from the driller control cabin or a safe position. After the pipe connection/disconnection, the mud flow is restored to the conventional standpipe line, the HoD manifold is disconnected and the clamp is removed from the sub.

E&P: ***What is the value of the high-resolution flow-rate monitoring system, and how does it work?***

Calderoni: Drillmec provides high-resolution flow-rate monitoring, where two measuring skids perform data acquisition from the circulating mud, allowing an accurate monitoring of mud parameters over a large range of flow rates, mud weights and types and providing a real-time alarm if influx of formation fluids or mud losses arise.

The combination of continuous circulation and flow-rate monitoring is an open-loop MPD, where continuous circulation acts as prevention of accidents, ensuring continuity of the hydraulic safety barrier, and the flow-rate monitoring helps operators to quickly make the right decision in case of kicks or mud losses.

E&P: ***Why is the anti-friction device important?***

Calderoni: The Drillmec patent-pending anti-friction device provides a wear-resistant and low-friction coating layer that reduces friction between the drillstring and the internal casing surface, particularly during extended-reach drilling. The device can be mounted on each HoD sub, ensuring maximum protection of casing surface and a reduction of stresses coming from the drillstring to the top drive.

Combining the continuous cuttings' transport ensured by continuous circulation with a friction reduction in the well makes it possible to increase the length of horizontal wells.

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NOV Rig Systems

E&P: ***What are the safety implications of the HoD system?***

Calderoni: The HoD package has been designed in compliance with the main industry standards for a working pressure of 7,500 psi and a maximum flow rate of 1,200 gal/min. The double safety barrier configuration of the HoD valve and the full remote control of any operation guarantee very high safety standards, in line with Drillmec's hands-off philosophy.

With the XHoD's HMI, the operator can manage and monitor continuous circulation components and high-resolution flow-rate monitoring data. It provides a full and clear overview of the status of any system components, focusing on the status of any HoD manifold valve, pressure line and main function of the HoD clamp.

During operations the software provides help to operators with help text messages and warnings.

E&P: ***What will be the next generation of MPD systems?***

Calderoni: Drilling 'continuously' is the present for some operators and will be the future for the entire industry. Preventing accidents and cost savings are the crucial aspects.

Continuous circulation increases both safety levels and performance with a very simple economically feasible configuration that can be easily integrated in all rigs in operation.

Similar to what happened for the top drive, the continuous circulation technology will be fully integrated into all new drilling rigs after a period where continuous circulation is provided as a service.

The next generation of fully automated drilling rigs will be designed considering continuous circulation as an integral part of the mud system. Drillmec, following its focus on innovation, has developed a new generation of fully automated hydraulic rigs for deep wells, named AHEAD, where the technology is already integrated. E&P

Montney drilling benefits from targeted bit design, cutter development

Cutters comprised of a new diamond material composition were 30% more thermally stable with 20% higher abrasion resistance.

Kevin Schader and **Devin Mintz**, Varel International

Changes in bit design and cutter enhancement aimed specifically at Canada's abrasive Montney Formation have significantly improved drilling performance in the competitive play. Altering bit wear profile, cutter positioning and other bit characteristics resulted in a 38% to 61% ROP increase and 55% to 105% increase in meters drilled in two different Montney applications.

The Montney is an abrasive, medium-to-fine grained lithology composed of interbedded siltstone and shale with dolomitic siltstone and fine-grained sandstone in the upper layers. The bit application is rotary and motor drilling in the horizontal section. Bits used in this hole section must typically address low-impact, high-abrasion conditions, although impact does occur when steering in and out of the formation.

To increase ROP and meters drilled, a Varel 156-mm (6⅛-in.) V613PDUX polycrystalline diamond compact bit was modified over several design iterations. Varel's proprietary design software allowed designers and field engineers to specifically address the formation and application.

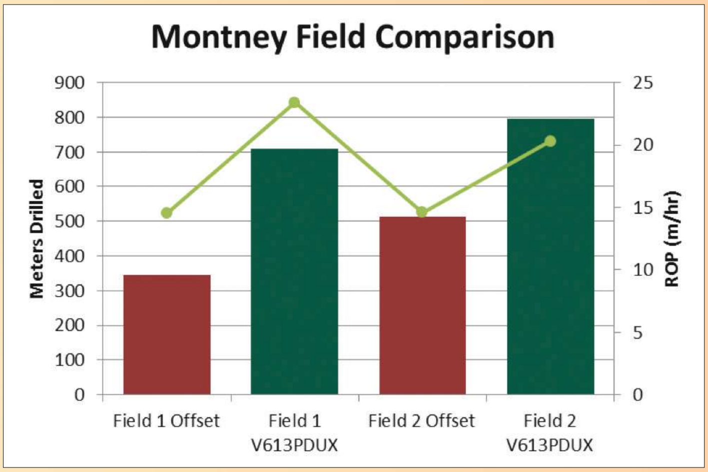
The program employs advanced algorithms, rock analytics, and extensive field operating and performance data directly from the rig to determine how changes in bit features will affect bit steerability, balance, cutter loading and vibration control for a particular well trajectory and bottomhole assembly.

The objective and end result of the bit redesign was to increase the average ROP from about 12 m/hr (39.4 ft/hr) to 15 m/hr (49 ft/hr) to 15 m/hr to 19 m/hr (62.3 ft/hr) while increasing the number of meters drilled from 300 m (984 ft) to 500 m (1,640 ft) to about 700 m (2,296 ft) to 800 m (2,624 ft).

The first design iterations were directed mainly at durability, which also would positively affect overall ROP. It repositioned cutters to more evenly distribute loading forces across the face of the bit and increase the diamond volume coming in contact with the formation. That improved performance but did not meet the final ROP and meters drilled objectives.

That led to the final design iteration, where cutters comprised of a new diamond material composition were incorporated. The cutter was developed in the Varel Technology Center using proprietary tests for measuring material toughness, abrasion and thermal stability. The new cutter is 30% more thermally stable and has 20% higher abrasion resistance than previous Varel cutters.

The Varel bit development process directly improved drilling results in the Montney Formation. The combination of bit design and cutter research supported the successful development of a targeted bit achieving the goals for this application. E&P



The total number of meters drilled and ROP both increased in the Montney Formation using a new diamond material composition that was incorporated in the cutter. The composition was developed in the Varel Technology Center. (Source: Varel International)

Advanced drillable casing bit reaches TD in record time

The technology was introduced to European-Caspian land drilling in early 2013 and has successfully drilled more than 43 well sections.

Ming Zo Tan and **Daniel Balasa**, Weatherford

Drilling techniques that go beyond conventional methods to reach total depth (TD) with lower costs and reduced nonproductive time (NPT) are essential as operators strive to boost recovery potential in deeper, more complex and aging oil fields. Drilling with casing (DwC) or liner, which enables simultaneous drilling, running, setting and cementing of casing at TD, has gained increasing industry acceptance over the past decade to meet the economic demands of reducing downhole complexity, drilling through unstable hole intervals and mitigating hazards.

Today DwC is commonly used in a wide range of wellbore types worldwide. By drilling the hole and setting casing in a single trip, operators can save time and mitigate a number of the problems normally encountered while drilling, tripping and running casing. The technique also simplifies well architecture by reducing surface casing size or eliminating contingency casing and liner strings and improves cementing and long-term well integrity.

In an ongoing project with integrated oil company OMV Petrom, Weatherford's European-Caspian Division has performed several single-run DwC operations on multiple well sections, significantly reducing time and achieving a time-savings record to reach TD. The centerpiece of the nonretrievable DwC system is an advanced drillable casing bit. The uniquely engineered polycrystalline diamond compact (PDC) bit is highly durable, which enables it to achieve high ROP for fast and easy drillout without damaging the drillout bit.

The operator's objective in this case was to reduce rig time and NPT, primarily by eliminating dedicated wiper trips in low-budget wells and to safely reach TD without HSE issues. The wells are located across several aging onshore oil fields, including the Babeni, Vata, Bustuchin, Slateoara and Preajba fields in Romania as well as Austria's Vienna Basin, which are characterized by soft-to-medium clay/sand formations.

Since the technology was introduced to European-Caspian land drilling in early 2013, the operator has successfully drilled more than 43 well sections using the Weatherford nonretrievable DwC system in conjunction with the Defyer DPA Series drillable casing bit. Weatherford has deployed DwC systems in 9⅝-in. and 13⅜-in.

OMV Petrom has drilled more than 43 well sections using the Weatherford nonretrievable DwC system and Defyer casing bit. (Source: Weatherford)

The Defyer DPA Series drillable casing bit can be drilled out with any standard oilfield drillbit. (Source: Weatherford)

vertical well intervals ranging from 350 m to 900 m (984 ft to 2,953 ft) in length. In one case, where the casing was not run to surface, a 7-in. drilling-with-liner application was deployed.

OMV Petrom selected Weatherford's integrated DwC approach after an initial test verified the system's capability to deliver a wide range of operational benefits, including significantly improving drilling efficiency, ease and time of drillout, which resulted in substantial savings in cost and time.

Casing set at TD in single runs

The system, which has drilled all the well sections in a single run, enhances operational safety with simplified and streamlined procedures, less manual handling of tubulars, and minimal rig floor equipment. Drilling efficiency is maximized by eliminating conventional drillstring tripping and the associated trip margin required to mitigate the swabbing effects caused by tripping out of the hole. It also reduces sticking problems and keeps trouble zones behind the pipe. It is designed to overcome drilling hazards caused by depleted zones, pressure transitions and wellbore instability; to eliminate lost circulation; and to reduce mud costs.

In undertaking the multiwell project, Weatherford applied an engineered approach that relies on upfront planning. Prior to deploying any equipment, offset well data were analyzed to determine formation drillability and performance to advise the operator of the suitable casing bit choice and establish drilling parameters for executing the operation in the required time per nonretrievable procedures.

The integrated solution also includes a poppet-valve float collar, installed one joint of casing above the casing bit, which helps to prevent U-tubing during the primary cementing operation. The string also includes one or two Weatherford SpiraGlider centralizers on the first casing joint followed by one every third joint to the surface.

The fit-for-purpose Defyer drillable casing bits are designed for drilling with casing in soft, medium and medium-hard formations and are rated to 204 C (400 F). They feature a proprietary thin steel-alloy strip that is brazed with PDC cutters and mounted to the aluminum blade using a unique interlock profile. Multiple models are available, with various blade counts and cutter sizes to suit the targeted distance and rock hardness.

A key design feature of the DPA series is a selectable blade count and a cutter size that can be configured to suit the formation type and application. The blades are made of a special steel alloy, and the PDC cutters are mounted on the face of the tool to maximize drilling efficiency and durability.

Because about 80% of the core drillout area is composed of drillable aluminum, the Defyer bit is extremely fast and easy to drill out. This enables operators to continue drilling to TD with the planned bottomhole assembly using any standard oilfield drillbit, including a PDC drillbit, without compromising drillout-bit durability.

This improvement over conventional casing bits eliminates the need to make dedicated drillout trips and/or to pull out of the hole due to bit damage. A damaged or partially damaged bit also can negatively impact ROP. Interchangeable nozzles composed of either copper or erosion-resistant ceramics are available to ensure optimal hydraulics, bit cleaning and drilling performance. The nozzles, which come in a range of sizes, can be removed and replaced easily at the drillsite.

Achieving time-savings record

After completing each DwC operation, the operator had the option of drilling out the casing bit using either roller cone bits or PDC bits. For the Caspian operation, the operator chose a light-set aggressive PDC-drillable casing bit suited for the soft-to-medium formations. It took between 30 and 60 minutes to drill each shoe track, including 10 to 15 minutes to drill out the Defyer casing bit.

To date, each section has been drilled in between 11 and 53 hours, depending on length, with an average on-bottom ROP of 33 m/hr (108 ft/hr). Notably, the team drilled a 355-m (1,165-ft) measured depth section in 10.6 hours with an on-bottom ROP of 67.5 m/hr (221 ft/hr) and a 354-m (1,161-ft) section in 11.7 hours with an on-bottom ROP of 59.5 m/hr (195 ft/hr).

One 344-m (1,129-ft) section, which the operator anticipated would take 28 hours, was drilled in 14.75 hours with an at-bottom ROP of 28.8 m/hr (94 ft/hr) and zero NPT. In reducing the drilling time by 47%, the DwC system produced considerable cost savings.

The operator is planning to deploy the integrated DwC system in two additional well sections. With more than 1,500 global deployments in land and offshore operations, the nonretrievable DwC system has achieved a success rate of more than 98%.

Compact solids control system provides effective fluids management

Better control of solids reduces the need for chemical additions to the drilling fluids and minimizes the rates of dilution typically used.

Brandon Buzarde, Cubility

The current low oil prices, decline in drilling activity and focus on the bottom line has brought the effectivenessof drilling fluids management into the spotlight like never before.

In North America, for example, the drilling fluids market—valued at $4.3 billion in 2012—is expected to reach $7.2 billion by year-end 2019, according to industry anlysts Transparency Market Research.

With costs and the demand for drilling fluids predicted to continue to rise (despite the current low oil prices anddrilling activity), it's clear that maintaining the quality and effectiveness of such drilling fluids is vital. Drilling fluids (or muds) play a crucial role in global drilling activity today—cooling and lubricating drillbits, carrying drill cuttings to the surface, controlling pressure at the bottom of the well and ensuring that the formation retains the properties defined for that well. Drilling fluids also need to be capable of keeping the cuttings in suspension when circulation is stopped to prevent the cuttings from accumulating on the bottom of the hole and causing pipe sticking.

How can drilling fluids be optimized to ensure maximum drilling efficiencies and performance on both offshore and onshore wells? A successful drilling fluids strategy and the effective separation of drilled solids from such fluids are crucial to protecting fluid quality and enhancing drilling performance.

Drilling fluids are vacuumed through a rotating filter belt using high airflow to separate the cuttings from the fluid more effectively. The MudCube is a compact solids control system that eliminates using high levels of vibration to separate fluids and solids. (Source: Cubility)

Effective solids control

Any effective drilling fluids strategy is dependent on the efficient separation of drilled solids from the drilling fluids since rock particles and cuttings can vary in size and texture from fine silt to gravel. The higher the percentage of solids removed, the more efficient the drilling fluid will be.

Effective separation leads to operational, cost and environmental benefits for the operator. From an operational standpoint, better quality fluids and stable mud properties result in low equivalent circulating density (ECD), which is the density exerted by the circulating fluid against the formation.

It also preempts the risks associated with high ECD such as induced fractures, lost circulation and high fluid loss. Effective solids control also provides higher ROP, reduced risk of stuck pipe and improved wellbore stability.

From a cost perspective, better control of solids reduces the need for chemical additions to the fluids and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The MudCube system provides improved drilling efficiencies though stable mud properties and a decrease in NPT. (Source: Cubility)

minimizes the rates of dilution typically used when solids removal efficiency has not been optimized. With the cost of oil-based mud around $1,300 per cubic meter, the reduction in the cost of drilling fluid per offshore well can be as much as $150,000.

Environmental issues

There is an additional cost as well as an environmental issue. Effective mud and solids separation leads to less waste and reduced costs. On the Norwegian Continental Shelf, for example, the treatment and disposal of drilling waste is conservatively estimated at $1,580 to $1,750 per ton, and onshore costs for waste disposal are also significant.

From an environmental perspective, the Transparency Market Research report said that the drilling-fluid market is facing some tough challenges, such as "growing environmental concern toward the excessive usage of drilling fluids and their disposal, which can lead to dangerous contamination."

At a time when there is an increased focus on the environmental impact of drilling (e.g., the recent and ongoing gas emissions in Los Angeles), reducing the volume of fluids lost is a critically important component in meeting environmental regulations while reducing the costs of disposal and treatment.

Addressing the challenges

Are today's solid control technologies meeting these criteria and supporting drilling fluids management and drilling operations?

Previous solid control solutions have been based around shale shakers, where through vibrating G-forces solids are filtered out for discharge or treatment and then incorporated into the fluid system.

The high G-forces, however, tend to break down the drilled solids into finer particles, reducing the amount of solids that can be removed and increasing the solids content in the drilling fluids. High volumes of mud also are often lost with an increase in the volume of drilling waste generated.

It's in answer to these challenges that Cubility has developed the industry's first compact solids control system called the MudCube. The system eliminates using high levels of vibration to shake the fluids and solids apart.

Rather than relying on high G-forces to separate mud and drilled solids, drilling fluids are vacuumed through a rotating filter belt using high airflow to separate the cuttings from the fluid more effectively.

The cleaned drilling fluids are then returned to the active mud system, and the drilled solids are carried forward on the filter belt and then discharged.

The separation capabilities of the system lead to better quality mud, more mud recycled back to the mud tanks to be reused for drilling and fewer chemicals. An operator and mud company, for example, reported the reduced use of premix chemicals brought savings of as much as $270,000 when using Cubility's system.

The system also provides improved drilling efficiencies though stable mud properties and a decrease in nonproductive time (NPT). Furthermore, as mud properties are field-proven to be stable throughout the entire well when using the system, there are corresponding low-maintenance requirements to control drilling fluid properties with optimum parameters. This provides significant financial benefits to expensive onshore and offshore drilling rigs.

Offshore, onshore applications

Cubility recently signed a multimillion dollar deal on the Johan Sverdrup Field, one of the most important industrial projects in Norway over the next 50 years. Production startup on the field is scheduled for year-end 2019 and will consist of four platforms on which the MudCubes will be based.

In this case, the MudCube will provide Statoil with improved drilling efficiencies, lower mud consumption, reduced waste volumes and improved HSE.

Other offshore applications include the installation on the *Maersk Gallant* rig, where the system is addressing space utilization and HSE issues; the Peregrino A platform operated by Statoil Brazil, where the conventional solution was not controlling solids effectively when drilling in sand formations; and the *Maersk Gallant* rig.

In addition, the system is gaining considerable traction onshore North America, where the rise in drilling costs and declining oil price have increased the need to monitor the bottom line and put in place effective fluids management strategies.

To this end Cubility is in the final stages of kicking off multiple U.S. land trials with major operators and drilling contractors. Initial cost analysis based on various land operations from a fluid cost and disposal standpoint show the MudCube reducing overall operating expenses by as much as 15% per well.

This is a significant figure based on the fact that many U.S. land drilling operations are now based on pad drilling with multiple wells drilled much more quickly and efficiently.

The separation of drill cuttings and fluids is central to optimizing drilling performance and maintaining drilling fluid parameters.

Operators now have the tools for effective fluids management and solids control strategies at a time when a focus on the bottom line and drilling performance has never been more important. E&P

Emulsion technology reduces O/W ratio to 40/60

Lower costs result by reducing usage of diesel/synthetic oil and chemical surfactants and lessening the HSE impact associated with emulsion-based mud fluids.

Corey Patterson, ViChem Specialty Products

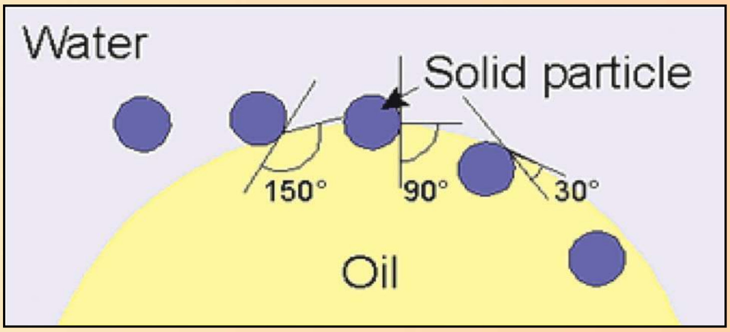
Due to the downturn in the market and the negative environmental impact of emulsion-based drilling fluids, ViChem Specialty Products set out to determine the viability of lower ratio oil-water emulsions other than the traditional 80/20 diesel/synthetic-based drilling fluids.

ViChem started a diligent R&D project to develop its HyperOil Technology. The company was working with Pickering emulsion based on solid-stabilized emulsions as these might advantageously replace conventional emulsions containing tall oil fatty acid-derived surfactants. In Pickering emulsions, the stabilizing film between the droplets includes very rigid layers, providing a mechanical barrier against coalescence.

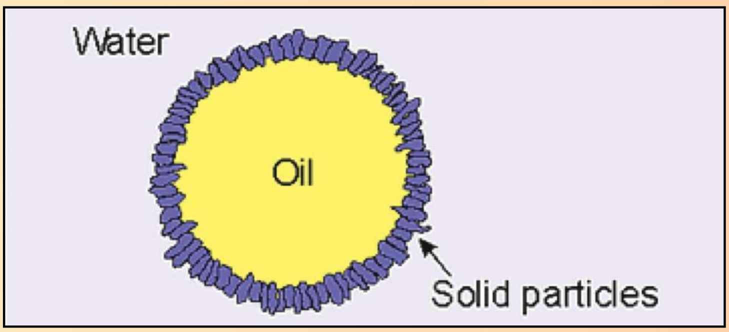
The solid particles are irreversibly anchored at the oil-water interface and develop strong lateral interactions. The aim of this technical research is to exploit the solid particles as stabilizing agents to easily obtain a large variety of new materials such as direct oil-water and invert water-oil emulsions that are surfactant-free.

The initial goal was to prepare emulsions of great complexity and instability, common in emulsions with an oil-water ratio from 50/50 to 40/60. These emulsions have a range of benefits:

- Lower cost in terms of reducing diesel/synthetic oil usage, chemical surfactants and the HSE impact associated with emulsion-based muds;
- Free of inorganic salts such as sodium or calcium chloride, which have well-known negative environmental impacts;
- Aid in creating low-weight drilling fluids to drill subpressured areas where fluid losses will be critical; and
- Reducing environmental costs for the treatment and disposal of water-based muds, which might be used as one of the phases of the proposed new emulsions. E&P



The contact angle on the emulsion influences the stabilizing action of the solid particles. (Source: ViChem Specialty Products)



Solid particles are used in stabilizing the emulsion. (Source: ViChem Specialty Products)

Keeping dust down on proppant use

In advancing dust control technologies for use during fracturing operations, worker safety is improved, and the impact on air quality is reduced.

Matthew Navea, Preferred Sands; and
Peter Rozowski, The Dow Chemical Co.

Hydraulic fracturing is one of the final steps in completing a well in preparation for production of oil and gas, a process requiring a mixture of water, proppant and chemicals to be pumped downhole at extremely high pressures. Silica sand proppant is a key ingredient that is currently in high demand because of its durability, and its shape and size are well suited to prop open fractures in shale formations.

Regulatory parameters

Despite silica sand's benefits as a proppant in hydraulic fracturing, it generates crystalline silica dust during handling and transport. When exposed to and inhaled by workers onsite, it is associated with the risk of developing silicosis, an incurable but preventable disease that causes lung damage. Workers with silicosis have an increased risk of serious conditions such as tuberculosis and lung cancer, and the most severe cases of silicosis can be fatal.

The U.S. Occupational Safety and Health Administration (OSHA) estimates that nearly two million workers in the U.S. are at risk of silica exposure, and more than 100,000 are in high-risk jobs.

OSHA enforces permissible exposure limits (PELs) to regulate the inhalation and exposure to respirable crystalline silica. The PELs for respirable crystalline silica in the general industry are calculated based on the percentage of silica (in this case quartz) found in a collected sample. For this article the OSHA PELs will be conservatively based on 100% quartz, and the calculated PELs will be equal to 0.1 mg/cu. m.

The administration is working to significantly update regulations, which has led to a new proposed rule that would reduce PELs for respirable crystalline silica by about 50%, a necessary industry improvement. In one of the final steps toward publishing this proposed rule, OSHA has submitted a final draft to the Office of Management and Budget for final review. OSHA has stated that it hopes to publish a final rule in first-half 2016.

In 2011 the National Institute for Occupational Safety and Health (NIOSH) found that, "worker exposure to wellsite workers (engaged in hydraulic fracturing) routinely exceeded occupational criteria, in some cases by 10 or more times." Since 2011 there has been a dramatic

Silica sand is coated with DustPRO prior to transport to the well site. (Source: Preferred Sands) increase in silica sand proppant consumption due to industry advancements in completion techniques. As a result, significantly more sand is used per well completion since 2011, increasing potential respirable crystalline silica exposure risk for all workers in the frack sand supply chain.

NIOSH has recognized several points of dust generation at the well site, including

- Dust ejected from thief hatches (access ports) on top of the sand movers during refilling operations while the machines are running (hot loading);
- Dust ejected and pulsed through open side ports on the sand movers during refilling operations;
- Dust generated by onsite vehicle traffic;
- Dust released from the transfer belt under the sand movers;
- Dust created as sand drops into or is agitated in the blender hopper and on transfer belts; and
- Dust released from operations of transfer belts between the sand mover and the blender.

NIOSH has identified a variety of levels of control to address occupational hazards as described in the widely accepted method to reduce risk under its hierarchy of controls. Two controls, elimination (or physically removing the hazard) and substitution (replacing the hazard) of the proppant, are significantly effective at reducing the risk of respirable crystalline silica exposure.

These are difficult levels of control as the silica sand proppant is necessary to fracture the shale. Eliminating silica sand proppant from the hydraulic fracturing process is not currently feasible due to the requirements of the shale fracturing process. Effective and safe innovations in silica sand proppant technology are the future of the industry.

Dust control technology

In response to anticipated changes in regulations and as a way to improve worker safety at the well site, Preferred Sands and The Dow Chemical Co. joined forces to help reduce industry workers' exposure to risk in energy production by creating a product that inhibits exposure to respirable crystalline silica.

The collaboration resulted in a breakthrough proppant technology called DustPRO, a silica dust control innovation that uses a proppant-coating technology for dusting at the source and throughout the product life cycle. The treated proppant technology is a cost-effective safety measure that is designed to inhibit exposure to respirable crystalline silica and has been found to meet silica exposure limits while maintaining downhole performance.

The advanced silica dust control technology treats sand using the Tersus/Preferred DC chemistry, a proprietary inert polymer that is sprayed onto sand prior to transport to the well site. The product was designed with the goal of very low incremental environmental impact. Product components were selected based on requirements of low toxicity, flammability and high biodegradability.

Shown are samples of DustPRO treated sand (left) vs. uncoated sand in water. (Source: Preferred Sands)

The proppant technology does not require any additional dust control equipment on site, thereby helping to eliminate bulky ventilation equipment, remove dozens of unsafe tripping hazards and allow safe access to all critical equipment.

Field tests

Since its introduction in early 2014, the technology has gone from bench tests and research to onsite implementation. From May 2014 to May 2015, more than 360 million pounds of the treated proppant was pumped downhole by 16 E&P companies and 11 oilfield service providers across all major shale basins in the U.S. and Canada.

During that time, third-party industrial hygienists monitored the technology's performance. Researchers collected personal and area samples at 12 different well sites in Colorado, Louisiana, North Dakota, Texas, West Virginia and British Columbia. Each site varied in topography, geography, altitude and weather conditions, but results across the board were impressive.

During well completion activities, 140 personal breathing zone samples were taken, and 95% of the samples came in below OSHA's current PELs of 0.1 mg/cu. m, and 86% were below OSHA's proposed PELs of less than 0.05 mg/cu. m.

Though this statistically significant research is preliminary, there are indications that silica sand treated in this manner will be considered an effective substitution control to minimize exposure to crystalline silica dust at the well site and during all sand transfer points. Emerging dust control technologies are helping to advance safe domestic energy production and simultaneously reducing the dust level at the well site. The use of this proprietary technology leads to a safer work environment, improving morale of workers on location and mitigating perceived risk to neighbors and the surrounding community. E&P

Evolving effective offshore regulatory future

Oil and gas industry regulatory regimes are evolving, allowing both active and planned offshore operations to progress efficiently while ensuring that due attention is given to HSE performance.

Graham Bennett, DNV GL

Occupational safety has improved greatly in recent years. DNV GL's analysis of data from companies' annual and sustainability reports shows a tenfold reduction in reportable incidents per 200,000 man-hours during the last 20 to 30 years when lost-time injuries are excluded.

Occupational safety is monitored using common industry metrics, is included in company annual reports and receives board-level attention. However, while occupational safety (as measured by reportable incidents) has improved in general, major accidents and near-misses still happen, and the rate at which they occur is not significantly dropping.

More could be done to reduce the risk of these occurring. The industry should strive to learn and share more from what is successful in major accident management. In other words, the industry should not just study failures—it also should learn more from its successes.

Operators based in EU countries are required to produce a Major Accident Prevention Policy, but the EU also has deemed this to be applicable to their global operations and not just those within the EU's borders. (Source: DNV GL)

Analysis of the EU major accident report system and the U.S. Environmental Protection Agency risk management plan-star (RMP-Star) databases shows a steady frequency of major accident events and no reduction in their level of severity. Similarly, insurance brokerage firm Marsh & McLennan examined insurance claims for property damage losses in the hydrocarbon industry between 1974 and 2013 and found no clear reduction since 1994.

Statistics from the Country Performance Project of the International Regulators Forum (IRF) for Global Offshore Safety also supports this picture. Fatalities per million hours worked from 2008 to 2012 do not show a unified trend toward global improved performance. Against this backdrop of industry data, DNV GL decided to take a new look at what an enhanced risk management regime should look like.

Global/local challenge

Social, political and economic frameworks for regulation vary considerably worldwide and might evolve in different directions with varying levels of prescriptive or risk-based requirements.

Oil and gas companies operating globally must therefore not only increase oversight where requirements are less developed but also proactively align global operating standards and procedures toward unique local regulatory changes. This is particularly true for those operators based in EU countries who are now required to produce a Major Accident Prevention Policy, which the EU deems to be applicable to their global operation and not just those within the EU.

In its report, "Regulatory outlook: The way forward for offshore regulatory safety regimes," DNV GL has assessed offshore regulatory frameworks in Mexico, Brazil, the EU, Angola and Australia. It also covers the Arctic from an international regulatory perspective as well as nationally for the U.S., Canada, Greenland, Norway and Russia.

Gauging the path of regulation

The case studies in the report are regional high-level summaries of offshore oil and gas activities, with a particular focus on regulatory safety regime status and possible developments.

Each case study is divided into two parts: a background and an outlook. The background summarizes historic developments up to the present day and was assembled mainly through research of publicly available information. The outlook suggests possible future evolution and was produced through a combination of research, workshops and internal interviews with DNV GL experts and customers worldwide.

Possible scenarios are discussed for regulatory developments in these jurisdictions, and these scenarios are mapped to DNV GL's safety model to identify key factors that could help reduce major accident hazards in each region.

Four fundamental scenarios for the development of regulatory regimes are analyzed:

- **Global safety:** Each major accident in the industry is reviewed and learned from globally by both industry players and regulators;
- **New moral imperative:** Governments recognize society's unwillingness to tolerate major accidents, so operators' responsibility for safety is increased;
- **Operators' rule:** Governments are reluctant to improve their regulatory capability and rely on operators' global experience; and
- **Local safety:** Regulators focus on improving their own safety regimes.

These scenarios correspond to varying degrees with current offshore regulatory regimes and are not intended as accurate illustrations of the future. However, they are a useful starting point for discussing how safety regimes should develop, particularly when used in conjunction with DNV GL's safety model.

This incorporates six interconnecting performance levers and dependencies which, if recognized, should lessen the probability of a major accident occurring. In no particular sequence, these are:

- Existence of performance-based regulations and independent verification;
- Clear roles and responsibilities for safety, including ensuring that stakeholders share common goals;
- Information sharing from monitoring safety performance;
- Advanced barrier management that includes mitigating as well as preventive barriers;
- Stakeholder access to a tool that records up-to-date risk identification and provides a complete view of risk exposures for an asset, asset cluster, project or company; and
- Interaction between people, technology and the organization.

The importance of sharing lessons learned locally and globally should be further emphasized, DNV GL said. The IRF, along with other industry bodies, already take an active role in sharing information and trends that help to improve global safety. (Source: DNV GL)

A global safety scenario, where each major accident is reviewed and lessons learned by all regulators and industry players, includes many elements of DNV GL's preferred approach. This scenario also envisages large fines for major accident hazards and harmonization of HSE regimes to reduce compliance costs and administration.

The importance of sharing lessons learned locally and globally should be further emphasized. In this respect, the IRF, along with industry bodies such as the Norwegian Oil and Gas Association, American Petroleum Institute, International Association of Drilling Contractors and the classification societies, take an active role in sharing information and trends that in turn help improve global safety. The new International Association of Oil & Gas Producers 456 Recommended Practice on process safety is another recent example of such collaborative efforts. All such efforts are to be commended.

Ultimately, it must also be recognized that the management of major accident risk makes sound business sense.

While the focus must of course be on the safety and environmental impact of such risks, one should not underestimate or ignore the business risk impact of major accident events. Actively managing safety and environmental risk is an investment that is clearly beneficial to the health of the business overall. E&P

Protecting against internal corrosion

The wide range of GRE liner applications offers operators options to protect tubulars.

David Marshall, Duoline Technologies

Internal corrosion of oilfield tubulars is a prevalent risk in the oil field. This common problem can be caused by many sources, including hydrogen sulfide (H_2S), CO_2, dissolved oxygen, brinish disposal water, highly acidic soil conditions and more. Damage from corrosion can cause significant setbacks such as reduced productivity, maintenance downtime and even equipment replacement.

The costs of corrosion add up to billions of dollars per year in lost revenue and reduced operating profit for oil and gas companies.

Oil and gas operating companies must follow safe and timely production schedules, and therefore it is important to prevent the setbacks of corrosion damage. Without some form of internal protection, most tubulars will have a significantly diminished life cycle due to corrosion.

There are options available for protecting tubulars and minimizing internal corrosion. Two of the most common choices are internal coatings and liners. However, before a specification can be made, it is important to have a basic knowledge of the characteristics and capabilities of both coatings and liners to know which option will offer reliable protection in the application.

These GRE liners are being installed in oilfield tubulars. (Source: Duoline Technologies)

Internal coatings

Internal coatings were originally composed of an organic solvent-based solution, which was changed in the 1970s. Due to the Clean Air Act, the industry cut the use of solvents and began making powder coatings to reduce emissions. However, coating with powder often is unsuccessful for a number of reasons.

Powder coatings are thin, not very durable and easily damaged by impact. Powder coatings do not have a guaranteed consistent thickness. Chipping usually begins in thin areas first, allowing imperfections to grow easily and cause enough corrosion damage to prematurely shut down a system due to piping failure.

Many powder coatings have improved over the years, but it is essential to understand that coatings can only perform reliably under certain environmental and operational parameters. Adhesion failure is more likely to happen in higher temperature applications. Exposure to wireline tools or coiled tubing operations will very likely cause damage to coatings.

Qualification tests should be conducted for each coating option before selecting a powder coating. Care must be taken during the selection process that the coating standards are not confused with one another and that the testing during fit-for-purpose trials is relevant to the system in question since some standards might not be suitable for internal coatings.

Internal tubular polymer liners

The two most common liner options are thermoset glass-reinforced epoxy (GRE) liners and polyvinyl chloride (PVC) liners. GRE liners perform well in high-temperature and high-strength applications, while PVC liners operate in low-temperature applications. Recent developments include a family of liners that vary in chemical resistance but share a primary distinguishing feature—the allowable service temperature of each liner material.

The unique features and durability of GRE liners have made them a more efficient and reliable solution to many common challenges. Even in high-temperature applications, GRE liners resist deterioration due to their consistent strength and stability. GRE liners have proven to provide reliable long-lasting protection against corrosive fluids in a wide range of applications, including water injection, CO_2 injection, gas production,

This GRE liner survived years longer than the oilfield tubular it was installed in. (Source: Duoline Technologies)

gas-lifted oil production, environments containing H_2S, and onshore and offshore chemical disposal wells (Table 1).

The manufacturing process for GRE liners used by Duoline Technologies is different from others in that the wound, epoxy-reinforced fibers undergo an advanced high-temperature cure process that cures liners from the inside out. This prevents the entrapment of air pockets in liner walls, guaranteeing consistent strength and stability throughout the entire liner. The curing technique produces the smoothest internal lining option available on the market.

Internal lining installation

An internal lining system is made by inserting a rigid GRE tube into a steel tubular and filling the annular space with a special mortar. After the special mortar sets and the liner is firmly positioned in the steel pipe, the GRE liner is cut flush with the end of the steel tubular.

A molded flange called a "flare" protects the end of the GRE liner and mortar. The flare is bonded to the inside diameter of the liner with an adhesive, and a specially designed and reinforced corrosion barrier ring (CBR) is compressed in the connection by the opposing flares. These components effectively and reliably protect entire tubulars from exposure to corrosive fluids.

For American Petroleum Institute (API) connections, decision-makers need to choose one that provides an oil-resistant nitrile CBR with spring steel wire reinforcements to hold the ring in place during pressure cycles. For premium or proprietary threaded connections, Duoline provides a glass-reinforced teflon CBR that is designed exclusively for the DL-Ring.

The liner-flare-CBR combination along with the grout provides corrosion protection for the steel pipe and coupling. The liner and grout transfer internal pressure loads directly to the steel pipe that is the load-bearing member in the design.

Case study

A GRE liner was installed on a well in the Gulf of Mexico (GoM) due to the harsh environmental conditions. Initial installation of the liner for the customer presented challenges. The staff overcame these obstacles by providing technical support and maintaining constant contact throughout the installation. Duoline provided its customer with onsite field technicians to oversee all aspects of the liner installation and ensure proper running and handling procedures were followed.

The first completed installation and operation of injector wells in the GoM were such a success that it has resulted in the installation of eight total additional wells. All were completed with GRE liners coupled with the VAM connection. The success of these eight completed wells demonstrates that the GRE liner is an ideal option for companies seeking to overcome the corrosive and rigid conditions in the GoM.

PVC liners	GRE liners
Liners lack reinforcement; fibers are susceptible to collapse under rapid depressurization	Liners have high hoop strength and are resistant to collapse under rapid depressurization
Most limited to 71 C (160 F)	Suitable for costly applications up to 140 C (285 F)
Typically suited for low-end service conditions	Used in installations for "standard" API or higher service "premium gas tight" connections
Can require factory rework	Easily reusable
Can require coupling protection	Requires only standard couplings
Limited connections	Available in a wide range of premium and API connections

TABLE 1. A comparison shows that GRE liners are a more durable and versatile option in tubular corrosion prevention. (Source: Duoline Technologies)

A little extra knowledge goes a long way when choosing the proper corrosion protection option in oilfield tubulars. Operators need to know basic characteristics and capabilities of coatings and liners and perform a complete assessment of the environment in which the liner will have to perform. GRE liners are a reliable choice that will bring long-lasting, effective corrosion protection to investments in a wide range of applications. E&P

Integrated study pays dividends in Wattenberg

A joint project between Anadarko and CSM is revealing new information through time-lapse studies.

Janel Andersen, Anadarko Petroleum Corp.; and **Staci Mueller** and **Emma Butler**, Reservoir Characterization Project at the Colorado School of Mines

Horizontal development of unconventional shale reservoirs has given revival to the use of 3-D seismic data. Seismic data is a critical tool to maximize time in the pay zone, avoid drilling hazards or plan for faulting in the reservoir. However, attempts to use this powerful technology for more than just steering in these shale plays is still in its infancy. Much of the quantitative seismic work completed to date has been on characterizing static reservoir parameters such as "sweet spots" of more brittle, frackable rock.

Anadarko has undertaken a first-of-its-kind study in collaboration with the Reservoir Characterization Project (RCP) at the Colorado School of Mines (CSM) to characterize how seismic can help oil companies understand the dynamic response of unconventional shale reservoirs to hydraulic fracturing and production.

This study focuses on a 2.58-sq-km (1-sq-mile) section within the Wattenberg Field with 11 horizontal wells drilled in two reservoir zones. This section was designated a test area to optimize well spacing, hydraulic fracturing parameters and other engineering-driven questions. Therefore, this is an excellent area to study the usefulness of dynamic seismic reservoir characterization.

An initial multicomponent (9-C) 3-D seismic survey was acquired over this focus area after the wells were drilled but prior to hydraulic fracturing and production. This survey serves as the baseline for future monitor seismic surveys. It also is being used for static parameter analyses including brittleness, natural fracture characterization, geologic structure, stratigraphy and stress state.

A second survey was acquired immediately after the wells were hydraulically fractured to study the differences in the earth response to stimulation. Finally, a third survey was to be acquired during the winter of 2015 to study the response of the reservoir to multiple years of production. This integrated study also includes data provided by Anadarko, including core, well logs, microseismic, chemical tracers and the production data.

At least 24 students in RCP at the CSM use these data for their thesis research in geophysics, geology and reservoir engineering. Early theses already have been published that are changing the way Anadarko thinks about the reservoir and its response to hydraulic stimulation. Anadarko is using these results to optimize well spacing and hydraulic fracturing plans for future drilling campaigns.

Static characterization, development and frack design

The Wattenberg Field is dominated by many normal faults that cut through the two main geologic reservoirs, the Smoky Hill Member of the Niobrara Formation and the Codell Sandstone of the Carlile Formation. Understanding and accurately predicting the faulting patterns ahead of the bit is critical for well planning and steering, both to optimize the time in zone and to avoid swelling clays that are drilling hazards. Additionally, faults need to be taken into account when planning for the hydraulic stimulation.

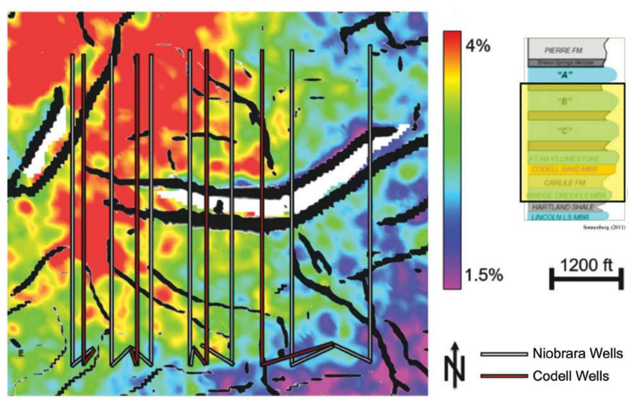


FIGURE 1. The P-impedance percent difference in the full reservoir interval was derived from the prestack inversion results. Higher percent differences are indicated by the warmer colors. (Source: Anadarko Petroleum Corp.)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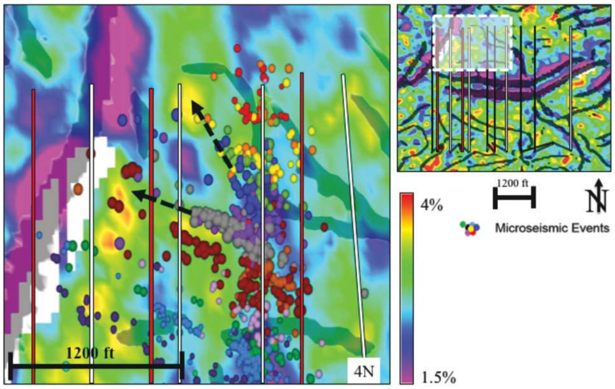

FIGURE 2. This base map shows the percent difference in S impedance derived from S inversion. Microseismic events from Well 6N diverge around the area of low percent difference, representing a faulted area partially picked up by the incoherence attribute of top Niobrara (pictured in dark gray). (Source: Anadarko Petroleum Corp.)

The compressional- (P)-wave portion of the data acquired during this study has helped Anadarko and CSM do an even better job characterizing these faults due to the high-quality nature of the data. Understanding the direction and magnitude of natural fractures and faults helps optimize the stimulation design. By carefully analyzing the multicomponent dataset, students have found that the shear (S) components of the 9-C data better characterize the natural fracture patterns in the rock than P-wave only data.

Work is currently underway to see if there are any ways to get this same information out of converted wave data due to the difficulty and expense in acquiring pure S seismic.

Time-lapse seismic data help to determine the effects of completions on the reservoir, overburden and underburden intervals. Hydraulic fracturing occurs along planes of weakness and therefore may open preexisting fractures. Time-lapse inversions were performed on the P (normal) and S seismic datasets. Post- and prestack inversions delineate small faults and observe geologic responses of varying completion techniques, well spacing and geology. The time-lapse post-stack S inversions characterize the stimulated reservoir volume through S inversion differences.

Time-lapse anomalies

Figure 1 represents the base map of the study area and the locations of the horizontal wells drilled in the section. The map represents the percent difference in P-impedance values between the baseline and the first monitor survey, where the warmer colors are higher percent differences. These percent differences displayed with the incoherence attribute show the major faults in the survey.

The time-lapse anomalies show a larger percent difference in P-impedance values in the western portion of the survey. The anomalies also can mark boundaries of the faults, represented by sharp changes in color. Therefore, these anomalies can be used to refine fault interpretations in the study area. By using the inversion results from the prestack seismic rather than the post-stack, the resolution is improved. Faults and fractures are further refined with the use of the S-wave seismic.

Figure 2 depicts the S inversion of the percent difference between the monitor and baseline surveys within the upper reservoir interval. Generally, lower percent differences indicate faulted areas, and higher percent differences indicate stimulated areas. In some cases, the inversion is able to detect faults that the incoherence attribute does not show.

Fault compartmentalization and communication has an effect upon the overall effectiveness of completions. Some of these features are highlighted by S inversion results and microseismic patterns. The S difference slice of the upper reservoir interval illustrates faults that compartmentalize individual stages, which are not visible on the incoherence map (Figure 2).

The frack barriers were interpreted in the prestack P inversion and post-stack S inversions based on microseismic patterns correlating with inversion anomalies. Figure 3 shows all of the interpreted frack barriers, which correspond mostly to north-south trending faults. Further studies will incorporate the convert-

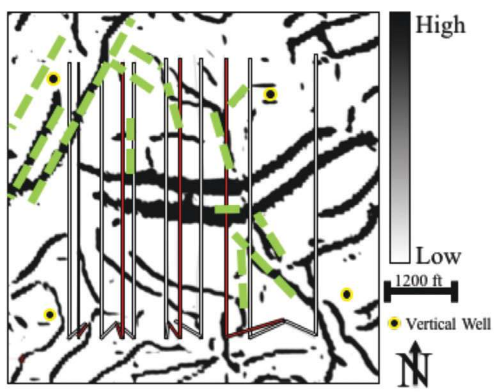

FIGURE 3. A base map of the study area shows incoherence attributes and interpreted frack barriers (green dashed lines) based on prestack P and post-stack S inversions. (Source: Anadarko Petroleum Corp.)

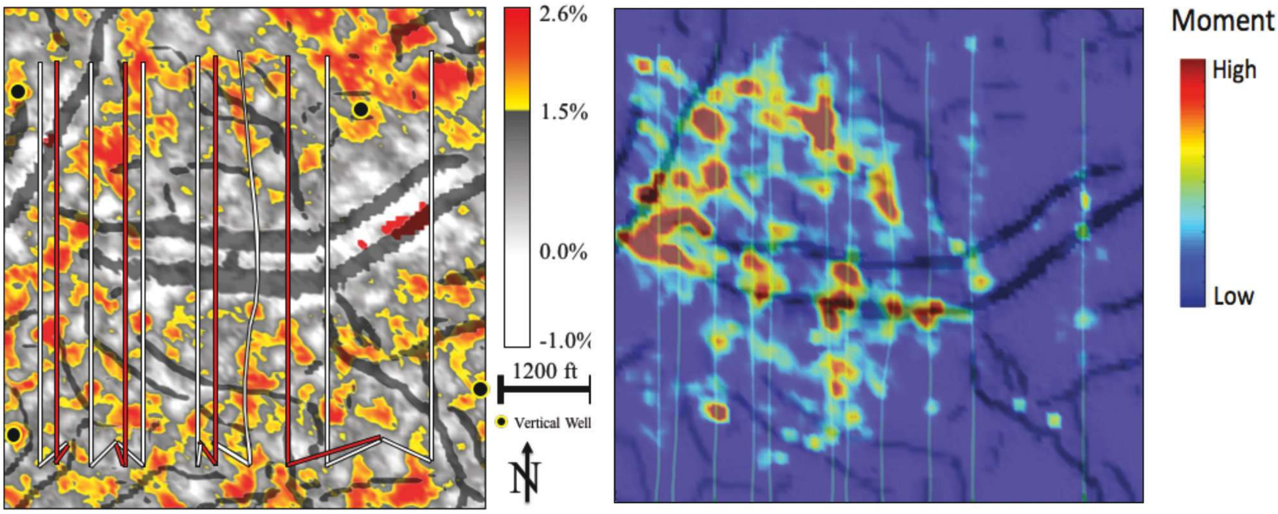

FIGURE 4. The stimulated reservoir volume is shown as the time-lapse percent difference between S inversions (a) and the microseismic moment (b). (Source: Anadarko Petroleum Corp.)

ed-wave seismic to determine the value of acquiring pure S data.

Hydraulic fracturing

Microseismic and time-lapse seismic acquired pre- and post-stimulation provide unique characterization of stimulated rock volume (SRV). Both techniques are limited but can be used in conjunction with one another for better results. By comparing the two different SRV predictions, Anadarko is gaining better insights into the effectiveness of the hydraulic fracturing.

Microseismic shows how the frack progresses out from the wellbore in real time, but the magnitude of these events are very small and therefore do not represent the big picture. Time-lapse seismic shows the gross response of the reservoir to the stimulation—in particular open, propped fractures and stress changes due to the pressure of the fluid injection—but cannot resolve vertical and temporal detail that the microseismic can provide. Therefore, the results are not expected to be the same, and they need to be used together for an optimal understanding of the hydraulic fracturing. The early results look promising.

A map of the SRV was created (Figure 4a) by taking percentage differences of S inversions in the upper reservoir interval (40 ms window below top reservoir horizon) and then subtracting the baseline from the monitor survey. The higher percentages in Figure 4a indicate areas that a) were not initially fractured and were stimulated or b) were initially fractured and encountered changes due to stimulation. Lower percentages correlate with major faults.

Overall, the stimulation is not uniform along the wells, and faults have a significant effect upon the SRV as indicated by the S differences. The microseismic density is shown in greater concentrations on the western portion of the study area (Figure 4b).

Figure 4a shows a high anomaly occurring in the northwest corner of the map. This anomaly probably occurs because the S datasets did not go through a residual rotation during processing. However, this area might also be affected by the vertical well shown in that corner, along with vertical wells in adjacent sections.

Production

After the reservoir has been produced, the propped fractures have closed and the stress state of the reservoir has changed due to depletion. The post-production time-lapse should have the ability to detect those changes. Prior results show depletion in the reservoir due to production from previous wellbores, and it is expected that the post-production seismic time-lapse will provide a greater understanding of produced rock volume. Anadarko is looking forward to these results, coming up in the next year or so.

Seismic already has proven to be very useful in the development of unconventional shale reservoirs, particularly for steering. The multicomponent time-lapse seismic studies being done now are allowing Anadarko and CSM to quantitatively characterize the static and dynamic states of the reservoir. E&P

Redefined closed-loop reservoir monitoring framework

Methodology provides a field-scale dynamic integrated Earth model.

Rhonda Duey, Executive Editor

Like most geoscience disciplines, time-lapse seismic (also known as 4-D seismic) is not an exact science. Feasibility studies from multiple disciplines must be taken into consideration and forward-modeled prior to the actual survey beginning.

This was the message from a paper presented at the 2015 Society of Exploration Geophysicists annual meeting by Kurt Eggenberger, David Hill and Dominic Lowden, formerly with Schlumberger, and current Schlumberger employees Sonika Sonika and Mehadi Paydayesh. The paper, "High-fidelity 4-D forward modeling as part of a redefined closed-loop seismic reservoir monitoring framework: A case study," provides a way to model anticipated seismic responses in a more quantitative way through a closed-loop procedure.

"Literature produces many successful examples of time-lapse seismic case studies with carefully analyzed 4-D signatures," the authors noted. "However, quantitative and even qualitative comparisons of differences between predicted and actually measured time-lapse seismic data are much less performed and discussed in open literature despite the obvious benefit for model reconciliation.

"An explanation can be found in the assumptions and methodology used for the feasibility study, which can be too simplistic to warrant … a meaningful comparison."

The authors go on to note that the actual 4-D signatures often are larger, smaller or different in shape than what the feasibility study predicted. These differences can be expressed as a difference between the actual geology and the modeled geology, between the actual physical properties and the model properties or by not taking into account the full complexity and interactions.

Closed-loop model

While proposed as early as 2000, the closed-loop approach was considered too costly to be practical in 4-D studies. But as compute power grew, two approaches became more commonplace. One is a well-log-based fluid-substitution and petrophysical modeling approach,

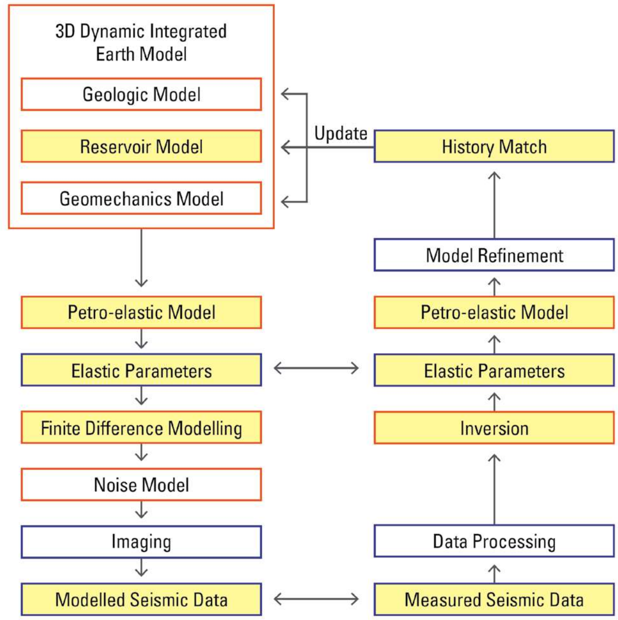

FIGURE 1. The redefined closed-loop seismic reservoir monitoring workflow caters to a 3-D dynamic integrated Earth model. White boxes indicate additional elements to earlier proposed frameworks. This workflow also allows model reconciliation based on high-fidelity seismic response. (Source: Schlumberger)

which neglects realistic noise, overburden and acquisition effects. The second is a simulation-to-seismic modeling approach that incorporates overburden and acquisition effects by ray-tracing. This method also neglects realistic noise, however.

A newer method uses 1-D convolutional modeling to create a cube for each angle of incidence and each vintage of data.

All of these approaches confine the modeling to the reservoir interval, the authors noted. Yet they're widely used because they're fast.

To truly model the 4-D response as it relates to production, the authors propose a methodology that incorporates the overburden, sideburden and underburden into the modeling. "To accurately predict a 4-D

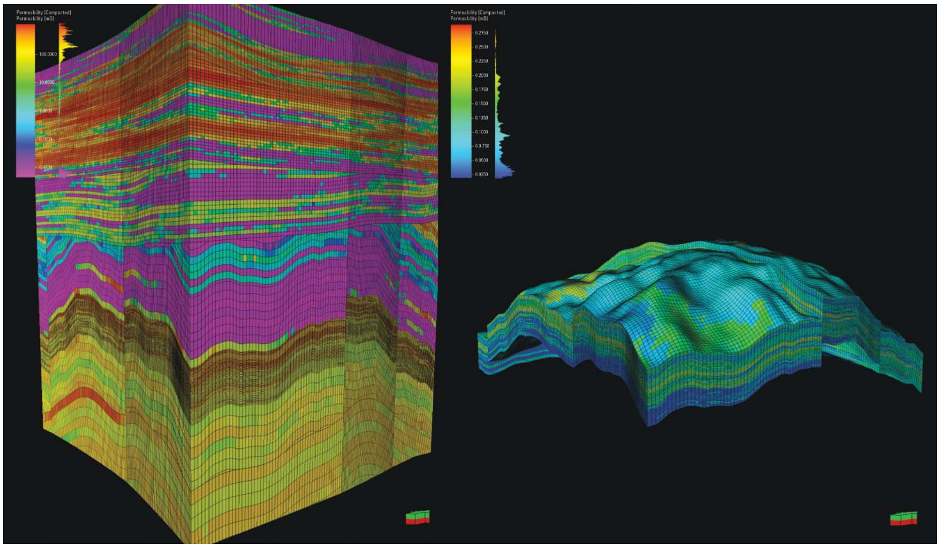

FIGURE 2. The Chimera reservoir model represents a faulted dome structure in a clastic environment governed by shale and sand. Figure 2a (left) is a full-field permeability model on the Earth grid, and Figure 2b represents the reservoir porosity model. (Source: Schlumberger)

response related to production, modeling cannot be limited to the reservoir only and has to be extended to the full field and its geomechanical effects, describing the acoustic and elastic response to both reservoir and fieldwide changes," they noted. This type of model must take into account the reservoir dynamics component encompassing fluid properties, fluid flow characteristics, field performance history, and pressure distributions and profiles over time. It also must incorporate pressure changes due to production. This, in turn, can only be accomplished by integrating geologic, reservoir stimulation and reservoir geomechanical models into a full Earth model.

Modern computing systems are now enabling fieldwide 3-D finite difference acoustic and elastic models to be viewed in conjunction with the elastic properties from the Earth model (Figure 1). At each step the modeled and measured data are analyzed and reconciled.

Chimera modeling

Schlumberger's Chimera model has been built to test the closed-loop monitoring framework. Figure 2 depicts an offshore turbidite-type reservoir with 25% maximum porosity and 200 nD maximum permeability in 200 m (656 ft) of water. A four-way closure contains the hydrocarbon accumulation, and a number of vertical faults are present.

To simulate the model, the authors generated time stamps in three-year intervals with the monitor baseline set in 2014. The reservoir was simulated in primary production for three years followed by waterflooding. Pressure, water, gas and oil saturation simulations were transformed through a petro-elastic rock physics model to get elastic properties.

Ancillary modeling parameters were then determined by 1-D conventional, ray trace and wedge modeling; then the finite-difference modeling was undertaken with the derived properties. This approach also requires a master geometry definition along with a representative noise model. Results indicated that this approach gave a better sense than conventional approaches of the amount of difference that could be expected between the modeled signature and the measured signature.

By incorporating geology, reservoir simulation and geomechanical models into an integrated full-field coupled dynamic integrated Earth model, the authors were able to derive high-quality elastic parameters by the petro-elastic rock physics model for input into the forward modeling. Also, by using finite-difference modeling with realistic calibrated noise, a high-fidelity prediction of the 4-D signal decreases modeling errors.

"Having modeled with such a high-fidelity 4-D signal, it can be determined if the baseline acquisition geometry will measure the 4-D signal at the required time interval and, if not, what acquisition geometry will," the authors noted. "Furthermore, seismic reservoir monitoring can make use of the high-fidelity forward-modeled data that goes beyond the traditional feasibility and survey design study with the objective to reconcile modeled with actual measured data, closing the loop to a dynamic integrated Earth model. Higher fidelity predictions of future reservoir behaviors are the result." E&P

Acknowledgment

This article is based on a presentation at the 2015 annual meeting of the Society of Exploration Geophysicists and has been written with permission by the authors. Kurt Eggenberger, David Hill, Dominic Lowden, Sonika Sonika and Mehdi Paydayesh (2015) High-fidelity 4-D forward modeling as part of a redefined closed-loop seismic reservoir monitoring framework: A case study. SEG Technical Program Expanded Abstracts 2015: pp. 5424-5429. doi: 10.1190/segam2015-5869039.1

Directional drilling, fiber-optic sensors expand range of CT operations

More complex operations such as multilateral branches, extension and larger hole sizes are being drilled with DCTD BHAs.

Toni Miszewski, AnTech

There is no doubt that current oil prices are presenting a difficult challenge to the industry and stretching people's creativity when thinking of solutions. Slashing costs, which means people and equipment, makes for more dramatic headlines, but simple efficiency gains also have their part to play as the industry adjusts to the new reality.

Extracting more from existing wells has an immediate effect on efficiency. A clear example is the migration of the shale operators to the most productive wells in the field that has seen production per well increase at the same time as the number of wells that are drilled dramatically decreases. Another way of increasing efficiency is to apply technological solutions that access more of the reservoir but from an existing wellbore or that provide more detailed well information that can optimize the amount of hydrocarbon extracted.

Two technologies that fit the bill are directional coiled tubing (CT) drilling and permanent monitoring with fiber-optic sensors. Both of these were in their formative phase in the early 1990s but have now developed into established products.

Directional CT drilling

The current sub $40/bbl oil market is putting a huge amount of pressure on operators to maximize the returns on current assets and to minimize the operational and financial risk associated with accessing these reserves. Reentering old wellbores and sidetracking to access new reserves in known reservoirs is a low-risk way to increase cash flow and return on investment from an operator's assets (Figure 1).

Directional CT drilling (DCTD) is a well-established technology for doing this. Over the last three decades significant advances in equipment reliability, metallurgy and the experience levels of personnel has made DCTD a very attractive method of reentering wells. Operators and service companies can focus on delivering productive wells effectively rather than dealing with technology issues.

DCTD also can provide significant benefits that are applicable to drilling new wells or for reentry. One of the most significant advantages of DCTD is its suitability for underbalanced drilling, which allows the formation to produce oil and gas while drilling (Figure 2). That means the formation is not damaged like it is in overbalanced drilling. This reduction in formation damage can lead to significant increases in the amount of oil produced from each well drilled.

More complex operations such as multilateral branches, extension and larger hole sizes are being drilled, enabling operators to make the most of their existing reserves. Consequently, DCTD bottomhole

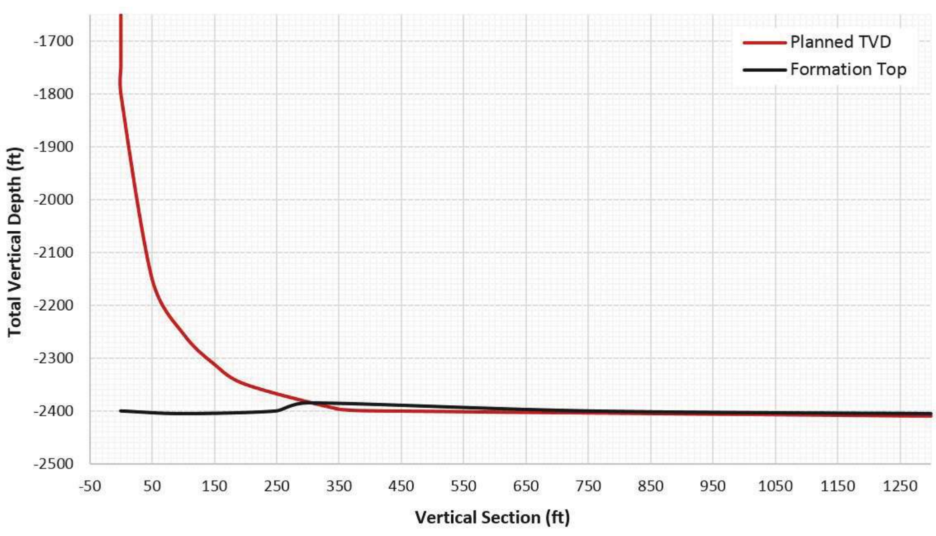

FIGURE 1. This example of a wellpath is for a sidetracked well. The long horizontal section increases the production of the well over that of a vertical well. (Source: AnTech)

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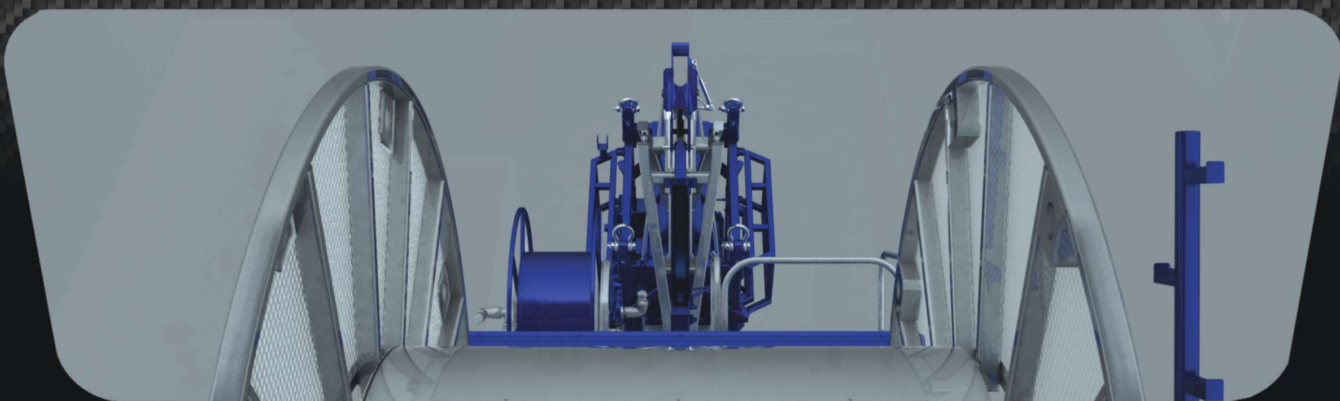

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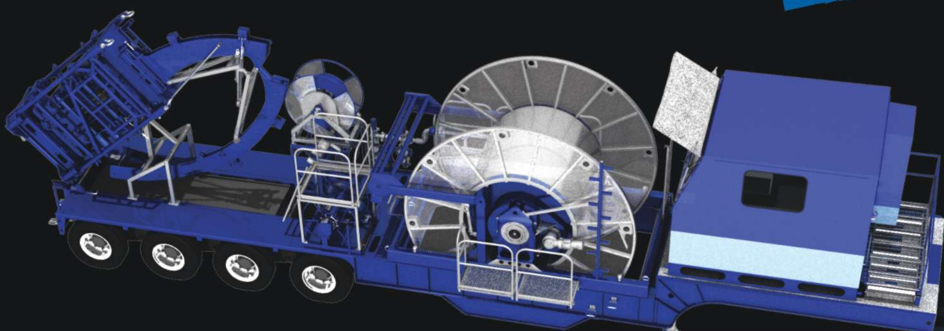

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assemblies (BHAs) are being deployed around the world to drill new wells and extend previous ones by accurately targeting pockets of oil and gas reserves. Successful drilling programs are ongoing in Saudi Arabia, Alaska and Australia as well as other places.

FIGURE 2. One of the most significant advantages of DCTD is its suitability for underbalanced drilling. (Source: AnTech)

DCTD, MWD BHAs

Ten years ago AnTech combined mechanical, electronic and software engineers, and the COLT and POLARIS DCTD BHAs were created. The COLT MWD BHA is a 3.192-in. outer diameter (OD) BHA that is steered magnetically.

The POLARIS MWD/gyro-while-drilling BHA is a 5-in. OD BHA, which is steered either using magnetic sensors or a gyro. The BHAs are run on CT with seven-conductor electric line inside the tubing (also known as e-coil). The connection to the BHA from the surface via a cable allows real-time telemetry and very high data rates. This capability allows extremely accurate wellbore placement, thereby increasing the chance of success on a project.

The two BHAs are short—under 12.2 m (40 ft) in length—allowing them to be deployed above the BOPs. This means that the well can be closed in while the BHA is made up to the coil and pulled into the lubricator. The well is then only opened up once the complete pressure control envelope is in place.

Distributed sensing with fiber optics

Also in the early 1990s permanent well monitoring started to become more widely used (price of oil at the time was $20). The systems in those days were electrical and provided point measurements of usually pressure, temperature and flow.

In addition to the electrical systems that have become cheaper and more reliable now, a new generation of fiber-optic sensors is available to operators. The nature of fiber-optic sensor systems is that they can provide distributed measurements. If they are measuring a parameter such as temperature, the temperature can be recorded with a 1-m (3.3-ft) precision along the whole length of the cable. This provides a whole new dimension of visibility about the wellbore that was previously unavailable. Pressures and acoustic and seismic signatures can all be measured in this way.

When these fiber-optic cables reach the surface, they need to be terminated and connected to the surface instrumentation. Keeping optical losses to a minimum is vital to ensure that the resolution of the sensors is not affected.

As a result, a whole new range of equipment has had to be developed to adapt super-precision assembly to the rugged environment around the wellhead. This is also a hazardous-area environment where electrical equipment needs to conform to international standards for use where explosive gases are present, such as the International Electrotechnical Commission System for Certification to Standards Relating to Equipment for Use in Explosive Atmospheres.

AnTech's dedicated products division has developed a whole new range of fiber-optic products, which continues to grow. Demands for equipment that can safely allow fiber-optic connections to downhole gauges in HP/HT environments can now be met.

AnTech has recently launched the Type-F range of fiber-optic wellhead outlets, which incorporates proprietary feedthrough that is designed to American Petroleum Institute 6A standards.

Furthermore, design and development on an explosive atmosphere certified Fusion Splicer has begun, and this will in turn help complement the Type-F wellhead outlet range by safely splicing delicate fiber at the well site.

Change can be a challenge in an industry that is historically cautious about change, and this is for a good reason. The risks of failure with new technology are high, so the benefits need to be significant. DCTD and fiber-optic monitoring are two technologies that have shown their worth over time, and now might be the time when these innovations offer an economic solution in a turbulent and challenging market. E&P

Extending well life where completions have barrier issues

The anchored production straddle assembly can be set across the side-pocket mandrel with a new gas-lift valve between the two sealing elements.

Bjorn Bill, Interwell

Following the drilling of a new well, a completion assembly will be installed to allow production to start. The completion design is typically split into a lower completion and an upper completion. The lower completion is normally placed across the production zone and is most often hung off by a liner hanger. The upper completion consists of all parts above the liner hanger to allow oil and gas to be produced in a safe manner by ensuring barrier control.

When a well has been producing for an extended period of time, there are several issues/problems that can arise with the well completion design that can cause failures that might stop the ability to produce the well in a safe way, such as sand production, scale deposit, corrosion, tubing-retrievable surface-controlled subsurface safety valve (TRSCSSV) issues, gas-lift valve issues, leaking polished bore receptacle (PBR) or a leaking production packer.

The APS packer is designed with high expansion and effective through-bore in mind when developing specific solutions for production control challenges. The top photo shows the entire tool, while the lower photo details the packer. (Source: Interwell)

To allow the continuation of production, the issue in the well must be corrected. The ideal solution is to pull the completion assembly out of the well and install a new one. However, this is often associated with extremely high cost. If a cost-effective, safe and efficient solution can be utilized, then this can extend the life of the well completion, and production can continue.

Safety valve issues

The TRSCSSV is operated by applying pressure from the surface through a control line, which will keep the safety valve open. There are multiple issues that can occur, such as a leak in the control line or a safety flapper valve that is stuck or unable to close properly due to scale buildup. For problems with the safety valve flapper due to scale, this can be cured by spotting acid to dissolve the scale, or a lock-open tool will have to be used to permanently isolate the entire TRSCSSV.

If the TRSCSSV is permanently closed off, an insert straddle with a new safety valve below will have to be installed. The insert valve carrier (IVC) provides the means of retrofitting third-party replacement valves by using the existing subsurface safety valve profile. This straddle assembly can be installed inside the locked-open TRSCSSV, or the straddle can be set across the TRSCSSV.

The solution to choose depends on how severe the damage is to the wellbore completion in this area. The preferred choice will always be to install a straddle inside the TRSCSSV since this will allow operating pressure of the safety valve to be maintained. Such a safety valve is operated through the existing control line by applying pressure from the surface. This pressure will then be trapped by the two sealing elements on the straddle. The bypass located in the lower element will allow communication to the safety valve hanging off below the straddle assembly.

The IVC avoids recompletion and reduces cost by allowing retrofitting of wireline-retrievable subsurface safety valves in damaged downhole safety valve nipples. (Source: Interwell)

Production tubing leaks

When faced with a leak in the production tubing due to severe corrosion or tubing joints not being correctly torqued, these leaks can be managed by installing a retrievable straddle assembly. The anchored production straddle (APS) is designed with high expansion and effective through-bore in mind when developing specific solutions for production control challenges.

These straddle assemblies can be used as a one-run or a multirun stackable system. The choice of straddle system depends on how long the section to be isolated is compared to how much available rigup height there is on the surface when installing the equipment inside a wireline lubricator.

Many completion designs include gas-lift valves due to the well needing assistance to achieve required lifting speed for fluid. These valves are operated by pumping gas down the production tubing-casing annulus. If these valves leak, get damaged/stuck or are placed at the wrong depth, this could lead to a costly loss of production.

The gas-lift valve is placed inside a side-pocket mandrel. To change these out, a specially designed kick-over tool is used both for retrieval and reinstalling. If such a valve is stuck due to debris or scale, an APS system can be set across the side-pocket mandrel with a new gas-lift valve between the two sealing elements.

For cases where the side-pocket mandrels are placed at the wrong depths, a tubing punch can be carried out to create a point of communication between the tubing and annulus. By isolating this point with a gas-lift straddle, gas can be injected into the annulus and into the production tubing via the gas-lift valve located in the straddle.

Using straddle assemblies

Well completions are sometimes fitted with a PBR installed just above the production packer when extreme movement is expected in the production tubing. Should the seals inside the PBR start to leak, there will be a barrier issue to the annulus. A retrievable APS assembly can then be set across the original PBR to isolate the leak. Between the two sealing elements, a new PBR is fitted so that the old and new PBR can move together.

The production packer is placed at the bottom of the production tubing to isolate reservoir fluid from entering the production tubing to casing annulus. Should this start leaking, there will be a barrier issue that will have to be repaired. Again, a retrievable APS assembly can be set across the production packer. This is done by placing the lower packer element inside the lower completion (liner) and the top element inside the upper completion. This way the installed straddle packer will function as the new production packer.

The described issues are very common in wells that have been in production for some time. For certain wells, these issues can arise early in the well life, while for other wells it can take several years before issues are encountered. It goes without saying that if all of the above challenges can be repaired with a wireline operation instead of killing the well, pulling the entire upper completion or conducting a side track, a considerable amount of money can be saved. This is especially so on subsea wells, where such problems can be carried out by the use of a light well-intervention vessel instead of using a drilling rig. The main conclusion is that wireline intervention can repair and fix damaged well completions in a safe, cost-effective and efficient way to extend the life of the producing well. E&P

Controlling emissions in the production process

Many options are available to help meet the regulatory demands of managing emissions at the well pad.

Sean MacLeod, Zeeco Inc.

Emissions pose both a safety and environmental hazard. In some cases, burning emissions via flare is the best solution, while in other cases vapor recovery might be preferred. Environmental pollution legislation is—almost without exception—the driver behind the decision to install a vapor recovery unit to meet the permitting requirements and to provide cleaner local environmental emission controls and safer working environments.

Beyond the environmental and safety advantages, the potential economic benefit from the recovery of a highly valuable product cannot be ignored. In addition to well-site waste gas, common fugitive emission points include tank vapors and vent lines on instruments.

The latest emissions regulations specify that emissions from compressor packing on reciprocating compressors must be controlled. With sales gas pipelines, compressor packages for collecting and compressing these gases can be employed. These packages recover and reroute gas emissions back into the gas pipeline. In stranded gas applications, gas-to-liquids packages recover valuable hydrocarbon liquids.

Combustion and environmental control companies can design a cost-effective combination vapor recovery flare package that allows producers to recover heavier gases as a liquid and safely flare lighter hydrocarbons like methane.

When processing combustible gases, a flare provides a safe means of disposal for gas releases. Instead of an accidental dangerous gas release into the atmosphere that could harm employees, the surrounding area or facility, potential release sources are collected and routed to a flare. At the flare, the gases are ignited by pilots and destroyed through controlled combustion in a designed-for-purpose system. While the fire visible from a flare might be alarming, the products of combustion—CO_2 and water—are better for the environment, plant and people when compared to raw gases.

The Zeeco Zephyr trailer-mounted enclosed vapor combustor produces zero grade-level radiation, has full turndown capability, produces no smoke and has the ability to relieve inert waste streams by using an assist gas-injection system. (Source: Zeeco Inc.)

Design considerations

Zeeco's experience in flare design has led to some adages and practical approaches for flare systems. In general, engineers work to minimize the size and diameter of a flare while still fully combusting gases. Using the smallest applicable diameter converts the potential energy of the gas (pressure) into kinetic energy (velocity). More velocity means a more erect flame, quicker air inspiration and less sweep gas—all lowering emissions.

Ultimately, designing the smallest possible tip while maintaining high destruction efficiencies lowers capital costs and extends the lifespan of equipment due to less destructive flame impingement (vs. a larger diameter flare tip). The evaluation of a flare's combustion performance is predictable by comparing the flare tip exit velocity to the heating value of the flared gases.

To ensure the flare gas has ample opportunity to combust fully, there should be sufficient heating value to the gas. The velocity of the gas must be correct to prevent a separation of the combustible zone from the pilot ignition source at the flare tip; this phenomena is known as

lift-off. A robust flame not detached from the flare tip and pilots demonstrates ample combustion efficiencies.

Meeting standards

Regulations are in place to ensure manufacturers and operators properly combust flare gases. In these regulations, the exit velocity of the tip is the primary operational consideration for the application of U.S. Environmental Protection Agency (EPA) standards.

With offshore platforms, flaring systems face challenges such as space availability, heat radiation, noise and environmental regulations. Offshore flares need to deliver high destruction efficiencies and stable flame patterns across a wide operating envelope and should be designed to meet the pressure, flow and gas composition ranges required. Reliable flare pilots are a critical component in maintaining safety and emission standards. Hurricane-proof pilots such as high-stability, low-flow, ballistic pellet ignition and monitoring systems help minimize common offshore flaring challenges.

Onshore production flares, wellsite flares and tank vent flares also are subjected to both climate challenges and remote areas. In the U.S., systems must be compliant with the EPA's New Source Performance Standards OOOO (NSPS Quad O), National Emissions Standards for Hazardous Air Pollutants, Maximum Achievable Controls Technology and other applicable requirements. NSPS Quad O requires gases that would otherwise be vented during periods of flowback be routed to a completion control device (CCD) instead. The CCD must achieve a minimum of 95% volatile organic compounds (VOCs) reduction. A properly designed flare will achieve greater than 98% VOCs reduction.

Common applications for rental or temporary combustion equipment

Emergency flare replacement	Vapor combustor backup
Flares for day-to-day equipment maintenance	Combustion equipment to meet new stream regulations
HP blowdowns (pipeline and product storage)	Capacity upgrades for existing systems
Low-pressure tank degassing	Performance enhancement for existing systems
Loading operations (gasoline and others)	Well testing and drilling
Vapor control	Soil and groundwater remediation

Control options

Portable open and enclosed wellhead and well pad flares that do not require a pre-poured foundation can be the solution to completing wells quickly and effectively while complying with oil and gas gathering field environmental regulations. The Zeeco enclosed wellhead flare system, for example, is a simple, low-maintenance flare providing smokeless, high-efficiency combustion without field operator attendance or adjustment requirements.

Often used with tank batteries, heater treaters, vapor recovery towers and other field equipment, the system's advantages include no visible flame, quiet operation and no moving parts. Due to a proprietary tip that inspirates air, this wellhead flare achieves up to 99% or greater destruction removal efficiency and comes preassembled on two small skids with pre-spooled interconnecting wiring to minimize installation time and expense.

In some cases, selecting a high-pressure/low-pressure (HP/LP) system, also known as dual flares, will allow an operator to effectively handle the HP wellhead separator/heater treater flows and LP tank battery vent gases that are common on most well pad locations. Solar energy-powered flare igniters also are available for remote locations where electricity is unavailable, as is often the case in remote fields.

Upstream and midstream operators sometimes choose rental or mobile systems to control emissions, which are typically trailer-mounted or skid-mounted. Many of these systems feature a hydraulic lift system for ease of installation. Open-flare, enclosed-flare, thermal oxidizers and vapor combustor systems are available and can be used to effectively destroy waste gases. Systems that can automatically control combustion and quench air along with fuel gas (in low-Btu applications) to maintain precise chamber temperatures for destruction and removal efficiencies of up to 99.9% will meet or exceed the most stringent clean-air standards.

Regardless of the type of flare system used, a properly engineered flare will include investment castings for the critical components in the heat-affected zones to minimize the potential for field failure. A continuous, monitored pilot that meets or exceeds American Petroleum Institute 537 design criteria for performance under high wind and rain conditions means fewer operations and maintenance issues in the field and ensures environmental performance.

Open-flaring equipment can range from small skid- and trailer-mounted flares to 91-m- (300-ft-) tall elevated systems. Enclosed vapor combustor, incineration and flare systems can dispose of anywhere from very small process vent streams to 1.4 MMcm/d (50 MMscf/d) emergency releases. E&P

Adding efficiency to greenhouse gas reporting

An automated approach to meeting the GHG Subpart W emissions compliance requirements will help operators reduce labor costs associated with reporting and increase efficiency.

Hong Qin, Wood Group Mustang

The Greenhouse Gas (GHG) Reporting Rule, 40 Code of Federal Regulations (CFR) Part 98 under Subpart W, is mandated by the U.S. Environmental Protection Agency (EPA), impacting those production sources annually emitting above an equivalent threshold of 25,000 metric tons of CO_2.

The reporting requirements place a tremendous strain on oil and natural gas producers as they struggle with the enormous data volume necessary to comply.

More challenging than just the sheer volume is the complicating fact that the information is tracked by separate functional groups for different purposes, including field operations at the well pad, work order management systems, operations engineering and financial accounting. Often the data are collected in different formats using dissimilar terminology.

Preparation for GHG reporting Subpart W production is highly labor-intensive, often overwhelming the environmental groups in subject organizations with data points exceeding 1 million annually for a company with multiproducing regions. GHG natural gas data required have been estimated at more than two orders of magnitude greater than any previous EPA report.

In October 2015 the EPA amended Subpart W to include onshore production gathering and boosting segments. This amendment was initiated on Jan. 1, 2016, with first reported data due in January 2017.

The additional segments add to the data volume and present even more challenges to the reporting entities. Recognizing some emission sources under the gathering and boosting segment might be intertwined with sources under production and processing, extra effort will be needed to extract or aggregate data from data sources used by the other two.

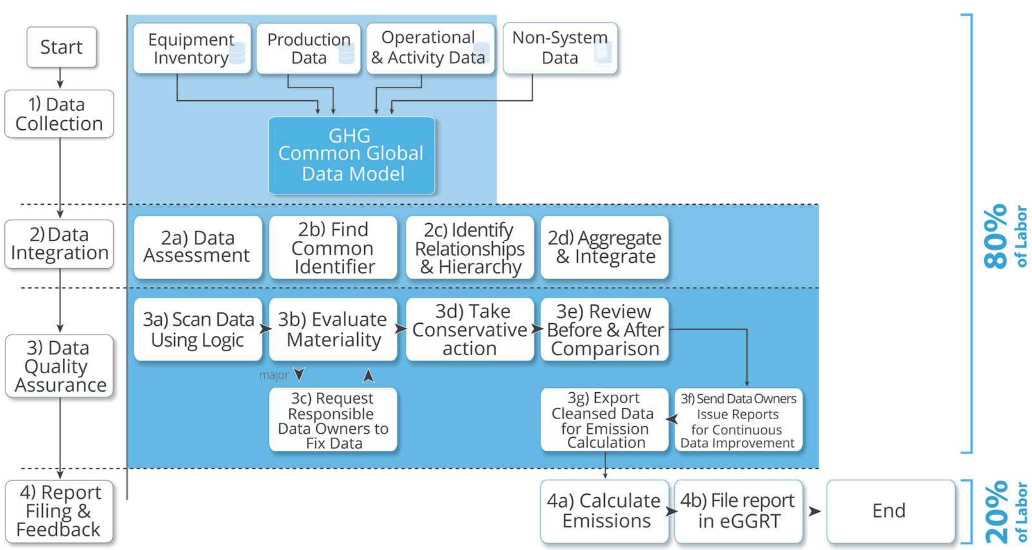

FIGURE 1. A workflow diagram shows the many steps involved in the GHG reporting preparation. (Source: Wood Group Mustang)

Steps to compliance success

GHG CFR 98.4 states that compliance reporting must be true, accurate and complete to the best

of knowledge of the reporters/business owners. How can that be best accomplished in the most efficient and cost-effective way?

The labor-reducing answer lies with an approach involving the automation of data collection, integration and quality control/quality assurance (QC/QA) using a centralized data warehouse and business logic. This procedure was recently completed at a major producer's southwestern U.S. asset of more than 9,000 well sites with more than 1.2 million data points.

In that specific case, and in other similar applications, a four-phase workflow process was effectively implemented, automating the first three stages to allow validated, consistent reporting. These phases, as depicted in Figure 1, include:

Data collection: During this initial phase, all sources that could provide required GHG data are identified. The main focus at this point is to assure that data from all these sources, regardless of the host system generating them, can be consolidated into a centralized database as a common model. This step segues into further aggregation and integration.

Data integration: This phase provides a more detailed assessment of which data fields are needed to integrate, selecting all relevant parameters and arranging them into a structure for the performance on a common platform. The stage also lays the foundation for a comprehensive QA.

This stage involves four separate steps of its own. First, an assessment is undertaken to determine the primary data spheres needing to be integrated. These can be either direct emission calculation input or taken from indirect data.

Next, a common identifier is found that integrates portions of data from different systems. This is a critical step in the integration and in assuring QC/QA.

Step 3 is needed to recognize relationships between the emission sources according to function and interrelatedness so that data points can be mapped structurally. For example, equipment such as pumps, engines and compressors should be mapped under wellpad in a hierarchical fashion, or nonhierarchically such as the horizontal relationship between engine-driven compressors and engines. Data integration becomes easier once that procedure has been completed. The relationship is driven by its physical data model, illustrated in Figure 2.

The last step in the data integration phase is the actual data aggregation organized by individual well of annual production, activity and equipment.

QC/QA: The compliance mandates of truth, accuracy and completeness in CFR Part 98.4 put additional burden on the reporter/owner to assure that the reporting results are of the required quality. This can be a daunting task when there are multiple dissimilar data systems involved that are not designed for environmental reporting or without standard guidelines for the data tracking of those systems. The task can be further complicated when there are more than one large geographic asset to report or if rigorous data entry protocol is lacking. Not resolving these

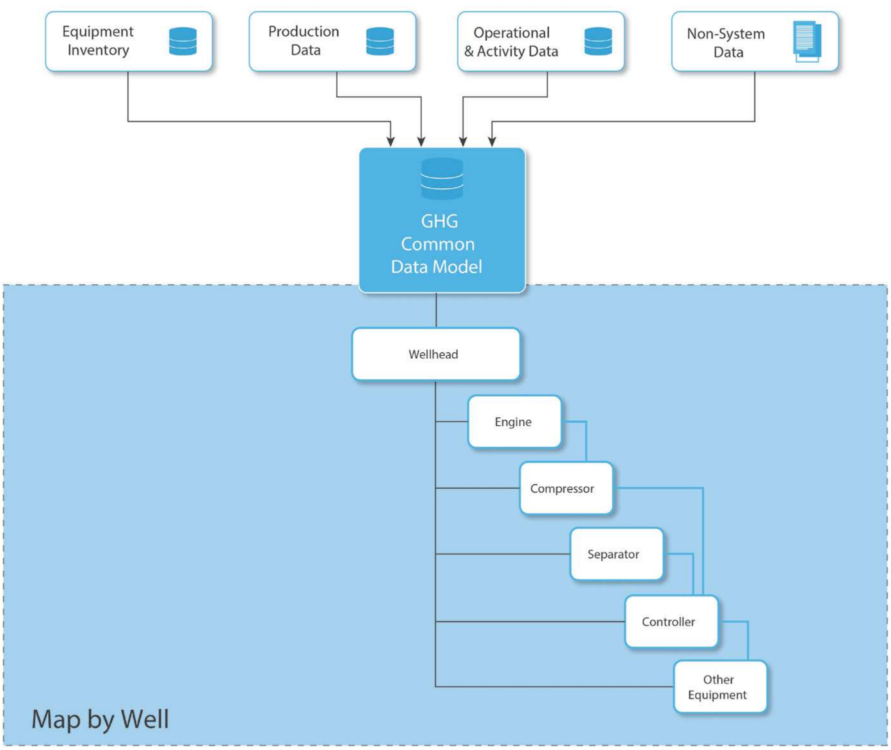

FIGURE 2. Step 3 in the data integration phase maps out the relationship between emissions sources according to function within the GHG data model. (Source: Wood Group Mustang)

factors can lead to incomplete, inconsistent or inaccurate information.

Based on the responsibilities inherent in the QC/QA phase, it has proven valuable to develop a series of business logics to integrate previous phases and perform data analyses and validation. To reach the best results from the QC/QA phase, a unique skillset is required that combines onshore upstream knowledge plus abilities and experience in data analysis. The logics performed become part of the common data model to

- Check individual systems for missing, duplicate or inaccurate information;
- Verify the well list and operating status among the equipment inventory, operating activity and production data systems; and
- Substantiate the equipment count based on the mutual relationships.

At the successful conclusion of automating these first three phases, environmental department personnel should be able to generate a clean and validated dataset complete for GHG emissions calculations.

The three phases account for 80% of the total effort. Once completed, the labor savings are enormous. Recently, a large gas producer previously requiring six man-weeks to complete the process dropped its work effort to less than two man-hours with a higher degree of accuracy than had previously been attained.

GHG report filing, feedback

At the final process stage, the reporter can use the previously obtained data output to submit its report to the EPA after sending the report to the data owners for review and any needed corrections. This portion encompasses about 20% of the reporting project. At this stage records can be centrally warehoused to satisfy the requirement of keeping historical records with a transparency for explaining how the information was derived and emissions calculated.

With the increased emissions data requirements mandated by the EPA and the additional volume needed for GHG Subpart W production components, U.S. producers are turning to automation of data collection, integration and QC/QA as a solution. This resolution will dramatically reduce labor time, increase efficiency and improve accuracy.

The data accumulated in this fashion can further allow environmental department personnel the opportunity for additional analysis of operating data for maximizing production while minimizing emissions and provides a reporting methodology for other state and federal agencies that eliminates duplication of effort. E&P

A deep philosophy

With Total operating more than 10% of the world's deepwater production, the French major's deep offshore philosophy is being firmly stress-tested by the low oil price environment.

Mark Thomas, Editor-in-Chief

The deepwater business has always been a long-term game for Total. Despite the latest lows being tested by the oil price, the operator's deep offshore business remains one that it has reaffirmed it wants to and is continuing to grow.

Its share of global deep offshore production (in more than 500 m [1,640 ft] of water) will rise to 15% by 2017, it forecasts, with its own projects flowing from an average water depth of 1,200 m (3,937 ft). That production stream will be gathered by a total of nine FPSO units, two floating production units (FPUs), and between 450 and 500 subsea wells, representing a total capacity of 1.8 MMbbl/d of oil.

With the industry close but not yet producing in more than 3,000 m (9,843 ft) of water, the operator already is talking on the record about achieving field development activities in up to 4,000 m (13,124 ft) within the next 10 years.

4,000 m by 2025

Total has an outstanding pedigree, of course. It has pioneered some of the deepest projects in the world so far, including its flagship developments offshore Angola such as Girassol, Dalia, Pazflor and CLOV (Cravo, Lirio, Orquida and Violeta).

The operator's head of technology innovation at Total E&P UK, Jeremy Cutler, pointed out at the SPE Offshore Europe Conference and Exhibition in Aberdeen recently that, "By the year 2020 a water depth of 3,000 m—from an oil development perspective—seems to be achievable. We see that by 2025 the expectation is that 4,000 m will be achieved."

The company deems anything beyond 1,500 m (4,921 ft) as ultradeep water and has dubbed the new frontier beyond 3,000 m as simply "frontier deep water." With more than 50% of its exploration portfolio in deep and ultradeep water, Total has a vested interest in R&D and enhancing new and existing deepwater production solutions. Cutler said simply that, "It will be very much a big part of our future and where much of our production revenue is going to come from."

The current difficulty remains the high development costs associated with these types of technology-intensive projects, which make them hard to launch in the low oil price environment. But as a result, Total and the industry as a whole are being forced to study more ways to reduce costs.

Total's deepwater *FPSO Pazflor* unit in Block 17 offshore Angola is bridge-linked to the *Jascon 31* accommodation and construction vessel. (Source: Total)

"The challenge for us now, going forward, is how do we go deeper, longer—and cheaper?" he said. Cutler flagged up Total and also Royal Dutch Shell as leading the push to develop frontier deepwater areas, with the industry's established group of majors as a whole generally holding by far the largest average areas in terms of frontier deepwater acreage.

Technology gaps

Each new field brings its own technology challenge, Cutler said, and the current technology gaps for frontier deepwater facilities remain plentiful.

Some have been well-known for a while, such as the multiple flow assurance challenges related to transporting the hydrocarbons back to the surface facility "across what is clearly a wide pressure and temperature domain." Cutler pointed out that below 600 m (1,969 ft) the water temperature is about -4 C (25 F), while at 1,500 m the hydrostatic pressure is 150 bar.

Other frontier deepwater gaps to be further researched and qualified include pipelay techniques and riser installation and maintenance, the mooring of FPSO units, subsea power distribution and water injection, seabed separation, multiphase pumps, and electric submersible pumps (qualified up to 6,000 m [19,685 ft] in wells).

Tieback limits

According to Cutler, these will all help the industry on its mission to increase the length of step-outs and tiebacks, especially for oil, which currently stands at about 70 km (43 miles) at relatively shallow-water depths.

In deep water, the benchmark figure so far has been set by Murphy Oil with its Dalmatian South tieback in nearly 2,000 m (6,562 ft) of water in the Gulf of Mexico (GoM), reaching more than 40 km (25 miles) to the Petronius compliant tower platform in shallower waters. There are deeper tiebacks than this, of course, but the distance reduces accordingly. For example, Petrobras's Cascade Chinook oil and gas project in more than 2,500 m (8,202 ft) of water in the GoM has subsea tiebacks but of less than 25 km (15.5 miles) in length.

For gas, Cutler added, "it's a little bit different, with the step-outs already longer." Total's own Tobermory subsea gas tieback, for example, is nearly 180 km (112 miles) in length, in a water depth of more than 1,500 m.

Subsea-to-beach

According to Cutler, Total is on a similar path as Statoil, with a serious long-term ambition to establish a subsea factory solution. "Eventually we want to remove the floater from the equation and go subsea-to-beach," he said. "We have in our R&D program a number of different projects related to the so-called subsea factory concept."

Multiphase production results in a high back pressure at the wellhead and the loss of potential deepwater reserves. So subsea processing segments such as the separation of gas and liquids and pressure boosting technologies will be required, he stressed. At present, 3,000 m or more "looks to be achievable with existing technologies, but not for subsea compression," he commented.

Laggan-Tormore reality

Total's subsea-to-beach vision already has become reality. The company's deepwater Laggan-Tormore gas-condensate field West of Shetland offshore the U.K. has been in the development phase for several years, but the field became operational early in February 2016.

The frontier project in 600 m of water is enabling an 18.8-MMcm/d (665-MMcf/d and 90 Mboe/d) gas export route from the area, with Cutler admitting Laggan-Tormore has been "a challenging project for us" but one that has been "a good test of subsea-to-beach." The subsea-to-beach development is the first of its kind in the U.K. offshore sector and consists of a 143-km (89-mile) tieback of four initial subsea wells to a new onshore gas plant on the Shetland Islands with a capacity of 14 MMcm/d (500 MMcf/d). The nearby Edradour and Glenlivet discoveries will be developed in the next development phase.

Following treatment at the plant, the gas is being exported to the mainland via the Shetland Island Regional Gas Export System, while the condensates are exported via the Sullom Voe Terminal. Total E&P UK operates Laggan-Tormore with a 60% interest with DONG E&P (UK) Ltd. (20%) and SSE E&P UK Ltd. (20%).

FPSO, subsea solutions

Cutler also went on to highlight the work that Total has previously done on some of its biggest recent developments offshore Angola, where the use of FPUs in combination with innovative subsea technologies has enabled FPSO units to be a vital building block in the company's development portfolio.

In particular, he flagged up Total's CLOV project in 1,400 m (4,593 ft) of water, which came onstream mid-2014 and where it employed helico axial subsea multiphase pumps for the first time—a technology it sees as crucial for improving reservoir recovery rates. "This was essentially four field developments in one and made four uneconomic fields economic. We used a standard building block—the FPSO unit—but used it very flexibly. It was the subsea side of it and the reservoir systems that were the biggest challenge," he said.

Cutler also highlighted the Pazflor development, where the company developed both light (Oligocene) and heavy (Miocene) oil reservoirs using a combination of bottom riser gas lift, three 1,000-tonne subsea separation units and six multiphase pumps—an industry first for two-phase separation and liquid boosting at the mud line. These pump the oil and gas to what was the world's largest FPSO unit when Pazflor first started flowing in 2011.

Asked at the Offshore Europe Conference how the industry can prove the business case for subsea processing projects going forward, Cutler concluded that the industry had to "simply work harder" to get around the problems. "These deepwater fields are bigger, which really helps the economics. However, the oil price is making us work that much harder to get a solution that works." E&P

Short-term deepwater pain before long-term gain

Deepwater production is vital in the long term for the upstream industry, being forecast to flow 11 MMbbl/d by 2040—but for now, the industry's busy conveyor belt of projects has come to a grinding halt.

Mark Thomas, Editor-in-Chief

Few doubt that deep and ultradeepwater developments will have their time again but, according to present forecasts, final investment decisions (FID) for new deepwater facilities will be a rare sighting for a while.

That's not to say that deepwater projects are not on the drawing boards of companies, with many being further "reengineered" into lower cost versions while their owners wait for better times (BP with its Mad Dog Phase 2 development in the Gulf of Mexico [GoM] being a case in point).

But until the industry has managed to reduce its costs enough to overcome an oil price that many believe is now set to stay at its current level for at least the next year, few are likely to get project sanction any time soon.

Shell's *Olympus* TLP on the Mars B Field in the GoM is shown with the original Mars facility in the background. The operator has applied lessons learned from building and operating its seven existing deepwater facilities in the GoM to substantially reduce development costs on its next two deepwater fields due onstream, Stones and Appomattox. (Source: Shell)

About 75% of deep water uneconomic

The accepted fact is that, at present, even at an oil price of $60/bbl, about 75% of deepwater projects were uneconomic as of mid-2015, according to a Goldman Sachs report at that time.

Recent announcements have shown just how much excess there is to cut out. On Statoil's Johan Castberg development, the operator has revealed that costs have been slashed from a huge $11 billion to circa $5 billion or $6 billion. Although an admirable reduction, it immediately begs the question as to how costs had been allowed to soar so high in the first place.

The field lying in the Barents Sea within the Arctic Circle is now set to be developed—although not yet sanctioned—using an FPSO vessel with an FID set for 2017, according to CEO Eldar Saetre. Previously, the operator had been considering a production semisubmersible unit as an alternative option. It is also likely that offshore offloading of the oil has helped to further reduce the costs as opposed to the alternative plans, which have included a possible pipeline to shore to a new standalone oil terminal.

Johan Castberg is located about 240 km (149 miles) northwest of Hammerfest in northern Norway and is comprised of the former Skrugard, Havis and Drivis fields, all within Production Licence 532. The field is estimated to contain recoverable reserves of up to 600 MMbbl of oil.

FID delays

A similar path is being followed by BP, which has two production semisubmersible units on the drawing board in the GoM, including Mad Dog Phase 2 and also its Hopkins discovery.

The operator originally planned to make a decision by early 2016, with Mad Dog Phase 2 already having been delayed several times over the past two years for further redesigns and cost-reduction efforts.

But the continued freefall in oil prices last year, and no sign of a recovery, means it is now unlikely to make any investment decision until later this year at the earliest, if not in 2017. The second phase of Mad Dog in Green Canyon Block 780 was originally planned to be developed using a large production spar, but that plan was ditched after its costs soared billions of dollars beyond its original planned budget.

Less is known about Hopkins, but the deepwater discovery in GC 627 lies about 319 km (198 miles) south-southwest of New Orleans and was last year put on a fast-track development process, only for the operator to now hit the brakes this year.

Deferred capex of $380 billion

BP's move is representative of the entire global upstream industry at present. According to Wood Mackenzie (WoodMac), the low oil price environment and other factors have caused companies to stall 68 upstream projects—many of them in deep water. These represent a combined capex of $380 billion.

"The impact of lower oil prices on company plans has been brutal," said Angus Rodger, principal analyst of upstream research for WoodMac, in a recent report. "What began in late 2014 as a haircut to discretionary spending on exploration and predevelopment projects has become a full surgical operation to cut out all nonessential operational and capital expenditure."

In second-half 2015, 22 major projects, including 10 in the North Sea, joined the list of 46 deferred projects already identified by WoodMac as of mid-2015—when oil was trading at about $60/bbl.

Many of the FIDs for these projects have been pushed back to at least 2017, delaying first production to a likely date anywhere between 2020 and 2023.

Twenty-nine deepwater projects stalled

Examples it listed of delayed projects included Statoil's Aasta Hansteen Field offshore Norway and the Mariner Field in the U.K. North Sea from 2017 to second-half 2018, citing increased costs.

WoodMac's list also included the deferral of the development of the Golfinho Area offshore Mozambique and Eni's Kashagan Phase 2 project in the Kazakh sector of the Caspian Sea as well as projects offshore Angola.

A sizeable number of the stalled projects are high-cost deepwater developments, it stated, with the number of these project deferrals jumping from 17 in June to 29 at year-end 2015.

WoodMac said more project delays and investment spending cuts are highly likely this year as a sub-$35/bbl oil price forces companies into survival mode.

Cost reduced

But substantial cost reductions on major deepwater developments already have been achieved.

Shell is a case in point on two of its highest profile projects underway in the GoM—Stones and Appomattox. The company produces more than 50% of its deepwater production from the Gulf, according to Martijn Dekker, Shell's vice president for appraisal and hydrocarbon maturation, out of the company's total deepwater production figure of 370,000 boe/d (2014).

On Appomattox, sanctioned in July 2015, Shell said it has reduced its total cost by 20% through supply chain savings, design improvements and by reducing the number of wells required. The 650-MMboe field is the first development in the Norphlet play, with the semisubmersible four-column production platform to be Shell's eighth and largest floating deepwater facility in the GoM. Appomattox is expected to hit average peak production of about 175,000 boe/d once it ramps up to full speed by around the end of this decade.

Lessons learned

The company achieved the savings largely by using advances and lessons learned from its previous four-column facilities such as the recently built Olympus tension-leg platform (TLP) used on its Mars B Field as well as ensuring a high degree of design maturity before construction.

A specific example given by Dekker highlighted a focus on design, equipment and scope specifications with increased standardization. This saw competitive scoping on the Mars/Ursa project's deepwater wells save about $95 million last year alone, he said.

With these and other cost reductions, the go-forward project breakeven price is currently estimated at about $55 per barrel Brent equivalent—still higher than today's price but expected to be within the expected oil price range from 2017 onward.

Savings of $1 billion

On Shell's Stones project, Dekker pointed out the company achieved capex savings of $1 billion through measures such as simplified and innovative well designs and supply chain savings on the FPSO and subsea systems.

Stones will be the world's deepest oil and gas development in 2,900 m (9,600 ft) of water and is expected to initially produce about 50,000 boe/d via its newbuild FPSO unit once it comes onstream later this year.

Other efforts Shell already has made to make its deepwater facilities operate more efficiently in the GoM include a program to improve its logistics and materials management—an initiative that saved it an estimated $60 million in 2015, Dekker said. The fall in costs within the industry over the past year also has helped, he added, with Shell achieving a 40% saving in the GoM on electric wireline services—equating to about $50 million. E&P

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Joining the 'Thousand Club'

Study shows unconventional North American shales with the most potential. The results are not surprising.

Rhonda Duey, Executive Editor

For those hoping to discover the next big North American resource play, the news from Bernstein & Co. LLC is not happy. In a report titled "Bernstein's E&Ps: What the 2015 'Thousand Club' tells us about 2016 emerging resource plays," researchers reported that most of the wells in the "Thousand Club"—wells that peak at more than 1,000 boe/d—are in well-known resource plays such as the Eagle Ford, Utica, Marcellus and Bakken.

"This observation supports our view that the hunt for new resource plays is increasingly difficult," the report noted.

This annual study relies on well files for wells in Canada and the U.S. Researchers extract the wells with more than 1,000 boe/d. "We expect that 1,000 barrels (oil equivalent) is a good (if arbitrary) cutoff to separate the elite plays from other plays, being representative of an economically highly attractive flow rate given sufficiently low costs," they noted.

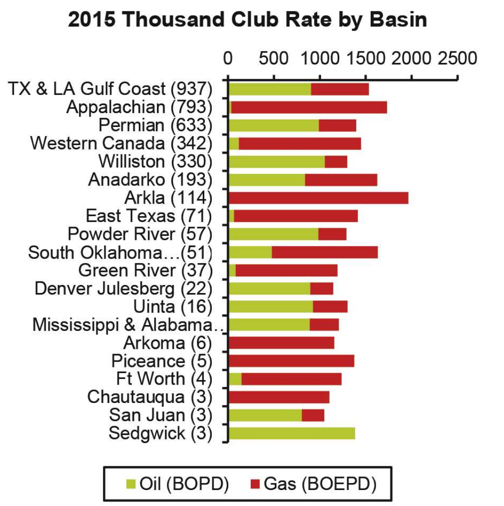


FIGURE 1. Top basins show a fairly even mix of oil and gas, a logical drilling response to favorable oil economics and the fact that gas-prone areas don't need to be drilled to be HBP. (Source: Bernstein & Co. LLC)

The winners

At the 1,000-boe/d cutoff point, about 3,600 wells make the cut from a population of about 40,000, meaning that roughly 10% of unconventional wells joined the club. About two-thirds of these high producers are in the states of Texas, Pennsylvania and North Dakota.

Since the authors were considering oil equivalent, they decided to pull out just the wells that are oil producers given the disparity between oil and gas prices during much of the study period (Figure 1). The 1,000 bbl/d of oil peak producers represent only 2% of all of the wells drilled during the time period studied. Not surprisingly, most of these wells are in Texas, New Mexico and North Dakota. Furthermore, only about 10% of these wells, fewer than 100, are in reservoirs other than the well-known unconventional oil plays such as the Eagle Ford, Bakken and Permian Basin.

"Said another way, two-tenths of one percent of North American wells are high-rate from 'new' potential plays or less-known plays," they noted.

Research indicates that the industry already knows the reservoirs that are most likely to add members to the Thousand Club. The authors noted that some wells might look inordinately productive due to reporting errors. Regardless, 74% of all of the wells come from four basins.

Location, location, location

The authors further broke down the Thousand Club wells by basin. "Not surprisingly, the Middle Cretaceous Eagle Ford Shale dominates both the overall Thousand Club but also this basin's Thousand Club," they noted. "The reservoir immediately above the Eagle Ford—the Austin Chalk—also made the list—a well-known prolific reservoir whose quality is good but quantity limited."

The Buda Lime, immediately below the Eagle Ford, also had three wells that joined the club. However, no wells from the Pearsall Shale made the cut. Other reservoirs that made the cut include the Edwards Lime (one well), Upper Cretaceous Olmos tight sand (eight wells), Woodbine, Frio, Vicksburg, Yegua, Wilcox and Midway. A single Cook Mountain reservoir with Yegua production also made the list.

In the Appalachian Basin, Marcellus wells dominate the Thousand Club, with the Utica coming in second. The database also includes Upper Devonian- and Ordovician-aged wells.

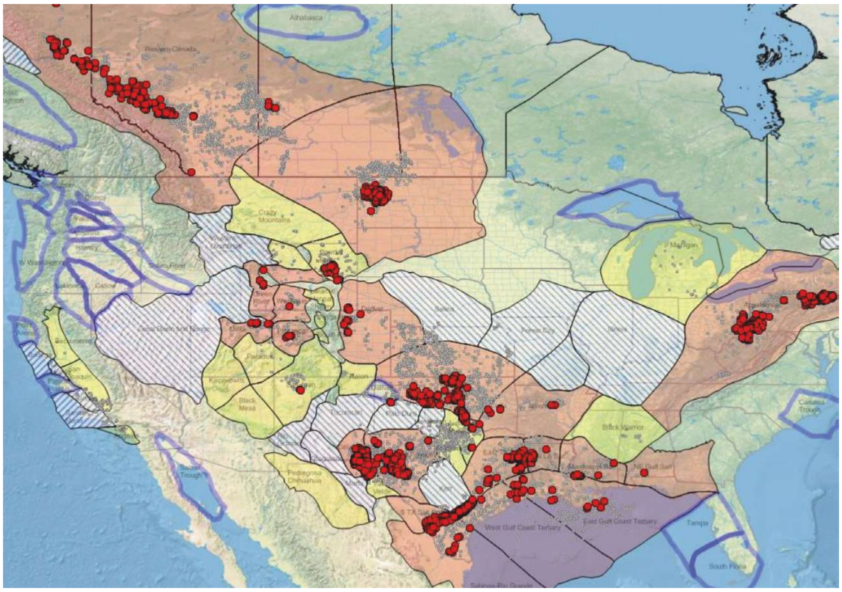


FIGURE 2. This map shows Thousand Club wells in red and other wells in gray. (Source: Bernstein & Co. LLC)

In the Permian, "The Trend," which is a mix of Spraberry and Wolfcamp reservoirs, along with Wolfcamp and Bone Spring shales, brought in the most 1,000-boe/d representatives. Canyon and Delaware also were present after previous absences. Other reservoirs that made a marginal appearance included Anhydrite, San Andres, Devonian, Penn, Wichita, Brushy Canyon and Clear Fork.

"Thus, while the basin is home to a number of stacked pay zones, for now industry is happy to exploit the most obvious targets," the authors noted.

The Western Canada Sedimentary Basin (WCSB) has greater variety than other resource plays as far as its Thousand Club representation. "At a high level, we express three 'rules' for the WCSB: (1) it is prolific and confusing (in the sense that many stratigraphic horizons are hydrocarbon-bearing and can be classified under a variety of names), (2) it is gas-prone (i.e., with a propensity for natural gas as opposed to black oil), and (3) it is distant (i.e., typically host to the worst pricing differentials and higher cost structures)," the authors noted. "As such, we note a number of members of the Thousand Club but caution against believing the next Eagle Ford is to be found."

Reservoirs that did make the list include the Montney, Mannville, Fahler, Horn River, Spirit River, Notikewin, Triassic, Doig, Evie, Cardium, Dunvegan, Gething, Edmonton, Belly River, Blue Sky, Celtic, Ellerslie, Wilrich, Halfway, Viking and Wabash.

The Williston Basin brings up few surprises; the Bakken, Three Forks and Sanish reservoirs all enjoy membership to the club. The authors noted that pre-Devonian opportunities might exist in this basin, but so far no wells have yielded the cutoff peak production rate.

In the Anadarko Basin, the Woodford, Mississippi Lime, Granite Wash, Cleveland, Hoxbar and Marmaton reservoirs top the list. The Springer Shale also made the club. Other newcomers include the Hunton Formation (conventional limestone); Wilcox (age equivalent to the Texas trend); the Bromide Formation (a conventional target sometimes referred to as Viola); the Cherokee tight gas sand; the Meramec (part of the Mississippi Lime sequence); and a few single-well members such as the Chester, Douglas, Lansind, Marchand and Oswego.

The Arkla Basin is completely dominated by the Haynesville, the authors noted.

The Powder River Basin was represented by the Parkman, Niobrara, Sussex and Frontier reservoirs. All but the Niobrara tend to be sandstones abutting source rocks, the authors noted.

Positioned for success

Companies whose wells are most likely to join or remain in the Thousand Club have, in the authors' opinion, two main advantages. "First, access to high-quality proven core resource play acreage is a compelling source of competitive advantage," they noted. "Second, companies exposed to potential emerging resource plays are also scarce and therefore prized. Companies overrepresented in the Thousand Club have such acreage.

"We also believe that discovering new resource play acreage is challenged. Finally, we believe that the best economics are found in the sweet spots of the best resource plays."

Of the myriad shale players in North America, EOG Resources and Devon Energy have the best exposure overall, they noted. "We believe the standout performance of Devon in [the] Thousand Club is indicative of [its] improving resource base and well execution as [it] joins industry leader EOG at the head of the club," they noted. E&P

The low-pressure source

New source provides an environmentally friendly broadband airgun replacement.

Steve Chelminski and **Jan Chelminski**, Chelminski Technology; **Stuart Denny**, Dolphin Geophysical; and **Shuki Ronen**, *Totumgeo.com*

About 150 years ago, the oil industry saved many whales from extinction. About 50 years ago, airguns saved much human and animal life. In the future, renewable sources of energy might replace hydrocarbons, and during the transition period the remaining oil and gas are increasingly more difficult to find and produce. Finding these hydrocarbons will require improved seismic methods, in particular, seismic sources with increased low-frequency content and reduced environmental impact.

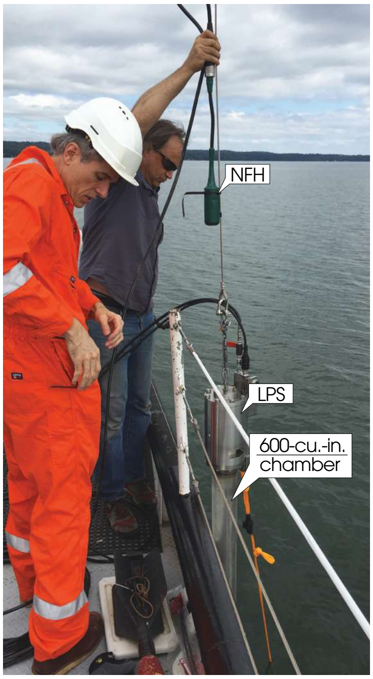


FIGURE 1. The LPS prototype is shown being deployed in Seneca Lake. A 600-cu.-in. firing chamber is hanging vertically below the main housing of the source. Above the source, there is a green NFH. Below the source already in the water (on an orange nylon rope), there is a vertical array of 24 FFHs. (Source: Dolphin Geophysical)

The low-pressure source (LPS) is an evolution of the conventional airgun; it is designed to operate at lower pressure but higher volume. Conventional airguns operate at 2,000 psi and have volumes of 40 cu. in. to 2,000 cu. in. An LPS operates at 600 psi to 1,000 psi and has volumes of 1,000 cu. in. to 6,000 cu. in. The lower pressure enables the volume increase without increasing the weight and the number of guns in the source array.

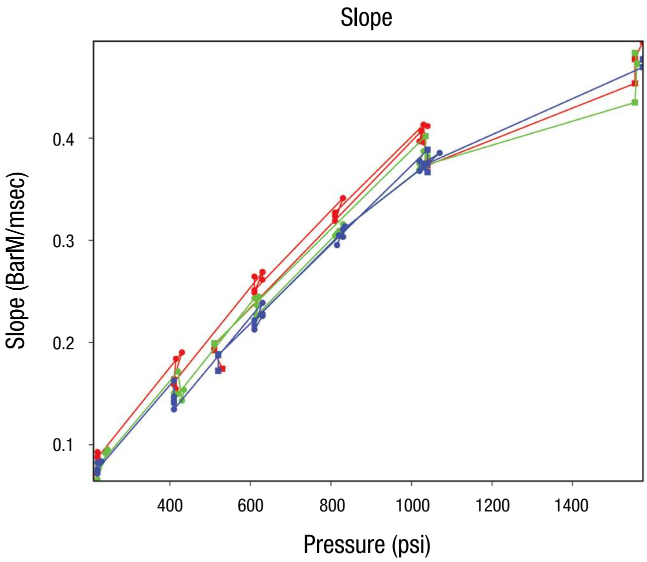


FIGURE 2. The far-field seismic wave slope was plotted vs. source pressure. The slope is the ratio of the peak sound pressure level divided by the rise time. It is a measure of environmental impact to minimize the sound pressure level and maximize the rise time. The slope does not depend on the volume but rather depends strongly on the source pressure and weakly on the source depth. Although the lake tests included only volumes up to 600 cu. in., Dolphin Geophysical is confident that full-scale LPS (up to 6,000 cu. in. are planned) will have as mild slopes as the 50-cu.-in. (square points) and 600-cu.-in. (round points) LPSs that were tested and are plotted above. (Source: Dolphin Geophysical)

In addition to larger volume, another modification that is enabled by lower pressure is larger ports that wrap twice as far around the source, with a total area that is four times that of a conventional airgun. Another new design feature of the LPS is a reduced acceleration distance. Rather than the jets of air that are initially shot into the water by conventional airguns, the LPS produces an annular ring of air that forms an expanding bubble. Instead of whistling jets of air, the expanding bubble radiates low-frequency waves. The LPS thus emits less high-frequency acoustic energy that has little or no geophysical utility for exploration and reservoir model building. It wastes less high-frequency noise and produces more low-frequency signal.

Operational impacts

Upgrading from conventional airguns to an LPS should have a small impact on seismic operations. There will be minor modifications to the compressors, to the umbilicals and to the source control systems. Seismic crews will be able to upgrade from airguns to LPSs with no or little delay. There also will likely be minor changes to data processing because although the time duration of the LPS pulse is longer than conventional high-pressure airguns and the peak-to-bubble ratio is smaller, the bubble is effectively not moving while radiating seismic waves, so there is no need for source motion correction in processing. The smaller peak-to-bubble ratio increases the dependency on improved source designature. However, this is an evolution of seismic data processing that is already underway for the purpose of broadband processing of conventional airguns; the low-frequency acoustic waves that are radiating from the bubble can be treated as signal and not as noise. The bubble has the desired amplitude but the wrong phase; it is coming some time after the main pulse. The phase (or timing) can be fixed without harming the amplitude in processing.

Seneca Lake test

As a proof of concept, the authors deployed an LPS prototype at Seneca Lake and recorded data with near-field and far-field hydrophones (NFH and FFH; Figure 1). The prototype had two firing chambers: a 50-cu.-in. chamber and a 600-cu.-in. chamber. The large volume was shot at pressures varying from 200 psi to 1,000 psi and the small volume from 500 psi to 2,000 psi. An NFH was tied 1 m (3.3 ft) above the LPS and recorded data at a 0.5-ms interval (2 KHz sampling and 1 KHz Nyquist frequency). The FFHs were a vertical array of 24 hydrophones. The nearest one was 75 m (246 ft) below the LPS, and the farthest was 121 m (397 ft) away, with a 2-m (6.5-ft) vertical interval between hydrophones. The FFH, sampling at 31.25 microseconds (32 KHz sampling, 16 KHz Nyquist frequency), provided much better data than the NFH. About 300 shots were recorded over two days. Shots at the same depth, volume and pressure were repeated three to six times to test the repeatability.

Several attributes from the Seneca Lake data were extracted and analyzed. Figure 2 shows two key attributes: The slope (rate of rise in pressure to the primary peak) is a measure of environmental impact, and the ratio of energy in low frequency to energy in high frequency is a measure of geophysical quality. The attributes are plotted against pressure with source depth encoded in color; red is 5 m (16.4 ft), green is 7.5 m (25 ft) and blue is 10 m (33 ft). With three to six times with the same parameters, the data show excellent repeatability.

The improvement in environmental impact was greater than expected (Figure 3). The improvement in geophysical quality was encouraging, and significant improvement in low-frequency content is expected with full-scale volumes and full design features.

With significant environmental and geophysical advantages and with minor changes to seismic acquisition and processing, the LPS is expected to replace conventional airguns as the main seismic source for *E&P* and development. E&P

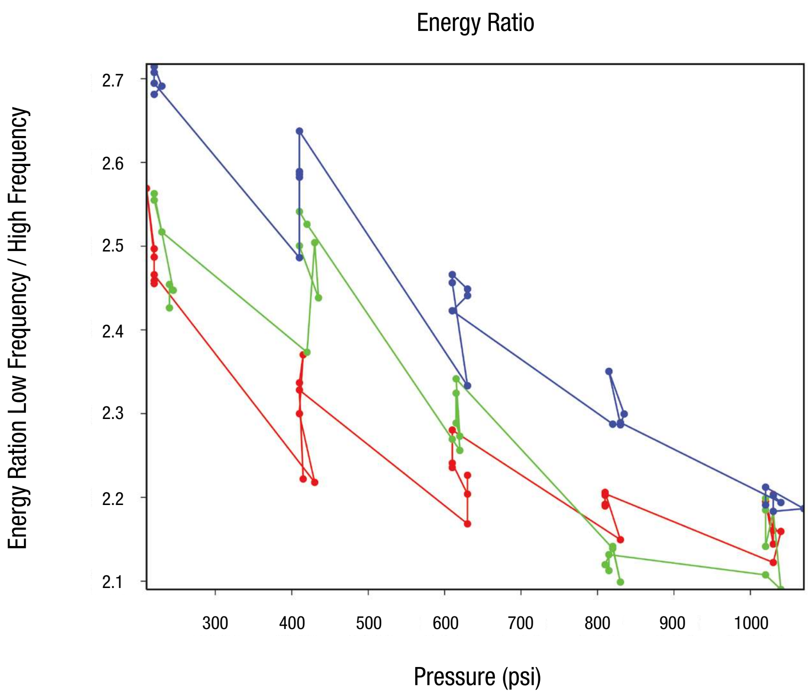


FIGURE 3. The ratio of energy below 128 Hz to the energy above 128 Hz was measured in the far field. This ratio is a measure of geophysical quality. Higher ratios mean better quality because broader band lower frequency sources provide more information that is useful to explore deep targets under complex overburden such as salt and basalt and to build blocky reservoir models. Energy above 128 Hz is absorbed and scattered and does not contribute much to exploration and reservoir model building. (Source: Dolphin Geophysical)

Operationalizing Big Data

Designing, planning and executing competitive well development programs will help operators survive the downturn.

Collin Miller, Capgemini Consulting

For the oil and gas industry, reducing cost and improving efficiency have become critical focus areas as commodity prices continue to push to levels not seen in the industry for several years. Where prices are going to bottom out, much less when they rebound, is anybody's guess. What isn't in dispute are the difficult decisions companies are being forced to make as debt concerns, hedging realities and operational pressures are pushing some executive teams into decisions that will impact how their organizations plan and execute projects going forward—particularly with onshore well development projects.

As organizations weigh whether to cut head count (and how much) or to continue drilling while delaying completions, these decisions made now will have ramifications for future capex. To identify the best alternative, leaders and asset teams have always sought access to critical data to help drive better decision-making and better planning. In the past, access to critical data, particularly offset well data, was often difficult to obtain, missing key elements or simply too much of an "apples-to-oranges" comparison to derive meaningful and credible insight.

Today technology is allowing organizations to pull information from multiple sources in such a way that key data and insights can be pulled from multiple locations depending on how search fields and parameters are defined. Data are abundant and available for analysis, key performance indicators (KPIs) and credible conclusions.

Competitive baselines

The opportunity for operators today in leveraging data availability is not so much in optimizing a specific function but in taking data to drive an integrated design, planning and execution system to realize competitive programs. This is key because, at the end of the day, organizations are competing for investment dollars.

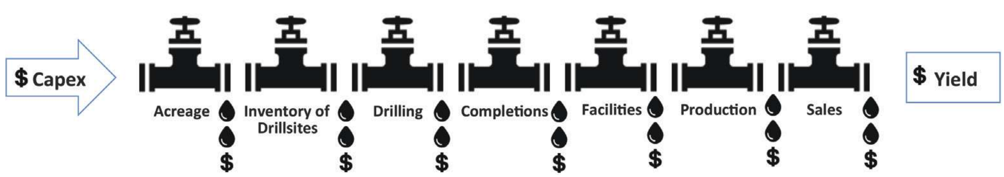
Investors are looking for organizations that can competitively differentiate themselves from other offset entities through cost, performance and returns. The right degree of integrated planning can minimize nonproductive time, as an example, especially in the handoffs from drilling through first production.

If an operator is going to maximize the value inherent in its acreage and, by extension, design an externally referenced program, it must have an idea of the competitive profile of the given basin or play. This is essentially a starting point for design. Each basin has a competitive profile that can drive an optimal well design.

The role that data, or greater data availability, can play in this is to allow organizations to develop a pool of operating information from offset wells. This can include drilling data (days, costs, other), completion data (days, costs, other) and facilities data. That pool of information can then be used to create a composite well that highlights what competitive performance looks like in a specific area serving as a baseline or foundation that reflects the best of what can be achieved in a particular basin that designing and planning assumptions rest on.

Design and planning

Given that the composite well data reflects the potential inherent in each basin, that quantitative foundation can be used as a basis to begin reverse-engineering a program. Determining the difference between internal objectives and externally referenced competitive basin performance can then allow an organization to ask whether internal functional goals and objectives are really in line with competitive performance.



Potential waste (value destruction) occurs throughout the well development value chain, hence the need for a focus on integrated planning and design to drive much more efficient execution. (Source: Capgemini)

This becomes a basis for teams to begin challenging or reassessing the original design and planning assumptions. For example, an asset team's supply chain and procurement strategies can be reevaluated once there is an understanding of what is

really achievable in an operating area, including materials, staging and pricing. Moreover, planning around crews, rigs and other equipment has an informed basis with which to be sequenced to reduce waste.

This type of exercise is typically a very granular view around procedural assumptions. We have worked with asset teams based in the Permian Basin and the Bakken, as examples, that have taken their drilling and completions procedures and walked through each line item to ask whether the design assumption and corresponding procurement/supply chain strategies are helping the team achieve cost reductions or efficiency gains tied to externally referenced data. It should be noted that the teams also factored in HSE considerations, ensuring that those standards were not sacrificed for costs or production gains.

Execution, sustainability

Once the program is designed from a competitively referenced basis, a project team can use the same external data to monitor execution and then work toward sustainability. Often, teams struggle to determine the right combination of metrics and KPIs to track and measure against. This is driven by a number of factors, including different levels of the organization focusing on different types of measures, functional metrics competing with asset or program metrics or a fundamental misalignment on what determines success in a given basin.

To determine whether the design basis is meeting competitively referenced expectations, a project team should be focused around a discrete set of "value metrics"—i.e., some variation of cost, time, production and yield (return on investment). Time is an especially important consideration as the transition among functional tradeoffs is often a leading cause of waste in that days go by without productive activity taking place as a well moves toward first production.

Using asset-focused rather than functional-focused value metrics to assess performance is one part of ensuring whether redesigned project objectives are being met.

Another aspect involves regular review and updating of the comparative data to keep design and planning assumptions current. Analysis should be refreshed on a regular basis to ensure the most recent competitive view of offset operator execution.

Operational limits

As data-driven competitive models are used as a foundation for project design and execution, asset teams also should be cognizant of the design and execution limitations inherent within each basin or play. Cost and performance are impacted by four factors that have a unique profile or limit depending on where the development project is being executed. These are acreage, people, process and technology.

The ability to drive toward competitively referenced baselines depends on how well a team acknowledges the realities of each factor in design, planning and execution. Acreage, for example, not only includes the geologic and reservoir modeling but can include existing infrastructure (or lack thereof).

People and process contemplate the experience levels and numbers of available resources in addition to maturity and optimization of relevant planning and execution processes. Finally, technology involves finding the right tool or enabler to help facilitate the realization of goals and objectives once goals, design and planning are all properly aligned.

The availability of Big Data to impact oilfield operations and project design is no longer a significant challenge facing the oil and gas industry. Instead, it is how to use these data to serve as a basis for informed and integrated design, planning and project execution.

Approaching cost and performance data in a systematic, fully integrated fashion can enable organizations to navigate current realities in a challenging operating environment as well as the inevitable hurdles the industry will face in the future from planning and budget decisions made today. E&P

Rock core imaging technology virtually removes resolution limitations

The ImaCore 3017, a new 3-D magnetic resonance imaging (MRI) technology, has been released by MR Solutions. MR Solutions, in partnership with Green Imaging Technologies, have combined technologies to bring complete high-resolution rock core imaging to the oil and gas sector, a press release stated. Traditionally, rock core analysis is an exercise in providing measured data, but equipment limitations can result in final analysis that involves using theories to understand what is happening at the pore level. The ImaCore 3017 will virtually remove these resolution limitations by allowing users to bolster the theoretical with actual images of all the fluid present in the rock core sample and thus the pore network. MR Solution's cryogen-free MRI technology is highly versatile as the magnet field can be adjusted from 0.1T to 3.0T, depending on image requirements. Sample sizes can range from 1-in. to 4-in. diameters, and ample space is provided for pressure and flow cells, allowing users to make measurements at reservoir conditions and to perform high-resolution flow studies. MR Solutions' technology, including the latest 3-D imaging pulse sequences, is combined with Green Imaging's software products to provide an easy-to-use interface. This provides workflow management and easy calibration and system monitoring. *mrsolutions.com*

The ImaCore 3017 will allow users to bolster the theoretical with actual images of all the fluid present in a rock core sample. (Source: MR Solutions)

Service improves maintenance strategies, operational effectiveness

The new diagnostic reliability service from Rockwell Automation helps manufacturers and industrial producers drive a streamlined maintenance strategy on mission-critical integrated equipment lines, a press release stated. The system deploys a layer of technology across plant devices and equipment to monitor and perform analysis as well as create a continuous improvement approach to reliability maintenance, reducing operational risk. As part of the service, a Rockwell Automation domain service expert closely tracks equipment performance to advise on reliability improvements to the production facility. The system automatically collects identity and health data from all networked devices on the production control network. The data are then modeled with asset management information to trigger events and send alerts to necessary personnel for proactive maintenance. With the service, Rockwell Automation asset reliability professionals assist users in applying the intelligence on their critical equipment to inform data-driven maintenance decisions and increase productivity. *rockwellautomation.com*

Subsurface workflows enhanced with more automation, tighter product integration

Paradigm has released its Paradigm 15.5 comprehensive solution suite aimed at extending its high-definition subsurface workflows and enhancing user productivity, a press release stated. According to the company, Paradigm 15.5 reinforces and enhances the performance gains established in the Paradigm 15 solution released in 2015 and helps users resolve stratigraphic details and recover the subsurface features that control hydrocarbon accumulation and recovery. Paradigm 15.5 is designed to improve the seismic interpretation process and experience with new and enhanced features such as memory-efficient multivolume, multihorizon and multisurvey flattening; multivolume attribute extraction and blending with geometric attributes in 3-D Canvas; quality-control attributes generated on the fly when propagating horizons; and horizon-fault contacts calculated and editable on the fly. Additionally, the Paradigm Quantitative Interpretation solution for recovering rock properties from seismic and well data has been updated with a wedge modeling application that analyzes the effect of bed thickness on seismic amplitudes and provides the option to easily test "what if" scenarios. *pdgm.com*

System helps avoid production interruptions

Baker Hughes has released its CENesis PHASE multiphase encapsulated production system, which helps operators avoid production interruptions in unconventional wells. Designed to separate natural gas from the oil stream before it can enter an electric submersible pumping (ESP) system, the system mitigates production downtime and potential ESP performance issues, which can ultimately improve reserve recovery, a product announcement stated. During the production phase in unconventional plays, higher levels of natural gas are usually released from the payzone as reservoir pressure depletes. This gas typically enters the horizontal wellbore and accumulates in the high-side of the lateral, creating large gas slugs that, as they move up the wellbore, cause low-flow or no-flow conditions in an ESP. The CENesis PHASE system mitigates this problem by surrounding the entire ESP system in a shroud, allowing lighter natural gas to continue flowing up the wellbore while heavier production fluid flows into the shroud and is produced through the ESP system. The shroud also provides a supply of production fluid so the ESP can continue to operate during gas slug events when natural gas completely displaces fluid in the wellbore. Mitigating this gas interference in the pumping system stabilizes production and reduces downtime associated with pump cycling and gas locking conditions. *bakerhughes.com*

Smartphone designed for rugged market

Cat Phones has released the Cat S50c rugged smartphone, connected exclusively on the Verizon network, according to a product announcement. The device has been rigorously tested and designed for challenging environments. The Cat S50c comes from Caterpillar Inc., and its robust design meets U.S. military standards and is IP67 certified, providing protection against drops, water, dust, extreme temperatures, humidity, thermal shocks, vibration and salt mist. The phone is fully impervious to dust, waterproof in 1 m (3.3 ft) of water for up to 30 minutes and is drop-proof up to 1.2 m (3.9 ft). It also features a scratch- and shatter-resistant Gorilla glass screen that won't crack under pressure. The 4.7-in. high-definition display is fully operational while wearing gloves up to 4 mm thick, with wet hands, and even in the rain or snow. Additionally, it features an 8-MP camera. The Cat S50c is also "Push to Talk" ready with a dedicated key to allow users to communicate instantly with one person or an entire workforce. The smartphone features a 1.2-GHz quad-core processor, 1GB of RAM, 8 GB of flash and is expandable by Micro SD up to 64 GB. *catphones.com*

The Cat S50c is waterproof in 1 m of water for up to 30 minutes. (Source: Caterpillar)

Self-retracting lifeline designed for harsh environments

Honeywell's Miller DuraSeal self-retracting lifeline (SRL) is designed to provide greater reliability and safety in the harshest environments, including onshore and offshore oil and gas, a press release stated. The DuraSeal SRL features patent-pending sealed technology that prevents contaminants from entering the mechanism, earning the design an IP69K certification, and it ensures that the SRL's brake system, power spring and bearings are never exposed to debris, water or chemicals. The braking system is designed to withstand multiple falls. The unit installs and transports easier, and quick, low-cost lifeline replacements in the field are possible. Engineered to be up to 30% lighter in weight than competitive sealed SRLs, the DuraSeal reduces user fatigue and increases productivity, according to the company. With a weight capacity of 420 lb (180 kg), the DuraSeal provides protection for a wide range of workers who often carry heavy tools. The DuraSeal requires no annual recertification. *honeywell.com*

The DuraSeal SRL has a weight capacity of 420 lb. (Source: Honeywell)

Software makes driver-based compliance the new regulatory standard

A better way for oil and gas companies to technologically manage their complex regulatory requirements is available from ACS Engineering through its Continuous Compliance Monitoring System (CCMS) software, according to the company. Eliminating the inefficient, awkward but widely used task-based approach, the CCMS is regulation/driver-based and unique in design, delivery and maintenance. For all the regulatory complexities, the system's operation is simple; now companies do not have to painstakingly figure out how to comply with applicable regulations. With the CCMS, companies only receive relevant regulations, which are auto-applied to compliance manuals and tasks. As a compliance-centric bonus, using only site-specific applicability rules (not more or less) loaded into the system saves time and increases economic efficiency, the company said. This system deals exclusively with permits, regulations, plans and manuals, for example, that drive the compliance tasks. After the system is populated with a company's applicable regulations, it continually expands its knowledge base with each new operation. By automatically tracking and continuously updating the drivers, the system stays current 24/7 without the traditional manual rigors. *acsengineering.com* E&P

Natural gas discoveries, developments keep Australasia active

Even though oil prices remain in the low US $30 range, Australasian countries continue the push for natural gas resources.

Scott Weeden, Senior Editor, Drilling

The demand for natural gas in the Far East and Southeast Asia continues unabated. With about 85% of the contracts for LNG supply in the Far East linked to the price of crude oil, the much lower gas prices have buoyed demand in the region. Even China, which is in the throes of a recession, has increased its demand for LNG.

At its meeting Dec. 4, 2015, OPEC approved Indonesia's readmission as the group's 13th member. Originally joining OPEC in 1961, Indonesia had been inactive since early 2009. It remains the only Asian member of OPEC and the only member that is a net importer of petroleum and other liquids.

Even though Indonesia remains a net oil importer, it now can buy crude directly from other OPEC members. The country continues to push floating LNG (FLNG) plants to provide domestic sources of natural gas at the same time it is exporting LNG as a source of revenue generation.

This is a prime example of the challenge facing Australasia. Indonesia, Malaysia and Australia are major exporters of LNG, yet Indonesia and Malaysia import LNG and crude oil and Australia imports refined products.

Low oil prices have put a major dent into project development because of the resulting lower gas prices. Many of the LNG projects in Australia, for example, began when oil prices were closer to \$100. The Gorgon LNG facility received its cooldown cargo at year-end 2015. The \$54 billion project is expected to export its first cargo in early 2016. At lower gas prices, it will take considerably longer to recoup those costs.

More than 65% of the Wheatstone LNG Project is complete. All of the process modules have been delivered for Train 1. (Source: Chevron)

Curtailing operations

Although the consumers in the Far East are benefiting from the low oil prices, the producers are still facing tightening budgets and reduced spending. Shell Malaysia, for example, is reducing its workforce by 1,300 jobs over a two-year period from a total of 6,500 employees, the company said in a Sept. 29, 2015, press release. The layoffs will come in the upstream division.

Even with the layoffs, the company remains active in the upstream. Shell Malaysia achieved an important milestone in the construction of a tension-leg platform (TLP) for its second deepwater venture, the Malikai oil field, 100 km (60 miles) offshore Sabah. In early September 2015 the topsides were safely integrated on the TLP. This is the company's first TLP designed and fabricated in Malaysia. The main drilling campaign for the field is scheduled to begin in 2016.

In Indonesia Chevron is withdrawing from some operations while remaining active in other areas. The company will release its contract to operate the East Kalimantan Block when it ends in October 2018. The company also said it planned to sell its interest in the South Natuna Sea Block B. Chevron will continue activities in deepwater operations in Indonesia.

Indonesian field developments

In its Nov. 20, 2015, edition *Subsea Engineering News* reported that Husky Energy and its partners achieved a significant milestone in the development of the Madura Strait BD gas-condensate field offshore Indonesia. The jacket and wellhead platform for the liquids-rich gas field were sailed out in late October and have been successfully installed in about 55 m (180 ft) of water. Development drilling is expected to begin soon, and the project remains on target for first production in 2017.

Inpex Corp. has ticked off another construction milestone at its Ichthys project after launching its CPF. (Source: Inpex)

The BD Field is the first of a series of gas developments the company is advancing offshore Indonesia, which are expected to add production in 2017 through 2019.

Malaysian gas projects

On Jan. 22, 2016, Lundin Petroleum agreed to sell the *Bertam* FPSO unit to M3nergy Investment Ltd., a wholly owned subsidiary of M3nergy Berhad of Malaysia, for a cash consideration of $265 million based on a transaction effective date of Jan. 1, 2016. The FPSO unit is now operating on the Bertam Field in Block PM307 offshore peninsular Malaysia.

Hess Corp. began development drilling in the North Malay Basin offshore Malaysia in December 2015. Full-field development is anticipated to be completed in 2017, the company said in its fourth-quarter 2015 report Jan. 27, 2016.

Offshore Sarawak Technip was awarded a subsea contract by JX Nippon Oil and Gas Exploration (Malaysia) Ltd. in the Layang Field on Block SK 10, Technip said in an Oct. 22, 2015, press release.

The contract covers the engineering, procurement, fabrication, installation and commissioning of three flexible pipes totaling 9.9 km (6 miles). The project is scheduled to be completed in second-half 2016.

Aker Solutions also tied up a deal in Malaysia with Murphy Sabah Oil Co. Ltd. to deliver the subsea production system for the Rotan deepwater natural gas development offshore. The contract calls for four subsea wells, a hub manifold, inline tees, a connection system and production control system. First deliveries are scheduled for second-quarter 2016, the release said.

Australia

Australia continues its efforts to supplant Qatar as the leading LNG producer in the world. But the pace of development has slowed considerably. The same could be said for the onshore shale industry.

In hopes of invigorating its shale efforts in the Northern Territory's McArthur Basin, Armour Energy agreed to a $130 million farm-in from Aubrey McClendon's American Energy Partners.

Onshore in the Perth Basin, AWE Ltd. made the final investment decision (FID) for Stage 1A of the Waitsia gas field development project in Western Australia, according to a Jan. 25, 2016, news release. Stage 1A includes installation and upgrades to existing assets that will connect the Waitsia-1 and Senecio-3 gas wells to the Xyris Production Facility. First gas is scheduled for August 2016.

AWE also is evaluating the potential for jointly developing the nearby Senecio/Synaphea/Irwin tight gas fields.

Moving offshore, Woodside, operator of the North West Shelf Project, said the project participants have approved the Greater Western Flank Phase 2 Project off the northwest coast of Australia.

The total investment for the project is expected to be about $2 billion, with initial project startup expected in second-half 2019.

AWE drilled the Senecio-3 well, which was the discovery well for the Waitsia gas field in the Perth Basin. The FID for Stage 1A of the Waitsia gas field development has been made. (Source: AWE Ltd.)

LNG projects

Subsea Engineering News reported in its Oct. 9, 2015, issue that Inpex Corp. launched its central processing facility (CPF) for the Icthys Field LNG development. The CPF is understood to be the world's largest semisubmersible unit and was officially launched from the Samsung Heavy Industries shipyard in Geoje, South Korea.

Once completed, the CPF will be towed 5,600 km (3,360 miles) to the Ichthys Field in the Browse Basin offshore Western Australia, where it will be permanently moored.

Inpex also submitted a revised development plan for its Abadi LNG Project in Indonesia's Arafura Sea, which calls for use of a larger floater than originally planned. The revised plan was awaiting approval by the Indonesian government.

Malaysia's *PFLNG 1* vessel, which will be renamed *PFLNG Satu*, was nearing completion in late August 2015.

The liquefaction plant was due onstream in early 2016.

At the same time, construction on the second and larger unit—*PFLNG 2*—is now well underway in partnership with Murphy Oil.

PFLNG 1 will be moored over the Kanowit gas field 180 km (108 miles) offshore Sarawak in 1,150 m (3,772 ft) of water. *PFLNG 2* is destined to be commissioned during 2018 and initially employed and centered on the deepwater Rotan gas field in Murphy-operated Block H, 130 km (78 miles) offshore Sabah.

Australia has a long list of LNG plants nearing production or an FID. For Woodside, Browse FLNG work continues on a range of activities related to the commercialization, timing and sequencing of FLNG development required to support an FID in second-half 2016.

The Wheatstone Project is more than 65% complete.

Recently Chevron signed heads of agreement (HOA) with two Chinese companies for delivery of LNG from Gorgon. The first HOA was a nonbinding agreement with ENN LNG Trading Co. Ltd. for delivery of LNG for 10 years, starting in 2018 or 2019.

The second nonbinding HOA was with China Huadian Green Energy Co. Ltd. When the agreement is finalized, China Huadian Green Energy is expected to receive up to 1 MMmt/year over 10 years starting in 2020.

New Zealand awards E&P permits

In mid-December 2015 the government of New Zealand awarded nine new oil and gas permits. The onshore and offshore permits are in the Taranaki Basin on the country's North Island.

Four offshore permits were awarded to OMV NZ Ltd. and Mitsui E&P Australia Pty. Ltd. A fifth offshore permit went to Todd Exploration and a sixth permit to Mont D'Or Resources Ltd.

Three onshore permits were granted to Petrochem Ltd., a unit of Greymouth Petroleum Ltd. E&P

Marlim—Brazil's original deepwater pioneer

More recent entrants into the upstream oil and gas industry might be forgiven for thinking that before Brazil's presalt bonanza began with the Tupi discovery in 2006, not much of global note had really occurred offshore Brazil.

Mark Thomas, Editor-in-Chief

That impression, however, is a misleading one. Those impressed that the giant Tupi (now named Lula) Field area will eventually feature a minimum of nine floating production facilities in a phased development should be even more dazzled by the fact that Petrobras has already done much the same before—about two decades previously.

The Brazilian national oil company discovered its deepwater Marlim Field in the Campos Basin in 1985, a pioneering time seemingly far removed from the very necessary and highly public bloodletting that is taking place today as Operation Car Wash continues to clean out the cancer of endemic corruption that has infected Petrobras over the past decade or so.

Although the country's offshore adventure began in the late 1960s in its shallower continental shelf waters followed by its more substantial discoveries during the 1970s in what was to become its Campos Basin heartland, it was its discoveries in the deeper areas of the Campos Basin in the mid-1980s that necessitated a step change in its approach to developing its resources.

Procap

Realizing that much of the technology that it needed to develop these deepwater fields simply didn't exist, Petrobras set up its Procap program—an initiative that would eventually see it become a world leader in this area.

Many of the company's major deepwater technology firsts took place on its 100%-operated Marlim Field complex, including the use of multiple floating production facilities, innovative subsea processing equipment and EOR techniques. Consisting of the field trio of Marlim, Marlim Leste (East) and Marlim Sul (South), they lie 110 km (68 miles) offshore Rio de Janeiro in water depths ranging from 610 m to 1,097 m (2,000 ft to 3,600 ft) in the northeastern part of the Campos Basin.

Marlim itself was found via exploration well 1-RJS-219-A in February 1985, with the probe encountering a 75-m (246-ft) thick Oligocene/Miocene turbidite reservoir covering an area of 137 sq km (56 sq miles). Holding an estimated 1.7 Bbbl of recoverable oil reserves (9 Bbbl oil in place), the field achieved a peak production of 586,315 bbl/d in 2002. Some 25 years after first oil was produced, Marlim is still pumping 390,000 bbl/d of oil.

The Marlim Field complex, discovered in February 1985, began producing in 1991 and currently has 12 deepwater floating production facilities spread over its reservoir, with the *P-53* on Marlim Leste one of the last to come onstream in late 2008. (Source: Petrobras)

Phased philosophy

To many observers Marlim perhaps best represents Petrobras' proven philosophy of developing its larger offshore assets in a phased manner, something that it has since replicated many times over up to the present day.

In the case of Marlim, a pre-pilot phase was undertaken using the *Petrobras 13 (P-13)* floating production unit (FPU) to flow two wells in March 1991 to both get vital insight into how the reservoir would produce and earn some early income to help toward the larger main development costs. The *P-13* produced for 14 months before being replaced by the *P-20* floater.

The first true "Phase 1" was split into two modules. Module 1 in 1994 saw Petrobras build a new semisubmersible production platform, the *P-18*, which was installed in 910 m (2,986 ft) of water over the northern part of the field. The facility produces via 16 production wells and 12 water injection wells. This was assisted by a converted FPSO vessel, the *P-32*, complete with an oil dehydration plant and offloading facilities and a storage capacity of 100,000 bbl/d.

Module 2 also focused on the field's northern area and saw a converted semisubmersible platform, the *P-19*, installed. Moored in 940 m (3,084 ft) of water, this facility has 12 production and seven water injection wells connected.

This was not all, as a further semisubmersible platform, the *P-33*, also was installed in the northeastern part of the field during the same "Module." The *P-33* came onstream in November 1998 via five satellite producer wells and three water injector wells.

The already-producing pilot phase vessel *P-20* also was then selected to be retained as part of the permanent development.

Phase 2

Almost simultaneously, Petrobras also brought on Phase 2 of the project. Made up of three further modules, this phase targeted the central and southern areas of Marlim.

Module 3 saw the converted *P-26* semisubmersible production platform installed in 990 m (3,248 ft) of water, coming onstream in early 1998 with a processing capacity of 100,000 bbl/d of oil. It produces via 12 production wells and eight water injection wells.

An FPSO unit was again employed for Module 4, with the converted *P-35* FPSO unit flowing as of May 1999 via 19 production wells and eight water injection wells tied back through two subsea manifolds. The turret-moored *P-35* is located in 860 m (2,822 ft) of water and has a processing capacity of 100,000 bbl/d of oil.

The next millennium saw Module 5 get underway with the installation of another converted FPSO unit, the *P-37*, in 1999. Moored in 905 m (2,969 ft) of water, the floater has a processing capacity of 150,000 bbl/d and is connected to 20 production wells and 15 water injection wells via four subsea manifolds.

A floating storage and offloading unit, the *P-47*, was added to the field in 2005 to ramp up the field's oil treatment capacity.

Although that was officially the end of the field's original planned development program, Petrobras then went on just four years later to add a further three FPUs to the field almost simultaneously—the 180,000-bbl/d converted *P-53* FPSO unit on Marlim Leste in November 2008; the 180,000-bbl/d newbuild *P-51* semisubmersible unit that came onstream in January 2009 on Marlim Sul; and the leased 100,000-bbl/d *FPSO Cidade de Niterói*, again on the Marlim Leste Field, less than two months later. The latter is the deepest of them all in terms of depth, sited over the Jabuti reservoir in waters about 1,400 m (4,593 ft) deep.

These three units added a further 50 wells to the Marlim Complex's total, 33 oil and gas producers and 17 water injectors.

Subsea world-first

Petrobras also has been proactive in employing innovative subsea technologies on Marlim, the most well-known being a world-first seabed separation system for deepwater heavy oil designed and built by FMC Technologies to help debottleneck production.

That $90 million contract saw the U.S. contractor supply a subsea module to separate the heavy oil, gas, sand and water at a water depth of 900 m (2,950 ft). The system reinjects the separated produced water to help counteract the mature field's naturally declining reservoir pressure. That means Petrobras did not have to opt for the more conventional alternative, which would have been to flow all the liquids, including increasing amounts of produced water and sand, to the surface for separation there.

The subsea separation, pumping and reinjection system first separates the gas from the liquids, then deals with the water by using a pipe separator design licensed and developed by FMC in cooperation with Statoil. The separation module also is retrievable to the surface, according to the company, making its maintenance and replacement less costly and disruptive. The system also incorporates its proprietary InLine HydroCyclone and DeSander modules for water treatment and sand management.

The separated gas is added back into the dewatered oil stream and sent on to the platform, while the treated water flows through the pump module for boosting and injection into the reservoir.

To a very real extent, Marlim has acted as a full-scale test bed for qualifying subsea separation equipment, a technology that is very much part of the industry's own ongoing drive toward realizing seabed production factories.

With a fleet of 12 floating facilities still producing via about 150 subsea production and water injection wells, Marlim represents a world-class development that has spanned more than two decades of successful and safe operations. E&P

Heerema's *Sleipnir* sets the pace

During what many believe is now the offshore industry's toughest ever downturn, vessel pioneer Heerema Marine Contractors has nailed its colors to the mast by building what will be the world's largest crane vessel.

With the continued growth in the size of offshore platforms and deepwater subsea equipment as well as an expected rise in the decommissioning of large production facilities, the need for greater offshore lifting capacity is pressing.

Despite the low oil price environment, Heerema Marine Contractors (HMC) is showing its faith in the long-term prospects for the offshore sector by proceeding with the building of a semisubmersible crane vessel at Sembcorp Marine's Jurong Shipyard in Singapore. Named *Sleipnir,* after the swift and strong eight-legged stallion of the god Odin from Norse mythology, the newbuild will have two powerful revolving cranes capable of lifting 10,000 metric tonnes each, both being designed and built by fellow Dutch company Huisman Equipment. The crane boom will have a length of 145 m (476 ft), and with the boom up, the crane will reach a height of 210 m (689 ft) above the waterline.

HMC said the self-propelled vessel—ready for operations by the summer of 2019—also will be used for the installation of subsea structures, foundations, moorings and deepwater floating structures.

Dual-fuel innovator

Interestingly, power will be generated by MAN Tier-III dual-fuel engines (marine gas-oil and LNG) from MAN Diesel & Turbo, the first time a vessel of this size will feature dual-fuel technology.

Twelve MAN 8L51/60DF four-stroke engines and 12 MAN SCR (selective catalytic reduction) systems will achieve a total power output of about 96 MW. MAN said that, with the exception of power barges, it will be one of the largest engine installations ever aboard a single ship, with the vessel to have four separate engine rooms. Engine delivery is scheduled for first-quarter 2017.

For station-keeping, the *Sleipnir* will use a dynamic positioning (DP3) or mooring system.

Like a number of other marine construction or transportation vessels coming onto or due onto the offshore market soon, this vessel is raising the bar in terms of scale. At a length of 220 m (722 ft) and width of 102 m (335 ft), the semisubmersible unit will be the world's largest crane vessel, HMC said, and the unit will help HMC meet demand for lifting capacities currently beyond what it can offer. With a large reinforced work deck, HMC said the *Sleipnir* also will be able to offer increased efficiency when installing or removing offshore facilities. The company already owns four of the world's largest heavy-lift vessels: *SSCV Thialf, DCV Balder, SSCV Hermod* and *DCV Aegir*. E&P

Vessel Facts	
Sector:	Marine Construction
Owner:	Heerema Marine Contractors
Name:	*Sleipnir*
Vessel Design:	GVA
Yard Built:	Jurong, Singapore
First Operations:	2019 (estimated)
Size (length/beam) overall:	220 m by 102 m (722 ft by 335 ft)
Topsides Lift Capacity:	10,000 metric tonnes each by two cranes
Transit Speed:	10 to 12 knots
Operating/Regional Arena:	Worldwide

HMC's dual-fuel Sleipnir semisubmersible unit will be the largest crane vessel in the world, with two Huisman revolving cranes each capable of lifting 10,000 metric tonnes. (Source: Heerema Marine Contractors)

For additional information on these projects and other global developments: READ MORE ONLINE EPmag.com

AFRICA

Africa Oil completes Kenyan farm-out deal with Maersk Oil

Africa Oil Corp. has completed a farm-out deal with Maersk Oil for Kenyan blocks 10BB, 13T and 10BA, Africa Oil said in a news release. At completion, Africa Oil received $427 million from Maersk. This amount represents $344 million of reimbursed past costs incurred by Africa Oil prior to the agreed March 31, 2015, effective date of the farm-out and $83 million representing Maersk's share of costs incurred between the effective date and Dec. 31, 2015, including a carry reimbursement of $15 million of exploration expenditures. An additional $75 million development carry might be available to Africa Oil upon confirmation of existing resources, which is expected to take place in first-quarter 2016. Upon reaching a final investment decision, Maersk will be obligated to carry Africa Oil for an additional amount of up to $405 million depending on meeting certain thresholds of resource growth and timing of first oil. Africa Oil now holds 25% interests in Kenyan blocks 10BB, 13T and 10BA. Maersk holds a 25% interest, and Tullow (operator) holds 50% interest in each of the blocks.

Sasol will develop new oil, gas fields in Mozambique

South Africa's Sasol has received the green light by Mozambique to develop more oil and gas fields in the southern African state, the company said on Feb. 1, without disclosing how much the project will cost, according to Reuters. Mozambique is sitting on huge gas reserves, and developing LNG export projects are expected to bring tens of billions of dollars to the impoverished state. The petrochemicals giant, which makes 40% of its revenue from oil, said the project, which is about 600 km (372 miles) north of the capital Maputo, will be rolled out in stages. The first phase will include an oil, LPG and gas project adjacent to its Pande and Temane fields. Natural gas from Pande and Temane fields, in which Sasol holds a majority stake, is currently produced and processed at a central facility before being transported through an 865-km (537-mile) pipeline to gas markets in Mozambique and South Africa.

Tullow launches new deepwater production vessel

Tullow Oil is sending one of the world's biggest floating deepwater oil production platforms to West Africa to pump crude for at least 20 years, Reuters reported. The 340-m-long (1,115-ft-long) production vessel was converted in Singapore from a very large crude carrier and was expected to set sail at the end of January to Ghana, where it is scheduled to gradually ramp up production from the TEN deepwater oil field from July/August 2016, the company's COO Paul McDade said.

ASIA

Gas flows at Chevron's Chuandongbei project in China

Chevron Corp.'s fully owned subsidiary Unocal East China Sea Ltd. began natural gas production from the first stage of the Chuandongbei project in southwestern China, a press release stated. Chuandongbei is one of the largest onshore gas projects developed by an international oil company and a national oil company in China. Jay Johnson, executive vice president, upstream, Chevron, said, "The project will be an important supplier of clean and affordable energy to the rapidly growing economy in southwest China." The Chuandongbei project covers more than 800 sq km (309 sq miles) in Sichuan Province and the Chongqing Municipality. Unocal East China Sea Ltd. holds a 49% participating interest as the operator, and China National Petroleum

The Nanba gas processing plant at the Chuandongbei Project in China is shown. (Source: Business Wire)

Corp. holds a 51% participating interest. The startup of the first train commences stage one of the project. Production is planned to ramp up over coming months as all three trains come online. The three trains have a combined design outlet capacity of 7.3 MMcm/d (258 MMcf/d) of natural gas. The Chuandongbei Project is estimated to contain potentially recoverable natural gas resources of 84.9 Bcm 3 Tcf).

AUSTRALIA

Fugro undertakes seabed investigations

Fugro has been awarded a combined geophysical and geotechnical project by Hess Exploration Australia Pty. Ltd. (Hess) to assist in Hess' activities in the Northern Carnarvon Basin offshore northwestern Australia, Fugro said in a news release. Fugro's work will include seabed and shallow geological investigations, including areas of difficult terrain. For the first phase of the survey, Fugro will use its Hugin 1000 AUVs to map the seabed. The data will be used to optimize planning for the subsequent sediment sampling phase, where a variety of techniques will be used. Fugro's geoconsultancy team also will deliver an integrated data model for input to Hess' ongoing analysis. The project is planned to take place in first-quarter 2016

Fugro is deploying one of its AUVs to map the seabed for Hess in the northern Carnarvon Basin. (Source: Fugro)

AGL will exit gas production business

AGL Energy Ltd., Australia's second largest energy retailer, said it will sell its gas E&P assets because of volatile markets, ending a decade-long attempt to diversify and resulting in a loss of nearly $460 million, Reuters reported. In a statement issued a week before it reports half-yearly earnings, the company said it decided to quit its wholesale gas production business in Queensland state because of "the fall in global oil prices with consequent effect on long-term gas prices."

EUROPE

Eni, Novatek receive 30-year Montenegro oil concessions

The Montenegrin government awarded 30-year concessions for oil and gas exploration in the Adriatic Sea to Italy's Eni and Russian No. 2 gas firm Novatek consortia, an economy ministry's spokeswoman said, according to Reuters. The concessions for four blocks have been awarded in line with the terms of a 2014 tender pending parliamentary approval, she said.

MIDDLE EAST

Saudi Aramco will keep same number of rigs in 2016, sources say

Saudi Aramco is expected to keep the same number of its oil and gas drilling rigs this year despite weak oil prices, industry sources said, according to a Reuters report. Saudi Aramco has asked oilfield service companies and suppliers again this year for discounts due to a slump in global oil prices. Saudi Aramco managed to make big savings last year on drilling costs, the sources said. "It is a normal situation in drilling activity," said one of the sources, who declined to be identified. Saudi Aramco is now operating about 212 oil and gas rigs, which is a level it has kept steady since 2015. That number does not include water rigs. "They want to maintain activity but reduce costs; there might be some movements by replacing offshore rigs to land or oil to gas," said a second source.

SOUTH AMERICA

CGG pursues survey work offshore Colombia

CGG has been awarded an extension to a major 3-D seismic survey it completed on the Caribbean coast offshore Colombia in late 2015, a news release stated. The new survey follows on from the original survey that covered more than 16,000 sq km (6,178 sq miles) over portions of the Col-1 and Col-2 blocks offshore Colombia. The extension was expected to start in February. The additional data will be processed in CGG's Houston subsurface imaging center. E&P

PEOPLE

Velocys Plc named **David Pummell** CEO.

Beach Energy Ltd. appointed **Matthew Kay** CEO, effective July 17 or such earlier date as is available and mutually agreed.

Guardian Global Technologies Ltd.'s CEO **Patrick (Paddy) Keenan** took early retirement and resigned as a director and officer of the company. Keenan's successor, **Emyr-Wyn Francis**, was previously the finance director and will assume the role of managing director.

Electromagnetic Geoservices ASA appointed **Hege A. Veiseth** CFO following the resignation of **Svein Knudsen**.

The board of SOCO International Plc announced the resignation of CFO **Anya Weaving**. Deputy CEO **Roger Cagle** will reassume the role and responsibilities of CFO.

Ithaca Energy Inc. appointed **Dr. Richard Smith** chief commercial officer.

Warren Resources Inc. named **John R. Powers** vice president, accounting.

MDU Resources Group Inc. selected **Peggy A. Link** as its CIO and **Anne M. Jones** as its vice president of human resources.

Lisa Mork Davis joined Industrial Scientific as director, advanced safety applications.

OFS Portal LLC welcomed **Mimi Stansbury** (left) as the new vice president of controls and administration, replacing **Randy Dutton**, who retired in January after more than 14 years as the senior vice president of control and administration.





BMT Group (BMT) has announced an internal reorganization: **Jan van Smirren** (top row, far left), who will lead the Energy Partnership, will join BMT in its Houston office; **Jeremy Berwick** (top middle) will take the lead for the Defense Partnership based in BMT's Bath, U.K., office; **Dr. Paul Wilkinson** (top row, far right) will take the lead for the Environment Partnership based in Brisbane, Australia; **Denis Welch** (bottom left) will take the lead for the Ports, Infrastructure & Resources Partnership based in Singapore; and **David Bright** (bottom right) will lead the Surveys, Ship Design & Vessel Performance Partnership.

Offshore Installation Services Ltd. named **Colin Shellard** managing director.



The board of directors of the Saudi Arabian Oil Co. (Saudi Aramco) made the following appointments: **Mohammed Y. Al Qahtani** (far left), senior vice president, upstream; **Ahmad A. Al Sa'adi** (middle), senior vice president, technical services; and **Muhammad M. Al Saggaf** (far right), senior vice president, operations and business services.

The International Association of Oil & Gas Producers appointed **Gordon Ballard** (left) executive director, effective Jan. 15. He succeeds **Michael Engell-Jensen**, who retired.

Borets named **David Langley** North American HSE manager.

Emco Wheaton has boosted its European sales team with the additions of **Olaf Stellberger** as global Marine Loading Arms sales manager in Emco Wheaton's Kirchhain, Germany, office and **Stefan Dubbledeman** joining the North and West Europe sales team as TODO sales manager.

IDC Energy Insights hired **Kevin Prouty** as vice president of research.

HTL, part of the HTL Group, appointed **Ian Mander** U.K. business manager.

Richard Edwards joined OPITO International's Houston office to help drive the adoption of common global safety training standards across the Americas.



Danos hired **Marc Distefano** (far left) as fabrication operations manager of the Amelia facility, **John Danos** (middle, no relation) as construction division general manager and **Jack Roszelle** (far right) as corporate quality director.

ACE Winches named **Lisa McPherson** human resources director.

Benthic selected **Chris Braithwaite** (left) chairman of the board of directors. **Russell Staley**, who has served as Benthic's interim chairman following the resignation of the late **John Smith** in August 2015, remains on the board as a director.

Tap Oil Ltd. appointed Tom Soulsby to the board of directors, with **Chris Newton** as his alternate.

Felix C. Spizale joined RedHawk Holdings Corp.'s board of directors.

Sembcorp Marine Ltd. selected **Eric Ang Teik Lim**, an independent director of the company, as a member of both the Executive Resource & Compensation

E&P

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Committee and Nominating Committee. **Bob Tan Beng Hai**, also an independent director of the company, was appointed a member of the Executive Committee.

Cameron Mitchell, technical disciplines assurance manager for Shell UK, and **Mark Richardson**, projects group manager for Apache North Sea, joined the board of Subsea UK.

COMPANIES

C&J Energy Services Casedhole Solutions opened its Giddings, Texas, facility to support regional pumping and acid services. The buildings were constructed on the eight-acre site at a cost of roughly $2.8 million and will serve as a regional office and maintenance hub for pumping and acid services. Onsite capabilities include a bulk acid plant as well as laboratory support for acid and stimulation services.

Wood Group is continuing to expand its automation and control business, establishing dedicated automation capabilities at Wood Group Mustang's Kuala Lumpur office to serve the Asia-Pacific market.

Trelleborg Sealing Solutions has opened a climate-controlled swivel-stack seal inspection facility for the

Trelleborg opened a seal validation facility in January in Barendrecht. (Source: Trelleborg)

validation of bespoke seals. The global facility is based in Barendrecht in the Netherlands and has been unveiled in a move to help ensure FPSO operators achieve the highest possible standards in seal quality. E&P

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How can the oil and gas industry perform better?

Imagine working on a 12-month project that starts with four months of solid planning.

David Squires and **Frank Sklenka**, LinRich Solutions

The global oil and gas industry is being challenged today perhaps like never before. Low oil prices, which first appeared to be a short-term inconvenience, now seem to be going even lower and might be around for much longer than we'd like. In the meantime, the industry still has very real financial performance expectations along with new—maybe extraordinary—regulations pending in the U.S.

Now more than ever the industry is required to perform better. So what can be done better right now to improve performance? In a word—planning.

Why planning? At its most fundamental level, the oil and gas industry drills holes in the earth, and the earth's strata and weather are not entirely predictable. It's this uncertainty that surrounds drilling, along with the nature of humans to constantly adapt to what's going on, that tend to trickle down throughout the supply chain. The result is an industry that is exceptional at reacting and creating innovative solutions for immediate problems. Where the industry sometimes falls short is planning for and applying solutions to prevent future problems.

Where the industry sometimes falls short is planning for and applying solutions to prevent future problems.

Planning starts with business case

How many projects are you working on right now where you really know the business case? What's the project going to cost, and what's the expected return on investment? What's the payback period? What value is being created? Who are the key stakeholders? What are the risks?

The business case must be known at various levels of detail throughout the organization, not just with management. It has to be communicated in a way that is relevant to stakeholders in their terms. They need to understand their role and how they can contribute to the project's success.

Planning requires a commitment to overhead and the resources required to ensure success.

The most successful projects that LinRich Solutions has been involved with had at least 30% of overall project time devoted to planning and risk management activities.

Imagine working on a 12-month project that starts with four months of solid planning. Managers who make this resource commitment can confidently prove the overall cost and time savings.

Many organizations in the industry "go through the motions" of planning and then succumb to the urge to "get going" or to "trim the fat." So they fail to work to solid business cases, breakdown structures, costed schedules and risk registers, and then they wonder why they're late and over budget and why their customers are angry.

Planning means identifying meaningful metrics

Many times project teams can look back on a failed project and see the warning signs that weren't properly acted upon. Maybe there was no sense of urgency. Maybe the means to measure status were not used or didn't even exist. On many projects, the team might think that they're making money or that they're on budget. But in the end, when it comes time to tally up the score, there is no profit.

Planning means having team of good partners

Do you have willing, helpful and committed partners? Do they believe in constructive, task-oriented conflict? Do they willingly share in both the risks and rewards? Are they committed to succeed, and are they working to metrics that are measured in their terms? Do you know how your project affects their cash flow?

We've never been involved with a successful project or profit and loss where the client thought that there was too much planning. As low oil and gas prices continue and companies seek ways to cut costs, we're firmly convinced that the way to improve performance is to insist upon better planning. E&P